THE 2006 PRUDHOE BAY SHUTDOWN: WILL RECENT REGULATORY CHANGES AND BP MANAGEMENT REFORMS PREVENT FUTURE FAILURES?

HEARING

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

ONE HUNDRED TENTH CONGRESS

FIRST SESSION

MAY 16, 2007

Serial No. 110–46

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energycommerce.house.gov

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U.S. GOVERNMENT PRINTING OFFICE

41–657 PDF WASHINGTON : 2008

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512–1800; DC area (202) 512–1800
Fax: (202) 512–2104 Mail: Stop IDCC, Washington, DC 20402–0001

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THE 2006 PRUDHOE BAY SHUTDOWN: WILL RECENT REGULATORY CHANGES AND BP MANAGEMENT REFORMS PREVENT FUTURE FAILURES?

WEDNESDAY, MAY 16, 2007

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON OVERSIGHT
AND INVESTIGATIONS,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 9:30 a.m., in room 2123 of the Rayburn House Office Building, Hon. Bart Stupak (chairman) presiding.

Members present: Representatives Melancon Green, Schakowsky, Inslee, Dingell, Whitfield, Walden, Burgess, and Barton.

Staff present: John Sopko, Scott Schloegel, Chris Knauer, Richard Miller, Rachel Bleshman, Alec Gerlach, Jodi Seth, Alan Slobodin, Dwight Cates, and Matthew Johnson.

OPENING STATEMENT OF HON. BART STUPAK, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. STUPAK. The hearing on the "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" will come to order. Each Member will be recognized for 5 minutes for an opening statement. I apologize to everyone. We are waiting for one or two Members who are stuck in traffic. They should be here soon, including chairman of the full committee, as he wants to participate in this hearing. So we started a little bit late today. I will begin with my opening statement.

On March 2, 2006, BP discovered that oil was leaking from a major transmission pipeline responsible for connecting its west oil field with the Trans-Alaskan Pipeline. Almost 200,000 gallons of crude spilled out of the pipeline and became the largest spill in Prudhoe Bay history. Prudhoe Bay oil field is the Nation's largest and most strategic oil field producing 400,000 barrels a day. What started as a single oil spill ended in the shutdown of the entire Prudhoe Bay oil field. As a result, the Nation faced a significant reduction, almost 8 percent, of its domestically-produced oil supply. This shutdown caused a severe spike in oil prices.

This committee's investigation into the failures of BP's Alaska operations began shortly after the Department of Transportation issued its March 15, 2006 Corrective Action Order. The CAO mandated that BP smart pig a number of key pipelines, including the Western Operating Area and the Eastern Operating lines.

At last year's September 6 Oversight and Investigations Subcommittee hearing, a number of key questions were posed to BP about its Alaska pipeline maintenance and safety. Among the key questions raised at that hearing was: "What role did cost-cutting play in managing the field and did it have any affect on whether to smart pig or maintenance pig the critical transit lines that ultimately led to the field's shutdown?" The committee members also posed a number of organizational and management question on how BP's pipeline maintenance decisions were made. Members were assured by BP that cost cutting measures did not affect maintenance and a lack of maintenance did not cause the oil leak.

Today's hearing was originally intended to be an update as to what corrective actions BP, as well as State and Federal agencies, had taken to improve conditions at Prudhoe Bay. Unfortunately, as a result of recent documents produced to the committee, we will also need to revisit the issue of what caused the leaks.

In the 6 months since our last hearing, a number of new developments have occurred, including a reorganization of BP's Alaska management structure and personnel, as well as the engineering and rebuilding of key pipelines. Evidence shows that severe cost cutting pressures existed between 1999 and 2005, which may explain why pipeline corrosion mitigation activities were never undertaken.

Several thousand documents recently provided by BP shed additional light on how the Prudhoe Bay oil field was managed. Some of these documents were actually available to BP officials before, before the September 6 hearing, yet BP failed to disclose this information to the committee. These documents show that cost cutting pressures on Prudhoe Bay operations were sever enough that some BP field managers were considering reducing or halting the range of actions related to preventing or reducing corrosion.

For example, some documents detail proposals to cut funding for corrosion inhibitor. These documents show that proposals were made between 1999 and 2004, and in such locations as the "produced water" lines which we understand are highly susceptible to corrosion. Documents also suggest that corrosion monitoring efforts such as smart pigging, coupon pulling and digging up crossroads for visual inspections were reduced or put on hold because of budgetary pressures. This was occurring while BP received more than $106 billion in profits. The documents further show that BP's Corrosion, Inspection and Chemicals Group, CIC Group, was under extreme pressure to constantly find new ways to cut costs.

For instance, one e-mail from October 2001 said, and I quote,

> As you know, we are under huge budget pressure for the last quarter of the year and therefore we have to take some rather disagreeable measures. Can you please implement the following changes/reviews:
>
> Shut down the PW, this is produced water lines, inhibition systems for the remainder of the year.
>
> Discontinue the additional corrosion inhibitor for velocity control.
>
> These need to happen as soon as possible.

The author of this e-mail refused to testify at the September 6 hearing and instead took the fifth amendment. While it is not known if specific activities as referenced in this e-mail occurred, other e-mails and documents show BP field managers were being asked to choose between saving money and critical maintenance.

BP recently released to the committee a major audit conducted by Booz Allen Hamilton which attempted to answer key questions on why last year's shutdown occurred. The audit assessed both management and processes which led to the corrosion and the failures of the Oil Transit Lines. The Booz Allen Hamilton report also found weaknesses in the way BP's Alaska unit was structured. The Booz Allen Hamilton findings included the following:

There was no formal holistic risk assessment for pipeline integrity.

BP's corrosion management strategy was developed in the late 1990's and had not been substantially reviewed or revised until recently, despite specific direction to do so in a 2004 internal audit.

BP's Alaska team often operated in vertical silos and there was little sharing of technical knowledge outside of Alaska or even across key business segments within Alaska.

BP's information technology infrastructure was fragmented and weak, making data analysis on key areas of the system difficult or impossible.

While some credit should go to Booz Allen Hamilton for identifying a number of weaknesses in BP's management of Prudhoe Bay operations, it also failed to answer why certain decisions were made or more importantly, not made. It also failed to explain why some of the field's key operational assets, such as the transit lines, were allowed to corrode and were not smart-pigged.

Two other reports about BP were also finalized since our last hearing. These include the Report of BP U.S. Refineries Independent Safety Review Panel, known as the Baker Panel Report, and the U.S. Chemical Safety and Hazard Investigation Board, CSB, report.

These reports focused on the 2005 Texas City refinery explosion, which resulted in 15 deaths and 180 injuries, as well as the other four BP refineries in the United States. The findings of these two reports have relevance to BP Alaska operations and they also explain what went wrong at Prudhoe Bay. We will hear today from the Chemical Safety Board that "There are striking similarities in the reported causes of the 2006 pipelines and the 2005 explosion at the BP Texas City refinery." In fact, as reported by the Chemical Safety Board, most, if not all the seven root causes that BP consultants identified for the Prudhoe Bay incidents have strong echoes in Texas City. These include the checkbook mentality of cost cutting where budgets and funding were largely based on affordability as opposed to necessity and were not supported by an analytical process to prioritize risk.

It is the committee's understanding that considerable design and construction work has already gone into rebuilding the systems that failed at Prudhoe Bay. BP should be applauded for their reconstruction. Nevertheless, we will hear from Department of Transportation and the State of Alaska on how these efforts are progressing, whether it believes BP's physical problems have been solved and how it will prevent future failures.

Within the past month, for example, the State of Alaska created the Petroleum Systems Integrity Office, which will attempt to serve as a bridge between the various State and Federal agencies now responsible for regulating Prudhoe Bay operations. The coordinator for that office will also testify today. We look forward to understanding how this new organization differs from what was used in the past and whether it will be more effective in regulating pipeline and oil production operations.

Roughly 6 months ago, BP president Bob Malone made a commitment to this committee that he would return to provide a progress report. I am pleased that he is before us, but I want to know is about Booz Allen report's findings; how senior management intends to restructure Prudhoe Bay operations so pipeline failures are not repeated and how the contributing factors which led to the tragic Texas City explosion reflect on the failures at Prudhoe Bay. Also, one of the primary findings in the Chemical Safety Board report was that cost cutting and budget pressures from BP executive managers impaired process safety at Texas City. BP's Health, Safety and Environment Business Plan for 2005 warned that the refinery would "kill someone in the next 12 to 18 months if changes were not made." Nonetheless, BP's Group Refining Management executives issued a 25 percent reduction challenge.

An internal BP document found and again, I quote, "A culture that evolved over the last years at Texas City seemed to ignore risk, tolerated non-compliance and accepted incompetence." It found that the Group Vice President for Refining "was well aware of under-investment at" Texas City refinery and failed to draw the necessary inferences from the warning signals, such as a 2002 report which found that there was potential for a major site incident. Isn't under-investment essentially a polite way of saying we will cut costs without regard to safety? Similarly, documents made available to this subcommittee suggest that BP field managers were under extreme pressure to cut costs in Alaska. E-mails and budget challenges paint an environment of extensive cost cutting to save money in the Prudhoe Bay operations.

While some may argue that these activities did not relate to the shutdown or any given spill, my review of the mountain of circumstantial evidence can only lead me to conclude that severe pressure for cost cutting did have an impact on maintenance of the pipelines. With such severe pressure to reduce costs, would a pipeline manager have been able to propose excavating the low points to examine for corrosion? Would a manager be allowed to smart pig or maintenance pig the oil transit lines? These corrosion maintenance activities are very expensive. In an atmosphere where managers were contemplating shutting down corrosion inhibitor to save money, I doubt the high costs associated with these proposals would have been tolerated.

This investigation has been difficult. Documents which should have been produced half a year ago were not made available to us until a few weeks ago and more seem to roll in each day. In fact, over 800 pages were provided to committee staff at 8:00 p.m. last night. The committee's findings thus far paint a picture of how cost cutting impacted the way the oil field was run. There are dozens of documents showing how employees, because of budget pressure from management, struggled to make the right call when it came to meeting the bottom line or to maintain pipeline integrity.

Perhaps most cynically, budget pressure was being exerted during the 1999–2006 time period when BP earned more than $106 billion in after-tax profits. As a result of BP's poor management of Prudhoe Bay, the public are the ones who ultimately are left footing the bill as the costs of supply interruptions are passed on to them in the form of higher prices at the pump. This practice of record high corporate profits coupled with continued cost cutting and neglect of infrastructure must end. The atmosphere of little accountability, minimal penalties and no financial risk due to the fact that oil companies merely heap their additional costs onto the backs of consumers at the pump, will not continue to be tolerated by this Congress or the American consumers.

This committee will continue to investigate BP's management of this strategic oil field and as more documents become available, additional hearings may be warranted. I just hope BP does not turn into the Los Alamos of the north.

And with that, I would yield time for opening statement to my friend, Mr. Whitfield, from Kentucky.

OPENING STATEMENT OF HON. ED WHITFIELD, A REPRESENTATIVE IN CONGRESS FROM THE COMMONWEALTH OF KENTUCKY

Mr. WHITFIELD. Thank you, Chairman Stupak, and this morning we revisit the topic that the Oversight and Investigation Subcommittee examined at some length last fall at a September 7, 2006 hearing. BP was and remains today responsible for the operation and integrity of the transit lines as they move crude oil from the wells on the north slope to the Trans-Alaska pipeline system. Specifically, BP-Alaska has operational unit known as the Corrosion, Inspection and Chemicals Group that is directly responsible for monitoring and mitigating pipeline corrosion.

During our investigation last year, we learned that a key component of this corrosion control program had been neglected with respect to the transit lines, a practice known as pigging, where devices are placed into the pipelines to clean out sludge, sediment, sand and other material. Smart pigs, on the other hand, provide pipeline operators with a comprehensive picture of internal and external corrosion of the pipelines. The western transit pipeline that leaked in March 2006 had not been pigged since 1998 and the eastern transit pipeline that leaked in August 2006 had last been pigged in 1991.

Documents recently produced to the committee by BP reveal that employees had discussed pigging the transit lines on many occasions, but the idea was routinely rejected. We were stunned that BP's transit pipelines, which transport one of the country's most vital domestic resources of crude oil, had been allowed to deteriorate to such a state. BP testified that they thought their corrosion and monitoring program was state-of-the-art and that pigging transit lines was not imperative. Obviously, that judgment was wrong.

In fact, some of the testimony by Admiral Barrett, the head of DOT's Pipeline and Hazardous Materials Safety Administration at that time, is worth repeating here. He said typically, up on the north slope and generally in the industry, he would see maintenance pigs every couple of weeks, certainly every couple of months, but never on these lines. Last year we sought to understand exactly what BP knew and when they knew it and what steps the company would take to adequately respond to the concerns raised by its own employees, as well as others.

We wanted to know why the transit pipelines were not properly maintained and did budget pressures lead to decisions that resulted in the neglect of these lines. BP has recently provided the committee with over 5,000 pages of documents related to these questions and as Chairman Stupak pointed out, many of these documents were available to them last September. And so we are disappointed that BP decided to withhold these documents for so long. However, the documents do provide insight on the cost pressures faced by pipeline safety managers that may have led to bad decisions on corrosion management. And these questions need to be explored more fully today.

We also look forward to testimony from the representatives of the Pipeline and Hazardous Materials Safety at DOT today, as well as the Chemical Safety Board and OSHA, as well as the Alaska Department of Natural Resources is represented here today, as well. We look forward to their testimony. We also welcome back Mr. Bob Malone, president of BP America and look forward to what he will say about BP's plans for future operations at Prudhoe Bay and at BP facilities around the country.

At a time when the American people are paying the highest prices for gasoline in a long time, and when the American people are consuming around 22 million barrels of oil every day, we do not have any margin of error for maintenance problems in this industry. And we want to make sure that the production and the transportation and the refining and the distribution is working the way it is supposed to work in order to protect our economy and to shield the American people from higher fuel prices.

So we look forward to the testimony as we all work together to address the serious issues facing our country and thank you again, Chairman Stupak, for having this hearing. I yield back my 19 seconds. Thank you, Mr. Chairman.

Mr. STUPAK. Mr. Melancon for an opening statement.

OPENING STATEMENT OF HON. CHARLIE MELANCON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF LOUISIANA

Mr. MELANCON. Thank you, Mr. Chairman. I appreciate it. Prudhoe Bay is an important component of our Nation's domestic energy supply, producing roughly 8 percent of domestic oil and gas. I do have an understanding of energy producing regions of the country and of energy production. As you may know, I represent much of the energy producing Gulf Coast of Louisiana, as my friend, Mr. Green, next to me, and we produce roughly 30 percent of our domestic supply of oil and gas out of the Gulf of Mexico.

The impact of shut in production during Hurricanes Katrina and Rita rippled across our Nation's economy in the form of higher prices at the pump for all Americans. Similarly, a shutdown of the distribution system in the oil fields of northern Alaska have disrupted supply. The Prudhoe Bay shutdown pushed the price of oil above $70 a barrel and gasoline above $3 a gallon. Because of tightly balanced supply and demand in the world markets and a lack of refining capacity in the United States, even a small disruption in supply can impact all our constituents' wallets.

As we speak, retail gasoline is climbing above a $4 threshold in parts of the country. Continued high prices have created a market dependent on production in unstable and dangerous regions of the world. We live in a time when a crude oil pipeline explosion in Nigeria will impact the downstream prices at the pump in New York City. Our energy supply is intertwined, tightly balanced and vulnerable to events far beyond our control. Because of geopolitical instability and consistent volatility in the prices, I believe that securing our domestic energy supply should be one of our Nation's top priorities. America's enemies know that creating a supply disruption like the refinery explosion in Texas City can take as much as 400,000 barrels a day out of the market.

What we have learned from the Chemical Safety Board investigation in Texas City, the Baker Panel Report on BP's five U.S. refineries, the BP-sponsored Management Accountability Project evaluation related to the Texas City refinery explosion and the Booz Allen report on Prudhoe Bay pipeline leaks is that the same kind of supply disruptions threatened by terrorists can result from underinvestment in basic refining maintenance, corrosion protection of critical pipelines and management's failure to keep hydrocarbons inside the pipes using long established process safety management.

Prudhoe Bay and the Gulf must keep producing, no matter what, in order for our economy to enjoy prosperity and our energy supply to remain secure. That means that BP and its working interest owners should not be making short-terms tradeoffs between cost cutting to boot the bottom line, and necessary investments in safety and pipeline integrity. I am glad that BP has been accessible in its dealings with the subcommittee and your recent efforts to disclose information requested is appreciated. However, I share some concerns of the committee about the speed in which documents have been produced.

Furthermore, I understand that many answers still remain illusive and we will ask many questions here today and hope that we will get honest and deliberative answers. I would like to thank the witnesses for appearing today and I am looking forward to learning more about the Prudhoe Bay and Texas City incidents and what BP is doing to learn from these past mistakes. Thank you, Mr. Chairman.

Mr. STUPAK. Thank you, Mr. Melancon. Mr. Walden, please, for an opening statement.

OPENING STATEMENT OF HON. GREG WALDEN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF OREGON

Mr. WALDEN. Thank you, Mr. Chairman. Thank you for providing this hearing for us, a follow-up from the one that I chaired last year. The leaks we deal with here in Washington generally don't hurt the environment, but leaks in oil pipelines in Alaska and elsewhere can and do and that is why we are here today, to figure out what went wrong, why did it go wrong and how do we make sure it doesn't happen again, to the best of our human ability. Because we want to make sure the environment is protected and that the flow of oil can proceed safely and efficiently. So I look forward to learning more about what went wrong, why it went wrong and what we can do to fix it so it doesn't happen again.

Why were alarms ignored when they went off? Why is somebody driving along the pipeline has to sniff out the hydrocarbons, since they are already leaking? How do we make sure that doesn't happen again? So Mr. Chairman, I look forward to hearing from our witnesses and the questions that we have to ask them and I thank you again for holding this hearing.

Mr. STUPAK. Thank you, Mr. Walden. Mr. Green for an opening statement.

OPENING STATEMENT OF HON. GENE GREEN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. GREEN. Thank you, Mr. Chairman, for holding the hearing and I want to welcome our panelists today. I especially want to welcome Ms. Merritt and thank you for the job you have done and your staff has done at the Chemical Safety Board on this particular issue. This issue is probably one of the most important in the district I represent in Texas, where we have both refineries, chemical plants and pipelines that play such an important part of our life and our local economy and of course, in the economy of our Nation.

As the father of two children, I have tried to teach them many life lessons; one of them, the most important, is when you make a mistake, you find out why you made that mistake and you learn from that experience. We must ask ourselves what went wrong and how can we improve and how can we emerge stronger than before. I hope today's hearing helps shed some light on whether BP America, the Occupational Safety and Health Administration and other industrial players learn from the mistakes of the past to help protect the health and safety of America's workers and maintain the integrity of our Nation's critical energy infrastructure.

Although unfortunately, I do not believe all the lessons have been learned from the accident in Prudhoe Bay nor the accident that hit home in Texas City. On March 15, 2005 an explosion at BP's Texas City refinery took 15 lives. One of them was a constituent of mine from Baytown, Texas, and injured 180 others. This was the worst workplace disaster since 1990, one that still affects the lives of these families who lost loved ones in the blast.

And I believe we look back at 1990, there was a chemical facility in Pasadena, TX, that is in our district, that exploded, which means this I take very seriously and I think between Charles Melancon and I, there is not two Members who are closer to the energy industries, because it is our tax base and our job base. But if you are making lots of money like BP does, no matter what company you are, and you are cost cutting and you are causing the lives of 15 people to be lost or product to be left out on the tundra in Alaska, you have to be answerable for it and that is why we are here today and I just wish we also had oversight in our committee on OSHA, because obviously they are not doing their job, either.

But I will let the Committee on Education and Labor take care of that with our encouragement.

The U.S. Chemical Safety Board, an independent agency that investigates major chemical accidents, completed the most thorough investigation in its history of the accident in Texas City and came up with several important conclusions. Cost cutting, failure to invest and production pressures from BP management, in the safety performance, BP did not provide effective oversight of its safety culture and major accident prevention program.

BP lacked an effective culture to report safety concerns and OSHA should increase inspection and enforcement at all U.S. refineries and chemical plants should require these corporations to evaluate the safety and impact of mergers, reorganizations and downsizing. As a result of the investigations, CSB has made new recommendations to BP board of directors, OSHA and others to rectify inherent flaws and discrepancies that led to the disaster.

I hope today's testimony and the question and answer will determine that those recommendations are followed. Although I have to admit, last summer I was at a plant in my district and I asked, touring that plant, I said seems like that construction shack is pretty close to the unit and I was told we are getting ready to move that. I said this last year at the hearing and I am saying it today, BP cost 15 peoples' lives and 180 injured. Those of us who work and live in the energy industry need to know we need to learn from the mistakes that BP made. And if they haven't moved those shacks now, that should be done; should have been done right afterwards.

After reviewing the recommendations, I introduced H.R. 141 in this 110th Congress and it seeks to require more accurate injury and accident logs for all employees, including contract workers at these sites across the country. These site logs, I believe, will better enable OSHA to determine which sites need inspection to protect workers' safety. When I found out that in the energy industry, so much of our work is now done by contract workers, but when that injury for that worker or death is not counted on that site, something is wrong.

One of the most startling conclusions I have come to realize, since reviewing BP's two major accidents, is many of the fundamental causes in Texas City and the exact same causes found in Prudhoe Bay almost 1 year later and obviously, we have a lesson that is lost. Whether BP's operations are in Alaska or Texas or anywhere in our country, Congress expects BP to invest in the necessary resources to protect human life and the environment and our economy and we should do all we can to ensure the commitment be followed through for the American people. These actions come at a most unfortunate time. One of the Congress's top priorities includes addressing climate change and believe an important part of this piece will be ensure adequate oil and natural gas production to provide affordable, reliable energy for U.S. consumers.

Incidents such as we are going to discuss today breeds on that distrust citizens already have in the high energy prices and apparent neglect that certain energy companies are providing to their workers in the infrastructure. Mr. Chairman and ranking member, thank you again for holding this hearing and I know we held one last year and I hope we will continue to do this because we make things in my district that are volatile and I want to make sure we use every safety precaution we can to protect my constituents, and I yield back my time.

Mr. STUPAK. Thank you. Mr. Burgess for an opening statement, please.

Mr. BURGESS. Thank you, Mr. Chairman. I have a prepared statement that I will put into the record, but let me just say, when we had this hearing last September and we specifically left out anything that dealt with the Texas City accident. I thought that was an oversight by the Oversight Committee. I thought we should have included the fact that there were 15 people lost in Texas. We should have included the facts of that accident as part of our hearing last September, so I am grateful that now we do have the chairman of the U.S. Chemical Safety Board to testify before us this morning and certainly, in reading through that testimony in preparation for this hearing, it does come up that there apparently were striking similarities between the accident that occurred in Texas City and the conditions that led to the non-inspection of the transfer lines in the Prudhoe Bay area that led to the hydrocarbon leaks on the north slope.

So I think this is getting at the essence of the critical heart of the problem. I obviously am anxious to hear BP's answer to some of the issues that have been raised, but I agree with my colleague from Texas that it is not just because those were Texans that were lost, but we all have an obligation to protect lives and safety and welfare of our constituents and while energy is of vital importance to our country and at no time in our country's history has it been more important than it is right now, we must not ignore the safety concerns for the people who provide us the ability to have that energy. So thank you, Mr. Chairman, for holding the hearing and I will yield back the balance of my time.

Mr. STUPAK. Thank you, Mr. Burgess. Texas City, as I made in my opening statement and we will hear today, there were so many similarities of management between what happened in Texas City and Prudhoe Bay, I think that is why you see greater emphasis upon it at this hearing and appreciate your input at this hearing.

Mr. Inslee, I think, is next for an opening statement, please.

Mr. INSLEE. Thank you. I will reserve my time, Mr. Chairman.

Mr. STUPAK. Ms. Schakowsky.

OPENING STATEMENT OF HON. JAN SCHAKOWSKY, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Ms. SCHAKOWSKY. Just a couple of things. I was at the hearing last September and so of course, I am very much looking forward to seeing the kinds of changes that were made, but I am looking now at the reports that BP commission from Booz Allen to examine the root causes of both Prudhoe Bay and the Texas City disaster. The No. 1 cause would be of deep concern and great surprise to my constituents who are now paying \$3.49–\$3.59 in Chicago for gasoline. The first is BP had a "deeply ingrained cost management ethic" as a result of low oil prices. That was last year and oil prices, gas prices were still pretty high then and for the Prudhoe

Bay and for Texas City, cost cutting and budget pressures from BP Group executive managers impaired the process.

Really, we are talking about record high oil prices and that is not new this year. We had this surge in prices last year, as well. I think people who are filling their tanks are expecting a little bit more, perhaps a lot more from British Petroleum, from BP, in the way of spending the necessary money to prevent these kinds of accidents and devastating oil leaks that do such damage to our environment. So I am looking forward to seeing what progress has been made and I want to commend our chairman. All too often we have hearings on a topic and reveal a problem, but sometimes we don't get back and check up and see how things have progressed, so I really appreciate this hearing today, Mr. Chairman, and I yield back my time.

Mr. STUPAK. I thank the gentlelady. Seeing no other Members who wish to be recognized, at this time I am going to ask unanimous consent, if it is OK with you, Mr. Whitfield, to, if Mr. Dingell or Mr. Barton comes for an opening statement, we will accommodate them when they arrive? Without any objection, so ordered.

That concludes the opening statements by members of the subcommittee and I will call our first panel of witnesses. Stacy Gerard, Assistant Administrator of the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration; Ms. Jonne Slemons, coordinator of the Petroleum Systems Integrity Office at the Alaska Department of Natural Resources; Ms. Carolyn Merritt, Chair and CEO of the U.S. Chemical Safety and Hazard Investigation Board; Mr. Richard Fairfax, Director of the Enforcement Programs at the Department of Labor's Occupational Safety and Health Administration.

I welcome the witnesses to the committee. It is the policy of this subcommittee to take all testimony under oath. Please be advised that witnesses have the right under the rules of the House to be advised by counsel during their testimony. Do any of our four witnesses before us wish to be represented by counsel at this time? All indicating no. Therefore, I would ask if you would please rise and raise your right hand and take the oath.

[Witnesses sworn.]

Mr. STUPAK. Let the record reflect that the witnesses replied in the affirmative. They are now under oath. We will begin with our opening statement. Ms. Merritt, you are on my left. We will start with you, please, if you would, for 5 minutes.

Ms. MERRITT. Thank you.

Mr. STUPAK. Excuse me a minute. We said that we would accommodate either Mr. Dingell or Mr. Barton. Chairman Dingell, has arrived and he has been very active in this investigation, so if you may, I will ask you to hold a minute. We will turn to the chairman of the full committee, Mr. Dingell, for an opening statement. Please, sir.

OPENING STATEMENT OF HON. JOHN D. DINGELL, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Chairman DINGELL. You are most gracious. Thank you.

The hearing today was supposed to be a simple follow up of last September's hearing that concerned the shutdown of the Prudhoe Bay field. This committee was preparing for today's hearing at that time. However, a number of documents were recently discovered by British Petroleum and turned over to us; for that, we commend them. These documents clearly shed new light on the cause of the Prudhoe Bay failures and raise questions about the testimony of BP officials who appeared least year.

They suggest that cost cutting drove many key management decisions in the Prudhoe Bay field and dovetail with a number of reports that surfaced since last year's hearings that also raise serious questions about BP management. One study conducted by the Chemical Safety Board found that severe cost cutting contributed to the refinery explosion in Texas City that killed 15 people.

These new documents and reports strongly suggest that BP field managers were asked to consider trimming key activities related to halting or mitigating corrosion to meet very tight safety and maintenance budgets. For example, we recently found an e-mail that discusses corrosion inhibitor and how it would prevent corrosion in the produced water lines. It reads, in part, that, and I quote now,

> Due to budgetary constraints, the decision has been made to discontinue the inhibitor currently being injected at Gathering Center 2 and Gathering Center 3. The bulk tank should run out within the next 2 days and will not be refilled.

What is particularly interesting is a follow-up e-mail that suggests that BP staff were aware that this would increase corrosion. The e-mail reads as follows, in part:

> FYI-We have conducted the field trial of the produced water inhibition chemical and found it to be very successful at cleaning up the system and arresting corrosion activity. Unfortunately, we did not budget a full year's chemical expense. We are now at a point where the original monies for this program are used up, so we will be shutting it down until year's end. In the meantime, the produced water system may be subject to increased corrosion activity and fouling.

Mr. Chairman, these e-mails are quoted because they capture the essence of what went wrong with Prudhoe Bay. Workers were often forced to forego safety measures to save money and to ultimately increase BP's profits. Other e-mails that we recently uncovered refer to stopping or halting other key corrosion inspection programs, including smart pigging, looking for corrosion under the insulation that covers and thus hides the pipe, and digging up key road crossings where corrosion can be a significant problem. These are all key activities in running a safe field. Yet these programs, in many cases, appear to have been halted or cut due to budgetary reasons.

This is the core of what we have learned about the way British Petroleum managed Prudhoe Bay. Until BP fully acknowledges the role cost cutting and budget pressure played in creating this mess, I fear other problems like this may be occurring at other BP facilities throughout the United States. At a time when oil and gas prices are again squeezing consumers, it is critical that we keep a vigilant eye on how these precious resources are managed. As the largest oil field in North America, oversight of Prudhoe Bay's management is a wise investment of the committee's time and attention.

I thank you for holding this hearing, Mr. Chairman, and I look forward to today's testimony. I yield back the balance of my time.

Mr. STUPAK. Thank you, Mr. Chairman, for your opening statement.

Ms. Merritt, we will begin with you now. I remind the witnesses that they are under oath, including your opening statement. Please start.

TESTIMONY OF CAROLYN MERRITT, CHAIR AND CHIEF EXECUTIVE OFFICER, U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

Ms. MERRITT. Thank you, Mr. Chairman, Ranking Member Whitfield and the distinguished members of the committee. I am Carolyn Merritt, Chairman of the U.S. Chemical Safety Board. The Chemical Safety Board is an independent, non-regulatory Federal agency that investigates major chemical accidents. Today, I speak as an independent member of that board.

The CSB recently completed a 2-year investigation of the disaster at the BP Texas City refinery, which killed 15 workers, injured 180 and was the worse U.S. workplace accident since 1990. On March 23, 2005 a distillation tower and blowdown drum were flooded with highly inflammable hydrocarbons, causing a massive explosion and fire that filled workers in a nearby trailer. This accident was the direct result of organizational and safety deficiencies at all levels of the BP Corporation.

At the committee's request, we reviewed the Booz Allen Hamilton report on Prudhoe Bay and compared its findings with our own. Mr. Chairman, there are striking similarities in the reported causes of the BP Prudhoe Bay pipeline incident and the BP Texas City explosion. Virtually all of the seven root causes identified for the Prudhoe Bay incidents have strong echoes in Texas City. Both reports point to the significant role of budget and production pressures in driving BP's decision-making and ultimately harming safety. Our report describes what BP itself called a "checkbook mentality." Budgets were not large enough to control known risks, but spending was nonetheless limited to the budgets provided.

Cost considerations led to drastic staffing and training cuts and even dissuaded BP from replacing its antiquated blowdown drums with an inherently safer flare system, which likely would have prevented this accident. Both investigations found deficiencies in how BP managed the safety of process change. The Booz Allen report speaks of a "normalization of deviance where risk levels gradually crept up due to evolving operating conditions."

In BP Texas City, abnormal startups were not investigated and became routine, while critical equipment was allowed to decay. By the day of the accident, the distillation equipment had six key alarms, instruments and controls that were malfunctioning. Trailers had been moved into dangerous locations without appropriate safety reviews.

In Prudhoe Bay, BP's internal audit findings faced "long delays in implementations, administrative documentation of close-out even though remedial actions were not actually taken, or simple noncompliance." In Texas City, the closure rate for action items from incident investigations was only 33 percent and maintenance personnel were authorized to close job orders even if no work had been completed. Other common findings include flawed communication of lessons learned, excessive decentralization of safety functions and high management turnover. BP focused on personal safety statistics but allowed catastrophic process safety risks to grow. I describe all these commonalities in greater detail in my written statement.

Finally, the CSB investigation included an analysis of OSHA's role in enforcing safety rules at refineries and chemical plants. We found that OSHA did not conduct any comprehensive, planned process safety inspections at the Texas City Refinery or any U.S. refinery for at least 10 years prior to this event. Other jurisdictions, including the United Kingdom, and California's Contra Costa County, are doing comprehensive regular inspections each year of major oil and chemical facilities every 3 to 5 years. Those are models that we should emulate at the Federal level. The CSB therefore recommended that OSHA conduct more comprehensive inspections and train more specialized inspectors.

Mr. Chairman, more stringent Federal oversight will help protect our workers and our communities from chemical disasters. Improved process safety also protects the American public from gasoline supply disruptions that analysts say cost millions of dollars a day at the pump. I thank the committee for convening this important hearing today and will be pleased to answer your questions. Thank you.

[The prepared statement of Ms. Merritt follows:]

Testimony of Carolyn W. Merritt
Chairman and Chief Executive Officer
U.S. Chemical Safety Board
Before the U.S. House of Representatives
Committee on Energy and Commerce
Subcommittee on Investigations and Oversight
May 16, 2007

Mr. Chairman, Ranking Member Whitfield, and distinguished members of the Committee: thank you for the opportunity to testify this morning. I am Carolyn W. Merritt, a member of the U.S. Chemical Safety Board or CSB, an independent federal agency that investigates major chemical accidents. I testify today in my individual role as Chairman of the Board and Chief Executive Officer.

On March 20, 2007, the CSB completed its investigation of the causes of the March 2005 explosion and fire at the BP Texas City refinery. This explosion killed 15 workers and injured 180 others. It caused the greatest loss of life of any U.S. workplace disaster since 1990.

The accident occurred during the startup of the refinery's octane-boosting isomerization (ISOM) unit, when a distillation tower and attached blowdown drum were overfilled with highly flammable liquid hydrocarbons. Because the blowdown drum vented directly to the atmosphere, there was a geyser-like release of highly flammable liquid and vapor. The equivalent of nearly a full tanker trunk of gasoline rained onto the grounds of the refinery in less than two minutes. The vapor ignited, causing a series of explosions and fires that swept through the unit and the surrounding area. All the fatalities and most of the injuries occurred in and around occupied work trailers, which were placed too close to the ISOM unit and were not evacuated prior to the startup.

Our investigation determined that the Texas City disaster was caused by organizational and safety deficiencies at all levels of the BP Corporation. Adhering to and enforcing federal regulations already on the books would likely have prevented this accident and its tragic consequences.

At the Committee's request, we reviewed a report prepared by Booz Allen Hamilton, under contract to BP, on the 2006 pipeline events in Prudhoe Bay, and compared the findings with our own. I emphasize that the CSB did not independently investigate the events in Prudhoe Bay, and we did not have access to the evidence, witnesses, or authors who contributed to the Booz Allen report. We took the statements and conclusions in the Booz Allen report at face value. Based upon that review, I make the following observations.

There are striking similarities in the reported causes of the 2006 events involving BP's Prudhoe Bay pipelines and the 2005 explosion at the BP Texas City Refinery. Most if not all of the seven root causes[1] that BP consultants identified for the Prudhoe Bay incidents have strong echoes in Texas City.

[1] Booz Allen Hamilton, *2006 Management Systems Review* (March 2007), p. 56

Budgetary Concerns Overshadowed Growing Risk

The Booz Allen report states that "Alaska was under severe budget pressure from BP."[2] The budgeting process was "largely driven by top-down targets"[3] rather than an analysis of risks, and the "top-down targets were considered sacrosanct and were rarely exceeded."[4] The cost pressures, we are told, resulted in staff reductions throughout BP Alaska and specifically in the corrosion control program, and in the deferral of integrity projects. The report states that "from 2002 to 2004, a series of reorganization projects focused on streamlining business operations and cutting costs."[5]

Furthermore, the Booz Allen report states that "budgets and funding [were] largely based on affordability (vs. necessity) and were not supported by an analytical process to prioritize risk. Senior management incentives [were] based on cost and production."[6] This finding is essentially identical to the "checkbook mentality" we uncovered at the Texas City Refinery, based upon a 2003 finding from BP's own health and safety audit of the facility. As noted in our report, "The 'checkbook mentality' meant that the budgets were not large enough to address identified risks, and that only the money on hand would be spent, rather than increasing the budget."[7]

In the CSB's report, we found that cost cutting, production pressures, and a failure to invest left the BP Texas City refinery vulnerable to a catastrophe. Shortly after acquiring Amoco in 1999, the BP Group Chief Executive ordered an across-the-board 25% cut in fixed spending. Such policies were particularly imprudent in light of the age and condition of some of BP's newly acquired assets, including the Texas City Refinery. A 2002 internal BP report, cited in our investigation, noted that "the prevailing culture at the Texas City refinery was to accept cost reductions without challenge and not to raise concerns when operational integrity was compromised."[8]

Cost considerations discouraged BP Texas City officials from replacing the refinery's antiquated and unsafe ISOM blowdown drum with an inherently safer flare system, a measure that would have prevented or greatly minimized the severity of the March 2005 accident.

The condition of BP Texas City's infrastructure and assets deteriorated due to a lack of required maintenance expenditure, and budget pressures also led to cuts in operator training and staffing levels. Training positions were cut by nearly 75%, and the training of operators was inadequate, particularly in the handling of abnormal situations. In 1999, to economize, BP also eliminated one of two control board operators who oversaw the ISOM unit and an adjacent process unit. In 2001, a third process unit was added to the

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[2] *Ibid.*, p. 3
[3] *Ibid.*, p. 71
[4] *Ibid.*, p. 41
[5] *Ibid.*, p. 27
[6] *Ibid.*, p. 82
[7] U.S. Chemical Safety and Hazard Investigation Board, *BP Texas City Final Investigation Report* (March 2007), p. 161
[8] CSB, p. 158

responsibilities of the sole remaining board operator. Each of these process units is itself a sprawling complex of pipes and equipment that may cover several acres. Our report documents how diminished human performance – due to poor communication, excessive work hours, fatigue, and a lack of adequate staffing, training, and supervision – contributed to the accident.

Although spending at the Texas City Refinery increased between 2000 and 2004, most of the increases were focused on environmental projects and emergency capital needs – not on correcting chronic problems with equipment maintenance and integrity. In 2004, BP executives challenged their refineries to cut yet another 25% from their budgets for the following year. This cut was promoted (and partially realized) despite clear evidence from safety audits, seen by at least one member of BP's executive board of directors, indicating that the lack of investment in maintenance and new equipment was compromising safety in Texas City and leaving the site at risk for a major accident.

Management of Change Processes Were Deficient

The Booz Allen report speaks of "a 'normalization of deviance' where risk levels gradually crept up due to evolving operating conditions."[9] In the case of the aging Prudhoe Bay lines, the report cites increasing water and sediment levels and decreasing flow as insidious risk factors for corrosion. We observed a similar indifference to growing catastrophic risk in our Texas City investigation. Unit startup procedures and processing conditions evolved over time without a formal assessment of the safety impact. Most startups of the ISOM distillation tower from 2000 to 2005 exhibited abnormally high internal pressures and liquid levels but these were not investigated as near-misses nor were corrective measures taken. Furthermore, the integrity of tower equipment deteriorated over the years, so that by the day of the accident there were six key alarms, instruments, and controls that were not functioning properly.

Changes in process conditions, instrument operability, or startup procedures should have immediately triggered what are called "management of change" safety reviews. Each review is a formal, documented process to analyze the safety ramifications of the change. In oil refineries, such reviews are mandatory under the OSHA Process Safety Management (PSM) standard. However, we found that there were serious, longstanding deficiencies in Texas City's management of change program.

As described in our report, a number of design and equipment changes were never evaluated under BP's management of change policy, even though the refinery had designated the equipment as "safety critical."[10] Our report also notes that BP management allowed operators and supervisors to alter, edit, add, and remove procedural steps without conducting management of change reviews to assess the safety risk.

BP policies required management of change reviews for the placement of trailers in the refinery. However, the majority of the portable trailers in the vicinity of the ISOM unit were placed in harm's way without conducting such safety reviews. Even when BP

[9] Booz Allen Hamilton, p. 78
[10] CSB, p. 332

conducted a management of change analysis – e.g. for the placement of a double-wide trailer where twelve occupants later perished – there was no closure of hazard review action items or final approval of the proposed change by the unit superintendent, as required by BP procedures.

The Booz Allen report draws broadly similar conclusions. It notes that BP Alaska operated under a management of change policy. However, "the established risk assessment processes and practices were not adequate to detect and address new risks due to evolving operating conditions."[11] In the words of the report, "There was no analysis of the potential effects of changing flow composition and rates on the [oil transit lines]." These lines were erroneously perceived as "low risk"[12] in the same way that Texas City's unsafe trailers, blowdown drums, obsolete procedures, and deteriorated equipment came to be treated as acceptable.

In an observation that also applies to Texas City, the Booz Allen report states: "The change management processes become more important as time passes, especially with an aging kit. If equipment drawings do not reflect the true as-built condition, there is added risk (that may be unknown to the operator) because of the lack of understanding of the system configuration."[13] In Texas, the written startup procedures for the ISOM unit became increasingly out-of-date, as various pieces of equipment ceased working as intended, and informal deviations from written procedures became the norm. Those deviations increased the likelihood of the catastrophic overfilling of the tower.

Failure to Close Action Items, Audit Findings

The Booz Allen report states that BP's "corrosion management strategy was developed in the late 1990s, and had not been substantially reviewed or revised until now, despite specific direction in a 2004 internal technical audit to do so .... A number of key assurance processes (e.g. Audit, Management of Change) were not 'closed loop' to ensure that required changes were truly implemented and documented."[14] The report goes on to state, "The absence of third-party verification and sanction led to long delays in implementation, administrative documentation of close-out even though remedial actions were not actually taken, or simple non-compliance."[15]

The CSB made essentially identical findings in Texas City. The CSB report points to a 2004 BP audit of 35 different business units, including the Texas City Refinery, which found common problems, including "a lack of leadership focus on closing action items from audits and other safety reviews, as well as a backlog of maintenance items."[16] More specifically, the closure rate for process safety management action items was actually decreasing in Texas City, falling to 79% by 2004. The closure rate for action items from process safety incident investigations was a dismally low 33%.

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[11] *Ibid.*, p. 56
[12] *Ibid.*, p. 73
[13] *Ibid.*, p. 81
[14] *Ibid.*, p. 7
[15] *Ibid.*, p. 75
[16] CSB, p. 166

We also found information system deficiencies, as did the Booz Allen report. For example, our investigation found that the refinery's computerized work order process did not require verification that required maintenance had been completed before closing a job order. We found that BP maintenance personnel were in fact authorized to close job orders even if work had not been completed.

Inadequate Communication and Excessive Decentralization

The Booz Allen report found that BP Alaska "operated in vertical silos. There was minimal cross functional communication …"[17] The report went on to state that inadequate communications "preclude the efficient exchange of information related to corrosion."[18] A 2004 safety audit in Texas City similarly revealed that the refinery lacked a formal process for communicating lessons learned from incidents. This finding was corroborated in the 2004 BP audit of 35 different business units, which found what it termed "poor processes"[19] to disseminate lessons learned.

Among the lessons *not* learned in Texas City were those from three serious process incidents at the BP refinery in Grangemouth, Scotland, in 2000, which became the subject of a major report by the U.K. Health and Safety Executive. The Grangemouth incidents were linked to excessive cost-cutting, a lack of focus on and measurement of process safety, and a decentralized management structure that impaired efforts to prevent major accidents.

The Booz Allen report also points to a decentralized management structure for the pipelines, stating, "There was no single owner of the [oil transit lines] as a system. Accountability for them was divided geographically among the six [Greater Prudhoe Bay] Area Managers."[20] The report notes that business unit leaders "are given significant autonomy to deliver against [their] performance contracts"[21] which is consistent with the CSB's findings about BP's management practices.

The Booz Allen report notes further, "Because [the Corrosion, Inspection, and Chemicals Group] was hierarchically four levels down from senior leadership, corrosion risk management had less visibility."[22] We made an analogous finding in our report: following BP's mergers with Arco and Amoco "process safety functions were largely decentralized and split into different parts of the corporation. These changes to the safety organization resulted in cost savings, but led to a diminished process safety management function that no longer reported to senior refinery executive leadership."[23] The decentralized approach led to a lack of focus on process safety, the CSB report concluded.

High Management Turnover

[17] *Ibid.*, p. 8
[18] *Ibid.*, p. 77
[19] CSB, p. 167
[20] Booz Allen Hamilton, p. 7
[21] *Ibid.*, p. 34
[22] *Ibid.*, p. 78
[23] CSB, p. 147

As stated in the Booz Allen report, BP Alaska's "senior management tenure averaged roughly three years. This lack of continuity contributed to perceptions of disconnection ...."[24] The report notes that only two senior managers from 2000 remained in place by 2006.[25] Both the CSB's report and the independent Baker panel report (which the CSB recommended and BP funded) draw similar attention to the extraordinary management turnover in Texas City. Since 1997, the refinery has had nine different plant managers. During the critical period between 2001 and 2003, there were five different plant managers, as noted in the Baker report.

The impact of this constant turnover was pointed out in a safety culture survey of the Texas City site completed on the eve of the accident, known as the Telos report. The Telos report authors stated, "We have never seen an organization with such a history of leadership changes over such a short period of time."[26] The Telos report as well as the CSB investigation found that the constant turnover impaired efforts to improve process safety at the facility. Constant management turnover persuaded employees that any new initiatives would be short-lived. It also promoted short-term decision-making by management, who would reap the reward for meeting cost targets but who would be gone before the consequences for such risk-loaded decisions were realized.

Focus Was Personal Safety; Process Safety Measures Lacking

One of the major themes in the CSB report, as well as the Baker panel report, is that BP did not use effective metrics for process safety. In fact, one of the principal organizational causes of the accident, according to our report, was that "BP management paid attention to, measured, and rewarded personal safety rather than process safety."[27]

BP focused its safety efforts on improving statistics for personal injuries – chiefly from slips, trips, falls, and vehicle accidents – and made progress in that area. However, growing catastrophic process risks were either overlooked or not effectively controlled. The CSB report found that in the refining and marketing sector, managers' performance contracts and incentive plans were heavily weighted in favor of financial performance and what was termed "cost leadership." Safety received a weighting of only 10% in pay plans and the sole metric for safety performance was the recordable injury rate, a measure of personal safety. Likewise, the Booz Allen report found: "Performance Contracts included metrics for recordable injury frequency (RIF) as the only explicit target for risk management."[28] The report also noted that "HAZOP [Hazard and Operability] studies focused on personnel safety ...."[29]

As stated in our report, "Financial and personal safety metrics largely drove BP Group and Texas City performance, to the point that BP managers increased performance site bonuses even in the face of the three fatalities in 2004."[30] Similarly, the Booz Allen

[24] Booz Allen Hamilton, p. 8
[25] *Ibid.*, p. 27
[26] CSB, p. 193
[27] *Ibid.*, p. 179
[28] Booz Allen Hamilton, p. 72
[29] *Ibid.*, p. 39
[30] CSB, p. 178

report found: "Because no leading risk indicators or root causes were studied, when the product composition changed, it was not flagged as an important corrosion management issue. This led to an increase in corrosion risk on the [oil transit lines] that ultimately precipitated the two incidents."[31]

Corporate managers and regulators should not rely on recordable injury rates to assess the likelihood of catastrophic process accidents. In its final report, the CSB recommended that the American Petroleum Institute (API) and the United Steelworkers (USW) collaborate with other stakeholders to develop a standard for leading and lagging process safety performance indicators in the refining and petrochemical industries. The recommendation ask the organizations to work together with a diverse group of industry, labor, public interest, and environmental organizations and scientific experts in developing the new standard. The Baker Panel also recommended that BP take a leading role, in collaboration with the CSB and other stakeholders, in developing and implementing process safety performance indicators.

OSHA Enforcement at High-Risk Chemical Facilities

As requested by the Committee, I will summarize the CSB's findings on OSHA enforcement at the BP Texas City refinery and other high hazard chemical facilities. Our BP investigation determined that diligent implementation of OSHA safety rules that are already on the books would have prevented the accident. Specifically, the OSHA Process Safety Management standard, enacted in 1992, has 14 required elements for preventing catastrophic accidents at facilities that handle highly hazardous chemicals.

The PSM standard requires process hazard analyses, management of change reviews, investigation of incidents, and preventative maintenance programs. All these functions were deficient for many years at the Texas City refinery, our report found. After the March 2005 accident, OSHA conducted an inspection at the refinery, focusing largely on the ISOM unit, which is but one of 30 units in the refinery. This inspection resulted in the biggest OSHA fine in history, $21 million, which is indicative of the extent of the pre-existing safety problems at the facility.

Our investigation found that prior to the 2005 accident, OSHA did not conduct any comprehensive, planned process safety inspections at the Texas City Refinery. Furthermore, our investigation found that in the ten years from 1995 to 2005, federal OSHA only conducted nine such inspections anywhere in the country, and none in the refining sector.

The Texas City Refinery was an extremely dangerous workplace, with 23 workers killed in the 30 years prior to March 23, 2005, not counting the 15 workers who were fatally injured that day. OSHA did conduct unplanned inspections of the Texas City Refinery in response to accidents, complaints, or referrals. But these unplanned inspections are typically narrower in scope and shorter than planned inspections. Proposed OSHA fines during the twenty years preceding the March 2005 disaster – a period when ten fatalities occurred at the refinery – totaled $270,255; net fines collected after negotiations totaled $77,860.

[31] Booz Allen Hamilton, p. 80

Our report concluded OSHA has focused its inspections for a number of years on facilities that have injury rates. While OSHA is to be commended for trying to reduce these rates, the Chemical Safety Board believes that OSHA should also pay increased attention to preventing less frequent, but catastrophic, process safety incidents such as the one at Texas City. If necessary, we suggest that Congress consider providing OSHA with additional resources for this activity. Following the Sago mine disaster, there has been an effort to significantly increase the resources for conducting federal mine safety inspections, and mines were already inspected far more frequently than most oil and chemical facilities.

When the PSM standard was created, OSHA envisioned a highly technical, complex, and lengthy inspection process for regulated facilities, called a Program Quality Verification or PQV inspection. The inspections would take weeks or months at each facility and would be conducted by a select, well-trained, and experienced team. Indeed, thoroughly inspecting a 1,200-acre chemical complex with 30 major process units – like the Texas City Refinery – is a significant undertaking. However, the statistics we gathered from public records during our BP investigation indicate that OSHA has not developed sufficient capacity to conduct these inspections on a widespread basis.

We note in our report that other safety authorities do conduct regular, comprehensive process safety inspections at hazardous chemical facilities. For example, the U.K. Health and Safety Executive, which oversees a much smaller oil and chemical industry than exists in the U.S., has 105 specialized inspectors for high-hazard facilities; each covered facility in the U.K. is thoroughly inspected every five years. Contra Costa County in California has its own industrial safety ordinance and has a program to inspect each covered oil and chemical facility every three years. A team of five engineers performs an average of 16 inspections each year. The program costs a relatively modest $1 million a year, which is financed through fees collected from the regulated facilities.

In our final report on BP, the Chemical Safety Board called on OSHA to identify and conduct comprehensive inspections of those facilities at the greatest risk of a catastrophic accident. We also recommended that OSHA hire or develop new, specialized inspectors and expand the PSM training curriculum at its National Training Institute. We urge OSHA to accept and promptly implement these recommendations, which will make U.S. chemical facilities safer and protect the communities where they operate from the consequences of chemical disasters.

Conclusion

The CSB report and the Booz Allen report point to similar cultural factors within BP, in both its upstream production and downstream refining operations. The similarity in the two reports underscores how safety culture truly is set at the top at a corporation. After all, the upstream and downstream sides of BP have separate reporting lines all the way to the Group Chief Executive and the board of directors in London.

Our report further points to the need for improved federal oversight of refineries and chemical plants. Many corporations are already doing an excellent job of preventing major process-related accidents and are investing the necessary resources on a long-term basis. More stringent federal oversight will not only help level the playing field but more importantly will protect our workers and our communities from chemical disasters. Improved process safety efforts also protect the American public from gasoline refinery and petroleum supply disruptions that can cost millions of dollars a day at the pump.

I thank the Committee for convening this important hearing today and will be pleased to answer any questions.

Mr. STUPAK. Thank you. Mr. Fairfax, please, opening statement.

TESTIMONY OF RICHARD FAIRFAX, DIRECTOR, DIRECTORATE OF ENFORCEMENT PROGRAMS, OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION, U.S. DEPARTMENT OF LABOR

Mr. FAIRFAX. Thank you, Chairman Stupak, Ranking Member Whitfield and Congressman Dingell and members of the subcommittee. I appreciate the opportunity to appear today before you to discuss OSHA's efforts to protect health and safety at America's refineries.

My name is Richard Fairfax. I am the director of OSHA's Enforcement Program and I have been with the agency for 29 years. As a side note, I just would like to point out, prior to joining OSHA, I worked in refineries in both California and Texas as a pipe fitter and welder, so I am somewhat familiar with those industries. Twenty-one States and Puerto Rico have chosen to exercise the option given to them by the OSH Act to operate their own occupational safety and health program. These State programs conduct inspections in their own jurisdictions. Alaska, where BP's Prudhoe Bay facility is located, is a state-plan State and not covered by Federal OSHA.

We believe that OSHA's efforts to address workplace safety and health are achieving results, as evidenced by all-time low occupational injury and illness rates and fatality rates. The overall workplace injury and illness rate is 4.6 per 100 employees in 2005. That is the lowest rate since the Bureau of Labor Statistics began collecting data in 1973. Since 2002, the injury and illness rate has fallen by more than 13 percent and the fatality rate has fallen by about 7 percent.

Enforcement is a key component to our strategy and let me be perfectly clear in stating that compliance with OSHA standards is mandatory, not voluntary, and all employers are responsible for ensuring the safety and health of the employees at their worksite. Since 2001, OSHA has proposed more than three quarters of a billion dollars in penalties for safety and health violations and we have made 56 criminal referrals to the Department of Justice since 2001. The refinery industry is a major focus for us. Last year we and our State partners conducted 98 inspections in refineries.

When OSHA encounters a company that repeatedly ignores its legal obligations and places employees at risk, the agency employs it Enhanced Enforcement Program. This program targets employers with serious violations related to worker fatalities or multiple and willful repeated violations of various laws that we have. For these employers, OSHA schedules mandatory follow-up inspections and negotiate comprehensive settlement agreements and provisions in those agreements to protect the workforce and we will conduct inspections of other work places of that same employer.

As to the inspection that killed 15 workers at BP Products in Texas City, OSHA conducted the most extensive inspection of a refinery in the agency's history. In a settlement agreement with BP, BP Products paid more than $21 million in penalties and agreed to abate all cite hazards and agreed to extensive additional monitoring analysis of safety operations at the Texas facility. In January 2006 OSHA referred this case to the Department of Justice to determine if criminal charges should be pursued against the company.

To determine whether similar conditions existed at other BP facilities, OSHA issued and enhanced enforcement alert to all its regional offices and state-plan States. OSHA's inspection at the BP facility refinery in Oregon, OH, under this alert, identified a number of violations very similar to those found in Texas City. Using the Enhanced Enforcement Program, OSHA penalized the company more than $2.4 million and this inspection resulted in 32 willful violations. Similar to Texas City, the violations found employees located in vulnerable buildings and found numerous ignition sources that compound the risk of fire and explosion; again, very similar to BP in Texas City.

Additionally, under this alert, with assistance from our staff and OSHA's region 5, Indiana-OSHA, which is a state-plan State, conducted an inspection of BP Products facility in Whiting, Indiana. That inspection resulted in over $300,000 in penalties and we issued several willful violations in that inspection. We are currently conducting a follow-up inspection at Texas City, including an investigation of an incident last month in which more than 100 workers were taken to the hospital after complaining of flu-like symptoms.

Since OSHA has begun enforcing the Process Safety Management Standard, there has been a steady decline in the number of fatality and catastrophe events. These are the types of incidents which the Process Safety Management Standard was promulgated to prevent. The number of fatal or catastrophic events related to PSM has declined from 24 in 1995 to five in 2005.

To address refinery safety and to address some of the recommendations of the Chemical Safety Board, prior to the event in Texas City, we began working on a National Emphasis Program for refineries. That program, our national program, is very close to being ready to be released. The emphasis program will use a new inspection strategy which frankly, I am quite proud of that we will use to yield better results in our inspections. OSHA will encourage its State partners to implement the emphasis program and/or to create their own emphasis program. Our agency will inspect, in the next 2 years, all 81 refineries under OSHA's jurisdiction under this program.

OSHA currently provides three course on Process Safety Management at its training institute. More than 200 of our compliance officers have received instruction in one or more of these classes. We project that by the time we complete our Advanced Process Safety Management Course this fall, we will have trained more than 280 workers or employees of OSHA.

Mr. Chairman, although we have made considerable progress in reducing injuries and illnesses in the American workplaces over the last 36 years, any fatality, including those at petrol and chemical companies is one death too many. We are aware of the devastation wrought by refinery explosions and fires in the communities where they are located. Our staff has met with the families of these workers and seen the toll that it takes. Our agency is using all its resources to reduce the dangers and risk in the refinery industry, as well as all companies nationwide.

Mr. Chairman, that concludes my testimony and I would be happy to answer your questions.

[The prepared statement of Mr. Fairfax follows:]

STATEMENT OF RICHARD FAIRFAX
DIRECTOR OF ENFORCEMENT PROGRAMS
OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION
BEFORE THE
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES

May 16, 2007

Chairman Stupak, Ranking Member Whitfield, and Members of the Subcommittee:

Thank you for the opportunity to testify today and discuss the Occupational Safety and Health Administration's (OSHA) role in safeguarding workers in the nation's refining industry.

My name is Richard Fairfax. I have worked for OSHA for 29 years. Since 1998, I have been the Director of OSHA's Directorate of Enforcement Programs, for which I coordinate the agency's federal inspection efforts. Federal OSHA conducts inspections from each of its 86 local offices around the nation. These efforts are overseen and supported by the agency's 10 regional offices. Twenty-one states and Puerto Rico have chosen to exercise the option given them by the Occupational Safety and Health (OSH) Act of 1970 to become "state-plan states" and operate OSHA-approved occupational safety and health programs covering employers and workers in their states. These state programs conduct inspections in their own jurisdictions. Alaska, where BP's Prudhoe Bay facility is located, is a state-plan state which is not under federal OSHA's jurisdiction.

OSHA uses a variety of strategies to accomplish its mission of saving lives and reducing injuries and illnesses. This balanced approach includes: 1) strong, fair, and effective enforcement; 2) safety and health standards and guidance; 3) training and education; and 4) cooperative programs, compliance assistance, and outreach.

OSHA's balanced strategy is achieving results, as evidenced by all-time low occupational injury, illness, and fatality rates. The overall workplace injury/illness rate, at 4.6 per 100 employees in 2005, is the lowest since the Bureau of Labor Statistics began publishing data in 1973. Since 2002, the injury/illness rate has fallen by more than 13 percent, and the overall fatality rate has fallen by 7 percent since 2001. These numbers highlight OSHA's commitment to protecting the safety and health of the nation's workforce.

Enforcement is a key component of our strategy. Let me be perfectly clear in stating that compliance with OSHA standards is *mandatory*. All employers are responsible for ensuring the safety and health of the employees at their worksites. Since 2001, OSHA has proposed more than three-quarters of a billion dollars in penalties for safety and health violations. In addition, the agency has made 56 criminal referrals to the Department of Justice when we believed that an employer willfully violated the law, and one or more employees died as a result. Referrals to the Justice Department have increased from six cases per year on average in the 10 years preceding Fiscal Year (FY) 2003 to 9 cases in FY '03, 10 cases in each of FY '04 and FY '05, and 12 cases in the last fiscal year. Last year's total is the highest number of referrals since FY 1991.

The refinery industry is a major focus for this agency. Last year, OSHA and its state partners conducted 98 inspections in refineries. Comprehensive refinery inspections are complex and lengthy, often taking hundreds and, in some cases thousands, of hours of inspector time for OSHA's multi-member inspection teams to complete.

The OSH Act provides us with the tools we need to deal with companies that have encountered systemic problems at multiple worksites. When OSHA encounters a company that repeatedly ignores its legal obligations and places workers at risk, the agency employs its Enhanced Enforcement Program (EEP). This program targets employers, such as BP Products, with serious violations related to a worker fatality or multiple, willful or repeated violations of the law. Since the EEP was launched in FY 2004, OSHA has identified 1844 establishments meeting the criteria defined by the EEP. These establishments were targeted for additional enforcement action. For these employers, OSHA schedules enhanced follow-up inspections, negotiates comprehensive settlement provisions to protect the site's workforce and may conduct inspections of other workplaces of the same employer, as well.

Prior to the explosion at BP Products in Texas City, Texas, in March of 2005, there were no incidents at the Texas City refinery that caused OSHA to employ the EEP. Following the March 2005 disaster, OSHA, utilizing the EEP, conducted an extensive inspection of the refinery. OSHA has since taken significant enforcement action against the company, including imposing the largest penalty in the agency's history, which BP is paying in full. In a settlement agreement, BP Products paid more than $21 million in penalties and will abate all cited hazards. As required by that settlement, the company retained a consultant with expertise in process safety management (PSM) and another expert consultant in human factor analysis to conduct refinery-wide audits and analyses. BP Products will also submit to OSHA and to the company's employee representative logs of occupational injuries and illnesses every six months for three years. Any incident at the Texas City site that results in workers losing one or more workdays during that period will also be reported to OSHA. BP has notified OSHA that the blowdown stack in the Isomerization unit, which was the cause of the explosion, has been permanently removed from service. In January 2006, OSHA referred this case to the Department of Justice to determine if criminal willful charges should be pursued against the company.

To determine whether similar conditions existed at other BP refineries, OSHA issued alerts to its regional offices and state plan partners concerning its findings for Texas City and began inspections at BP's other refineries. Soon after completing the Texas investigation, OSHA inspected the BP refinery in Oregon, Ohio (the only other BP refinery under federal OSHA jurisdiction), and identified a number of violations similar to those found at Texas City. Using the EEP, OSHA issued numerous citations and assessed the company more than $2.4 million in fines. OSHA issued 32 willful citations, focusing on the company's practice of placing employees in vulnerable buildings among its processing units, failing to correct de-pressurization deficiencies, as well as failing to correct deficiencies with gas monitors. Similar to Texas City, OSHA found numerous ignition sources that compound the risk of fire and explosion. BP has contested these citations and their accompanying abatement orders. This contested case is now pending before the Occupational Safety and Health Review Commission.

Comprehensive OSHA enforcement involving BP Products continues. We are currently conducting a follow-up inspection at the Texas City refinery, including an investigation of an incident last month in which more than 100 workers were taken to a hospital after complaining of flu-like symptoms. With assistance from our staff in OSHA's Region 5, Indiana-OSHA (a state-plan state) conducted an inspection of a BP Products refinery in Whiting, Indiana, resulting in over $300,000 in penalties and the issuance of several willful citations. In recent years, the California and Washington State OSHA plans have also conducted inspections of BP refineries (Carson, California, and Cherry Point, Washington).

Not all BP workplaces have safety and health problems, however. Nine of its facilities participate in OSHA's Voluntary Protection Programs, which recognize worksites that go *above and beyond* OSHA's requirements in protecting their workforce. OSHA officials have met with representatives of BP, who have expressed a desire to make improvements to their safety and health practices and procedures. OSHA will continue to monitor the company's facilities closely to ensure that these improvements do occur.

The refinery incidents we are discussing today are very serious matters. While large-scale disasters at these refining and chemical facilities are low-probability events, such events can have catastrophic consequences. OSHA is proud of the fact that since the agency began enforcing its PSM standard, there has been a steady decline in the number of fatality/catastrophe events. These are the types of incidents that the PSM standard was promulgated to prevent. The number of fatal or catastrophic events declined from 24 in 1994 to 5 in 2005.

In addition to ongoing effective enforcement activities, OSHA participates in Alliances with the petroleum industry to promote safety and health. For instance, an Alliance between OSHA, the American Petroleum Institute and the National Fire Protection Association (NFPA) facilitates worker training on safe tank entry, cleaning, maintenance and rescue operations in petroleum refining facilities and encourages workers to take NFPA courses on confined space practices and share this knowledge with fellow operators.

OSHA also shares expertise with the industry to help protect refinery workers. For instance, in 2003, OSHA and the Environmental Protection Agency (EPA) issued a Safety and Health Information Bulletin alerting workers, employers and emergency responders about the hazards associated with Delayed Coker Unit (DCU) Operations in the oil refining process. The bulletin addressed the batch stage of the operation, which is responsible for most of the serious incidents during the DCU operation. The bulletin was sent to hundreds of refineries and was posted on the websites of both OSHA and EPA.

As a result of the Texas City accident, OSHA began evaluating its data on fatalities and catastrophes and determined that refineries experienced more of these problems than the next three industry sectors combined. Accordingly, OSHA is preparing to launch a National Emphasis Program (NEP) for petroleum refineries focusing on the PSM standard. NEPs target establishments or industries based upon hazardous conditions such as employee exposures to trench cave-ins, lead exposure, or hazards of amputations. The NEP will use a new inspection strategy that we believe will yield more effective results than the current approach to enforcing PSM. OSHA's compliance officers will enter each facility with a list of items on which they will focus their attention during the visit. These items will represent the conditions most likely to be significant hazards to workers in the facility. Before the end of 2008, our agency will conduct enforcement inspections at all 81 refineries under federal jurisdiction. In addition, OSHA will encourage its state partners to implement our NEP or create their own emphasis program.

After the 81 refinery NEP inspections have been completed, OSHA will continue to address low-probability/high consequence events in refineries and high risk chemical operations. The agency is conducting research to identify indicators that are most useful in predicting which facilities are most at risk of a catastrophe.

As the Subcommittee knows, following the BP Texas City explosion, the Chemical Safety Board (CSB) made a number of recommendations to OSHA. For example, the Board suggested that OSHA strengthen enforcement of its PSM Standard by identifying facilities at greatest risk of catastrophic accident and conducting comprehensive inspections at those workplaces.

As stated earlier, OSHA had already begun work on its Refinery NEP in recognition of the need identified by its analysis of fatality/catastrophe data. In addition, OSHA has been conducting a comprehensive training program for its compliance officers on the PSM Standard, which contains requirements for the management of hazards associated with processes that use highly hazardous chemicals. OSHA's investigators are already capable and highly-trained individuals. This comprehensive training will enhance their expertise. OSHA currently provides three courses on this standard at its Training Institute. Enforcement personnel conducting the NEP inspections – Team Leaders and our top technical experts – will have taken all three courses: Advanced Process Safety, Hazard Analysis in Chemical Process Industries, and Safety and Health in the Chemical Processing Industries. By the time we conclude our Advanced Process Safety Course this fall, we project that we will have at least 75 Team Leaders or top technical experts trained. More than 200 of our compliance officers have received instruction in one or more of these classes thus far. We project that by the time we complete our Advanced Process Safety Course this fall, we will have trained 280 compliance officers in our PSM courses. These numbers of trained PSM compliance officers reflect those individuals who will have received PSM training since we began our aggressive approach to increasing our trained PSM staff last fall. We also have other OSHA personnel who have received advanced training and are conducting PSM inspections.

All of OSHA's efforts are intended to strengthen worker protections in this industry, as well as other industries. Although OSHA and our state partners have made considerable progress in reducing the injury/illness and fatality rates in America's workplaces over the past 36 years, even a single fatality is one too many.

Mr. Chairman, we are aware of the devastation wrought by refinery explosions and fires in the communities where they are located. Our staff has met with the families of these workers and has seen the toll it takes upon their lives. This agency is using all of its resources to combat the dangers in this industry and will continue to work to improve conditions in refineries nationwide.

I would be happy to answer any questions.

Mr. STUPAK. Thank you, Mr. Fairfax. Ms. Slemons, if you would for an opening statement, 5 minutes.

TESTIMONY OF JONNE SLEMONS, COORDINATOR, PETROLEUM SYSTEMS INTEGRITY OFFICE DIVISION AND OIL GAS, ALASKA DEPARTMENT OF NATURAL RESOURCES, ANCHORAGE, AK

Ms. SLEMONS. Chairman Stupak, Representative Whitfield, Vice Chairman Melancon and distinguished members of the committee, thank you for the opportunity to appear here today. My name is Jonne Slemons. I am the acting coordinator of the new State of Alaska Petroleum Systems Integrity Office.

The March 2006 pipeline corrosion in the Prudhoe Bay Unit led to a spill of approximately 200,000 gallons of oil from a transit line onto the tundra. Five months later, a different transit line on the same unit leaked 735 gallons onto the tundra. After the August spill, BP determined that the Prudhoe field, which accounts for 8 percent of domestic output, had to be partially shut down, reducing by half the field's production of 400,000 barrels of oil a day, directly affecting gasoline prices nationwide and costing the State of Alaska approximately a million dollars per day.

BP acknowledge problems when the leaks were discovered that called into question their assumptions and decisions regarding corrosion monitoring. Those events have been and continue to be carefully investigated. Remedial actions are underway and the flow of oil has resumed. But the spills and shutdown demonstrated to the State and to the Nation that preventive safeguards in both operator performance and government oversight were lacking. I would like to describe to you the actions being instituted by the State of Alaska in response to those events.

First, the Department of Environmental Conservation has promulgated regulations for oversight of flow lines upstream of the separation facility, pipelines not regulated by the Pipeline and Hazardous Materials Safety Administration. Those regulations were approved shortly after the events of 2006 and are now in phased implementation with full implementation scheduled for 2009.

Second, and on a much broader scale, on April 18th, Alaska's governor, Sarah Palin, signed Administrative order 234, which created the Petroleum Systems Integrity Office or PSIO. We believe that the PSIO will have a significant and long-term effect on preventing future incidents such as those described above.

The PSIO resides within Alaska's Division of Oil and Gas, a division of the Alaska Department of Natural Resources. The division conducts oil and gas lease sales, issues oil and gas leases, performs royalty accounting, administers the creation and operation of oil and gas units, approves surface activities and facilities, conducts inspections and reviews to ensure protection of coastal resources and compliance with the lease terms and stipulations. Traditionally, the division has not engaged in the review, approval or inspection of maintenance programs or practices. As is common throughout the country, the division has relied on the "enlightened self-interest" of operators to maintain their equipment properly in order to maximize the safe and continuing production of oil and gas resources.

The events of 2006 in the Prudhoe Bay Unit taught us that we cannot rely on "enlightened self-interest" to ensure that prudent maintenance practices are carried out. We also learned of several regulatory gaps in oversight of oil and gas infrastructure. The PSIO addresses these findings.

Governor Palin's Administrative order establishes that the PSIO resides within the Division of Oil and Gas, the State's landlord, and there the body responsible for ensuring that State leases are properly maintained. The PSIO will utilize the broad authorities vested in the division through our oil and gas leases.

The order also establishes that the Alaska Department of Natural Resources Commissioner shall be the lead official for communication and coordination with all Federal agencies relative to oversight of oil and gas exploration, production and transportation on State lands.

It further establishes that the Coordinator of the PSIO shall be the lead official in exercising oversight of maintenance of oil and gas facilities, equipment and infrastructure.

And finally, it establishes that designated State agencies coordinated by the PSIO shall participate in interagency activities and provide technical assistance as requested by the PSIO. Those designated State agencies are the Alaska Departments of Natural Resources, including the Office of Habitat Management and Permitting, the Office of Project Management and Permitting, the Division of Mining, Lands and Water, and the State Pipeline Coordinator's Office. It also includes the Alaska Oil and Gas Conservation Commission and the Departments of Environmental Conservation, Fish and Game, Public Safety, Revenue, Transportation and Public Facilities, Labor and Workforce Development, Law and the Washington, DC Governor's Office.

In regard to the PSIO's coordination with Federal agencies, we have conducted introductory meetings with the U.S. Coast Guard and the U.S. Army Corps of Engineers and we have met several times with the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation. Further, we have established a Letter of Intent with PHMSA to document our mutual commitment to work cooperatively in the regulation and oversight of oil and gas productions and transportation in Alaska. As part of that agreement, the State and PHMSA will delineate clear jurisdictional roles and develop a unified strategic plan for the oversight of oil and gas production and transportation, including risk assessment, standards, inspections and overall, communication.

In addition to coordinating the efforts of State agencies and providing a point of contact for Federal and local government coordination, the Administrative order also directs specific actions. Two primary tasks are identified as a starting point.

First, a regulatory gap analysis, which will assess the authorities and practices of State and Federal agencies regarding oil and gas oversight to avoid duplication and identify any regulatory gaps.

The second task is the evaluation and approval of operators' maintenance and oversight programs, including inspections, to ensure compliance with approved programs.

The regulatory gap analysis is underway. When it is complete, the PSIO will commence the assessment of operators' maintenance programs, beginning with that of the Prudhoe Bay Unit. I expect both of these efforts to be substantially completed within the calendar year. Follow-up tasks, such as development of regulations to address oversight gaps and assessment of the maintenance programs of other oil and gas units will be designed and implemented based upon the results of the gap analysis and the initial maintenance assessment. Concurrent with these efforts, a comprehensive risk assessment of all oil and gas facilities and infrastructure is planned to be conducted by an independent third part. This risk assessment will identify and prioritize areas of risk and will provide valuable direction to our focus going forward.

Alaska is the only State in the country to require industry to allow regulator access to operator facilities in order to ensure compliance with their own maintenance programs. We look forward to breaking this new ground and to cooperative efforts with our Federal partners, and in doing so, maximizing the safe and stable flow of our oil and gas resources to the Nation. Thank you.

[The prepared statement of Ms. Slemons follows:]

Testimony to the
U.S. House of Representatives
Committee on Energy and Commerce
Subcommittee on Oversight and Investigations

May 16, 2007

"2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?"

Jonne Slemons, Acting Coordinator
Petroleum Systems Integrity Office (PSIO)
Division of Oil and Gas
Alaska Department of Natural Resources

Chairman Stupak, Representative Whitfield, Vice Chairman Melancon, and distinguished members of the Committee. Thank you for the opportunity to appear today. My name is Jonne Slemons; I am the Acting Coordinator of the State of Alaska's Petroleum Systems Integrity Office.

In March 2006, pipeline corrosion in the Prudhoe Bay Unit led to the spill of 267,000 gallons of oil from a transit line onto the tundra. Five months later, a different transit line on the same unit leaked 735 gallons onto the tundra. After the August spill, BP determined that the Prudhoe field, which accounts for 8 percent of domestic output, had to be partially shut down, reducing by half the field's production of 400,000 barrels of oil a day, directly affecting gasoline prices nationwide, and costing the state of Alaska approximately a million dollars a day.

BP acknowledged problems when the leaks were discovered that called into question their assumptions regarding corrosion monitoring. Kemp Copeland, BP's Greater Prudhoe Bay field manager, stated, "Clearly in hindsight, we would have been doing some things different with those old transit lines."

Those events have been carefully investigated, remedial actions are underway, and the flow of oil has resumed. But the spills and shutdown demonstrated to the state and to the nation that preventive safeguards in both operator performance and governmental oversight were lacking. I would like to describe to you the actions being instituted by the State of Alaska in response to those events.

First, the Department of Environmental Conservation has promulgated regulations for oversight of flow lines upstream of the separation facilities, pipelines not regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation. Those regulations were approved shortly after the events of 2006, and are now in phased implementation, with full implementation scheduled for 2009.

Second, and on a much broader scale, on April 18th Alaska's Governor, Sarah Palin, signed Administrative Order 234, which created the Petroleum Systems Integrity Office or PSIO. We believe that the PSIO will have a significant and long-term effect on preventing future incidents such as those described above.

The PSIO resides within Alaska's Division of Oil and Gas, a Division of the Alaska Department of Natural Resources. The Division of Oil and Gas conducts oil and gas lease sales, issues oil and gas leases, performs royalty accounting, administers the creation and operation of oil and gas units, approves surface activities and facilities, conducts reviews to ensure protection of coastal resources, and routinely inspects facilities to ensure compliance with lease terms and stipulations. Traditionally, the Division has not engaged in review, approval or inspection of maintenance programs or practices. As is common throughout the country, the Division has relied on the "enlightened self interest" of operators to maintain their equipment properly in order to maximize the safe and continuing production of oil and gas resources.

The events of 2006 in the Prudhoe Bay Unit taught us that we cannot rely on "enlightened self interest" to ensure that prudent maintenance practices are carried out. We also learned of several regulatory gaps in oversight of oil and gas infrastructure. The PSIO addresses these findings.

Governor Palin's Administrative Order established the following:

- that the PSIO is established within the Division of Oil and Gas, the State's landlord and therefore the body responsible for ensuring that state leases are properly maintained. The PSIO will facilitate coordination of division management with other agencies, and will utilize the broad authorities vested in the Division through our oil and gas leases.
- that the Alaska Department of Natural Resources Commissioner shall be the lead official for communication and coordination with all federal agencies relative to oversight of oil and gas exploration, production and transportation on state lands.
- that the Coordinator of the PSIO shall be the lead official in exercising oversight of maintenance of oil and gas facilities, equipment and infrastructure.
- that designated state agencies, coordinated by the PSIO, shall participate in interagency activities and provide technical

assistance as requested by the PSIO. The designated state agencies are the Alaska Departments of:

- Environmental Conservation
- Fish and Game
- Public Safety
- Revenue
- Transportation and Public Facilities
- Labor and Workforce Development
- Law
- Natural Resources, including
    - Office of Habitat Management and Permitting
    - Office of Project Management and Permitting
    - Division of Mining, Lands and Water
    - State Pipeline Coordinator's Office
- Alaska Oil and Gas Conservation Commission
- Director, Governor's Office, Washington, D.C.

In regard to the PSIO's coordination with federal agencies, we have conducted introductory meetings with the U.S. Coast Guard, the U.S. Army Corps of Engineers, and the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation. Further, we have established a Letter of Intent with PHMSA to document our mutual commitment to work cooperatively in the regulation and oversight of oil and gas production and transportation in Alaska. As part of the agreement, the State and PHMSA will delineate clear jurisdictional roles and develop a unified strategic plan for the oversight of oil and gas production and transportation, including risk assessment, standards, inspections, and overall, communication.

In addition to coordinating the efforts of state agencies and providing a point of contact for federal and local government coordination, the Administrative Order also directs specific actions. Two primary tasks were identified as a starting point:

1. a regulatory gap analysis, which will assess the authorities and practices of state and federal agencies regarding oversight of oil and gas facilities to avoid duplication and identify any regulatory gaps; and
2. the evaluation and approval of operators' maintenance and oversight programs, including inspections to ensure compliance with the approved programs.

The regulatory gap analysis is underway. When it is complete, the PSIO will commence the assessment of operators' maintenance programs, beginning with that of the Prudhoe Bay Unit. I expect both of these efforts to be substantially completed within the calendar year. Follow-up tasks, such as development of regulations to address oversight gaps and assessment of the Quality Assurance programs of other oil and gas units, will be designed and implemented based upon the results of the gap analysis and initial maintenance assessment.

Alaska is the only state in the country to require industry to allow regulator access to operator facilities in order to ensure compliance with their own maintenance programs. We look forward to breaking this new ground, and to cooperative efforts with our federal partners, and in doing so, protecting the environment while maximizing the safe and stable flow of our oil and gas resources to the nation.

Thank you.

Mr. STUPAK. Thank you. Mr. Gerard, your opening statement, please.

TESTIMONY OF STACEY GERARD, ACTING ASSISTANT ADMINISTRATOR, CHIEF SAFETY OFFICER, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

Ms. GERARD. Thank you. Chairman Stupak, Ranking Member Whitfield, members of the committee, I am Stacey Gerard, the Chief Safety Officer of PHMSA, the Pipeline and Hazardous Materials Safety Administration. Thank you for the invitation to appear today. I am pleased to discuss PHMSA's actions to oversee the safe continued operations of BP Exploration Alaska. I would also like to thank the committee for its leadership in advancing the important safety legislation we know as the PIPES Act. PHMSA is moving forward with several rulemakings, including extending full, regulatory protection to low-stress hazardous liquid pipelines. Just yesterday we posted a supplemental notice proposing new additional requirements for low-stress pipelines.

We do have some progress report concerning our oversight of BPXA. Based on our ongoing monitoring and the degree of control over BP, we exercise, through orders, our confidence in engineering, operations and maintenance of the existing transit lines is cautiously increasing. BP has begun replacement of the Prudhoe Bay transit lines and is beginning to address management problems that contributed to the failures they experienced last year. They have a long road ahead to address these concerns.

We also are improving coordination with the State of Alaska, which will result in better oversight of future BPXA activities in Alaska. Earlier this week, as Ms. Slemons mentioned, we did sign a Letter of Intent to confirm our new and approved commitment, recognizing the impact on nationwide crude production following the shutdown of the system this past year. PHMSA maintained a monitoring presence on the north slope through the process of both getting a better understanding of the transit line conditions and controlling their safe operation. A review of the data from testing has been extensive.

It took an extraordinary effort to get BPXA ready to pig the transit lines, but it is done now. The end line inspection results, along with other external test findings, indicated that the lines are "fit" for continued use until the new pipelines are ready next year. Any damaged observed was not significant enough to warrant immediate repair, but PHMSA is requiring aggressive corrosion control and continuous monitoring. We issued a third amendment to our order on April 27 to that point.

Additionally, we are requiring that these lines be pigged on a 12-month cycle, that is smart pigged, and provide us with the results for review. We have continued our examination of corrosion to improve our understanding of how the leaks occurred and the risk of further line degradation. PHMSA is reviewing and analyzing the pipeline designs, maintenance policies, corrosion monitoring methods, inspection procedures and operating practices.

Last September, we believed that internal corrosion induced by microbial activity caused the western, the WOA, pipe to deteriorate at the low section at the Caribou Crossing. Additional testing since then reinforces that assessment. We have found evidence of an environment conducive to microbial sulfur reducing bacteria leading to localized corrosion.

Additionally, sludge likely reduced the effectiveness of any corrosion inhibitors that were being used prior to the cleaning regime we have required. Given the many risk factors on the north slope environment, including use of water in the production process, the chemistry of the crude oil product itself, and the varied geological factors in the production field, we believe that BPXA should have been running cleaning pigs on these lines on a regular basis to reduce the potential for this microbial process.

PHMSA has reviewed BPXA's plans for rebuilding the eastern and western pipelines and we oversee the construction. The plans reflect many upgrades over the existing system and construction of the new pipeline is underway. The new lines are designed to PHMSA code. Smaller pipe diameters to increase fluid velocity should minimize solids and microbial growth. Pipe elevation will be higher, providing better access for inspection and maintenance and reducing collection of water and solids. Better coatings and insulation will help to reduce external corrosion. A dedicated chemical injection system will provide greater effectiveness.

All segments will have pipe launching and receiving facilities that are appropriate to the harsh climate. BP's schedule calls for all of the new oil transit systems to be in operation by the end of December 2008. If the project milestones were to change, we would require BP to resolve issues with us. PHMSA requires a strong space systems approach to ensure pipeline safety and reliability. Our Integrity Management approach continues to show positive results. IMP, as we call it, is our primary strategy to protect infrastructure and people and managed system risks through processes that improve safety performance.

Integrity Management is solidly based on process safety management principles. IMP is the operator's responsibility. Company leaders must communicate this IM to all employees and know the approach is understood, executed and measured. Transparency is critical throughout the organization and identifying risks, choosing controls and evaluating program effectiveness. As risks change, the operator needs to be vigilant. They need to use the best data on risk, make the best risk control decisions and employ resources to the greatest risk, worst first.

We have championed this message for 15 years. More recently, we have looked at the lessons from the Texas City refinery accident as determined by the Chemical Safety Board and other reports. The Process Safety Management message should be highly instructive to BP. If safety demands, it is BP's responsibility to go beyond Integrity Management minimums. Top management must have and share safety values throughout the organization. Safety has to be integrated into business priorities. Employees need a trusting and open environment for the discovery and resolution of safety problems.

Emphasis needs to be on looking forward on what could happen, rather than solely through the rear view mirror on what has happened. We are currently working with BPXA and establishing leading indicators on improved processes to help track how safety programs are working. We will address how risk assessment and risk management can become more effective. BP is putting all their jurisdictional pipelines into the Integrity Management Program, a good first step. This is a change and they have a way to go. We will be monitoring this process carefully and for a long time.

I also want to highlight the commitment of the Department and the State of Alaska to coordinate our efforts. We believe better insights on improved safety, environment and reliability performance will be derived from a holistic systems perspective, looking at all oil and gas operations through the same lens. We foresee good opportunity for progress through improved coordination of our programs. Thank you. I would be pleased to answer any questions.

[The prepared statement of Ms. Gerard follows:]

WRITTEN STATEMENT OF STACEY GERARD
ASSISTANT ADMINISTRATOR/CHIEF SAFETY OFFICER
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
U.S. DEPARTMENT OF TRANSPORTATION
BEFORE THE
SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

May 16, 2007

I. INTRODUCTION

Chairman Dingell, Ranking Member Barton, members of the Committee: Thank you for the invitation to appear today. I am pleased to discuss the actions of the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) to oversee continued safe operations of BP Exploration Alaska, Inc. (BPXA) and to prevent future pipeline failures like the one that occurred on BPXA's operations on the North Slope in March 2006.

Since we last appeared before the Committee, Congress passed and the President signed the Pipeline Inspection, Protection and Enforcement Safety (PIPES) Act of 2006. I want to thank Chairman Dingell, Ranking Member Barton and the Committee for their leadership in advancing this important safety legislation. In compliance with the PIPES Act, PHMSA is moving forward with several rulemakings, including extending full regulatory protection to low-stress hazardous liquid pipelines, like the BPXA lines that are the subject of this hearing. These new requirements will reduce the risk of future failures of this type. We also recently launched our enforcement transparency website, to provide the public important information about

PHMSA's enforcement actions. I am pleased to report we took this action eight months in advance of the statutory deadline and we have received positive feedback from the stakeholder community on the use of this website. To further enhance the transparency of our operations we also have restored limited public access to the National Pipeline Mapping System. We took this action in close coordination with the Transportation Security Administration in order to properly balance important security and public right-to-know interests. We have a public meeting next week on improving control room management and human factors risks. We look forward to continuing to work closely with the Committee and keeping you apprised of our progress as we work to implement the PIPES Act.

We also have progress to report concerning our oversight of BPXA. Based on our ongoing monitoring of BPXA activities and pipeline inspection results, we have increasing confidence in engineering, operations and maintenance of the existing transit lines. BPXA has also begun replacement of the Prudhoe Bay transit pipelines and is beginning to address management problems that contributed to the failures they experienced last summer. We are also improving our coordination with the State of Alaska and our expectation is this improved coordination will result in better oversight of future BPXA activities in Alaska.

II. OVERVIEW OF DOT RESPONSE TO THE BPXA FAILURES

As you know, PHMSA immediately took action following a March 2, 2006 oil spill caused by the failure of a 34-inch diameter above ground pipeline in the Western Operating Area (WOA) referred to as OT-21. We exercised statutory jurisdiction over BPXA's three transit lines by issuing a Corrective Action Order (CAO), and directed the remediation and repair of the failed line. Our order covered the WOA line, which failed in March, as well as the Eastern Operating Area and the Lisburne lines, a total of 22 miles of low-stress lines. Our mission remains knowing the condition of these lines, understanding past and potential failure mechanisms, and ensuring that the operator takes all needed action to keep the pipelines operating safely in the future.

Our Corrective Action Order required BPXA to determine the condition of its pipelines and to repair defects. We ordered BPXA to run what are known as cleaning or maintenance pigs to remove solids in the line and to perform in-line inspections, known as smart pigging, to understand the pipe condition from the inside out. We directed more frequent testing and an enhanced corrosion management plan, including addressing the use of corrosion inhibitors to improve corrosion prevention. We required running cleaning pigs on a routine basis to remove water and other constituents that could contribute to internal corrosion.

Since then, we dispatched multiple teams to inspect the pipe that failed; assess the cause of failure; review operations and maintenance records; review qualifications of personnel; monitor operations, including testing; inspect repairs; and verify compliance with our requirements. PHMSA personnel evaluated fully all potential integrity threats to the transit lines along with BPXA programs to mitigate those threats.

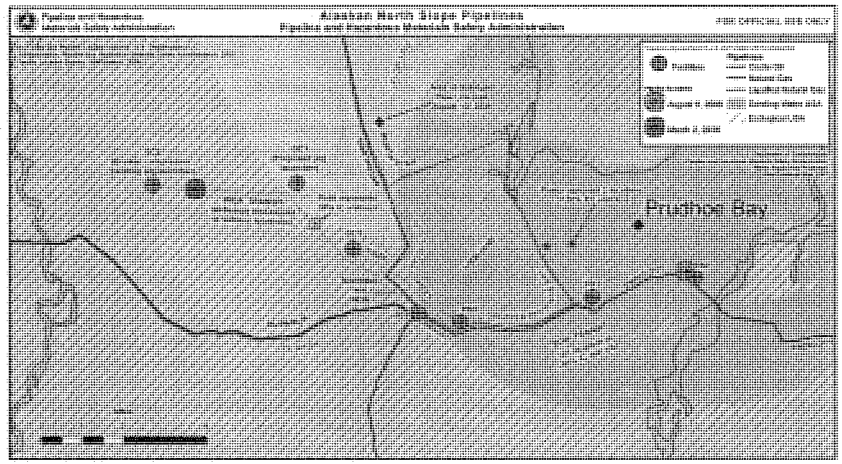
We directed improvements of BPXA's Interim Monitoring Strategy such as increased corrosion monitoring points to reduce the risk that vulnerable locations could be overlooked. PHMSA directed BPXA to utilize extensive non-destructive testing to better evaluate the condition of the pipelines until the lines could be fully assessed with an in-line inspection tool or smart pig. We directed that more stringent repair criteria be utilized and that communications be improved between analysts and field teams. We also required frequent patrolling of the pipelines, including the use of infrared technology. We have maintained a field oversight presence to ensure the operator was taking the actions necessary to maintain safety.

Before we allowed BPXA to proceed with pigging, we investigated the amount, composition and density of "sludge" material and how it would be handled to be sure that BPXA operations posed no risk to the safety and reliability of the Trans-Alaska Pipeline System. On July 20, 2006, we issued an amendment (Amendment Number One) to our original order, mandating that BPXA develop specific plans and timetables or parallel tactics to expedite pigging operations on lines that had not yet been cleaned. We required safe "de-oiling" of the idled OT-21 line segment that failed in March, 2006. The pipeline still contained approximately 17,000 barrels of oil. We also ordered BPXA to obtain post-pigging wall samples and gamma ray photography post pigging to gain the best possible understanding of the real-time levels of remaining solids.

On July 22, 2006, 37 days after the deadline established in our March order, BPXA performed the smart pigging ordered by PHMSA on the 30-inch segment of the FS2-FS1 Eastern Operating Area (EOA) pipeline. BPXA informed us of the results of the testing on August 4. BPXA's report identified 16 locations of wall loss in excess of 70 percent of the original thickness in 12 separate areas. Two locations showed over 80 percent loss and 187 sites showed pipe wall loss exceeding 50 percent. While the failure on the WOA line occurred on a low spot in a caribou crossing, the locations of severe wall loss on the EOA line were on straight pipe, indicating the possibility of different types of corrosion processes occurring in different operating areas.

On August 6, 2006, BPXA discovered a leak while performing direct examination of the EOA as a follow-up to the mandated smart pig inspection. On the basis of this leak and the discovery of several other locations that were beginning to leak, BPXA reported to us its initial decision to shut down both the EOA line and the WOA line. BPXA subsequently decided to keep the WOA line operating and to consider restarting the 34-inch segment of the EOA line.

In response to this second spill on the EOA line, on August 10, 2006, PHMSA issued a second amendment to our order (Amendment Number Two), requiring, among other safety measures, additional rigorous, automated ultrasonic inspections on a continuous basis of the pipelines that had not yet been pigged and outlining the standards BPXA would need to meet to restart its EOA pipeline. The order also required the de-oiling of the failed segment of the EOA line. Given that BPXA was not able to sufficiently explain the causes of the corrosion on the Eastern line at that time, and the potential extent of damage to the pipe wall, PHMSA required that BPXA demonstrate that the EOA line was in safe condition for pigging operations. PHMSA authorized restart for testing only when we had adequate data and corrosion modeling plus analysis of data regarding the EOA line.



III. DOT HAS TAKEN ACTIONS TO REQUIRE SAFE OPERATION OF THE PRUDHOE BAY OIL TRANSIT LINES

Recognizing the impact on nationwide crude production following the shut down of this system, PHMSA maintained a monitoring presence on the North Slope through this assessment process, focused on getting a better understanding of the condition of the EOA line to determine whether it could safely return to operation for the purposes of cleaning and inspection, and eventually operation. Our review of the data collected for the EOA 34-inch diameter pipeline was extensive. We engaged expert independent consultants to provide an additional perspective on the statistical sampling approach that BPXA employed and the effectiveness of the corrosion field testing. PHMSA expertise, combined with opinions provided by these additional resources, as well as the results of BPXA independent consultants, were integrated into our decision in September of last year to allow the 34-inch EOA pipeline to return to operation for the purposes of cleaning and inspection.

Following DOT protocol for preparing the EOA pipeline for return to service, BPXA launched a magnetic flux tool in the 34-inch diameter pipeline, which could detect the level of internal and external corrosion on the full circumference of the pipeline.

As a parallel activity, as required by our CAO, BPXA continued to conduct external tests, using ultrasonic means and other approved technologies on the WOA pipeline, to provide data to support that pipeline's continued safe operation.

With respect to the WOA pipeline which was still in operation. BPXA removed the sludge from the line and launched an in-line inspection tool, as required by PHMSA orders, to determine the extent of corrosion on the line.

The in-line inspection results for both of the oil transit lines, along with results from the other external tests, indicated that the lines are "fit" for continued use until the new pipelines that are currently under construction are operational next year. Any damage observed is not significant enough to warrant immediate concern, but aggressive corrosion control and continuous monitoring is required. Prior to making this determination, PHMSA staff physically inspected all of the higher profile corrosion sites identified by the smart tool runs.

As added protection to people and the environment, with a third Amendment of the CAO issued on April 27, 2007, PHMSA is requiring frequent corrosion monitoring of numerous sites on the pipelines. Additionally, we are requiring that BPXA repeat in-line inspections for these pipelines on a 12-month cycle and provide data from the inspections for our review and analysis.

To complete our investigation, PHMSA and subject matter experts from the Oak Ridge National Laboratory are reviewing and analyzing the WOA and EOA pipeline designs, maintenance policies, corrosion monitoring methods, inspection procedures and operating practices.

IV. MORE INSIGHT INTO CORROSION

We've continued our examination of corrosion mechanisms affecting these lines to improve our understanding of how the leaks occurred and the risks of further line degradation.

Last September, based on our analyses at that time, we believed that internal corrosion, induced by microbial activity, caused the WOA pipe to deteriorate at the point where it failed – a low section in a caribou crossing. Additional testing conducted since the fall reinforced that assessment. Given the many risk factors in the North Slope environment, including use of water in the production process, the chemistry of the crude oil product itself, and the varied geologic factors in the production field, we believe BPXA should have run cleaning pigs on these lines on a regular basis to reduce the potential for this microbial process.

Under PHMSA's direction, independent corrosion experts reviewed the conditions of the EOA and WOA pipelines and found evidence of emulsified/entrained water in the oil – and that the water has a high chloride concentration. This environment is conducive to microbial populations leading to localized corrosion. Additionally, sediments/sludge likely reduced the effectiveness of any corrosion inhibitors that were being used, prior to the cleaning regimen required by PHMSA.

Laboratory test results and analysis on the WOA pipe sample, from BPXA's third party consultant, became available on March 30, 2007. The pipe contents included a 5-inch thick layer of sand and silt with evidence of corrosion inhibitor bound to it. The BPXA analysis confirms our original assessment from last year that the primary corrosion mechanism involved sulfur-reducing bacteria.

Last week, we observed final testing of the EOA pipe sample and reviewing the results. We will withhold a determination on the EOA until we have reviewed the data from this testing.

V. CONSTRUCTION OF NEW PIPELINES UNDERWAY

In response to a formal request, on January 10, 2007, BPXA presented PHMSA its plans for rebuilding the EOA and WOA pipelines. The plans reflect many engineering and safety upgrades over the existing pipeline system and construction of the new pipeline is underway.

The new lines are being designed to PHMSA code requirements. BPXA is utilizing smaller pipe diameters to increase fluid velocity to a point that should prevent any water from dropping out of the oil mixture; minimize the accumulation of fine solids; and reduce the opportunity for microbial growth. The pipe elevation will also be higher, providing better access for inspection and maintenance. The higher elevation will also eliminate intentional dips for animal- and road-crossings and will reduce the potential collection of water and solids. In addition, new and deeper pipeline supports for stability, and better coatings and insulation, will also be utilized to reduce external corrosion.

Additionally, BPXA has committed to installation of new and redundant leak detection systems which are more sensitive and more likely to detect small leaks. A dedicated chemical injection system will provide better control and greater effectiveness of corrosion inhibitors in the fluid stream. The system design will include pig launching and receiving facilities for all segments and will also be appropriate to withstand the harsh climatic conditions.

PHMSA continues to provide in the field oversight of the construction activities. Progress is constrained by weather conditions, allowing for heavy construction only during the winter months of January through April when ice roads provide for travel over tundra without damage. BPXA's schedule calls for all of the new Oil Transit System lines to be in operation by the end of December 2008. Communication from BPXA to PHMSA with respect to the project milestones is required by our third Amendment of the CAO.

VI. GOOD ENGINEERING IS ONLY PART OF THE SOLUTION

PHMSA requires a strong risk-based systems approach to ensure the safety and reliability of our nation's energy pipeline infrastructure, and our Integrity Management Program (IMP) (49 C.F.R. 195.452) approach continues to show positive results. PHMSA uses integrity management as the primary strategy to integrate protection of infrastructure and people and manage the pipeline systems' risk through plans and safety processes that attain improved safety performance.

The IMP process is the operator's responsibility. In using this strategy, operators must communicate it through their leadership to all employees and know the approach is understood, implemented, documented and measured. Operators need to provide transparency throughout their organization in identification of risks; controls chosen; and evaluation of risk control effectiveness. As risks change over time, operators need to be vigilant to assess these risks thoroughly and systematically and measure risk control performance. Operators need to use the best available data on risk history and potential; analyze results; make the best decisions; and deploy attention and resources against the greatest risks--worst risk first.

In evaluating BPXA's posture on the North Slope, in addition to our own observations, PHMSA took a hard look at the important lessons learned from BP's Texas City Refinery accident as determined by the U.S. Chemical Safety and Hazard Investigation Board and other reports prepared for BP. These examinations, and their focus on BP's "process safety management" programs and systems, should be highly instructive to BP. In addition, reports have noted that a strong culture in personal safety does not necessarily translate to a strong culture in process safety. PHMSA agrees and because our pipeline integrity management program is based on these process safety principles, we believe expanding the application of the IMP system-wide by BPXA is a good first step.

BPXA is, in fact, doing this on the North Slope. We believe that to improve performance and continue to make progress, it is BPXA's responsibility to go beyond IMP regulatory minimums if safety demands. To advance safety culture, the set of clearly defined values must be communicated and demonstrated by top management and shared throughout the organization. Safety must be integrated into business priorities. Safety culture promotes a trusting and open environment for the discovery and resolution of safety problems and emphasizes the importance of looking forward, rather than looking solely through a "rear view mirror" which focuses only on incident data.

We are currently working with BPXA in reviewing leading indicators to get better insights into their operations. We will address how BPXA can make more effective the practice of comprehensive risk assessment and risk management – we believe this is critical to their improved safety, environmental and reliability performance.

BPXA is significantly modifying its approach to managing risks on the Prudhoe Bay systems, and has included all jurisdictional pipelines in its integrity management program, whether or not the lines are actually in or near a high consequence area. We are pleased to see this higher level of commitment from BPXA and will be monitoring its implementation carefully.

I also want to highlight the commitment of the Department and the State to coordinate our efforts to provide more effective oversight of BPXA and other pipeline operations in Alaska. PHMSA jurisdiction over the transportation of oil and gas products covers only a part of a vast system of oil and gas operations. For the most effective oversight, we believe insights on improved safety, environment, and reliability of performance will be derived from a holistic systems perspective. We have offered to share our data and approaches with the State as part of broader efforts in this area. We foresee good opportunity for progress through improved coordination of our programs.

Thank you. I would be pleased to answer any questions you may have.

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Mr. STUPAK. Thank you, Ms. Gerard. Before we go to questions, I see the ranking member of the full committee, Mr. Barton, is here. Mr. Barton, would you care to make an opening statement?

Mr. BARTON. Thank you, Mr. Chairman, but in the interest of time, I want to apologize for being late. We have got another hearing going upstairs, so I have to shuttle back and forth.

[The prepared statement of Mr. Barton follows:]

PREPARED STATEMENT OF HON. JOE BARTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. Chairman, I am very pleased that you have continued our investigative work on this issue, because more work is needed to get to the bottom of what went wrong last year.

At our subcommittee hearing last September, I had hoped that the committee would get to the bottom of what caused the leaks that led to the shut-down of Prudhoe Bay oil field last August. I had hoped that the subcommittee could make sure that all the facts were in the public domain on what caused the corrosion that led to the spills in both the east and west transmission lines on the North Slope of Alaska.

BP left many questions unanswered last September. The subcommittee issued a subpoena to Mr. Richard Woollam—the BP executive in charge of corrosion control and the individual most knowledgeable about what went wrong—but Mr. Woollam asserted his fifth amendment right against self-incrimination and declined to provide testimony or answer questions before the subcommittee.

After the hearing, the subcommittee discovered that BP failed to produce important documents that were its possession before the hearing. In October, we sent BP a letter demanding an explanation on why some of these documents were not provided. Finally, just last month, the floodgates opened and BP provided thousands of documents responsive to several written requests from the committee from last year and that should have been provided much earlier.

I had hoped that this hearing could focus on BP's path forward, the company's plans to replace corroded transit lines, and BP's efforts to rebuild the public trust in its North American operations.

But how do we know that BP has taken the necessary steps to correct its past mistakes? Instead, BP and its lawyers have withheld important information from the committee throughout our investigation. And now it looks like the company had plenty to hide. The recently provided documents reveal questionable corrosion management decisions in the years leading up to the leaks in 2006. Until these concerns are fully understood and addressed, no one should conclude that BP has turned the corner.

In addition to problems in Alaska, BP has experienced more serious problems at its refinery in Texas City. The U.S. Chemical Safety Board recently investigated the Texas City Refinery explosion that killed 15 people in March 2005. That report found "organizational and safety deficiencies at all levels of the BP Corporation." I am glad the CSB is here today to discuss their findings.

I look forward to the testimony today from chairman and president of BP America Mr. Bob Malone. I believe Mr. Malone has taken several positive steps since he took over last summer, and I am confident that he wants to set things right. His company got off to a bad start and then it made things worse. Now would be a good time to demonstrate that BP can be a reliable producer of petroleum and a reliable producer of truth, too.

I thank the chairman and I yield back.

Mr. STUPAK. I understand and there are a number of hearings. I know I will be shuffling back and forth as well, and Mr. Melancon will have to take over.

Mr. Whitfield asked unanimous consent that the binders—which I will be asking questions from—be made part of the record. Without objection, so ordered.

Members will have 10 minutes for questions.

Ms. Merritt, if I may start with you, please, with my questions. On page 25 of your Chemical Safety Board's Investigation Report on the Texas City refinery explosion, the first finding is cost cutting and budget pressures from BP Group executive managers impaired process safety performance at Texas City. Is that correct? And how deeply had BP cut and for how long? I mean, was this recent, did it go back at this Texas City refinery? Could you explain a little bit more on page 25 of your report?

Ms. MERRITT. Thank you. Yes, that is correct. How far back did it go? Well, actually, 1999 we know that the first 25 percent operating budget cut was issued.

Mr. STUPAK. So 1999, that is when BP just purchased it from Amoco?

Ms. MERRITT. That is correct. And that was issued by Lord Browne.

Mr. STUPAK. OK. And Mr. Browne, at that time, was the CEO of BP, right?

Ms. MERRITT. That is right.

Mr. STUPAK. In your testimony you state there are striking similarities in the reported causes of the 2006 events involving BP's Prudhoe Bay pipelines and the 2005 explosion at the BP Texas City refinery. What are those similarities?

Ms. MERRITT. Well, there were a number of them. One of them is management had changed efficiencies. One of the things that we found in our investigation was that changes were made in processes, procedures and operations without an appropriate evaluation of those risks. Failure to close action items from audit; there were many audits that were conducted at Texas City, as well as is reported in the Booz Allen report, and items that were identified in those audits that should have been red flags were not evaluated by management and they were not properly addressed, investigated or corrected.

Inadequate communications and excessive decentralization; the organization at BP was highly decentralized. There were a lot of people responsible for a lot of things, but it was almost impossible to find a chain of accountability for process safety in the organization.

Mr. STUPAK. The committee asked you to take a look at the Booz Allen Hamilton report and on page 2, and you alluded a little bit to this in your testimony, the Booz Allen Hamilton report found that, and I quote, "budgets and funding levels were largely based on affordability versus necessity and were not supported by an analytical process to prioritize risk." Is this finding essentially identical to a checkbook mentality, the words you used, found by the Chemical Safety Board in their audit of BP?

Ms. MERRITT. Yes, exactly. Budget cost cutting became the driving factor in management bonuses and recognition and as a result, short-term cost cuts were often made at the risk of long-term risks, so we found that consistent with the BP investigation.

Mr. STUPAK. You said bonuses. Did the bonuses, I take it, for the executives, were they based upon profitability of the company? I know I brought up $106 billion over the years; we are talking about from 1999 to 2006. So if you cut your maintenance costs, which increases the risk factors, but if you cut costs, therefore there is more money, therefore more profits, i.e. bigger bonuses, is that fair?

Ms. MERRITT. That was the plan. Their performance standards focused only 10 percent on safety and that was based on a lost time incident rate rather than a recognition of risk, of growing catastrophic risk.

Mr. STUPAK. Thank you. Ms. Slemons, there should be a binder there with a bunch of tabs. Can you go to No. 28 for me?

Ms. SLEMONS. Yes, sir.

Mr. STUPAK. And No. 28, if you will, is an August 31 letter to Mr. Malone from this subcommittee signed by Mr. Barton, Mr. Dingell, Mr. Whitfield and myself. Again, this is back in August 2006. There is another letter, October 4, from Mr. Whitfield and if we go on there, in the letter of—all letters are there and in order as they were written. There is a letter of October 28 and attached to it is the Compliance Order by Consent before the State of Alaska Department of Environmental Conservation.

Ms. SLEMONS. What was the date of the letter, sir?

Mr. STUPAK. October 28. But it would be CBOC there. The compliance order, Compliance Order by Consent.

Ms. SLEMONS. Yes, sir, I am looking for it. I don't see it here. Tab 28, correct?

Mr. STUPAK. Yes.

Ms. SLEMONS. I have the Compliance Order by Consent.

Mr. STUPAK. OK, there you go. Let me ask you this. On that compliance order, when I take a look at it here—I am on page 5, paragraph 23. It says in order to address the violations outlined, count 1 through 4, specifically, BPXA agrees to perform the following tasks by the dates indicated herein. Then there are about eight items they have to do, two of them which, No. 3 was take EOA, that is the Eastern Operating Area pipeline, from FS1 launcher to Skid 50 by 6/30/02 right underneath there.

The next one, No. 4, pig WOA, Western Operating Area, pipeline segments, if necessary, by 9/30/02. Then we find they are required to do the pigging. Now, this is going back some time. Yet, Alaska reversed this requirement. It was a consent agreement. BP agreed to pig these two operating areas, Eastern and Western, by 2002, but then suddenly there was an agreement not to do it, not to do the pigging. Do you have any reason why that was rescinded by the State of Alaska after they agreed to do it in a compliance order?

Ms. SLEMONS. I have asked the Department of Environmental Conservation for the reasons for that decision. The intent of the consent order by decree, as I understand it, was to identify the actions that BP needed to take prior to testing a leak detection system, specifically. Sediments were raised as an issue that could affect test performance and were the prime reason for requiring the pigging. This consent order by decree took quite some time to actually accomplish and to move through and there were several actions that took place over the course of, as I understand it, about a year.

Approximately 1 month before the leak detection test was to be performed, BP responded to the various issues identified and noted that sedimentation would not affect the leak detection test results, therefore the pigging was not necessary. And in conversations with the Department of Environmental Conservation, it is my understanding that DEC did consider that issue to be addressed and that it would not affect the leak detection system test, which was their primary goal.

Mr. STUPAK. But was anyone aware that even at that date, it was probably 10 years before that, it was the Eastern line, I think it was, had not been pigged for 10 years?

Ms. SLEMONS. I can't answer to what the DEC officials' knowledge was at that time.

Mr. STUPAK. What about the solids in the pipeline? Wouldn't that affect the flow and the integrity of those pipelines?

Ms. SLEMONS. One would think, of course.

Mr. STUPAK. And isn't the standard now every 3 years you have to pig a pipeline, transit oil pipeline?

Ms. SLEMONS. Yes. And in fact, they are pigged quite frequently.

Mr. STUPAK. You said this took a long time to put together. This consent order was issued in May 2002 and then on August 9, 2002, BP asked to eliminate the requirement of piggings for the lines and then let us say in a month later, actually 5 days later, State of Alaska agreed to it. It seems like it takes a long time to put together but then as soon as they want something, snap, quick, it is done, it is resolved and that is a critical element of maintaining the integrity of these lines, were they not?

Ms. SLEMONS. I agree that it is a critical element, yes, sir.

Mr. STUPAK. OK, thank you.

Ms. Gerard, in your testimony, you said something there about the—and I want you to explain a little bit more—the sludge build up makes the corrosion inhibitor that we have been talking about ineffective. Explain that a little bit more for us, if you would, please.

Ms. GERARD. The corrosion inhibitor should be able to reach the wall of the pipeline, but if sludge and sediment is adhering to the wall of the pipeline, then the inhibitor doesn't have a good chance to do its job.

Mr. STUPAK. So how would you get the sludge that is adhering to the wall of the pipeline, how would you get it out?

Ms. GERARD. By regular cleaning of the pipeline.

Mr. STUPAK. By pigging, is that correct?

Ms. GERARD. Usually by cleaning pigs, yes, sir.

Mr. STUPAK. Ms. Slemons, I know you weren't there at the time, but any reason why Alaska didn't require them to do it then? I mean, we had it in the order, they rejected the order; no explanation why other than they didn't think it was necessary. I mean, if you get the sludge building up, you know you have to get it out. You have got to pig it. They were told to do it and less than a month later, you were told you don't have to do it.

Ms. SLEMONS. Mr. Chairman, it has been explained to me that the entire focus of the COB was the leak protection system and that the explanation that BP offered regarding the sediment and the requirement of pigging, that the pigging was not a requirement to address the leak detection system was sufficient at the time. Beyond that, I am afraid that is just beyond my expertise. I would be happy to find any answers that I can for you and provide them later.

Mr. STUPAK. When you have sludge building up on the side walls, the corrosion inhibitors are not working and then you don't pig, that pipeline is going to leak eventually, right?

Ms. SLEMONS. And so we saw that it did, sir.

Mr. STUPAK. Thank you. My time has expired. Mr. Whitfield for questions, please.

Mr. WHITFIELD. Thank you, Mr. Chairman.

Ms. Gerard, Mr. Malone took over the reins of BP America sometime last year, after the event at Prudhoe Bay, and my understanding that he replaced the entire management team in Alaska and I am assuming that you all, and I would ask all of you involved, that new team, I am assuming, has been more responsive than certainly they were before. Would that be accurate?

Ms. GERARD. The new team has been extremely responsive.

Mr. WHITFIELD. And have you been involved with them at all?

Ms. SLEMONS. No, sir.

Mr. WHITFIELD. Ms. Slemons, I am sure you have.

Ms. SLEMONS. Yes, I have, sir.

Mr. WHITFIELD. And what is your assessment of the new team?

Ms. SLEMONS. I also find them to be extremely responsive and cooperative.

Mr. WHITFIELD. OK. Now, in your testimony, you mentioned that Prudhoe Bay taught you that you cannot rely on enlightened self interests to ensure that prudent managed maintenance practices are carried out and by that, I am assuming that you meant that the company took on that responsibility and no one really monitored it at all, is that correct?

Ms. SLEMONS. That is correct. That has traditionally been the status.

Mr. WHITFIELD. And prior to the formation of the integrity group that you are now with, what authority did the State of Alaska have over these pipelines?

Ms. SLEMONS. Over the specific pipelines, we did not have oversight authority. The Department of Environmental Conservation has authority, generally, throughout the State, for environmental concerns, protection of land, water and air.

Mr. WHITFIELD. Right. But you had no authority over the actual maintenance of these low-stress pipelines?

Ms. SLEMONS. That is correct. We believe that to be the fact.

Mr. WHITFIELD. And DOT, prior to the passage of the PIPES Act by Congress last year, you had no authority over the low-stress pipelines, Ms. Gerard?

Ms. GERARD. That is not exactly correct. We had authority that we had not exercised over the low-stress pipelines in rural areas. We had the authority prior to the PIPES Act. The PIPES Act gave us some specific additional requirements.

Mr. WHITFIELD. And so that is when you did this correction action order or——

Ms. GERARD. We did the correction action order the week following the accident.

Mr. WHITFIELD. And Ms. Merritt, did your agency have any oversight or responsibility for these pipelines and safety issues or do you primarily become involved after an accident?

Ms. MERRITT. Yes. Well, we have authority to investigate hazards, but normally, the pipeline would not have been something we have looked at.

Mr. WHITFIELD. And Mr. Fairfax, what about OSHA? What responsibility did you all have prior to the leakage?

Mr. FAIRFAX. Alaska is a state-plan State, so we had no really involvement or authority, although I will point out if there is a complaint related to pipeline safety, that way we would have jurisdiction for investigating the complaint of the whistleblower related to pipeline safety.

Mr. WHITFIELD. OK. Well, looking back in retrospect, I mean, obviously BP had some major problems and some major failures in their maintenance program, but in retrospect, did government fail in any way in this process? Yes, Ms. Gerard.

Ms. GERARD. We regret that we did not have the regulation of rural low-stress pipelines in effect before the accident occurred. We had regulation on low-stress pipelines in populated areas and of course, all high-pressure pipelines, but we had just begun the process of public meetings and proposing regulation just about the time the accident occurred.

Mr. WHITFIELD. So you had the authority to oversee these, but the regulations were not in effect?

Ms. GERARD. That is correct.

Mr. WHITFIELD. But they are in effect today?

Ms. GERARD. We have just issued a supplemental notice that adds to our original proposal the additional requirements that the PIPES Act mandates for all low-stress pipelines. The PIPES Act broadened areas of coverage to include all low-stress pipelines and all parts of part 195 of the Federal Pipeline Safety Code. That is a bit broader than what the administration had proposed.

Mr. WHITFIELD. And if you had had those regulations in place prior to this event, what steps would you have taken to be more up to speed on the maintenance and the condition of those pipelines?

Ms. GERARD. If this was a regulated pipeline, we would have been conducting a comprehensive Integrity Management inspection, operator qualification inspections and all other types of inspection of our code that we routinely do for all regulated pipelines.

Mr. WHITFIELD. And how many miles of pipelines do you regulate today? Do you have any idea?

Ms. GERARD. All pipelines in the United States.

Mr. WHITFIELD. And pigging is a regular maintenance step that is taken on all those pipelines, correct?

Ms. GERARD. We believe that most operators routinely clean their pipelines in order to be able to maintain them in a safe condition. The Pipeline Safety Code doesn't specifically use the word cleaning. We do require smart pigging in high-consequence areas to be able to assess condition of pipeline.

Mr. WHITFIELD. And how expensive is that for a company, say, smart pigging? Do any of you on this panel have any idea of the cost of that?

Ms. GERARD. I would say an average segment of pipeline would be about $50,000 to $80,000 to pig, to smart pig, based on the length, the condition, the type of pig.

Mr. WHITFIELD. I see. Now, it is my understanding that the Western and the Eastern pipelines are now in operation and yet there is a construction project going on for 16 miles of pipeline, is that correct, Ms. Slemons?

Ms. SLEMONS. Yes, that is correct.

Mr. WHITFIELD. And do you feel confident that BP can operate the old transit lines safely over the next few years as they try to complete this new pipeline?

Ms. SLEMONS. We are confident in census assessment that those lines are fit for use and we are keeping a close eye.

Mr. WHITFIELD. And does the State of Alaska have the authority to impose fines or take other actions to see that that is done?

Ms. SLEMONS. The Department of Environmental Conservation has recently promulgated new regulations that address flow lines, which are those lines that extend from the wellhead to the production facilities and those regulations are in phased implementation now and do include several different layers of penalty, including fines. For the OTL lines, themselves, the State of Alaska does not have fining capabilities. PHMSA regulates those lines.

Mr. WHITFIELD. Oh, so you have no authority to enforce on those lines, the OTL lines?

Ms. SLEMONS. We believe that the broad authority in our oil and gas leases allow us to assert ourselves and exercise oversight wherever that is necessary, however it is our policy not to duplicate oversight where it is sufficient and PHMSA's oversight of those lines is what we rely on at this time.

Mr. WHITFIELD. And since BP acquired these lines from Amoco in 1999, have there been any additional spills in Alaska other than this one, what, it was 210,000 gallons, is that correct? Is that the only spill that you are aware of?

Ms. SLEMONS. Since 1999 there have been several very small spills, most of them below the reporting threshold, some at the reporting threshold. There have not been, to my knowledge, any major spills other than those.

Mr. WHITFIELD. And my understanding is that BP operates, what, five refineries in the U.S., is that correct, today or is it four?

Ms. MERRITT. Five.

Mr. WHITFIELD. Five? And they operated the Texas City refinery, as well, correct?

Ms. MERRITT. That is correct.

Mr. WHITFIELD. And that refinery is not in operation today or——

Ms. MERRITT. Yes, it is in operation. However, the unit where the explosion occurred in 2005, I believe, is not operational.

Mr. WHITFIELD. Yes. Now, I know that Lord Browne resigned. I am not sure if he resigned or he was asked to resign as chairman of BP International, but I am assuming that part of that probably came about because of these events at Prudhoe Bay and the Texas City refinery and just that culture of problems relating to maintenance and so forth. Are you all aware of that from your personal knowledge?

Ms. MERRITT. No.

Mr. WHITFIELD. OK. I yield back my 25 seconds.

Mr. STUPAK. Can I use your 25 seconds? Ms. Gerard, I asked Ms. Slemons about the Compliance Order by Consent on Alaska. You issued compliance orders, do you not, DOT?

Ms. GERARD. Yes, we do, under our statutory authority.

Mr. STUPAK. In fact, on this one, you are requiring them to pig every 12 months, if I remember correctly, right?

Ms. GERARD. That is correct.

Mr. STUPAK. Do you ever waive, after you ask them, if it is part of a consent order, do you ever go back and waive the pigging requirements, like Alaska did? I just find that highly unusual, because that is such a critical part of maintaining integrity of a line.

Ms. GERARD. We would not waive pigging requirements.

Mr. STUPAK. OK, thank you. Mr. Melancon.

Mr. MELANCON. Thank you, Mr. Chairman. Let me start by asking, if I could, each one of you, and I think I understand Alaska does not have the ability to fine on the pipeline incident because of the spills?

Ms. SLEMONS. We do not have regulatory fining authority for those pipelines, however the Department of Law is investigating both civil and criminal suits as we speak.

Mr. MELANCON. OK. You have the ability to fine, is that correct? I am sorry.

Ms. GERARD. We have the ability to fine for violations of our regulations.

Mr. MELANCON. And to date, how much have you fined BP?

Ms. GERARD. We have reserved the right to fine BP and have not completed that enforcement action yet.

Mr. MELANCON. What is the preliminary estimates of fines?

Ms. GERARD. It would be preliminary to say what the preliminary fine was.

Mr. MELANCON. So then, maybe I should ask you if BP is consulting with you to determine how much it is going to be.

Ms. GERARD. I would not say that, but the fines are established in statute.

Mr. MELANCON. They are in statute?

Ms. GERARD. Yes, they are.

Mr. MELANCON. On the chemical safety, the fines for the refinery, after these incidences that BP has had, what are the total fines that have been issued against BP?

Ms. MERRITT. The OSHA fine was—and Mr. Fairfax probably could answer that better than I can.

Mr. MELANCON. Yes, I will go to him first.

Ms. MERRITT. I think it was $21.6 million.

Mr. MELANCON. OK. And that is from your agency?

Ms. MERRITT. No, no, we do not issue fines or penalties or write regulations. We are an investigative board, similar to the National Transportation Board; make recommendations.

Mr. MELANCON. I have got you. Then, Mr. Fairfax, on the issue of fines, we have got at one plant five dead, I believe, another plant 15 dead, 180 people injured. What was the total fines against BP for these?

Mr. FAIRFAX. The total fine for the British Petroleum for the explosion was a little bit over $21 million and then we followed up with an inspection at the Oregon, Ohio facility and the penalties issued in that one were a little bit in excess of $2.4 million.

Mr. MELANCON. Do you recall the profits of BP in these specific years? Do you know?

Mr. FAIRFAX. No, no. I heard it mentioned earlier but I just don't remember what was quoted.

Mr. MELANCON. Just based upon what I have seen of earnings of all companies, in recent years, and I have been in support of them, $21 million sounds like kind of a low ball to me.

Mr. FAIRFAX. Well, that is the highest penalty ever issued by OSHA.

Mr. MELANCON. Maybe we, as legislators, need to review it. Is that by statute or is that by rule or regulation?

Mr. FAIRFAX. It is in the statute.

Mr. MELANCON. It is in the statute. Ms. Gerard, last September the Pipeline Hazardous Materials Safety Administration proposed new regulations to cover low stress oil transit lines such as the Texas City refinery to Prudhoe Bay. Yet, 7 months later, these regulations have not been issued. Why haven't they been issued?

Ms. GERARD. The passage of the PIPES Act did significantly expand the original proposal that we issued and we are required to do regulatory analysis to consider the additional mileage and the effect on small business, the effect on the Nation's energy supply. Comments on the docket, in fact, have indicated that there could be an adverse impact for western States who may not be able to keep pipelines in operation if these requirements were imposed, so we have to address those requirements in going to a final rule. The supplemental notice that we published yesterday, or we posted yesterday, picks up all the additional requirements of the PIPES Act and seeks comment on that, which is required by due process.

Mr. MELANCON. Now, the PIPES Act was effective when?

Ms. GERARD. In December.

Mr. MELANCON. This past December?

Ms. GERARD. Just this past December.

Mr. MELANCON. But this goes back to 2006 when we started the problem with the Prudhoe Bay issue?

Ms. GERARD. Well, the PIPES Act that passed at the end of December only at the end of December gave us clear additional requirements that we needed to add to our regulatory proposal, so those new requirements were only effective, basically, at the beginning of this year.

Mr. MELANCON. OK. So you have got all of these regulations that have been issued?

Ms. GERARD. They have been proposed and we were required to propose additional requirements to be consistent with the new law that passed in December. We have to get comments on those in the next 30 days and we will be proceeding with all due haste to meet the statutory deadline in the PIPES Act, to be complete within a year.

Mr. MELANCON. Within a year. Now is that year going to be back to 2006, because I think we have past a year.

Ms. GERARD. It would be a year from December 2006. But in the meantime, BP is—they are protected by the compliance order that PHMSA has issued and amended three times, so we have 36 to 37 specific requirements which we can enforce using our statutory authority.

Mr. MELANCON. Do you find that the approval is a slow in coming or is this normal? I understand. How much did you add into it with the PIPES Act?

Ms. GERARD. It was quite significant to consider all the additional regulations in the Federal Code, in addition to the requirements that we have proposed and given the fact that there is a lot of small operators in parts of the United States, we had to hear their comments and issues with, for example, the high cost of doing assessments like pigging and consider the effect on their operations, particular an issue in the Rocky Mountain States.

Mr. MELANCON. It is kind like I tell my son, if you can't afford Mercedes, you get a Chevrolet because buying is the cheap part. It is the maintaining that is the problem.

Ms. GERARD. Well, we have to be concerned about drinking water supply and if the pipelines operators chose not to operate, whether it would be as safe in a truck on a Rocky Mountain road.

Mr. MELANCON. Is there no regulations for preconstruction of ownership and maintenance and requirements of bonds, none of that?

Ms. GERARD. Until we bring the rural low-stress operator under regulation, they are not regulated, but we expect them to have good corporate stewardship no matter whether they are regulated or not.

Mr. MELANCON. Now, BP is under compliance under audit presently?

Ms. GERARD. That is correct.

Mr. MELANCON. And how long on the Prudhoe Bay issue do we plan to keep them under audit?

Ms. GERARD. As long as it is necessary.

Mr. MELANCON. Meaning?

Ms. GERARD. Years.

Mr. MELANCON. Years?

Ms. GERARD. As long as it is necessary.

Mr. MELANCON. So what do we do during those years, are we going to be checking them or are they going to be pigging these things or are they going to be cleaning these lines? What exactly is the agency going to be doing?

Ms. GERARD. Well, first of all, when this low-stress regulation is final, any of the system that is still low stress would be regulated. With the rebuilding of the pipelines, the majority of the lines we expect will no longer be low stress and they will become regulated when they are rebuilt and operational and they are a higher stress. In the meantime, PHMSA maintains, on-duty, several inspectors who are on site to witness all the required activities, including in the construction activities. And so they are required to assess and maintain corrosion protection, patrol, surveil, basically continuously understand the threats and address those threats on a priority basis.

Mr. MELANCON. BP indicated that the reason why this replacement line they were building in Alaska, because of lack of steel, they asked for a deferment or something to that effect. When did they make that request?

Ms. GERARD. I am not sure what request you are referring to. I know that there was a commitment to have the new construction done sooner than December 2008, but we reviewed their plans and for the significance of the upgrades that they have proposed, and pig launching and receiving, design to code, corrosion inhibitor systems, replacing the pipelines on new supports, deeper and stabilizing the soil, we believe that the rebuilding plan is worth the time of the December 2008 deadline.

Mr. MELANCON. So next year, 2008?

Ms. GERARD. December 2008.

Mr. MELANCON. Thank you, Mr. Chairman. I yield back my time.

Mr. STUPAK. For questions, Mr. Barton, please.

Mr. BARTON. Thank you, Mr. Chairman. My first question is to you, Mrs. Gerard. We passed what we call the PIPES Act last fall, on a bipartisan basis, giving more authority to regulate some of these low-stress, low-pressure lines. From what I can tell, that authority, you are attempting to use it but your final rule has not been implemented yet because of some problem at OMB. Is that correct or incorrect?

Ms. GERARD. No, sir, we published a supplemental notice yesterday which picks up the additional requirements that you PIPES Act, and I want to say thank you very much for giving us the PIPES Act. It is a great improvement for safety. So with that supplemental notice being out and getting public comment in the next 30 days from operators, about any additional burdens or operational problems we might need to consider, we expect to get the final rule on time, in accordance with the statutory deadline you gave us, sir.

Mr. BARTON. So you think that is going to be implemented in the time we fashioned?

Ms. GERARD. Yes, sir.

Mr. BARTON. OK. Now to you and the rest of the group, I know we have got a different mix of regulatory authorities, both State and Federal. Is there any additional Federal legislation that this committee or other committees need to implement to help you do your jobs?

Ms. MERRITT. One of the things I would like to comment on is that the process safety rule, which was implemented in 1993, was well thought out and an excellent rule. From the industry perspective, I have been in process engineering in many different industries for a long time. It was needed but it hit the nail on the head. There are two sides to that. One is the 14 elements that industry is required to implement, but the other side of that is the enforcement element that is written into the rule. OSHA has the authority to do program quality verifications and the way it was conceived is that these would be conducted as multi-day, possibly multi-week investigations by multiple inspectors who have education in engineering, refineries, chemical facilities, and they know what they are looking at. If this part of the rule had been implemented, which it was not, these program quality verifications would have done a lot to have sustained the implementation of PSM in industry. In 1993, I was part of the requirement, both at corporate and facility levels, to put it into place and I can tell you that the perspective of having a PQV audit did a lot to help us with that implementation.

Mr. BARTON. Is that something that you want Congress to take a look at legislatively, or is that something you just want somebody in the administration to arbitrate between you and OSHA?

Ms. MERRITT. Well, I don't think it is between us and OSHA, but the necessity for implementation and enforcement of the process safety rule is certainly necessary and the provision is there if OSHA were to implement it to have the authority to do the PQV audits. Our recommendation is that OSHA conduct the PQV audits. These are not the same thing as just a one-day inspection.

Mr. BARTON. OK. Thank you. We will continue that. Now you, ma'am. I think you represent Alaska?

Ms. SLEMONS. I do, the State of Alaska. Thank you for the question. I would like to speak to OSHA funding, if I could. You opened the door about improvements to Federal legislation.

Mr. BARTON. We will stipulate that you can always use more money. I mean, if that is what you are going to say, I can save you 2 minutes.

Ms. SLEMONS. It is not, sir.

Mr. BARTON. OK.

Ms. SLEMONS. The problem that we see with the OSHA funding is not that we need more, as you know, because everyone could always use more, but one of the problems is that Federal funding does not keep pace with increasing costs and it is our understanding that legislation does not allow it to do so. Increasing funding can be interpreted in several ways. We interpret it as not applying to simply inflation proofing the funding that we get. Over time, the funds available to Alaska, for both consultation and the enforcement arm of Alaska OSHA, have been eroded to the point where inspector positions are kept vacant in order to free up those funds for day-to-day business. So the ability to inflation proof the OSHA funding that comes our way would be important to the State of Alaska.

Mr. BARTON. Thank you.

Ms. SLEMONS. Thank you, sir.

Mr. BARTON. Well, I have only about 4 full minutes, so I am going to kind of cut to the chase. In response to either Mr. Whitfield or Mr. Stupak's question about how BP was cooperating, everybody gave an affirmative answer, that you thought BP was trying to cooperate. That is a little bit surprising to me, since the number one person, Mr. Richard Woollum, who was their corrosion manager, as far as I can tell, BP is putting on leave, he is still being fully paid, but he is not allowed to talk to anybody. Have any of you folks or your designees been able to interview Mr. Woollum? That doesn't sound like cooperation to me. The guy that is most responsible for the program, who apparently is part of a criminal investigation, I say apparently, because I don't know that for a fact, and he won't—his attorneys won't let him to talk to the committee staff. He took the fifth amendment, which he has every right to take. But if I had a full-time employee working for me and I was cooperating, I would at least let that individual who worked for me, while protecting his individual rights under the Constitution, I would at least make him available to be interviewed, especially if the company says he is fully cooperative.

Now, I have got also a list of things here in the committee memo that, since the investigation started in this subcommittee back in September of last year, kind of a timeline of what has been going on, and a retired U.S. District Court judge, who has been tasked with interviewing all of the complaints that the employees of BP have on safety. They have looked at 11 so far. In nine cases, the judge said they were substantiated, one is still to be determined and one was unsubstantiated. It says, our committee staff believes that the Alaska BP managers have resisted recommendations by the ombudsman and as a result, problem resolution has been delayed. That doesn't sound like cooperation to me.

I am also made aware, in October 2006, we finally got a copy of an Alaska Department of Environmental Conservation consent order, by decree, that BP was aware of sediment buildup in the oil transit lines. This is back in 2002. They did not provide that document to our subcommittee staff. Everything that is in this document, it looks like BP is trying to do the right thing in public and they are fighting like a tiger in private, but not implementing. So I know Mr. Malone is in the audience and he has been in to see me and I assume he has seen Mr. Stupak and Mr. Whitfield and Mr. Dingell and I will stipulate that he is trying to do the right thing, but it sure seems to me that everybody below him is resisting at least the implementation phase. Am I wrong? Are these staff reports that are given to me just incorrect?

Ms. GERARD. The answer that we gave on responsiveness related to new executive leadership put in place in December-January timeframe. We have under orders requested actions in about 37 areas under corrective action orders, and the company has been responsive to those. We are beginning to pursue inquiry with the BP on the extent to which the system BP has put in place to address employee concerns, how it is working, how it is organized, and we have notified BP that we intend to pursue investigation in that area.

Mr. BARTON. How strongly are you pursuing interviewing Richard Woollum?

Ms. GERARD. We have not attempted to interview Richard Woollum. We have been working with Mr. Bill Hedges and his team and we have requested required sampling of pipe wall, pipe fluids, solids, extensively and we have gotten access to the materials, we have done the analysis, we have looked at the results and we feel that the response we are getting from the current corrosion management leadership team is acceptable.

Mr. BARTON. Well, my time has expired, Mr. Chairman. I am going to yield back. I hope that we can continue to pursue this. I know it is a difficult balancing act between the rights of the individuals and also, frankly, the rights of the corporation. But the Booz Hamilton report that BP authorized talks about a ingrained corporate culture and systemic management failure. And that is not congressional investigation words. Those are words of their own consulting company. And these folks that represent the regulatory authorities at the State and Federal level can do the very, very best that they are allowed to do by law and if the entity in question, in this case British Petroleum, doesn't admit the problem and willingly agree to redress it, you are just going to shuffle the deck chairs. You are not going to really get the change that you need to in order to operate the BP facilities, not only efficiently and profitably, but safely. And this is an issue of a safety and we had numerous people killed. We have had a complete shutdown, at least temporarily, of the largest oilfield in North America, because of, apparently, a management culture that just refuses to get it, or at least did refuse to get it. And I don't know how we get to the bottom of that, but I hope, on a bipartisan basis, we will continue to try. And with that, I yield back.

Mr. STUPAK. I thank the ranking member. You know me, I am persistent and I will get the answers and I am sure we will have another hearing. I said in my opening that I hope that BP did not become the Los Alamos of the north, but you never know. I think we are headed for another hearing. We have three votes on the floor, but I think we can still get in Mr. Green for 10 minutes.

Mr. GREEN. Thank you, Mr. Chairman. Mr. Fairfax, I want to appreciate Occupational Safety being before the Energy and Commerce Committee and Oversight Committee. I know our jurisdiction is elsewhere. But you heard my opening statement and I have similar plans along the use of ship channeling and I want to make sure that we learn from those mistakes. The Texas City Refinery experience and the extraordinary high number of deaths, 23 workers over 30 years, 10 workers died during the previous 20 years, yet in your testimony you state that, prior to the explosion at BP Products in Texas City in March of 2005, there were no incidents at the Texas City Refinery that caused OSHA to employ the Enhanced Enforcement Program, a program OSHA uses to identify companies that repeatedly place its workers at risk. How can a refinery that, we know now, has one of the worst safety records in America not raise that red flag at OSHA?

Mr. FAIRFAX. Well, the Enhanced Enforcement Program actually started in October of 2004, so an incident before that did not get picked up in the program. That was a program we launched.

Mr. GREEN. There wasn't any effort to look at previous safety records?

Mr. FAIRFAX. No, we always look at previous safety records and the incidents that happened previous to the 2005 explosion, we certainly investigated, we have issued citations and penalties in those incidents, the Enhanced Enforcement Program we have was not in place at that time, so the 2005 inspection was really the first one where we launched that effort and did an alert for British Petroleum and conducted several other inspections.

Mr. GREEN. The Chemical Safety Board reported on the Texas City accident and found that, while OSHA did conduct a few unplanned inspections of the refinery in response to accidents or referrals, OSHA did not conduct a comprehensive planned process safety inspections at the refinery. In addition, from 1995 to 2005, OSHA only conducted nine such inspections anywhere in the country and none in the refinery section. How do you explain this low inspection record on the refinery industry, which statistically has more fatalities and catastrophe problems than the next three industry sectors combined?

Mr. FAIRFAX. I would have to go back and look at the data. I don't think I really agree with that. We have certainly done program inspections. I will agree that we haven't done as many as we should have, particular in the Texas area during that time period. We were focusing a lot on chemical plants, which you have and in Louisiana, have a lot of chemical plants. We had a local emphasis program at that time and it was focusing on process safety management in the chemical industry. One thing I want to make clear, I have been listening and it sounds like everyone seems to think that process safety management only applies to refineries. It doesn't. It applies to lots and lots of facilities, poultry plants, meatpacking plants, chemical facilities. We are doing inspections under that program in all of them. Just prior to the explosion in 2005, we did start putting together an national emphasis program and you know, I certainly appreciated the recommendations from Chem. Board, because that helped us in further developing a program. I will say that the Secretary just approved that program yesterday and we will be launching it shortly and under that program we will be doing process safety management inspections in every refinery under our jurisdiction for the next 2 years.

Mr. GREEN. Well, I know budget is always the issue, but it seems like, in our area, in Texas, the particularly the Houston area and Texas City, if there is an accident, it is not just somebody in a meatpacking plant that may have a problem, it is one person, but we make volatile chemicals. Unless you are very safe, they are going to blow up and they are going to kill people, plus the pollution, and that is why I think the emphasis ought to be looking at where the most injuries and the most damage could be done. So I am glad it was started. When did you say it was started?

Mr. FAIRFAX. Just before the explosion.

Mr. GREEN. OK. The Chemical Safety Board has made several major recommendations to OSHA, some of which OSHA has acted upon. And in 2002, after a 2-year study, the Chemical Safety Board recommended that OSHA expand the process safety management standard to include reactive chemicals, which could possibly prevent such reactive chemical accidents in and near our district. What is the status of that recommendation at OSHA, and why hasn't OSHA moved forward on that recommendation?

Mr. FAIRFAX. We have actually moved forward on the recommendation. We evaluated that recommendation, as we do every recommendation we get.

Mr. GREEN. You have been reevaluating, though, since 2002?

Mr. FAIRFAX. No, we have gotten, I think, 16 recommendations from the Chem. Board and we have implemented, Carol may know better, but I think nine of those recommendations. I am the one dealing with reactive chemicals. We did evaluate, at the time, the recommendation that came. We did not feel that we needed to open up the rulemaking for the Process Safety Management Standard. We have developed, and it is not done yet, but we have developed a directive for dealing with interpretation and inspections for reactive chemicals. We think that will cover the recommendation, plus some other things.

Mr. GREEN. Let me ask you, I had the impression in 2002, after the two-study, that CSB recommendation to OSHA, on the process safety management, PSM. Has it not been 5 years since you recommended that?

Ms. MERRITT. Yes, just about almost exactly 5 years.

Mr. GREEN. Mr. Fairfax, as I sit here today, in 5 years, do you know how many plants that should have been looked at that, again, are very volatile unless everything works right? And we need those chemicals, we need those refined products and I want to—their jobs and out tax base, but I also know that if there is not oversight from the Federal agency for inspections for job safety, 5 years is way too long to act on a recommendation.

Mr. FAIRFAX. I certainly hear you. In fact, you missed my oral testimony earlier. I used to work in the refineries in your area many years ago, so I am familiar with it, but it is not just to say that just because we haven't completed a directive on reactive chemicals, that we haven't been doing anything. We have been doing a lot in the area and we certainly can do more in our refinery emphasis—points to that. But we have done a tremendous amount of process safety work. We are retraining all of our investigators and we have done inspections. As I mentioned earlier, we had a local emphasis program where we were targeting the chemical plants in your area as well as in Louisiana and throughout what we call our region 6, which is the Texas area.

Mr. GREEN. Well, I know OSHA has and I have plants that have been awarded, because of their safety record, and so I appreciate that OSHA is proactive on that side. But I also know, if there is a problem, like whether it is Texas City or some other plant that is in my area, I want to be very proactive so we don't end up having another loss of 15 lives. And I guess the frustration is, and like I said in my opening statement, as Democrats, we are a minority here on energy legislation and what happens up here with this, this flies in the face when you see BP's profits, even in the years that they were doing the cost cutting, whether it is in Alaska or in Texas City, and we see that. So if we can't depend on the management to do it, that means the Federal agency has to do it. And again, 5 years is way too long, because I would hope that I don't go home tomorrow or Friday and see another tragedy, but it is just frustrating to see that.

Mr. FAIRFAX. I understand, Congressman. Let me just say a couple of things. First off, every workplace death that comes in that happens in this country comes across my desk and we prepare a condolence letter for that. It deeply affects me. But as far as reactive chemicals, under the Process Safety Management Standard, we are working on a directive to implement and it will deal with reactive chemicals and deal with that on our inspections, but also the Process Safety Management Standard incorporates the NFPA standards that deal with reactive chemicals and we are addressing it through those industry consensus standards, which direct how industry should be applying and dealing with reactive chemicals.

Mr. GREEN. Well, I appreciate the condolence letter, but I would rather it be done before the fact.

Mr. FAIRFAX. I understand.

Mr. GREEN. And I have been a legislator both on the State level and the Federal level for my area and I have watched, when the accident happens, the people who feel the worse are the plant managers, because they are also under the pressure. And I have also watched what has happened. The same thing that happened at BP/ Texas City, it happened at ARCO, in Sheldon and Channelview in the 1980's. They start writing big checks to survivors, but it is real difficult to explain that to a 6-year-old child, that you have a million dollars, son, to take care of your education, but you don't have a father, and that is what OSHA is tasked to do and that is our job to make sure that if you are not doing it, we do whatever we can to encourage you to do it, whether it is funding or statutory law, and I guess that is the frustration that, again, Congressman Melancon and I both have that problem and we want those chemicals and we want that refined product, but we also want it done safely.

Mr. FAIRFAX. That is our same goal, also.

Mr. GREEN. Thank you, Mr. Chairman.

Mr. STUPAK. Before I yield back, Mr. Fairfax.

Mr. FAIRFAX. Yes, sir?

Mr. STUPAK. When Ms. Merritt talked about the PVQ Audit Program, is OSHA in favor of that?

Mr. FAIRFAX. It is the PQV.

Mr. STUPAK. PQV.

Mr. FAIRFAX. It is program quality verification .

Mr. STUPAK. OK.

Mr. FAIRFAX. That is a targeting system and process safety management evaluation that we launched when the Process Safety Management Standard came out. Yes, we are in favor and yes, I agree with it, but we found, in launching that program, that it ended up being too open-ended and resource intensive. The inspections just took too long and we weren't doing our job elsewhere.

Mr. STUPAK. In order to get the safety that Mr. Green and we all insist upon, you almost have to do it, do you not?

Mr. FAIRFAX. We do but the new program we are getting ready to launch, I think it is far better than anything we have ever had before.

Mr. STUPAK. Can you do this PQV plus your new program?

Mr. FAIRFAX. The new program is basically an improvement of the PQV. We will cancel the PQV program and replace it with this new one, which incorporates the elements of the PQV system that we did. And you know, it allows us to more effectively, and with better use of resources, address process safety management in the refinery industry, and once we are done with the inspections, we plan on expanding that. I think it is a better system. It is one of the best emphasis programs I have ever seen developed. I have been with OSHA 29 years, so——

Mr. STUPAK. OK, we will be interested in seeing that. We have got three votes on the floor. We will hold this committee in abeyance for the next half-hour. We should be back by 12:10. Then they promised us, for 3 hours we don't have any votes. We should be able to finish this hearing. You are not excused. We would like you to come back because we have got a couple more Members yet who would like to ask questions, OK, before this panel here. Then we will go to Mr. Malone after that. Thanks.

[Recess]

Mr. STUPAK. Before we hear questions from Mr. Inslee, a couple of housekeeping matters. I talked with Mr. Whitfield, with unanimous consent, to submit the Chemical Safety Board of March 23, 2007, the Booz Allen Hamilton report. It is a very thick report but I will now make it part of the record; the management of change document received last night. It is 13 pages. I provided it to you earlier, Mr. Whitfield. In the upper right-hand corner, the work order No. is 29314644. And last but not least, the March 12, 2003 VECO Alaska report. That report will also be entered, with unanimous consent, into the record. Without objection and hearing none, those four documents will be entered.

Next, I would turn to Mr. Inslee for questions, please. Ten minutes, sir.

Mr. INSLEE. Ms. Slemons, I want to ask you about the compliance order by consent situation. In May 2002, the State of Alaska required BP to determine sediment levels and to commencing pigging. On August 9, BP asked for that elimination. On August 14, the State of Alaska sent a letter removing that requirement. It is well understood that suspected sediment buildup is really a red flag and I listened to your testimony saying, well, this wasn't your requirement, originally. It was not related to issues of corrosion. But I am having a hard time understanding how you could have and why you would have required, originally, pigging for reasons of preventing corrosion, if that is the reason you do it, and then think it is not important enough. How could that have happened?

Ms. SLEMONS. I was not present in the discussions that were held between DEC and BP. I was also not present at the discussions internal to DEC determining what they would require and why. All I can report to you today is what they have reported to me, which is that leak detection was their focus. I share your concern about the change in that decision and I do intend to look into this. What I find, I will be happy to provide to you afterwards, but I simply don't have that information now.

Mr. INSLEE. Well, I appreciate that and if you would provide us any more, I would appreciate it, because I am continually flabbergasted of the failure to do pigging after our loss in Bellingham, WA, a loss to these kids. We have been asking the industry to do pigging because it is the most acceptable, most reliable way. The industry has come back with news and said, oh no, we have other sort of abstract models to do it. But models don't prevent corrosion, always, as we have found out and so we expect our regulators to be aggressive on this and if you could provide us more information, and hopefully you will take back to the State of Alaska that we want you to be aggressive on this and we will back you with aggressive on this. I hope that you will continue to do so. I want to ask you if you could turn to tab 24 to talk about the budget issues and the lack of corrosion inhibitor. On tab 24 there is an e-mail of October 2005 and it says, "attached, please find a list of potential budget control objects broken out by chemicals and manpower." Do you have that before you?

Ms. SLEMONS. I do.

Mr. INSLEE. And the next page is a spreadsheet which is attached to the e-mail and it talks about a proposal to reduce the injection rates of corrosion inhibitor. It would save $400,000 a month. Do you see that?

Ms. SLEMONS. Yes, sir.

Mr. INSLEE. And then another line item says reduce biocide frequency to every 2 weeks. Projected savings of $36,000 a month. And of course, biocide is used to prevent organisms from eating away the walls, when it does, right?

Ms. SLEMONS. Yes.

Mr. INSLEE. And then at both of those items you will see a column marked risk category and it is rated as high. In other words, BP has seemed to understand that that reduction or that safety measure would create a high risk and yet they decided to take that risk anyway, for cost reasons. Does that appear pretty clear to you of what happened there?

Ms. SLEMONS. It does.

Mr. INSLEE. OK. If you look at tab 16 now. At tab 16, it talks about CIC grew 2002 budget challenge $1 million opportunities, which I assume mean the things listed there are opportunities to save a million dollars. And it shows in the third line 40H chemical ops, corrosion, and below that, about halfway down in the notes it says 10-percent reduction in inhibition levels would result in a 30-percent increase in corrosion rate. Could you explain what that means?

Ms. SLEMONS. I can take a guess at it. It appears to me that the relationship in the reduction in inhibition levels, the use of that particular chemical is not linear and that, in fact, a small reduction in the use of that chemical would reduce—would result in a larger increase in corrosion rate than the actual reduction.

Mr. INSLEE. In the dangerous side of the nonlinear side, you get a larger risk factor than you do a linear cut in expenditures.

Ms. SLEMONS. That is my interpretation, yes.

Mr. INSLEE. Now I want to ask, in relationship to the budget pressure issue, I want to ask what you have done to prevent budget pressures, in regard to executive compensation, from allowing these kinds of decisions to happen again. Has the State done anything to address the issue of executives increasing their bonuses by making decisions like this?

Ms. SLEMONS. We have not, Congressman, and I would explain that answer. Our oil and gas leases give us very broad authorities on several issues, especially regarding access to plans for construction, operations, maintenance plans and performance logs and records of the operators. Our authorities do not address the intent of management decisions. Neither do they allow us to go in and look at the internal decision-making processes of the company. To the extent that PHMSA has a window into the operational management system of BP and into the similar systems in other companies, with our letter of intent, we will be looking at that information. The State of Alaska does not have the authorities that allow us to do that.

Mr. INSLEE. And do you know if the Department of Transportation is looking at that issue? The concern is, if you have an executive compensation system that rewards danger and increasing risk in a nonlinear fashion, you are going to have problems no matter how observant and the regulatory ambitions you have. Do you know, is anyone else looking at that potential?

Ms. SLEMONS. I certainly understand the concern and we share that concern. I am told by Mr. Nard that, in fact, they are looking at that, which encourages me that we too will be able then to see that information.

Mr. INSLEE. OK. Could you go to tab 13, if you will, please? Tab 13, a part of this, it says ideas for saving money. It is on page 18 and I will just read it. You don't have to follow around. "Ideas for saving money, in no particular order, to turn off PW, produced water and chemical and OBCQ—will help out here." Then on page 6 it says, "as you know, we are under huge budget pressure from the last quarter of the year and therefore we have to take some rather disagreeable measures. Can you please implement the following changes-shut down the PW innovation systems for the remainder of the year-discontinue the addition of corrosion inhibition for velocity control."

So it looked to me like BP was changing their existing status quo maintenance protocol in a way that would create a known increased risk. Does your regulatory scheme prevent companies from going backwards from the status quo on maintenance? In other words, do you have something that would prevent them from going backwards from existing maintenance protocols, or at least require your approval from doing so?

Ms. SLEMONS. Yes, we will. We don't currently because this program is just getting off the ground. But one of the tasks that was identified in the administrative order is the development by operators of maintenance plans or quality assurance plans that come to the PSIO for review and approval. Where we find them weak, we will require that they be beefed up before they are approved. Once those plans are approved, then there is an open and transparent, if you will, agreement. The operators know what they are conforming to and we know what we are inspecting to, and any changes to that maintenance regime, those plans that are included in that document, would require our approval before we would sign off on it.

Mr. INSLEE. And will that regime be in place?

Ms. SLEMONS. For BP, we have asked for their preliminary documentation in July. We will be looking at the Prudhoe Bay unit first and then we will be proceeding to look at other units around the State, in a priority order based on risk.

Mr. INSLEE. Ms. Gerard, could you address this issue of executive compensation and how it is tied to safety decisions and whether or not the regulatory arm or arms of the Federal Government should do something to prevent that from being an incentive for risk taking?

Ms. GERARD. Our integrity management requirements today are focused on the assessment of the condition of the pipeline, identification of risk, prioritization of that risk, remediation and evaluation. Up until this point in time, we have not established requirements that go to cultural issues. However, as it relates to our ongoing relationship with BP and oversight under our corrective action order, we have had discussion with BP about a number of organizational and cultural program activities that we believe is necessary for us to oversee, as part of their implementation of their OMS, Operating Management System. One of the items involves identification of metrics related to safety culture, creating transparency in the organization, as it regards all employees' participation in hazard identification, for example, and we believe that there should be metrics that are part of the executive performance plan; that we believe that we should be able to take a look at how executives are doing at meeting those metrics as part of their annual——

Mr. INSLEE. Are you going to insist on having that, then?

Ms. GERARD. That is the plan.

Mr. INSLEE. Because I have respected some of the things BP has done. They have done some good things in energy and I have admired some of the things they have done. But obviously there is a cultural failure here that was rather broad-based and to deal with it you need something sort of intrinsic in the organization. Thank you.

Mr. MELANCON [presiding]. I think that concludes the questions. I want to thank the panel for coming here and I will apologize for the delay in our process if you all can move your process a little quicker. Thank you so much for being with us today.

The committee will call before it Mr. Robert Malone, chairman and president of BP America, please. Thank you, Mr. Malone, we appreciate you being here today. It is the policy of this subcommittee to take all testimony under oath. Please be advised that witnesses have the right under the rules of the House to be advised by counsel during your testimony. Do you wish to be represented by counsel?

Mr. MALONE. No, sir.

Mr. MELANCON. Then, if you would please rise and I would swear you in?

[Witness sworn]

Mr. MELANCON. Let the reflect that the witness replied in the affirmative. You are now under oath. You may proceed with your opening statement.

TESTIMONY OF ROBERT A. MALONE, CHAIRMAN AND PRESIDENT, BP AMERICA, INC.

Mr. MALONE. Mr. Chairman and members of the subcommittee, my name is Bob Malone and I am chairman and president of BP America. We are privileged to be the Nation's largest producer of domestic oil and gas and we take our commitments here seriously.

When I accepted the position in the summer of 2006, BP was facing the biggest challenge we have ever had. I agreed to take this job to move BP forward and I set six goals: (1) do all I can to ensure that BP never again experiences a tragedy like Texas City, or allows portions of the critical North Slope pipeline to degrade to the point that we must shut it down. (2) to create a culture in which workers are confident that their concerns and ideas will make a difference. (3) to provide our people with the skills, the systems and the support they need to ensure that budget pressures never compromise the safety or integrity of our operations. (4) put in place a central team of auditors and process safety experts to monitor our operations, identify gaps and ensure that they are closed. (5) restore trust in BP America by ensuring that we deliver on the promises we have made to workers, to regulators and the communities in which we operate; and (6) to work with employees and regulators to make BP America an industry leader in process safety and integrity management.

I am encouraged by the changes I have seen during my visits to BP operations around the Nation. I am pleased with the progress we are making, but there is still much to do. Today, I want to assure you that we get it. We have learned the lessons of the past. Thanks to the State of Alaska, DOT, OSHA, other regulators, the Baker Panel, the U.S. Chemical Safety Board, our own investigations, recent reviews by independent consultants and input from this committee, we have a far deeper understanding of the gaps in our operations than ever before. Some of these assessments have been harsh and they have been deeply troubling, but we recognize that unless we understand the cause of what happened, we cannot make the necessary changes to ensure that it doesn't happen again.

The reports were based on in-depth reviews of our operations. Hundreds of interviews of members of our workforce and reviews of the written records and documentation requested by investigative teams. I have reviewed all of these reports and some of the supporting documentation. It is apparent from reading these reports, from visiting our operations and talking to our employees, that process safety and integrity management was not given sufficient priority or focus in our operations. That finding is a common theme throughout the reports and my own assessment.

I have also read some of the key e-mails selected from thousands of pages that we provided to this committee. It is disturbing to me if even one person in our organization thought of options of placing budget considerations over the safety and the integrity of our operations. It is clear that budget impacted our culture and that we stopped being curious. We asked our people to keep our operations cost competitive and safe and we failed to provide them with the systems and the skills required to recognize and mitigate all of the risks that are inherent in operating complex facilities. Adequate risk assessment tools were not applied with the type of rigor and challenge that we now expect.

There were many reasons for the budget pressures that exist in Alaska, including a 17-year, 75 percent decline in Prudhoe Bay and years of low wellhead prices. And although the corrosion program spending increased ever since 2001, it appears as though our corrosion team members developed options for operating within budget. Some workers expressed opposition to some of the measures being considered. The cause of the level of frustration evident in some of the e-mails is absolutely unacceptable to me and I am encouraged that our workers did make their concerns known. It is important that we communicate the risks they see associated with any reduction in budget or activity levels so that accountable managers can make sound decisions. However, I am not going to be satisfied until no one feels it is necessary to suggest cost-cutting options that he or she believes compromises the safety of our operations.

As to the cause of the leaks on the oil transit line that occurred last year, the fact is, is that our corrosion team had an unwarranted sense of confidence in their own program. They believed that they were appropriately managing risk, but they did not have the right tools to challenge their own assumptions. Booz Allen Hamilton concluded that without better risk assessment processes sensitive to changing conditions in the field, larger corrosion program budgets alone would not have prevented these leaks.

When I appeared before this committee last September, I made a number of commitments. As promised, I have retained a panel of corrosion and large infrastructure maintenance experts to recommend improvements in the way we manage corrosion. We increased operations in maintenance spending in Alaska and Texas City and our other U.S. refineries. I appointed to Judge Stanley Sporkin as our U.S. Ombudsman and assigned his office responsibility for responding to current concerns as well as reviewing all of the employee concerns raised since 2000. I created an internal operations advisory board and recruited an external advisory council. I built a team of internal safety and operations and compliance and ethics experts and we have engaged with employees and contract workers at all levels across the organization. We have also conducted safety culture assessments and are addressing work environment changes.

Progress on another commitment to replacement of the Prudhoe Bay OTL system is well underway. Rather than just replacing old pipe for new, we opted to design a new $250 million system, sized for the future Prudhoe Bay production. During the winter, more than 600 workers constructed 8 miles of ice roads, completed 1,250 wells and they did it all in subzero conditions without a single lost-time accident. I was there in March to check on the project and I can guarantee you that it was well below 40 degrees. About 8 miles of new pipe had been installed and we are on track to commission this system in late 2008. Full implementation of our new corrosion strategy is going to take time. We are adding more engineers, we are meeting with the teams at each of the facilities, and we are identifying areas of concern to operators and to technicians working on the front line. The plan is to finish these reviews by October of this year and to complete all of the follow-up inspections by year-end. If there are problems, we are going to find them and we are going to fix them.

We are using BP's new operations management system to drive change in a way that the company approaches four key areas: people, plant, process and performance. We want the right people with the right skills in the right places. The members of the new Alaska and Texas City leadership team have deep operating experience. Our two top operating managers for the North Slope have each been involved in oilfield operations for more than 30 years. We are expanding and renewing our Alaska workforce and during 2006 and 2007, we will add nearly 400 BP employees. We have changed the structure of the organization, creating what we call a technical directorate that sets engineering and operation standards and verifies that they are met and adequately resourced. The head of the technical directorate reports to the head of BP Alaska and to me. We are making a significant culture change across our operations, ensuring that all employees feel free to raise concerns and ideas and that their contributions are taken into consideration in how we do business.

Under plant we are focusing on all of the conditions of our process facilities and pipelines. The OTL replacement is part of a larger renewal program designed to extend the Prudhoe Bay oil and gas production another 50 years. Under process we are working to become an industry leader in process safety and integrity management. And under performance our new operating management systems defines what is expected from our team in Alaska, in the areas of plant integrity, process safety and safety culture.

It is impossible to visit Texas City, Prudhoe Bay or other BP locations across this country and not be impressed by what has already been done, what is being done, and by the people that are doing it. I believe that when embedded in Alaska our U.S. refineries, the operating management system and the right safety culture will deliver sustainable change and make BP an industry leader in these critical areas. Please know we get it. We know what is wrong. We have a plan for fixing it. We have the people and the funding. We just need time to make these changes. Thank you and I would be happy to answer any questions.

[The prepared testimony of Mr. Malone follows:]

STATEMENT OF ROBERT A. MALONE

My name is Bob Malone and I am Chairman and President of BP America Inc. BP America and its subsidiaries employ more than 36,000 people and produce 666,000 barrels of crude oil and 2.7 billion cubic feet of natural gas per day. We operate five refineries with a capacity to process nearly 1.5 million barrels a day of crude oil, and a system of pipelines and terminals throughout the United States that supply over 70 million gallons per day of gasoline and distillate fuels to customers in 35 States.

We are privileged to operate the largest oil field in North America—Prudhoe Bay on Alaska's North Slope (exhibit 1). The Texas City Refinery is our largest and most complex refinery (exhibit 2). Our charge is to operate these assets in a safe, efficient and environmentally responsible way for the benefit of neighboring communities, our business partners, our customers, our employees and our shareholders. The public's faith in us has been tested over the last two years by the tragic explosion, fire and deaths at Texas City and by corrosion in the oil transit pipeline system that moves processed crude oil from Greater Prudhoe Bay to the Trans Alaska Pipeline System (TAPS).

These experiences have changed BP and all of us who work for the company. We are determined to learn from what happened and to become a better, stronger company. I was sent here in July 2006 by our Group CEO and the BP Board, to lead that effort. I came with a set of principles that guide my work in the U.S. We are making progress towards our goals. However, there is much to do and accomplishing all that needs to be done will take time.

I was asked by Chairmen Dingell and Stupak to address whether budget pressures led to the corrosion and leaks which occurred last year on the oil transit lines at Prudhoe Bay. Additionally, they asked whether we suspended the use of corrosion inhibitor chemicals for extended periods of time due to budget pressures.

We have found there was false sense of confidence in the effectiveness of the existing corrosion management program and in the condition of the oil transit lines. BAH concluded that in the absence of better risk assessment processes, budget increases alone would not have prevented the leaks. Our own work has revealed that the workforce did not have an adequate process to challenge their own assumptions.

This question is also addressed in a recent investigation conducted for me by Booz Allen Hamilton (BAH). Their report, and other documents produced to this subcommittee, makes it clear there was a concerted effort to manage the costs in response to the continuing decline in production at Prudhoe Bay. The documents also reveal that the effort to manage costs frustrated some workers who were accountable for delivery of certain aspects of the corrosion management program.

Booz Allen Hamilton concluded, however, that the leaks that occurred on the OTL system last year resulted not from budget pressures, but primarily from the lack of a formal, holistic risk assessment process that was sensitive to changing operations and conditions in the field.

We are making the corrosion management program improvements recommended by Booz Allen Hamilton. We are adding people and resources. And most importantly, we are revamping our corrosion management strategy. At the heart of that strategy will be a comprehensive risk assessment process sensitive to changing operating conditions. The strategy will apply to all Greater Prudhoe Bay facilities and systems and will utilize an industry recognized, proven and commercially available risk based inspection (RBI) program.

We understand that budget pressures, poorly managed, can impact the culture of an organization. It can lead to a "make do/can do" mentality. It can dampen the willingness of people to raise concerns or think in new or different ways—especially if they believe they will not be heard or that there is no money to spend on their idea or concern.

We now know as a result of the studies done at both Texas City and Alaska and from our own employee surveys that we must change the way we identify, assess, understand and communicate risk. We also recognize that we must do a better job of listening to and resolving employee concerns. And finally, we understand that we must change the way we integrate what we have learned into our operations and our budget decisions.

Better communication and better risk assessments will mean better budget decisions. The foundation of this risk management process is to understand that occupational safety, process safety and environmental standards cannot be compromised. The next step is to be equally clear that budget discussions recognize and address our priority of safe, reliable operations.

BP America is committed to safety, and the expectation of our management is that budget guidelines should never result in a compromise in safety performance. That is and has long been our philosophy, but we believe we can improve the way we receive and resolve employee concerns and enhance the way we identify, assess, eliminate and/or manage risk, and that, by doing so, we can make sure that that philosophy is more than just words.

Chairman Dingell referred us to several email communications from the Alaska workforce that BP America has provided to the committee regarding budget pressures and considerations about ways to lower budgets or limit budget overruns. We are researching the situations described to determine how the issues raised in those emails were ultimately resolved. The frustration evident in some of those emails causes me concern. It is clear to me the employees were troubled by some of the cost-saving options identified for consideration. I am encouraged, however, that they were making their concerns known.

Regarding the use of corrosion inhibitor chemicals, an investigation is being conducted by the BP Ombudsman, Judge Stanley Sporkin. This investigation will include a review of documents and interviews with personnel and is expected to be completed in July. I expect that Judge Sporkin will keep you apprised of his progress, and I will share his final report with the committee upon completion. However, we are not waiting on the outcome of this investigation to take action. BP America has initiated a review of our inspection programs for all North Slope facilities and systems. This will verify the current condition of the pipelines and processing facilities, identify concerns in each operating area and inform the implementation of the comprehensive RBI program.

I am here today to provide you with an update on the commitments I made at the hearing last September; update you on the status of the Greater Prudhoe Bay Oil Transit Line replacement project; share what we have heard and learned from the reports and studies of the incidents; and outline the actions we are taking to reestablish BP as an industry leader in the area of process safety and to restore the faith and confidence of the American people in our operations.September 2006 Commitments

I committed to initiate a number of actions to drive operational and safety change within BP America, and I am pleased today to report back to you on the progress we have made in fulfilling these commitments:

I retained three of the world's foremost experts on corrosion and infrastructure management. They have received unhindered access to review our corrosion management system on the North Slope and to suggest management and operational changes to improve it. Their report will be complete this summer. We will apply what we learn to all of our pipeline operations.

BP America committed to significant spending increases to upgrade all aspects of safety at our refineries. We have publicly committed to spend $7 billion to improve those operations. In addition, we have more than doubled our spending on major maintenance projects in Alaska.

I appointed retired U.S. District Court Judge Stanley Sporkin, as Ombudsman, reporting directly to me. He has initiated a review of all worker allegations that have been raised on the North Slope since 2000 and has conducted other reviews to investigate concerns raised by our employees.

I created an Operational Advisory Board, composed of fifteen senior business leaders in BP America, to lead our effort on safety, operational integrity and compliance. This group meets quarterly and each member has committed to implementing a different, holistic approach to managing U.S. operations.

I have recruited an External Advisory Council to assist and advise me on all aspects of BP America's US businesses and to focus in particular on safety, operational integrity, compliance and ethics. We have met as a Council twice, most recently two weeks ago. That meeting included a day at the Texas City refinery.

I have built my own team of internal experts on employee safety, safety culture, process safety, operational integrity, and compliance and ethics to assist me in monitoring these aspects of our business.

I continue to meet with employees to reinforce my expectations of them: that they must ensure that our operations are safe, that they understand they have both a right and responsibility to shut down any process they feel is unsafe or operationally unsound, and that they are encouraged to raise concerns on any issue. This engagement has been through town hall meetings, site visits, conferences, email and internal company publications. I have even created my own web blog to communicate with employees.

These conversations have provided me with encouragement that we are on the right path. In fact, in a survey now being conducted on the North Slope by the Ombudsman's office, 98 percent of respondents would report issues that impact health, safety or environmental protection; and the safety culture survey indicates that 97 percent of employees believe they have the ability to report and to stop any unsafe operation. Further, 92 percent felt comfortable reporting concerns directly to their supervisors or line managers. Similarly, across refinery operations, we have initiated a "Stop Work If You Think It Is Unsafe" program as a condition of unit startups.

I have also been to Texas City and the North Slope a number of times and the work I have witnessed demonstrates that all of us are unified behind the need and the desire to improve. The milestones achieved at Texas City and Alaska are significant. At Texas City, those milestones include:

- Nearly 300,000 hours of leadership and other training;
- A total rebuilding of the training program with more than 30 new instructors;
- More than 400 new people hired;
- 15.5 million man-hours worked in 2006—3 times the average U.S. refinery—under entirely new safety systems;
- An infrastructure renewal program so large that it requires scaffolding sufficient to scale Mt. Everest 7 times; and
- A complete overhaul and safe re-commissioning of the 27-mile steam system.

Similar achievements have been made on the North Slope during this past Arctic winter:

- Since the incident we have completed 21,000 ultrasonic tests on the oil transit lines;
- Since the incident we have removed insulation and inspected and re-insulated more than 43,000 ft (8 miles) of pipe;
- Since August 2006, we have increased BP employees on the North Slope by more than 10 percent; and
- We had 110,000 construction man-hours worked this winter on oil transit line replacement without a lost time accident or recordable injury.

OIL TRANSIT LINE (OTL) REPLACEMENT

Prudhoe Bay's oil transit line system is undergoing a major upgrade, initially focusing on rebuilding the field's most critical pipe segments, a phase that will take until the end of next year. By then, we will have installed approximately 16 miles of oil transit lines from the flow stations and the gathering centers to Skid 50, near the starting point of TAPS.

The winter 2007 construction season recently ended. I am pleased to report that approximately 8 miles of new pipe has been installed. This feat is impressive given that during the 3-month construction season more than 600 workers constructed 8 miles of ice roads, installed 680 vertical support members, performed 1,250 welds and installed this nearly 42,000 feet of new pipe all in sub-zero arctic conditions.

WHO HAS INFORMED BP AMERICA'S THINKING?

The progress made in Alaska and the actions taken at Texas City are among the many examples that prove that BP America is a different company than it was six months ago. This change has only been accomplished with the support of our employees, management, and the entire BP Group. And, this is why I am confident that we are on the right path to distinguish ourselves as a leader in personnel safety, process safety and operational integrity.

However, these early actions are just the starting point. There is much more to do to drive renewal within BP America. The first step of renewal was to assess the incidents, take the learnings and then develop a set of actions to respond. Since the Texas City tragedy and the Alaska pipeline incidents, BP America has commissioned a number of studies and also received third-party reports that have assisted us in our efforts. These reports and studies have been freely shared with State and Federal regulators and Congress and are supporting the changes occurring within BP America.

I would like to briefly describe the nature of these reports; how they were received by BP America and the actions we have taken or are contemplating as part of our operational renewal plans within the U.S.

BOOZ ALLEN HAMILTON STUDY

I commissioned Booz Allen Hamilton (BAH), as an independent third party, to identify any organizational, process, information systems and/or governance issues that may have contributed to the March and August 2006 oil transit line (OTL) leak incidents. BAH conducted its study between November 2006 and January 2007and recently delivered its final report. BAH received BP's full cooperation during its review. The consultants interviewed past and present members of the Alaska management and Corrosion Inspection and Chemicals (CIC) teams and were provided all documents they requested as part of their review. I understand that some questions about the report have recently been raised by the committee, and we are working with Booz Allen Hamilton to provide the answers.

INDEPENDENT CORROSION ASSESSMENT TEAM STUDY

I initiated this study in August 2006, just after the shutdown of the Eastern Operating Area (EOA) of the Prudhoe Bay field, to provide an independent assessment of our Alaskan operation's current corrosion management program and to make recommendations needed to firmly establish the program up to an industry-leading position. This is a "forward looking" study that is intended to meet the needs of our commitment to a fifty-year future in Alaska.

To develop recommendations, an Independent Corrosion Assessment Team (ICAT) was assembled comprised of two internationally recognized experts in corrosion mechanisms and an internationally recognized expert in large asset management. The ICAT will issue its final report this summer.

Additionally, a BP Alaska Corrosion Strategy—overviewed by members of the ICAT—is complete and is being implemented.

LEGACY EMPLOYEE CONCERNS STUDY

During the hearings last year, I committed to review all employee concerns raised at our Alaska operations since 2000 to determine whether there were any unresolved issues or whether the resolution of concerns adequately addressed matters that presented health, safety or environmental questions. This task was assigned to the Ombudsman's office, and they retained MPR, Inc., an independent engineering firm, to assist in the review and disposition of the technical issues.

The initial task was the collection, review and categorization of the historical employee issues. There are approximately one thousand concerns in the Legacy Review Issue process at this time. While none of the issues has been identified by the Ombudsman's office as representing an imminent safety threat, the analysis work is ongoing.

The committee staff has had an ongoing dialogue directly with my Ombudsman regarding his investigations. A final report from the Ombudsman's office on the Legacy Issue Review will be provided with identification of issues needing further evaluation or corrective action. The target date for completion of this project is July, 2007.

NO TOLERANCE FOR RETALIATION

On the broader issue of employee retaliation, BP was asked to ensure that there is no tolerance for retaliation against workers who raise safety and health concerns and to provide a transparent mechanism to ensure concerns are resolved in a timely manner.

BP does not tolerate retaliation against workers who raise safety concerns. It is prohibited by our Code of Conduct and I have made it clear that I expect appropriate action to be taken to anticipate and prevent, or mitigate, any such incidents or behaviors that may discourage workers from raising safety, environmental or other concerns. However, I also recognize that tackling long term behaviors takes time and training.

BP America has a number of systems and processes for resolving employee concerns including the BP "Open Talk" Program and the Ombudsman's office. BPXA currently has seven different avenues—we are evaluating how to streamline these avenues for greater effectiveness and efficiency, but for now we would rather have more opportunities than fewer.

COMPLIANCE ORDER BY CONSENT (COBC) REVIEW

Following the hearing in September 2006, the Oversight and Investigations Subcommittee asked BP America to investigate whether BPXA failed to disclose information regarding its awareness of sediment in the OTLs to the Congressional staff prior to the hearings, and, if so, to explain that failure.

This concern arose because of the post-hearing identification of a 2002 Compliance Order by Consent (COBC) entered into between BPXA and the Alaska Department of Environmental Conservation (ADEC) that referred to the existence of sediment in the lines.

In November 2006, I asked Billie Garde, as a consultant, to conduct an investigation on behalf of BP America and to provide a report to me. An interim report has just been completed and a briefing of the interim findings has been provided to committee staff, at its request. The investigation found that our preparation for the September, 2006 hearing was not based on all information available to the corporation, and thus neither I nor the committee staff had information that may have been helpful for the hearing. For that, I apologize.

FATAL ACCIDENT INVESTIGATION REPORT—ISOMERIZATION UNIT EXPLOSION FINAL REPORT (MOGFORD REPORT)

Following the March 23, 2005 incident at the Texas City Refinery, BP assembled an incident investigation team, led by John Mogford, to identify the underlying root causes of the incident. On May 17, 2005, the team released an interim report to communicate its preliminary findings. The team released its final report on December 9, 2005. The report was intended to deepen understanding of the causes of the incident; to recommend corrective actions to prevent recurrence of a similar incident; and to improve safety performance at the site. The investigation used the BP root cause methodology supplemented by guidance issued by the Center for Chemical Process Safety.

The interim report made recommendations in the areas of: (1) People and Procedures; (2) Control of Work and Trailer Siting; and (3) Design and Engineering. The final report augmented those recommendations and made a significant number of additional detailed, site-specific proposals for corrective actions designed to address the root causes and underlying cultural issues identified by the investigation team.

BP U.S. REFINERIES INDEPENDENT SAFETY REVIEW PANEL (BAKER PANEL)

Pursuant to a recommendation from the Chemical Safety and Hazard Investigation Board (CSB), BP convened an independent safety review panel, chaired by former U.S. Secretary of State James A Baker III to assess process safety management systems and safety culture at its five U.S. refineries.

The Panel carried out its work throughout 2006 and reported its findings in 2007. The report is hard-hitting and unique. We have committed to implement all of the report's recommendations, and many measures have already been taken, or are underway, a fact the Panel recognized when it observed that "since March 2005, BP has expressed a major commitment to a far better process safety regime, has committed significant resources and personnel to that end, and has undertaken or announced many measures that could impact process safety performance at BP's five U.S. refineries."

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

The CSB report addressed the causes of the Texas City incident. We recognize and appreciate the effort CSB put into this investigation.

BP America will implement actions consistent with the recommendations of the CSB and will communicate this to Chairman Merritt within the next few days.

LEARNINGS

What did these reports teach us and how have they informed our changes? We have spent considerable time analyzing the findings of these studies and integrating their recommendations into a cohesive plan to help BP America grow to become an industry leader in process safety. We found these reports to contain several common themes that have been incorporated into our new operating management system (exhibit 3). These common themes and some corresponding observations are shown below:

Communications and Leadership—The reports indicated that some concerns were either not communicated effectively or sufficiently heard. The organizational culture must consistently encourage greater upward and cross-functional communication. The Mogford report regarding Texas City, for example, noted that a "lack of leadership visibility and poor communication through the complex siloed organization did not assist in delivering the right messages" regarding the priority of safety at the site.

Management's Technical Knowledge—As observed in the Booz Allen Hamilton report, because the corrosion group "was hierarchically four levels down from senior leadership, corrosion risk management had less visibility." As a result, "the technical evaluation of corrosion risk was not challenged by senior management to fully understand the tradeoffs made within CIC and at the Field Operation level." Regarding management knowledge at Texas City, the Mogford report stated "there needs to be a greater line management understanding and ownership of process safety management."

Accountability and Clarity of Expectations—BP America's entrepreneurial culture engendered significant discretion and autonomy to its business unit leaders, and expectations, responsibilities or accountabilities were not always well understood. Greater organizational clarity must be pursued to ensure understanding of operational accountabilities.

Knowledge, Expertise, and Training—Technical and institutional knowledge in some businesses rested with a few key individuals. Greater depth and technical capability needs to be embedded more consistently across the organization. BP America has begun to substantially increase the number of hires, training and the knowledge base across the U.S.

Risk Identification and Assessment—BP America businesses have always conducted risk assessment across their operations but those assessments were not always the result of a comprehensive, systematic risk assessment process that was consistently applied throughout the businesses. The Mogford Report observed that the Texas City site had "no comprehensive and consistent business plans focused on the systemic reduction of process risks." The Booz Allen Hamilton Report found that "there was no formal, holistic risk assessment process for pipeline integrity."

Effective Process Safety/Integrity Management System—As operational and environmental conditions changed, BP America's systems and processes haven't been sufficiently sensitive to make the corresponding adjustments. These processes must be more flexible and subject to greater input and challenge from the organization.

Sufficiency of Resources—We now know as a result of the studies done at Texas City and Alaska and our own employee surveys that we must make changes in the way we identify, assess, understand and communicate risk. We must also change the way we integrate that knowledge into our operations and our spending decisions. I believe that better risk assessments will lead to improved budget discussions and spending decisions will be better as a result.

BP has a strong cost-focused performance culture. We made a virtue out of doing more for less. The mantra of more-for-less says that we can get 100 percent of the task completed with 90 percent of the resources. This approach needs to be deployed with great judgment and wisdom. When it isn't, we run into trouble.

We are committed to safety and the expectation of our management is that budget guidelines should never result in a compromise in safety performance.— We believe we can come closer to always achieving this goal by improving the way we receive and resolve employee concerns and by enhancing the way we identify, assess, eliminate or manage risk. Safety must be the overriding priority in all we do—and it will be.

Audit, Compliance, and Monitoring—We have several different systems for monitoring and auditing performance and compliance. Enhanced rigor must be applied together with common standards, appropriate capabilities and adequate resources to follow up and address identified concerns. According to the Mogford Report "[audit] action items did not appear to be tracked and effectively closed." The Booz Allen Hamilton Report observed that "a number of key assurance processes (e.g., Audit, Management of Change) were not 'closed loop' to ensure that required changes were truly implemented and documented."

Process Safety as a Core Value—Process safety must be instilled as a core value. BP America has always held safety as a core value as reflected in the company's concerted effort to continually reduce the number of workplace injuries and fatalities across its operations. The success of this effort can be seen in our occupational safety performance metrics. At Texas City, the company reduced OSHA injury rates by more than 70 percent in the five year period before the March 23 explosion. We relied on these metrics as an indicator of process safety as well. We now understand that this reliance was a mistake.

In addition, we are taking action in the area of worker fatigue and overtime, adherence to formal processes and incident investigations and reporting.

THE OPERATING MANAGEMENT SYSTEM

We are folding BP America's Health, Safety & Environment management system into a broader, comprehensive operating management system. This new system is based on the International Standards Organization's management system framework and is designed to support a more rigorous approach to compliance and risk management. Implementation of the system, which will be introduced to BP operations worldwide, is first taking place in U.S. refineries, Alaska and other selected locations.

This enhanced framework provides clear guidance in what we have defined as the eight elements of operating in BP America: risk; procedures; assets; optimization; organization; leadership; results; and privilege to operate.

At its core, the framework helps define and add clarity to the people, plant, process and performance measures facilities need to undertake to ensure reliable, safe operations. We have begun to implement this new system in Alaska through the "Renewal" program and at Texas City through the "Focus on the Future" program. In both cases, we are integrating the learnings from the expert studies and analyses and adopting action plans that focus on critical operational components.

HOW HAS OMS INFLUENCED BP'S OPERATIONS?

The operating management system framework is changing the way BPXA approaches the people, plant, process and performance issues that influence our operations (exhibit 3).

PEOPLE

The new head of BPXA has assembled a new leadership team since last September with a renewed emphasis on operational capability and clarity in their accountabilities. An example of this is the separation of technical assurance from operations.

To achieve this, BPXA created and staffed a Technical Directorate organization of 150 technical experts that are responsible for setting and verifying the standards to which BPXA will operate. The Directorate will review budgets of the line and provide assurance that major risk items are adequately funded. They are independent of the line organization and have direct accountability to both me and the President of BPXA.

Similarly, the oil transit lines will now be managed as a system by a single area manager. This will ensure better oversight and accountability over their operation.

PLANT

When we committed to replace the 16 miles of oil transit line serving Greater Prudhoe Bay, we could have approached the project as simply a repair and maintenance project. That is, replace the existing pipe with new pipe of the same composition and quality using existing associated infrastructure. In fact, our preliminary plan announced in August 2006 reflected just that scenario. However, upon further analysis and with a view to the future, we decided to incorporate additional technologies into the project to ensure oil transit line integrity and long-term safe operations.

An important component of this project was the engagement and involvement of the field operations staff in the planning and design of the new pipeline facilities. In addition, we re-designed the project to incorporate best available technology designed both to enhance daily operations and streamline its use. The OTL system will include a range of leading technology and equipment, such as improved corrosion-resistant pipe (insulated carbon steel with special epoxy coating) and elevated vertical support members where possible, upgraded ancillary pipeline facilities, addition of permanent pipeline pigging facilities, improved corrosion monitoring and new leak detection systems.

NEW ABOVE-GROUND STRUCTURE (EXHIBIT 4)

To protect the fragile tundra environment and wildlife, the project is installing hundreds of Vertical Support Members designed to hold the pipeline higher above the tundra. Where possible, the new 7-foot clearance will protect the permafrost, accommodate wildlife movement, discourage snowdrifts and support more effective and efficient pipeline maintenance activities.

Better ancillary pipeline facilities

Pipeline facilities throughout the system will be equipped with best available technology, operator-friendly equipment. Twenty new modules will support operations and enhanced maintenance of the pipeline, built with an eye toward the future and easy worker access to equipment.

Key elements of this system include equipment to measure and remove factors associated with corrosion that can lead to pipeline leaks. The factors associated with the recent leaks—stagnant water, sediment buildup, and bacteria—have been "engineered" out of the new pipeline system.

The infrastructure will include the necessary facilities to support use of "maintenance pigs," capsule-shaped devices that run through the pipeline to clear out sediment and stagnant water; "smart pigs," devices that measure pipeline wall thickness; equipment that injects corrosion-inhibiting chemicals directly into the oil transit lines; and a demonstration project to determine if a new, highly sensitive leak detection technology that allows detection of even small leaks, will work in above-grade Arctic piping.

NEW PERMANENT PIGGING FACILITIES (EXHIBIT 5)

The OTL project upgrade includes permanent, heated facilities that accommodate maintenance and smart pigs, as well as newer higher-quality equipment. The new facilities, designed for access to all equipment, will include new pig "launchers" at upstream locations and "receivers" at downstream locations so a maintenance pig can be inserted into a stream of oil to clean out the pipe or a smart pig can be inserted to inspect and diagnose internal and external pipeline corrosion.

The new modules will allow us to run maintenance and smart pigs regularly. Maintenance pigs, run on a routine basis, will help to reduce water and sediment build-up. Any solids resulting from regular runs will be analyzed for bacteria growth and/or sediment build-up to help identify changing conditions in the pipeline system. Pipeline and corrosion specialists will then make appropriate adjustments in operations or inspections.

NEW EQUIPMENT TO SUPPORT "CHEMICAL-INJECTION"

By cleaning the inside of the pipe through pigging and "sweeping" fluid velocities, corrosion-inhibiting chemicals are much more effective at adhering to the pipe surfaces where they both coat the internal pipe and are toxic to bacteria. We are installing equipment that will inject these chemicals directly into the transit lines, rather than relying on carry-over from upstream applications. This equipment will work hand-in-hand with our corrosion-monitoring techniques.

LEAK DETECTION (EXHIBIT 6)

Complementing pigging and corrosion control is a new leak detection system to measure the volume of flow in the line. This new equipment will be installed as the primary system for the entire OTL renewal project.

The primary method will use several types of meters, including a new software program, to read the volume of liquid going into and coming out of the pipeline segments. This system is designed to detect leaks as small as 1 percent of the flow rate, as well as catastrophic leaks.

The secondary pilot system uses a chemical analysis method that passes an air sample past a hydrocarbon analyzer, which indicates whether any crude oil has escaped from the pipe and, if this has happened, triggers an alarm. This method is intended to detect pinhole leaks, such as the ones experienced in 2006.

PROCESS

Underlying these new investments and organizational changes is the adoption of new risk assessment and management procedures. These tools will allow us to better identify, evaluate and target concerns with adequate budget support. BP has already initiated risk-based inspections for its entire North Slope operation and modified its operating and maintenance practices on the OTLs. For example, CIC staff has been doubled and they have expanded their work to include greater interaction with operations personnel and with in-field inspectors including face-to-face dialogue and more rigorous hands-on-pipe visual and other inspection protocols.

PERFORMANCE

Management assurance has been facilitated by the adoption of a new closed-loop safety and operations integrity management system. This new system will incorporate clear leading and lagging indicators, enhanced communication and transparency up the line, formal reporting and clear authorities and accountabilities that are properly linked to incentives. The BP Group Safety Culture & Leadership initiative is well underway for Greater Prudhoe Bay, and is beginning at other facilities. Culture change is among the goals of the OMS process.

While it is clear that OMS has begun to drive renewal in Alaska, behaviors have also begun to change elsewhere in the organization. Recently, the steam provider to our Toledo refinery experienced a plant upset causing a loss of steam to the refinery. The refinery initiated emergency shut-down procedures as designed and without incident. A day later, as Toledo began normal restart, personnel noticed a leak on one of the overhead lines from a process unit. The refinery was again taken down and upon inspection, it was determined that a stress fracture had occurred on a pipe weld during the initial steam-provider induced refinery shut-down. We could have performed a spot repair on the unit and continued restart operations but, informed by a comprehensive risk assessment, we are performing additional unit inspections to properly identify any other impacts, perform repairs and initiate safe restart. This is exactly the behavior that OMS drives and what I am reinforcing throughout BP America's operations.

CONCLUSION

Much of my job over the past year as Chairman and President of BP America has been to assess and develop new standards of operation and to ensure that the standards we have set are met.

When I appeared before the committee last September, I asked that we be measured by "what we do, not what we say." We have made tremendous progress over the past several months due to the deep commitment of BP America's management and employees to this renewal process. I am pleased with the progress but not yet satisfied.

Renewal is taking hold. We are investing for the future but the process of renewal will take a number of years to fully realize. Similarly, culture change will require the same sustained commitment of management for employees to embrace BP America's new OMS model. I know that BP America and its 36,000 employees are up for the challenge. My commitment is to make this all happen.

Exhibit 1

BP in Alaska — Building a 50-Year Future

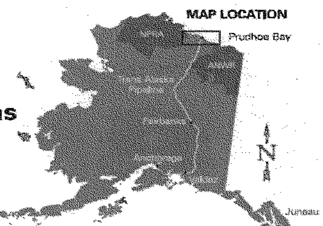
bp

The hallmarks of the Alaska business are its large resource base (second only to Russia in BP's portfolio) and its 50-year future. The BP Alaska strategy focuses on these known resources in order to: 1) manage the decline of light oil production; 2) unlock heavy oil; 3) renew our facilities, infrastructure and people; and 4) bridge to future gas production.

BP Alaska underpins BP's worldwide operations, accounting for 7% of the company's global production and almost 7% of the global E&P capex budget. Our strategy is shaped to support the existing profit center's framework by exploiting our known resource base and delivering strong free cash flow to the business.

BP Alaska operates five producing units including Prudhoe Bay (the largest oil field in the U.S.), four common carrier pipelines, and owns a significant interest in the Kuparuk River Unit. Our Midstream business provides oversight for our 47% interest in the 800-mile Trans-Alaska Pipeline System as well as chartering and overseeing the performance of a fleet of tankers that transport North Slope crude oil over 2,100 miles to the U.S. West Coast. The workforce is comprised of 1,035 bp employees on the slope and 585 bp employees in the Anchorage office. Additionally, bp relies on more than 2,000 contractors statewide.

BP Alaska is on the frontier of a new future; a future that can be long and sustainable if the challenges of that frontier are met. As of January 1, 2007 BP Alaska's net cumulative oil production was approximately 6.2 billion bbls which is nearly equal to the remaining proved and non-proved reserve base (5.5 billion bbls). However, that future is not yet secure and requires a transformation in the way we do business. The mix of products is changing dramatically; heavy oil and gas resources are of a similar scale to the remaining light oil resource. Technical challenges increase as we are driven to thinner, more complex reservoirs and heavier oils. All the while we bear the burden of the highest cost of supply anywhere in BP's portfolio.



BP's North Slope Operations

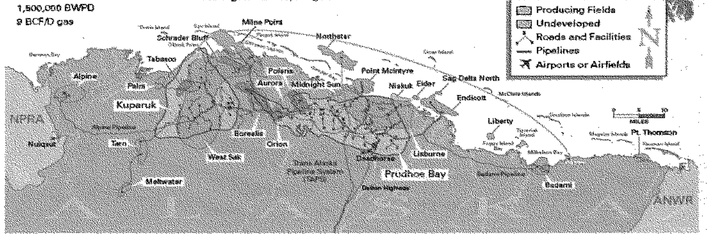
Facilities
11 Major separation facilities
2 Major gas fecilities
3 Water handling facilities
2,000 production/injection wells

Production
700,000 BOPD
1,500,000 BWPD
9 BCF/D gas

Pipeline Network
1,500 miles of pipe lines

Vessels
3,500 regulated vessels

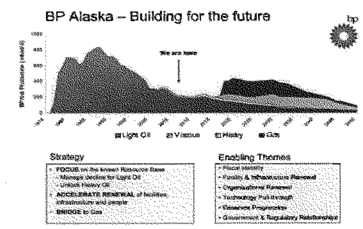
Tanks
750 regulated > 10,000 gals
700 regulated < 10,000 gals



FACT SHEET • BP IN ALASKA - BUILDING A 50-YEAR FUTURE

Exhibit 1, page 2

BP in Alaska — Building a 50-Year Future



This diagram, the "Green Mountain," highlights the contrast between our heyday of light oil production in the past and our evolution toward a diverse and challenging future. Our success will lie in our ability to retain the best of the Green Mountain while adapting and responding to different needs in the future. The Alaska strategy, articulated below, is the vehicle through which we will deliver that future.

1) Manage Light Oil Decline

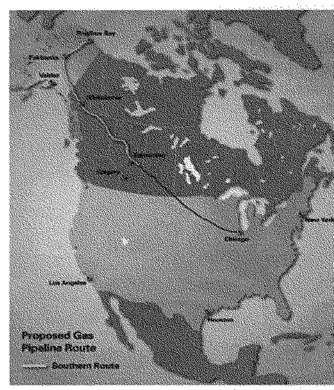
BP Alaska produced 236 mbd net oil during 2006. The natural decline from all of our producing fields averages to about 18% per year. This means that by 2009, light oil production would have fallen to half that of today, however, through the application of enhanced recovery technology, well work and infill drilling, we have stemmed the decline of light oil production to 9% (overall decline including viscous oil production is 7%).

2) Unlock Heavy Oil

Waterfloodable viscous oil accounts for about 9% of 2006 production and 570 million bbls of reserves. However, a larger heavy oil prize of 1.3 billion bbls is contained within a non-waterfloodable tranche which requires technologies not yet employed in Alaska. In order to unlock these substantial resources, the Heavy Oil Team is taking ownership of technology challenges through the establishment of a local Heavy Oil Center of Excellence.

3) Accelerate Renewal of Facilities, Infrastructure and People

Renewing the BP Alaska organization is vital to building our 50-year future. Safety & Operations Integrity (S&OI) is the core of our renewal effort to protect the health and safety of our employees and minimize our impact on the environment. Additionally, evaluating, updating and repairing our facilities and infrastructure will ensure that we efficiently and dependably deliver our production. Finally, as activity ramps up throughout the organization, with the Strategic Workforce Plan (SWP) we will renew our most important asset – our people.



4) Bridge to Gas

BP Alaska's interests in the Prudhoe Bay (26.4%) and Point Thomson (32%) fields total over a quarter of the North Slope's 35 tcf known gas resources. Construction of a pipeline from Alaska's North Slope to the U.S. Midwest to develop this resource would be the largest private sector project ever undertaken, requiring 30% of the high-strength steel world output per year for three years and a projected investment of $25 billion gross. Four key elements are required to progress this project: U.S. Federal legislation; an efficient regulatory framework in Canada; a clear and durable fiscal contract with the State of Alaska; and finally, capital cost reductions through the application of advanced technology. While the long-term prosperity of our oil business will depend on the development of North Slope gas, it is its health in the near-term that will enable us to forge the bridge to gas.

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Exhibit 1, page 3

Prudhoe Bay — How we produce oil

bp

After 30 years of production, Prudhoe Bay remains the largest oil field in North America and ranks among the 20 largest fields ever discovered worldwide. Of the 25 billion barrels of original oil in place, approximately 13 billion barrels can be recovered with current technology. Today the field has produced nearly 11 billion barrels. The current liquids production from the Greater Prudhoe Bay Area, which includes the nearby satellite fields of Midnight Sun, Polaris, Aurora, Orion, and Borealis, totals 430,000 barrels per day. The field also contains an estimated 26 trillion cubic feet of natural gas resource (in place) in an overlying gas cap and in solution with the oil.

Prudhoe Bay produces from the Sadlerochit sandstone formation nearly 9,000 feet underground. The oil-bearing column was 500 feet thick in some areas at the time of the field's discovery.

The Prudhoe Bay field was discovered in 1968 and the field came on-stream June 20, 1977. Production averaged more than 1.5 million barrels of oil and gas liquids per day for more than a decade.

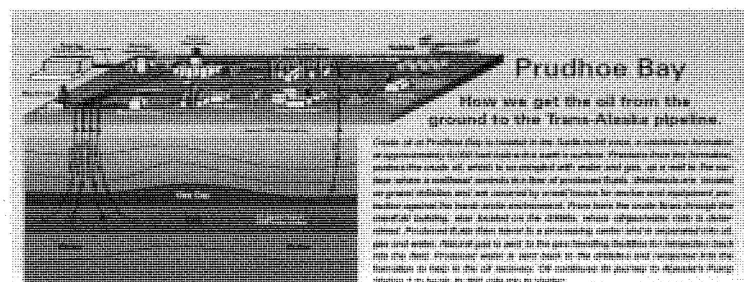
Prudhoe Bay's 30th anniversary milestone and the events of 2006 have placed a new emphasis on the renewal field's infrastructure and workforce. Workforce renewal and hiring Alaskans is a fundamental part of achieving BP's 50-year plan in Alaska. We support educational and technical training programs aimed at preparing Alaskans for jobs.

There has been focus on the installation of the oil transit pipeline system, the installation of pigging and corrosion-inhibitor injection facilities, as well as state-of-the-art leak-detection and metering facilities. This is in addition to work on the affiliated electrical and emergency systems. The result will be a $250 million upgrade the field's oil transit line system and related infrastructure by yearend 2008. BP will continue to commit the necessary resources to evaluate and renew its infrastructure at Prudhoe Bay.

Prudhoe Bay Satellites

Satellite fields are small accumulations of oil that can often be developed using existing infrastructure. There are five satellite fields currently produced from existing Prudhoe Bay gravel pads and the liquids are processed through the field's facilities. Aurora and Borealis produce from similar formations and were brought on-line in 1998 and 2000 respectively. Midnight Sun produces from a sandstone formation at 8,000 feet below sea level.

Orion and Polaris satellite fields both produce the difficult viscous oil from the Schrader Bluff formation, at depths of 4,000 to 5,000 feet. By using advanced drilling technologies the fields currently produce about 10,300 barrels per day.



FACT SHEET • PRUDHOE BAY - HOW WE PRODUCE OIL

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Exhibit 2

BP Texas City - Perspective and Scope

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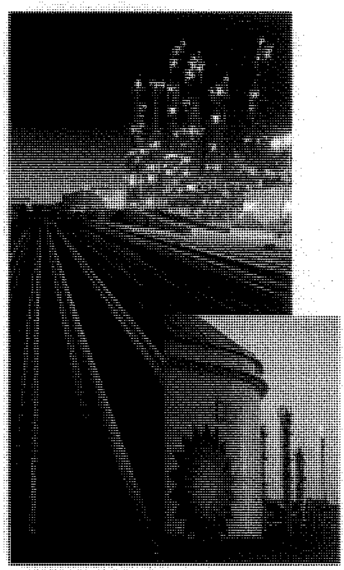
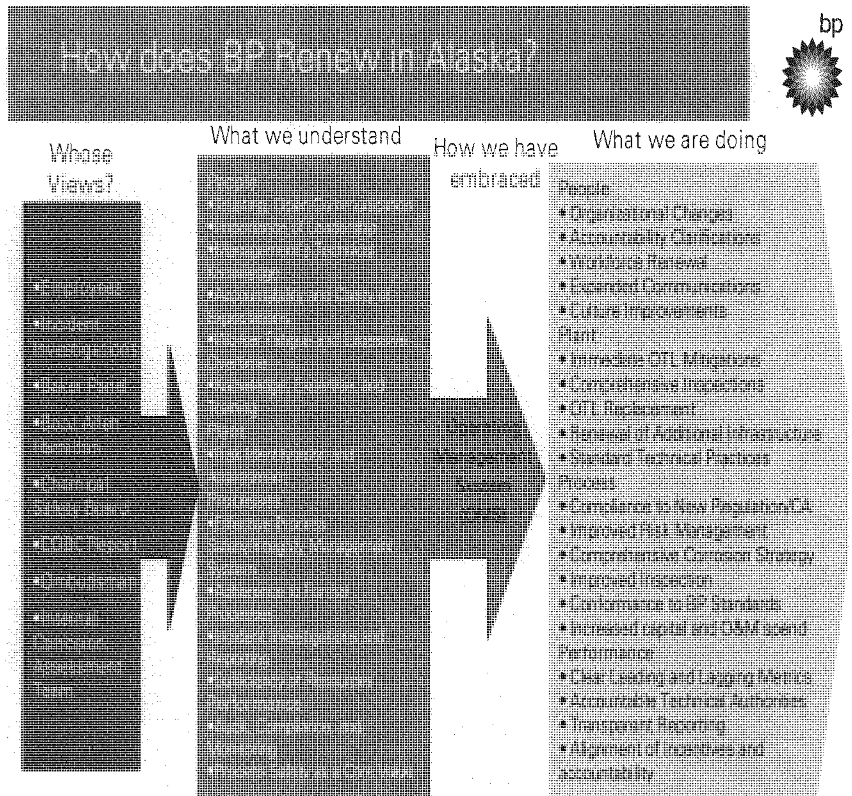


- Third largest U.S. refinery
- 1200 acres, 2 square miles
- 33 process units
- One of the most complex refineries in the world
- 460,000 barrels per day capacity, equivalent to 7.6 Bn gallons per year
- Three percent of U.S. gasoline supply
- 2,100 company employees
- About 5,000 contractor employees daily
- Major area/county employer and tax-payer
- Highly integrated with BP's adjacent chemical plant
- 70% of crude comes via marine terminal
- 75% of products goes out via three pipelines
- Serves East Coast and Midwest

Exhibit 3



How does BP Renew in Alaska?
bp
Whose Views?
•Employees
•Baker Panel
•Booz Allen Hamilton
•Chemical Safety Board
•Ombudsman
What we understand
How we have embraced
Operating Management System (OMS)
What we are doing
People
• Organizational Changes
• Accountability Clarifications
• Workforce Renewal
• Expanded Communications
• Culture Improvements
Plant
• Immediate OTL Mitigations
• Comprehensive Inspections
• OTL Replacement
• Renewal of Additional Infrastructure
• Standard Technical Practices
Process
• Compliance to New Regulation/CA
• Improved Risk Management
• Comprehensive Corrosion Strategy
• Improved Inspection
• Conformance to BP Standards
• Increased capital and O&M spend
Performance
• Clear Leading and Lagging Metrics
• Accountable Technical Authorities
• Transparent Reporting
• Alignment of incentives and accountability

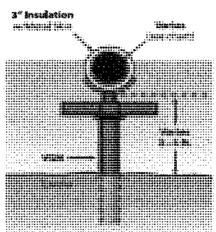
Exhibit 4

Vertical Support Members (VSMs)

bp

PRUDHOE BAY PIPELINE REPLACEMENT PROJECT

To protect the tundra environment and wildlife, The Prudhoe Bay Pipeline Replacement Project will install Vertical Support Members (VSMs) designed to suspend the pipeline higher above the tundra. The new 7-foot (where possible) clearance protects the permafrost, accommodates wildlife movement, discourages snowdrifts, and supports efficient pipeline surveillance activities. The project also calls for driving the VSMs deeper in the ground to enhance VSM stability.

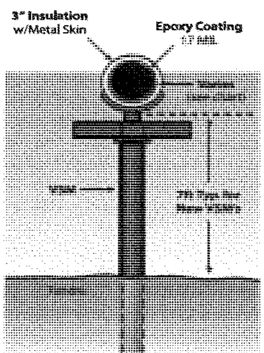


Existing Pipeline Cross Section

The current clearance above the tundra and the depth of the VSM into the tundra

Replacement Pipeline Cross Section

The new-foot clearance above the tundra and the depth of the VSM into the tundra



TECH TALK

VSM numbers: The new lines require installation of about 1,200 new VSMs with a typical spacing of 55 feet. The VSMs will have a minimum embedment depth of 18 feet to reduce the likelihood of jacking. New VSMs will be constructed of 12-inch diameter X 55 pipe with a 0.500-inch wall thickness.

Special support: Horizontal Support Members (HSMs) are also used in building pipeline trestles. HSMs have a 16-foot width to accommodate the new pipeline and will have room for an additional line as needed for future expansion. HSMs are at the top of VSMs, about 7 feet above ground.

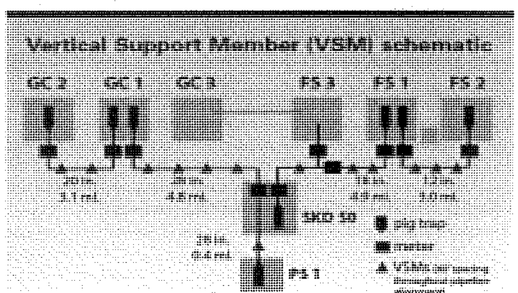


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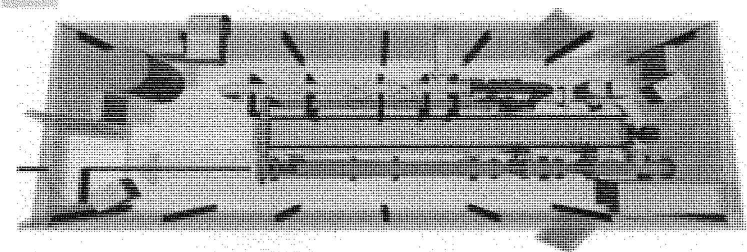
Exhibit 5

Pigging and chemical injection

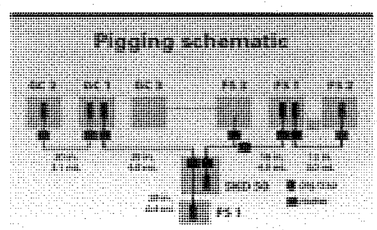
bp

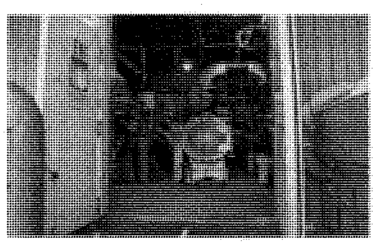
PRUDHOE BAY PIPELINE REPLACEMENT PROJECT

A major focus in the Prudhoe Bay Pipeline Replacement Project is the installation of new equipment to fight internal corrosion in the pipelines. This equipment centers on "maintenance pigs," capsule-shaped devices that run through the pipeline to clear out sediment and stagnant water; "smart pigs," devices that inspect and measure a pipeline's wall thickness; and equipment that injects corrosion-inhibiting chemicals into the pipeline. The new facilities will also feature a design that allows operators easy access to all equipment.



***Above:** Production facilities will include new pig "launchers" and "receivers." A launcher is installed at the pipeline input point and a receiver is installed at the pipeline output point. Working in concert, launchers and receivers send a maintenance pig in a stream of fluid to clean out the pipe or a smart pig to inspect and diagnose internal pipeline corrosion. The new modules allow BP to run maintenance and smart pigs regularly. Maintenance pigs that are run on a regular basis can keep water and sediment from building up.*





***Left:** By cleaning the inside of the pipe, pigs produce a clean surface that can be easily coated with corrosion inhibitor chemicals that provide a protective layer and act as a "biocide" for bacteria. These chemicals interface with the pipe body itself. BP is installing equipment that can inject these chemicals directly into the transit lines. This equipment will work hand in hand with corrosion-monitoring techniques.*

Exhibit 6

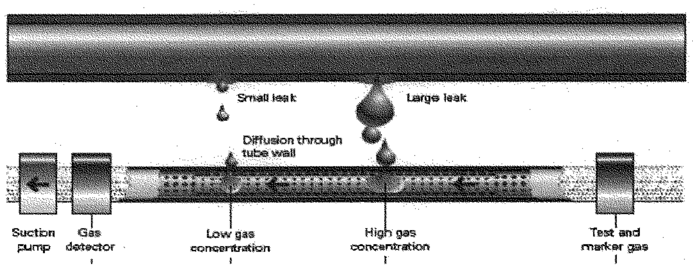
bp

Leak Detection

PRUDHOE BAY PIPELINE REPLACEMENT PROJECT

Complementing pigging and corrosion control is a new leak detection system being installed as part of the Prudhoe Bay Pipeline Replacement Project.

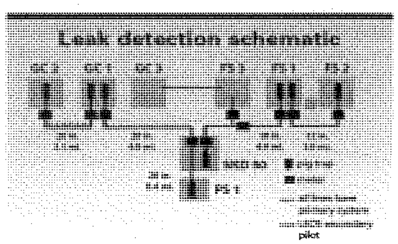
The new system offers enhanced reliability. Leak detection involves measuring the volume of flow in the line. The replacement project features both a primary upgraded system that meets current regulations and a pilot system being tested in above-grade applications that's designed for the detection of very small leaks. The primary method uses several types of meters to read the volume of liquid going into and coming out of the pipeline segments. This method detects large, catastrophic leaks. The pilot system (see below) uses a gas chromatograph method that passes an air sample past a hydrocarbon analyzer, which then indicates whether any crude oil has escaped from the pipe. If it has, the system triggers an alarm. This method can detect even very small leaks.



TECH TALK

Super software: The software package for the new leak detection has a proven track record in the energy industry and is one of the most widely tested leak detection systems in the world. The system has been applied to oil, gas, multi-phase, chemicals, water, and multi-product pipelines, both on land and subsea.

A 'sound' system: The new leak detection system will use ultrasonic meters, which detect leaks by measuring the flow in the pipeline. The meters inject a sound wave into the crude oil stream and receive it at the other end as it emerges from the stream. These meters are rugged-able to survive even hurricane force.



Schematic shows primary leak detection system and secondary system (LEOS) that is being piloted between GC 2 and GC 1.

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Mr. MELANCON. Mr. Malone, thank you and I am going to apologize for the second time in one day. We are going to suspend to go vote and then we will reconvene as soon as we can get back up here. Thank you.

[Recess]

Mr. STUPAK [presiding]. I call the subcommittee back to order. I apologize again. There is procedural games being played on the floor, so we think we have a couple hours. Another motion arose. But since we are through all the rules in that, there will be no intervening votes for a while, so maybe we can get through this, so I appreciate your patience. It is just hard getting continuity going in testimony or questions. Mr. Malone, if I may, there should be a document there. Does he have it, the hazardous review statement, the one we put in by UC?

Mr. MALONE. Yes, sir, I have it.

Mr. STUPAK. OK. If you would go to page, well, in the upper right-hand corner on the fax, page 7, if you would. Hazardous review statement. My concern is this: I am sorry I was in and out on your opening statement. I did have a chance to see it. As I ran to the floor, they handed me a copy of it and I am encouraged about what you said about cooperation and things like this, but I am a little concerned. This document before us, which is 13 pages long, if you read it, it talks about this chemical change does pose HSE, that is Health Safety and Financial risk. Are you with me?

Mr. MALONE. Yes, I am.

Mr. STUPAK. OK. And the last paragraph says suspending the supplemental injection into the PW system is, therefore, unlikely to cause loss of contaminant of equipment material in the short term, 1 or 2 years; however, it will shorten the life of the system, resulting in either abandonment or expensive repair or replacement in the medium to long term, 3-plus years, and this is 1999. The concern I have is, if it is one person or two persons, it seems to be systemic throughout the whole BP organization; cut maintenance, increase profits, and whether you get bonuses or whatever you guys have, the $106 billion in profits during this period of time. But we got this document last night. In response to us, you said you have this database of 20 million documents, so everything will be in there and you will peruse it and make sure we have everything, but this isn't in the database. So while I am encouraged by your testimony, I don't know how we can be assured that we are going get the documents we need. And you end up your statement by saying judge me by what we do, not what we say, but yet we still have to go outside of even your folks to get documents we need to ask questions on. Why wouldn't this have been in your main 20 million and all of that? Are there other documents like that? You heard Chairman Barton rather frustrated today about what is going on. Do you care to respond on that?

Mr. MALONE. Well, this is the first time I have seen this document. I was told that it was found during our ombudsman review that he is doing, Judge Sporkin is doing currently, and it was provided to the committee.

Mr. STUPAK. But why isn't Judge Sporkin's documents in part of those 20 million we are supposed to have access to?

Mr. MALONE. Mr. Chairman, I don't have an answer for that. We have populated the database with something over 20 million documents and I heard earlier this week, we think we have them all in there, but obviously we do not, but I can't say why this one wasn't in the database.

Mr. STUPAK. Well, around here, especially where we sit on this side of the dais, it is not unusual for departments and agencies to dump documents on us the night before and hope we miss something, but this committee staff on both sides is very good and they are going to go through this. If you will, you have got that binder in front of you, walk with me through these documents, if you will. And something you probably won't have to look at, and you have heard about them and I sure you are familiar with them. If you go to page 82 on tab 10, that is the Booz Allen Hamilton report, and in there they say the report is the folly in finding poor corrosion management at Prudhoe Bay. OK, Booz Allen is a separate binder. I am sorry, sir. There should be a separate binder, Booz Allen, page 82, table 10.

Mr. MALONE. Yes, sir, I have it.

Mr. STUPAK. OK. I am looking at the second one, risk management. Budgets and funding were largely based on affordability versus necessity and were not supported by an analytical process to prioritize risk. Senior management incentives were based on cost and production. And if you go to tab 4, page 2, on the bottom, this is an 1991 e-mail from John Todd in the CIC group and it concerns the halting of use of the corrosion inhibitor in produced water lines and here is what it says: "Due to budgetary constraints, the decision has been made to discontinue the PW inhibitor currently being injected at GC–2 and GC–3. The GC–2 bulk tank should run out within the next 2 days. It will not be refilled."

Mr. Malone, in fact, if you go to page 1 of that same tab, No. 4, you will see how this was viewed by superiors. This e-mail is from the head of the CIC group, Richard Woollum, the gentleman who refused to testify. It says, "John and Rick, my impression from the FMT meeting is that we will not be getting any relief on the budget. They all think that PW—is the right thing to do, but no one is prepared to let loose the purse strings." That is 1999 when the profits of BP was $5.1 billion. If you go to tab 16, this document is a 2002 budget challenge document for the corrosion group. On the third line down they suggest a reduction of the use of inhibitor to save money. What is troubling is that there is also a note which states, "A10-percent reduction in innovation levels would result in a 30-percent increase in corrosion rate." This is 2002 when your profits were $6.9 billion.

If you look at tab 20 in your binder, you will find a spreadsheet, Greater Prudhoe Bay/2004 Field Lifting Cost Challenge, Maintenance and Reliability. Essentially, each year various groups within the CIC group were asked to search for ways to save money. Mr. Malone, the second entry states, and I read, "cancel partial PW inhabitation at GC gathering centers. That action could save the company $670,000." That is 2004. Your profits were $17.2 billion that year. If you go to tab 13, page 8, this is now 2001 and this e-mail sent to Richard Woollum from a person named Dominic, who we know from the first document I showed you, is a corrosion engineer. Dominic says, this document was from the 2003 time period and yet again, there is discussion about halting the injection of corrosion inhibitor in the produced water lines, in order to save money and meeting tight budget. And it states, "ideas for saving money, in no particular order: turn off PW chemical and halt PCQ inhibitor will help out here." Again, in 2001, your profit was $8 billion.

Then finally, if you go to tab 13, page 6, towards the bottom is a similar e-mail from Richard Woollum. He is advocating shutting down the inhibitors to save money, but even he acknowledges that this is a very disagreeable measure to take. Here is what he has to say. "As you may know, we are under a huge budget pressure for the last quarter of the year and therefore we have to take some rather disagreeable measures. Can you please implement the following changes to reduce: shut down the PW inhibitor for the remainder of the year, discontinue the addition of corrosion inhibition for velocity control." Again, in 2001, your profits were $8 billion.

Here is the part that bothers us, Mr. Malone. Having looked at all of these six examples, these six e-mails, will you agree with me that there is a pattern of cost-cutting pressure during a time of healthy profits?

Mr. MALONE. Mr. Chairman, as my opening statement said, we recognized there were extreme budget pressures at Prudhoe Bay, yes, sir.

Mr. STUPAK. OK. Will you agree with me that this cost-cutting pressure could have contributed to a culture that disincentifies or discourages preventive maintenance?

Mr. MALONE. Mr. Chairman, not only could, we believe it did.

Mr. STUPAK. As has been said a couple of times today, you have over $106 billion in profits during this time period. Was it really necessary to skimp or save on this maintenance, especially when we talk about the health, safety and welfare? And I know, in your opening, you mentioned Texas City and you mentioned Prudhoe Bay, but you see the same thing in Ohio and some of the other places that we have talked about. All four of them, your other locations that the reports have been on, the Baker report, they all indicated the same thing. At what point is your corporate responsibility where you put maintenance to make sure that it is safety, not just for healthier workers, but also to make sure that strategic oilfields are not shut down. Where the corporate responsibility where profits are secondary to really your responsibility to the American people?

Mr. MALONE. Mr. Chairman, if I could. I followed most of the documents and I apologize. The last couple I was not able to follow the tabs with you, but I understand. There are two important comments for me to make, is that I need to make sure that we understand the time of the Prudhoe Bay and the cost budget pressures that we had at that time. This was a time when the field was declining. It declined over 75 percent over that time period. And also the price of oil was, I think, on average about $15 a barrel. That is what I have been told. Yes, there were budget pressures because we had a huge infrastructure, a very expensive infrastructure, built for artic environment and as the production level dropped, so did we need to find the facilities to match up against that production level.

Mr. STUPAK. I don't disagree, but you knew that field was dropping when you bought it, because you have been partners up there for some time and you bought it from ARCO shortly before 1999, right?

Mr. MALONE. No, we started it with ARCO.

Mr. STUPAK. Right, but then you bought them out. When did you buy out ARCO? 2000. So you knew that had to be declining and therefore, as you get declining quality of oil, you get more water and you get more sediment. So therefore that would increase costs of maintaining the pipe, not lessen the cost of maintaining corrosion inhibitors and smart pigs and maintenance pigs from going down. You had to have a due diligence to report or something, before you purchased out ARCO or something. I would think they would say the last time they pigged a pipe, because it is what, 16 years and we now find out. So 10 years before, they didn't even pig before you bought it.

Mr. MALONE. Well, Mr. Chairman, I wanted to at least give that as the backdrop—excuse me—of the climate that we had during that time. What I am not saying to you is that we don't recognize that the budget pressures that existed created on our employees a very difficult situation and I would say that we see these e-mails and that is what we have asked on the inhibitor. As you know, I have asked Judge Sporkin to look at that. I can't respond to the complete picture of that. We have a review going on there. On the OTLs, we asked that it be looked at by Booz Allen Hamilton and their conclusion, which you have, was that even with more money, they wouldn't have pigged the line. They were that confident in what they were doing on that pipeline.

Mr. STUPAK. But Booz Allen, in the March 2007 report, says on page 72, budget pressure eventually led to de-scoping some projects and deferring others. For example, the plan to run a smart pig in the OTL you just talked about was dropped in 2004 and 2005. So that sort of counters what you just said. That is in the Booz Allen report, March 2007.

Mr. MALONE. Mr. Chairman, I have been told that Booz Allen Hamilton has sent a correction in to the committee on that.

Mr. STUPAK. See, here is my problem. Whether it is this one, Booz Hamilton, or else Billie Garde's report, when something comes up that is critical and proves the point that you dropped maintenance which led to this leak which led to the shutdown of the field, it gets whitewashed. This was your final report. The other witnesses who appeared before us on the first panel, and I know you listened to them, especially Ms. Merritt, you lied on the Booz Allen report. Now, when Booz Allen comes to the committee and we dig through it and we find a line that is pretty damning of BP, suddenly Booz Allen Hamilton wants to pull back that report and drop that line. I get real suspicious. My time is up but I am sure we will probably go another round. I will to Mr. Whitfield.

Mr. WHITFIELD. Thank you, Mr. Chairman. And Mr. Malone, thanks for being with us today. When did you actually become the president and chairman of BP America?

Mr. MALONE. July 1 of last year, but it feels like an eternity.

Mr. WHITFIELD. And where were you prior to that?

Mr. MALONE. I was the chief executive of BP Shipping Limited. I was based on London, England.

Mr. WHITFIELD. Yes. And I am glad to hear you acknowledge that decisions were made frequently on budgetary reasons rather than on safety reasons and so forth, and I think that is certainly reflected and it is refreshing that you acknowledge that. But when you look at the Baker Panel report and the Chemical Safety Board's report and the internal reports that you all did and Booz Allen and others, when you look at all of the shortcomings of the culture and management at BP America, it is really quite disheartening that such a large company could, for example, they talk about problems in leadership and trusting and open communication and management technical knowledge and accountability and clarity of expectations and worker fatigue and excessive overtime and process safety is a core value. All of those things came up lacking. And so when you came in and from your perspective, trying to move off in a new direction now, in your experience as a manager, what did you find most perplexing in the culture of BP Petroleum for you to deal with?

Mr. MALONE. I think there are two things that are very important, which is I want to highlight that we are looking at all of those reports and we have looked at all of the recommendations and we are incorporating all of those report recommendations and if they supplement or assist us in moving forward—excuse me—we are going to use those recommendations. The direct answer to your question, the most striking to me was the rigor around process safety management and the Baker Panel, Congressman, gave us a real gift and that is that we didn't have that embedded in our culture and that was striking to me coming back.

Mr. WHITFIELD. It is so important that, particularly with companies being in oil today, they have some management principles and be above board and be transparent and be honest and straightforward, because there is a large segment of the American people who, particularly with fuel prices being what they are, are looking for a culprit and you are the ideal culprit to look at and particularly when you have this kind of history. And you feel quite confident moving forward, though, with the new management changes in Alaska and elsewhere, that you all can address some of these problems.

Mr. MALONE. I am. It is going to be a long process. This is not something that is going to occur in the next year or two. To embed process safety management under our system, it is going to take years, but I am very encouraged with, as I go to Alaska and as I go to Texas City, the new management in both of those locations have embraced process safety management and our Alaskan team, which is essentially a brand new team, I have been very impressed with their commitment to get this right.

Mr. WHITFIELD. And do you all operate, is it five refineries in the United States?

Mr. MALONE. Yes, sir, five.

Mr. WHITFIELD. And what is the capacity of those five refineries? Or the total capacity would you say per day?

Mr. MALONE. I thought I might be asked that. Right now, when they are full capacity, we can produce, for example, crude rate at each one of the refineries, I going to—if you don't mind, I will just try to do a quick add. The crude capacity is almost 3 million barrels a day.

Mr. WHITFIELD. Three million barrels a day?

Mr. MALONE. That is correct.

Mr. WHITFIELD. Of those five refineries?

Mr. MALONE. Yes, sir.

Mr. WHITFIELD. Now, has BP given any thought to building additional refineries in the United States?

Mr. MALONE. No, sir, we have not. What we have been doing, Congressman, is trying to expand our existing refinery capacity and we have been doing that over the last 10 or 15 years.

Mr. WHITFIELD. So it is your intention to continue to expand where you are located today?

Mr. MALONE. Yes, Congressman, and in fact, we announced about less than a year ago that we were taking our Whiting refinery and we were expanding capacity there to be able to take heavy crude from Canada and that goes as planned, it is about 1.2 million gallons of gasoline more a day.

Mr. WHITFIELD. Yes. Let me just ask you, if you were at a Rotary Club in a rural part of the country and you had given your remarks and someone stood up and asked you the question and they said, Mr. Malone, you are the chairman and president of a large oil company and I personally think that your salaries are too high and your performance awards are too high and that oil companies are gouging us consumers down here and the amount of money that we pay for gasoline is just outrageous, although we recognize that in other parts of the world, they pay more than here. But how would you respond to the charge that the oil companies are gouging the American people today?

Mr. MALONE. Well, we have been trying to do an education right now—excuse me—because right now we depend on imports to meet our demand here in the United States and if you look at the last few months, and this is what I talk to people about, one, our actual consumption was higher in the first quarter of this year, 2 percent higher than the year before and normally that is the time when consumption is down of gasoline. It has actually risen. The economy is strong; people are driving. The second thing is that we have less turn around time, so a lot of our refineries were down and also, at the same time, we have a lot of refineries that had bad incidents and there are still down. And third, the imports, turn around is going on in Europe at the same time, so there is not the volume of gasoline to come in. So what has happened, price has risen strictly based on supply and demand.

Mr. WHITFIELD. I have no further questions.

Mr. STUPAK. Now, for Members, we have got another quorum call, I understand. If we have a real vote, I will go there, but I am not going to go with this quorum call, so I am going to keep this hearing moving. Mr. Melancon for 10 minutes for questions.

Mr. MELANCON. Thank you, Mr. Chairman, I appreciate it. Mr. Malone, thank you for being patient with us on the floor. Mr. Malone, when you were asked away, were you—before, I bet there are days you wished you were back.

Mr. MALONE. I know I shouldn't say this, but I remember my shipping company. It was a great job.

Mr. MELANCON. One of the things that, and as I look at what transpired, the explosion in Texas City, the spill in Prudhoe and I look at the profits that year. Do we or has anybody provided us with the executive bonus packages were those 2 years, or what the dividends that were paid to the stockholders during those periods? And if not, I would like to request, if you could, that we could get that information. The President was up at Wall Street a couple of weeks and talking about executive salaries. He wasn't very warmly received and I am not one for fooling with them, but if you are going to be cutting safety for the workers in your company, then it is a concern to me if, in fact, there—and I would like to see that, if I could, maybe on a 5-year spread, just to see, was the management back then, or executives, trying to just keep a steady bonuses or dividends going to your stockholders.

I have been a person that defends the oil and gas industry. As Mr. Green mentioned and I think you were here, it is difficult for me to try to convince Democrats on my side of the aisle that oil companies are doing a good job in the Gulf of Mexico and offshore when things like this occur. As a matter of fact, I am sure some of them are giggling around, saying Melancon says everything is cool. But one of the things I guess caught my attention early is Mr. Woollum and you know, your testimony was about working with us and trying to bring the company and move it in the right direction and do the right things, and I have heard of witness protection, but usually it is for the prosecutors and not the defendant. And so I guess my question is simply who has made that determination that no one can talk to Mr. Woollum?

Mr. MALONE. Congressman, Mr. Woollum, as you may know, in September, chose to take the fifth [amendment] at the hearing. That was his choice. He was represented by counsel. So the reasons for that would have been addressed with he and his counsel. I am not in a position to do that.

Mr. MELANCON. I heard earlier the lady from Alaska talk about that there has been no fines and no penalties. As a matter of fact, it almost sounded like everything went away. That bothers me. I mean, I am from Louisiana. We have been accused of everything, so I thought every other State was doing everything right. Does anybody in your executive chain know what has led to just no fines, no penalties? Is there something in their statutes that deal with criminal negligence and whether you can continue to operate in the State if it is found such? That bothers me.

Mr. MALONE. Well, Congressman, I know there are actions to be taken by the Federal Government and I think we have heard that today. I don't know the status with the State, but I will get that for you.

Mr. MELANCON. One of the things, and if you will go to tab 20, the spreadsheet called the Greater Prudhoe Bay/2004 Field Lifting Cost Challenge, Maintenance and Reliability. This spreadsheet appears to be part of the budget challenge process employees seem to go through each year. The first item listed is the CIC, Corrosion Inspection Chemicals group. Cancel 2004 smart pig program. If you follow over to the right of the spreadsheet, you see that this could save the company $250,000. Do you know that this cut was made and again, why are they talking about having to cancel something as important as a smart pig to save money?

Mr. MALONE. Congressman, I don't know what they are speaking of here, whether it is the oil transit lines or the flow lines or produced water lines, I don't know. If it is using inhibitor, as I mentioned earlier, we do have someone looking at that. If it was on the OTL, I had Booz Allen look at that. I am happy to take a look at that for you, but I don't have any information today.

Mr. MELANCON. Yes. Looking just at that first question and with all due respect, maybe we ought to have some people that are down further in your organization in Alaska or the United States operation that were there and that were part of what transpired at those times. Is there any problems with us requesting those folks, some of those folks, and can you help us identify those?

Mr. MALONE. Congressman, the answer is we will work with Congress, absolutely.

Mr. MELANCON. Also in the same document, tab 20, there is a line item, cut all Sunday barbeques, CPS fund runs, CPS safety fair booths. BP was examining a $25,000 cut in areas intended to boost employee morale and promote safety. I mean, it got that bad? How much money did they make that year, $17.2 billion?

Mr. MALONE. We will put this fund run back in right away, sir.

Mr. MELANCON. I am not a runner but you know——

Mr. MALONE. Congressman, it was difficult in Alaska. If I could just say that we recognized that those budget pressures put our employees in a very difficult place and if that goes on long enough, we know that you create a culture, and as I said in my opening statement, where the word I used was curious, but it where people no longer begin to challenge and think. And what we need to do and what we are working on is to establish a culture where every employee will raise an issue and will have a comprehensive risk assessment. That means it takes all the risk, water in the lines, solids, all the expertise we can get and run it through a comprehensive risk to understand what that risk is and then have a management process to allow that a decision gets made at the right level around the risk and that every employee has a voice, and that is our ultimate objective in what we are trying to do in Alaska and in Texas City and across all our businesses.

Mr. MELANCON. And I realize that you run just the American operations for BP and their worldwide company. They made $17.2 billion. Did they lose money in the Alaska operation that year or in the next year? Did you lose money in the American operations when the Texas City facility exploded or, I think, the year before when the other facility exploded with five people killed?

Mr. MALONE. We normally don't record that way. I can get that answer for you, sir.

Mr. MELANCON. OK. I guess where I am coming from there is you are big multinational corporation. You would expect that, at some points in time, with justifiable information, for instance, the downturn in the production out of the Prudhoe field, that corporate would say we understand why things are tight and you maybe cut a little bit, and that is where I keep trying to get to. Who specifically made those recommendations? Was it up the chain or at the bottom of the chain? It appears that it was more up the chain. And can you help identify those folks so we can maybe find out what actually took place on the ground before and after these events?

Mr. MALONE. Congressman, the way BP's management system works, that ultimately local management is accountable for its budget and it is held accountable for its production and its safety and integrity. That rests with the business unit. And a business unit is our language for Alaska or Texas City.

Mr. MELANCON. I guess if I was in Alaska I would say you sent me here. Move me elsewhere. I don't want to do this.

Mr. MALONE. Well, Congressman, we have a new head of Alaska. His name is Doug Suttles and he has assembled an outstanding team in the last few months that is moving the process that I had talked with you about forward. We have a new refinery manager at Texas City, a gentleman named Keith Casey. They are committed to process safety management and to getting this right through the culture and both of them are actively engaged in moving us forward.

Mr. MELANCON. Well, with the price of a barrel of oil, they ought to be able to get this thing cleaned up, I would hope. I think my time has run out. Thank you. I yield back the balance of my time.

Mr. STUPAK. I thank the gentleman. Mr. Green for questions.

Mr. GREEN. Thank you, Mr. Chairman. And welcome again from all of us, Mr. Malone. I have a district in Houston not too far from Texas City and one of my constituents was a contract worker there and died in 2005. I also understand that BP and other companies have that similar philosophy that the plant manager is responsible. But I also know the criteria comes from the home office, wherever it is at, whether it is for Exxon Mobil in Las Gallinas or wherever. And I have dealt with a lot of plant managers on the use of the ship channel in 20 years and they are given that criteria and they are under pressure to cut that, not for themselves, but for above. And to say that I am glad you have new people at both places, but I also know they need the support and the encouragement from the folks above them so they don't get these hard and fast numbers that say this is what you need to cut, whether it is the smart pigs in Alaska or some of the safety inspections or safety things in Texas City. So you could put anybody there, but if you don't give them support from the upper management, their bosses, it doesn't do you any good. The main plate capacity at Texas City Refinery is 460,000 barrels a day, as far as you know?

Mr. MALONE. Yes, sir.

Mr. GREEN. Do you know how many barrels are currently being produced?

Mr. MALONE. About half that. We are about 130,000 right now.

Mr. GREEN. OK. Do you know, is there a plan for being able to get up to the capacity safely?

Mr. MALONE. Yes, and if I could, just for the record, I am an engineer but my math is pretty poor and I just noticed that I took total and added the backup. So in answer to your question, the capacity of our refinery system is 1.525.

Mr. GREEN. OK.

Mr. MALONE. Congressman, yes, we do have a plan. We are hoping to have Texas City back at full production by the end of the year.

Mr. GREEN. OK. I know you have five other refineries in the United States. Are any of them operating at full capacity now?

Mr. MALONE. Right now our Carson and our Cherry Point refineries are operating near capacity. Carson is main-plated to 265. It is operating currently at 265 and operating at 235. Cherry Point is 235; operating at 225. And Texas City, 465; 225 now. Lido is at 155. It was up 30, but we had an incident. And Whiting, 405; it is currently operating at 225.

Mr. GREEN. Well, next week we will put on a different hat in our committee and ask about production capacity in not only BP, for other refineries. And I wanted to ask you before our chairman did from northern Michigan, but——

Mr. MALONE. I thought that, maybe, it was where the question was coming from.

Mr. GREEN. At the last hearing last year, Mr. Marshall, who was then president of exploration in Alaska, responded to a question I asked him, stating, safety and integrity spending at BP are their highest things. They don't get cut. They are the things that get through the budget and cost is not a consideration. However, the Booz Allen report for Prudhoe Bay, the CSB report for Texas City, and the Baker Panel report for all five of BP's U.S. refineries, all concluded that cost cutting and budget pressures impaired safety performance at your refineries. Mr. Marshall is not here, but since you are, is there a disconnect from what he told us last year?

Mr. MALONE. Well, I can't speak for Mr. Marshall, but what I would tell you is that we have learned a lot. As I said in my opening statement, we have learned a lot since this last hearing and we now recognize that there were pressures on our employees.

Mr. GREEN. I understand. But after the 2005 accident in Texas City, BP conducted what is termed the management accountability review to determine responsibility. Isn't it true that various current BP executives and safety officials that were interviewed in private during this process believe that budget cuts were one of the major causes of the Texas City Refinery accident?

Mr. MALONE. I am sorry, I can't answer that question. I have read the report but I can't answer that.

Mr. GREEN. After the March 2005 accident, I also understood that BP pledge about $7 billion to upgrade equipment in U.S. refineries and I think that tells us some concern about what we needed to do to have that kind of investment in those refineries. What improvements have been made since that commitment over a year ago now?

Mr. MALONE. Well, I think those expenditures were what we think, over the next four or 5 years, I believe, we would be spending in order to get process safety management and our integrity management in place at our refining system in Alaska, so I think you will see progress being made in all our refineries as we are taking out, and this has been highlighted, blow-down stacks and putting in flares, as we are moving trailers out, as we are putting in explosion-proof buildings. You will see that activity taking place across our refining system.

Mr. GREEN. I don't know if you heard my questions of the first panel. Having spent a lot of time at both refineries and chemical plants in my area, I hope that a lot of your competitors and some colleagues are listening and responding to what you are doing because, like I said, I was at a plant last year, it was a chemical plant, and there was a portable building much closer than it should have been to a unit. And I asked them at that time, I said I hope you all have learned from what happened. You don't want to go through what BP is going through. And I hope the rest of the industry is hearing that, because it just does so much damage, not only to BP, but also to the industry as a whole.

Mr. MALONE. Congressman, if I could just make one comment on that. We found the industry to be very, very interested and I am told are in contact with us and I know they read the Baker Panel report and it has been distributed widely. We put it on the web so that everyone had it.

Mr. GREEN. Mr. Chairman, I have no other questions right now, but there are some I would like to submit for the record. I know we have a vote and I don't know if you and I have already missed that vote or not.

Mr. STUPAK. It is a quorum call and it is still open and I am not going to go back. I want to get through this hearing. It will probably be followed by a vote and we will have to do it because will be a recorded vote. You yield back? OK. The record shall reflect that Congresswoman Sheila Jackson Lee is here and she has been throughout these hearings monitoring them and even on the floor she catches Members and shares her concerns about the health and welfare of BP and its employees, so I am always glad to have her here.

It has been requested that we put in a Vinson & Elkins report, dated February 22, 2007, entitled "BP Comments on Chemical Safety Board's Draft of Final Report of March 23, 2005 Explosion at the BP Products Texas City Refinery". Without objection, we will enter that.

I would also like to put in the interim report of investigation on failure to disclose sealed BP documents to a congressional subcommittee, and other issues prepared on behalf of BP America by Billie Garde. So without objection, those two will be entered.

I have a couple me questions, if I may. I would ask you just at the end of my questions about those budget pressures found on page 72 of the final report of March 30 of Booz Allen Hamilton, and you said that line is going to be taken out. Is it going to be replaced with anything, do you know, or is it just going to be scratched out?

Mr. MALONE. I do not know. It is Booz Allen's report and they have not told me.

Mr. STUPAK. OK. Those 29 words, if it is Booz Allen's report that we received to explain those 29 words, 159 pages from BP's attorneys, not Booz Allen. So that is why I was wondering if they are going to. I just think a little overkill. As I said earlier, 159 pages to explain 29 words and it is not coming from Booz Allen, it is coming from Vinson & Elkins. So let me ask you this. If you go to Booz Allen report page 80, after seeing this you will probably want to take this out too. But it says, page 80, "Because no leading risk indicators or root causes were studied when the product composition changed, it was not flagged as an important corrosion management issue. This led to an increase in corrosion risk on the oil transit lines that ultimately precipitated the two incidents.” Now, you don’t disagree with that statement, right?

Mr. MALONE. And which paragraph?

Mr. STUPAK. The second paragraph, the second line. However, it starts, “because no leading risk indicators or root causes were studied when the production composition changed” and that was that oil makeup you were talking about, “it was not flagged as an important corrosion management issue. This led to an increase in corrosion risk on the OTL that ultimately precipitated the two incidents.” Do you see that there?

Mr. MALONE. I do.

Mr. STUPAK. OK. You don’t disagree with that statement? Basically it says, because of lack of maintenance, we had the two leaks.

Mr. MALONE. Again, Congressman, when Booz Allen concluded that had we—the answer is that if we pigged the line, and which we now know in hindsight, it could have prevented the leak.

Mr. STUPAK. Or even a corrosion inhibitor would have been maintained, maybe, or extended the life of that line a little longer, at least.

Mr. MALONE. My understanding is that we were using corrosion inhibitor.

Mr. STUPAK. Correct. But as the earlier panel said, corrosion inhibitor doesn’t work if you have got so much sludge in the pipeline, therefore it doesn’t get to the walls and cleans it out.

Mr. MALONE. I understand.

Mr. STUPAK. Yes, OK. And you basically testified that the lack of maintenance did in fact cause the two leaks, correct? I don’t mean to put word in your mouth.

Mr. MALONE. No, what we found in both cases, that had Booz Allen found for me that had we given them more money, they would not have pigged the line; that they believed they had a system that was preventing corrosion. They believed they knew what they were doing in order to prevent those leaks. So Mr. Chairman, that is the data I have to go on, is what Booz Allen has found. We now know——

Mr. STUPAK. But if you go to page 72, before you drop those 29 words where Booz Allen said the plan to run the smart pig in the OTL, oil transit lines, was dropped 2004 and 2005.

Mr. MALONE. Mr. Chairman, I only know——

Mr. STUPAK. You dropped that.

Mr. MALONE. What I heard was that, again, this is what I have been told, is that was not for the OTLs. It was for the other pipelines, not for the—which is why what they misread. This was actually a flow line, which is above the gas handling.

Mr. STUPAK. Yes, I know, we have got 159 pages trying to explain that, but I still—it is no more confusing than anything, but let go here. Here is the point I am trying to make. Carolyn Merritt of the Chemical Safety Board testified that there were striking similarities in the reported causes of the 2006 events involving BP’s Prudhoe Bay pipelines and the 2005 explosion at BP Texas City Refinery. And in her statement she said the lack of investment in maintenance and new equipment was compromising safety in

Texas City and leaving the site at risk for a major accident. It goes on. The Chemical Safety Board, page 147, changes to the safety organization resulted in cost savings, but to a diminished process safety management function. What this is all telling me, whether it is Ms. Merritt or the Chemical Safety Board or whether it is all of this testimony that we have had today, if you would have increased maintenance, we might not have had these problems. So my question is, today, what percentage of BP's budget goes to maintenance of your refineries? You have five refineries, the one in Texas, Texas City, California, Indiana, Washington, Ohio, and then you have the Alaska or North Slope. So what percentage? Has that percentage gone up?

Mr. MALONE. I don't know. I will find that for you.

Mr. STUPAK. As your profits go up, will your maintenance budget increase?

Mr. MALONE. Take our commitment that we made to spend, Mr. Chairman, $7 billion over the next few years on our refinery system as an indication to commit.

Mr. STUPAK. But if I remember correctly, you spent $1.5 billion at Texas City and that is only at 50-percent capacity, so you could spend $7 billion right at Texas City just to get back to the capacity you were at before the explosion, and all of the rest of your maintenance in your fields up in the North Slope and the other four refineries would still be in bad shape. Ohio obviously is in bad shape when you have got a $24 million fine or they wouldn't have investigated that. So I want to make sure the whole operation, as your profits increase, I would hope your maintenance and safety would increase in the same proportion. Let me ask you this, if I may. Now VECO, you are familiar with the VECO report, this one right here? It is March 12, 3003.

VECO was a contractor, QBP. The finalized report, which estimated cost of installing—excuse me—pig launching and receiving facilities at 71 locations identified in the aforementioned pigging facility priority list, that pigging facility priority list included three sections of the eastern operating area line, which hadn't been pigged for 16 years, and it was one of the three lines listed. It was one of the lines that was severely corroded and found leaking in August 2006. Why was the VECO report prepared for BP in 2003? Why did BP want to a VECO report?

Mr. MALONE. I don't have an answer to that.

Mr. STUPAK. OK. The VECO report, can you get us one in writing, if you can, who wanted it and why? The VECO report provided a range of estimates from $164 million to $643 million to install these 71 pig launchers and receivers. The staff was told that this report went nowhere because of cost. Do you know if that is true?

Mr. MALONE. No, I do not.

Mr. STUPAK. Will you check that out for us and get back to us? The day before this hearing, the committee received communications from your staff, BP's staff, I should say, indicating that the VECO report was promising to install pig launchers and receivers in locations where BP already had pig launchers and receivers. Is BP now suggesting that VECO was sent off to prepare cost estimates for work that didn't need to be done and that the corrosion inspections and chemical group was so unaware of the assets under its stewardship that it prepared a pigging priority list which contained launchers which already had fully functional launchers and receivers? I mean, we were—reports. VECO does a report and when we asked questions from staff, your staff, BP's staff, they say, oh no, we didn't need it because we already had it. Why would you spend all of that money for a report if you already knew you had it?

Mr. MALONE. I can't answer that, Mr. Chairman.

Mr. STUPAK. OK.

Mr. MALONE. Mr. Chairman, if I could? I tried to have, as I committed to this committee, to have Booz Allen do an extensive review of interviews and materials that related to the transit line and then to produce its report, and that is what I have done and I am going on their recommendation on my——

Mr. STUPAK. And we hope that BP is not pressuring Booz Allen to change their reports when they get a little critical. Let me ask you this one because I think this is actually one of your documents. Tab 29 in your folder there. BP gave us a document showing where each of the many of the reports that BP needed to make to progress in several key areas, and it is right there. It is a colored chart, a one-pager.

Mr. MALONE. Yes, sir.

Mr. STUPAK. Did you prepare this? I was told you prepared it.

Mr. MALONE. My team prepared that with me.

Mr. STUPAK. OK. All right. So according to this document, it is the various reports, they say that BP needs to make progress in almost every item with the exception of one. Does this suggest that BP U.S. operations are in need of a major overhaul? I mean, look, you have got the Baker Panel, the Chemical Safety Board, Mogford, Booz Allen Hamilton, and the map, and everything needed to be improved upon. Did you guys need a major overhaul?

Mr. MALONE. Mr. Chairman, we tried to take all of these reports, which we did voluntary most of them, to try to learn from both of these tragedies. We looked across all of these and we said where are the common elements that we can learn in order so that we can design our forward program and cover all of the gaps? This was meant to show that we listened to everyone, CSB, Baker Panel, everyone, in designing that forward program. But there were similarities in what we found in these reports between Texas City and Alaska.

Mr. STUPAK. Mr. Whitfield, questions?

Mr. WHITFIELD. No, sir.

Mr. STUPAK. Mr. Melancon? I guess with that, we have completed. I thank you very much for your time. I think it is safe to say that, after this hearing, there will probably be another one. When I said earlier that I hope you don't become the Los Alamos of the north, I sincerely mean that. But we have a number of things we are still looking for and we are still receiving documents. As I said, we received some last night and we want to see what the final Booz Allen says. So with that, you are excused, sir. Thank you for your time and we look forward to your questions and answers to some of your questions you provide to this committee and make sure they will be followed up in writing. Thank you.

Mr. MALONE. Thank you, Mr. Chairman.

Mr. STUPAK. That concludes our questions. I want to thank all of our witnesses for coming today and your testimony. I apologize again for the disruptions because of the procedure votes on the floor. I ask for unanimous consent that the hearing record will remain open for 30 days for additional questions for the record. Without objection, the record will remain open. That concludes our hearing. The subcommittee is adjourned. Thank you.

[Whereupon, at 2:45 p.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

Ex. #	Description	Date
1	Internal Correspondence on Inspection of Oil Sales Lines	06/05/90
2	Email on "Oil Transit Pigging" from PBU, CIC Flow Lines	07/17/97
3	Email Reply on "Smart Pigging of oil transit line" from PBU, CIC Flow Lines	07/27/97
4 pg. 1	Email Reply on "Draft - Budget Review 1 Pager" from Richard Woollam	06/02/07
4 pg. 2	Email Reply on "PW inhibitor at GC2 and GC3" from PBU, CIC NS TL Felix/Phillips	06/04/99
4 pg. 4	Email Reply on "MOC for Discontinuation of EC1081A" from PBU, CIC Prod Chem Todd/Spano	06/08/99
4 pg. 6	Email Reply on "PW Inhibitor at GC2 and GC3" from PBU, Operations Manager	06/09/99
5	Email Reply on "Urgent - Please Review and Comment" from Exxon to BP	06/09/99
6	Email Reply on "APC Budget" from Richard Woollam to Bob Malone	03/08/00
7	Preliminary 2001 Budget from CIC Town Hall	Jan-01
8	Email on "Smart Pigging of Oil Sales Lines" from Richard Woollam	01/07/01
9	Email Reply on "Smart Pigging of Oil Sales Lines" from Kip Sprague	01/08/01
10	Email Reply on "CIC Group Team Leader Meeting - 21st May" from Nancy Foust	05/14/01
11	Email Reply on "CIC Group Team Leader Meeting - 21st May" from Richard Woollam	05/14/01
12	Email Reply on "CIC Group Team Leader Meeting - 21st May" from PBU, CIC NS TL Felix/Phillips	05/16/01
13	Email Reply on "ACTION: 2001 Year End Forecast" from Nancy Foust	10/15/01
14	Email on Budget Reduction	10/16/01
15	Email on "Removal of additional corrosion inhibitor" from NSU, CIC TL	10/16/01
16	Spreadsheet on "CIC Group 2002 Budget Challenge - $1 Million Opportunities"	undated
17	Email Reply on "Master ID 2996 GPB Pig Launcher and Receiver Prelim Engineering" from C Drais Farnham	02/05/03
18	Forwarded Email on "ACTION: 2003 August LE's and Field OVERVIEW" from NSU, CIC TL	12/07/03
19	Slide on "Opportunity to Make Stretch Budget"	undated
20	Spreadsheet on "Greater Prudhoe Bay/2004 Field Lifting Cost Challenge (LCC) Maintenance and Reliability"	02/05/03
21	Email Reply on "Cost Challenge Feedback" from Richard Woollam	04/16/04
22	Letter from Tower Petroleum Corporation to Northwest District Debarment Council	05/08/04

23	Email Reply on "Emailing: CIC MR-Capex AFE Tracker 2006.xls" from Kip Sprague	04/10/05
24	Email on "Emailing: Control Options 10 22 05.xls" with attachment from NSU, CIC TL	10/22/05
25	Email Reply on "GC-2 Oil Transit Line Spill" from John Dengler	03/09/06
26	Email Reply on "Pigging Facility Walk Down - Need your input on Pigging Concerns" from GPB, FS2 Ops Lead	03/23/06
27	Email Reply on "Sales Oil Pipeline Protection" from NSU, CIC Prod Chem (Nalco)	06/04/06
28	Correspondence Regarding Oil Spill and Subsequent Investigation	08/31/06 - 05/14/07
29	Chart on Themes Highlighted in Various Reports on BP	undated
30	Article on "BP admits knowing of corrosion problems: Workers had predicted 'major catastrophic event' because of cost-cutting"	08/09/06
31	Notes from "CIC Strategy & Planning" Interview of Bill Hedges by Tom Williams in Anchorage, AK	12/14/06

Exhibit 1

ARCO Alaska Inc. — Internal Correspondence

Date: June 5, 1990 **File Code:** Corrosion File

Subject: Inspection of Oil Sales Lines

From: M. A. Morris/G. D. Herring PRB Box 5

To: S. J. Massey/J. D. Ottoson PRB Box 20

As previously discussed, the Corrosion Group recommends smart pig inspections of the oil sales lines from Flow Station 2 to Flow Station 1 and from Flow Station 1 to Skid 50. A discussion of this recommendation, an alternative and the advantages and disadvantages of each follows.

Background

Sales oil flows from FS 2 through a 30" pipeline (15,794' long) to Module 4922 at FS 1, where it is commingled with oil from FS 1. The combined stream is transported through a 34" line (25,996' long) to Skid 50 and then to Pump Station 1. Production from FS 3 goes through a 30" line which tees into the 34" line near FS 3. The normal operating temperature of the lines is about 115 degrees F., although they have been operated in the 140 degree range in the past.

To date, only minimal monitoring and inspection data has been gathered on the lines. A coupon location has been added to the FS 2 line at FS 1's Module 4922. This location has been pulled only two times. The first pull, from the fourth quarter of 1989, was graded "D" due to a single pit in one of the coupons which may have been mechanical in origin. The coupons from the first quarter of 1990 were graded "A". No organic deposits, such as paraffin, were on the coupons. Coupon locations will be added to the FS 1 and FS 3 lines and the main line outside of Skid 50 as soon as operationally feasible. Only about 115 square feet of piping at the 4922 module and Skid 50 has been inspected with automated UT (C-scan); no corrosion indications were identified. The lines are insulated with GE insulation, which is scheduled to be replaced this year due to external corrosion concerns.

Because of the low water content of the crude in the sales lines (the spec is 0.35%), significant internal corrosion is not expected. To our knowledge, none has been detected by the smart pig inspections performed to date in the TAPS line. On the other hand, severe corrosion has been experienced in the uninhibited flowlines and tubing strings of wells making only trace amounts of water early in the life of the field. If the water in the sales line segregates and flows along the bottom of the line, there is the potential for bacterial or underdeposit corrosion, which could result in scattered pitting, or carbonic acid attack, which could lead to a more continuous channelling type of damage. In either case, the most severe damage would be expected at bottom dead center of the lines.

There are two proven inspection methods which could be used on the sales lines: smart pigging and C-scan. The other option, of course, is to do no inspection. The Corrosion Group believes that the "do nothing" option is not prudent. The inspection options are discussed below.

Smart Pigging - (Recommended)

Smart pigging would involve running a series of cleaning pigs and the inspection pigs through the lines from FS 2 to FS 1 and from FS 1 to Skid 50. As far as we know, the lines have not been pigged since field start-up. Tentative plans have been made to run the Pipetronix smart pig in October, 1990. Preliminary cleaning and gauge pigs could be run as soon as operationally feasible.

Advantages

- Comprehensive inspection: The smart pig inspection would yield information about the entire circumference of the line, from the launcher to the receiver. It would locate external as well as internal corrosion. However, because the insulation on the sales lines is to be reconditioned this year, external corrosion should not be an issue. In addition, future repeat inspections would be relatively simple to perform.

- Production impact: Since the entire operation can be done on line, no reduction in production rates is necessary.

- Cost: The estimated cost of the entire smart pigging operation for both lines, including support labor and cleaning runs, is about $150,000.

Disadvantages

- Risk of sticking: Although the risk of sticking either a cleaning pig or an inspection pig is very low, we acknowledge that the cost of such a mishap would be quite high. The chance of an incident can be minimized by planning thoroughly and following a carefully developed procedure. The Corrosion Group is developing a detailed procedure for preparing the lines and running the smart pigs. In addition, a contingency plan will be developed to minimize the down time in the event that a pig does get stuck.

Automated UT - (Second choice)

If the C-scan UT method of inspection were to be employed on the sales lines, the scanning would probably be limited to the bottom 6" or 12" of the line. We would recommend scanning all accessible areas of the lines. As discussed above, if there is significant internal corrosion in the lines, it is most likely to occur at bottom dead center. The lines will be stripped of insulation later in the summer; this provides an opportunity to perform a C-scan inspection without the incremental cost of insulation removal.

Advantages

- No production impact or risk of sticking: C-scan can be performed on the lines while in service. Of course, there is no risk of getting anything stuck or lost in the line when using an external NDT device.

Disadvantages

- More expensive: If a one foot wide strip of pipe is C-scanned, the cost of inspection would probably be about $30 per linear foot. Scanning all accessible areas of the lines would cost about $1,065,000.

- Less comprehensive: The proposed C-scan inspection would yield no information concerning the existence of corrosion or defects anywhere away from the bottom of the lines. A 12-inch wide scan would give us 11% radial coverage on the 34-inch line and 13% on the 30-inch line. Saddle areas, anchor blocks and eleven road and caribou crossings would not be inspected, further reducing our confidence in finding corrosion. The road and caribou crossings are of particular concern, as there are currently no plans to replace the GE insulation in these areas.

- Recurring inspections more difficult: After the insulation is reconditioned, any external NDT method becomes much more difficult. Any repeat scans would involve stripping the new insulation, coating and tape wrap, which would be considerably more expensive.

Summary

The Corrosion Group recommends smart pigging the sales lines because it is a reliable, comprehensive inspection method. We believe the risk of encountering significant operational difficulties is small. The alternative, C-scanning the bottom of the accessible areas of the lines, is a viable alternative. However, it is considerably more expensive than smart pigging. The proposed C-scan inspection would give us a lower confidence in finding corrosion or defects because we would not be inspecting the road crossings, anchor blocks and saddle areas and because radial coverage is limited. Since very little monitoring or inspection has been done on these lines in the past, we strongly recommend against doing no inspection.

Michael L. Morris

Corrosion Control Supervisor

cc: D. F. Scheve	ATO 1576
E. W. Skaalure	ATO 1526
W. W. Patterson	ATO 1796
D. E. Powell	ATO 1786
J. M. McCarthy/J. S. Dayton	PRB Box 10
R. Farque/D. Siekkinen	PRB Box 15
D. Cavin/D. Beaudry	PRB Box 14
H. Hong/	PRB Box 13
N. J. Mabile/M. R. Engblom	PRB Box 5
B. A. Servin/A. L. Dahlquist	PRB Box 5

Exhibit 2

Sprague, Kip P

From:	PBU, CIC Flow Lines
Sent:	Thursday, July 17, 1997 5:44 PM
To:	PBU, CIC Supt
Cc:	PBU, CIC Fld TL Felix/Woollam
Subject:	RE: Oil Transit Pigging

Greg,

We have been UT monitoring the oil transit line since 1988. Excluding the by-pass at Skid 50, CIC has identified ~70 locations with internal corrosion between GC2 and Sk 50. The by-pass (320' ft) @ Sk 50 is corroded almost the entire length and three sleeve repairs were made in 1991. Today we have three locations at the by-pass with an MAOP below design. Joel/Chuck have these listed on the PMP tracker for action, (MOC to derate the line).

In 1995 a substantial increase of internal corrosion was observed. During the 1996 survey, a baseline Automated UT program (CRM) was established to determine internal corrosion rates. We hope this years CRM program will provide current internal corrosion activity/rates.

Of equal or more concern is external damage on the line. The oil transit was last smart pigged in 1990 at which time there were a few locations of CUI detected, worst case near 50% wall loss. Unfortunately because of the type of insulation and diameter of the line, reliance on spot TRT examination for integrity assurance will not eliminate a whole lot of risk. We had initially planned to smart pig examine the oil transit this year but, the launcher and trap will no longer accommodate the new high resolution smart pig vehicles without modification. As it stands, plans are to modify launcher and trap and smart pig in '98. Depending on completion of some of the other projects there is still some consideration to perform limited spot TRT inspections this year.

Kind of a brief summary but if you want more detail let me know. .... Kip

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From:	PBU, CIC Fld TL Felix/Woollam
Sent:	Thursday, July 17, 1997 3:40 PM
To:	PBU, CIC Flow Lines
Subject:	FW: Oil Transit Pigging

Kip - response pls.

Thx, Rick

From:	PBU, CIC Supt
Sent:	Wednesday, July 16, 1997 12:08 PM
To:	PBU, CIC Fld TL Felix/Woollam
Subject:	FW: Oil Transit Pigging

Rick;

Do we already have UT or TRT info on this transit line? Could let me know how much we already may know.

Greg

From:	PBU, Pigging Operators
Sent:	Saturday, July 12, 1997 6:15 PM
To:	PBU, CIC Fld TL Felix/Woollam; PBU, CIC Fac TL Phillips/Merrett; PBU, Prod Ctl & Optimization
Cc:	PBU, CIC Corrosion Engr; PBU, CIC Flow Lines; PBU, CIC Prod Chem Todd/Wasem; PBU, CIC QA/Vessel; PBU, CIC Supt; PBU, Chemical Foreman
Subject:	Oil Transit Pigging

Rick,

I talked to Tom Carnahan (Pump Station #1 Planner) and he only recalls one problem when Arco pigged their transit line and that was plugging the strainers.

I contacted Kevin Mahoney (Pigging Tech that performed that job). He informed me that they had two people at the strainers to change them as they plugged off. It takes about 1.5 hours to pull a strainer. He also stated by blocking in a strainer for about 10 seconds after it plugged, the heavy solids would fall to the bottom and then they could reopen the strainer and get approximately 80% flow. The metering had to be bypassed also to prevent damage to meters. The finer solids that passed through the strainers collected in the Pump Station tanks.

Based on the current daily average production the run would take approximately 6.5 hours actual run time.

GC-2 to GC-1 102 MBPD 1.1 fps 255 minutes
GC-1 to GC-3 176 + 102 = 278 MBPD 3.0 fps 68 minutes
GC-3 to Sk-50 73 + 278 = 351 MBPD 3.8 fps 56 minutes

379 minutes (6.5 Hours) actual run. + set up and returns cleaning etc....

Still need to get approval from Alyeska.

Hope this helps. A lot of people are out of the office at Arco. 4&3 schedule which limited my information gathering. Please respond if you need more info.

Doug

Exhibit 3

Sprague, Kip P

From: PBU, CIC Fld TL Felix/Woollam
Sent: Sunday, July 27, 1997 2:15 PM
To: PBU, Field Ops Mgr
Cc: PBU, CIC Flow Lines; PBU, CIC Supt; GPB, Prod Opt TL; PBU, CIC Fac TL Phillips/Merrett; PBU, CIC Fld TL Felix/Woollam; GPB, Pigging Operators
Subject: RE: Smart Pigging of oil transit line

John,

Thanks for the support on this issue.

This line has been both maintenance pigged and smart pigged in the past, so we do have some history on this line. The main concern is the fact that velocities in this line have been significantly reduced over the last few years and the quantity of solids which are laying in the bottom is entirely unknown.

Should these solids be significant, then we will have a problem at Pump 1 with the meter sieves blocking off. The conem therefore has to be to have sufficient contingency plans in place to allow us to pig and capture the solids without knocking Pump 1 over.

We are currently working through Bill and Garry with Pump 1 to get a consensus with Alyeska as to the contingencies which we need to have in place, and plan to maintenance pig the line a couple of months prior to to the smart pig run in 1998.

We are at present working with British Gas to come up with a long term smart pigging contract which will secure a price break on BGs services in exchange for minimum/maximum number of lines to be pigged in any given year. Our approach, is likely to consist of a rolling 5-10 year program which inspect ALL the major WOA flow lines, gas/oil/water, over the life of the contract. This will require putting together an suitable long term AFE.

As plans progress I'll keep you informed, however, if you have any comments or questions please let me know.

Thanks.

Richard.

From: PBU, Field Ops Mgr
Sent: Sunday, July 27, 1997 1:59 PM
To: PBU, Field Maint Ctlr; PBU, CIC Fld TL Felix/Woollam
Cc: PBU, Facility Ops Mgr; PBU, Prod Controllers
Subject: Smart Pigging of oil transit line

Richard,

I understand Smart pigging of the Oil Transit line was considered this year, but decided against given the short preparation time. Can you please work towards making a recommendation on Smart pigging of this line for 98 and work the schedule and any budget issues with Bill/Garry and Dan/Dennis. We'll also need to address the operational issues/risks of which I believe you are aware and I would appreciate your assessment of them.

Thx,

John

Exhibit 4

rcw_home
From: Woollam, Richard C
Sent: Thursday, June 03, 1999 4:31 PM
To: Felix, Rick D; PBU, CIC NS TL Felix/Phillips
Subject: RE: Draft - Budget Review 1 Pager

Rick/John,

Sounds like a plan, 9:00 am ASCG Monday morning - 7th June, OK?

Richard.

From: PBU, CIC NS TL Felix/Phillips
Sent: Thursday, June 03, 1999 11:40 AM
To: Felix, Rick D
Cc: Woollam, Richard C.
Subject: RE: Draft - Budget Review 1 Pager

RDF/RCW,
I'll plan to be in Sunday night, back to Fairbanks Monday PM.
JP

From: Felix, Rick D
Sent: Thursday, June 03, 1999 7:56 AM
To: PBU, CIC NS TL Felix/Phillips; Woollam, Richard C.
Subject: RE: Draft - Budget Review 1 Pager
Importance: High

Let's do it on 6/7 - better to get this phase of work off of our plate. I'm assuming that FMT & Dave are "comfortable" with the associated risks.

John - can you make it in Sun. night?
Thx,

Rick

From: Woollam, Richard C.
Sent: Wednesday, June 02, 1999 8:05 PM
To: PBU, CIC NS TL Felix/Phillips; Felix, Rick D
Subject: RE: Draft - Budget Review 1 Pager

John/Rick,

My impression from the FMT meeting is that we will not be getting any relief on the budget. They all think that PW inhibition is the right thing to do, but, no one is prepared to let loose the purse strings. However, I think we might be able to make a better case in 2000, if we go into the budget process with PW as additional line item.

So we would move forward assuming this to be the case and plan on taking out the PW and x% on the Corrosion Inhibition and y% on the inspection program - ugly I'm afraid.

When would be a good opportunity in the near future to get together and plan the way-forward? Monday 7th or the 14th June?

rcw_home

From: Woollam, Richard C
Sent: Friday, June 04, 1999 6:09 PM
To: PBU, CIC NS TL Felix/Phillips
Subject: RE: PW Inhibitor at GC2 and GC3

John,

Excellent! Good note - when we've decided what we wish to trim from the budget on Monday, we should write something similar to Dave Calvin et al, explaining and making sure that they do realise what they are asking us to do.

Richard.

From: PBU, CIC NS TL Felix/Phillips
Sent: Friday, June 04, 1999 2:53 PM
To: PBU, Operations Manager
Cc: Woollam, Richard C.; PBU, Field OTL; PBU, GC1 OpsTmLdr; PBU, GC2 OpsTmLdr; PBU, GC3 OpsTmLdr
Subject: FW: PW Inhibitor at GC2 and GC3

Frank,

FYI - We have conducted the field "trial" of the PW inhibition chemical and found it to be very successful at cleaning up the PW system and arresting corrosion activity. Unfortunately, we did not budget for a full year's chemical expense as the program was highly experimental at the time of the budget planning process. We are now at a point where the original monies for this program are used up, so we will be shutting it down till year's end, with the intent of raising it as a line item for next year's budget.

In the meantime, the PW system may be subject to increased corrosion activity and fouling. This may have some impact on corrosion repair activity and also possibly BS&W quality during pigging operations. We will be putting the remainder of our EC1081A inventory into the S pad PW line for the rest of the year, as this is our highest risk cross country PW line at this time.

I presume you may be getting some feedback on this so wanted to assure you're informed. (You may have been at the session with Richard Woollam the other day where this was discussed).

Regards,
John

From: PBU, CIC Prod Chem Todd/Spano
Sent: Friday, June 04, 1999 11:42 AM
To: PBU, GC2 OpsTmLdr; PBU, GC2 Lead Techs; PBU, GC3 OpsTmLdr; PBU, GC3 Lead Techs
Cc: PBU, Matl Coord - FOC; PBU, CIC NS TL Felix/Phillips; Crawford, Gary R; Paisley, Dominic M.; Woollam, Richard C.; 'RA Brown'; Sprague, Kip P
Subject: PW Inhibitor at GC2 and GC3

All,

Due to budgetary constraints, the decision has been made to discontinue the PW inhibitor (EC1081A) currently being injected at GC2 and GC3. The GC2 bulk tank should run out within the next two days and it will not be refilled. Please shut the pump down and flush the equipment with water once the tank is empty. The GC3 tank was recently filled and is

estimated to last about 13 more days (around June 17th). Again, when the tank is empty, please shut the pump down and flush the equipment with water.
The current plan is to inject the remaining inventory of EC1081A into the high risk S-69 line that runs from M to S pads. At a 40 ppm rate, we will have enough product to treat this 40,000 BWD for about 250 days.

Best Regards,

John Todd

3

rcw_home

From: Paisley, Dominic M
Sent: Tuesday, June 08, 1999 4:06 PM
To: PBU, CIC Prod Chem Todd/Spano
Cc: Woollam, Richard C.
Subject: RE: MOC for Discontinuation of EC1081A

Andy,

Here are a couple of paragraghs to summarise the technical aspects of shutting off the PW treatment.

The corrosion mechanism in the PW system is microbially induced corrosion. Bacteria thrive in dirty systems and treatment requires injection of a chemical with strong surfactant and biocidal properties to clean the lines and reduce bacteria numbers. Various chemicals have been tried at GC-2 over the past year with the aim of finding a suitable, low cost chemical. The program has been successful and the data shows that the PW systems at GC-2 and GC-3 have been cleaned and bacterial numbers have been reduced. The corrosion monitoring and inspection data have also improved significantly.

The net effect of these improvements is to significantly increase the projected life of the PW system. Much of the system is in poor condition and, without injection of supplemental chemical, well line replacements are predicted from 2001 onwards, with flow lines from 2003 onwards. Supplemental injection is estimated to delay these near-term line replacements by approximately 7 years and many of the replacements would be delayed indefinitely. For example, the retirement of S-69 is predicted to be delayed from 2003 to 2016.

Suspending the supplemental injection in to the PW system is therefore unlikely to cause loss of containment or equipment retiral in the short term (1 to 2 years). However, it will shorten the life of the system, resulting in either abandonment or expensive repair/replacement in the medium to long term (3 years+). The longer the corrosion continues at the uncontrolled rate, the harder it will be to arrest it and achieve satisfactory life of the equipment.

Feel free to cut and paste so it fits in with the rest of the MoC document and the data from the QPR that Richard sent.

Dominic

From: Woollam, Richard C.
Sent: Saturday, June 05, 1999 10:43 AM
To: PBU, CIC Prod Chem Todd/Spano
Cc: Crawford, Gary R; PBU, CIC NS TL Felix/Phillips; Paisley, Dominic M.; Felix, Rick D
Subject: RE: MOC for Discontinuation of EC1081A

John/Andy,

I would suggest that you use as the basis of the risk assessment, not only technical but financial, the following material which we was lifted staright out of the QPR.

<<File: PW CI Injection FMT II.ppt>>

As far as the requirement to complete the MOC is concerned, surely any action which increases the risk of significant HSE/financial impact to the business or the environment should be thoroughly reviewed and documented by senior management prior to implementation. This is the point, isn't it, of the MOC process to ensure that any process/system changes should be thoroughly reviewed and documented in order to indentify risks associated with that actions - exactly what is happening here!

In the mean time, please move ahead with the stopping the program and implementing the S pad injection as quick as possible as noted in your E-mail yesterday.

Thanks.

Richard.

From: PBU, CIC Prod Chem Todd/Spano
Sent: Saturday, June 05, 1999 10:58 AM
To: Paisley, Dominic M.
Cc: Crawford, Gary R; PBU, CIC NS TL Felix/Phillips; Woollam, Richard C.
Subject: MOC for Discontinuation of EC1081A

<<File: CIHAZA~1.DOC>>

Dominic,

I have been asked by Richard and John P. to initiate an MOC to document the discontinuation of the EC1081A CI injection at GC2 and GC3. This is a somewhat unique MOC, as far as I am concerned, and it is probably not legally required. However, the idea is to make management formally sign off on the change and to briefly outline the risks. I will discuss the process impacts (BS&W and possibly water quality), but I need you (or Gary) to outline the corrosion risks to the PW system. It doesn't need to be terribly detailed or something that takes a lot of your time. Andy and I use the enclosed Hazard Review document most of the time for chemical changes, and it is nothing more than a one or two paragraph statement. However, you may have other documentation that you want to add. Your input will constitute part of the Technical Review (Stage 3 of the MOC) and I will then present all the data to Operations for signatures at Stage 4 and 5. Thanks for your help.

Best Regards,

John T.

rcw_home

From: PBU, Operations Manager
Sent: Wednesday, June 09, 1999 2:08 AM
To: PBU, CIC NS TL Felix/Phillips
Cc: Woollam, Richard C.; PBU, Field OTL
Subject: RE: PW Inhibitor at GC2 and GC3

John/Rick,

Thanks for the warning. Is this the right thing to do?

-does this place the line integrity in jeopardy in the short term and give us a risk of a spill near term? I assume not or you wouldn't be recommending this?

-does this jeopardise or significantly shorten the life of these lines? If so does the discounted cost of accelerated repair exceed the cost of the inhibitor for this year?

-are we putting our expenditure on chemicals in the critical areas? I thought that the PW lines were the ones least in control and therefore the ones we are most worried about. Could we discontinue chemical injection on some other lower risk systems to provide the financial space to continue this treatment?

How much money are we talking about if we continue the chemical injection at the optimal rate?

Frank

From: PBU, CIC NS TL Felix/Phillips
Sent: Friday, June 04, 1999 2:53 PM
To: PBU, Operations Manager
Cc: Woollam, Richard C.; PBU, Field OTL; PBU, GC1 OpsTmLdr; PBU, GC2 OpsTmLdr; PBU, GC3 OpsTmLdr
Subject: FW: PW Inhibitor at GC2 and GC3

Frank,

FYI - We have conducted the field "trial" of the PW inhibition chemical and found it to be very successful at cleaning up the PW system and arresting corrosion activity. Unfortunately, we did not budget for a full year's chemical expense as the program was highly experimental at the time of the budget planning process. We are now at a point where the original monies for this program are used up, so we will be shutting it down till year's end, with the intent of raising it as a line item for next year's budget.

In the meantime, the PW system may be subject to increased corrosion activity and fouling. This may have some impact on corrosion repair activity and also possibly BS&W quality during pigging operations. We will be putting the remainder of our EC1081A inventory into the S pad PW line for the rest of the year, as this is our highest risk cross country PW line at this time.

I presume you may be getting some feedback on this so wanted to assure you're informed. (You may have been at the session with Richard Woollam the other day where this was discussed).

Regards,
John

6

[redacted]

From: [redacted]
Sent: Friday, June 04, 1999 6:46 PM
To: [redacted]
Subject: FW: PW Inhibitor at GC2 and GC3

Here's one for our HSE files. We'll see if this is a "safe" way to do business
[redacted]

From: PBU, CIC Prod Chem Todd/Spano
Sent: Friday, June 04, 1999 11:42 AM
To: PBU, GC2 OpsTmLdr; PBU, GC2 Lead Techs; PBU, GC3 OpsTmLdr; PBU, GC3 Lead Techs
Cc: PBU, Matl Coord - POC; PBU, CIC NS TL Felix/Phillips; Crawford, Gary R; Paisley, Dominic M.; Woollam, Richard C.; 'RA Brown'; Sprague, Kip P
Subject: PW Inhibitor at GC2 and GC3

All,

Due to budgetary constraints, the decision has been made to discontinue the PW inhibitor (EC1081A) currently being injected at GC2 and GC3. The GC2 bulk tank should run out within the next two days and it will not be refilled. Please shut the pump down and flush the equipment with water once the tank is empty. The GC3 tank was recently filled and is estimated to last about 13 more days (around June 17th). Again, when the tank is empty, please shut the pump down and flush the equipment with water.
The current plan is to inject the remaining inventory of EC1081A into the high risk S-69 line that runs from M to S pads. At a 40 ppm rate, we will have enough product to treat this 40,000 BWD for about 250 days.

Best Regards,

John Todd

7

Exhibit 5

From:	Daniel_G_Rey@nalcoexxon.com
Sent:	Wednesday, June 09, 1999 6:53 AM
To:	"David Horsup at SUG_HUB.CCNEEC"@nalcoexxon.com; "Daniel G Rey at SUG_HUB.CCNEEC"@nalcoexxon.com; Crawford, Gary R
Cc:	PBU, CIC Prod Chem Todd/Spano; Brown, Richard A (NEEC)
Subject:	Re[2]: Urgent - Please Review and Comment

Additional Header Information:
Received: from amgw3.bp.com ([208.221.178.129]) by mail.nalcoexxon.com (Lotus SMTP MTA v4.6.1 (569.2 2-6-1998)) with SMTP id 86256789.007B350E; Mon, 7 Jun 1999 17:25:45 -0500
Received: by amgw3.bp.com; id SAA19350; Mon, 7 Jun 1999 18:22:21 -0400

Received: from amclvx8.clv.am.bp.com(161.99.146.100) by amgw3 via smap (V2.1)
id xma019311; Mon, 7 Jun 99 18:21:55 -0400
Received: by AMCLVX8 with Internet Mail Service (5.5.2232.9)
id <M36MQY5G>; Mon, 7 Jun 1999 18:21:55 -0400
Message-ID: <05481C2F274CD011882A0000F8024BCD02E70A91@AMANCX2>
From: "Crawford, Gary R" <CrawfoGR@BP.com>
To: "'David_Horsup@nalcoexxon.com'" <David_Horsup@nalcoexxon.com>,
"'D. Rey'" <Daniel_G_Rey@nalcoexxon.com>
Cc: "PBU, CIC Prod Chem Todd/Spano" <PBUCICProdChem@BP.com>,
"Brown, Richard A (NEEC)" <BrownR1@BP.com>
Subject: RE: Urgent - Please Review and Comment
Date: Mon, 7 Jun 1999 18:20:41 -0400
MIME-Version: 1.0
X-Mailer: Internet Mail Service (5.5.2232.9)
Content-Type: multipart/mixed;
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David and Danny,

We will be pursuing field conversion of 99VD049 on an accelerated schedule to help meet the budget pressure for this year (Discontinuing EC1081A is the other key part to meeting the budget). We feel that this is less risky than an across-the-board cut of 10% which we are most confident would allow significant measurable corrosion damage to occur. The good news is that we have enough 98VD019 and 99VD054 in Alaska or on its way, that conversion cannot logistically happen before September 1 which is just in time to meet the budget! Also, very importantly, this gives us time to gather more B, X, and R LDF data as well as complete the well line test at A-13.

Attached, are some slides summarizing our intentions at this time.
The
timeline is critical and we have been instructed to work back from September 1 to nail down the dates for ordering and shipping 99VD049. Please review these slides and provide input regarding the drop-dead order and ship dates.
We will not be ordering any more 98VD019 or 99VD054 unless something goes wrong with the 99VD049.

Preliminary ER probe data from X pad indicates no change in performance.
However, R pad data may show a shift toward slightly higher corrosivity (2.8 to 4.3 mpy) but we feel it is still too early to judge that small of change.

Also, significant production changes from R pad have been occurring, creating more complexity. The EOA still has no corrosion data from their well line test sites.

Are there any other concerns that need to be addressed before we finalize the plan for Richard?

John/Andy - I assume we still have EB at the WPM's and GC's to inject if OIW/BS&W become a problem?

Thanks,

Gary

<<99VD049ExpPlan.ppt>>

> ----------
> From:
> David_Horsup@nalcoexxon.com[SMTP:David_Horsup@nalcoexxon.com]
> Sent: Monday, June 07, 1999 9:48 AM
> To: Paisley, Dominic M.; Crawford, Gary R; Woollam, Richard C.
> Cc: "Richard A Brown at SUG_HUB.CCNEEC"@nalcoexxon.com; PBU, CIC
NS TL
> Felix/Phillips; Felix, Rick D; PBU, CIC Prod Chem Todd/Spano;
"Daniel G
> Rey at SUG_HUB.CCNEEC"@nalcoexxon.com
> Subject: Re: Urgent - Please Review and Comment
>
>
>
> Richard,
>
> The team discussed this, this morning and the general consensus
was
> that migration over to the 049 chemistry would offer the
minimum risk
> scenario. Obviously there are risks associated with it but
these
> would be less than a total field-wide reduction in dosage of
10%.
> Since this product contains a new demulsifier at a lower
dosage, it
> might be wise to have some of this on hand in case of an upset
at the
> Gathering Centres. In terms of logistics I do not foresee any
> problems at this end. Danny will be able to give you a clearer
> indication of timings for subsequent rail car quantities. How
soon
> would you look to implement this?
>
> Best wishes,
> David
>
>
> ______________________________ Reply Separator
> _________________________________
> Subject: Urgent - Please Review and Comment
> Author: "Woollam, Richard C." <WoollaRC@BP.com> at NEEC
> Date: 06/06/99 21:29
>
>
> Additional Header Information:
> Received: from amgw3.bp.com ([208.221.178.129]) by
mail.nalcoexxon.com
> (Lotus SMTP MTA v4.6.1 (569.2 2-6-1998)) with SMTP id
> 86256788.00766E10; Sun, 6 Jun 1999 16:33:34 -0500

> Received: by amgw3.bp.com; id RAA08296; Sun, 6 Jun 1999 17:30:15
-0400
>
> Received: from amclvx8.clv.am.bp.com(161.99.146.100) by amgw3 via
smap
> (V2.1)
> id xma008266; Sun, 6 Jun 99 17:30:10 -0400
> Received: by AMCLVX8 with Internet Mail Service (5.5.2232.9)
> id <LX5S10HJ>; Sun, 6 Jun 1999 17:30:11 -0400
> Message-ID: <05481C2F274CD011882A0000F8024BCD02E6A68D@AMANCX2>
> From: "Woollam, Richard C." <WoollaRC@BP.com>
> To: "Paisley, Dominic M." <PaisleDM@BP.com>,
> "Crawford, Gary R"
> <CrawfoGR@BP.com>
> Cc: "'Brown, Richard A (NEEC - Anchorage)'"
> <Richard_A_Brown@nalcoexxon.com>,
> "PBU, CIC NS TL Felix/Phillips"
> <PBUCICNSTL@BP.com>,
> "Felix, Rick D" <FelixRD@BP.com>,
> "PBU, CIC Prod Chem Todd/Spano" <PBUCICProdChem@BP.com>,
"'Rey,
> Danny (NEEC - Sugarland)'"
> <Daniel_G_Rey@nalcoexxon.com>,
> "'Horsup, David (NEEC - Sugarland)'"
> <David_Horsup@nalcoexxon.com>
> Subject: Urgent - Please Review and Comment
> Date: Sun, 6 Jun 1999 17:29:05 -0400
> Importance: high
> X-Priority: 1
> Return-Receipt-To: "Woollam, Richard C." <WoollaRC@BP.com>
> MIME-Version: 1.0
> X-Mailer: Internet Mail Service (5.5.2232.9)
> Content-Type: multipart/mixed;
> boundary="----_=_NextPart_000_01BEB063.C15A110E"
>
>
> --------------------------------
>
>
>
>
>
>
> Gary/Dominic,
>
> As we discussed we are under significant pressure to reduce the budget.
>
> One of the options that was discussed was to reduce chemical
injection
> rates
> by approximately 10% through the remainder of the year. As
alternative
> I
> would like to also consider expanding the 049 to the pads shown in
the
> attached, effective immediately.
>
> If we were to pursue the 049 expansion, I think we would get almost
as
> much
> cost reduction as we would be cutting 10% on injection rates, can
you
> please
> confirm this is the case including the timing and logistics. Can we
> target an August 1st start date?

BPXA-CEC00000012643

> From a risk perspective, if we need to reduce cost by 10% then with
> the current corrosion inhibitor technology we would simply be taking
> 10% out of the system with the resultant increase in corrosion rate.
> If we move to 049, we will get the 10% reduction in corrosion
> inhibitor costs and we
may
> not
> get the increase in corrosion rate.
>
> I fully accept that this is a risky call and we will have to review
> the risks associated with it.
>
> In order to maximize the benefit from such a move we will have to
make
> some
> decisions very quickly. John, Rick and I are meeting Monday to
discuss
> this
> and a number of other budget options. Could you please have your
> thoughts together, cost implications, timing, logistics etc., by noon
> Monday, June 7th, so we can make a decision in the afternoon.
>
> The above, and the cessation of the PW injection (with the exception
> of S
> pad) should put us on track for the budget through the remainder of
> the year.
>
> If you have any questions, concerns then please let me know (break
> into the TL's meeting as required).
>
> Thanks and sorry for the short notice - it only occurred to me
> yesterday that this was an option!
>
> Richard.
>
> <<Chemical Budget Buster.xls>>
>
> PS Danny/David - Can you please start working some of the issues
first
> thing
> in Houston - the logistics are going to be a big part of this one! I
> would also like some thoughts from Sugarland on the potential risks -
likely
> performance of 049 in essence!
>
>

Gary:

Thanks for the heads up. You indicate in the PPT slides that you will order RC quantities of 99VD049 on July 7 for a July 15 ship date. What is the anticipated quantity? Are staggered ship dates ok?

We need to make sure we're ready on this end with production scheduling, raw materials, etc.

Thanks, Danny

Exhibit 6

From: Woollam, Richard C.
Sent: Wednesday, March 08, 2000 10:57 AM
To: PBU, APC Manager
Cc: Martin, Michelle O; 'Gabrielson, Lee'; 'Burrows, Don'; Laasch, Jack (APCI); PBU, Chemical Foreman; PBU, CIC NS TL Felix/Phillips
Subject: RE: APC Budget

Bob,

Thanks for the note.

Unfortunately, the oil business is essentially assessed on lifting cost not on the oil price, therefore, as the production level at PBU continues on its relentless decline so must our costs follow. The general decline rate over the last few years has been between 12 and 15% and while the forecast is for this to reduce it still represents a reduction of some 10% per annum. Just to emphasise the point, the amount of money/budget is almost completely independent of the oil price.

As a consequence, the overall PBU budget is declining and the CIC Group, as part of that overall, is also declining. The type of performance we are asking of you is not different to that which we expect of anybody in the organization.

The idea behind a managed service is that you, as the expert, are best able to reduce cost and increase efficiency, if this is something that you do not wish to do then please let me know and I'll do it. However, clearly, if I manage the program rather than yourselves then we need to look at the contract structure in detail.

We have a meeting scheduled for next week - I will be available between now and then if to discuss the way-forward.

Thanks.

Richard.

From: PBU, APC Manager
Sent: Tuesday, March 07, 2000 7:16 PM
To: Woollam, Richard C.
Cc: Martin, Michelle O; 'Gabrielson, Lee'; 'Burrows, Don'; Laasch, Jack (APCI); PBU, Chemical Foreman; PBU, CIC NS TL Felix/Phillips
Subject: APC Budget

Richard,

Thank you for your response to our proposal to reduce the APC budget by 8% for the year 2000. I am disappointed in your answer.

Over the last several years, the management and employees of APC have worked tirelessly to meet BP expectations for service quality and cost. 1999 was our most challenging year yet. Our crews worked hard and made many personal sacrifices to try to meet your goals. Now, they're tired. They haven't had raises in years. There aren't enough people to do the demanded work load. They are frustrated because they can't get everything done; frustrated because they can't meet their own expectations for a high quality of thorough work; and frustrated because your employees are quick to make negative comments about APC as an employer.

When oil prices were below $10.00 per barrel, we were all willing to pitch in and help reduce costs. We did as much work as before (or as close as we could get) with reduced resources. Now, with oil at over $30.00 per barrel, you are asking us to cut another approximately $300,000.00.

We can't cut people (we don't have enough to do the work now!), we can't cut wages (we'll lose the excellent people we have worked so hard to keep!), and about $55,000 of the cuts is from money paid to vendors (VECO, PEAK, ARCO, etc.) over which we have little hope of control.

So, what you are asking us to do is to give up almost $300,000.00 in corporate profits. Profits that have already been cut from what was available in previous years. Profits that go to Alaska Natives - not a nameless corporation but real people who depend on this money for their existence, for basic human services, and to develop a future for their children.

You have demanded that I take $300,000.00 away from our shareholders, and then continue to find some way to make our employees continue to work beyond their capacity, deny them any additional help (or finance help by taking even more money from the shareholders), and then expect the employees to keep their high standards of service quality, safety and environmental stuardship.

I can not, in any manner of good faith, make such a suggestion to my employer, my employees, or even to BP. I will be meeting with Lee tomorrow (March 8) here in Deadhorse and will discuss my concerns with him. I urge you to reconsider your demands. In my opinion, they are not in the best interests of your company.

Bob Carmichael

Exhibit 7

Preliminary 2001 Budget

All $ in $000's	2000			2001	
	EOA	WOA	00 Total	-10%	01 Total
CIC Manager/Staff	$ 1,420	$ 1,300	$ 2,720	$ (272)	$ 2,448
Process	$ -	$ 710	$ 710	$ (71)	$ 639
Corrosion Inhibition	$ 14,627	$ 8,761	$ 23,388	$ (2,339)	$ 21,049
Monitoring	$ 1,052	$ 450	$ 1,502	$ (150)	$ 1,352
Pigging	$ -	$ 400	$ 400	$ (40)	$ 360
Inspection	$ 7,852	$ 3,050	$ 10,902	$ (1,090)	$ 9,812
Total $	**$24,952**	**$14,671**	**$39,623**	**$(3,962)**	**$35,661**
PW Inhibition					$ 1,000
Wet gas inhib					$ 500
Total $					**$37,161**

Exhibit 8

From: Woollam, Richard C
Sent: Sunday, January 07, 2001 5:38 PM
To: Sprague, Kip P (ASCG)
Cc: Matthews, Lonnie T; PBU, CIC NS TL Felix/Phillips
Subject: Smart Pigging the Oil Sales Lines

Kip,

Can we smart pig both the EOA and the WOA oil sales line? If there are issues what are they?

Also, what sort of inspection data and damage, if any, are we seeing in the oil sales lines?

The reason is, as part of the 1% leak detection for ADEC rather than install $ 20 million of metering one option would be to smart pig every 3 years instead, at approx $50,000 x 2, every third year is considerably cheaper than $ 20 million!!!

Thanks.

Richard.

Exhibit 9

From: Woollam, Richard C
Sent: Monday, January 08, 2001 12:10 PM
To: Anderson, Doug M (ASCG)
Cc: Sprague, Kip P (ASCG)
Subject: FW: Smart Pigging the Oil Sales Lines

Attachments: OT Metal Loss.ppt

Doug,

Could you please pull the inspection data for the EOA and WOA oil sales lines and review.

Thanks.

RIchard.

-----Original Message-----
From: Sprague, Kip P (ASCG)
Sent: Monday, January 08, 2001 10:43 AM
To: Woollam, Richard C
Subject: RE: Smart Pigging the Oil Sales Lines

Richard,

We could likely Smart Pig each of these lines but not without considerable amount of work. A few issues are:

- Difficult launch do to short traps and long pigs. (managed in '98 but had to modify the nose cone of the pig to squeeze it in the trap)
- Flow rates are below smart pig recommended specifications. Successful in the '98 and data was pretty good but, PII cannot guarantee quality/sizing.
- Current configuration of EOA piping at SK-50 (18" jumper to WOA 34"). Piping would have to be reconfigured and I believe the PS1 metering has been removed. Would likely have to speak with shared service to find out hat would be required or what options exist. Also, I am not familiar with physical access to the launch trap but, assume we can load the pig.

WOA has seen quite a bit of internal and a fair amount of external damage. Internal is small pit networks @ 6:00 azimuth. I don't have access to CATS right now but my thoughts are that the oils sales line has continued to degrade very slowly. I am fairly sure we did very little of the planned flowline program in 1999 and 2000 so, not sure there is much recent inspection to analyze.

EOA has done little or nothing for inspection of the sales line. Nothing to offer there.

Enclosed plot of '98 S_Pig Reported Metal Loss -

Let me know if you want to proceed with the smart pig option, when you have to have all the answers, and I will do some investigation.

Kip

Exhibit 10

From: Foust, Nancy C
Sent: Monday, May 14, 2001 7:47 PM
To: Woollam, Richard C
Subject: RE: CIC Group Team Leader Meeting - 21st May

Richard --

I had not heard this. I will be attending the FMT meeting tomorrow and will attempt to ascertain the status of these programs in regards to the MR budget.

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 7:24 PM
To: Foust, Nancy C
Subject: FW: CIC Group Team Leader Meeting - 21st May

Nancy,

Please see below, obviously these are difficult times for the GPB budget and, unfortunately, I shall not be at the FMT meeting tomorrow, however given all the press coverage recently around integrity I would like to understand the thinking behind the decision John/Rick are indicating has been taken for the CUI (corrosion under insulation) and below-grade road crossings (smart pigging). Could youn please help me understand the context/forward plan

Thanks.

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:36 PM
To: Woollam, Richard C
Cc: Felix, Rick D
Subject: RE: CIC Group Team Leader Meeting - 21st May

Based on what RDF just showed me at handover, CUI Mitigation, CUI Detection, and Smart Pigging are all on "hold" and are below the line. I believe he just found this from Jack out prior to handover, so hadn't had time to relay it yet. It does look quite bad thus far. Rick can provide better context than I can on the discussions held over the past few days.
John

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 6:30 PM
To: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

John,

What is the latest on the MR? Did s-pigging/CUI fall off the list?

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:28 PM
To: Woollam, Richard C

Subject: RE: CIC Group Team Leader Meeting - 21st May

I take it the current ASCG issues will be covered under Inspection Program delivery? Also, we need to be ready to commit to what we're really going to do (or not do) this year based on the new bloodbath numbers...i.e. drop s-pigging, scale back CUI, drop crews/activity, whatever.
John

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 5:50 PM
To: PBU, CIC NS TL Felix/Phillips; Paisley, Dominic M; Felix, Rick D
Cc: Foust, Nancy C
Subject: CIC Group Team Leader Meeting - 21st May

All,

Please plan on a CIC Group Team Leader meeting for the 21st May, 10:00 am start.

The main agenda topics,

- YTD HSE Review
- YTD Technical Review
- YTD Financial Review
- New people issues
- Inspection program delivery
- GPB budget pressure and options

Are there any other topics? Please be prepared to talk about our options around the GPB budget, in particular, can we see any cross-department opportunities?

Richard.

Exhibit 11

From: Woollam, Richard C
Sent: Monday, May 14, 2001 7:57 PM
To: Foust, Nancy C
Subject: RE: CIC Group Team Leader Meeting - 21st May

Nancy,

Thanks, I know there are some tough decisions to be made, but, on the face of it this seems like a poor choice, however, there maybe some other grand plan which I am simply not aware of or some other circumstances/background - I'd really just like to understand the context.

If, at the end of the day, the FMT has decided that the this is the most appropriate action and the FMT is prepared to deal with the regulatory/reputational fallout then we, the CIC Group, will defer the external program and stand-down our current contract manpower.

Did you get copied on the FMT agenda?

Thanks.

Richard.

-----Original Message-----
From: Foust, Nancy C
Sent: Monday, May 14, 2001 7:47 PM
To: Woollam, Richard C
Subject: RE: CIC Group Team Leader Meeting - 21st May

Richard --

I had not heard this. I will be attending the FMT meeting tomorrow and will attempt to ascertain the status of these programs in regards to the MR budget.

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 7:24 PM
To: Foust, Nancy C
Subject: FW: CIC Group Team Leader Meeting - 21st May

Nancy,

Please see below, obviously these are difficult times for the GPB budget and, unfortunately, I shall not be at the FMT meeting tomorrow, however given all the press coverage recently around integrity I would like to understand the thinking behind the decision John/Rick are indicating has been taken for the CUI (corrosion under insulation) and below-grade road crossings (smart pigging). Could youn please help me understand the context/forward plan

Thanks.

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:36 PM
To: Woollam, Richard C
Cc: Felix, Rick D

Exhibit 12

From: PBU, CIC NS TL Felix/Phillips. Sent:5/16/2001 12:14 PM.
To: Felix, Rick D; Woollam, Richard C; Paisley, Dominic M.
Cc: .
Bcc: .
Subject: RE: CIC Group Team Leader Meeting - 21st May.

Gents,

Discussed all this with Ruth yesterday. She indicated that $2MM will be earmarked from contingency to do CUI work; we're already working on a program redesign based on that assumption. Several of us will be having a telecon meeting this morning at 10:00 to discuss further. I assume we will focus on detection and let repairs get covered outside the CIC AFE's.

I also have a meeting with Ruth and George Blankenship tomorrow to plead our case for smart pigging. Dominic/Kip are working up some backup material to support that discussion, i.e. ADEC commitments and pipeline integrity management philosophy.

I am also intending to tell ASCG Site Supervisor to freeze hiring till they hear from us next week after our related discussions are held. There was a package rolled out at the morning Ops meeting today which attempts to explain why we're taking the budget measures that are happening, will roll that out to core staff today. Other groups are in the process of scaling back work, so the work environment here at GPB is not going to be too good the next few weeks.

Regards,
John

-----Original Message-----
From: Felix, Rick D
Sent: Wednesday, May 16, 2001 1:07 AM
To: Woollam, Richard C
Cc: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

Richard,

Those projects are indeed below the line. Discussions at Sundays Ops meeting definitely recognized (by Jack and several of other OTLs) that at least "some" of the CUI work had to get done this year. However, no one volunteered to drop any of the items above the line to make room. My understanding is that Jack/Ruth or ?? will be taking the latest iteration of the MR Budget back to the Owners to show/tell them what we've decided (or not) to do. My guess, and I think Jack's, is that they will also see that not doing CUI will put us at odds with the regulators, resulting in them authorizing more funds or will expect BP to identify which items above the line will fall off to make room.

John - can you talk with Ruth if she's up this week to see what spin she has. Any repsonse from Jack on the smart pigging?

Rick
CIC NS Team Leader
x5050, bpr 2267

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 6:40 PM
To: Felix, Rick D
Cc: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

Rick,

What's the story here? How did it all change or was there no rationale?

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:36 PM
To: Woollam, Richard C
Cc: Felix, Rick D
Subject: RE: CIC Group Team Leader Meeting - 21st May

Based on what RDF just showed me at handover, CUI Mitigation, CUI Detection, and Smart Pigging are all on "hold" and are below the line. I believe he just found this from Jack out prior to handover, so hadn't had time to relay it yet. It does look quite bad thus far. Rick can provide better context than I can on the discussions held over the past few days.
John

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, May 14, 2001 6:30 PM
To: PBU, CIC NS TL Felix/Phillips
Subject: RE: CIC Group Team Leader Meeting - 21st May

John,

What is the latest on the MR? Did s-pigging/CUI fall off the list?

Richard.

-----Original Message-----
From: PBU, CIC NS TL Felix/Phillips
Sent: Monday, May 14, 2001 6:28 PM
To: Woollam, Richard C

Exhibit 13

From: Foust, Nancy C
Sent: Monday, October 15, 2001 10:34 AM
To: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Thanks, Richard. If the things you're working come to fruition, along with the increases, you should end up $2.0m over instead of the current $3.0m. Hopefully additional insights will come up that will help to reduce the negative variance even more.

Nancy

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, October 15, 2001 8:52 AM
To: Foust, Nancy C
Cc: NSU, CIC TL; Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2001 Year End Forecast

Nancy,

The following budget adjustments are known to date,

- ~$ 750,000 moving as much O&M money to CUI AFEs as appropriate
- ~$ 300,000 of MeOH which should have been charged to the field
- ~$ 100,000 in stores issues which can be charged to ASCG Insp Inc. under the contract
- ~$ 50,000 in overhaul crew costs/manhours which should have been charged to Operations Support

Being worked,

- ~$ 150,000 in scaffolding costs which should be charged to Operations Support as this was a temporary installation rather than permanent
- ~$ 100,000 in AII overhead costs and manpower if negotiations are succesful

Upward pressure/declined options,

- ~$ 200,000/month in PW/CI costs which can not be saved as indicated by George
- ~$ 200,000/month in AII manpower coists which can not be saved, again as directed by George, however, I have not told AII as I'm still trying to get an overhead reduction and this is all part of the pressure
- ~$ 200,000/month in increased CI costs when B Train and Big AL come back on line

If there are anyt questions please let me know.

Thanks.

Richard.

-----Original Message-----
From: Foust, Nancy C
Sent: Monday, October 15, 2001 8:12 AM

To: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Richard --

What is the impact of this for you?

Nancy

-----Original Message-----
From: Blankenship, George R
Sent: Friday, October 12, 2001 11:01 AM
To: Foust, Nancy C
Cc: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Two issues. 1) stopping the planned CUI program at the end of the program. I think we are clear, we will stop.
2) where the money gets charged. I do not have an opinion on that, it all comes out of the opex budget and it does not change how much is available to spend.

George

-----Original Message-----
From: Foust, Nancy C
Sent: Friday, October 12, 2001 10:47 AM
To: Blankenship, George R; Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Yes, it makes sense. To make sure we're all clear, you want Richard **to move the $800k from O&M to the $2.0m AFE?**

-----Original Message-----
From: Blankenship, George R
Sent: Friday, October 12, 2001 10:38 AM
To: Foust, Nancy C; Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

The planned program for the CUI inspection has been completed therefore the program is over for 2001. We will have a stepped up program for 2002. The sound bite is that this is NOT a reduction, but a completion of the planned program.

Does that make sense?

George

-----Original Message-----
From: Foust, Nancy C
Sent: Friday, October 12, 2001 10:16 AM
To: Woollam, Richard C; Blankenship, George R
Subject: RE: ACTION: 2001 Year End Forecast

George --

Refresh my memory -- did you decide to leave the $800k CUI O&M where it is (i.e. not move it to the $2m CUI AFE which would effectively shut down the program for the rest of the year)? I don't recall a decision but you did ask about the possible explanatory "sound bite."

Nancy

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 4:59 PM
To: Blankenship, George R
Cc: GPB, Ops Mgr; Foust, Nancy C; NSU, CIC TL; Felix, Rick D (Anchorage)

Subject: RE: ACTION: 2001 Year End Forecast

George,

Just to confirm our conversation,

- CIC Group will look for all and every opportunity to close the budget gap and save funds through the remainder of this year, including, eliminating overtime, giving folk the opportunity to go on vacation, reducing stores/warehouse issues etc., etc...

However, the following options are not, at this time, viewed as viable,

- PW corrosion inhibition - reinstate this program which was terminated yesterday

- Production adding corrosion inhibtion - make sure that the added production is cost effective, highly likely, otherwise continue

- Seek opportunities to reduce NDE manpower costs, as discussed above, but do not implement a 1/3 reduction in workforce

- Move the $ 800,000 O&M money to the AFE therefore completing the 2001 program of $ 2 million

- It is recognized that there will be an up-tick in corrosion inhibition costs with the start-up of B-Train at FS-2 and with Big Al

To be implemented,

- Back-out corrosion inhibition changes due to ER probes - do this quietly

Hopefully, this summarizes the discussion, if I made any errors, please let me know.

Thanks.

Richard.

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 2:25 PM
To: Blankenship, George R
Cc: GPB, Ops Mgr; Foust, Nancy C
Subject: RE: ACTION: 2001 Year End Forecast

George,

Certainly, 4:00 pm it is. In summary, here are the imediate actions I'm proposing to take to reduce the CIC Group costs/over-run,

- Shut-off the PW corrosion inhibitor on the WOA

- Remove the corrosion inhibitor added for velocity control/management and lower the velocity limit to the new operating procedure

- Back-out some chemical changes which were implemented based on ER probes, these are pretty conservative changes so not a huge risk

- Reduce the O&M NDE/inspection crews by approx. 1/3 for remainder of the year, this is approximately 30 people. The concern is that they are members of PACE/OCAW and how this would be interpreted in view of the integrity issues raised by ORT

- Move O&M costs which have been spent on external corrosion to the external corrosion AFE. In a sense this will reduce expenditure on external corrosion since we would have effectively spent an additional ~$1 milion had we not been forced to move this money to the AFE

There is a major up-tick coming in CIC costs with the re-start of FS-2 B Train/Big AL and the large water volumes associated with this production.

Hope this helps.

Richard.

-----Original Message-----
From: Blankenship, George R
Sent: Thursday, October 11, 2001 2:12 PM
To: Woollam, Richard C
Cc: GPB, Ops Mgr; Foust, Nancy C
Subject: RE: ACTION: 2001 Year End Forecast

Richard, apparently me and several other folks are confused. I have a meeting in Jack Fritts' office at the BOC with Nancy at 4pm. Can you call in there and we can talk about this.

Thanks,

George

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 2:01 PM
To: Blankenship, George R
Subject: RE: ACTION: 2001 Year End Forecast

... I'm confused because I haven't suggested at anytime reducing our external corrosion program, the NDE crew reductions are for the general/internal inspection program.

The only impact for external is that we are going to move some costs which are currently carrying under the O&M budget, which we accumiulated in the first half of the year awaiting various decisions, into the correct AFE.

Richard.

-----Original Message-----
From: Blankenship, George R
Sent: Thursday, October 11, 2001 1:58 PM
To: Woollam, Richard C
Subject: RE: ACTION: 2001 Year End Forecast

Specifically "corrosion under insulation" inspection, I thought the second sentence said that. Sorry if I confused you.

George

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, October 11, 2001 1:48 PM

To: Blankenship, George R
Subject: RE: ACTION: 2001 Year End Forecast

George,

Sorry, I'm confused, does this refer to the external inspection program? Internal inspection program? PW inhibition? Can I give you a call somewhere to clarify?

Thanks.

Richard.

-----Original Message-----
From: Blankenship, George R
Sent: Thursday, October 11, 2001 1:26 PM
To: Woollam, Richard C; Foust, Nancy C; GPB, Ops Mgr; GPB, Ops Support Mgr
Cc: Farnham, C Drais
Subject: RE: ACTION: 2001 Year End Forecast

We have actually had quite a bit of discussion on this subject with Neil McCleary and Steve Marshall up here on the slope the last couple of days. It is a consensus that reducing corrosion under insulation for the last couple months of this year is not a good business decision, given all the factors involved. While I appreciate and applaud the effort to identify opportunities for savings, we need to keep looking. This one will not pass the test.

Thanks,

George

-----Original Message-----
From: Woollam, Richard C
Sent: Wednesday, October 10, 2001 12:00 PM
To: Foust, Nancy C; Blankenship, George R; GPB, Ops Mgr
Subject: RE: ACTION: 2001 Year End Forecast

All,

I agree, we need to understand the variances, however, I needed to take some immediate action in order to get after reducing costs. Given the timing before year-end which didn't allow time to analyse and then react.

If I need to reverse the PW because of employee/integrity concerns then please let me know, the others, I think are good solid optimization opportunities.

Richard.

-----Original Message-----
From: Foust, Nancy C
Sent: Tuesday, October 09, 2001 8:44 PM
To: Woollam, Richard C; Blankenship, George R; GPB, Ops Mgr
Subject: RE: ACTION: 2001 Year End Forecast

Richard --

Although, I believe this particular proposed cost-cutting measure is a George/Ruth/Jack call, I am concerned about making decisions of this sort when we don't know what really is driving our negative variances. It may be that we find it necessary to jerk around because it's imperative we meet the budget and we have a very short time to make up the variance. It does really highlight, however, the need for us to stay on top of our costs and understand what is driving them so that we can respond early and in a controlled, thoughtful manner. Been a great (although not fun!) learning experience for me.

I encourage you and your team leaders to continue digging to determine what it is that is driving the costs and what may be differing in our operations from the 2001 plan.

Let me know if there is anything at all I can do to help.

Nancy

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, October 09, 2001 6:51 PM
To: Foust, Nancy C; Blankenship, George R; GPB, Ops Mgr
Cc: NSU, CIC TL; Felix, Rick D (Anchorage)
Subject: FW: ACTION: 2001 Year End Forecast

Nancy/George/Ruth/Jack,

Please see below, we are taking some very specific short term actions to reduce the spend rate within the CIC Group. Note that some of this action is to reduce and/or eliminate chemical injection in the last three months of this year, these are the lower risk options available to us, but, you should be aware that there may be some concerns raised within the workforce.

If there are any questions, please let me know.

Thanks.

Richard

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, October 09, 2001 6:44 PM
To: Morales, Noah L (NEEC); Crawford, Gary R; NSU, CIC TL
Cc: Felix, Rick D (Anchorage); Foust, Nancy C
Subject: FW: ACTION: 2001 Year End Forecast

Gary/Dominic/Noah,

As you may know we under a huge budget pressure for the last quarter of the year and therefore we have to take some rather disagreeable meaures. Can you please implement the following changes/reviews,

- Shut down the PW inhibition systems for remainder of the year
- Dis-continue the addition of corrosion inhibition for velocity control
- Reverse all chemical changes made since 1/1/01 which were based on purely ER probe changes and which did not involve either WLC > 2 or alpha > 0
- Wet gas inhibition to continue - the consequences are too high here
- Review all the CL/LDF data for potential reductions beyond the reversals identified above

These need to happen as soon as possible.

Thanks.

Richard.

-----Original Message-----
From: NSU, CIC TL
Sent: Tuesday, October 09, 2001 8:51 AM
To: Woollam, Richard C
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2001 Year End Forecast

Richard,

Based on your other note, it appears that Ops Corrosion and Inspection are the 2 areas that are over spent based on 3 quarters of the year.

The **Ops Corrosion** is not too surprising as 1Q and some of 2Q were expensive, with 129/118 on the East and Summer version not in the system. The comparison I did with Andy's numbers indicated we *are broadly in line to meet the (non linear)* projections for chemical & transportation costs, with costs currently running under projections by $0.25 million. The detail showed costs to be down by $1 million at FS-2 due to B-train etc but up elsewhere, *most nobably GC-2.* There is a potential over-spend of ~ $0.5 million if B-train, Big AL and 16/17C come on mid-October, which seems a worst case estimate.

Of course, this doesn't compare the current status with the budget but it does indicate that chemical and transportation costs are largely where we predicted them to be, with the exception of GC-2. As we predicted a spend of ~ $3.5 million less than we started the year, it looks like we are still going to deliver the $3 million we set out to, even if B-train comes back up.

Re: **Inspection**, do these costs include the external inspection that we have not transferred to an AFE ? If that is backed out, where do we stand ? Can we work up some simple inspection costs from the ground up in a similar manner, to give an indication if the costs are reasonable i.e. X,000 items at Y items/manhour and Z $/hour. It may give us something to focus us.

Ideas for saving money, in no particular order:

- Turn off PW chemical and hope the BCQ inhibitor will help out here.
- Turn off the wet gas inhibitor on the West (not a wise choice but could be defended as a short term measure ?).
- Stop the velocity additional chemical. This is proposed in the revised velocity g'lines but not enacted until the new g'lines are formally adopted by Ops. ~ $125,000/qtr. Easy win.
- Re: backing out CI increases. There are a couple of options:
  - We recently decided to limit CI increases based on ER probe data to +5% due to data quality/reliability. We could apply this retroactively to the start of the year. This would have the advantage of not breakng any of our protocols - just back dating a recent revision.
  - Remove all ER-probe based changes since 1/1/01, as proposed.

I can carry on digging in to cost codes but it would be great to get some professional help. Who can help us one on this ?

Cheers,

Dominic

Exhibit 14

- Satellite production and E/F pad impacts $ 0.750 million

Total **$ 1.155 million**

Details below,

RE: F and E PAD Production Imp...

The intent, as discussed in the e-mail above is to meet both these challenges within the original $44.5 million budget for 2002 through judicious program management and optimization. As a conseqeunce of these pressures there is little room for further program 'optimization' however, with careful management of OT and strict closure of programs at completion of work scope it is probable that a revised LE for 2002 of $44 million is a challenging but achievable target for 2002.

Note, the proposed target of $44 million is approximately $0.5 million below the last LE submitted at the beginning to Steve St J and John B., please see below.

RE: GPB Budget LE Update

Further reductions beyond the proposed LE of $ 44 million will require significant changes to the program scope above and beyond the optimization opportunities which will allow us to deliver the $44 million discussed above.

In order to deliver substantial costs in the second half of 2001 then major changes to the major elements of the CIC's programs would be required. The major drivers for the program are,

Amount of in-service equipment	Drives inspection activitiy Drives monitoring activity
Fluid composition and rates	Drives chemical activity

Below are a list of options from within the CIC budget, each of which will deliver approximately $1 million if implemented in the seocnd half of the year. In summary,

- **Inhibition Program Reduction 8%** Reducing second half inhibition rates by approximately 8%, while it is difficult to estimate this associated corrosion rates, based on past years for a 10% change in inhibition rate there would be an approximately 30% increase in corrosion rates in flow lines and well lines

- **Internal Inspection Program Reduction 30%** Reducing the inspection program in the second half of the year by 30%, moving from approximately 9 to 6 crews, would reduce the 2H inspection scope by about 10,000 items. The obvious concern here is with impacts/perceptions of ORT and possibly PACE.

- **External Corrosion Inspection Reduction 40%** Reducing the external inspection program by 40% yield a new 2H scope of 10,000 versus the plannned 17,500 for a total of 28,000 items as opposed to the 35,000 commitment to both partners and ADEC. In addition to the ORT perception impacts and ADEC, there is also the issue of partner perception since partners were concerned that money for external corrosion would be diverted once agreed.

Detailed calculations for the above options are contained in the attached spreadsheet. It should be noted that some gross assumptions about average unti costs have been made in order to arrive at the above estimates.

2002 Budget Options.xls (51 KB...

The above options reflect action being taken within the CIC Group. There are an option which could be taken by

Operations/Production which would impact our budget directly, in summary,

- **Reduce Water Rates** Shutting-in the 30 most expensive wells across the field would reduce 2H 02 expenses by approximately $3 million in corrosion inhibition costs - see e-mail exchange below. This data is a little out of date, but, it is save to assert that a $1-2 million could be removed with the shut-in of the appropriate suit of wells **provided** that this production was not repalced elsewhere in the field.

RE: Vol vs exp

If you need any additional information on the items discussed above please let me lknow.

Thanks.

Richard.

Exhibit 15

From: GPB, GC1/GC2/Fld Proc Engr
Sent: Tuesday, October 16, 2001 05:45 AM
To: GPB, Fld AMC
Subject: FW: MOC Velocity change & Removal of additional corrosion inhibitor

Attachments: FW: Operational Limits for Management of Erosion and Corrosion

Jerry
here is the gist of it.
Richard

-----Original Message-----
From: GPB, Ops Mgr
Sent: Saturday, October 13, 2001 10:59 PM
To: Demby, Richard A; Powell, Jim E
Cc: GPB, Fld TL; GPB, FS1 TL; GPB, FS2 TL; GPB, FS3/GC3 TL; NSU, CIC TL; GPB, Prod Opt TL
Subject: MOC Velocity change & Removal of additional corrosion inhibitor

Richard and Jim,
I was wondering if you guys would take the lead on putting together the MOC raising the allowable erosional flow velocity for the WOA to match that used on the EOA. Attached is the recommendation sent to Ruth and I in August by the CIC Group. If you need additional information or insight from me, let me know. If you have any other questions, please give Dominic or John a call.

Thanks in advance for your assistance,
Jack

-----Original Message-----
From: NSU, CIC TL
Sent: Thursday, October 11, 2001 1:58 PM
To: GPB, Ops Mgr; GPB, Prod Opt TL; GPB, Gas Lift Engr
Cc: Woollam, Richard C; G SST Corr Engrs
Subject: Removal of additional corrosion inhibitor

Jack, Hal & Russ,

We have made the decision to stop the practice of adding extra corrosion inhibitor to mitigate corrosion at elevated flow velocities, in order to meet our 2001 budget.

The practice of adding extra chemical was introduced last year and enabled CIC and Operations to raise the allowable flow velocities by 25 ft/sec and therefore increase production. In the new unified velocity guidelines we proposed dropping this program as it is inefficient, both in terms of chemical management and time. Our proposed guidelines allow for elevated flow velocities typically 10 to 15 ft/sec higher than the old guidelines without the requirement for additional chemical to be added proactively; rather we will add extra corrosion inhibitor in response to observed corrosion through our monitoring programs, as we have always done. The new guidelines also recommend raising the allowable erosional flow velocity (V/Ve) from 2.0 to 2.5, thereby increasing production. I believe therefore that implementation of the new guidelines should be broadly production neutral, relative to the curret status although Russ will know much better.

As the proposed guidelines have not been formally adopted, the removal of the extra chemical program will return us to the previous default velocity limits. There will clearly be a production impact associated with this and therefore we should re-visit the recommendations to see if and when we can implement them. To quote from the recommendations:

"It should be recognized that these are only recommendations; unlike other operational parameters such as temperature and pressure, there are no codified limits for flow velocity and therefore you may accept or reject these recommendations. These recommendations are presented as appropriate technical limits that aim to maintain the integrity of equipment whilst enabling high production rates and minimizing operational costs such as chemical consumption and equipment repair or replacement."

What this means in practice is that CIC and Operations can work together to implement a program quickly that meets the main requirements of the guidelines while maintaining production and this should probably be done via an MoC. Let me know how you want to proceed,

FW: Operational Limits for Man...

Cheers,

Dominic
Dominic Paisley
North Slope Team Leader
Corrosion, Inspection & Chemicals Team
BPX Alaska
E-mail: nsucictl@bp.com
Phone: +1 (907) 659 5050
Fax: +1 (907) 659 5152
Pager: +1 (907) 659 5100, pager 2267

Exhibit 16

CIC Group 2002 Budget Challenge - $ 1 Million Opportunities

		Full Year	Half Year					$ 1,000		Half Year
	Budget Area	2002 Bud.	2002 Bud.	Scope	Unit	Rate		New Scope	% Redction	New 02 2H
4DF	CIC Supervisor	$ 1,948	$ 974							$ 974
4DG	Chemical Ops - Process	$ 2,591	$ 1,296							$ 1,296
4DH	Chemical Ops - Corrosion	$ 25,392	$ 12,696	1.5	MM Gals	8.46	$/gal	1.38	7.9%	$ 11,696
4DI	Field Pigging Operations	$ 1,259	$ 630							$ 630
4DJ	Inspection	$ 7,285	$ 3,643	35000	Items	104	$/Item	25,391	27%	$ 2,643
4DK	External Corrosion	$ 5,000	$ 2,500	17500	Items	143	$/item	10,500	40%	$ 1,500
4DY	N/S Svcs - Anc Tech Labor	$ 1,078	$ 539							$ 539
	Subtotal CIC Group	**$ 44,553**	**$ 22,277**							**$ 19,277**

Notes

4DF Largely BP labour and therefore difficult to impact in the short term

4DG Process chemicals such as EB which is impoacting to production if altered

4DI Major BP labour component

4DI Smart pigging program for which work is complete or commitments made to service supplier

4DY Largely BP labour and therefore difficult to impact in the short term

4DH Difficult to assess but based on history a 10% reduction in inhibition levels would result in a 30% increase in corrosion rate

4DJ Obvious impacts wrt ORT and PACE

4DK Partner perception since this is the very issue they were concerned about

Note: The commitments made in the 2001 Corrosion Report to ADEC for 2002 were based on the $44.5 million budget clearly this would be a concern to the agency if the program was substantially lower than forecast.

Exhibit 17

was needed on the WOA. However, there has not been any communication with partners since that time that I am aware of.

Rick

Corrosion, Inspection, Chemicals
Anchorage, AK
(907)564-4466
(907)748-3961 (cell)

-----Original Message-----
From: NSU, CIC TL
Sent: Wednesday, February 05, 2003 12:53 PM
To: Felix, Rick D (Anchorage)
Subject: FW: Master ID 2996 GPB Pig Launcher and Receiver Prelim Engineering

Rick,

Any input?

Thx,
John

-----Original Message-----
From: Farnham, C Drais
Sent: Wednesday, February 05, 2003 11:59 AM
To: GPB, Ops Support Mgr; GPB, Ops Mgr; Woollam, Richard C; NSU, CIC TL
Cc: GPB, Business Lead; Northcott, John (Accenture)
Subject: Re: Master ID 2996 GPB Pig Launcher and Receiver Prelim Engineering

Folks, can anyone tell me if we have Partner "buy-in" on the above subject project anymore than we did on AFE 4N0492 which they rejected and requested withdrawn.

While I was of the understanding that the above subject AFE was related to preliminary engineering related to temporary / portable pigging facilities I would still have to ask if this is a way forward conversation which has been had with our Partners. While I am sure it is not our intention, approving the subject AFE within existing operator authority (WEOA) and communicating to our Partners as an fyi, could be misconstrued as circumventing the approval process and subject BP to future audit claims, given their position on 4N0492. We very much want to have them in agreement on this AFE, regardless of WEOA.

Also of concern is the description / justification ..... should this proceed as an AFE I would have expected it to be significantly different than the earlier AFE rejected / with drawn.

Master ID 2996 ..... to be approved WEOA $1.0M:

Develop scope and perform preliminary engineering for temporary or portable pig launching and receiving facilities on selected lines across GPB. Installations are required to support maintenance pigging activities to reduce corrosion rates on GPB cross-country lines. Facilities will also provide availability to intelligent pig GPB cross-country lines for the detection of both internal and external corrosion. New installations will be concentrated on historic EOA production common lines, and transit sales lines. These pigging facility installations will be for FS1, FS2, and, FS3, and associated drill sites to support integrity operations at these operating areas. See attachment " Pigging Facility Priority Listing" for an itemized listing of exact pipeline locations and relative priority. The purchase of some long lead materials will also be covered under this AFE.

Maintenance pigging is required to optimize existing corrosion control programs. Maintenance pigging will also eliminate flow restrictions present from sediment and fouling within the pipelines. Intelligent pigging is required to provide a full evaluation of current pipeline condition to ensure pipeline integrity and meet regulatory requirements. Intelligent pigging will provide an economic inspection opportunity for both internal and external corrosion monitoring. Intelligent pigging provides a comprehensive survey of the pipeline profile, which then allows other inspection resources to be more effectively utilized in verification of damage networks, which have already been discovered.

AFE 4N0492 ..... rejected by Partners for approval $2.5M:

Install permanent pig launching and receiving facilities on selected lines across GPB. Installations are required to support maintenance pigging activities to reduce corrosion rates on GPB cross-country lines. Facilities will also provide availability to intelligent pig GPB cross-country lines for the detection of both internal and external corrosion. New installations will be concentrated on historic EOA production common lines, and transit sales lines. These pigging facility installations will be for FS1, FS2, and, FS3, and associated drill sites to support integrity operations at these operating areas. See attachment " Pigging Facility Priority Listing" for an itemized listing of exact pipeline locations and relative priority.

Maintenance pigging is required to optimize existing corrosion control programs. Maintenance pigging will also eliminate flow restrictions present from sediment and fouling within the pipelines. Intelligent pigging is required to provide a full evaluation of current pipeline condition to ensure pipeline integrity and meet regulatory requirements. Intelligent pigging will provide an economic inspection opportunity for both internal and external corrosion monitoring. Intelligent pigging provides a comprehensive survey of the pipeline profile which then allows other inspection resources to be more effectively utilized in verification of damage networks which have already been discovered.

My "two cents" ..... please let me know as to George / Partner "buy-in". As I noted below I am genuinely interested in not putting George between a "rock and hard spot", and not degrading the Partner relationships we have "grown" over the last couple years, and want to make sure we have appropriately communicated.

Thanks, Drais

-----Original Message-----
From: GPB, Business Lead
Sent: Wednesday, January 29, 2003 4:13 PM
To: Farnham, C Drais
Cc: Northcott, John (Accenture); GPB, Ops Support Mgr; Woollam, Richard C; NSU, CIC TL; GPB, Ops Mgr
Subject: RE: AFE 4N0492 Install Pig Launchers/Receivers in Flowlines

Drais,
Just finished the MR/Capex meeting and the subject line item was discussed. The subject AFE is being dropped and replace by different scope. Nancy agreed to follow-up with the WIO's request for 'full scope' with regard to what are the total plans for GPB and pig launchers/receivers. My understanding is the original AFE was for permanent pig launchers / receivers the new approach calls for portable launchers / receivers.
Certainly agree that we do not want to put George in a difficult situation with the WIO's as you have outlined below.
Thanks,
Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

-----Original Message-----
From: Farnham, C Drais
Sent: Wednesday, January 29, 2003 3:54 PM
To: GPB, Business Lead
Cc: Northcott, John (Accenture)
Subject: RE: AFE 4N0492 Install Pig Launchers/Receivers in Flowlines

Steve, getting further into my e-mail ..... I do not think this is a good idea; not sure who's idea it is. At the last Ops Forum, both ConocoPhillips and ExxonMobil requested that this AFE also be removed from the list ..... except their reasons were quite different.

CPAI indicated that they had rejected this AFE and therefore saw no reason for it to be on the list, while ExxonMobil asked for it to be removed as they were also not likely to approve until further discussion and understanding of the Pig Launcher / Receiver strategy had been held and agreed to. They see this as the "tip of the iceberg" relative to projects of this sort and want to understand how they fit within the greater corrosion mitigation / management program.

I absolutely do not think dropping this below the threshold is the right thing to do ..... and before we put George between a "rock and hard spot", maybe discuss this with him. I know he does not like the Partners "directing" our work efforts, but I know he also doesn't want to have to explain this after the fact either.

Thanks, Drais

-----Original Message-----
From: GPB, Business Lead
Sent: Monday, January 27, 2003 1:53 PM

To: Farnham, C Drais
Subject: AFE 4N0492 Install Pig Launchers/Receivers in Flowlines

Drais,
The subject AFE is listed on the Ops Forum, you can pull it off (it's for $2.5M & was submitted June-03). Speaking with Rick Felix today they are going to revise it & change the scope which will bring it below the $1m threshold. The rev. will be for front end loading and engineering only.
Thanks,
Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

Exhibit 18

From: NSU, CIC TL
Sent: Sunday, December 07, 2003 5:39 PM
To: Woollam, Richard C
Subject: FW: ACTION: 2003 August LE's and Field OVERVIEW

Importance: High

FYI...

-----Original Message-----
From: NSU, CIC TL
Sent: Wednesday, September 10, 2003 2:43 PM
To: Woollam, Richard C
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW
Importance: High

Richard,

Steve generated a report for Roger and Jack showing CIC Actuals vs. Budget through August. His primary focus was on salaries which were apparently over estimated due to an error in a spreadsheet calculation when the 2003 budgets were created. The same error was propagated through all budgets and has been adjusted out of other LE's so significant pressure was placed on CIC to do the same. Steve calculated that CIC's salary budget had been over estimated by $1MM so we were expected by the Ops and Ops Support Managers to adjust our LE.

I met with Roger and Nancy both this morning for a few hours (at separate times - they changed out).

Roger was very clear that we needed to adjust the budget and that he was mainly concerned about the overall Ops Support budget and individual groups would be viewed based upon that success (most other groups have increased 2003 budgets over 2002 while ours was significantly less carrying much of the organization). He wanted us to generate a challenging LE (25% probability of success), acknowledged that we have invoicing (outstanding $2.3MM from August) and extra pressure issues (Y-36). His belief was that due to phasing in December and the salary error we could handle the budget reduction and still have a chance to meet the target.

Nancy was not in favor of the cut but felt we had to do it based upon pressure and Steve's comments. She was clear that she would not allow program cuts without being directed by George to do so and is sensitive to news of this cut getting out to the workforce which would undoubtedly cause HSE concerns regardless of impact on performance. Based upon burn rate through August and outstanding invoices of $2.3MM for August (BJ for $350k, BE/PTI for $700k, Canspec for $800k, U2 for $400k) we calculated the LE to be $40MM but obviously did not know how the entire budget had been planned so realized this simple exercise was not without risk. If we get into a position where the budget will be exceeded, she wants us to get with her to develop a plan as soon as possible.

Steve adjusted our LE by taking the $1MM from the salary budgets.

Thanks,

Gary

-----Original Message-----
From: Woollam, Richard C
Sent: Tuesday, September 09, 2003 7:11 PM
To: NSU, CIC TL
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Gary,

An interesting list, please note I do not want to roll-over on any of this stuff so don't use the term minimal risk. We are being asked to cut our budget because others were not responsible budget owners at the beginning of the year - hence there is an overview while we cut our budget 5%.

There needs to be greater emphasis on regulatory impacts, relationship with ADEC, workforce perception, as well as the increased corrosion risks.

I have added a couple of comments, please amend the risks as per my comments. Once again, I don't want to give Roger et al any easy decisions as this whole process is bullshit - we should not have to compensate for other incompetence. Therefore, the bulk of the decisions the FMT should be forced to make should be difficult.

Richard.

<< File: Budget Challenge III.xls (Compressed) >>

-----Original Message-----
From: NSU, CIC TL
Sent: Tuesday, September 09, 2003 4:46 PM
To: Woollam, Richard C
Cc: Felix, Rick D (Anchorage)
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Richard,

Please see the attached draft of options within CIC control. Also, we feel the high cost well lists could be useful for Operations to help reduce our costs.

Please let me know your comments. I will forward to Roger tomorrow when necessary with a note that you have not reviewed this if I do not hear back from you due to travel.

Thanks,

Gary

<< File: Budget Challenge II.xls (Compressed) >>

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, September 08, 2003 5:11 PM
To: NSU, CIC TL; Felix, Rick D (Anchorage)
Cc: GPB, Ops Support Mgr; Foust, Nancy C
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

John/Rick,

Please see below a request from Roger.

As with previous years, our variable costs are in basically in two areas,

- Inspection scope - reduce scope and increase risks
- Inhibition levels - reduce inhibition levels and increase risks

When outlining the risks, it will be important to make sure that we note the all the potential risks not just the increased corrosion and leak risks, including,

- Commitments to ADEC
- Reputational issues
- Workforce perception if reducing inspection/inhibition levels

- Regulatory requirements - any risks here

Need to also identify any added workscope issues we face including Y-36 and whether to not these will be impacted.

I'll try and check my e-mail tomorrow morning your time, if the phone connections from Siberia permit, if you have any additional comments or questions.

Thanks.

Richard.

-----Original Message-----
From: GPB, Ops Support Mgr
Sent: Monday, September 08, 2003 7:01 AM
To: Woollam, Richard C; GPB, Business Lead
Cc: NSU, CIC TL
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Richard, you and your team need to work up a plan to safely reduce your spend. All teams are being asked to participate in this effort, including CIC. I want to see what it will take in terms of actions and risks and mitigations to those risks to reduce your LE by 1 million bucks by Wednesday morning. Then we will decide if the LE remains unchanged.

John, I know Richard wont see this note till tonite due to his trip, so you need to take the lead to make this happen.

Thanks,
Roger

-----Original Message-----
From: Woollam, Richard C
Sent: Monday, September 08, 2003 1:59 AM
To: GPB, Business Lead
Cc: GPB, Ops Support Mgr; NSU, CIC TL
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Steve,

The LE remained and remains unchanged, as we agreed earlier - Nancy/Steve and I, due to the fact we have a significant outstanding invoices and the NDE costs associated with the Y-36 spill.

Richard.

-----Original Message-----
From: GPB, Business Lead
Sent: Sunday, September 07, 2003 6:13 PM
To: NSU, CIC TL
Cc: Woollam, Richard C; GPB, Ops Support Mgr
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Richard/John,
I agree with what is stated. However it doesn't change the fact that we have an $11M overview that has to be addressed or we will bust the budget and risk eating the over run 100% BP dollars. We are in the process of shutting down major repair work to contribute some $2m to $4m.

Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

-----Original Message-----
From: NSU, CIC TL
Sent: Sunday, September 07, 2003 6:05 PM
To: GPB, Business Lead
Cc: Woollam, Richard C
Subject: RE: ACTION: 2003 August LE's and Field OVERVIEW

Steve,

At last month's LE review, Richard was hesitant to change our LE because of the following:

- In inspection, Canspec invoices have been lagging on submittal
- In pigging, the smart pigging vendor has yet to be paid for work just completed in August. This will drive the burn rate up near normal in this area

I have copied this memo to Richard directly so he can further comment. I would be hesitant to change our LE significantly until we understand what the costs of the above are going to be.

Thanks,
John

-----Original Message-----
From: GPB, Business Lead
Sent: Sunday, September 07, 2003 5:31 PM
To: G GPB Operations OTLs
Subject: FW: ACTION: 2003 August LE's and Field OVERVIEW
Importance: High

All,
This is the note I spoke to in the Ops / Ops Support TL meeting and that Ruth asked me to forward to you (Gary H. this doesn't reflect the additional $200k from GC-1 O&M).
Thanks,
Steven E. St. John
GPB, Business Lead
Phone (907) 659-8054
GPBBusinessLead@bp.com

-----Original Message-----
From: GPB, Business Lead
Sent: Saturday, September 06, 2003 8:06 PM
To: GPB, Ops Mgr; GPB, Ops Support Mgr; GPB, Field Services TL; Hawley, Robert S; Higgs, Joseph A; Seccombe, Jim C; Merrill, Mark J; Gunkel, Fritz; Stanley, Mark J (ANC); Wiggs, Craig L; GPB, Safety TL; Seymour, Len I
Cc: Farnham, C Drais; Boland, Dan (Accenture)
Subject: ACTION: 2003 August LE's and Field OVERVIEW
Importance: High

All,
Enclosed is the roll up of the August 2003 Field LE's as submitted.
<< File: 2003 Monthly LE INPUTS.xls (Compressed) >>
If I publish as is we will be flagging an $8.7M overview to upper management and the WIO's. I do not believe the remaining overview is that large and would propose the enclosed additional LE adjustments (see tab # 1). Tab # 2 shows the Aug YTD Actuals vs submitted LE's.
<< File: Aug_2003 LE's.xls >>
We Need to land this early this week or we will delay the publishing of the WIO / Management reporting.

If You have any questions please give me a call.

Thanks,
Steven E. St. John
GPB, Business Lead

Phone (907) 659-8054
GPBBusinessLead@bp.com

Exhibit 19

Opportunity to Make Stretch Budget

- *Reduce WOA Weight Loss Coupon Program*
  - Reduce WOA weight loss coupon program by 25%
  - Relax the WOA weight loss coupon pull frequency from every three months to every four months
  - Estimated cost saving: 1.1 man yr ($250,000)

Exhibit 20

TEMP00067592.0001

Grater Prudhoe Bay / 2004 Field Lifting Cost Challenge (LCC) Maintenance and Reliability — First Pass RBG

Opportunity	Sustaining (Yes / No)	2004 Savings / Efficiencies / Deferrals $M	Future Annual Savings / Efficiencies / Deferrals $M	Opportunity Implications (LTO, HSE, Production, People, Deferral, Can Do)
CIC: Cancel 2004 Smart Pigging Program	No	$250	$0	* LTO/HSE Defer smart pig on three 24" lines on the WOA. * **Reputation**
CIC: Cancel partial PW Inhibition at GC's	No	$670	$0	* LTO/HSE Will cause rate of pipe wall loss to increase. * **Reputation**
CIC: 25% Reduction in AES Chemical Operators	YES	$150	$200	* Inefficient use of corrosion inhibitor. Eliminates one position but can be managed. * Reputation and workforce concerns
CIC: 17% Inhibition Program Reduction*	No	$1,560	$0	* LTO/HSE Maybe able to attain part of savings without significant risk. Requires detailed review. * Reputation
CIC: 17% Inspection Program Reduction*	No	$1,370	$0	* LTO/HSE Maybe able to attain part of savings without significant risk. Requires detailed review. * Reputation
Managed Service: VECO Reduce ESI program by 50%. Eliminate UOSS inspectors and replace with VECO inspector/repair. Make easy repairs part of inspection eliminating steps. Same folks that do inspection do repairs.	YES	$150	$300	Still demonstrates a presence but time doubled to complete project. Will generate employee concerns. Performing risk assessment prior to implementation may reduce employee concerns. EA may offset some issues. Major Repair.
Managed Services: VECO Project Manager budget reduced 10%	YES	$300	$400	Since Project Manager Budget is tied to head count VECO would have to do an additional 10% lay off for a total of 20%. HSE Production LTO
Managed Services: ASCI Reduce ASCI by 10%	No	$300	$0	Any reductions in ASCI will directly impact service and would most likely increase costs in other areas. Would negatively impact resolution of Exxon audit findings. Production and People.
Managed Service: Utilities Reduce contract services.	No	$100	$0	Will cause work to be deferred into 2005.
Managed Service: Utilities Revisit charging lighting upgrade to a capital AFE. Lighting upgrade eliminated the need for scaffold or the construction of platforms.	No	$70	$0	Work is complete. Only involves transferring charges. Originally intended for capital AFE but ended up below the line.
Managed Service: Utilities Eliminate contract vacation relief position.	No	$50	$0	LTO and People. Eliminates our ability to develop renewal (Certifications) and runs a high risk of being out of compliance. Reduction of BP personnel either cause immediate compliance issue or only displace folks to other jobs with no cost savings. Reducing contractors is the only alternative.
CPS: Defer all CPS turbine field device PM's to be performed only when unit comes down for HGP or Full Major Overhaul.	YES	$28	$28	WE have a full real time SCADA system that tells us with alarms if we have a problem with our turbines/generators. This is definitely a 'CAN DO". BP policy change required.
CPS: Cut one permanent BP position.	No	$200	$0	Safety, Production, People and power reliability. CPS is already minimally staffed for all the duties it performs. Also CPS is at a time when we should be putting on a couple of trainee positions in both Operators and T&D ranks. CPS already has approximately one third of its total staffing getting three vacations a year.
CPS: Cut all Sunday BBQ's, CPS Fun Run and CPS Safety Fair booth for Safety Fairs	YES	$25	$25	People, Safety, Morale, will be viewed as take aways and could affect morale and productivity. BBQ's are used as a means of enhancing working relationships betweem non-bargaining, bargaining and contract employees. The CPS fun run and Safety Fair booth are Health, Safety and morale builders for CPS/T&D personnel. These would be viewed very negatively as take aways.
CPS: Cut all discretionary spend on materials that are absolutely not required to produce electricity or maintain Safety, SCADA, COE and equipment for power production.	YES	$20	$20	Can do, may not be as convenient or exactly what employees want, but is a can do,
CPS: Cut 10% Veco/AIM contract services to CPS	No	$80	$0	Production, Safety and People impacts, not sustainable for safety of all production facilities or power reliability.
F&G: Discontinue Sunday Team Meetings	No	$100	$50	Long-term impact on HSE performance and PM Effectiveness (e.g. knowledge sharing and skills improvement). Reduction maybe possible as a result of increased efficiency. *Do not recommend as a sustained opportunity, as impacts have proven to eventually out way savings.*
F&G: Vendor Technical Training	No	$25	$0	Long-term impact toward maintaining F&G Engineer and Technician skills and knowledge base. *Do not recommend as sustained opportunity.*
F&G: Transfer as built responsibility for project closeouts to document control	Yes	$50	$100	Eliminate 1/2 position by finishing shop drawing updates. Work will be complete on 6/1/04.
F&G: Transfer WOA/EOA Halon Shop refurbishment expenses to AFE 4N0705	No	$100	$0	Ops CAPEX budget impact of $100k, in progress, AFE already approved.
AE&I: Eliminate Flow Measurements Contractor	No	$75	$0	LTO - Possibility exists that environmental or custody meter proving could backlog could force a non-compliance situation.
AE&I: Reduce 619 Misc Personnel Expense	No	$30	$0	Deferral - This bucket carries software license renewals, test equipment replace and upgrades. Risk is that maintenance and support for some test equipment may not be available.
AE&I: Reduce 133 Parts and Materials	NO	$20	$0	Deferral - This bucket carries parts and materials and operations costs primarily for generator set maintenance and testing for fixed generator sets. This defers some discretionary costs for non-generator items

TEMP00067590.0001

Exhibit 21

From: Woollam, Richard C
Sent: Friday, April 16, 2004 8:27 AM
To: NSU, CIC TL
Subject: RE: Cost Challenge feedback

John,

If, by the end of your shift, you could take a look at North Slope activities and identify any opportunities for cost reduction in 2004 that would be helpful.

Thanks.

Richard.

-----Original Message-----
From: NSU, CIC TL
Sent: Friday, April 16, 2004 6:00 AM
To: Woollam, Richard C
Subject: RE: Cost Challenge feedback

OK, the feedback was requested by Nancy at her last Monday's meeting, Gary had passed on the info at handover.

-----Original Message-----
From: Woollam, Richard C
Sent: Thursday, April 15, 2004 6:18 PM
To: NSU, CIC TL; Sprague, Kip P; Felix, Rick D (Anchorage)
Subject: RE: Cost Challenge feedback

All,

We need to coordinate our response back to Nancy thru me. Our budget position is not as it appears in the Field Cost Management (FCM) reports due to some issues with accruals - for example we will have a reversal of nearly $1 million from correcting AES accurals alone!

Therefore, what we really need to look for is some options for removing costs from 2004 which have little or no material impact on the 2004 program - items 1 and 2 below are material in my opinion - so what activities do we not need to do in 2004!?!

Thanks.

Richard.

-----Original Message-----
From: NSU, CIC TL
Sent: Thursday, April 15, 2004 5:59 PM
To: Sprague, Kip P
Cc: Woollam, Richard C
Subject: Cost Challenge feedback

Confidential

Kip,

Gary was at a budget session the other day, and we require some feedback on consequences of a couple of options for Nancy by Monday. (Richard may have already briefed you).

- One option is to cancel the 2004 smart pigging program - what are the consequences of not doing it this year (the 3 LDF's)?
- Another option is to cancel partial PW inhibition at GC's - any opinions?
- There are also some reductions of inhibition and inspection programs proposed, although RCW doubts those will be necessary.

Thanks,
John

Exhibit 22

06/03/04 THU 11:33 FAX ⧉005

FROM : FAX NO. : May. 24 2004 03:14PM P3

P.01

TOWER PETROLEUM CORPORATION

10101 Slater Avenue, Suite 120
Fountain valley, CA 92708
Phone (714) 593-8723 • Fax (714) 593-8724

Jeanne Pascal, Esq.
Northwest District Debarment Counsel
U.S. Environmental Protection Agency
Seattle, Washington

May 8, 2004

Re: Conversation with [redacted], Alaska

Dear Ms. Pascal,

This letter is being sent at your request relating to my telephone conversation with [redacted] in April, 2004.

As you are aware, Mr. [redacted] was previously employed by British Petroleum as a corrosion control supervisor for their production operations on the North Slope of Alaska. He has also had considerable additional experience and credentials as a corrosion control expert. I am somewhat familiar with the Prudhoe Bay operations from my previous experience in Alaska, both in the oil industry and in government. Therefore, I felt I was in a position to understand the concerns expressed by Mr. [redacted].

First, Mr. [redacted] impressed me with the scope of his knowledge as it relates to the corrosion control applications necessary for the production operations at Prudhoe Bay and to what was actually being implemented (or neglected) by the local management of British Petroleum. During our hour and a half conversation, I found him to be sincere and very concerned for the welfare of the workers at Prudhoe Bay as well as for the negative effect any major incident would have on the future of the ANWR development. In over fifty years of experience in the oil industry, I found him to be one of the most knowledgeable corrosion experts to whom I have talked. He definitely is not someone with an "ax to grind" In fact, he made it very clear, he is currently very successful with his corrosion control business and has no further interest in working for B.P.

Mr. [redacted] advised me that proper corrosion control, detection, monitoring, and repair procedures were often being ignored in favor of "cost saving". He also said necessary (in his opinion) repairs were being delayed beyond the projected critical time for piping and associated equipment to the extent it has now become a hazard to the safety of workers and that procedures were being used to hide these problems from higher management. I am sure you are aware that corrosion detection and control is one of the major problems facing all oil and gas production operations. Pitting of the flow lines and associated piping causes thinning of the walls reducing the allowable internal operating pressure, otherwise the resulting burst pipe and sudden release of hydrocarbons to the surrounding atmosphere, indoor or outdoor, can cause serious harm to personnel and the environment. This can range from a minor oil spill problem in low-pressure "stripper" wells, to a very serious problem at Prudhoe Bay where much higher pressures exist.

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FROM : MAY-20-2004 16:00 FAX NO. : May. 24 2004 03:15PM P4

It is Mr. [redacted] opinion, and I concur, the upper management of British Petroleum consists of men and women of integrity who would never deliberately endanger employees to enhance the "bottom line". This type of unconscionable managerial behavior would never be sanctioned by the upper management in London. Therefore, it must be assumed they are unaware of the problems being created resulting from the decisions being made by some lower-level managers in Alaska.

I hope this serves to clarify, at least in part, the issue of B.P. corrosion control on the North Slope of Alaska.

Yours Truly,

Charles A. Champion
Registered Petroleum Engineer
State of Alaska 1738EP
State of California P1098

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Exhibit 23

To: Sprague, Kip P
Subject: RE: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Kip,

What I would like to get out from under is relying on the Detection Coordinator to determine what work gets done and when to call it complete - too many times burned by them not being organized enough to accomplish this.

From: Sprague, Kip P
Sent: Sunday, April 10, 2005 5:03 PM
To: NSU, CIC TL
Subject: RE: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Gary,

What I think, wouldn't actually be helpful and what is being asked isn't practical.

Reliable funding and resources is a yo-yo, accurate scheduling activities is a joke and predicting line lifts or impacts is even further out of the real of reality. We are sitting on a backlog of over 1000 locations with CUI and there are a dozen road crossings that need to be dug up and we have a huge infrastructure that is hanging-on with no margin for error. Without margin, we are not in a position for long-term detail planning, it is difficult enough just reacting to keep product inside the pipe. What we have is a log-term strategic plan and that should not be confused with a detailed execution plan.

Analogy: Plan-do-check act: You been asked to provide the 'plan' (which is fine, but that is short-term not long-term). You have also been asked to provide the 'act' before we have done, 'do - check', which of course determine that 'act' and as a result changes the 'plan'. Ridiculous to think we can predict all this (that is the fallacy).

Same story, can't do effective planning overnight after 20 years of minimalist resources and maintenance (which doesn't seem to be keeping pace with the current lofty ideas).

Bitch, bitch, bitch... I will try to wrestle down some middle ground between the reality of the situation and some feel good placeholders just to get people off your back. However, I will not run/sacrifice an inspection strategy and program with limited resources based on the conveyance of maintenance and/or operation impact. That, in my opinion, is negligent.

Wednesday, is the goal. Thanks for the reminder.

Kip

-----Original Message-----
From: NSU, CIC TL
Sent: Sunday, April 10, 2005 3:29 PM
To: Sprague, Kip P
Cc: Keck, Danny L; GPB, Planner 6 East
Subject: FW: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Kip,

A few items for discussion/comments.

CUI Detection Schedule

From a field execution perspective I believe we need to establish an external corrosion inspection schedule - something to show what category of equipment will be looked at when. My initial thought is the CUI detection work should be treated like the CIP's for the purpose of execution in the field (take a logical block of work, based upon system risk and geography which is similar to current methodology, but complete it as close to 100% as possible within access constraints then move to the next block). The blocks of work should be chosen by taking saddle lifts and repairs into consideration along with execution efficiency (currently, we can lift water injection and production lines on stream while gas/MI lines need to be depressured).

Line lifts

In addition to generating a 2006 line lift list based upon what we know now, we should probably ensure a list is complete for lift work this year - I have not seen anything like this yet.

Cased piping

In addition to getting the cased piping scope together for 2006 (at least what we suspect), we need to get the 2005 scope nailed down so we can begin the planning process.

I believe if we head toward the direction of having as much of our work scope as possible defined for 2006 soon (drop dead is around June 1st to match budget cycle goal), we can at least get the place holders in the planning and maintenance systems to ensure folks do not feel like we are 'surprising' them.

Please let me know what you think.

Thanks,

Gary

Danny - how is the list coming along?

-----Original Message-----
From: NSU, CIC TL
Sent: Sunday, April 03, 2005 1:17 PM
To: Keck, Danny L
Cc: Sprague, Kip P; GPB, Planner 6 East; Kuzma, John H; ACT, CIC Ops Integrity Support Specialist; NSU, CIC Fld Integ Ops; NSU, CIC Mech Integrity Insp; NSU, CIC OU Insp
Subject: Emailing: CIC MR-Capex AFE Tracker 2006 .xls

Danny,

I would like to get an initial draft list for our potential 2006 MR and Capex projects put together by mid week (Wednesday). I sent a note out several weeks ago to folks to solicit ideas and have received some feedback which is captured in the spreadsheet.

In addition to typical MR and Capex project work, we need to capture any O&M work that could impact operations next year (potential for production impacts). It appears that all known vessel/tank/PMP work scope has already been captured and relayed to Operations and the TAR TL.

Some potential areas for projects...

1) Cased piping digs
2) Any external corrosion special projects (lifts that could impact production or require special attention such as DOT regulated piping)
3) Smart pigging

John/Ray/Lumber - I would like to start adding ACT projects to the list also, please forward any potential projects you would like considered next year (EB tank at MPU, etc.)

Thanks,

Gary

Exhibit 24

From: NSU, CIC TL
Sent: Saturday, October 22, 2005 6:43 AM
To: Leach, Brett W
Cc: Sprague, Kip P; Hedges, Bill
Subject: Emailing: Control Options 10 22 05.xls

Attachments: Control Options 10 22 05.ZIP

Control Options 10 22 05.ZIP (...

rett,

Attached, please find a list of potential budget control options - broken out by chemicals and manpower. If you are interested in exploring more detail about any of the options please let me know.

Bill/Kip - if you have any edits or additions, lets discuss so I can update the list...

Thanks,

Gary

Option	Rank	Category	Monthly Savings	2 Month Savings	Purpose	Risk	Risk Mitigation	Reputation/Perception Risks
3 Phase CI: Eliminate Xylene		Chemical	$ 75,000	$ 150,000	Potential for plugging continuous injection system	High	Batch treatment program	ADEC/Workforce - only if problem occurs
3 Phase CI: Shut in top 5 CI users		Chemical	$ 75,000	$ 150,000	Production exceeds cost by >10x	Low	None	Governor/ADEC/Partners/Workforce
3 Phase CI: Potential Optimization (5%)		Chemical	$ 40,500	$ 81,000	Plan not fully developed and locations not identified, 2-4 weeks to implement	Low	Follow technical review protocol. Increase rates if data suggests necessary.	Workforce
PW CI: Slow deployment/reduce injection rates		Chemical	$ 400,000	$ 800,000	Lot of effort spent on getting the system up and running this year based on owner approvals. Technically, probably the least short-term risk of the options presented	Medium	Increase rates January 1, 2006. Corrosion mechanism is relatively slow. Initial cleaning to remove deposits may reduce corrosion rates substantially.	ADEC/Partners/Workforce
STP: Reduce Biocide frequency to every two weeks		Chemical	$ 36,000	$ 72,000	MIC locations established resulting in long term effects	High	Increase rates January 1, 2006.	ADEC/Partners/Workforce
Production Chemicals		Chemical	$ -	$ -	Without these chemicals, facilites would shutdown.	High	Shutdown facilities	Governor/ADEC/Partners/Workforce
Corrosion Monitoring		Manpower	$ -	$ -	Regulatory commitments and significant attention over the last few years. There was an effort to unify the coupon schedule, but that is on hold.	High	Inspection	ADEC/Workforce
Chemical Deployment (C Pad and Chem. Ops.)		Manpower	$ -	$ -	Reduction in chemical volumes in 1 and 2 contain a labor component	High	Third pary contractors	ADEC/Partners/Workforce
Pigging: Contract support crew		Manpower	$ 16,700	$ 33,400	Eliminate support crew - 2 personnel. Program has only been meeting ~75% of target YTD.	Medium	BP Operators still pig with help of BP Ops and ad-hoc contractor help	Workforce
Pump Crew: Eliminate TD jobs		Manpower	$ -	$ -	Program has been focused on freeze protects, with only 5 TDs performed in the past 3 months.	Low	Restart program January 1, 2006	Workforce
Inspection: Comprehensive Inspection Program		Manpower	$ 66,667	$ 133,333	Eliminate program to YE - 4 positions. 9750 items	Medium/Hi	Reschedule FS1, LPC, STP, SIP and remaining FL/WL programs	ADEC/Workforce
Inspection: Corrosion Rate Monitoring		Manpower	$ 66,667	$ 133,333	Eliminate program to YE - 4 positions. 1840 items	Low	Rely on monitoring only	ADEC
Inspection: Erosion Rate Monitoring		Manpower	$ 16,667	$ 33,333	Eliminate program to YE - 1 positon. 768 items	High	Reduce maximum allowable mixture velocities/ Minimize or cancel well-work and well strat-ups)	Workforce
Inspection: Corrosion Under Insulation Detection		Manpower	$ 66,667	$ 133,333	Eliminate program to YE - 4 positions. 6000 items	High	Shut-in Y LDF	ADEC
Inspection: Frequent Inspections		Manpower	$ 16,667	$ 33,333	Eliminate program to YE - 1 positon. 384 items	High	Repair or shut-in equipment (PMP - High wastage areas i.e. G&I)	ADEC/Workforce
Inspection: Special Request/ADHOC		Manpower	$ 16,667	$ 33,333	Eliminate program to YE - 1 position. 536 items	Medium	No response or action as a result of observations/discoveries	Workforce
Rope Access Technology		Manpower	$ 16,667	$ 33,333	Eliminate RAT to YE - 1 position	Medium	Built scaffold for percieved or at risk locations	Workforce
Veco		Manpower/Materials	$ 195,000	$ 390,000	Eliminate CUI Mitigation program to YE - 9 positions	Medium	No response or action as a result of observations/discoveries	ADEC/Partners/Workforce

Exhibit 25

From: Dengler, John M
Sent: Thursday, March 09, 2006 4:45 AM
To: Neill, David H (Baku)
Subject: RE: GC-2 Oil Transit Line Spill

Attachments: image001.jpg

image001.jpg (2 KB)

The Daily News - now there is a source to believe.
It isn't pretty,
Refresh my memory - wasn't the line from FS 2 to FS 1 so packed with solids just downstream of Module 4922 that an ultrasonic meter wouldn't work? Think there is any corrosion in that section of line?
John

From: Neill, David H (Baku)
Sent: Wednesday, March 08, 2006 8:04 PM
To: Dengler, John M
Subject: RE: GC-2 Oil Transit Line Spill

John,

Thanks for the update. I have been following the Daily News stories also. Too bad about the leak detection system not picking this up. I'm sure there will be renewed pressure from DEC regarding leak detection. FYI.. I am installing the EFA leak detection system on our Western Route pipeline to the Black Sea. Stay Warm!

Dave

From: Dengler, John M
Sent: Wednesday, March 08, 2006 1:39 AM
To: terrymorgan_wyo@yahoo.com; James Ferguson; James. steward (James.steward@nana-colt.com); Schwab, Lorinda A; Connick, Eugene (Baku); Neill, David H (Baku); Athans, Murray P; Huff, Richard E.; Collins, Matt G (ConocoPhillips)
Subject: FYI: GC-2 Oil Transit Line Spill

I'm headed to the slope tomorrow to get more involved. I don't like the second sentence of the first bullet. I REALLY don't like the second sentence of the fifth bullet.

John

From: Johnson, Maureen L
Sent: Tuesday, March 07, 2006 12:21 PM
To: G AK All Users; G ANC ALT; G ANC Extended Leadership Team; G ANC External AFFRS Group; Pillari, Ross J;

Taggart, Sally B; Chappell, Ronnie W; Markin, Thomas A; Miller, Brian W; Hudson, Peggy R; Caballero, Jaime E.; Chapman, Neil A; Depland, Hugh; Tiernan, Elizabeth P; Foust, Nancy C; Nicolson, Don; Brock, Tony; 'sonny.rix@exxonmobil.com'; Hanus, Michael (Exxon); Jones, Darren C. (ConocoPhillips); Kruse, Dan P. (ConocoPhillips); Stramp, Ryan L (ConocoPhillips); Richard J. Owen; Tison, Joel K
Subject: Update #8: GC-2 Oil Transit Line Spill

BPXA GC-2 Oil Transit Line Spill

[illegible]

03/07/06 1100

Spill Response

- Leak was discovered 16'8" from east culvert. Visual indications are that the leak was caused by internal corrosion.
- Preparation is underway for line lift procedure. In addition to removing all non-essential personnel, job review meeting will be held to insure this procedure is safely performed. Additional safety personnel are being sent to the North Slope to augment the current coverage.
- As of 0630, 3/7/06, 1335 bbls. of liquids have been recovered; recovery efforts have been temporally shut-down due to line lift.
- Volume estimation survey will continue during daytime.
- Temperature is -20 Fahrenheit and getting colder. Thursday's weather prediction is -35.
- Contingency plan for blowing snow conditions is under development and snow fence is under construction

Business Resumption

- **Pipeline integrity**: UT inspection around leak site is planned for today.
- **Repair options**: sleeving plans at the known areas of integrity concern are being developed and material ordered. A temporary repair is currently in place for source control at the leak site.
- **Return to service**: options to return GC2 to service are being studied. Engineering, Operations, and CIC will be reviewing details for the selected option.
- **Priorities**: Unchanged - Focus is on pipeline integrity assessment, repair execution, jumper options, GC-2 start-up and return to normal operation.
- **Source control**: source control achieved this morning by technical staff on team.

Incident Investigation

- The investigation team is up and running. The team consists of the lead, Bryant Chapman - Performance Unit Leader, Operations Excellence of Houston, John Alkire - EPTG Corrosion Expert, BJ Harris - Safety Engineer, Barry Vest – GC2 Operator and union rep, Gary Evans – DEC, Shelia Barnes – Administrative Assistant.

Please Note

- The Joint Information Center (JIC) continues to provide ongoing communication materials to the ADEC website: http://www.dec.state.ak.us/spar//qc2 and continues to provide requested information to various organizations/agencies.
- Next update tentatively planed to be provided at 11:00 a.m. AST on Wednesday, March 8, 2006. Now that temporary source control has been achieved, we expect to reduce the frequency of the updates in the near future. Your feedback is welcome in determining update frequency.

Maureen Johnson
Performance Unit Leader, GPB
(907) 564-5671
johnsml@bp.com

Exhibit 26

From:	GPB, FS2/COTU Area Mgr
Sent:	Thursday, March 23, 2006 2:24 PM
To:	Leach, Brett W
Subject:	FW: Pigging Facility Walk Down - Need your input on Pigging Concerns

Brett,
I know this is a little later than you requested but here's our input.....yes we can do it but it will require some effort.

In my opinion this is extreme overkill. Pigging is probably not a bad idea but the frequency should be more along the lines of twice a year or once a quarter.....not weekly.

Chris Rhoads
alt: Bob Walker
FS-2/COTU Area Manager
office: (907) 659-5492
pager: (907) 659-5100 #1115
fax: (907) 659-8405
e-mail: rhoadsca@bp.com

From:	GPB, FS2 Ops Lead
Sent:	Thursday, March 23, 2006 2:09 PM
To:	GPB, FS2/COTU Area Mgr
Subject:	RE: Pigging Facility Walk Down - Need your input on Pigging Concerns

Chris,
I have a couple concerns; the biggest being that we haven't pigged our sales transit line in over 15 years and I really don't know what to expect... Also, the condition of the launcher, i.e. the launcher door seal o-ring, the sump, sump pump and all of the associated piping are unknown. We can functionally check the drain sump system, but it would probably be prudent to have all of the associated lines inspected prior to returning this system to service as they are at a low point and have been stagnant for years. We need to spec out and order some replacement o-rings for the launcher doors - they haven't been opened for fifteen years. And operating procedures will need to be developed to include FS1 for their part in receiving the pig.

Otherwise, yeah - we can do it...

From:	GPB, FS2/COTU Area Mgr
Sent:	Thursday, March 23, 2006 12:39 PM
To:	GPB, FS2 Ops Lead
Subject:	FW: Pigging Facility Walk Down - Need your input on Pigging Concerns

Brad,
Will you take a look at this and give me your ideas/opinions?
Thanks,

Chris Rhoads
alt: Bob Walker
FS-2/COTU Area Manager
office: (907) 659-5492
pager: (907) 659-5100 #1115
fax: (907) 659-8405
e-mail: rhoadsca@bp.com

Exhibit 27

(907) 670-3331
alternate: George Ahumada

From: NSU, CIC Prod Chem (Nalco)
Sent: Sunday, June 04, 2006 3:10 PM
To: Pogue, Cleve C; Todd, John B (Nalco); Spano, A J
Cc: Ahumada, George R; Kuzma, John H
Subject: RE: Sales Oil Pipeline Protection

Cleve,

Certainly there has been a lot of discussion lately about what to do with the oil transit lines. I think that virtually everyone agrees that the most important piece of preventive maintenance that can be done is to keep the line clean by pigging it on a regular basis. That will cure almost all your "ills". Currently, GC2 is the only one that is adding a supplemental corrosion inhibitor directly into their transit line for reasons that are probably obvious. We need to get John Kuzma involved in the discussion as I can't answer your question directly. Whether or not to treat the systems will certainly be an issue that will require further discussion, likely at a high level. My personal belief is that pigging is by far the most important single thing that you can do to prevent problems.

Best Regards,

John T.

From: Pogue, Cleve C
Sent: Sunday, June 04, 2006 11:12 AM
To: Todd, John B (Nalco); Spano, A J
Cc: Ahumada, George R; Pogue, Cleve C
Subject: Sales Oil Pipeline Protection

John and Andy,
Dale and myself had a discussion about corrosion concerns in the MPU Sales Oil Pipeline. What has been the common practice across the slope on Sales Oil Lines. I know you guys are reviewing a lot of the current practices. Should we or do we plan to do anything along the lines of chemical injection.

Cleve Pogue
Milne Point Facilities Supervisor
(907) 670-3331
alternate: George Ahumada

Exhibit 28

04/27/2007 FRI 13:17 FAX 202 289 8992 CLIFFORD & GARDE 002/003

Aug-31-06 08:48am From-House Energy & Commerce Cmte Ford 202-225-2447 T-586 P.002/003 F-087

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515-6115

JOE BARTON, TEXAS
CHAIRMAN

August 31, 2006

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
501 Westlake Park Boulevard
Houston, TX 77079

Dear Mr. Malone:

As you are aware, the House Committee on Energy and Commerce is conducting an investigation into several recent crude oil spills on transmission pipelines operated by BP on Alaska's North Slope. Because these lines transport nearly 8 percent of the country's domestic oil supply, the Committee has great interest in ensuring that no further leaks occur that might threaten human lives, the environment, or reliable production. Accordingly, the Subcommittee on Oversight and Investigations has scheduled a hearing for Thursday, September 7, 2006.

Over the past few weeks, Committee staff has made several informal record requests to BP. While BP has provided many of the requested materials in a timely manner, several important items remain outstanding, including: (1) all records and communications relating to discussions about sludge/sediment, pigging, and/or corrosion on BP's Prudhoe Bay transmission lines (primary focus on the period from January 2006 to the present); (2) a list of engineers who have resigned from the Corrosion, Inspection, and Chemical Group since 2000 and copies of any resignation letters; and (3) an unredacted copy of the Vinson & Elkins Report. The purpose of this letter is simply to memorialize the numerous conversations between BP and Committee staff so there is no confusion as to precisely what remains to be produced.

Accordingly, in support of the Committee's investigation and pursuant to Rules X and XI of the United States House of Representatives, we request that BP provide items (2) and (3), above, as well as any records responsive to item (1) collected to date, by close of business on Friday, September 1, 2006. All records responsive to item (1) should be produced no later than 10:00 a.m. on Wednesday, September 6, 2006. We would also urge timely and complete production of any other relevant records.

04/27/2007 FRI 13:17 FAX 202 289 8992 CLIFFORD & GARDE 003/003

Aug-31-06 05:48am From-House Energy & Commerce Cmte Ford 202-226-2447 T-996 P.003/003 F-007

Mr. Robert A. Malone
Page 2

Thank you for your cooperation. If you have any questions, please contact Andrew Snowdon or Thomas Feddo, Majority Oversight and Investigations Counsel, at (202) 225-2927, or Chris Knauer, Minority Investigator, at (202) 226-3400.

Sincerely,

Joe Barton
Chairman

John D. Dingell
Ranking Member

Ed Whitfied
Chairman
Subcommittee on Oversight
and Investigations

Bart Stupak
Ranking Member
Subcommittee on Oversight
and Investigations

ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515–6115

JOE BARTON, TEXAS
CHAIRMAN

October 4, 2006

Mr. Steve Marshall
President
BP Exploration Alaska, Inc.
900 East Benson Boulevard
P.O. Box 198612
Anchorage, AK 99519-6612

Dear Mr. Marshall:

Thank you for appearing before the Subcommittee on Oversight and Investigations at the September 7, hearing entitled "BP's Pipeline Spills at Prudhoe Bay: What Went Wrong?" We appreciate the time and effort you gave as a witness before the Subcommittee.

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open to permit Members to submit additional questions to witnesses. Attached are questions directed to you from certain Members of the Committee. In preparing your answers to these questions, please address your response to the Member who has submitted the questions and include the text of the Member's questions along with your response. In the event you have been asked questions from more than one Member of the Committee, please begin the responses to each Member on a new page.

To facilitate the printing of the hearing record, your responses to these questions should be received no later than the close of business on Wednesday, October 18, 2006. Your written response should be delivered to 2125 Rayburn House Office Building and faxed to 202-225-1919 to the attention of Matthew Johnson, Legislative Clerk. **An electronic version of your response should also be sent by e-mail to the Legislative Clerk (Matt.Johnson@mail.house.gov) in a single Word formatted document.**

Mr. Steve Marshall
Page 2

Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Matthew Johnson at 202-225-2927.

Sincerely,

Ed Whitfield
Chairman
Subcommittee on Oversight
and Investigations

Attachment

The Honorable Marsha Blackburn

1. How will BP's revenues be affected because of the shutdown?

2. How much are you spending to restore the Eastern Operating Area and upgrade both areas?

3. How often do you "pig" your lines for internal corrosion? Inspect for external corrosion?

4. What is your schedule for each of these types of inspections? Is this the normal industry standard?

5. How long does it take to perform a complete internal and external inspection of all your lines?
   a. Is this on a continual cycle?

6. What is the normal business practice for an oil industry to have a complete inspection of its pipelines?

7. When you identify corrosion problems, what measures do you take?
   a. What is the average time and cost to solve them?

8. What corrosion prevention practices were in place when the West field pipelines were installed?

9. Were there any policies or procedures in place that would be triggered if severe corrosion is detected or might be detected?

10. How long and at what cost does it take to replace or install one mile of a pipeline?

11. How much pipeline is needed to construct a bypass line in the East fields? Can this be done immediately for a temporary fix?
    a. How long would it take a similar type of bypass to be done in the lower 48 states?

The Honorable Michael Burgess

1. Did BP Exploration Alaska receive any warnings from employees that there were possible corrosion problems with these Prudhoe Bay transmission lines?

2. Wasn't the 2004 Vinson & Elkins Investigation, instigated by whistleblower concerns about pipeline integrity, corrosion, and safety that the environmental protection agency shared with BP?

   a. What was the basis for this report?
   b. The Vinson & Elkins Report contains dozens of allegations that concern safety and corrosion issues. Do you have any idea, over the past five years, how many times BP Alaska has been notified by employees or anonymous tips regarding concerns about corrosion in the Prudhoe Bay pipelines?
   c. What does BP do with each of these tips or concerns?
   d. The Vinson & Elkins Report contains an appendix of 72 allegations about the corrosion control program and specific safety concerns. Have all of these issues been addressed to your satisfaction, and completely remedied if necessary, since BP received the law firm's report?
   e. Allegation number 29 points out that some corrosion experts – including one particular individual – resigned over concerns about pipe integrity. This seems very relevant to the topic of corrosion control. So, why wasn't this individual located and interviewed by the Vinson & Elkins investigation?
   f. Wouldn't it be important for BP to contact this individual and determine exactly what his concerns were, and whether they were valid?
   g. Allegation number 19 mentions that agency inspectors are directed to inspect only good areas of the pipeline, although Vinson & Elkins found no evidence of this. Can you speak to the relationship between the Alaska Department of Environmental Conservation and BP Alaska? Can and do inspectors go wherever they want when inspecting BP's pipeline?
   h. Allegation number 10 and 11 describe concerns that over the past several years there have been concerns raised about cost-cutting and that corrosion control and monitoring was suffering – that serious damage was occurring to the pipelines and infrastructure. Has there been cost cutting in the corrosion control program over the past several years?
   i. If the corrosion control budget was increasing, why would Mr. Woollam be aggressively trying to reduce costs? Did company management direct the CIC Group to reduce costs?
   j. It is my understanding that monitoring corrosion coupons is the key to keeping tabs on where corrosion rates are getting too high, so that action can be taken before conditions get too bad. Why then, as the Vinson & Elkins Report decribes, did Mr. Woollam push so hard to reduce the

corrosion coupon team by 25%? Did management direct Wollam to cut the coupon monitoring team?

k. Why did Vinson & Elkins recommend that Mr. Woolam be removed from his management position on the corrosion control team? Was he removed? If so, when did you remove him and why?

l. On page 4 of the appendix, allegation number 13 discusses an allegation of data scrubbing, and allegation number 17 describes concerns that corrosion field data was being manipulated. What does the report mean that no evidence was found of manipulation? In other words, the status comment doesn't explain where the investigation looked for evidence, and seems simply to imply that data may receive a "positive spin"; isn't "spin" and manipulation the same thing?

ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives

Committee on Energy and Commerce

Washington, DC 20515–6115

JOE BARTON, TEXAS
CHAIRMAN

October 4, 2006

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
501 Westlake Park Boulevard
Houston, TX 77079

Dear Mr. Malone:

Thank you for appearing before the Subcommittee on Oversight and Investigations at the September 7, hearing entitled "BP's Pipeline Spills at Prudhoe Bay: What Went Wrong?" We appreciate the time and effort you gave as a witness before the Subcommittee.

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To facilitate the printing of the hearing record, your responses to these questions should be received no later than the close of business on Wednesday, October 18, 2006. Your written response should be delivered to 2125 Rayburn House Office Building and faxed to 202-225-1919 to the attention of Matthew Johnson, Legislative Clerk. **An electronic version of your response should also be sent by e-mail to the Legislative Clerk (Matt.Johnson@mail.house.gov) in a single Word formatted document.**

Mr. Robert A. Malone
Page 2

Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Matthew Johnson at 202-225-2927.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Oversight
and Investigations

Attachment

The Honorable Marsha Blackburn

1. Is ultrasonic testing better than smart pigging to identify corrosion in oil pipelines?

2. Does the oil industry standard on testing for internal corrosion involve ultrasonics, pigging, or both?

3. Has BP expressed any interest in developing the oil in ANWR if the area became available for drilling?
   a. Have the recent incidents affected your future interest in development in ANWR?

4. There have been some concerns about BP's safety record as this incident now joins several other accidents at BP installations. Because of these accidents, did the U.S. Chemical Safety and Hazard Investigation Board order your company to appoint an independent safety review panel? What is the current status of this panel? Is it examining BP's safety management structure and looking at all of BP's installations to determine if there are any safety concerns at any of them?

ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives

Committee on Energy and Commerce

Washington, DC 20515–6115

JOE BARTON, TEXAS
CHAIRMAN

October 4, 2006

Mr. Kurt Fredriksson
Commissioner
Alaska Department of Environmental Conservation
410 Willoughby Ave., Ste. 303
P.O. Box 111800
Juneau, AK 99811-1800

Dear Mr. Fredriksson:

Thank you for appearing before the Subcommittee on Oversight and Investigations at the September 7, hearing entitled "BP's Pipeline Spills at Prudhoe Bay: What Went Wrong?" We appreciate the time and effort you gave as a witness before the Subcommittee.

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Mr. Kurt Fredriksson
Page 2

Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Matthew Johnson at 202-225-2927.

Sincerely,

Ed Whitfield
Chairman
Subcommittee on Oversight
and Investigations

Attachment

The Honorable Michael Burgess

1. Exactly what does the state of Alaska do with the Coffman Reports that you submit to them in final form? How does that state utilize the analyses and recommendations? Can you force BP to undertake the recommended actions within the reports?
   a. In Tab 28; there is an email dated November 20, 2001 in which Richard Woollam notes that Susan Harney explained to him that she was reluctant to enforce changes in that report. Did you share Susan Harvey's view that the document was not unlike an independent third party audit?
   b. Did you or Larry Dietrich or any other ADEC employee ever instruct or pressure Coffman engineers in any way to change the tone and content of the 2000 Coffman Report?

2. In 2001, Did ADEC staff recommend that settlement of the enforcement action (for BP's for failure to install the required leak detection systems) include a requirement to smart pig these pipelines, enhance the corrosion control programs, and require non-destructive testing (NDT) examination?

3. During the period 2000 the present, has anyone from BP, either directly or indirectly, contact you, Larry Dietrick, Michele Brown, or the governor's office to complain about any investigations or enforcement actions that ADEC staff was carrying out with respect to BP operations on the north slope?

4. Are you aware of any instances where an individual or entity outside of the department has requested or pressured ADEC to terminate, reassign, or demote ADEC staff?

ONE HUNDRED NINTH CONGRESS

U.S. House of Representatives

Committee on Energy and Commerce

Washington, DC 20515–6115

JOE BARTON, TEXAS
CHAIRMAN

October 6, 2006

Mr. Kurt Fredriksson
Commissioner
Alaska Department of Environmental Conservation
410 Willoughby Ave., Suite 303
P.O. Box 111800
Juneau, AK 99811-1800

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
501 Westlake Park Boulevard
Houston, TX 77079

Dear Commissioner Fredriksson and Mr. Malone:

Attached please find a copy of Compliance Order by Consent No. 02-138-10 between the State of Alaska and BP Exploration (Alaska) Inc. (BPXA). Several of the issues contained in this Order appear directly related to the spills on the Prudhoe Bay Western Operating Line (WOL) and the Prudhoe Bay Eastern Operating Line (EOL) that were the subject of a hearing by this Committee on September 7, 2006.

As you are aware, on March 15, 2006, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order (CAO) in response to the WOL failure. The CAO delineated specific requirements that BPXA needed to undertake to bring both its Eastern and Western lines into compliance.

Among the several items in the CAO was a requirement that BPXA "pig" several pipelines including the EOL and WOL. Subsequent to the issuance of the CAO, it was revealed that large sections of both the WOL and the EOL contained potentially significant amounts of scale, sludge, and/or other solids. For several months, following the issuance of the March CAO, BPXA attempted to develop solutions to (a) determine the amount of solids in each line, and (b) determine if and how it could pig these lines as required by the CAO. In early August of this year, BPXA discovered, after pigging part of the EOL, that numerous instances of corrosion existed. Upon learning of this corrosion, BPXA subsequently ordered the shutdown of the Prudhoe Bay field.

In our September 7, 2006, hearing, BPXA acknowledged that it should have pigged both the WOL and EOL more frequently and that it had been caught off guard by the amounts of solids that were presently in these lines, particularly the EOL. However, this Compliance Order shows that BPXA was aware in at least 2001 that these lines possibly contained unacceptable amounts of solids and that the lines should be pigged. On page 5 of the Order are the following requirements:

-- Determine sediment levels in EOL and WOL pipelines at Skid 50. [by 3/31/02]
-- Modify EOL pig receiver at Skid 50. [by 3/31/02]
-- Pig EOA pipeline from PS - 1 launcher to Skid 50. [by 6/30/02]
-- Pig WOL pipeline segments if necessary. [by 9/30/02]
-- Test and select flow meters at EOL pipelines, Skid 50 if necessary. [by 9/30/02]
-- Complete WOL crude oil flow smoothing modifications. [by 12/31/02]
-- Install and test meters on all pipelines. [by 12/31/02]
-- Evaluate and establish leak detection systems' compliance. [by 12/31/02]

Had these actions been taken, BPXA would likely have been in a better position to understand the conditions that were forming in both the WOL and EOL -- conditions that ultimately resulted in the failures of these lines. However, it is unclear which, if any, of these actions occurred. Given the potential seriousness of this Order, and the direct relevance to the matters that occurred on both the Western and Eastern lines, we ask that you respond to the following questions by no later than Friday, October 20, 2006:

1. Was this Order received by BPXA? If so, by whom, and what actions were taken? If certain of these actions were not taken, explain why not.

2. The order is signed by a BPXA employee named Mr. Jack M. Fritts who is identified as the Greater Prudhoe Bay Unit Operations Manager. Does Mr. Jack M. Fritts still hold this position with the company? If not, is Mr. Fritts still employed by BPXA? If not, explain why not and provide the Committee with any documents surrounding his departure. Who did Mr. Fritts report to when this Order was signed, and is that person still employed by BPXA?

3. Why was this Order not provided to the Committee by BPXA pursuant to the Committee's document request letter dated August 31, 2006?

4. Prior to their sworn testimony before the Committee on September 7, 2006, was either Mr. Robert A. Malone or Mr. Steve Marshall briefed on or otherwise made aware of the existence of this Compliance Order? If not, why not? If so, why didn't either of them discuss the Order in their

Mr. Kurt Fredriksson
Mr. Robert A. Malone
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written testimony, oral testimony, or in response to questions posed by members of the Committee?

Sincerely,

Joe Barton
Chairman
Committee on Energy
and Commerce

John D. Dingell
Ranking Member
Committee on Energy
and Commerce

Ed Whitfield
Chairman
Subcommittee on Oversight
and Investigations

Bart Stupak
Ranking Member
Subcommittee on Oversight
and Investigations

cc: The Honorable Frank Murkowski, Governor
State of Alaska

The Honorable Ted Stevens, Senator
U.S. Senate

The Honorable Lisa Murkowski, Senator
U.S. Senate

The Honorable Don Young, Member
U.S. House of Representatives

The Honorable Alberto R. Gonzales, Attorney General
Department of Justice

Vice Admiral Thomas J. Barrett, USCG (Ret.), Administrator
Pipeline and Hazardous Materials Safety Administration

Attachment

BEFORE THE STATE OF ALASKA
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

N. McCleary
G. Blankenship
J. Fritz / R Germany
G. Campbell
R. Jacobsen
C. Phillips
R. Klie
M. Merill
N. Glover

In the Matter of:)
STATE OF ALASKA, DEPARTMENT OF)
ENVIRONMENTAL CONSERVATION)
)
Complainant,)
)
vs.)
)
BP Exploration (Alaska) Inc.)
)
Respondent.)

BPXA LAW DEPT
WHG CC RMJ JHH TD SJS DDB
KJW
JUN 3 2002
Fully executed
File:
Copy:

Consent Order No. 02-138-10

COMPLIANCE ORDER BY CONSENT

Whereas the Complainant, the State of Alaska, Department of Environmental Conservation ("ADEC"), and the Respondent, BP Exploration (Alaska) Inc. ("BPXA" or "Respondent"), desire to resolve and settle a disputed matter and to avoid the uncertainty and expense of formal enforcement proceedings, it is hereby agreed as follows:

I. JURISDICTION

1. This Compliance Order by Consent (hereinafter Order) is entered into under the authority of ADEC under AS 44.46.020, AS 46.03.020, AS 46.03.760(e), AS 46.03.765, AS 46.03.850, and 18 AAC 95.160, and the settlement authority of the Attorney General under AS 44.23.020.

II. BACKGROUND

2. BPXA is an owner and the operator of the Greater Prudhoe Bay Unit crude oil transmission pipeline system (hereinafter "FACILITY"). BPXA operates the FACILITY on the North Slope of Alaska, and receives mail at: P.O. Box 196612, Anchorage, Alaska 99519-6612. The FACILITY is a system of "pipelines" as that term is defined in AS 46.04.900(18).

3. In January 1999, ADEC approved and issued to ARCO Alaska Inc.

("AAI") a renewal of oil discharge prevention and contingency plan number 984-CP-4138 for the Prudhoe Bay eastern operating area ("EOA") crude oil transmission pipeline system ("EOA Plan"). Condition of approval number 8 of the EOA Plan required AAI to submit to ADEC a proposed leak detection system for the EOA crude oil transmission pipeline system that met the 1 percent daily throughput standard in 18 AAC 75.055(a) ("1% Standard") and a best available technology ("BAT") analysis for the leak detection system that met the BAT requirement in 18 AAC 75.425(e)(4)(A)(iv) ("BAT Requirement") by the end of August 1999.

4. In January 1999, ADEC approved and issued to BPXA a renewal of oil discharge prevention and contingency plan number 984-CP-4129 for the Prudhoe Bay western operating area ("WOA") crude oil transmission pipeline system ("WOA Plan"). Condition of approval number 8 of the WOA Plan required BPXA to submit to ADEC a proposed leak detection system for the WOA crude oil transmission pipeline system that met the 1% Standard and a BAT analysis for the leak detection system that met the BAT Requirement by the end of August 1999.

5. In August 1999, AAI submitted a proposed leak detection system for the EOA crude oil transmission pipeline system to ADEC. ADEC determined that the proposal was too general, did not include a BAT analysis and, accordingly, was insufficient for review. AAI requested an extension to submit a revised proposed leak detection system and the BAT analysis. ADEC granted an extension to October 15, 1999.

6. In August 1999, BPXA submitted a proposed leak detection system for the WOA crude oil transmission pipeline system to ADEC. ADEC determined that the proposal was too general, did not include a BAT analysis and, accordingly, was insufficient for review. BPXA requested an extension to submit a revised proposed leak detection system and the BAT analysis. ADEC granted the extension to mid October 1999.

7. In October 1999, AAI resubmitted a proposed leak detection system for the EOA crude oil transmission pipeline system and a BAT analysis. ADEC determined these submissions satisfied the EOA Plan condition of approval number 8 requirement and initiated review of both documents under 18 AAC 75.455.

8. In mid-October 1999, BPXA resubmitted a proposed leak detection for the WOA crude oil transmission pipeline system and a BAT analysis. ADEC determined these submissions satisfied the WOA Plan condition of approval number 8 requirement and initiated

review of both documents under 18 AAC 75.455.

9. In June 2000 operational control of the EOA crude oil transmission pipeline system changed from AAI to Phillips Alaska, Inc.

10. On July 1, 2000, BPXA assumed the sole operator role for the EOA and WOA crude oil transmission pipeline systems (the FACILITY).

11. In August 2000, ADEC requested BPXA to submit an engineering package to verify that the proposed leak detection system for the EOA and WOA crude oil transmission pipeline systems would meet the 1% Standard for the FACILITY.

12. In October 2000, BPXA submitted the requested engineering package to ADEC.

13. In December 2000, ADEC determined that the proposed leak detection system for the FACILITY did not meet the 1% Standard and that the BAT analysis did not meet the BAT Requirement. ADEC interpreted the 1% standard as applying to each pipeline segment in the pipeline system, while BPXA's analysis used the combined flow into pump station 1 against which to measure the 1% detection accuracy. ADEC required BPXA to submit a revised leak detection system proposal for the FACILITY that met the 1% Standard and a BAT analysis that met the BAT Requirement by January 31, 2001.

14. In January 2001, BPXA submitted to ADEC a revised leak detection system proposal for the FACILITY that it maintains will meet the 1% Standard.

15. On March 1, 2001, BPXA submitted a BAT analysis to ADEC for the FACILITY leak detection system that it maintains will meet the BAT Requirement.

16. On April 30, 2001 BPXA met with ADEC to discuss BPXA's revised leak detection system proposal for the FACILITY. BPXA agreed to verify that the proposed leak detection system meets the 1% Standard for each pipeline segment by completing 12 action items within specified timelines in 2001. However, PBXA discovered settled solids in some pipeline segments that interfered with the proper functioning and operability of the meters. Those pipeline segments containing solids will need to be cleaned out, which will require the installation of pipeline pigging facilities prior to functional testing of the meters and leak detection system. Due to the unexpected discovery of these solids, BPXA completed only 5 of the action items within the agreed timelines. BPXA expects to complete the remaining action items on or before December 1, 2002.

III. ADEC ALLEGATIONS

COUNT I

17. Since at least December 7, 2000 BPXA has failed to comply with EOA Plan condition of approval number 8 and WOA Plan condition of approval number 8 which require BPXA to submit a leak detection system for the FACILITY that meets the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

18. Based on the facts set out in paragraphs 2-16 above, since at least December 7, 2000 BPXA has operated the FACILITY in violation of AS 46.04.030(b) which requires operation of a pipeline in compliance with an oil discharge prevention and contingency plan.

COUNT II

19. Under this Order, BPXA will not comply with EOA Plan condition of approval number 8 and WOA Plan condition of approval number 8 and, accordingly, will continue to violate AS 46.04.030(b) until BPXA verifies that the proposed leak detection system for the FACILITY meets the requirements in 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

COUNT III

20. Since at least December 7, 2000, BPXA has not equipped the FACILITY with the enhanced leak detection system to satisfy the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv).

21. Based on the facts set out in paragraphs 2-16 above, since at least December 7, 2000, BPXA has been operating the FACILITY in violation of 18 AAC 75.055(a).

COUNT IV

22. Under this Order, BPXA will continue to operate the FACILITY in violation of 18 AAC 75.055(a) until BPXA verifies that the proposed leak detection system for the FACILITY satisfies the requirement in 18 AAC 75.055(a) consistent with 18 AAC 75.425(e)(4)(A)(iv).

IV. REMEDIAL MEASURES

23. In order to address the violations outlined in Counts I-IV of Section III of the Order, the Respondent agrees to complete all outstanding action items to verify that the leak detection system for the FACILITY satisfies both the 1% leak detection requirement in 18 AAC 75.055(a), as applied to each pipeline segment, and the BAT requirement of 18 AAC 75.425(e)(4)(A)(iv). Specifically, BPXA agrees to perform the following tasks by the dates indicated herein:

- Determine sediment levels in EOA and WOA pipelines at Skid 50. [by 3/31/02]
- Modify EOA pig receiver at Skid 50. [by 3/31/02]
- Pig EOA pipeline from FS-1 launcher to Skid 50. [by 6/30/02]
- Pig WOA pipeline segments if necessary. [by 9/30/02]
- Test and select flow meters at EOA pipeline, Skid 50 if necessary. [by 9/30/02]
- Complete WOA crude oil flow smoothing modifications. [by 12/31/02]
- Install and test meters on all pipelines. [by 12/31/02]
- Evaluate and establish leak detection systems' compliance. [by 12/31/02]

24. BPXA and ADEC agree to meet and/or confer as necessary to reach a common understanding of the meaning and interpretation of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv), and to evaluate the Facility's compliance with those regulations.

V. TIME FOR COMPLIANCE

25. Time is of the essence in the Order. Failure to submit any document or make any payment by the deadlines set forth in this Order is a violation of the Order triggering any suspended damages and penalties unless a written extension of time is obtained from ADEC pursuant to paragraph 27.

26. Failure to submit any document or make any payment by the deadlines set forth in the Order, unless a written extension of time is obtained from ADEC pursuant to paragraph 27, may also terminate or serve as the basis for termination of the Order.

27. ADEC, in its discretion, may grant a written extension of time if the Respondent requests the extension prior to the deadline, and proves to the satisfaction of ADEC that any delay is beyond the control of the Respondent due to unforeseen circumstances such as adverse weather or natural disaster. Increases in costs incurred by the Respondent shall not be a basis for any extension of time. Any request for an extension of time must be provided in writing. A request for an extension of time does not toll any deadlines unless ADEC provides a written extension.

28. Unless otherwise specified, all references to days in this Order are to calendar days; however, if a deadline occurs on a weekend or legal holiday the deadline is extended to the next working day.

VI. ADMINISTRATION FEES

29. The Respondent agrees to reimburse ADEC for ADEC and Department of Law staff time spent developing and implementing this Order.

VII. OTHER PAYMENTS

30. Damages and Penalties. The Respondent agrees to pay damages and penalties pursuant to AS 46.03.760(e) as follows:

a. the Respondent agrees to pay the State of Alaska the sum of $300,000 in damages and penalties, with $150,000 suspended on the condition that the Respondent complies with all terms and conditions of the Order to the reasonable satisfaction of ADEC. For purposes of this Order, $121,000 represents economic savings realized by the Respondent in not complying with the requirements for which the violations were alleged; and $29,000 represents the "gravity component" designed to deter future noncompliance;

b. the Respondent agrees to pay the State of Alaska the unsuspended portion of the damages and penalties, $150,000, within thirty days of the effective date of the Order;

c. the Respondent agrees to pay the State of Alaska the suspended portion of the damages and penalties within seven calendar days after failing to submit any document or make any payment by the deadlines set forth in the Order, or after receiving notice of termination if the Order is terminated pursuant to the provisions of paragraph 43(a) or 43(b) of this Order;

d. all payments under this section shall be made payable to the State of Alaska, Department of Environmental Conservation, shall include the number of the Order, and shall be directed to the Attention of: Cost Recovery Unit, SPAR Director's Office, Alaska Department of Environmental Conservation, 410 Willoughby Ave., Suite 105, Juneau, Alaska 99801-1795.

31. If any payment required by paragraph 30 of the Order is not made, or if any negotiable instrument presented as payment is not honored, ADEC may file a civil action to collect the amount due under the Order, plus interest, attorney's fees, and costs. In any collection action, the validity, amount, and appropriateness of damages and penalties is not subject to review.

VIII. RESERVATION OF RIGHTS

32. The requirements, duties, and obligations set forth in the Order are in addition to any requirements, duties, or obligations contained in any permit or plan approval which ADEC has issued or may issue to the Respondent and are in addition to any requirements, duties, or obligations imposed by State, local, or federal law. Other than as expressly provided herein, the Order does not relieve the Respondent from the duty to comply with requirements contained in any such permit or plan approval or with any State, local, or federal law.

33. ADEC expressly reserves the right to initiate administrative or legal proceedings relating to any violation not expressly described in Counts I-IV of Section III of the Order. In addition, ADEC expressly reserves the right to initiate administrative or legal proceedings and to seek additional civil assessments or seek injunctive relief for violations described in the Order if the Respondent does not comply with the provisions set forth herein to the reasonable satisfaction of ADEC or if, in ADEC's reasonable opinion, subsequently discovered events or conditions constitute an immediate threat to public health, public safety, or the environment, regardless of whether ADEC may have been able to discover the event or condition prior to entering into the Order. In the event that ADEC seeks civil assessments for violations described in the Order, amounts required to be paid under paragraph 30 of the Order may offset any subsequent assessments for those violations, but in no event shall a refund of any

portion of the penalties and damages assessed in this Order be required.

34. In signing the Order, the Respondent and ADEC do not admit, and reserve the right to controvert in any subsequent proceedings, other than for enforcement of the Order, the validity of, or responsibility for, any of the factual or legal determinations made herein.

IX. COVENANT NOT TO SUE

35. Subject to the provisions of Section VIII (Reservation of Rights), and provided the Respondent complies with the terms of the Order to the reasonable satisfaction of ADEC, ADEC shall not institute any further action against the Respondent for the violations alleged in Counts I-IV of Section III of the Order. However, nothing herein shall be construed as limiting ADEC's right to seek damages, penalties, and fines for violation of the terms and conditions of the Order.

36. The Respondent acknowledges and agrees that the Order constitutes a lawful order of ADEC for the purposes of AS 46.03.760, AS 46.03.765, AS 46.03.790, AS 46.03.850, 18 AAC 95.160 and for all other purposes. The Respondent shall not institute any action challenging the validity of the Order or the authority of ADEC to enforce the Order. The Respondent shall not controvert or challenge, in any subsequent proceedings initiated by the State of Alaska, the validity of the Order or the authority of ADEC to issue and enforce the Order.

37. The Respondent acknowledges that, by executing the Order, with regard to violations alleged in Counts I-IV of Section III of the Order, it is waiving the rights and procedures that would otherwise protect it in any formal administrative adjudicatory proceeding or any civil action in a court of law including the right to the filing of a notice of intent, to present evidence and witnesses on its behalf, to cross-examine ADEC's witnesses, to a jury trial, and to administrative and judicial review. The Respondent acknowledges that it is knowingly and voluntarily waiving these rights.

X. DISPUTE RESOLUTION

38. The parties agree to make reasonable efforts to informally resolve at the staff level all disputes that may arise in connection with this Order. If any dispute is still unable to be resolved, the Respondent may make a written request for the ADEC Commissioner or the Commissioner's delegate to resolve the dispute. The pendency of any dispute pursuant to this

paragraph shall not affect Respondent's responsibility for timely performance of the requirements of the Order. The Commissioner or the Commissioner's delegate will issue a final determination in writing. The written decision will be final for purposes of judicial review pursuant to Alaska Rule of Appellate Procedure 602(a)(2). The determination of the Commissioner or the Commissioner's delegate will remain in effect pending resolution of any judicial appeal unless a stay is sought and granted by the court on appeal.

XI. REPORTING

39. BPXA will submit monthly reports to ADEC that summarize activites undertaken under this Order. Either BPXA or ADEC may request a meeting at any time to discuss issues associated with this Order, and the party receiving such a request shall make itself available as promptly as practicable.

XII. JURISDICTION AND VENUE

40. Any judicial action brought by either party to enforce or adjudicate any provision of the Order shall be brought in the Superior Court for the State of Alaska, Third Judicial District at Anchorage.

XIII. EFFECTIVE DATE

41. The effective date of the Order shall be the date of the last signature when the Order is signed by authorized representatives of the BPXA, ADEC and the Alaska Attorney General's Office.

XIV. SUCCESSORS

42. The Order shall be binding upon the Respondent, its agents, successors, and assigns (including any lessee or grantee of the FACILITY), and upon all persons, contractors and consultants acting on behalf of the Respondent. The Respondent shall incorporate a copy of the Order into any conveyance of its interest in the FACILITY and into any lease or management agreement, and shall require in any conveyance that the grantee or lessee shall comply with all of the requirements of the Order.

XV. TERMINATION

43. The Order shall terminate on the first to occur of the following:

a. the day after the Respondent misses a deadline imposed under paragraph 23, unless the delay is excused pursuant to paragraph 27;

b. the day after ADEC notifies the Respondent that ADEC is terminating the Order due to the Respondent's failure to comply with any of the provisions set forth herein to the reasonable satisfaction of ADEC;

c. the day after ADEC issues a voluntary written termination of the Order; ADEC will terminate the Order upon request if Respondent establishes to ADEC's satisfaction that it has established compliance for all of the issues outlined in Counts I-IV of Section III of the Order and has complied with the provisions of this Order.

DATED: 5/29/02

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

By: Jeffrey L. Mach

Jeff Mach
Oil and Gas Coordinator

DATED: 30 May 2002

BRUCE M. BOTELHO
ATTORNEY GENERAL

By:

Cameron Leonard
Assistant Attorney General

DATED: 05-14-02

BP EXPLORATION (ALASKA) INC.

By: Jack M. Fritts

Jack M. Fritts
Greater Prudhoe Bay Unit ~~Field~~ Operations Manager

I, JACK M. FRITTS, hereby certify that I hold the position of Greater Prudhoe Bay Operations Manager and that I am a responsible official for the Respondent's FACILITY and that I have the authority to enter into agreements on behalf of the Respondent and the FACILITY and to otherwise legally bind the Respondent and the FACILITY. I hereby acknowledge that I have freely and voluntarily entered into this agreement with the State of Alaska on behalf of the Respondent.

SUBSCRIBED AND SWORN to before me this 14th day of May, 2002.

MONICA P. BREWSTER NOTARY PUBLIC STATE OF ALASKA

Monica P. Brewster
Notary Public, State of Alaska
My commission expires:

My Commission Expires
November 9, 2004

bp

Stephen A. Elbert
Vice Chairman

BP America Inc.
4101 Winfield Road
Suite 300
Warrenville, IL 60555

Direct +1 630 821 2573
Fax +1 630 821 2582
Mobile +1 630 915-8053

April 17, 2007

BY HAND DELIVERY

The Honorable Bart Stupak
Chairman of the Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
United States House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Ed Whitfield
Ranking Member of the Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
United States House of Representatives
2411 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Stupak and Rep. Whitfield:

I am writing to summarize the responses of BP America, Inc. to the various inquiries by the Subcommittee on Oversight and Investigations.

Document Requests and Productions To Date

In light of the many discussions over the last year among various BP America ("BPA") and BP Exploration Alaska ("BPXA") and Subcommittee representatives about the nature and scope of the Subcommittee's inquiry and how BPA can best be helpful, I thought it would be useful to summarize where we are. Based on those discussions, I understand the Subcommittee to be interested in the following categories of documents relating to our North Slope operations in Alaska: (1) maintenance and "smart" pigging of the oil transit lines, (2) knowledge of sediments in the oil transit lines prior to the March and August 2006 incidents, with a primary focus on the period from January 2006 to the present, and (3) budgeting for the corrosion program from 2000 to 2006. The Subcommittee staff has made clear that it did not want *all* documents relevant to these issues, the universe of which could be quite voluminous, but, rather, a subset of documents that would, in the company's opinion, appear to be most relevant to the Subcommittee's inquiry.

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decisions. For example, some of the documents discuss pipelines other than the oil transit lines, and many do not indicate whether subsequent actions were taken in connection with an issue discussed in a particular document. To provide the relevant context, without overwhelming the Subcommittee with additional documents, we would like to provide a substantive briefing to Subcommittee staff. We would, of course, also be happy to expand on any part of the search, if that would be helpful.

Finally, this production contains highly sensitive business and financial information regarding the operations of BPXA. Accordingly, BPA respectfully requests that these documents be maintained confidentially and that, if the Subcommittee wishes to consider whether any of these documents should be made public, BPA and BPXA be given an opportunity to be heard on that question. In addition, please note that, to the extent that any documents produced to the Subcommittee and information contained in this letter are protected by the attorney-client privilege, work product doctrine, or other applicable privilege, such documents and information have been provided at the Subcommittee's request and in response to the Subcommittee's assertion of authority to compel such documents. By providing these documents and information to the Subcommittee, BPA has not waived and does not intend to waive its ability to assert such privileges in other fora.

Company Inquiries and Assessments

In addition to the requests for documents addressed above, the Subcommittee has asked BPA to share the results of certain internal inquiries and assessments and to undertake an independent investigation to address specific concerns raised by the Subcommittee. The company has been working with the Subcommittee to address those requests.

(1) *Booz Allen Hamilton Report.* On April 5, 2007, BPA produced to you a copy of a confidential report conducted by the consulting firm Booz Allen Hamilton at BPA's request. This report assesses BPXA's organizational structure, processes, information systems, and management practices as they relate to the operation of the oil transit lines and identifies potential non-technical root causes and contributing factors to the March and August 2006 leaks. On April 10, 2007, Tom Williams (the primary investigator for the report from Booz Allen) and Bob Malone (Chairman and President of BPA) provided a briefing on the report at the Subcommittee's request.

(2) *COBC Report.* Last fall, the Subcommittee requested that BPA undertake an independent inquiry into specific issues relating to a 2002 compliance order by consent ("COBC"), which was produced to the Subcommittee after the September 2006 hearings. In October 2006, BPA retained Billie Garde to conduct this inquiry. On March 30, 2007, Ms. Garde and her colleague Mr. John Clifford briefed Subcommittee staff on her interim findings. BPA expects to produce the final report to the Subcommittee upon its completion.

(3) *Investigation into Worker Concerns.* As you know, last fall, BPA appointed Hon. Stanley Sporkin, a retired federal judge, to serve as the independent ombudsman. One of the assignments to the Office of the Ombudsman was a review of all technical concerns raised by workers (employee and contractor) on the North Slope of Alaska since 2000. While significant progress has been made, and no issues have been identified that presented imminent safety

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concerns, the review is not yet complete. When the project is complete, BPA will ask a representative of the Ombudsman's Office to brief the Subcommittee on the conclusions.

* * *

With the production today and those noted above, we have responded to the Subcommittee's inquiries with the exception of the anticipated production of the COBC report and the briefing by the Ombudsman's office regarding worker concerns. If you feel that further information would be helpful, please let me know. Over the course of this process, we have gained insight into some of the issues addressed in the earlier hearing, and we hope that today's production and the reports produced over the past seven months help round out the picture and provide additional context for the company's responses at the hearing and in our correspondence with the Subcommittee and the Committee.

We reiterate our commitment to cooperate fully with the Subcommittee in an open manner. If the Subcommittee has any remaining questions concerning its requests for information to date or BPA's responses to those requests, please feel free to contact me directly. My team and I welcome the opportunity to discuss these matters with you.

Sincerely,

Stephen A. Elbert

Stephen A. Elbert

Enclosures

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In an attempt to expedite production, the company initially relied primarily on the institutional knowledge of BPXA and its employees' personal recollections to identify responsive documents. This process, combined with responses to Subcommittee requests for specific documents, resulted in our production to you of about 700 documents, primarily reports by third-party and internal investigators and correspondence with, and productions to, the Department of Transportation.

Today, BPA is supplementing that initial production with additional documents responsive to the Subcommittee's requests (Bates numbers BPXA-CEC00006970 to BPXA-CEC00010587). This production includes documents that are the product of searches[1/] of a database of more than 20 million documents developed in response to subpoenas issued by the U.S. Department of Justice ("DOJ") and the Alaska Department of Environmental Conservation ("ADEC"), as well as documents that were identified by attorneys in preparation for the September 2006 hearings.[2/] As the document collection efforts in response to the subpoenas have continued, additional documents have been added to the database since the searches were conducted.

We hope and expect that this process has identified documents responsive to the Subcommittee's interests. It is important to note that the process was designed to be responsive to the Subcommittee's request for only certain types of documents without a voluminous production. As a result, the documents produced today do not tell a comprehensive story and, because they lack context, may create an inaccurate picture of the company's actions and

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[1/] Documents from the database relating to pigging and to sediments were identified through the following database search process. First, a database containing more than 20 million documents collected primarily from BPXA was sorted using search terms developed by BPA's outside counsel, Vinson & Elkins, based on the DOJ and ADEC subpoenas and areas of inquiry identified by the Subcommittee. As a result, approximately 2.5 million documents have been identified as potentially relevant, reviewed, and categorized by attorneys. Second, to target documents most relevant to the Subcommittee's interests, attorneys isolated potentially relevant documents using category searches and conducted supplemental word searches. This process yielded approximately 21,000 documents. Third, Vinson & Elkins attorneys then reviewed the 21,000 documents and identified highly relevant documents.

Documents from the database relating to corrosion program budgeting are less susceptible to identification through search terms. Accordingly, those documents were identified through a more targeted search, including direct requests for documents from employees involved in the budgeting process, and focusing on year-end budgeting documents rather than voluminous documents related to budget planning and revisions to those plans.

[2/] Documents related to pigging bear the Bates numbers BPXA-CEC00009252 to BPXA-CEC00010587. Documents related to sediments bear the Bates numbers BPXA-CEC00007223 to BPXA-CEC00009251. Documents related to budgeting for the corrosion program bear the Bates numbers BPXA-CEC00006970 to BPXA-CEC00007222. All documents within each subset have been arranged in chronological order for ease of review.

ONE HUNDRED TENTH CONGRESS

U.S. House of Representatives

Committee on Energy and Commerce

Washington, DC 20515–6115

JOHN D. DINGELL, MICHIGAN
CHAIRMAN

April 30, 2007

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
200 Westlake Park Boulevard
Houston, TX 77079

Dear Mr. Malone:

BP recently provided documents to the Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce that suggest a severe cost-cutting atmosphere existed between 2000 and 2005 in crude oil production operations at Prudhoe Bay. Last week, BP representatives met with Committee staff to discuss these documents and explain what impact budget cuts may have had on Prudhoe Bay's Corrosion, Inspection, and Chemicals Group (CIC), which was responsible for corrosion mitigation at BP Exploration (Alaska) Inc. BP's representatives also commented on whether these budget cuts were in any way associated with the recent failures that led to last year's shutdown of the Prudhoe Bay field.

The documents suggest that budget pressures were severe enough that some BP field managers were considering measures as draconian as reducing corrosion inhibitor to save money. BP provided e-mails that detail proposals to cut funding for corrosion inhibitor during at least two different years and in two different locations. These locations included the "produced water" lines that are highly susceptible to corrosion. If senior BP managers were willing to consider turning off inhibitor at these locations, it suggests a budgetary environment in which other corrosion management activities may have been eliminated or reduced to a degree that may have directly affected corrosion of the portions of the oil transit lines (OTL) that experienced leaks last year.

Similarly, the documents suggest that corrosion-monitoring efforts such as smart pigging, coupon pulling, and digging up road crossings for visual inspection, were either reduced, put on hold, or "squeezed" in some cases due to budget constraints. In other words, important action items related to health, safety, and the environment, were being delayed, or cut altogether, and that this was related to tight budgets possibly in an effort to maintain "flat lifting costs."

The documents provided to the Subcommittee confirm that people on the front lines of corrosion management believed that they were under extreme pressure, and they were attempting to do their best with what they had. As you prepare your testimony for the Subcommittee's hearing regarding operations at Prudhoe Bay, we ask that you be prepared to discuss your understanding of the impact that budget had on the CIC Group and how this may have affected both employee morale and the integrity of the corrosion monitoring program, including the willingness to raise concerns regarding imprudent decisions. As long as BP lacks an understanding of the environment in which these individuals were working, we remain skeptical that effective policies can be implemented to prevent recurrences of these kinds of incidents.

In light of this recent information, we ask that you include in your written testimony responses to the following questions regarding the CIC group's corrosion mitigation efforts:

1. At any time from 2000 to 2005, did BP managers order corrosion inhibitor injection to be turned off, specifically to save money or stay within budget constraints? If so, where in the system did this occur, during which dates, and what potential impact did such actions have on the lines or systems when it was halted?

2. On April 15, 2004, an e-mail was sent to Messrs. Kip Sprague and Richard Woollam in the CIC Group (Bates number 7159) referring to a proposal to cancel corrosion inhibitor at "GC's." Assuming that this abbreviation refers to the Gathering Centers, where within the Gathering Centers was the halting of inhibitor being proposed (regardless of whether such action was ever taken)? In view of the changing composition of crude oil being produced at Prudhoe Bay, would reducing corrosion inhibitor at the Gathering Centers have any impact on "carry over" to the OTLs that leaked?

3. Provide all records related to any requests for smart pigging and maintenance pigging from any officials in the CIC Group for the years 2000 through 2005.

4. Provide all e-mails sent and received by the CIC Group involving reducing, suspending, or cutting back on corrosion inhibitor, or any general concerns regarding corrosion in the OTLs.

Mr. Robert A. Malone
Page 3

If you have any questions on this matter, please contact us or have your staff contact Christopher Knauer or Richard Miller with the Majority Committee staff at (202) 226-2424, or Dwight Cates with the Minority Committee staff at (202) 225-3641.

Sincerely,

John D. Dingell
Chairman

Bart Stupak
Chairman
Subcommittee on Oversight and Investigations

cc: The Honorable Joe Barton, Ranking Member
Committee on Energy and Commerce

The Honorable Ed Whitfield, Ranking Member
Subcommittee on Oversight and Investigations

bp

Robert A. Malone
Chairman & President

BP America Inc.
4101 Winfield Road
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USA

April 30, 2007

The Honorable Bart Stupak
Chairman
Oversight and Investigations
Committee on Energy and Commerce
2352 Rayburn House Office Building
Washington, DC 20515

The Honorable Ed Whitfield
U.S. House of Representatives
2411 Rayburn House Office Building
Washington, DC 20515

Direct 630 821 2588
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MaloneRA@bp.com

Dear Chairman Stupak and Representative Whitfield:

A hearing currently is scheduled before the Subcommittee on May 3, 2007, as a follow on to the September 7, 2006 hearing regarding the Prudhoe Bay issues resulting from the two Oil Transit Lines (OTLs) on the North Slope of Alaska. For the reasons explained below, BP respectfully requests that the hearing be rescheduled.

First, it has recently come to my attention that information relevant to the September, 2006 hearing was not provided to the Subcommittee – or to the President of BP Alaska or me. By way of background, as you know, I commissioned an investigation into the reasons that the OTL leak detection Compliance Order by Consent (COBC) was not disclosed to the Subcommittee prior to the first hearing. While that investigation is not yet complete, I have received, reviewed and provided to the Subcommittee staff the Interim COBC Report.[1] The Interim COBC Report identified a breakdown in our response and preparation process that resulted in relevant documents not being provided. Some of these documents are the same documents that the Subcommittee staff has identified as raising questions on the impact of the budget process on operational decision-making during 2000 - 2005.

Second, some of the documents recently produced to the Subcommittee staff raise concerns about previous spending decisions that cause me concern. We need time to determine how the concerns and frustrations expressed by workers were ultimately resolved. For example, as set out in some of the documents, it appears that there were serious discussions about discontinuing injection of corrosion inhibitor into some of the Produced Water lines in 2001- 2004. I do not know whether this happened at all; or, if it did, for how long, or what was the impact on the lines. I want to have, and I want the Subcommittee to have, a complete understanding of what happened in this case and why.

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[1] I am advised that the final investigation cannot be completed until all the relevant documents are reviewed and any necessary follow up interviews are completed.

The Honorable Bart Stupak
The Honorable Ed Whitfield
April 30, 2007
Page Two

Additionally, I was troubled to see in some of the documents the extent of the frustration being expressed by the workforce throughout the 2000-2005 time frames. I want to eliminate the frustration voiced in many of the documents by creating a culture in which workers are confident their concerns will be heard and addressed before they would ever reach the level of frustration expressed in these historical documents. This process takes time, but I believe that we are making changes in the way we manage our business, and in building a positive safety culture.

I recognize that the Subcommittee wants to ensure that BP fully understands what led to the situation in Alaska and that it incorporates the lessons learned into its processes going forward. I want to do that as well. In order to do that, I would request additional time to complete investigations and document searches, and to ensure that the Subcommittee staff has all of the information it needs to complete its work.

Finally, as we have explained to the Subcommittee staff on a number of occasions, BP is involved in a substantial document production process in cooperation with various governmental investigations of the Prudhoe Bay spills of 2006.[2] Despite enormous effort the database is not yet complete. In some cases, the searches may have to be refined. As a result some of our responses on specific issues are not yet complete, while certain questions may require additional information, research and investigation. This will also apply to responding to the document request that we understand the Subcommittee is submitting to us today.

It has always been my intention to be fully responsive to the Committee, and I apologize for the breakdown in our process that has occurred. For these reasons, I respectfully request that the May 3 hearing be rescheduled so that we are able to more fully develop the record prior to the hearing.

Regards,

Robert A. Malone

[2] As we said in our transmittal letter of April 17, 2007, we have created a searchable database of over 20 million documents, which we winnowed down in the interest of providing the subset of documents that appeared most relevant to the Subcommittee's interests. Our letter noted that we anticipated and welcomed additional questions. Following our further discussions with Subcommittee staff, we are searching for additional responsive documents and will invest the time and resources needed to provide them.

ONE HUNDRED TENTH CONGRESS

U.S. House of Representatives

Committee on Energy and Commerce

Washington, DC 20515–6115

JOHN D. DINGELL, MICHIGAN
CHAIRMAN

May 2, 2007

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
200 Westlake Park Blvd.
Houston, TX 77079

Dear Mr. Malone:

We are in receipt of your April 30 letter (attached) requesting a postponement of the hearing scheduled for May 3, 2007, before the Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce entitled "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" This hearing had been planned for some time as a follow up to our September 7, 2006, hearing. It was intended to assess the adequacy of efforts BP and various regulators have taken to address the organizational and mechanical failures leading to the March 2, 2006, leak in the "Western Operating Area" transit line and the subsequent discovery of severe corrosion and leaking in the "Eastern Operating Area" transit line.

Your request for a postponement of the hearing is based upon your recent discovery that "information relevant to the September, 2006 hearing was not provided to the Subcommittee." In addition, this information was apparently neither disclosed to you nor Steve Marshall, the former President of BP Alaska, before your testimony at our September hearings. The discovery of this material has clearly raised questions about the adequacy of your response to the Committee, as well as previous spending decisions made by your company—concerns that you clearly acknowledge in your April 30 letter and that form the basis for your request for additional time to investigate both issues in more detail.

Despite numerous requests for such material, going back nearly a year, it was only on April 17, 2007, that BP provided the Committee with a number of BP documents which reveal important internal discussions suggesting a severe cost-cutting atmosphere existed in your crude oil production operations at Prudhoe Bay. On their face, this new material raises concerns that shortsighted cost-cutting may have led to the spills and corrosion problems in Alaska. Some of

Mr. Robert A. Malone
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the documents discuss stopping the injection of corrosion inhibitor to meet budget targets. Others suggest that other activities related to corrosion mitigation had to be reduced or put on hold due to budget constraints.

Equally troubling, these documents raise questions about the accuracy of Mr. Marshall's testimony when he suggested that "cost is not a consideration" as it relates to issues of both safety and integrity in Prudhoe Bay operations.

It is our understanding that significant redesign and rebuilding has already occurred on some of the key transit lines that failed last year. It is also our understanding that BP has made a number of management and personnel changes in Alaska, and that these efforts appear to be taking the company in a positive direction. We applaud your company for those undertakings. Nevertheless, to assess whether BP's new path forward will be successful, the Committee needs to explore whether the climate of top down cost-cutting affected the health, safety, or the environment of the Prudhoe Bay field and its workers. In order to make such a determination, we need you to respond to the questions raised by the newly discovered documents, as well as all previous requests for information made by this Committee.

As you know, in response to our receipt of the newly discovered documents, we forwarded to you another document request on April 30, 2007, which included: (1) documents that discuss whether BP managers ordered that corrosion inhibitor be turned off due to budgetary constraints; (2) answers to the question of if, when, and where corrosion inhibitor may have been turned off, and what consequences this may have had on program integrity; (3) records related to requests for smart pigging and maintenance pigging from officials in the Prudhoe Bay's Corrosion, Inspection, and Chemicals (CIC) Group from 2000-2005; and (4) e-mails sent or received by the CIC group related to reducing, suspending, or cutting back on corrosion inhibitor.

We are pleased that BP has promised to respond quickly to this request and accept BP's explanation that it needs "additional time to complete investigations and document searches, and to ensure the Subcommittee has all of the information it needs to complete its work."

Based upon your assurances that you need additional time to comply with our document requests and to be prepared to respond to the issues raised by the newly discovered internal BP documents, we have acquiesced to your request for a continuance and have rescheduled the hearing for 9:30 a.m. on Wednesday, May 16, 2007. At that hearing, we expect you and other BP officials to be prepared to address the following issues:

- BP's plan to rebuild and sustain the integrity of the oil pipeline system, including the Eastern Operating Area and Western Operating Area transit lines that failed and caused last year's shutdown. How is this effort progressing and what are the expected milestones for completion?

Mr. Robert A. Malone
Page 3

- Whether BP believes the environment of cost-cutting as apparently reflected in some of these documents affected the ability of workers to safely operate the Prudhoe Bay field and, in particular, ensure adequate corrosion control. To the extent BP believes these documents do suggest a climate where workers had to make difficult decisions between budget savings and program integrity, what steps does the company intend to take to prevent the reoccurrence of such an atmosphere?

- What role did top down cost-cutting play in both Texas City and Alaska? What changes is BP institutionalizing that would reflect the lessons learned from both Texas City and Alaska, as identified in the Baker Panel report, the Booz Allen Hamilton report, and the Chemical Safety Board Investigation report?

- How will BP ensure that there is no tolerance for retaliation against workers who may attempt to raise safety and health concerns? In addition, as new concerns arise, how will BP put in place a transparent mechanism to ensure they are resolved in a timely manner?

If you have any questions regarding this matter, please contact us or have your staff contact Christopher Knauer or Richard Miller with the Committee staff at (202) 226-2424.

Sincerely,

John D. Dingell
Chairman

Bart Stupak
Chairman
Subcommittee on Oversight and Investigations

Attachment

cc: The Honorable Joe Barton, Ranking Member
Committee on Energy and Commerce

The Honorable Ed Whitfield, Ranking Member
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce

bp

Stephen A. Elbert
Vice Chairman

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May 3, 2007

BY HAND DELIVERY

The Honorable Bart Stupak
Chairman of the Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
United States House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Ed Whitfield
Ranking Member of the Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
United States House of Representatives
2411 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Stupak and Rep. Whitfield:

I understand that the Subcommittee has requested the reports of the Process Safety Management ("PSM") Systems Compliance Audit at the Texas City Refinery, conducted by AcuTech Consulting Group in 2006. BP America Inc. ("BPA") is today producing the report of the AcuTech audit, which was delivered in two parts in June and August 2006. We are also producing AcuTech's first Progress Report against its audit recommendations, dated February 2007. In the interest of completeness, we are also producing three "statements of action," which BP Products North America prepared in July 2006, September 2006, and March 2007. These documents have all previously been provided to the Occupational Health and Safety Administration. BPA is producing these documents **[BPXA-CEC00010822** through **BPXA-CEC00011781]** in response to the Subcommittee's request.

In addition, I understand that the Subcommittee has requested that BPA provide a summary of its understanding of common themes, or "crosswalks," between the Chemical Safety Board, Booz Allen Hamilton, Independent Panel, Fatal Accident Investigation ("Mogford"), and Management Accountability Project reports. BPA is producing a document **[BPXA-CEC000011782]** in response to the Subcommittee's request.

I am also providing to you the Final Report of the Management Accountability Project on the Texas City Isomerization Explosion ("Management Accountability Report") **[BPXA-CEC00011783** through **BPXA-CEC00011836]**. Although the report is not directly responsive to the Subcommittee's requests for documents or information, BPA wishes to make the

Chairman Stupak
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Page 2

Subcommittee aware of this document, which has been subject to a protective order but which, as of today, has been made public by a third party.

The Management Accountability Report is the product of an internal BP management review aimed at assessing whether BP managers and executives in the Refining reporting chain properly discharged their accountabilities in connection with the Texas City incident in March 2005. The assessment was conducted confidentially and was completed in February 2007. Pursuant to a document request from plaintiffs in the tort litigation related to the Texas City incident, BP thereafter produced the report subject to a protective order, which has expired. BP has litigated the issue whether the protective order should remain in effect and has not prevailed; plaintiffs have elected to release the report.

BP nonetheless continues to treat the report as a confidential internal document. As a matter of policy, BP does not comment on personnel matters and does not intend to comment on the specific contents of the report, the individuals discussed in the report, or any actions taken or contemplated as a result of the report. Because of the privacy concerns associated with the document, and notwithstanding the use that plaintiffs in the tort litigation have made of it, BPA respectfully requests that the report not be released publicly by the Subcommittee at this time.

This production contains highly sensitive business and financial information. Accordingly, BPA respectfully requests that these documents be maintained confidentially and that, if the Subcommittee wishes to consider whether any of these documents should be made public, BPA and BPXA be given an opportunity to be heard on that question. In addition, please note that, to the extent that any documents produced to the Subcommittee and information contained in this letter are protected by the attorney-client privilege, work product doctrine, or other applicable privilege, such documents and information have been provided at the Subcommittee's request and in response to the Subcommittee's assertion of authority to compel such documents. By providing these documents and information to the Subcommittee, BPA has not waived and does not intend to waive its ability to assert such privileges in other fora.

If the Subcommittee has any questions concerning this request for information or other matters, please feel free to contact me directly. We welcome the opportunity to discuss these matters with you.

Sincerely,

Stephen A. Elbert

Stephen A. Elbert

Enclosures

Booz | Allen | Hamilton

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McLean, VA 22102

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May 13, 2007

The Honorable John D. Dingell
Chairman, Committee on Energy and Commerce

The Honorable Bart Stupak
Chairman, Subcommittee on Oversight and Investigations
United States House of Representatives
Washington D.C. 20515-6115

Dear Congressmen Dingell and Stupak,

This letter is pursuant to your inquiry to Mr. Robert Malone, President of BP America, dated May 11, 2007.

No one at BP pressured any member of the Booz Allen Hamilton Inc. team to change any aspect of the report. The allegation to this effect that has appeared in the press is entirely groundless.

Booz Allen discovered the need to update the information on page 72 of the report as a result of our reviewing the 2004 AFEs that were provided to us by Rick Cape on April 24, 2007, and in response to requests for clarification on this and other aspects of the report from BP on April 30. We take professional integrity and ethics very seriously, and willingly make revisions as needed. We brought this matter to the attention of BP America on May 7, 2007.

The March 2007 Booz Allen report referred to in the Committee's letter was prepared based on work that was conducted for BP on a "best efforts" basis in a relatively short time frame over the winter holiday period. The revision to page 72 of the report does not alter its findings and recommendations.

Over the course of the project, Booz Allen conducted over 100 interviews and reviewed thousands of pages of documents. However, our review was not exhaustive and we had to make informed judgments based on the information available to us.

The Honorable John D. Dingell
The Honorable Bart Stupak
May 14, 2007
Page 2

What analysis (including interviews) did Booz Allen Hamilton conduct in support of the sentence as written? How did Booz Allen Hamilton conclude that the OTL was proposed to be pigged?

The Booz Allen team interviewed BPXA management, GPB Field management, CIC management and staff, and commercial management to understand the budget process (interview notes enclosed). In addition, we reviewed financial reports and an extensive body of email traffic. Many of these emails deal with technical and budget issues.

The email traffic in documents labeled BPXA-CEC00007003-7005 from May 2001 follow an email exchange involving CIC and the GPB Technical Services Director regarding the impact of a budget over-run on CIC activities. A number of corrosion management activities are put on "hold." The team noted this and looked for similar patterns in later years.

The team believed they found a similar pattern, involving many of the same principals, in emails labeled BPXA-CEC00007126-7129, BPXA-CEC00007133-7134, and BPXA-CEC00009674-9675. The relevant passage is, "One option is to cancel the 2004 smart pigging program - what are the consequences of not doing it this year (the 3 LDF's)?" Also included in this set of material are documents BPXA-CEC00007135-7158, the "Greater Prudhoe Bay / 2004 Lifting Cost Challenge (LCC) Maintenance and Reliability". On the first page (7135) is the line item "CIC: Cancel 2004 Smart Pigging Program" for a one-time savings of $250,000. Other opportunities to reduce inhibition or inspection are also listed.

The team crossed this finding with M&R and Field Opex spending from 2001-2005 (see file "Copy of BAH - 0806GPB 2001-06 MR Ops Capex Category Summary.xls". There are no "pigging" entries in the MR tabs until 2006. Under Ops Capex Sort 1, lines 1212-1213 for GPMA Commonline Smart Pigging show an expenditure of almost $1 million in 2003, a nominal amount in 2004, and zero in 2005.

Prior to receiving additional information, the team drew several preliminary conclusions that were subsequently revised:

- It failed to distinguish between oil transit lines (OTL) and large diameter flow lines (LDF).
- It believed the "smart pigging program" was comprehensive, and not limited to the LDF.

The Honorable John D. Dingell
The Honorable Bart Stupak
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Page 3

- It concluded the lack of spending in 2004 and 2005 was a deferral.

Documents recently provided to the Committee, notably BPXA-CEC00010069-10082, which the team did not see until April 27, 2007, provide additional clarity.

Did Booz Allen Hamilton review the attached AFE to determine if this effort was attempted and subsequently denied due to a lack of funding? If not, why not?

The Booz Allen team did not review AFE 4N092 and did not see the relevant email traffic (BPXA-CEC00009637-9640) until April 27, 2007 when the batch of documents was provided to us by WilmerHale. The team was unaware that the AFE existed until April 24, 2007.

Please provide all supporting documents and interview notes contained in footnote 38.

Enclosed.

Sincerely,

BOOZ ALLEN HAMILTON INC.

Thomas D. Williams
Senior Executive Advisor

cc: Robert Malone
Stephen Elbert
Rick Cape
Robert Stout Jr.
Carol Dinkins

bp

Stephen A. Elbert
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May 14, 2007

BY HAND DELIVERY

The Honorable John D. Dingell
Chairman of Committee on Energy and Commerce
United States House of Representatives
2328 Rayburn House Office Building
Washington, D.C. 20515

The Honorable Bart Stupak
Chairman of the Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
United States House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairmen Dingell and Stupak:

I am writing to provide you with responses to several outstanding requests that you have posed to BP America, Inc. ("BPA").

May 11, 2007 Letter

On May 11, 2007, you asked, in a letter addressed to Robert Malone, for information regarding an error identified by Booz Allen Hamilton in its March 2007 report on the 2006 Greater Prudhoe Bay OTL incidents. This error is corrected in a May 10, 2007 letter from Tom Williams to Rick Cape, which we are attaching hereto.

The error concerns the following sentence on page 72 of that report: "Budget pressure eventually led to de-scoping some projects and deferring others. For example, the plan to run a smart pig in the OTL was dropped in 2004 and 2005." Question #1 in your May 11 letter asks why BP believes "that the aforementioned finding in the referenced Booz Allen Hamilton report is in error"

BPA believes that the statement regarding the plan to run a smart pig in the OTL was simply factually mistaken; there was no plan to run a smart pig in the OTL that was dropped in either 2004 or 2005. I am providing to you today, on behalf of BPA, documents that demonstrate that this statement in the Booz Allen report is erroneous. These documents were identified in the iCONECT document production database, previously described in our April 17, 2007 letter to you, using a series of searches that employed a variety of search terms designed to identify documents on BPXA's planned and executed smart pigging operations for 2004 and 2005:

Chairman Dingell
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- An e-mail chain beginning on March 31, 2004 that indicates that BPXA planned to "smart pig" three-phase cross country large diameter flowlines ("LDFs") in 2004 and 2005, and had no plans to run a smart pig in the 34" oil transit lines ("OTLs") for the Western Operating Area ("WOA") or the 34" and 30" OTLs for the Eastern Operating Area (EOA) in 2004 or 2005. This document bears the Bates numbers **BPXA-CEC00018457-59**.

- A series of e-mails and various attachments (some previously produced), which show that, while budget pressures were applied to the CIC group in 2004, this did not lead BPXA to "drop" its LDF smart pigging plans. These documents bear the Bates numbers **BPXA-CEC00007128**; **BPXA-CEC00007155-56**; **BPXA-CEC00007133-34**; **BPXA-CEC0009674-75**; and **BPCA-CEC00018460-62**.

- Several documents that indicate that BPXA planned and did in fact execute smart pig runs on three-phase cross-country LDFs in 2004 and 2005 (as noted on the pages marked by green tape flags for your reference). These documents are:

  - August 18, 2004 Corrosion Monitoring Review Meet and Confer VIII PowerPoint presentation. This document contains the label **00058062.0001**.

  - December 2004 GBP Lifting Costs Summary. This document contains the label **FARNHAMR-A-028 0149**.

  - 2004 Commitment to Corrosion Monitoring Report. This document contains the label **00021830.0001**.

  - 2005 Commitment to Corrosion Monitoring Report. This document contains the label **00018171.0001**.

We believe that Questions 2-4 of your May 11 letter are questions directed to Booz Allen Hamilton. Accordingly, Booz Allen Hamilton is submitting written responses to those questions in the attached letter from Tom Williams. Booz Allen Hamilton is also providing documents, attached to that letter, that address your requests.

<u>April 30, 2007 Letter</u>

<u>Request 2</u>

Request 2 in your April 30, 2007 letter to Robert Malone poses two questions related to an April 15, 2004 e-mail sent to Messrs. Kip Sprague and Richard Woollam in the CIC Group (BPXA-CEC00007159). BPA respectfully submits the following responses to those questions.

Assuming that this abbreviation ["GC's"] refers to the Gathering Centers, where within the Gathering Centers was the halting of inhibitor being proposed (regardless of whether such action was ever taken)?

The abbreviation refers to the Gathering Centers in the Western Operating Area. The e-mail's discussion of a proposal to discontinue the use of chemical inhibitor concerned a program that involved injection of corrosion inhibitor into the Produced Water ("PW") lines that run from the Gathering Centers to the well pads. The PW lines are not connected to the Oil Transit Lines ("OTLs"), which are the lines that experienced leaks in March and August 2006. PW lines carry water that has been separated from the oil and gas in the fluid stream at the Gathering Centers, and deliver it back to the well pads, where it is re-injected down the well bore to help maintain pressure in the formation.

Moreover, although the option of discontinuing use of chemical inhibition was discussed in this e-mail, the option was not pursued and the corrosion inhibitor injections into the PW lines were not reduced. Indeed, during 2004, BPXA used <u>more</u> corrosion inhibitor than was used in 2003. In 2003, BP used 2.52 million gallons of corrosion inhibitor (an effective concentration of 147 ppm). In 2004, BP used 2.67 million gallons of chemical (a concentration of 151 ppm). BP also spent more on corrosion inhibitor -- $23 million in 2004 versus $22 million in 2003.

In view of the changing composition of crude oil being produced at Prudhoe Bay, would reducing corrosion inhibitor at the Gathering Centers have any impact on "carry over" to the OTLs that leaked?

There was no reduction in corrosion inhibitor at the Gathering Centers. Had the inhibitor been reduced, however, it would <u>not</u> have had any impact on the corrosion inhibition that "carries over" to the OTLs that leaked because there is no connection between the PW lines, which transport water from the Gathering Centers back to the well pads for reinjection, and the OTLs, which transport sales quality crude oil from the Gathering Centers to the Trans-Alaska Pipeline System. In short, the two lines carry different streams in opposite directions from the Gathering Centers; thus, reducing, or even eliminating, chemical inhibition in the PW lines would have had no effect on the OTLs.

*****

Both in 2004 and currently, BPXA's primary corrosion inhibition program consists of injection of chemical corrosion inhibitor at the wellhead. Corrosion inhibitor injected at the wellhead is designed to provide protection throughout the oil transmission system, as it follows the path of the oil stream from the well to the LDF lines, then to the Gathering Centers, and finally on to the OTLs. Corrosion inhibitor injection rates at the wellhead have been progressively increased and, through the late 1990s and into the first years of this century, the observed rate of corrosion actually decreased.

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May 14, 2007
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BPXA's CIC group was concerned, however, that the PW lines, which carry water as described above, were subject to degradation. As a consequence, the CIC group began a program of supplemental injection of chemical corrosion inhibitor directly into the PW lines. The program was deemed "supplemental" because the primary inhibition program was -- and remains today -- the injection of corrosion inhibitor at the wellhead. For a number of years, this supplemental program was limited to only some of the PW lines. Starting in 2005, it was expanded to apply to all of BP's Greater Prudhoe Bay PW lines on the North Slope; this project was completed in January 2007.

Request 3

Finally, we are producing six additional documents that we have identified as potentially responsive to request #4 in the April 30, 2007 letter. These documents bear the Bates numbers **BPXA-CEC00018438** through **BPXA-CEC00018456.**

Because we are providing these documents to you on an expedited basis, as you requested, this production may contain some duplication. We apologize for any inconvenience but wanted to provide the documents to you as quickly as possible.

* * *

This production contains highly sensitive business and financial information. Accordingly, BPA respectfully requests that these documents be maintained confidentially and that, if the Subcommittee wishes to consider whether any of these documents should be made public, BPA and BPXA be given an opportunity to be heard on that question. In addition, please note that, to the extent that any documents produced to the Subcommittee and information contained in this letter are protected by the attorney-client privilege, work product doctrine, or other applicable privilege, such documents and information have been provided at the Subcommittee's request and in response to the Subcommittee's assertion of authority to compel such documents. By providing these documents and information to the Subcommittee, BPA has not waived and does not intend to waive its ability to assert such privileges or confidentiality protections in other fora.

Chairman Dingell
Chairman Stupak
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If the Subcommittee has any questions concerning this request for information or other matters, please feel free to contact me directly. We welcome the opportunity to discuss these matters with you.

Sincerely,

Stephen A. Elbert

Stephen A. Elbert

Enclosure

cc: The Honorable Joe Barton, Ranking Member
Committee on Energy and Commerce

The Honorable Ed Whitfield, Ranking Member
Subcommittee on Oversight and Investigations

Exhibit 29

		REPORT				
		Baker Panel	CSB	Mogford	Booz Allen Hamilton	MAP
THEMES	**PEOPLE**					
	Trusting & Open Communications	X	X	X	X	X
	Importance of Leadership	X	X	X	X	X
	Management's Technical Knowledge	X	X	X		X
	Accountability and Clarity of Expectations	X		X	X	X
	Worker Fatigue and Excessive Overtime	X	X	X		X
	Knowledge, Expertise, and Training	X	X	X		X
	PLANT					
	Risk Identification and Assessment	X	X	X	X	X
	PROCESSES					
	Effective Process Safety/Integrity Management System	X	X	X	X	X
	Adherence to Formal Processes	X	X	X	X	X
	Incident Investigations and Reporting	X	X	X	X	X
	Sufficiency of Resources	X	X	X	X	X
	PERFORMANCE					
	Audit, Compliance, and Monitoring	X	X	X	X	X
	Process Safety as a Core Value	X	X	X	X	X

Exhibit 30

MSNBC.com

BP admits knowing of corrosion problems

Workers had predicted 'major catastrophic event' because of cost-cutting

By Lisa Myers
Senior investigative correspondent
Updated: 7:35 p.m. ET Aug 9, 2006

WASHINGTON - BP now admits that senior company officials were warned three years ago about serious corrosion problems in the pipeline being shut down this week.

The warnings were laid out in correspondence obtained by NBC News, between Chuck Hamel, an advocate for oil workers, and senior BP officials.

Hamel writes that BP workers had come to him predicting a "major catastrophic event" and warning that "cost cutting" had caused "serious corrosion damage to flow lines and systems."

"They were cheating in what's required of them in normal business practice in an oil field to save money, to cut corners," Hamel says.

BP officials responded at the time, but said: "We cannot investigate or act without specific information."

In the last few months, a number of BP workers have told the FBI that beginning in 1999, supervisors ordered them to cut back on a key chemical — known as corrosion inhibitor — put into the system to protect pipes. After a major spill last March, BP told federal regulators there was "a reduced level of corrosion inhibitor" in the system that failed. Federal officials ordered BP to inject more chemicals into the pipeline.

On Wednesday, BP America's CEO defended the company's anti-corrosion program.

"We're learning," says Ross Pillari. "We recognize that we thought we had a program that was sufficient, that we need to do more."

A learning process likely to soon cost consumers at the pump.

URL: http://www.msnbc.msn.com/id/14273574/

Exhibit 31

Interview Name:	Bill Hedges	Date:	12/14/2006
Interview Title:	CIC Strategy & Planning	Location:	Anchorage
Interviewers:	Tom Williams		
Notes:			

Prior to the arrival of Tony Brock and the creation of the Technical Directorate, there was no formal process for assessing risk.
There were many informal processes, run by individuals.
They had no process for trying to quantify risk.

Kip Sprague, almost single-handedly tried to develop and keep up a kind of risk register as he built the annual facility reviews. This was mostly in his spare time, outside of his normal job.

In the past, they sat down with senior leadership as part of the QPR. They identified some major risk areas they were concerned with, but one-off

- Production water system
- Seawater system
- CUI

CIC was resourced to be a reactive team. Did not have the resources to be truly forward looking.

After the first leak, management started to seek out CIC, which was in another building until recently. Bernard Looney (ACT) came by to ask what risks he might be facing.

The major vehicle for communicating to senior management was the QPR and the annual review.
CIC had very limited time (20-30 minutes) as part of the broader M&R presentation (usually around 2 hours). Usually talked about what was going on, what CIC was doing, no time for a discussion around risk assessment.

There has been a big change since the leak. Lots more management attention and inquiry about risk issues.

The PAIT (Pipeline Assessment and Intervention Team) look at all the equipment was the major CIC input into the Risk Register
Risk Register is developed under Technical Director (Tony Brock). Cory Herod manages its development.

For example, CUI has always been a big issue.
Use radiographic inspection of low points on pipeline. Plan was to cut backlog of known corrosion issues in half.
At the end of 2005, this follow up list was about 2,000 items (inspection revealed corrosion issues)
Rather than reduce the backlog, the list has grown to 3,000 items that require visual inspection and follow-up.

For the first time, they have actually taken some lines out of service (e.g., Point McIntyre)

PAIT was an effort following the first leak to get at the state of the infrastructure. Assess each piece of kit with a view to:

- Shut in now
- Replace now
- Replace in 3 years

For risk assessment, PAIT is all about probability, since severity of any leak is high (zero tolerance).

Soon after he arrived here from Trinidad in July 2005, he asked for 3 more people in CIC town, and was turned down.
He now has 19 open slots in CIC town, and another 14 in Field.

He gave me a demonstration of the query capabilities of MIMIR, producing a list of all level "F" inspections in 2005. It took about 1 minute.

June 13, 2007

Ms. Carolyn Merritt
Chair and CEO
U.S. Chemical Safety and
Hazard Investigation Board
2175 K Street, NW, Suite 400
Washington, DC 20037-1809

Dear Ms. Merritt:

Thank you for appearing before the Subcommittee on Oversight and Investigations on Wednesday, May 16, 2007 at the hearing entitled " 2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" We appreciate the time and effort you gave as a witness before the Subcommittee.

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open to permit Members to submit additional questions to the witnesses. Attached are questions directed to you from certain Members of the Committee. In preparing your answers to these questions, please address your response to the Member who has submitted the question(s) and include the text of the Member's question along with your response. In the event you have been asked questions from more than one Member of the Committee, please begin the responses to each Member on a new page.

To facilitate the printing of the hearing record, your responses to these questions should be received no later than the close of business Friday, June 29, 2007. Your written responses should be delivered to 2125 Rayburn House Office Building and faxed to 202-225-5288 to the attention of Kyle Chapman, Legislative Clerk. An electronic version of your response should also be sent by e-mail to Mr. Kyle Chapman at kyle.chapman@mail.house.gov in a single Word or WordPerfect formatted document.

Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Kyle Chapman at (202) 226-2424.

Sincerely,

JOHN D. DINGELL
CHAIRMAN

Attachment

1. **The Booz Allen report on Prudhoe Bay speaks of "a 'normalization of deviance' where risk levels gradually crept up due to evolving operating conditions." In the case of the aging Prudhoe Bay lines, the report cites increasing water and sediment levels and decreasing flow as insidious risk factors for corrosion. In your testimony, you stated, "We observed a similar indifference to growing catastrophic risk in our Texas City investigation." Please provide examples of BP's indifference to catastrophic risk at Texas City.**

The CSB investigation found that, at least since 2000, procedural deviations, abnormally high liquid levels and pressures, and dramatic swings in tower liquid level were the norm in almost all previous startups of the Texas City refinery's ISOM unit, where the March 2005 accident occurred. Operators typically started up the unit with a high liquid level inside and left the drain valve in manual - not automatic - mode to prevent possible loss of liquid flow and resulting damage to a furnace that was connected to the tower. These procedural deviations - together with the faulty condition of valves, gauges, and instruments on the tower - made the tower susceptible to overfilling.

None of the previous abnormal startups were investigated by BP, nor were operating procedures updated to reduce the likelihood or consequences of flooding the tower. As American Petroleum Institute safety guidance notes, when operating procedures are not updated or correct, "workers will create their own unofficial procedures that may not adequately address safety issues".[1] At the Texas City refinery, procedural workarounds were accepted as normal.

The CSB report documented the occurrence of eight previous instances between 1994 and 2004 where flammable hydrocarbon vapors were discharged from the same blowdown drum which ultimately released liquid and vapor on March 23, 2005. In two of these incidents the blowdown system caught on fire. The eight incidents were not properly investigated, and appropriate corrective actions were not implemented. The investigation of a 1994 incident resulted in an action item to analyze the adequacy of the blowdown drum. The area superintendent was responsible for the completion of this item. However, the item was never finished, and management officials did not follow up to assure completion.

Despite numerous previous fatalities at the Texas City refinery (23 deaths in the 30 years prior to the 2005 disaster) and many hazardous material releases, BP did not take effective steps to stem the growing risk of a catastrophic event.

In each year from 2002 to 2005, BP made its own significant findings about the culture and safety of the Texas City site. In 2002, the new refinery manager found the infrastructure and equipment to be "in complete decline". A follow-up study by BP found "serious concerns about the potential for a major site accident" due to mechanical integrity problems. Later in 2002, another internal report explicitly connected the safety problems to earlier cost-cutting, stating, "the current integrity and reliability issues at

[1] API 770, 2001

TCR [Texas City Refinery] are clearly linked to the reduction in maintenance spending over the last decade ... The prevailing culture at the Texas City refinery was to accept cost reductions without challenge and not to raise concerns when operational integrity was compromised."

Similar findings were made in 2003, when a study of maintenance found that "cost cutting measures have intervened with the group's work to get things right - usually reliability improvements are cut." An external BP safety audit found inadequate training, a large number of overdue action items, and a concern about "insufficient resources to achieve all commitments." The report stated that "the condition of the infrastructure and assets is poor."

The year 2004 was marked by three major accidents at the refinery, including a $30 million process fire and two other accidents that caused three deaths. Meanwhile, an analysis conducted by BP's internal audit group in London found common safety deficiencies among 35 BP business units around the world, including widespread tolerance of non-compliance with basic health, safety, and environment rules and poor implementation of safety management systems.

In 2004, BP documents show that maintenance spending increased, but the increases were largely due to complying with environmental requirements and responding to major accidents and outages. There was still not an adequate focus on preventative maintenance before accidents occurred. The investigation found that BP's executives relied unduly on injury statistics in assessing the safety of their facilities.

BP managers and executives attempted to make improvements from 2002 to 2005 but they were largely focused on personal safety - such as slips, trips, falls, and vehicle accidents - rather than on improving process safety performance, which continued to deteriorate.

Later in 2004, a safety culture survey of the refinery was conducted and endorsed by the site leadership. The study, known as the Telos report, pointed to "an exceptional degree of fear of catastrophic incidents" among other conclusions, and it stated respondents' belief that "production and budget compliance gets ... rewarded before anything else." Finally, a safety business plan for 2005 cited as a "key risk" the possibility that "Texas City kills someone in the next 12-18 months".[2]

Taken as a whole, these findings point to a culture that had grown increasingly blind to catastrophic process risks.

2. **Your testimony indicates that incentive programs for refinery managers were weighted "in favor of financial performance" and "BP managers increased site bonuses even in the face of three fatalities in 2004." Similarly, Booz Allen found that senior management incentives in Alaska were based on cost and production. How should this type of organizational deficiency be corrected? Should**

[2] HSSE (Health, Safety, Security, and the Environment) '05 Business Plan, March 15, 2005.

regulators incorporate minimum standards for management compensation incentives as part of the process safety management plans, and disqualify those plans with counterproductive incentives?

BP Group executives and Texas City management focused on personal safety rather than on process safety and preventing catastrophic incidents. The emphasis on financial performance and personal safety was driven from the highest levels of the organization and underscores the need for greater and more effective board oversight.

The CSB recommended that BP Global Executive Board of Directors appoint an additional non-executive member of the Board of Directors with specific professional expertise and experience in refinery operations and process safety and appoint this person to be a member of the Board Ethics and Environmental Assurance Committee.

The CSB recommendation is consistent with recommendations of the Financial Reporting Council (FRC), the UK independent regulator for corporate reporting and governance. The FRC has adopted guidance entitled, "Internal Control: Guidance for Directors on the Combined Code," commonly referred to as the Turnbull guidance. The Turnbull guidance recommends that UK boards maintain a system of internal risk control that includes health, safety, and environment, and that boards review the system's effectiveness annually.

In addition the CSB recommended that OSHA amend its Process Safety Management (PSM) standard to require that covered facilities perform management of change reviews for organizational changes, such as mergers, acquisitions, staffing changes, and budget cuts. If facilities were required to perform such reviews, it would provide a safeguard against pursuit of financial targets without adequate analyses of the safety impacts.

3. **A 2005 BP "Health, Safety and Environment Plan" referenced in the Chemical Safety Board's (CSB's) Investigation Report warns of people being killed in the next 12-18 months if safety was not improved. Was this warning cry heard at the highest levels of the company? Was it heeded?**

The 2005 HSE Business Plan was dated March 15, 2005, just eight days prior to the accident, and the warning unfortunately could not avert the events on March 23. However, the estimate of a worker fatality every 12 to 18 months reflected the historical average fatality rate at this troubled facility. An October 2004 presentation by the Texas City Business Unit Leader to the Global Chief Executive for Refining and Marketing recounted the fatal incidents with pictures of the deceased. However, this and other meetings between Texas City and BP corporate executives did not result in effective actions to improve process safety. Late in 2004, a further 25% budget cutting challenge was issued to BP's refineries. The cut was partially implemented at Texas City.

As described in the CSB investigation report, numerous warnings were made years earlier about unsafe conditions at the refinery, include BP's internal Veba and Kearney reports from 2002, a Maintenance Gap Assessment (2003), and a GHSER [Getting Health, Safety, and Environment Right] Audit (2003). The Group Chief Executive for

Refining and Marketing, who was a member of BP's executive board, was familiar with the findings of audits of the Texas City refinery. However, BP's response focused largely on improving personal safety and procedural compliance, and did not correct certain core deficiencies, such as the lack of preventative maintenance and the use of obsolete safety equipment, such as blowdown drums.

4. **Please list the recommendations made by the Chemical Safety Board to the Occupational Safety and Health Administration (OSHA) related to BP's refinery at Texas City. Has OSHA implemented all of these recommendations? If not, what follow up has the CSB undertaken to make the Secretary of Labor and Office of Management and Budget aware of this?**

2005-4-I-TX-R5

1. Implement a national emphasis program for all oil refineries that focuses on:

   a. The hazards of blowdown drums and stacks that release flammables to the atmosphere instead of to an inherently safer disposal system such as a flare. Particular attention should be paid to blowdown drums attached to collection piping systems servicing multiple relief valves;

   b. The need for adequately sized disposal knockout drums to safely contain discharged flammable liquid based on accurate relief valve and disposal collection piping studies.

2. Urge states that administer their own OSHA plan to implement comparable emphasis programs within their respective jurisdictions.

2005-4-I-TX-R8

Strengthen the planned comprehensive enforcement of the OSHA Process Safety Management (PSM) standard. At a minimum:

a. Identify those facilities at greatest risk of a catastrophic accident by using available indicators of process safety performance and information gathered by the EPA under its Risk Management Program (RMP);

b. Conduct, or have conducted, comprehensive inspections, such as those under your Program Quality Verification (PQV) program at facilities identified as presenting the greatest risk;

c. Establish the capacity to conduct more comprehensive PSM inspections by hiring or developing a sufficient cadre of highly trained and experienced inspectors;

d. Expand the PSM training offered to inspectors at the OSHA National Training Institute.

2005-4-I-TX-R9

Amend the OSHA PSM standard to require that a management of change (MOC) review be conducted for organizational changes that may impact process safety including:

a. Major organizational changes such as mergers, acquisitions, or reorganizations;

b. Personnel changes, including changes in staffing levels or staff experience; and

c. Policy changes such as budget cutting.

On May 16, 2007, OSHA sent the CSB a letter indicating that the agency is reviewing all three recommendations. The CSB has not received any specific documentation on OSHA's intended actions to fulfill the recommendations. On June 12, 2007, OSHA publicly announced a National Emphasis Program on refinery safety but has not provided documentation or correspondence to the CSB concerning this program.

5. **The Chemical Safety Board recommended that BP "Appoint an additional non-executive member of the Board of Directors with specific professional expertise and experience in refinery operations and process safety." Has this been implemented?**

The CSB received a letter dated May 18, 2007, from BP America Chairman Robert Malone stating that BP had appointed an independent expert to advise the board of directors on safety issues and that "in the future, the CSB recommendation will be taken into account by the Board as part of its continuing development of skills as mentioned above, and in light of the Board's experience of working with the independent expert."

The CSB will be requesting additional information from BP about its intentions concerning this recommendation. Upon receipt of that information, the CSB Board will vote on designating the response as acceptable, unacceptable, or acceptable as an alternative.

6. **Are there leading indicators that could warn OSHA, refinery managers, and unions about a breakdown in process safety management before an accident occurs? What are these leading indicators? Should OSHA require new safety indicators for process safety? Has the CSB made specific recommendations to OSHA regarding the need for leading indicators?**

Leading indicators provide a check of system functioning before serious accidents occur. Examples of possible leading indicators are the percentage of equipment inspections completed by the target date or the rate of closure for process safety management (PSM) action items. Lagging indicators, such as near misses, can provide evidence that a key system is failing to meet its objectives. Active monitoring of both leading and lagging indicators is important to the health of process safety systems.

Currently, there is no consensus set of either leading or lagging indicators for use by the process industries. Prior to March 2005, BP measured safety performance largely on the basis of a lagging indicator, the occupational injury rate, which provides little information about the condition of process safety systems.

The CSB did not recommend that OSHA require companies develop new process safety indicators. However, the CSB did recommend that OSHA identify and inspect those facilities at the greatest risk of a catastrophic accident using available indicators and information gathered by the EPA under its Risk Management Program (RMP).

The CSB further recommended that the American Petroleum Institute and United Steelworkers of America "... create performance indicators for process safety in the refinery and petrochemical industries. Ensure that the standard identifies leading and lagging indicators for nationwide public reporting as well as indicators for use at individual facilities. Include methods for the development and use of the performance indicators." In addition, the CSB hopes to convene a panel of outside experts, representing a broad spectrum of stakeholders, to accelerate the development of leading safety indicators in the petrochemical sector.

New indicators will facilitate efforts by industry to identify facilities with serious problems and to compare safety performance between different sites and between different companies. In the future, OSHA could use new indicators developed through a consensus process to better target its process safety inspections.

7. Did OSHA cooperate with the Chemical Safety Board's investigation of the BP Texas City disaster, by furnishing its inspection records and making its personnel available for interviews?

In the course of its BP investigation, the CSB found a number of pre-existing deficiencies in the Texas City refinery's PSM program. Such deficiencies might have been uncovered had OSHA conducted a comprehensive process safety inspection of the refinery, known as a Program Quality Verification (PQV) audit. In addition, the CSB learned that in 1992, OSHA had cited a blowdown drum at the refinery as unsafe, but the citation was later withdrawn and blowdown drums continued in use at the refinery.

For over a year the CSB sought information, records, and interviews from OSHA to understand these issues better. Although a few interviews were allowed, other requests were denied. The CSB submitted a number of requests for documents and interviews from OSHA regarding the PQV inspection program, including the number, training, education, and experience of inspectors. The requested information and interviews were not provided. The CSB also sought an interview with the OSHA inspector who cited the blowdown drum in 1992, and this request was also denied.

8. Did OSHA withhold information from CSB? If so, what was withheld and did OSHA provide CSB with any justification for why this information was withheld?

OSHA's last correspondence on this issue is provided as an attachment. OSHA stated that the issues on which the CSB sought information were "committed entirely to OSHA's discretion" and were outside the proper scope of a CSB root-cause accident investigation.

9. Do statutory changes need to be made to ensure CSB has unfettered access to information from OSHA during an investigation?

CSB investigations would benefit from reasonable access to OSHA and EPA records and personnel. Congress charged the CSB with examining OSHA and EPA standards and programs for accident prevention, and to do so the agency must first be able to gather the facts. The Senate legislative history accompanying the Clean Air Act Amendments directs the CSB to take an "all cause" approach in its investigations, presumably including weaknesses in inspection and enforcement systems as possible causes. The lack of access to information during the BP investigation signifies the need for clarification of interagency relationships, which could be done through a statutory change.

10. Are there other statutory changes concerning the Chemical Safety Board that you would recommend? Please provide a list of such recommendations and the justification.

The current statute authorizing the CSB is now 17 years old. The CSB has gained considerable first-hand experience in how these provisions apply at accident sites and in our relations with other parties.

Congress could compare the CSB's existing statutory authorities with those of the older and more established National Transportation Safety Board. While not all the conditions are exactly the same between the two agencies, there is much in common, and the CSB would benefit significantly from some of the clearer authorities in the NTSB statute. For example, the authority of the CSB to preserve and determine the testing of evidence is much less explicit than the NTSB's authority. Last year, when the CSB proposed a procedural rule on evidence preservation at accident sites, some industry voices objected that Congress had never intended the CSB to exercise such preservation authority. The result of these statutory issues is very concrete: investigations are often delayed, and in some cases important physical evidence is actually lost or destroyed. Clarification of these issues by Congress would improve the quality and speed of CSB investigations.

In addition, Congress should clarify that no local, state, or federal agency may block the access of the Board to the site of a chemical release, particularly during the early stages when the physical evidence is its most pristine condition but is also in the greatest peril. From time to time, local assertions of criminal jurisdiction have been used to impede the access of CSB investigators to accident sites. During the period while such issues are resolved, critical evidence is exposed to damage or loss.

Congress could also consider providing the CSB's investigative records with a limited degree of statutory protection, to prevent indiscriminate use in litigation and criminal prosecutions. The possible future use of information gathered by the CSB in the courtroom can have a strong chilling impact on our ability to conduct our safety investigations and can detract from our independence.

The CSB remains a very small agency that seeks to have an impact on very broad issues.

The Congressional authorizing committees have not provided the agency with mission guidance, priorities, or funding targets since the enactment of the original statute. A 1989 version of the Clean Air Act envisioned a CSB that was funded at half the then level of the National Transportation Safety Board, the agency on which we were modeled, but today the CSB is barely a tenth the size of the NTSB. As a result of chronic shortages of personnel and resources, the CSB can deploy investigators to just a handful of the serious accidents that arguably warrant its attention. The CSB also hopes that Congress may provide explicit support for the Board's safety studies and outreach programs.

The CSB would benefit if Congress reviewed the structure of the Board itself and provided for a vice chairman to assure an orderly transition during times when the chair is vacant. Periodic vacancies in the chair, and the resulting absence of executive authority, pose a significant risk to the success of the agency. Under the existing statute, CSB board members cannot serve beyond the expiration of their five-year terms, and thus vacancies in the chair and other board seats are all but inevitable.

Finally, the CSB has requested that Congress discontinue a highly unusual auditing arrangement under which the EPA Inspector General serves as IG for the Board. This relationship – which was established through annual appropriations riders and has never been reviewed by the authorizing committees – compromises the Board's statutory independence and should be ended.

June 13, 2007

Mr. Richard Fairfax
Director
Directorate of Enforcement Programs
Occupational Safety and Health Administration
U.S. Department of Labor
200 Constitution Avenue, NW
Washington, DC 20210

Dear Mr. Fairfax:

Thank you for appearing before the Subcommittee on Oversight and Investigations on Wednesday, May 16, 2007 at the hearing entitled " 2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" We appreciate the time and effort you gave as a witness before the Subcommittee.

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open to permit Members to submit additional questions to the witnesses. Attached are questions directed to you from certain Members of the Committee. In preparing your answers to these questions, please address your response to the Member who has submitted the question(s) and include the text of the Member's question along with your response. In the event you have been asked questions from more than one Member of the Committee, please begin the responses to each Member on a new page.

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Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Kyle Chapman at (202) 226-2424.

Sincerely,

JOHN D. DINGELL
CHAIRMAN

Attachment

U.S. Department of Labor

Assistant Secretary for
Occupational Safety and Health
Washington, D.C. 20210

AUG - 3 2007

The Honorable Bart Stupak
Chairman
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
United States House of Representatives
Washington, D.C. 20515-0115

Dear Chairman Stupak:

This is in response to your questions enclosed in Chairman John D. Dingell's June 20, 2007, letter to Richard Fairfax, Director, Directorate of Enforcement Programs for the Occupational Safety and Health Administration (OSHA). These questions relate to Director Fairfax's May 16, 2007, appearance before the Subcommittee on Oversight and Investigations hearing on to the 2006 Prudhoe Bay Shutdown and British Petroleum (BP) management practices.

Question 1: The Chair of the Chemical Safety Board testified that if BP had complied with regulations and standards, the Texas City refinery accident could have been prevented. Do you agree?

Response: OSHA believes that, if BP had complied with all applicable safety and health standards, the Texas City refinery accident may have been prevented. The primary responsibility for the safety and health environment for employees at our nation's workplaces rests with employers. OSHA's accident investigation findings indicate that BP abdicated its responsibility for the safety and health of its employees and suggest that the accident at the Texas City, TX, refinery (BP TCR) on March 23, 2005, could have been prevented or the severity mitigated had OSHA safety regulations been followed. Furthermore, OSHA determined that BP willfully violated OSHA safety standards. OSHA believes this disregard for applicable OSHA standards led to the deaths of 15 employees at BP TCR. As a result, OSHA has referred this case to the U. S. Department of Justice for criminal prosecution.

Question 2: Over the five years prior to the Texas City Refinery explosion in March 2005, has there been sufficient enforcement of the Process Safety Management Standard in the refinery sector?

Response: Enforcement of OSHA's Process Safety Management Standard [29 CFR 1910.119] is an OSHA priority. Between March 2000 and March 2005, Federal OSHA conducted 34 inspections focusing on Process Safety Management (PSM) in refineries; State OSHA programs conducted an additional 14 inspections. There were other inspections based upon complaints and referrals that did not focus solely on PSM.

OSHA has launched a National Emphasis Program (NEP) for refineries. Under this program, OSHA will conduct 81 inspections at petroleum refineries over the next two years. However, the NEP is just one component of several significant enforcement initiatives in the oil, gas, and refining industries on which OSHA is working. In addition to the above nationwide effort, OSHA also has two Regional Emphasis Programs in Region 6, which covers Louisiana, Arkansas, Oklahoma, Texas and New Mexico, that focus on reducing workplace injuries and fatalities in the petrochemical industry, as well as in the oil and gas well drilling and servicing sectors.

Question 3: Are deaths an adequate leading indicator of a failed process safety management system? Are there alternatives?

Response: While employee deaths may certainly be an indicator of problems associated with an employer's PSM system, neither OSHA nor the industry should rely exclusively on tragic accidents to identify PSM performance problems. Typically, industry views employee deaths as a lagging indicator. Indeed, the independent "Baker Panel" conducted a thorough review of BP's corporate safety culture, safety management systems, and corporate safety oversight at its U.S. refineries, and its report states the exclusive use of lagging indicators is not necessarily a good predictor of PSM performance.

OSHA agrees. Although employers have had access to leading indicator information, including their internal statistics and proprietary data from industry associations to determine if specific areas of their PSM program need improvement, this information has generally not been disclosed publicly. OSHA is evaluating the possible use of leading and lagging indicators as a tool to target PSM inspections. The challenge for OSHA is to determine which combination of leading and lagging indicators are the best predictors of deficient PSM programs for various types of employers that process chemicals.

Question 4: Your testimony indicates that the Texas City Refinery did not come up with red flags that would have warned OSHA's Enhanced Enforcement Program (EEP). Why did red flags not go up at OSHA when there were three deaths and multiple explosions in 2004?

Response: OSHA conducted two inspections in response to the 2004 incidents at the Texas City refinery and issued citations on August 16, 2004 and February 25, 2005 based on its findings. The EEP requires either that a fatality was related to a serious, willful, or repeat violation; or that there were three or more willful or repeat citations or failure-to-abate notices where the violations reflect grave hazards and an accident was probable. The citations issued in August 2004 did not qualify for the EEP because there was no fatality; nor were there violations meeting the classification criteria. In response to your question, OSHA further reviewed its enforcement activity following the February, 2005 BP citations. Our review has clarified that the February 25, 2005, inspection findings did qualify for inclusion in the EEP due to two fatalities and the issuance of a related willful violation. BP was placed in the EEP less than a month before the March 2005 explosion.

Following the BP March 2005 accident, however, OSHA did issue an "Alert" to its field staff. Under the alert, OSHA conducted inspections of BP refineries and similar processing facilities in states under federal jurisdiction. OSHA also worked with state plan states to inspect BP refineries in state plan states. In response to the alert, OSHA inspected the BP refinery located in Oregon, Ohio; found hazards similar to those found at Texas City; and issued BP 34 willful and 5 serious citations with proposed penalties totaling more than $2.4 million for unsafe operations in Ohio. Those citations are being contested.

Recently, on July 20, 2007, as the result of its monitoring of the Texas City refinery, OSHA issued BP one willful and four serious citations with proposed penalties of $92,000 for violations related to, among other matters, an inadequate pressure relief system.

In addition, for any case in which a willful violation appears to have caused the death of any employee, such a violation will be carefully considered for possible criminal referral to the Department of Justice (DOJ), under Section 17 (e) of the OSH Act.

Question 5: Please list the recommendations made by the Chemical Safety Board to OSHA arising out of the Texas City Refinery accident. Please list the implementation status of each recommendation.

Response: See Attachment A, *CSB Recommendations to OSHA Related to the BP TCR Investigation,* for the subject list of recommendations and OSHA's response.

Question 6: Has OSHA modified its regulations to require blowdown drums to be burned off through a flare instead of venting to the atmosphere?

Response: OSHA has no current plans to modify its regulations as to blowdown drums. We believe the existing PSM requirements adequately address the situation you have described.

Because there are tens-of-thousands of PSM-covered processes that are, in most cases, configured differently, the PSM standard relies on general performance requirements. A requirement for blowdown drums to be burned off through a flare would be a specification requirement. If the PSM standard were to contain specification requirements, it would need to be vastly expanded to address not only specific types of processes, but their unique configurations, technologies and chemistries in order to assure that the regulation covered the many combinations of potential hazardous conditions at chemical facilities.

This approach to regulating chemical process safety would be too prescriptive to be practical. Instead, the performance approach sets up general performance requirements with which employers are required to comply. This approach requires that employers demonstrate that their performance is in compliance with the PSM standard.

In the case of venting of flammable and/or toxic chemicals to the atmosphere, the PSM standard does not specify a method to relieve the products produced by excess pressures from, for example, a runaway reaction, that is, by a blowdown drum venting to atmosphere or a flare.[1] Rather, the standard mandates that an employer conduct a process hazard analysis (PHA) to, "... *identify, evaluate and control the hazards involved in the process.*" 29 CFR 1910.119(e) (1). Under the PSM standard, among other responsibilities, an employer is required to identify hazards through an evaluation performed by a knowledgeable team, to document that its equipment complies with recognized and generally accepted good engineering practices, and to implement the controls identified by the PHA. Under the standard, if the process relieves to a blowdown drum and vents excess relief products to the atmosphere, the employer must conduct a PHA to identify, evaluate, and control the hazards of the process, including hazards created by the

[1] Blowdown drums that vent to the atmosphere are an older method of technology that even if currently well-maintained may no longer be adequate to relieve the products produced by overpressures for various reasons. For example, the process may have been modified to process greater amounts of product at higher temperatures and pressures, creating a situation where the blowdown drum and vent could be overwhelmed. On the other hand, the blow down drum may currently be well-maintained and provid effective and safe pressure relief.

use of this method of pressure relief. The employer is under the same obligation if the process relieves to a flare. For a process tied to a flare, the employer would be required, for example, to evaluate whether the pressure relief equipment tying the process to the flare is properly sized. Failure to meet these requirements subjects the employer to citation for failing to control the process hazards.

To comply with this particular PSM paragraph, the employer with a blowdown drum that vents a Highly Hazardous Chemical (HHC) to the atmosphere must first identify this hazardous condition in its PHA, and then evaluate if the HHC released could expose employees to catastrophic hazards, i.e., fire, explosion or toxic release.

If the employer cannot demonstrate through its evaluation that any HHC released through a vent to the atmosphere will not result in harm to employees, then the employer cannot demonstrate that its performance has complied with this requirement. If the employer cannot demonstrate that existing controls are adequate for this hazardous condition, then additional controls, such as venting the blowdown through a closed system to a flare, would be required. If controls needed to safely control the hazardous condition are not provided or are inadequate, then the employer could be cited for not performing its obligation to control the identified hazardous condition.

Question 7: Several reports indicated concern about the use of contract workers in the petrochemical industry. An OSHA commissioned study found increased use of contract workers could pose increased hazards in petrochemical plants due to differential levels of training and lack of communication between permanent and contract workers. Contractor injuries and illnesses are not recorded on the facility's OSHA 300 logs of injuries and illnesses. What steps is OSHA taking to hold the site owner responsible and accountable for the injuries and illnesses experienced by subcontractor employees? Why does OSHA not require a common OSHA 300 log at these facilities?

Response: While OSHA's occupational injury and illness recordkeeping regulation at 29 CFR Part 1904 does not require host employers to record the injuries and illnesses of contractor employees they do not supervise on a daily basis, OSHA's PSM standard does require site controlling employers to maintain a log of contract employee injuries and illnesses for PSM covered processes. In Appendix C - *Compliance Guidelines and Recommendations for Process Safety Management (Nonmandatory)* of the PSM standard, OSHA explained that its requirement to maintain a contract injury and illness log would give the host employer a complete representation of the injuries and illnesses related to contractors working on or near a covered process:

> *Maintaining a site injury and illness log for contractors is another method employers must use to track and maintain current knowledge of work activities involving contract employees working on or adjacent to covered processes. Injury and illness logs of both the employer's employees and contract employees allow an employer to have full knowledge of process injury and illness experience.*

Question 8: After several large explosions at chemical plants, the Chemical Safety Board recommended that OSHA expand the Process Safety Management standard to address reactive chemicals. Has that been implemented? If not, why not?

Response: OSHA staff is continuing to review the CSB's rulemaking recommendation. OSHA has implemented or is developing a number of regulatory and non-regulatory initiatives to prevent these types of incidents. The Agency's initiatives related to chemical reactivity hazards are listed in Appendix C, #5.

Question 9: Your testimony indicated that OSHA has made 56 criminal referrals to the Justice Department since 2001. Please provide a list of these 56 referrals, with the name of the party referred, the facility, the location, and a brief summary of the alleged criminal violation.

Response: Please note that a total of 58 criminal referrals have been made to date. See Attachment B, *Criminal Referrals By OSHA To DOJ or US Attorneys (2001 through July 23, 2007)*, for a list of the referrals to DOJ. Please note that only the names of those companies against whom action has been taken can be revealed. In those instances where a decision to move forward has not yet been made or prosecution was declined, OSHA can disclose neither the names of the entities nor their locations.

Question 10: How many recommendations has OSHA received from the Chemical Safety Board? Please provide a list and their status with respect to OSHA's implementation. For those recommendations that have not been implemented by OSHA, please explain why they have not been implemented.

Response: OSHA received 22 recommendations from CSB. Some of these recommendations contain multiple parts. See Appendix C, *CSB Recommendations to OSHA* for a list of CSB recommendations to OSHA and the implementation status of each of the recommendations.

I believe that the above answers are responsive to your questions relative to OSHA's testimony before the Subcommittee. If you should have any additional questions, please feel free to contact me.

Sincerely,

Edwin G. Foulke, Jr.

cc: The Honorable John D. Dingell
The Honorable Joe Barton
The Honorable Ed Whitfield

Enclosures

A - 1

Attachment A

CSB Recommendations to OSHA
Related to the BP TCR Investigation

CSB Recommendation	OSHA's Response	Implementation status
2005-4-I-TX-R5 1. Implement a national emphasis program for all oil refineries that focuses on: - The hazards of blowdown drums and stacks that release flammables to the atmosphere instead of to an inherently safer disposal system such as a flare. Particular attention should be paid to blowdown drums attached to collection piping systems servicing multiple relief valves; - The need for adequately sized disposal knockout drums to safely contain discharged flammable liquid based on accurate relief valve and disposal collection piping studies	Prior to the issuance of this recommendation to OSHA, the Agency was in the process of developing a national emphasis program to inspect petroleum refineries. Since CSB issued this recommendation, OSHA has implemented the *Petroleum Refinery Process Safety Management National Emphasis Program* (Refinery NEP), which among other requirements, instructs inspectors to evaluate blowdown systems at all refineries in Federal jurisdiction. All the specific issues addressed by CSB related to blowdowns as well as others are addressed in Appendix A, Section C of the Refinery NEP.	Completed. The Refinery NEP was implemented on June 7, 2007 and is expected to be completed by June 7, 2009.
2005-4-I-TX-R5 2. Urge states that administer their own OSHA plan to implement comparable emphasis programs within their respective jurisdictions.	The Refinery NEP strongly encourages OSHA State-Plan States to adopt the NEP.	Completed. See Section VII, *Federal Program Change* of the NEP. The Refinery NEP was implemented on June 7, 2007. OSHA expects that most, if not all, State-Plan States will adopt the NEP.
2005-4-I-TX-R8 1. Strengthen the planned comprehensive		

enforcement of the OSHA Process Safety Management (PSM) standard. At a minimum:		
1.a. a. Identify those facilities at greatest risk of a catastrophic accident by using available indicators of process safety performance and inf rmation gathered by the EPA under its Risk Management Program (RMP).	Prior to the issuance of this recommendation to OSHA, the Agency was in the process of determining which facilities and inspection strategy it should employ to conduct additional programmed inspections at PSM-covered facilities. From a review of OSHA's IMIS data base, the Agency determined that petroleum refineries had experienced more fatal and catastrophic incidents since 1992 (promulgation of PSM) than the next 3 industry sectors combined. From this data, OSHA decided that based on their history, petroleum refineries presented a great risk and consequently the Agency developed the Refinery NEP to address catastrophic type hazards covered by PSM. OSHA believes that its PSM fatality study it conducted based on its IMIS database provides as good if not better indicator of facilities at greatest risk of catastrophic type hazards as does EPA's RMP 5 Year Accident Database. Note: OSHA is currently updating its general PSM compliance directive. This directive covers all PSM-covered processes, not just refineries. As such OSHA is evaluating possible inspection targeting systems which will put our inspectors in facilities which are at greatest risk of catastrophic releases of highly hazardous chemicals. We are evaluating leading and lagging indicators that are publicly available that would be appropriate for use as targeting tools for the Agency.	Completed. The Refinery NEP was developed as a result of a data review of the types of facilities which experience the types of incidents PSM was promulgated to prevent and mitigate, i.e. fatal and catastrophic incidents which are a result of the release of *highly hazardous chemicals*.
1.b. Conduct, or have conducted, comprehensive inspections, such as those	OSHA has developed and implemented, *Petroleum Refinery Process Safety Management National Emphasis*	Completed. The Refinery NEP was implemented on

under y ur Program Quality Verification (PQV) program at facilities identified as presenting the greatest risk.	*Program* (Refinery NEP). It contains an inspection strategy which utilizes "*Inspection Priority Items*" (IPI) that we feel is a better inspection strategy for conducting PSM inspections at refineries than our PQV inspection strategy. See the Refinery NEP, Section X.D., *Inspection Process* for a description of the IPI inspection strategy. . Note: Inspections conducted under the NEP are programmed comprehensive inspections.	June 7, 2007 and is expected to be completed by June 7, 2009.
1.c. Establish the capacity to conduct more comprehensive PSM inspections by hiring or developing a sufficient cadre of highly trained and experienced inspectors.	Last summer and prior to the CSB's recommendation, OSHA began an accelerated training initiative for its compliance officers (CSHOs) to conduct PSM inspections. In FY 2007, OSHA trained 184 federal students in PSM courses with another 110 estimated to complete courses by the end of the FY, for a projected total of 294. Please note that other OSHA personnel who had received PSM training prior to our current initiative are available to conduct PSM inspections.	Completed/On-going
1.d Expand the PSM training offered to inspectors at the OSHA National Training Institute.	See above response.	Completed
2005-4-I-TX-R9 (CSB2005-04-I-TX-R9) 2. Amend the OSHA PSM standard to require that a management of change (MOC) review be conducted for organizational changes that may impact process safety including: a. major organizational changes such as mergers, acquisitions, or reorganizations; b. personnel changes, including changes in	OSHA is currently evaluating this CSB recommendation and will respond to CSB when we have determined the Agency's course of action.	Evaluating recommendation.

staffing levels or staff experience; and c. policy changes such as budget cutting.		

Appendix B

Criminal Referrals By OSHA To DOJ or US Attorneys (2001 *through July 23, 2007*)

Fiscal Year 2001 [3]

1	Tyler Pipe Co. (crushed in machine)	7/01 Guilty plea 7/19/02 $250,000 fine, 1 yr. probation
2	Moshe Junger (Mordechi Rubbish) (building collapse)	5/01 Guilty plea; sentencing 6/02 4 months imprisonment, one year supervised release, $100,000 fine
3	# Company C(trenching)	6/01 Declined by DOJ

Fiscal Year 2002 [6]

4	Tri-State Scaffolding Equipment and Supplies, and Phillip Minucci (scaffold collapse)	11/01 Indictment by Manhattan D.A. 10/01/02 Guilty pleas 9/02 minimum jail term 3.5 yrs
5	# Company B (electrocution)	5/02 Declined
6	* Oscar Miranda (Azteca Services)	6/02 Guilty plea 8/03 (one count each of false stmts & mail fraud) 30 mos. jail, 3 yrs supervised release, restitution to USPS, payment of ee med. bills and OSHA penalties
7	# Company D (trenching)	6/02 U.S. Atty. declined
8	Steve Pate (Pate & Pate Enterprises)	6/02 Guilty plea 11-18-04; 5 yrs probation; must

	(trenching)	inform OSHA of companies & work sites; requirements for daily and weekly safety inspections.
9	* Russel Nickel (Pyro Products)	6/02 Guilty plea 5/04; 2 mos. prison, 2 mos. home confinement; $2,000 fine
	Fiscal Year 2003 [9]	
10	*,# Company A (trenching)	10/02 U.S. Atty. declined 11/02
11	# Company B	2/03 U.S. Atty. declined 12/03
12	*,# Company C	2/03 U.S. Atty declined
13	# Company D (crushing)	2/03 U.S. Atty. declined 8/03
14	*,** Atlantic States Cast Iron Pipe Co. et al	3/03 12/03 Indictments 4/06 convictions: environmental crimes, false statements (company and Scott Faubert), and obstruction (company, John Prisque, and Jeffrey Maury).
15	*,# Individual E	3/03 DOJ declined 4/03
16	*,# Company F (crane collapse)	4/03 U.S. Atty. declined 5/04

17	Hillandale Farms of Florida (confined space engulfment)	4/03Guilty plea 8/05; $128,800 fine, implement safety program with annual audits, submit article to industry magazine and assist Extension Service with training materials
18	# Company H (trenching)	6/03 U.S. Atty. declined 8/03
	Fiscal Year 2004 [10]	
19	# Company A	2/04 U.S. Atty declined/04
20	#,*,** Company B	3/04 No decision yet
21	# Company C	3/04 DOJ declined 6/04
22	# Company D	3/04 U.S. Atty. declined 7/04
23	# Company E	4/04 U.S. Atty. declined 4/05
24	Union Foundry (crushing)	4/04 Guilty plea 9/05 (OSH Act & RCRA counts) $4.25 M. fine & commun. service project; 3 yrs probation
25	# Company F	6/04 No decision yet
26	# Company G	7/04 No decision yet
27	** Jared Bailey (EKK Grading)	7/04 Indictment 8/05 Acquittal 12/05
28	# Company H	7/04 U.S. Atty. declined 9/04

Number of cases discussed with DOJ/US Atty. but not referred: 10

Fiscal Year 2005 [10]

29	# Company A (fall)	10/04 US Atty declined 11/04
30	Glen Wagner; Wagner Excavation Services (trenching)	11/04 Information filed 10/4/05 Guilty plea 10/12/05 fined $50,000
31	Kang Yeon Lee (Big Apple Constr.) (balcony collapse)	12/04 Guilty plea 4/05 30 months jail; 2 years probation; $2M restitution and civil penalties
32	* Ralph Guarnieri (Global Electric)	3/05 Indictment 6-8-06
33	#,* Company C	3/05 US Atty declined 10/06
34	# Company D	4/05 No decision yet
35	** Nasir Bhatti & Tariq Alamgir (Metla Const.) (fall)	6/05 Complaint 5/06; guilty pleas 12/06
36	Greg Clark (Greg Clark Roofing) (fall)	6/05 Information 2/06 guilty plea - fine
37	# Company G	7/05 No decision yet
38	# Company H	7/05 US Atty declined 11/05

Number of cases discussed with DOJ/US Atty. but not referred: 11

Fiscal Year 2006 [12]

39	# Company A (electrocution)	12/05	No decision yet
40	# Company B	12/05	No decision yet
41	# Company C	12/05	No decision yet
42	# Company D (caught in machine)	1/06	No decision yet
43	# Company E (trench)	1/06	US Atty declined 2/06
44	#, * Company F	1/06	No decision yet
45	American Asbestos Control (fall)	2/06	Guilty Plea 4/12/07 Sentenced 1 yr. probation $25,000 fine
46	# Company H (fall)	4/06	No decision yet
47	#, ** Company I	4/06	No decision yet
48	# Company J (electrocution)	7/06	No decision yet
49	# Company K (building collapse)	8/06	No decision yet
50	#, * Company L	9/06	No decision yet

Initial contacts on other cases: 6

Fiscal Year 2007

51	# Company A (trench)	2/07	No decision yet
52	# Company B (trench)	2/07	No decision yet
53	# Company C (confined space)	2/07	No decision yet
54	# Company D (fall from scaffold)	3/01	No decision yet
55	# Company E (fall from scaffold)	3/01	No decision yet
56	# Company F (fall from scaffold)	3/21	No decision yet
57	# Company G (wet concrete collapse)	6/15	No decision yet
58	# Company H (lack of machine guarding)	6/13	No decision yet

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* False statements (29 U.S.C. §666(g); 18 U.S.C. §1001)

** Interference with OSHA inspection, 18 U.S.C. §1505, or attempted bribery, 18 U.S.C. §210(b)(1)(A)

+ Assault on compliance officer

Company name withheld. Prosecution has not yet been initiated OR referral did not result in prosecution.

Appendix C
CSB Recommendations to OSHA

#	CSB Recommendation	Implementation Status (per CSB)	Explanation of Implementation Status for Recommendations NOT "closed" by CSB
1	**1998-05-I-LA-R4** (Union Carbide Corp. Nitrogen Asphyxiation Incident) **Issue a safety alert that addresses the hazards and provides safety guidelines for the use of temporary enclosures that are erected around equipment containing hazardous substances.**	Closed	
2	**1998-06-I-NJ-R8** (Morton International Inc. Runaway Chemical Reaction) **Issue joint guidelines on good practices for handling reactive chemical process hazards.**	Open	In process of developing chemical reactivity guidelines as recommended.
3	**1998-06-I-NJ-R9** (Morton International Inc. Runaway Chemical Reaction) **Participate in a hazard investigation of reactive chemical process safety conducted by the CSB.**	Closed	
4	**2001-01-H-R1** (Improving Reactive Hazard Management) **Amend the Process Safety Management Standard (PSM), 29 CFR 1910.119, to achieve more comprehensive control of reactive hazards that could have catastrophic consequences.**	Open	While OSHA is still contemplating this rulemaking recommendation, the Agency feels it has completed this recommendation as we have implemented or are developing a number of regulatory and non-regulatory initiatives related to chemical reactivity hazards including: - Continued enforcement of existing OSHA regulations related to chemical reactivity hazards such as PSM, 5(a)(1), and other applicable standards which apply to

			reactives, i.e. Hazard Communication, Flammable and Combustible liquids, etc. - Led a group of stakeholders in paying the majority of a 3-year subscription fee to the CCPS book , *Essential Practices for Managing Chemical Reactivity Hazards;* - Developed a chemical reactivity Alliance with stakeholders including EPA, CCPS, ACC, SOCOMA, Mary Kay O'conner Process Safety Center - Participate in the Reactivity Management Roundtable, a stakeholder group developing safe practices for managing chemical reactivity hazards - Developed a chemical reactivity hazards webpage; - In process of developing a compliance directive for OSHA CSHOs to enforce regulations related to catastrophic chemical reactivity hazards; - In process of developing chemical reactivity hazard guidance -Continued outreach activities associated with chemical reactivity hazards, e.g. OSHA Assistant Secretary spoke at CCPS International Conference, Director of Enforcement spoke at Mary Kay O'Conner Process Safety Annual Symposium.
5	**2001-01-H-R2** (Improving Reactive Hazard Management) Implement a program to define and record information on reactive incidents that OSHA investigates or requires to be investigated under OSHA regulations. Structure the collected	Open	OSHA believes it has completed this recommendation as we responded to CSB stating that we have a procedure to compile incident data, including reactive chemical incident data. OSHA obtains this type of data during investigations and the data is

	information so that it can be used to measure progress in the prevention of reactive incidents that give rise to catastrophic releases.		available through our Integrated Management Information System (IMIS) database. OSHA continues to provide CSB investigators unfettered access to our IMIS data, even that data which is not yet publicly available. With respect to obtaining information from reactive incidents which are required to be investigated and reported, OSHA does not have a regulation which requires employers to submit this information to the Agency. We have reviewed the Clean Air Act Amendments of 1990 and believe that Section 112(r) gives CSB the authority to collect such information.
6	2002-02-I-NY-R8 (OSHA, Region II) Occupational Safety and Health Administration) Disseminate information on the requirements of the Hazard Communication Standard, 29 CFR 1910.1200, in the major languages spoken by workers in New York City with limited or no English speaking proficiency.	Open - Acceptable Response or Alternate Response	OSHA considers this recommendation complete as OSHA continues to provide training and outreach in chemical safety including our *Hazard Communications* Standard in many of the major languages spoken in New York City. Some of these training and outreach activities include: • New Spanish-language page on OSHA's website ; • New Spanish-language option on OSHA's 1-800 number; • Numerous Spanish translations including Todo Sobre la OSHA (All About OSHA) and new publication, OSHA: Listos para ayudarle! (OSHA: Here to Serve You); • Collaborative effort working with the Catholic Church in New York; • Liaison with the Mexican Consulate in NYC;

			• Conduct outreach sessions in Chinese (Mandarin and Cantonese) and Hindi in NYC area; • Some 1300 individual International Chemical Safety Cards (ICSC) from the International Programme on Chemical Safety are available in 14 different languages through the OSHA website . An ICSC summarizes essential health and safety information on chemicals for their use at the "shop floor" level by workers and employers in factories, agriculture, construction and other work places; • Training modules on various safety and health subjects including Hazard Communication can be accessed through our Spanish-language page using a link to Oregon OSHA's website ; • Collection of new data when investigating fatalities to determine the role language and country of origin play in accidents; • Conducted six 10-hour safety training courses in Spanish in NY metro area; • Outreach being conducted in French and Haitian to Restaurant & Nursing Home workers in NY Metro Area; • Safety materials are being translated into Korean for dissemination in NY Metro Area; • Translated OSHA Poster into French and Polish and translation of the poster into Russian, Italian and Portuguese is currently in process; and • Univision, a Spanish Language Channel in New York ran a Special Presentation on

			OSHA on February 16, 17 and 18, 2004 (different presentations) during their 6 PM and 11 PM news.
7	**2002-02-I-NY-R9** (OSHA, Region II) Occupational Safety and Health Administration) Establish a complaint and referral system with the New York City Fire Department (FDNY) to provide for a coordinated enforcement effort	Open - Acceptable Response or Alternate Response	OSHA considers this recommendation complete as OSHA has developed and implemented a complaint and referral system with the New York City Fire Department (FDNY) to provide for a coordinated enforcement effort. Additionally, OSHA's Region 2 and its Manhattan Area Office worked with the Manhattan District Attorney in its investigation of Kaltech to obtain a guilty plea of "Reckless Endangerment" by the company. As a result, the plea agreement calls for Kaltech Industries to provide and pay for a comprehensive twenty-four hour chemical safety training course which will result in an OSHA certification for all employees who attend. This course will be for employees of sign manufacturers in the New York City area using chemical processes in their work. All Kaltech employees - and those of other sign and chemical companies owned by Kaltech's principals - were required to attend the training courses.
8	**2003-06-I-TX-R13** (BLSR Operating Ltd. Vapor Cloud Fire) Issue a Safety and Health Information Bulletin on the potential flammability hazard associated with bulk transportation of oilfield exploration and production (E&P) waste liquids.	Open - Acceptable Response or Alternate Response	OSHA is developing a Safety and Health Information Bulletin to address this issue, therefore, we consider this recommendation complete.

9	**2001-05-I-DE-R1** (Motiva Enterprises Sulfuric Acid Tank Explosion) Ensure coverage under the Process Safety Management Standard (29 CFR 1910.119) of atmospheric storage tanks that could be involved in a potential catastrophic release as a result of being interconnected to a covered process with 10,000 pounds of a flammable substance.	Open	Although the subject of this recommendation is important, at this time OSHA continues to believe this issue has not risen to a level where the Agency would consider changing its regulatory priorities. However, to ensure that PSM is being applied to process tanks similar to MOTIVA's spent acid tank, OSHA is developing a compliance directive. We believe that properly instructing our compliance staff with respect to differences in process tanks versus storage tanks will result in a more consistent application of PSM.
10	**2005-4-I-TX-R5** (BP America Refinery Explosion) 1. Implement a national emphasis program for all oil refineries that focuses on: - The hazards of blowdown drums and stacks that release flammables to the atmosphere instead of to an inherently safer disposal system such as a flare. Particular attention should be paid to blowdown drums attached to collection piping systems servicing multiple relief valves; - The need for adequately sized disposal knockout drums to safely contain discharged flammable liquid based on accurate relief valve and disposal collection piping studies 2. Urge states that administer their own OSHA plan to implement comparable emphasis programs	Open	The compliance directive is published. OSHA believes we have completed this recommendation. See Appendix A, *CSB Recommendations to OSHA From BP TCR Investigation* for an explanation on OSHA's development and implementation of its *Petroleum Refinery Process Safety Management National Emphasis Program* (Refinery NEP).

	within their respective jurisdictions.		
11	**2005-4-I-TX-R8 (CSB2005-04-I-TX-R8)** (BP America Refinery Explosion) 1. Strengthen the planned comprehensive enforcement of the OSHA Process Safety Management (PSM) standard. At a minimum: a. Identify those facilities at greatest risk of a catastrophic accident by using available indicators of process safety performance and information gathered by the EPA under its Risk Management Program (RMP). b. Conduct, or have conducted, comprehensive inspections, such as those under your Program Quality Verification (PQV) program at facilities identified as presenting the greatest risk. c. Establish the capacity to conduct more comprehensive PSM inspections by hiring or developing a sufficient cadre of highly trained and experienced inspectors. d. Expand the PSM training offered to inspectors at the OSHA National Training Institute.	Open	OSHA believes we have completed this recommendation. See Appendix A, *CSB Recommendations to OSHA From BP TCR Investigation* for an explanation of OSHA's development and implementation of its *Petroleum Refinery Process Safety Management National Emphasis Program* (Refinery NEP) and an explanation of its expanded/accelerated PSM training of the Agency's compliance officers.
12	**2005-4-I-TX-R9 (CSB2005-04-I-TX-R9)** (BP America Refinery Explosion) Amend the OSHA PSM standard to require that a management of change (MOC) review be conducted for organizational changes that may impact process safety including: a. major organizational changes such as mergers, acquisitions, or reorganizations;	Open	OSHA is currently evaluating this recommendation and will respond to CSB when our evaluation is completed.

	b. personnel changes, including changes in staffing levels or staff experience; and c. policy changes such as budget cutting.		
13	**2005-03-I-NJ-R5** (Acetylene Service Company Gas Explosion) Update the OSHA 1910.102 Acetylene Standard (a. Cylinders, b. Piped Systems, and c. Generators and filling cylinders) to remove the existing references to unavailable and obsolete Compressed Gas Association Pamphlets (CGA G-1-1966, G 1.3-1959, G 1.4-1966). As an alternative, consider incorporating by reference NFPA 51A Standard for Acetylene Cylinder Charging Plants.	Open - Acceptable Response or Alternate Response	OSHA considers this recommendation to be complete as the Agency intends to update the subject references in its rulemaking project, *Updating OSHA Standards Based on National Consensus Standards*.
14	**2006-1-H- -R1** (Combustible Dust Hazard Investigation) Issue a standard designed to prevent combustible dust fires and explosions in general industry. Base the standard on current National Fire Protection Association (NFPA) dust explosion standards (including NFPA 654 and NFPA 484)	Open	OSHA is currently evaluating this recommendation and will respond to CSB when our evaluation is completed.
15	**2006-1-H- -R2** (Combustible Dust Hazard Investigation) Revise the Hazard Communication Standard (HCS) (1910.1200) to: - Clarify that the HCS covers combustible dusts, including those materials that may reasonably be anticipated to generate combustible dusts through downstream processing or handling. - Require Material Safety Data Sheets (MSDSs) to include the hazards and physical properties of	Open	OSHA is currently evaluating this recommendation and will respond to CSB when our evaluation is completed.

	combustible dusts, as well as clear information on safe handling practices and references to relevant consensus standards.		
16	**2006-1-H- -R3** (Combustible Dust Hazard Investigation) Communicate to the United Nations Economic Commission for Europe (UNECE) the need to amend the Globally Harmonized System (GHS) to address combustible dust hazards	Open	OSHA is currently evaluating this recommendation and will respond to CSB when our evaluation is completed.
17	**2006-1-H- -R4** (Combustible Dust Hazard Investigation) Provide training through the OSHA Training Institute (OTI) on recognizing and preventing combustible dust explosions.	Open	OSHA believes this recommendation is complete as the Agency has committed to and is in fact developing a training program at its OTI on recognizing and preventing combustible dust explosions. This training will supplement the National Emphasis Program discussed below.
18	**2006-1-H- -R5** (Combustible Dust Hazard Investigation) While a standard is being developed, identify manufacturing industries at risk and develop and implement a national Special Emphasis Program (SEP) on combustible dust hazards in general industry. Include in the SEP an outreach program focused on the information in the Safety and Health Information Bulletin (SHIB), Combustible Dust in Industry: Preventing and Mitigating the Effects of Fire and Explosions.	Open	OSHA believes this recommendation is complete as the Agency has committed to developing and completing a National Emphasis Program (NEP) for conducting enforcement inspections at facilities with combustible dust hazards. This NEP is in the final stages of concurrence before issuance.
19	**2006-3-I-FL-R6** (Bethune Point Wastewater Plant Explosion) Revise 29 CFR 1910.106 to specifically exclude the use of thermoplastics in aboveground flammable liquid service.	Open	OSHA is currently evaluating this recommendation and will respond to CSB when our evaluation is completed.
20	**2006-8-I-IL-R1** (Universal Form Clamp Co. Explosion and Fire)	Open	OSHA is currently evaluating this recommendation and will respond to CSB

	Amend 1910.106 Flammable and Combustible Liquids to require facilities that handle flammable and combustible liquids to implement the requirements of 1910.38 Emergency Action Plans.		when our evaluation is completed.
21	**2006-8-I-IL-R2** (Universal Form Clamp Co. Explosion and Fire) Amend 1910.38 Emergency Action Plans to require employers to conduct practice evacuation drills at least annually, but more frequently if necessary to ensure employees are prepared for emergencies.	Open	OSHA is currently evaluating this recommendation and will respond to CSB when our evaluation is completed.
22	**2006-07-I-MS-R4** (Partridge-Raleigh Smith County Oilfield) Implement a Local Emphasis Program (LEP) to inspect companies in the oil and gas production and extraction sector.	OSHA is currently evaluating this CSB recommendation and will respond to CSB when we have determined the Agency's course of action.	Evaluating recommendation.

June 13, 2007

Ms. Jonne Slemons
Coordinator
Petroleum Systems Integrity Office
Division and Oil Gas
Alaska Department of Natural Resources
550 West 7th Avenue, Suite 800
Anchorage, AK 99501

Dear Ms. Slemons:

Thank you for appearing before the Subcommittee on Oversight and Investigations on Wednesday, May 16, 2007 at the hearing entitled " 2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" We appreciate the time and effort you gave as a witness before the Subcommittee.

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open to permit Members to submit additional questions to the witnesses. Attached are questions directed to you from certain Members of the Committee. In preparing your answers to these questions, please address your response to the Member who has submitted the question(s) and include the text of the Member's question along with your response. In the event you have been asked questions from more than one Member of the Committee, please begin the responses to each Member on a new page.

To facilitate the printing of the hearing record, your responses to these questions should be received no later than the close of business Friday, June 29, 2007. Your written responses should be delivered to 2125 Rayburn House Office Building and faxed to 202-225-5288 to the attention of Kyle Chapman, Legislative Clerk. An electronic version of your response should also be sent by e-mail to Mr. Kyle Chapman at kyle.chapman@mail.house.gov in a single Word or WordPerfect formatted document.

Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Kyle Chapman at (202) 226-2424.

Sincerely,

JOHN D. DINGELL
CHAIRMAN

Attachment

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL & GAS

SARAH PALIN, GOVERNOR

550 WEST 7TH AVENUE, SUITE 800
ANCHORAGE, ALASKA 99501-3560
PHONE: (907) 269-8800
FAX: (907) 269-8938

July 6, 2007

The Honorable Bart Stupak, Chairman
Subcommittee on Oversight and Investigations
Committee on Energy and Commerce
U.S. House of Representatives
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Stupak:

I am in receipt of a June 20, 2007 letter from Chairman John D. Dingell of the Committee on Energy and Commerce which forwarded 13 questions related to my testimony, on May 16, 2007, at the hearing entitled "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" Per Chairman Dingell's request, I am responding directly to you regarding those questions. The response, in italics, immediate follows the question.

1. Does the build-up of sediment in a pipeline send up a red flag, since bacteria can flourish under sediment and lead to aggressive microbial corrosion?

   Yes. Sediment in a pipeline can cause or contribute to problems, including providing an environment in which corrosion-causing bacteria can grow, creating difficulties with intelligent pigging, and blocking of corrosion inhibitor interface with the pipe wall. The presence of sediment is therefore a red flag for consideration of these issues, and generally calls for measures to remove it and to prevent its build-up.

2. Does the build-up of sediment in the bottom of a pipeline act as a shield which prevents biocide and other corrosion inhibitors from reaching corrosion causing bacteria?

   Yes. Build-up can interfere with the effectiveness of biocides or corrosion inhibitor, which work best on clean pipe.

3. A "Compliance Order by Consent" was issued to BP by the Alaska Department of Environmental Conservation (ADE) in May 2002, which included a requirement for BP to determine sediment levels and to commence pigging certain oil transit lines by September 2002. However, on August 9, 2002, BP asked to eliminate the requirement for pigging these oil transit lines. On August 14, 2002, ADEC sent a letter to BP agreeing to eliminate the requirement for pigging these lines. Why did ADEC agree to eliminate the requirement for maintenance pigging these oil transit lines to remove sediments? Is there documentation to support this decision? Do you agree with this decision?

I answered these questions in my letter of June 5, 2007, and provided copies of the documentation supporting my response. That letter and its attachments are provided as an attachment to this letter.

4. Your testimony states: "The events of 2006 in the Prudhoe Bay Unit taught us that we cannot rely on 'enlightened self interest' to ensure that prudent maintenance practices are carried out." Please explain why, in your view, BP's enlightened self interest allowed their assets to corrode and deteriorate into an unserviceable state – leading to the partial shutdown of the field?

   The State is investigating the exact sequence of events and decisions that led to the final state of BP's Prudhoe Bay Unit assets in 2006. One can surmise, however, that the cost-saving benefits realized in the short-term were an important factor in the initial decisions made regarding routine pipeline maintenance procedures such as pigging, and use of corrosion inhibitor. It is dismaying that appearances seem to indicate what may have begun as a means to short-term budget relief became, in the end, a long-term practice.

5. What specific steps will the Petroleum Systems Integrity Office (PSIO) take to prevent cost cutting from compromising the safety and integrity of the pipelines under your jurisdiction?

   The PSIO will require submittal of Systems Integrity Plans (SIPs) from unit operators, to identify the maintenance programs and quality assurance programs that they will use. The adequacy of those plans will be assessed by the PSIO independent of any cost considerations. Compliance will be determined through self-reporting, and compliance audits and site inspections performed by the PSIO.

6. Please describe the milestones and deadlines for BP Prudhoe Bay's operations with respect to the new quality assurance program led by your Office.

   At this time, firm deadlines have not been established for submittal of BP's System Integrity Plan, a key component of the PSIO quality assurance program for the Prudhoe Bay Unit. The Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation is considering a Consent Agreement with BP to close the Compliance Orders and Amendments issued in 2006. The significant changes required of BP through the Compliance Orders and Amendments, as well as any that may be forthcoming via a Consent Agreement, will determine to a large extent BP's structure and work processes that will be an integral element of the System Integrity Plan that BP will submit to the PSIO. It is of great value to the quality assurance interests of the PSIO to allow the requirements for those structures and work processes to be fully defined before the Prudhoe Bay Unit System Integrity Plan is required and submitted.

7. Has the State assessed the extent of cost cutting in BP's corrosion protection programs at Prudhoe Bay?

   The State is examining many of the same documents provided to your Subcommittee before, during and after the May 16, 2007 hearing. That examination is continuing.

No conclusions have been reached regarding the extent of cost cutting in BP's corrosion prevention programs at Prudhoe Bay.

8. Was the State of Alaska ever advised of BP's proposals to save money by turning off corrosion inhibitor in its produced water lines? If so, what steps were taken by ADEC?

   The State was not informed of such a proposal. We were told in approximately March of 2003 that supplemental produced water injection systems had been initiated in 2002. See Commitment to Corrosion Monitoring Year 2002 at p. 51. In approximately March of 2004, BP repeated its statement that supplemental produced water corrosion inhibitor injection had been initiated, and that general corrosion rates in the produced water system had fallen. See Commitment to Corrosion Monitoring Year 2003 at p. 49. BP also stated that its corrosion control program "now includes limited inhibitor injection in the PW system at FS-1, FS-3, GC-1, GC-2 and GC-3." Id. at 52. This same information was repeated the following year, see p. 21 of Commitment to Corrosion Monitoring Year 2004. In approximately March 2006, we were also told that "supplemental corrosion inhibition of the PW system will be expanded to FS2 in 2006," see p. 87 of Commitment to Corrosion Monitoring Year 2005. The referenced Corrosion Monitoring reports are available at: http://www.dec.state.ak.us/spar/ipp/nscharter.htm.

9. Booz Allen identified the absence of a process safety management system as a key failing in BP's Prudhoe Bay operations. What specific actions is your office taking to ensure that BP implements an effective process safety management program with respect to pipelines under your jurisdiction?

   The Alaska Occupational Safety and Health (AKOSH) program intends to increase and focus enforcement efforts on oil and gas infrastructure inspections within its jurisdiction to ensure compliance with process safety management (PSM) requirements. These inspections will not be focused solely on BP's Prudhoe Bay operations, but will include those sites as potential enforcement targets.

   In addition, the AKOSH program is working with BP and other companies in the oil and gas industry on a consultative basis. These inspections will also evaluate PSM systems, when applicable, at oil and gas processing facilities to ensure compliance with occupational safety and health standards.

   Under federal regulations adopted by the State of Alaska for process safety management standards (29 CFR 1910.119(a)(2)), "oil or gas well drilling or servicing operations" and "normally unoccupied remote facilities" are not subject to the standards. These exceptions are noteworthy, as several facilities at Prudhoe Bay fall into one of these categories.

10. The Office of Pipeline Safety testified that they will be monitoring BP management incentives to ensure that management does not incentivize decisions which could compromise process safety or corrosion protection. Will the State of Alaska be taking parallel actions with respect to pipelines under its jurisdiction?

The State of Alaska does not have the authority to require information relating to management salaries, contracts, and incentives. The State is a joint signatory to a Letter of Intent with the Office of Pipeline Safety that includes the sharing of information and findings. The State may therefore be informed of such information through that avenue, but does not plan to independently seek the authority to require or engage in those issues.

11. The Federal Occupational Safety and Health Administration (OSHA) asserts that Alaska OSHA has authority to regulate process safety management in the gathering centers and compressed gas operations at Prudhoe Bay. Does Alaska OSHA have process safety management regulations that mirror those of Federal OSHA?

    The State of Alaska's Department of Labor and Workforce Development has adopted the federal OSHA standards (29 CFR 1910.119)d for process safety management pursuant to Alaska Statute 18.60.030(6) and 8 Alaska Administrative Code (AAC) 61.1010(b). Additionally, the State has adopted particular standards beyond those of federal OSHA related to petroleum refining, transportation and handling under 8 AAC 61.1190, and related to petroleum drilling and production under 8 AAC 61.1180. (See Alaska Statute and AAC references, Attachment 2.)

12. Has Alaska OSHA ever conducted a process safety management inspection of the gathering centers and the gas compression center? How many times and on what dates?

    AKOSH has conducted several inspections of the gathering centers and gas compression center at Prudhoe Bay (see spreadsheet, Attachment 3).

13. BP's fire and gas systems in the gathering centers have aged and are in need of a major upgrade. Please describe the PSIO's plans with respect to overseeing process safety management at the gathering centers?

    PSIO defers oversight of fire and gas systems to the Department of Public Safety, Division of Fire Prevention (DFP). The DFP has authority to establish regulations for the design, installation and maintenance of all fire and gas detection, suppression and inerting systems, establishes the adoption of the state building, fire and mechanical codes and conducts fire and life safety plan reviews for all new and renovation construction. Additionally, the DFP conducts fire and life safety facility inspections based on hazard risk to life safety.

    The DFP agrees that the fire and gas detection systems in the Gathering Centers have aged and are in need of upgrading. The DFP identified this fact through trend analysis of system failures that resulted in numerous halon discharges, false alarms and system "down time." The DFP determined that fire and gas detection system obsolescence resulted in the non-availability of replacement parts and the need of to upgrade some facilities and cannibalize older systems for parts, specifically in Gathering Center 1 (GC-1).

In response the DFP reviewed BP's maintenance practices, procedures and documentation, and found that BP's self-monitoring of its maintenance program needed improvement. BP revamped its maintenance system, increased its manpower pool of certified fire and gas technicians and conducted its own risk analysis of the system.

As a result, BP developed a test bed for advanced technology in the late 1990s with implementation of a pilot project, the new Autronica Fire and Gas system, at GC-1. This led to an expansion of the system throughout GC-1 in 2005.

Gathering Center 2 (GC-2) and 3 (GC-3) have not been updated. Maintenance is becoming more difficult for the same reasons as it did at GC-1 prior to its fire and gas detection/suppression upgrade. BP has verbally acknowledged this but has committed no funding for the engineering required to effect upgrades, nor has it established a timetable for upgrades by which it holds itself accountable. As a stop gap measure, obsolete CP 250 fire panels are being replaced piecemeal with new Detronic Notifier panels, where possible in the facilities.

As long as BP can continue to keep the fire and gas systems of GC-2 and GC-3 working and maintained, as specified by state regulation, the DFP cannot mandate but only suggest that the system be upgraded. The authority of the PSIO will be evaluated to determine if additional action by BP in this regard can be pursued.

In addition to the DFP's efforts regarding fire and gas suppression systems, the Department of Labor and Workforce Development/AKOSH is targeting oil and gas infrastructure in Alaska for compliance with process safety management standards. The gathering centers are included in this targeting focus.

Thank you for the opportunity to provide additional information in response to your questions, and for the opportunity to appear before the Subcommittee.

Sincerely,

Jonne Slemons
Petroleum Systems Integrity Office Coordinator

Enclosures:

1) Letter from J. Slemons to Ch. B. Stupak, June 5, 2007 and attachments:
    a) October 16, 2006 Fredriksson/ADEC Letter to Hon. Joe Barton
    b) August 9, 2002 Campbell Letter to L. Miner/ADEC
    c) August 14, 2002 Miner/ADEC Letter to G. Campbell
    d) November 26, 2002 Conrad letter to C. Leonard/ADEC
    e) March 25, 2003 Bronson Letter to J. Mach/ADEC
    f) April 3, 2003 Hutmacher/ADEC Letter to J. Fritts

g) October 13, 2006 Gaynor Letter to Snowdon, Knauer
h) February 13, 2002 Phillips Letter to M. Barnes
i) January 31, 2002 Conrad Letter to C. Leonard/ADEC, with attachments
j) October 19, 2002 Campbell E-mail to Phillips, Blankenship, Conrad
k) September 16, 2002 Jacobsen E-mail to Phillips, with attachments
l) November 18, 2002 Phillips Letter to M. Barnes
m) October 1, 2001 Campbell Letter to R. Watkins, with attachments
n) "Redacted Interim Report of Investigation" by Garde and Clifford
o) "GPB Leak Detection Summary 10-13-2002"
p) October 18, 2002 Bruchie E-mail to Neill
q) Excerpt, "Commitment to Corrosion Monitoring, Year 2002"
r) Excerpt, "Commitment to Corrosion Monitoring, Year 2003"
s) Excerpt, "Commitment to Corrosion Monitoring, Year 2004"

2) Alaska Statute and Administrative Code Citations provided in response to Question 11.

3) Inspection Spreadsheet referenced in Question 12.

cc (w/enclosures):
The Honorable Sarah Palin, Governor, State of Alaska
The Honorable Ted Stevens, Senator, U.S. Senate
The Honorable Lisa Murkowski, Senator, U.S. Senate
The Honorable Don Young, Representative, U.S. House of Representatives
The Honorable Joe Barton, Representative, U.S. House of Representatives
The Honorable Ed Whitfield, Representative, U.S. House of Representatives
Vice Admiral Thomas J. Barrett, USCG (Ret.), Deputy Secretary, U.S. Department of Transportation
Stacey Gerard, Chief of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation
Commissioner Thomas Irwin, Alaska Department of Natural Resources
John Katz, Director, Alaska Governor's Office, Washington, D.C.
Christopher Knauer, U.S. House of Representatives

June 13, 2007

Ms. Stacy Gerard
Acting Assistant Administrator
Chief Safety Officer
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building
1200 New Jersey Avenue, SE
Washington, DC 20590

Dear Ms. Gerard:

Thank you for appearing before the Subcommittee on Oversight and Investigations on Wednesday, May 16, 2007 at the hearing entitled " 2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" We appreciate the time and effort you gave as a witness before the Subcommittee.

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open to permit Members to submit additional questions to the witnesses. Attached are questions directed to you from certain Members of the Committee. In preparing your answers to these questions, please address your response to the Member who has submitted the question(s) and include the text of the Member's question along with your response. In the event you have been asked questions from more than one Member of the Committee, please begin the responses to each Member on a new page.

To facilitate the printing of the hearing record, your responses to these questions should be received no later than the close of business Friday, June 29, 2007. Your written responses should be delivered to 2125 Rayburn House Office Building and faxed to 202-225-5288 to the attention of Kyle Chapman, Legislative Clerk. An electronic version of your response should also be sent by e-mail to Mr. Kyle Chapman at kyle.chapman@mail.house.gov in a single Word or WordPerfect formatted document.

Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Kyle Chapman at (202) 226-2424.

Sincerely,

JOHN D. DINGELL
CHAIRMAN

Attachments

The Honorable John D. Dingell
Chairman
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Dingell:

Thank you for the opportunity to testify before the Subcommittee on Oversight and Investigations on May 16, 2007 at the hearing entitled "2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?"

I am pleased to submit these responses to the questions for the record. Please let me know if I can be of further assistance to you

Sincerely,

Stacey Gerard
Assistant Administrator/
Chief Safety Officer

Cc: The Honorable Joe Barton, Ranking Member
Committee on Energy and Commerce

The Honorable Bart Stupak, Chairman
Subcommittee on Oversight and Investigations

The Honorable Ed Whitfield, Ranking Member
Subcommittee on Oversight and Investigations

QUESTIONS FOR THE RECORD SUBMITTED BY CHAIRMAN DINGELL TO THE U.S. DEPARTMENT OF TRANSPORTATION

The Honorable Bart Stupak

Question 1. Last September, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposed new regulations to cover the low stress oil transit lines, such as those that leaked at Prudhoe Bay. When will these rules be finalized?

Answer: On May 18, 2007, we issued a supplemental notice of proposed rulemaking, modifying our September 2006 proposal in order to address certain additional requirements imposed by Section 4 of the Pipeline Inspection, Protection, Enforcement and Safety Act (PIPES) Act of 2006, which was signed into law in December 2006. We are finalizing our proposal to address the highest risk areas this year and are expeditiously working on a proposal to address those areas of lesser risk in a second phase of the rulemaking. We discussed our proposal in July with our Technical Hazardous Liquid Pipeline Safety Standards Advisory Committee, which endorsed the proposal.

Question 2. For how long does PHMSA plan to keep BP under a compliance order at Prudhoe Bay?

Answer: PHMSA will have BP North Slope operations under an order for as long as necessary to verify that BP has corrected the hazardous conditions in its pipeline operations. Because this involves the construction and start-up of new facilities; the implementation of new operating and maintenance procedures; and verification of compliance through repeated successful performance, we would expect to have BP under an order for at least five years. PHMSA will closely oversee BP's North Slope pipeline operations for the duration of the order.

Question 3. How will PHMSA prevent cost cutting from compromising the safety and integrity of the BP pipeline systems it oversees? Will this include steps to assess the bonuses and incentives provided to managers to ensure they are not rewarded for cutting costs for process safety?

Answer: PHMSA is using its full authority to direct BP to develop and implement better risk management processes and priorities, with a focus on the safety and integrity of its system, and to evaluate the effectiveness of these programs. As I explained above, we expect to continue this level of oversight for at least several more years and, in any case, as long as is necessary. By that time, all of BP's North Slope pipeline operations will be subject to full regulation, including PHMSA's integrity management requirements.

Question 4. Was BP positioned to successfully respond to PHMSA's March 2006 order?

Answer: Although we had twice extended the deadlines at BP's request, BP failed to complete cleaning and inspection of its pipelines by the dates required under the March 15, 2006 Corrective Action Order. BP could have met these deadlines if it had made reasonable efforts to do so.

Question 5. What specific organizational and process safety weaknesses identified by the Chemical Safety Board at BP's Texas City Refinery were also observed by PHMSA in evaluating BP's Prudhoe Bay operation?

Answer: In connection with our ongoing inspection and oversight activities arising out of the 2006 spills, PHMSA has observed organizational and process safety weaknesses in BP's North Slope operations that appear similar to findings of the Chemical Safety Board concerning the Texas City Refinery fire. Specifically, PHMSA has observed weaknesses in the following areas and activities:

- Pipeline threat and risk characterization, and segment prioritization
- Pipeline risk control
  Personnel risk characterization and control
- Clarity of responsibilities and sufficiency of resources
- Management process
- Performance characterization and management
- Safety culture and climate
- Communications.

Question 6. Attached to this letter, please find an exhibit entered into the record for the May 16, 2007 hearing, pertaining to cutting the frequency of coupon pulls. BP's coupon program was designed to show how much corrosion was occurring on various pipelines. This document suggests that coupons pulls were reduced to "Make Stretch Budget" and that cutting it 25 percent would save 1.1 man-years or about $250,000. If BP was so reliant on the coupon program, why would they want to reduce the number of coupons and pulls by 25 percent? Was this a wise move?

Answer: The referenced exhibit suggests BP's proposal to reduce the frequency of coupon pulls on the pipelines was motivated by short-term cost-cutting. We understand that BP did reduce coupon pulls, and we believe that was not a wise move. Under PHMSA's oversight following the 2006 spills, BP has been required to significantly increase its corrosion control and monitoring activities.

June 13, 2007

Mr. Robert A. Malone
Chairman and President
BP America, Inc.
200 Westlake Park Boulevard
Houston, TX 77079

Dear Mr. Malone:

Thank you for appearing before the Subcommittee on Oversight and Investigations on Wednesday, May 16, 2007 at the hearing entitled " 2006 Prudhoe Bay Shutdown: Will Recent Regulatory Changes and BP Management Reforms Prevent Future Failures?" We appreciate the time and effort you gave as a witness before the Subcommittee.

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open to permit Members to submit additional questions to the witnesses. Attached are questions directed to you from certain Members of the Committee. In preparing your answers to these questions, please address your response to the Member who has submitted the question(s) and include the text of the Member's question along with your response. In the event you have been asked questions from more than one Member of the Committee, please begin the responses to each Member on a new page.

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Thank you for your prompt attention to this request. If you need additional information or have other questions, please contact Kyle Chapman at (202) 226-2424.

Sincerely,

JOHN D. DINGELL
CHAIRMAN

Attachment

bp

Robert A. Malone
Chairman & President

BP America Inc.
200 WestLake Park Blvd.
Houston, TX 77079
USA

Direct 281 366 3355
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July 6, 2007

The Honorable John D. Dingell
U.S. House of Representatives
Chairman, Committee on Energy and Commerce
Washington, DC 20515-6115

Dear Chairman Dingell:

Thank you for the opportunity to address several of the issues that were raised during the May 16, 2007 hearing of the Subcommittee on Oversight and Investigations on the 2006 Prudhoe Bay shutdown. As discussed with your staff by telephone yesterday, BP is today submitting responses to questions 1 through 14 raised by Congressman Stupak in your June 20, 2007 letter. Your staff agreed that we may provide responses to Mr. Stupak's questions 15 and 16 no later than July 13, 2007.

Please feel free to call me if I may be of further assistance.

Sincerely,

Robert A. Malone

Attachments

Responses to June 20, 2007 Questions from Congressman Stupak

1. **Mr. Malone, what other companies own the Prudhoe Bay field? What control, if any, do these working interest owners have over BP's budget for operating the field?**

Four companies have an interest in the field leases at the Prudhoe Bay Unit ("PBU"): ExxonMobil (36.4%), ConocoPhillips (36.1%), BP (26.4%), and ChevronTexaco (1.1%).[1] As described in the Prudhoe Bay Unit Operating Agreement ("UOA"), each of these companies is a Working Interest Owner ("WIO").

Because the budgeting and planning process for the PBU requires authorization by the WIOs, there is not a "BP budget" for operating the field. There is a PBU field expense budget that covers operations and maintenance for the field and that represents the collective budget for all the WIOs. As provided in the UOA, BP, as the field operator, prepares a proposed field expense budget and submits it to the other WIOs for consideration. As a practical matter, the operator's proposed field expense budget has rarely, if ever, been accepted without amendment by the WIOs; however, the process has generally resulted in an understanding of the potential range of expenditure against which BP, as operator, has worked. In addition to the budget approval process, expenditures for all rig workovers and expenditures related to major repairs or studies that exceed the operator's expenditure authority limit (currently $1.35 million per project) need case-by-case approval from the WIOs. The WIOs approve projects above the operator's expenditure authority limit via an Authorization for Expenditure ("AFE") for the project in question.

2. **Do working interest owners have veto power with respect to the budget for maintenance and related capital spending? Have they ever exercised that authority?**

Maintenance and capital expenditures are covered in two separate budgets: maintenance is a part of the field expense budget, while capital expenditures are funded through a separate capital budget. Similar to the approval process for the field expense budget, BP, as field operator, proposes an annual capital budget for WIO consideration. As with the expense budget, the capital budget is rarely approved as submitted, and negotiations to a final capital budget follow. In addition, for any capital projects that exceed the operator's expenditure authority limit, which today is $1.35 million per project, the operator must obtain case-by-case approval from the WIOs. Project approval above the operator's expenditure authority is requested of the WIOs, on an individual project basis, by means of an AFE.

While the Prudhoe Bay UOA does not explicitly provide for "veto" power, the majority owner WIOs, ExxonMobil and ConocoPhillips, have the ability to approve or reject the field expense and/or capital budgets (as noted above), as well as individual AFEs above the operator's expenditure authority, and they have done so.

---

[1] For ease of discussion, "BP" is used as shorthand throughout this letter to refer to corporate actions that may have been taken by any of a number of legal entities affiliated with BP, including BP Exploration (Alaska) Inc. and BP Products North America, Inc. The use of "BP" in this context should not be understood as a reference to BP p.l.c. or as an equation of separate legal entities with any parent and/or other affiliate.

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3. **According to Booz Allen's interview with Bill Hedges, the head of BP's corrosion group in Alaska, the backlog of corrosion related items at the end of 2005 was 2000 items. He said that by 2006, the backlog had grown even further to 3000 items that require visual inspection and follow up. Is this statement correct? What is the backlog on corrosion inspections at Prudhoe Bay today?**

In his interview with Booz Allen Hamilton ("Booz Allen"), Mr. Hedges discussed locations for which corrosion-under-insulation ("CUI") mitigation was planned. At year-end 2005, there were 2,114 such locations. Although BP does not wish to allow CUI issues to linger over time, a standard element of effective maintenance scheduling is the planning of maintenance through what is colloquially termed a "backlog." The term "backlog" in this context is a misnomer—it simply refers to the deliberate accumulation of non-safety critical work orders so that work can be planned, prioritized, and scheduled efficiently. The "backlog" allows the consolidation of routine work and maximizes the use of maintenance crews to attend to those matters. Industry experts consider developing a work schedule to address routine maintenance items over time to be a best practice in order to plan work safely and maximize efficiency.

At year-end 2006, there were 3,609 locations for which CUI mitigation was planned, even though, during calendar year 2006, BP actually mitigated 1,215 locations with CUI issues. The increase in the overall number can mostly be explained by enhanced and aggressive detection efforts that BP employed as part of the mitigation process. As of June 2007, that overall number had decreased to 3,086 locations.

BP has been devoting significant resources both to increasing its detection efforts and to mitigating these CUI issues. BP has already spent $14.2 million year-to-date on CUI mitigation efforts and projects that it will need $40.9 million by year-end 2007 to reach its goal of having zero outstanding CUI issues.

4. **Is it BP's position that cost cutting pressure and its impact on the decision making environment had no impact whatsoever on BP failing to smart pig the oil "transit" lines that leaked?**

As Mr. Malone said in his testimony, BP recognizes that budget decisions can affect a company's operations and its workforce in many ways. Over the past two years, BP has learned a great deal—both through direct feedback from employees and through formal studies of operations—about what those effects can be. BP has learned, for example, that budget decisions can impact employee morale, influence the openness of communications between management and the workforce, and affect the degree to which fo rmal processes are followed. Those effects are relevant from a management perspective: risk assessments must inform all budget decisions, and the best information must be elicited from workers by fostering an environment in which everyone is willing to discuss issues and raise concerns.

BP does not believe that "cost cutting pressure" caused the leaks in the oil transit lines in 2006 or impacted the Corrosion, Inspection & Chemicals ("CIC") group's decisionmaking process with respect to whether and when to run in-line ("smart pig") inspections of the oil transit lines. The question as posed appears to imply that the CIC group identified a need to smart pig the oil transit lines in the Western Operating Area ("WOA") and Eastern Operating Area ("EOA") but that smart pigs were then not run. That is not the case.

From the time of the 1998 smart pig run on the WOA oil transit line until 2005, the CIC group did not perceive a need for BP to smart pig either the WOA or EOA oil transit lines. The CIC group believed the corrosion risks on the oil transit lines were being managed by the existing monitoring, inspection, and mitigation programs and that the oil transit lines had a low probability of failure, based on the results of the 1998 pigging, subsequent inspection and monitoring data, and the fact that the lines carry sales-quality crude oil, which is considered to have a low corrosion risk.

The CIC group's decisions regarding the need for pigging the oil transit lines from 1998 through 2005 did not hinge on the availability of funding but rather on the group's internal analysis of these data, which was based on many years of inspection and successful experience managing corrosion on the WOA oil transit line. As Mr. Malone has testified, in hindsight BP now knows that the corrosion prevention program was inadequate.

5. **Is it BP's position that even if the Alaska Corrosion, Inspections, and Chemical Group (CIC) had a larger budget, they would not have smart pigged the oil transit lines that were later found to be so corroded that they leaked?**

Yes. This question is addressed in the independent report by Booz Allen. The CIC group believed that the corrosion risks on the oil transit lines were being managed by then-existing monitoring, inspection, and mitigation programs. Thus, the CIC group's decisions between 1998 and 2005 not to smart pig the oil transit lines were not tied to the availability of funding. Indeed, Booz Allen found that, if the CIC group had had more funds during this period, it would have applied them elsewhere because smart pigging the oil transit lines was not deemed to be a high priority.

Booz Allen found that the CIC group did not prioritize smart pigging of the oil transit line for two reasons:

1. They believed that, because the oil transit lines carried sales-quality crude oil, they were inherently at low risk for corrosion; and

2. They interpreted their historical inspection data of 29 years, including the 1998 smart pig run in the WOA,[2] as confirming that there was little corrosion risk in the oil transit lines.

In 2005, when inspection and monitoring results indicated greater incidence of corrosion, the CIC group took corrective actions by recommending and scheduling both smart and maintenance pigging. Unfortunately, a spill occurred before the corrective measures were performed.

BP now understands the need for, and has adopted, a more comprehensive and systematic approach to corrosion risk assessment. That approach incorporates greater sensitivity to changes

[2] The 1998 pigging of the WOA oil transit lines produced very few solids. The OT-21 segment showed moderate corrosion but was within BP's fit-for-service criteria.

in operating and environmental conditions when assessing risk and encourages improved upward and cross-functional communication so that any concerns relating to safety are raised within the organization.

6. A February 5, 2003 e-mail discusses the approval of a $1 million study for portable pig launching and receiving facilities in the Eastern Operating Area on cross country and oil transit lines to "detect both internal and external corrosion." Attached to that e-mail is a list entitled "pigging facility priority listing." That document was also placed into the record for this hearing. Why did BP's CIC Group commission this study? What was the cost of this study? Given an environment where discussions were taking place about reducing corrosion inhibitor, why did the CIC group expend scarce resources on the VECO report?

BP commissioned the study—an "Appraisal-Level Cost Report"[3]—from VECO Alaska, Inc. ("VECO") in 2003. The study was intended to provide BP with rough, order-of-magnitude cost estimates for AFE development associated with a potential future decision to add or upgrade pigging facilities on 71 lines in the EOA. This report followed two proposals that the Anchorage CIC group had developed between mid-2002 and early 2003:

- In June 2002, the CIC group submitted AFE #4N0492 seeking authorization from the other WIOs to install permanent pig launcher and receiver facilities on 25 lines in the EOA at a projected cost of $2.5 million. This was not a request by the CIC group to pig the lines. The objective of this request was to provide some infrastructure to make pigging easier if it were later determined to be necessary. The AFE was ultimately rejected by one WIO and not approved by the other WIO pending additional engineering detail. Around the same time, the BP business unit planning department asked the CIC group for a technical package and detailed cost analysis, including an engineering estimate for the project.

- In response to that request, CIC prepared Master ID #2996 in January 2003 to "develop scope and perform preliminary engineering for temporary or portable pig launching and receiving facilities." Since this project fell within a $1 million threshold, it could be approved within the operator's expenditure authority as it existed at that time. This also was not a request to pig the lines.

Following the preparation of Master ID #2996, the CIC group's project team (which had not been involved in either proposal to date) evaluated the proposals. The project team quickly observed that both proposals—the initial $2.5 million proposal to install pig launcher and receiver equipment and the second proposal to perform an engineering assessment for such a project for less than $1.0 million—likely underestimated (by many orders of magnitude) what the project team expected to be a major capital project.

[3] "Appraisal-level" refers to the first step in the "Capital Value Process," a generic "stage-gate" approach to approving and managing major projects that BP and many other corporations employ. The "Appraise" stage may be thought of as the very first "brainstorming" step that must be taken before any major capital project is begun, and it includes numerous activities, only one of which in this instance was the VECO study. The steps following Appraise are Select (where a decision is actually taken to make a capital expenditure), Define, Execute, and Operate.

BP thereafter retained VECO to provide a better assessment of the likely cost of such a project. The CIC group, wishing to have as comprehensive an estimate as possible, expanded the list of lines for VECO to consider from the original 25 in AFE #4N0492 to 71 lines, *i.e.*, all the large-diameter lines (of various sizes and design pressures) on the EOA that it wanted to consider for facilities to launch and receive smart pigs. This list included the segments constituting the EOA oil transit lines and the oil transit line for Lisburne so that upgrades to pigging capability could be considered.

The resulting appraisal-level cost report prepared by VECO represented a high-level evaluation of costs. It confirmed that adding or upgrading pigging facilities on those 71 lines would be a major capital project far in excess of the $2.5 million estimated for the 25 lines in the June 2002 AFE. The VECO report's three options for completing the full project estimated expenditures at $643 million (for permanently installed, indoor pig launcher/receiver facilities); $180 million (for "portable," modularized launcher/receiver equipment); or $164 million (for "temporary," component-assembled launcher/receiver facilities). The preliminary engineering costs would similarly have been many times higher than the less-than-$1 million contemplated by Master ID #2996. As a rule of thumb, engineering costs on a project typically run about 10% of the total budget, with preliminary engineering roughly 30% to 40% of the total engineering costs. Under the $643 million option, therefore, the preliminary engineering costs would likely have run between $19 and $26 million; even under the $164 million approach, the preliminary costs would still likely have been between about $5 and $6.5 million.

The cost of the VECO study was roughly $28,000. BP commissioned the report because it wanted to understand the potential scope of such a project. The study was designed to deliver an estimate for the lowest reasonable cost of such a project. That the report did not ultimately lead to a field-wide project estimated to cost $160 million at a minimum does not mean that the project wasted BP's resources.

7. **On March 12, 2003, VECO Alaska, a contractor to BP, submitted to BP a reconnaissance level estimate report for installing pig launching and receiving facilities at 71 locations identified in the "pigging facility priority listing" mentioned in question #6. That pigging facility priority list included 3 segments of the Eastern Operating Area line—which had not been pigged for 16 years. One of the three lines listed in the "pigging facility priority listing" was an oil transit line, which was severely corroded and found to be leaking in August 2006. Was the VECO report commissioned to identify the cost of installing pig launchers and receivers, which would accommodate the larger "smart pigs"?**

Yes. The 71 locations, representing lines of various sizes and design pressures, were under consideration for installation of launcher and receiver facilities for smart pigging, and VECO was retained to provide a rough, order-of-magnitude cost estimate for such a project. Although certain lines, such as the oil transit lines, already had launcher and receiver facilities installed, their dimensions probably could not have accommodated the longer smart pigs in use as of 2003. Indeed, the CIC group needed to modify the cone of the smart pig used in the 1998 smart pig run for just this reason.

8. **The VECO rep rt provided a range of estimates from $164 million to $643 million to install the 71 pig launchers and receivers. What actions did BP take after receiving this report? Were any budget requests made to install any new pig launchers or receivers mentioned in the VECO report? In what year(s) were budget requests made? Were these budget requests approved? Were any of the pig launchers and receivers actually installed?**

The VECO appraisal-level cost report was undertaken to provide a better assessment of the potential costs associated with the installation of pig launcher and receiver facilities. The report was intended to help BP make appraisal-level and programming decisions about how to develop and budget for such a project.

Upon receipt of the report, BP decided not to pursue additional pig launcher and receiver facilities on a field-wide basis and did not submit a capital proposal for WIO approval at that time. The CIC also did not request funds for pig launcher and receiver facilities in its budget. These determinations were primarily based on the fact that BP believed it had adequate processes in place to address potential corrosion issues on the lines that presented the highest risks of corrosion, such that a capital project of this scale was not necessary. Nevertheless, BP had the capability to smart pig many of the lines deemed to have the highest risk of corrosion by installing temporary launchers and receivers when the inspection and/or monitoring data indicated a need to do so. Indeed, in the latter part of 2003, the CIC group requested funds for a smart pig inspection of a line in the EOA because of potential corrosion; it was provided those funds, and the inspection occurred.

When the "pigging facility priority listing" spreadsheet was prepared in 2003, many of the lines listed on it were deemed not to be at high risk for corrosion. Included on the list was the FS2/FS1OIL line, which is the line on which a leak occurred in August 2006. As review of the list demonstrates, the data available in 2003 indicated that this segment of the EOA transit line was not a top priority line among the 71 lines considered as part of the VECO assessment: in 2003, that line was estimated to have only a 1% loss in wall thickness [*see* column marked "~% Wall T"] and was listed as a "Priority 2" line on that chart. Indeed, the line would have been ranked Priority 3 as a matter of pure risk but was ranked as Priority 2 for a business reason, *i.e.*, because the line carried sales-quality crude.

9. **BP has told the Committee that the VECO report had assessed the cost of installing pig launchers and receivers in locations where BP already had pig launchers and receivers. Did the CIC Group commission VECO to prepare cost estimates for potential work that did not need to be done? Was the CIC Group so unaware of the assets under its stewardship that it prepared a "pigging facility priority listing" which contained locations which already had fully functional pig launchers and receivers?**

At the time the VECO study was commissioned, BP was aware, based on records obtained prior to its assumption of sole operatorship in 2000, that 19 lines in the EOA, including the EOA oil transit lines, had been smart-pigged in the past. BP had not, however, evaluated whether the pig launcher and receiver facilities used on those lines were temporary, permanent, or in need of major modifications; whether they could accommodate the newer, longer smart pigs that had been developed; or whether they needed repairs for maintenance pigging. Indeed, BP believed that some degree of work would have been required on all lines. VECO thus did not factor any existing facilities into its assessment, which was a rough, order-of-magnitude estimate. Since understanding the potential cost of such work was important, the decision was made to assume full launcher and receiver cost for all lines in this high-level assessment, rather than to examine and/or quantify the precise amount of work that would have to be done on each.

This high-level approach was consistent with the project's scope as a short-duration, "table-top" review conducted in Anchorage. No project-specific estimates of engineering effort were prepared for individual lines; there was no on-site review of the hundreds of miles of pipelines; and there was no attempt to review the "as-built" drawings for the lines or to evaluate the type or quality of individual pigging facilities that already existed on some lines. Approximate cost was instead estimated using factors like pipeline diameter, pipeline operating pressure, and historical data on similar projects. The project resulted in a ballpark estimate that provided a better perspective of the potential costs than the significantly underestimated numbers that the CIC group had proposed in AFE #4N0492 and Master ID #2996 such that decisions about how or whether to approach the project could be properly formulated.

10. What specifically does BP disagree with in the Chemical Safety Board's (CSB's) findings on Texas City? Please explain specifically where BP believes the CSB is in error?

In its review of the U.S. Chemical Safety and Hazard Investigation Board's ("CSB") report on the Texas City Refinery explosion ("Report"), BP found many factual errors, the use of information that was taken out of context and omissions of relevant and important information. BP has not prepared a comprehensive list of the errors of fact and analysis contained in the Report and does not believe that it is beneficial or productive to catalog each point of disagreement. BP has highlighted some areas of disagreement, including the following:

- The Report contains inaccurate assertions that BP did not follow certain of its own procedures, including, for example, policies governing pre-start up safety reviews and the use of blowdown stacks.

- The Report speculates that this tragic accident was foreseeable, a conclusion to which BP particularly objects. The management information that was available to BP decisionmakers prior to the tragedy is not the same information that is now available to BP and the CSB after two years of intensive investigation. Conclusions in the Report that are presented as obvious in hindsight must be evaluated in light of the information that was available to decisionmakers at the time that decisions were made. Moreover, the Report incorrectly implies that decisionmakers knew and appreciated the significance of warning signs. The facts show that, while BP had identified issues and concerns at the Texas City Refinery, those decisionmakers believed that appropriate corrective measures were being implemented. During the years prior to the incident, managers at the Texas City Refinery continually focused on the need to maintain process reliability, and, as a consequence, improve process safety. In 2001 and 2002, BP conducted various studies of the Texas City Refinery from which it determined that additional spending was necessary to improve the physical condition of the Refinery and, hence, its reliability. At the time, BP management believed that the spending programs enacted in response to those studies would correct the issues that the studies had identified. In fact, problems with the physical condition of the plant did not cause the March 23, 2005 explosion.

- The Report mischaracterizes positive actions by BP and then criticizes BP on the basis of those mischaracterizations. For example, the Report states that programs such as the Piping Integrity Program and the South Houston Infrastructure for Tomorrow program did not address process unit vulnerability. Those programs were in fact developed to provide necessary equipment and process unit improvements.

- The Report incorrectly implies that cost cuts at the Texas City Refinery caused the explosion and fails to recognize the significant increase in expenditures at the Texas City Refinery in the years before the incident. Further, the Report does not reflect that BP's budget process included guidance that budget decisions should not have an adverse impact on safety.

- The Report states that BP engineers proposed connecting the isomerization unit's blowdown system to a flare but that BP chose a less expensive option. This statement is misleading because of the implication that the decision was one in which safety was compromised for financial reasons. BP identified in its own internal investigation report (the "Mogford Report") prior opportunities for the Texas City Refinery to have eliminated the F-20 blowdown stack. These opportunities were rejected because they were outside of the scope of the projects (for example, a number of projects were related to environmental issues such as manufacturing clean fuels or compliance with benzene standards), not because of concerns over cost as CSB asserts.

Notwithstanding BP's significant, substantive disagreement with certain of CSB's findings and conclusions, BP is giving full and careful consideration to the CSB report as part of the activities it already has underway to improve process safety management. BP and its employees are ready, willing and able to achieve the goal of becoming an industry leader in process safety management. BP has undertaken extensive work in numerous areas to improve process safety at Texas City since the March 23, 2005 explosion. These actions are based on BP's own assessments of the needs at the refinery; the recommendations of the BP US Refineries Independent Safety Review Panel ("Baker Panel"); and the recommendations from the CSB's Report among other sources.

BP deeply regrets the occurrence of the explosion and fire and the resulting loss of life and injuries and has worked diligently to compensate all who were affected by the tragedy. BP is fully committed to assuring such a tragedy never happens again. To that end, BP has shared with many internal and external audiences what it has learned from the many investigations conducted into the causes of the tragedy. BP continues to work with entities such as the American Petroleum Institute, the Center for Chemical Process Safety, and ORC Worldwide, Inc. (as well as individual companies in the energy industry and other industries) to share its views and to deepen its understanding as it continues the journey to becoming a leader in process safety.

11. What specifically does BP disagree with in CSB's recommendations regarding Texas City?

BP does not disagree with CSB Report's recommendations regarding the March 23, 2005, isomerization unit explosion and fire. BP has implemented actions in alignment with each of these recommendations. While BP has disagreements with the CSB's Report (described above), those differences do not affect BP's commitment to implement the CSB recommendations or take appropriate action based upon its own assessments and the recommendations of others, including the Baker Panel. Indeed, most of the CSB's recommendations are consistent with those of the Baker Panel and other investigations that have been conducted, both internally and externally, in the last two years, and they are well aligned with BP's existing improvement plans.

BP is developing a comprehensive action plan that integrates these recommendations with existing plans to enable BP to achieve the goal of becoming an industry leader in process safety management. To harmonize recommendations from several disparate sources, BP has sought to implement the intent of some recommendations.

BP submitted letters responding to the CSB's Report on May 18, 2007 that provide more detailed information regarding BP's responses to the recommendations. Copies of those letters are attached.

12. Has BP implemented all of the Chemical Safety Board Recommendations regarding Texas City? If not, which have not been implemented and why?

BP is diligently working to implement actions in alignment with the recommendations of the CSB, the Baker Panel, and others and has completed initial implementation of some recommendations. Many of the CSB's recommendations will be implemented over time as they involve on-going processes of continuous improvement. The letters that BP submitted to the CSB on May 18, 2007 provide more detailed information regarding BP's responses to the CSB's recommendations and the anticipated timetable for implementation of the responses.

13. Did the Booz Allen report, the Baker Panel report, the Management Accountability Project, and the Chemical Safety Board find common weaknesses in BP's management? What are these common weaknesses?

Since 2005, BP has undergone a number of reviews, some commissioned by BP out of a desire better to understand and improve operations and some conducted by government agencies. BP has spent considerable time analyzing the findings of these studies and integrating their recommendations. In analyzing the findings, BP has identified several common themes, including the needs to

- Establish process safety as a core value;
- Ensure the use of comprehensive and systematic risk identification and assessment;
- Ensure that commitment to safety be reflected in budget decisions;
- Rigorously address identified safety concerns;
- Be sensitive to the effects of changing operating and environmental conditions;

- Enhance operational knowledge and capability;
- Improve communication of concerns both upward and across the organization; and
- Better understand organizational accountabilities.

BP is strongly committed to making improvements in each of these areas, and this commitment is evident in the company's new operating management system. That system is designed to provide clear guidance in the eight elements of BP's operations: risk, procedures, assets, optimization, organization, leadership, results, and privilege to operate. It will define and add clarity to the people, plant, process, and performance measures that facilities need to undertake to ensure safe, reliable operations. BP is confident that this management system will help BP achieve the goal of becoming an industry leader in process safety management.

14. Why is the Billy Garde report "Failure to Disclose COBC Documents to Congressional Subcommittee and Other Issues" still not final?

Ms. Garde expects the final COBC report to be completed by the end of July 2007. Since production of the interim version of the report on April 30, 2007, Ms. Garde and her team have been conducting additional interviews and reviewing additional documents that were produced to to the Committee prior to the May 16, 2007 hearing.

bp

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May 18, 2007

Carolyn W. Merritt
Chairman/CEO
United States Chemical Safety and Hazard Investigation Board
2175 K Street NW, Suite 650
Washington DC, 20037-1809

Dear Chairman Merritt:

Your letter dated March 20, 2007, requested a response within 60 days on actions taken or contemplated in response to the recommendations made by the United States Chemical Safety and Hazard Investigation Board (CSB) to the BP Products North America, Inc. ("BP Products") Texas City Refinery based upon CSB's investigation into the incident that occurred at the Refinery on March 23, 2005.

We have undertaken extensive work in numerous areas to improve process safety at the Refinery since the incident in 2005. The actions are based on our own assessments of needs at the refinery as well as the recommendations from our internal investigation into the incident, from the High Reliability Organization Assessment (HRO) led by Jim Stanley, from Implementation of BP Group Standards such as the Integrity Management Standards, from Refining SPU minimum expectation improvement projects such as the Maintenance Accelerator, and now the recommendations from the CSB Final Investigation Report.

We have implemented actions in alignment with each of the seven recommendations that CSB made to Texas City, are implementing and contemplating further actions to be taken, and are committed to continuous improvement in each of these areas. Continuous improvement is one of BP's core values and was recommended by the BP US Refineries Independent Review Panel. BP Products' response to the Isom explosion is marked by continuous improvement rather than one time actions. BP Products' responses to several of CSB's recommendations identify actions contemplated by BP Products for continuous improvement in the areas identified by CSB's recommendations.

This letter provides a summary of actions that are underway or contemplated in alignment with CSB's recommendations to the Refinery.

CSB Recommendation 1: Evaluate your refinery process units to ensure that critical process equipment is safely designed.

At a minimum,

a. **Ensure that distillation towers have effective instrumentation and control systems to prevent overfilling such as multiple level indicators and appropriate automatic controls.**

b. **Configure control board displays to clearly indicate material balance for distillation towers.**

RESPONSE Recommendation 1:

(a) We are developing updated technical standards and specifications for Relief Systems that include instrumentation and control systems on distillation towers, which, we believe, are effective to prevent overfilling. We anticipate that the updated standards and specifications will be completed by the end of the third quarter of 2007. These standards and specifications will define instrumentation requirements, which will include multiple-level indicators on distillation towers, and will require hazard review via Layer of Protection Analysis (LOPA) to determine the need for any additional safety instrumented systems per ISA 84.01.

Even though these standards are not yet finalized, we have embarked on a program that is beginning to fulfill the requirements that will be incorporated within the standards. As part of this program, we have completed LOPA's on 60% of towers and installed minimum instrumentation on 20% of towers. As a result of the LOPA's, we have installed additional interlocks and safety instrumented systems on several towers to mitigate tower overfill. Additional systems will be added as part of our strategy of ongoing risk reduction.

(b) BP determined that PI-Process Book is the preferred tool for the purpose of indicating material balance on distillation towers. To assure that this information is available and used by operators and support staff, we have created material balance tools for all units that are currently operating and will assure the tool is operational for each unit before it is re-commissioned. The material balance tools are monitored by staff during the start up. We have also developed enhanced operations training and procedures to prevent overfilling distillation towers.

Continuous Improvement: BP Products has a multi-year project to upgrade process unit control systems, instrumentation, and safety instrumented systems to state of the art Emerson Delta V technology. The Delta V system has the capability to clearly indicate material balance information within the control system and we will consider appropriate configuration as part of the project execution.

CSB Recommendation 2: Ensure that instrumentation and process equipment necessary for safe operation is properly maintained and tested.

At a minimum,

a. Establish an equipment database that captures the history of testing, inspections, repair and successful work order completion.

b. Analyze repair trends and adjust maintenance and testing intervals to prevent breakdowns.

c. Require repair of malfunctioning process equipment prior to unit startups.

RESPONSE Recommendation 2: (a) BP Products has, over the last two years, implemented what is called a Maintenance Accelerator. The Maintenance Accelerator is a work process designed to assure that proper prioritization, planning, testing, inspection, and repair activities are executed through a work order process. Under the Maintenance Accelerator program we are looking to integrate the databases used to capture maintenance and testing information.

(b) Reliability efforts to prevent breakdowns are executed by using management information from the Maintenance Accelerator work, learning from investigations and Root Cause Analysis, and trending and analysis of repair and inspection data. Consistent work processes are being driven by the Reliability Group for these analyses which are conducted by specialty groups under the direction of the Maintenance Manager.

(c) The Pre-Startup Safety Review (PSSR) procedure that has been implemented at the site assures that equipment necessary for safe operation is repaired and available prior to unit start ups. In addition, the stand taken "What you say matters" over the course of the last two years has enhanced the communications from unit personnel in addressing any concerns that may arise.

Continuous Improvement: BP Products is developing a Preventative Maintenance Policy and Procedure for the Texas City Refinery. We anticipate that the Policy will be completed and in place during the third quarter of 2007. The policy will holistically outline plans in this area and will be in alignment with CSB's recommendations.

CSB Recommendation 3: Work with the United Steelworkers Union and Local 13-1 to establish a joint program that promotes the reporting, investigation, and analysis of incidents, near-misses, process upsets, and major plant hazards without fear of retaliation. Ensure that the program tracks recommendations to completion and shares lessons learned with the workforce.

RESPONSE Recommendation 3: BP Products is working with the United Steelworkers and Local 13-1 (collectively "USW") to address this recommendation. As part of the USW/BP Joint HSE Initiative, we have agreed to implement USW's Triangle of Prevention program at the Refinery.

In addition, we are reviewing a letter agreement between the union and BP that has been in place since 1999 which states there will not be disciplinary action as a result of incident investigation findings.

CSB Recommendation 4: Improve the operator training program.

At a minimum, require

a. Face-to-face training conducted by personnel with process-specific knowledge and experience who can assess trainee competency, and

b. Training on recognizing and handling abnormal situations including the use of simulators or similar training tools.

RESPONSE Recommendation 4: (a) BP Products has expanded its face-to-face training programs. We also selected Unit Training Coordinators based on a combination of seasoned multi-year operations experience, expertise in their given operating area, and demonstrated proficiency in sharing their expertise in training and coaching peers and new operators. We currently have approximately thirty of these Unit Training Coordinators on site.

Face-to-face classroom training for operations began with distillation training, in January 2006. Subsequently, we have conducted face-to-face classroom training for operations personnel covering unit commissioning and board operator refresher training. We are currently offering a three-day furnace firing training program which includes use of a simulator, classroom and unit-specific aspects. Based on the course, competency is verified through testing and/or demonstration methods with a defined level for a passing grade, typically 85%.

Experts in adult education and learning agree that this is not a one size fits all answer for training. As such, all of our training and education programs are being evaluated for maximum effectiveness of delivery; face-to-face, computer-based, field demonstration, simulation, and testing. Based on this analysis, additional face-to-face training programs are anticipated in the future.

(b) At the beginning of 2006, we also implemented a monthly training program across the site, with an emphasis on abnormal (such as unit upsets) and emergency operations (such as emergency shutdown) training. Once each month each shift conducts face-to-face discussions covering abnormal operating situations and emergency drills. We plan to conduct at least one emergency drill per month for every shift across the refinery. In addition, we began site wide unit evacuation drills in 2005. Each unit and each shift must participate in at least one such drill annually.

We began to use generic simulators on distillation and furnace firings for operations training to practice start-ups, shutdowns and to manage abnormal situations. Since the beginning of 2006, approximately 600 incumbent employees and 150 new hires have received 8 to 10 hours each of this training.

Continuous Improvement: We plan to implement unit-specific custom simulators for many of the refinery units as part of the unit control system upgrade to the Emerson Delta V project discussed above. In addition, we plan to establish a permanent process simulator training room at the new Employee Services Building. We plan to use the simulator training room to provide board operators with refresher training and to train new operators, supervisors and engineers.

CSB Recommendation 5: Require additional board operator staffing during the startup of process units. Ensure that hazard reviews address staffing levels during abnormal conditions such as startups, shutdowns, and unit upsets.

RESPONSE: After March 23, 2005, we revised the Refinery Pre-Startup Safety Review ("PSSR") policy to require leadership sign-off prior to re-commissioning a unit and prior to post turnaround startups. The PSSR includes consideration and documentation of appropriate levels of staffing for the planned start-up. The site has also implemented an Exclusion Zone (EZ) policy that is put into effect when there is a unit start up or abnormal situation. As part of the EZ policy, non-essential personnel are evacuated from the unit and technical support for essential personnel is enhanced.

Unit staffing decisions for normal operations have been historically reviewed through the PSM process and are based on having a sufficient number of operators to operate the unit safely and, in the event of an upset, to bring the unit to a safe off condition.

Continuous Improvement: Many actions have taken place in this area and there is even more work under way, most notably the commitment to evaluate with USW the opportunity for "Chief" operators as part of the BP & USW ten point plan.

Recommendation 6: Require knowledgeable supervisors or technically trained personnel to be present during especially hazardous operations phases such as unit startup.

RESPONSE: The modified PSSR policy includes requirements for unit staffing by supervisors and appropriate personnel with technical training.

Continuous Improvement: There is significant overlap on these activities with Recommendation #5. We are approaching this in a holistic manner. Immediate steps have been taken to assure support and we are working with USW and ther key stakeholders to develop the most comprehensive and robust system for our future.

Recommendation 7: Ensure that process startup procedures are updated to reflect actual process conditions.

RESPONSE: The modified PSSR policy includes requirements review of a situation specific startup procedure prior to startup. We also have existing processes for review of operating procedures.

We have learned a great deal, and accomplished a lot over the past two years. We continue to learn and find improved ways to safely operate the Refinery with an engaged and committed workforce. Simply stated, we are investing heavily in People, Processes, Plant, and Perfomance. As part of each investment, we assure that we have mechanisms in place to continuously improve. We have on-going actions and are evaluating actions that are aligned with CSB's recommendations.

Sincerely,

Keith M. Casey

bp

Robert A. Malone
Chairman & President

BP America Inc.
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May 18, 2007

Carolyn W. Merritt
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Dear Chairman Merritt:

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By letter dated March 20, 2007, to John Browne, CEO of BP p.l.c., you requested that BP respond regarding actions taken or contemplated in response to the recommendations made by the United States Chemical Safety and Hazard Investigation Board (CSB) to the BP p.l.c. Board of Directors (the Board) based upon CSB's investigation into the incident that occurred at the BP Products North America's Texas City Refinery on March 23, 2005. Since your investigation relates to BP's US refineries, the Board has asked that I respond to your letter.

BP is making a concerted and lasting effort to improve its process safety management and performance. I am leading that effort on behalf of BP America. The standard we seek must be one of excellence and we are committed to become an industry leader in this area. We know that it will be a long journey, but it is one we are determined to make.

Before turning to our actions in response to your recommendations, I would like to thank the CSB and its staff for the diligence and effort expended investigating the incident at Texas City. While we do not agree with all of the findings, we have gained insights through the investigation and appreciate the hard work of the investigation team.

Most of the CSB's recommendations are consistent with those of the BP US Refineries Independent Safety Review Panel (the Panel) and other investigations that have been conducted, both internally and externally in the last two years. Further, they are well aligned with our existing improvement plans. We are actively developing a comprehensive action plan that integrates all the recommendations made and improvements necessary to make BP the leader in process safety management that we aspire to be.

CSB Recommendation 1: Appoint an additional non-executive member of the Board of Directors with specific professional expertise and experience in refinery operations and process safety. Appoint this pers n to be a member of the Board Ethics and Environmental Assurance Committee.

Both the Panel and the CSB made recommendations aimed at adding to the Board's expertise in the area of refining and process safety. The Panel recommended this through an independent expert, and the CSB through the appointment of a non-executive director. The Board's consideration of these recommendations needs to be made in the light of its existing practices. As part of its normal processes the Board keeps under review the mix and balance of skills of Board members against the background of all BP's global operations, both upstream and downstream.

The Board has now appointed Duane Wilson to be its independent expert. Mr. Wilson is a former Panel member and will work directly with the Chairman of the Safety, Ethics and Environment Assurance Committee (SEEAC). He has refinery operations and process safety experience and will provide independent technical expertise to assist the SEEAC and the Board in monitoring improvements in BP's process safety performance. In the future, the CSB recommendation will be taken into account by the Board as part of its continuing development of skills as mentioned above, and in light of the Board's experience of working with the independent expert.

CSB Recommendation 2: Ensure and monitor that senior executives implement an incident reporting program throughout your refinery organization that

a. encourages the reporting of incidents without fear of retaliation

b. requires prompt corrective actions based on incident reports and recommendations, and tracks closure of action items at the refinery where the incident occurred and other affected facilities; and

c. requires communication of key lessons learned to management and hourly employees as well as to the industry.

BP has a system in place for incident reporting and that system is currently being revised, with implementation planned for later this year. The enhanced program is designed to bring clarity and reset expectations on reporting of all incidents, including process safety events. Our analysis indicates that a lack of understanding of reporting requirements is one of the reasons that incidents are not always reported.

To understand the perceived fear of retaliation associated with reporting, we surveyed our employees in 2006 to establish a baseline on their willingness to report safety incidents. We plan to conduct another survey in mid-2007 to understand if the actions we have underway are achieving the desired effect.

In the new incident reporting system, levels of severity, or potential severity, will be assigned to each incident; major incidents (MIA's) and high potential incidents (HIPO's) will be reported to applicable senior leaders and investigations will be completed. The new program will have the capability to track action item closure and the functionality to create reports on outstanding action items for management follow-up. We are implementing a system in our Refining organization including a process to share and embed appropriate lessons learned, which will form the basis of a group-wide practice to embed and track learning within the wider BP organization. We believe targeting the cultural aspects of reporting and investigation, consistent messages from senior leaders that reinforce actions being taken at the local level, and demonstrated closure of action items will encourage full reporting of incidents and facilitate learning from these events.

CSB Recommendation 3: Ensure and monitor that senior executives use leading and lagging process safety indicators to measure and strengthen safety performance in your refineries.

We developed new metrics in 2006 that include both leading and lagging indicators, which we are now working to improve upon. We anticipate concluding the next phase of this work in the coming months. The revised indicators will be used within BP and will serve as input to the work we committed to undertake with CSB, the industry and other interested parties, as recommended by the Panel (in Recommendation #7.) Our commitment is to continue to improve upon our metrics and working with the CSB and others, attempt to develop a comprehensive set of metrics with industry consensus.

Our current suite of leading and lagging indicators (including MIA's and HIPO's) is monitored on a quarterly basis by the Group Operations Risk Committee (GORC). This committee was established several months ago; membership includes the most senior line executives in BP, the Senior Group Vice President of Safety and Operations, and the Chief Engineer. GORC is the forum to prioritize and monitor group-wide progress in process safety, the focal point for role-modeling leadership behaviors and the steward of the overall improvement program. The metrics that GORC reviews are also monitored by the SEEAC on a quarterly basis.

We believe the above demonstrates that we have actions underway to address each of the three CSB recommendations made to the Board and ask that you close the recommendations contained in your report. We are confident that Duane Wilson, as independent expert, will be actively engaged with our operations and will provide the expertise and experience to the Board and SEEAC that is intended by your recommendation. Further, while we have programs in place and improvements underway that address the latter two recommendations on incident investigations and metrics, we believe that they will never be fully complete as we strive for continuous improvement.

For the past two years the accident at Texas City has been at the forefront of our thinking, planning and actions throughout BP. While we have learned a great deal and have made substantial progress, as we have stated before there is more to do, and we will do more. Thank you for your contributions to advancing our goal of becoming an industry leader in process safety.

Sincerely,

bp

Robert A. Malone
Chairman & President

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June 27, 2007

BY HAND DELIVERY

The Honorable John D. Dingell
U.S. House of Representatives
Chairman, Committee on Energy and Commerce
Washington, DC 20515-6115

Dear Chairman Dingell:

Thank you again for the opportunity to address questions pertaining to the May 16, 2007 hearing of the Subcommittee on Oversight and Investigations on the 2006 Prudhoe Bay shutdown. On July 6, 2007, we provided responses to questions 1 through 14 raised by Congressman Stupak in your June 20, 2007 letter. Following please find responses to Mr. Stupak's questions 15 and 16, which your staff agreed could be provided today.

Please feel free to call me if I may be of further assistance.

Sincerely,

Robert A. Malone

Chairman Dingell
July 13, 2007
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<u>**Additional Responses to June 20, 2007 Questions from Congressman Stupak**</u>

15. What responsibilities did BP's new CEO, Tony Hayward, have with respect to BP Prudhoe Bay Alaska operations, maintenance, and budgeting between 1998 and 2006?

Dr. Hayward was not responsible for BP's Prudhoe Bay operations, maintenance, or budgeting between 1998 and 2006. Those responsibilities rested throughout that period with the business or performance unit leader accountable for BP's Prudhoe Bay operations. In 1998, Dr. Hayward was serving as Group Vice President for BP Exploration, a position in the chain of leadership for all of BP's producing operations, including those in Alaska.[1/] During the course of that year, Dr. Hayward reviewed and approved overall business performance plans for those operations, including the plans for overall financial and operating performance for the Alaska businesses. His responsibilities, however, did not extend to reviewing or approving the details of expenditures at Prudhoe Bay. Plans at the field level would have been developed and approved by local business unit management. From January 1, 1999 to the present, Dr. Hayward has served in positions in which he was not responsible for reviewing or approving plans for the Alaska businesses.

16. Did Mr. Hayward have any role in approving budget for the BP Alaska CIC Group? Was Mr. Hayward aware of the implications of cost cutting on corrosion protection activities?

Dr. Hayward has had no role in approving the budget for the BP Exploration (Alaska) Inc. ("BPXA") Corrosion, Inspection & Chemicals ("CIC") group at any point in his career at BP. Dr. Hayward was one of a number of people who received an internal technical report on the BPXA corrosion management program ("BPXA Corrosion Management System Technical Review Final Report") from John Baxter, BP's Group Engineering Director, in or about April 2005. This report was produced to you on August 31, 2006 and may be found at Bates range BPXA-CEC00000301—BPXA-CEC00000311. Although the report concluded that the corrosion management program was technically sound, it made recommendations as to steps BPXA might consider to improve it over time. Among other things, it discussed BPXA's cost management strategy, which it found may have led to some "counterproductive" behaviors related to corrosion management, and encouraged BPXA leadership to consider the implications of the strategy in evaluating future plans and budgets related to corrosion management.

1/ Unless otherwise noted and for ease of discussion, "BP" is used as shorthand throughout this letter to refer to corporate actions that may have been taken by any of a number of legal entities affiliated with BP, including BP Exploration (Alaska) Inc. and BP Products North America, Inc. The use of "BP" in this context should not be understood as a reference to BP p.l.c. or as an equation of separate legal entities with any parent and/or other affiliate.

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