OCS Report
MMS 99-0053

Investigation of Chevron Pipe Line Company Pipeline Leak South Pass Block 38 September 29, 1998

Gulf of Mexico
Off the Louisiana Coast

U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

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David M. Moore - MMS
Frank Torres - MMS
Mike Joseph - MMS
Buddy Sheets - USDOT
LCDR George Butler - USCG

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New Orleans
September 1999

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Abbreviations and Acronyms

BPD	Barrels Per Day
BOPD	Barrels of Oil Per Day
BP	British Petroleum
CPDN	Chevron Production
CPL	Chevron Pipe Line Company
CRTC	Chevron Research and Technology Center
CSC	Customer Service Center (Chevron)
CSCC	Customer Service Center Controller
CSR	Customer Service Representative
CUSA	Chevron, U.S.A.
FTL	Field Team Leader
GOMR	Gulf of Mexico Region
HAZ	Heat Affected Zone
LACT	Lease Automatic Custody Transfer
LCDR	Lieutenant Commander
MAOP	Maximum Allowable Operating Pressure
MC	Mississippi Canyon
MMS	Minerals Management Service
MMSCFD	Million Standard Cubic Feet per Day
MSO	Marine Safety Office
NRC	National Response Center
OCS	Outer Continental Shelf
OXY	OXY U.S.A., Inc.
PL OP	Pipeline Operations Orders
PSI	Pounds per Square Inch
PSL	Pressure Safety Low
ROW	Right-of-Way
SCADA	Supervisory Control and Data Acquisition
SN	Segment Number
SP	South Pass
USCG	U.S. Coast Guard
USDOT	U.S. Department of Transportation
WD	West Delta

Investigation and Report

Authority

On or about September 29, 1998, an oil spill occurred in the Gulf of Mexico in South Pass (SP) Block 38 as a result of a pipeline rupture. The spill volume, in conjunction with activities surrounding source identification, resulted in a decision by the Minerals Management Service (MMS) to conduct an investigation of the incident. The investigative process is designed to be a fact-finding proceeding with no civil or criminal issues and no adverse parties and with the ultimate purpose being to prepare a public report. The report is a compilation of relevant facts surrounding the spill and includes findings, conclusions, and recommendations.

The following MMS personnel were designated as members of a spill investigation panel by the Regional Director of the MMS Gulf of Mexico Region (GOMR):

Name	Department/Section
David M. Moore	Field Operations, Pipeline Section
Frank Torres	Field Operations, Pipeline Section
Mike Joseph	Production and Development, Surface Commingling and Production Measurement Section

The panel members were named by memorandum dated October 20, 1998 (see Attachment 1), pursuant to Section 208 (subsections 22 d, e, and f) of the Outer Continental Shelf (OCS) Lands Act, as amended (1978), and the Department of the Interior Regulations 30 CFR Part 250. David M. Moore was designated as panel chairman.

Staff from other agencies that have direct authority over right-of-way (ROW) pipelines in State offshore waters or offshore spill response were also solicited by MMS to assist in the investigation, and included:

Name	Agency/Department
Buddy Sheets	U.S. Department of Transportation (USDOT), Office of Pipeline Safety
LCDR George Butler	U.S. Coast Guard (USCG), Marine Safety Office, Morgan City

Procedures

On November 17, 1998, investigation panel members, including David M. Moore, Frank Torres, Mike Joseph, and Buddy Sheets, attended a meeting conducted at Chevron Pipe Line Company's (CPLs) office located at 935 Gravier Street, New Orleans, Louisiana. The purpose of the meeting was to obtain data collected by CPL staff resulting from their internal investigation of the pipeline spill incident as well as to begin preliminary inquiry into events surrounding the spill.

The meeting consisted of presentations by CPL personnel on the sequence of events, repair procedures, and recommended action items, and was followed by an open discussion period. A copy of the CPL report "South Pass 49 Pipeline Root Cause Analysis and Pipeline Repair Presentation – 11/17/98," was obtained for panel review and was made part of MMS investigative files. A copy of the report was subsequently forwarded to the USCG panel representative who was unable to attend the presentation.

On January 14, 1999, the investigation panel chairman forwarded a list of questions to CPL. The questions were developed based upon input from all panel members seeking additional data or clarification of information presented in CPL's internal report. Questions focused mainly on data required for accounting of oil presumed lost as a result of the spill, internal company communications, and standard versus upset operating practices.

Investigation and Report

On January 15, 1999, the panel investigation chairman met with two representatives of CPL to confirm data provided in the CPL spill report through review of a time line analysis prepared by the panel chairman from available event data. During the discussions, CPL staff provided additional insight into pipeline and supervisory control and data acquisition (SCADA) operations, problems with communication during the spill, and tank gauging practices.

At that time, CPL staff provided written responses to questions posed by the investigation panel. Answers to each question and associated data provided to support answers were reviewed for completeness and clarity. Subsequent to the meeting, answers were forwarded to all panel members for review.

On January 22, 1999, the Chevron Customer Service Center (CSC) E-mailed answers to questions posed during the meeting between MMS and CPL personnel on January 15. An additional request for information was forwarded to CSC on January 25, 1999, following review of Chevron's responses to the original MMS data request. CSC's responses were received by facsimile on January 27.

The investigation panel convened on Wednesday, January 27, to review all data collected during the discovery portion of the investigation. The panel began the process of reviewing, editing, and approving portions of the report that had been prepared by the panel chairman. The panel also collectively discussed the preparation of the remaining portions of the report and developed draft report conclusions and recommendations. All panel members were present.

On Tuesday, March 2, additional questions on issues ranging from safety system operations to established post-hurricane operational procedures were faxed to personnel at BP Exploration, Inc. (BP), OXY USA, Inc. (OXY), and CPL. By March 29, all affected parties had responded to the questions posed by the investigation panel. The panel chairman also conducted a telephone interview with an employee of Taylor Energy Company on March 8.

Preparation of the draft report was completed and it was forwarded to panel members on April 13, 1999. Following inclusion of revisions by members and completion of the MMS publication approval processes, the final report was published for public review in July 1999.

Introduction

Background

The South Pass (SP) 49 pipeline system, which originates in SP Block 49 and connects to the SP 49 Onshore facility, is partially located off the Louisiana coast and is part of the West Bay Pipeline System (see Attachment 2). The SP 49 system is operated by CPL but is jointly owned by Mobil Eugene Island Pipeline Company, Pogo Offshore Pipeline Company, Unocal Pipeline Company, BP Offshore Pipelines, Inc., Conoco, and CPL.

The pipeline system consists of a 10–inch right-of-way (ROW G07561) pipeline (SN 5625), 156,288 feet in length, of which 125,279 feet are in OCS waters. The system has an operating capacity of 59,000 barrels per day (BPD) and a static capacity of approximately 13,995 barrels. Recent throughput was 17,250 BPD. The pipeline, constructed in 1980, has a maximum allowable operating pressure (MAOP) of 1,440 pounds per square inch (psi) and normal operating pressures that vary from 0 psi to 360 psi along the length of the pipeline. Water depths along the pipeline's route, which crosses through SP Blocks 49, 50, 52, 53, 46, 45, 37, 38, 27, 26, and 25, and Mississippi Canyon (MC) Blocks 151, 150, 149, range from sea level to approximately 780 feet deep.

Four primary oil production platforms are connected to the pipeline, including SP 45 A, operated by OXY; MC 109 A, operated by BP; MC 20 A, operated by Taylor Energy Company; and SP 49 A, operated by Chevron, U.S.A. (CUSA) (see Attachment 3). Two additional platforms, SP 49 B and SP 49 C, produce to SP 49 A, where production is metered. As a result, only SP 49 A will be addressed. For the remainder of the report platforms will be identified by their location only, e.g. CUSA's SP 49 A will be referred to as SP 49.

Following are basic production and platform data for each of the facilities that deliver oil to CPL's 10–inch transportation pipeline:

	SP 49	MC 20	MC 109	SP 45
Avg. Daily Oil Production (BOPD)	6,200	600	10,300	180
Avg. Daily Gas Production (mmscfd)	24.5	6	8.8	3
24-Hour Manned Facility?	Yes	Yes	Yes	Yes
SCADA System?	Yes	Yes	Yes	Yes

MC 20 connects to the SP 49 system via a 6–inch oil pipeline, 53,570 feet in length (SN 7296), constructed in 1984; MC 109 connects to the SP 49 system via an 8–inch oil pipeline, 36,959 feet in length (SN 9347), constructed in 1991; and SP 45 connects to the SP 49 system via a 4–inch oil pipeline, 4,480 feet in length (SN 8738), constructed in 1989. SP 49 is the originating point of the SP 49 pipeline system.

Oil delivered to the SP 49 pipeline system is flowed to a tank battery referred to as SP 49 Onshore (see Attachment 3). The battery consists of three tanks, each with a capacity of 5,000 barrels. One inch of height in the three tanks combined equals 52 barrels. Only one of the tanks is equipped with a gauge that allows visual confirmation of fluid height. Levels in the tanks are maintained at five feet. When fluid height in the tanks reaches eight feet, pumps automatically cut on in order to transfer the oil into the onshore pipeline network. Operation of the pumps that lower fluid level can be accomplished manually by an operator on site or remotely by an operator stationed at Chevron's Customer Service Center (CSC), located in Houston, Texas. In no case, however, can pumps be started if the fluid level is below five feet.

Incident Description – Pre-Hurricane Pipeline System Operations

During the latter part of September 1998, Hurricane Georges threatened oil production and handling facilities in the Gulf of Mexico. With the imminent impact of the Category 4 hurricane, operators of facilities that tied into the CPL 10–inch pipeline began preparations to shut down facilities and evacuate personnel. As part of the evacuation procedures, all facilities were required to read meters manually and then to fax the readings to CPL.

On the afternoon of September 25, BP personnel stationed on MC 109 shut down power at approximately 1400 hours, prior to departing the platform. On the same day, OXY personnel followed a similar set of actions. In both cases, termination of power resulted in the cessation of SCADA communications with Chevron's CSC. On September 26, Chevron CSC lost SCADA communications with Taylor Energy Company's MC 20 platform, which had also been shut down due to the impending storm. While CUSA evacuated personnel from SP 49 during the same period, the platform remained on production and was operated remotely by Chevron Production (CPDN) staff located at the Gravier Control Center. The platform was eventually shut in on the morning of September 27 because of the loss of SCADA communications with the platform.

All facilities remained shut in through the remainder of September 27 and the entire day of September 28 as Hurricane Georges passed through the Gulf of Mexico as it moved northward to make eventual landfall in Mississippi. Throughout this period, SCADA communications were inoperative because of the lack of power at all platforms as well as at SP 49 Onshore.

Introduction

Incident Description – Post-Hurricane Startup Operations

By early afternoon on September 29, operators of the various facilities had already or were in the process of transporting personnel back to their platforms and were actively assessing platform damage and performing post-hurricane inspections per individual operations manuals. Coordination of startup operations of the SP 49 pipeline system was to be overseen by the CPL Gulf Coast Operations Team, headed by the Region Operations Manager. The team consisted of Field Team Leaders (FTL), the CSC Team Leader, Tech Services and Health, Environment, and Safety staff personnel.

It should be noted that both SP 49 and MC 20 remained shut in following the hurricane. The emphasis of this report is thus placed on operations of CSC, SP 49 Onshore, MC 109, and SP 45, and events surrounding the pipeline leak that occurred in SP Block 38.

Following the hurricane, Chevron staff inspected the onshore facilities for damage. As there was no apparent significant damage, a standup test was conducted on the West Bay System from SP 49 Onshore to the Empire Terminal (see Attachment 2). The test was conducted on September 29, from 1330 to 1430 hours, at a pressure of 238 psi. Discussions internal to Chevron personnel resulted in the determination that a standup test was not required for the offshore portion of the SP 49 system, as SCADA communications had been restored at that time. As SCADA was not, however, operational for SP 49 Onshore, a Chevron employee was dispatched to the tank battery to monitor tank levels and to relay this information to the CSC controller for comparison to SCADA readings from the facilities that would be pumping into the SP 49 pipeline system.

On September 29, at 1500 hours, the Chevron FTL, following discussions with CSC, gave SP 45 permission to start up production operations and to pump into the system. When all wells are on production, SP 45 has a production rate of approximately 180 BOPD. Production is collected in a 200 barrel tank at the facility and then pumped into the SP 49 system when the pump cycles on at approximately 75 percent of tank capacity. During each pump–down phase, 100 barrels of oil are pumped into the system. This sequence occurs approximately once every 12 hours.

On September 29, personnel on MC 20 began placing wells back on production with produced oil being collected in a 120–barrel tank on the platform. When the tank was near its capacity and was ready to be pumped down, CPL staff were notified and permission was requested to pump collected oil into the SP 49 system. CPL withheld permission for MC 20 to pump, resulting in facility staff having to shut in all affected wells.

At 1630 hours, the Chevron Pipe Line FTL is reported to have given MC 109 permission via telephone to resume production operations, with the instructions that startup was to take place during daylight hours only, so that overflights of the pipeline could be made to ensure prompt sighting of an oil spill, should one occur. They were also instructed to look for released oil around their platform.

When all wells are on production, MC 109 has a production rate of approximately 10,300 BOPD. Full production, however, is not reached for approximately three days. As a result, MC 109 never reached full production during the post-hurricane startup sequence in which gas-lift wells were being slowly placed on production. While it is reported that MC 109 came on production at approximately 1900 hours, charts indicate that the platform did not resume pumping until approximately 2200 hours on September 29.

Neither CSC nor the Chevron FTL received verbal confirmation from BP that oil was being pumped into the SP 49 pipeline system. Although SCADA communications were initially restored with MC 109 at approximately 1000 hours, the CSC lost SCADA communications with MC 109 at approximately 2000 hours.

Throughout startup, the SCADA communications systems at CSC which, when operational, can monitor pressures and flow rates at SP 49, MC 20, MC 109, SP 45, and SP 49 Onshore, were working intermittently. Hard line communications between all facilities were also intermittent because of hurricane damage. As a result, the CSC was unable to monitor flow rates continuously at the facilities flowing into the SP 49 system or at the SP 49 Onshore tank battery, or to maintain constant voice communication to verify operations. The only means of voice communication between CSC and personnel at MC 109 was a cellular phone on MC 109. This, too, became inoperative during the evening of September 29 because of battery failure.

To monitor production, given the problems being experienced with both SCADA and hard lines, the Chevron FTL had dispatched a gauger to SP 49 Onshore to hand–gauge the tanks. Per instructions, the gauger recorded and reported field measurements to CSC staff for comparison with available SCADA readings throughout the evening of September 29 and the morning of September 30.

Both MC 109 and SP 45 remained on production throughout the morning of September 30. It was not until 0900 hours, however, that CSC became aware, through the use of restored SCADA, that MC 109 was pumping oil. In fact, the SCADA communications with MC 109 had been restored since 0740 hours.

The CSC controller noted at 1000 hours that SCADA communications with SP 49 Onshore had been restored, providing full access to data for volumetric comparisons to assess system integrity.

At 2015 hours on September 30, following review of tank level readings taken by the gauger, confirmation of tank gauge operation, and review of SCADA data, MC 109 was ordered to shut down operations. The decision followed CSC's realization that MC 109 had been pumping oil into the SP 49 pipeline system for approximately 25 hours without any apparent change in levels in the SP 49 Onshore tank battery.

During its initial construction, the MC 109 pipeline was equipped with a safety breakaway joint. The joint, which incorporates check valves, is designed to fail when the pipeline is subjected to sufficient tension and ensures that the amount of oil released due to the failure is minimized. Given the assumption that this breakaway joint on the MC 109 pipeline had parted, SP 45, which is downstream of MC 109, was allowed to remain on production during the morning of October 1. It too, however, was eventually ordered shut-in at 0715 hours, with production ceasing approximately 15 minutes later. At this point, all potential sources that could produce or pump oil into the SP 49 system were shut in.

The BP Incident Management System had been initiated during the previous evening (September 30 at 2100 hours) through contact of the BP Operations Section Chief following the orders from CPL to shut in production because of apparent line shortages. On October 1, at 0900 hours, as a result of CPL's inability to determine the cause of the line shortage, BP reported the spill to the National Response Center (NRC) on the basis that MC 109 had pumped approximately 7,500 barrels of oil unaccounted for by CPL. At 1030 hours, BP activated their spill management team to respond to the spill.

Prior to BP's reporting of the spill, there had been no reports of sightings of oil in or around MC 109 or along the SP 49 pipeline route. Shortly after the report, a USCG surveillance helicopter flight located a major oil slick in the MC/SP vicinity.

For a review of response actions taken by BP during the initial phases of the spill, see the report "Incident: South Pass Spill Volumes 1-III," which is part of the MMS investigative files. MMS conducted an investigation of the BP response, which can be found in the report "October '98 Chevron Pipeline Oil Spill Environmental Impact and Response Evaluation" (see Attachment 4).

Oil Spill Observation Reports

During the initial phases of startup of the SP 49 system, CPL conducted a number of overflights to look for signs of oil from their pipeline. After SCADA and tank level readings pointed to a significant oil loss, BP also initiated overflights of their pipeline. The Morgan City Marine Safety Office (MSO) also began overflights in the SP/MC areas following notification by the NRC of a possible major leak. Available overflight data are summarized below, while a map showing locations of reported spills can be found in Attachment 2.

September 29

- 1515 hours – No oil sighted during overflight by CPL.
- 1630 hours – No oil sighted during overflight by CPL.

September 30

- 0700 hours – Overflight of SP 49 system by CPL during system startup did not reveal any oil on water.
- 1300 hours – Overflight of SP 49 system by CPDN during system startup did not reveal any oil on water.

October 1

- 0645 hours – Overflight did not sight any oil slicks.
- 0900 hours – No oil sighted during overflight by CPL.
- 0930 hours – No oil sighted during overflight by CPL.
- 1030 hours – No oil sighted during overflight by CPL.
- 1030 hours – Oil slick sighted during helicopter flyover. Slick reported to be located 12 miles west of MC 109.
- 1208 hours – NRC report to MSO Morgan City indicates location of incident is WD Block 143 at 28° 39' 42" N, 89° 33' 5" W. Slick described as thick and dark brown, 200 feet wide and extending beyond the horizon. Reported by Shell Offshore, Inc. Incident No. 457970.
- 1230 hours – USCG reports to CPL of sighting of slick 27 miles by one half mile located in WD Block 143.
- 1232 hours – NRC report to MSO New Orleans indicates location of incident SP Block 87 at 28° 43' 12" N and 89° 25' 50" W with slick described as silver/rainbow. Reported by Marathon Oil. Incident No. 457977.
- 1320 hours – No oil sighted during overflight by CPL.
- 1430 hours – No oil sighted during overflight by CPL.

- 1522 hours – NRC report to MSO New Orleans indicates location of incident MC Block 109 at 28° 5' 0" N, 90° 0' 0" W with volume shown as 7,500 barrels of crude oil. Reported by BP. Incident No. 458019.
- 1530 hours – No oil sighted during overflight by CPL.
- 1600 hours – Spill reported to be 30 miles southwest of mouth of Mississippi River delta. Spill size 27 miles by 7 miles. Estimated volume is 3,700 barrels.
- 1645 hours – No oil sighted during overflight by CPL.
- USCG overflight observed dark brown slick with light sheen 15 nautical miles by 1 nautical mile running NE to SW. Position 28° 50.6' North and 89° 12.8' West to 28° 51.7' North and 89° 19.7' West.

October 2

- 1100 hours – No oil sighted during overflight by CPL.
- 1229 hours – USCG locates sheen approximately 5 x 5 miles in position 28° 54.8' North and 89° 16.3' West. Described as light rainbow with areas of heavier rainbow.

October 3

- 1245 hours – No oil sighted during overflight by CPL.
- 1715 hours – No oil sighted during overflight by CPL.

October 4

- 0700 hours – No oil sighted during overflight by CPL.
- 0900 hours – No oil sighted during overflight by CPL.
- 1145 hours – Aerial surveillance finds no oil on water.
- 1245 hours – No oil sighted during overflight by CPL.
- 1315 hours – Aerial surveillance finds no oil on water.

- 1520 hours – CPL overflight observes spill from pressure testing sequence. Latitude 28° 56' 44.4", Longitude 89° 16' 47.9". Estimated volume = 85 barrels.
- Surveillance flight sights oil on water at Latitude 28° 54.31' N and Longitude 89° 14.66' W with an estimated volume of between 50 and 100 barrels.

October 5

- 1500 hours – Overflight locates slick at Latitude 28° 56.74' and 89° 16.8'. Slick described as being 0.75 miles by 200 yards.

Analysis of System Receipts and Deliveries and Leak Detection

At the time of the incident, Chevron considered the pressure safety low (PSL) on the pipeline system as the primary method for detection of pressure losses indicative of leaks in the pipeline system. The following is excerpted from data provided by CPL in response to MMS questions regarding the incident. "As this offshore pipeline has MMS required PSL shutdown equipment and meets [US]DOT 195.402 for operation with fail safe equipment, CPL 'lightly' monitors this pipeline for abnormal conditions including pipeline leaks. The controller displays, continuously, the SP 49 Onshore tank levels trend line for monitoring the operations of this system. The pipeline graphic is pulled up intermittently to note LACT [lease automatic custody transfer] status, specific tank level and pipeline pump status, etc. By monitoring all of these, a controller when noting an abnormal condition, makes the determination of a probable pipeline leak."

During the early stages of the pipeline system startup following the hurricane, tank level readings were being recorded at the CSC by SCADA.

At the same time, the FTL had dispatched field personnel to the tank battery to gauge the tank physically and to report the readings to the CSC controller. Following are readings that show a comparison of the tank levels recorded by each method. Please note that the time intervals are not equal, with lapses between noted readings ranging from several minutes to several hours.

		Tank Levels	
	Time	SCADA	Gauger
September 29	1800	7.1'	
	1833	5.6'	
	2100	4.6'	4' 10 ½"
	2140		4' 10 ½" (OL)
	2240		4' 10 ½" (OL)
	2340		4' 10 ½" (OL)
	2400	4.8'	4' 10 ½"
September 30	0040		4' 10 ½" (OL)
	0140		4' 10 ½" (OL)
	0240		4' 10 ½" (OL)
	0300	4.8'	4' 10 ½"
	0340		4' 10 ½" (OL)
	0440		4' 10 ½" (OL)
	0500	4.9'	4' 10 ½" (OL)
	1000	5.13'	
	1400	5.13'	
	1600	5.13'	
	2210		4' 8 ½" (OL)
	2215	4.99'	4' 8 3/4"

(OL) - Source of data is Operator Log.
All other data reported by CPL in incident report.

To assist in leak detection during start-up operations, CPL dispatched helicopters to overfly the SP 49 pipeline system for prompt observation of any sheens on the water. Details on flights and observations are noted in the previous section on oil spill observation reports.

Possible Oil Spill Volume

Initial estimates of the oil spill volume ranged from 850 to 8,500 barrels, based upon visual observations and worst-case estimates. On October 4, the Unified Command published a report indicating the spill size to be 3,690 barrels, based primarily upon visual estimates of slick size. Estimates from BP from mass balance calculations indicated a discrepancy of approximately 7,500 barrels. The only consistency in spill volume estimates was their inconsistency.

During their post-incident investigation, CPL provided the following data to support their estimate of the total volume of oil spilled during the incident:

	Volume Description	Facility	Gross Volume (Bbls)
a.	Volume pumped after startup	MC 109	7,549
		SP 45	263
b.	Volume of second release		85
c.	Volume to fill lines to pressure test	MC 109	15
		SP 45	1
		MC 20	9
		SP 49	97
d.	Volume recovered to tank when pressure test bled to zero	SP 49 Onshore	(61)
	TOTAL		7,958

An initial estimate by CSC on October 9 of the spilled volume indicated that MC 109 had pumped 7,765 barrels since the hurricane, and that SP 45 had pumped a total of 301 barrels. Using these figures in conjunction with the volume of the second release and oil recovered during the pressure test sequence noted above would yield a potential total volume spilled of 8,212 barrels.

The largest volume of oil that could have spilled during the incident takes into account a review of historical production trends and the SP 49 pipeline capacity. A review of MC 109 records indicates an average production rate of 9,901 barrels per day; however, as noted earlier, full production levels are not achieved for three days after full shutdown. Assuming that wells were placed on production and the facility pumped at a rate of 333 barrels per hour from 1900 hours on September 29 to 2015 hours on September 30, a maximum of 8,400 barrels of oil could have been produced. With a daily production rate of 180 barrels per day, SP 45 could have pumped 298 barrels of oil while on production from 1530 hours on September 29 to 0715 hours on October 1. The SP 49 pipeline system has a total static capacity of 13,995 barrels. Considering that the pipeline depth ranges from -110 feet at the leak location to a depth of -780 feet, a nominal amount of oil would be expected to escape from the pipeline until the pressure equalized at the leak point. It is assumed, however, that the pipeline was covered with sufficient mud to prevent a significant release of oil through line drainage. The largest volume of oil that could have spilled during this incident, therefore, given the above assumptions and volumes, is 8,698 barrels.

Leak Source Identification

During the early afternoon of October 1, a standup test was conducted on the SP 49 system to determine the exact location of the suspected pipeline leak. Pressures at the platforms were monitored to ensure that check valves were operating properly. Natural gas was the pressure test medium. Pressure readings at MC 109, SP 45, MC 20, and SP 49 Onshore remained at 0 psi throughout the test. Pressure readings recorded by SCADA at SP 49 were:

Time (hours)	Pressure (psi)	Comment
1300	58	
1400	73	
1500	68	
1530	165	Test started.
1600	165	
1700	164	
1730	164	Test completed.
1800	70	
1900	79	Pressure stabilized at 72 psi.

On October 3, BP confirmed, through the use of a remotely operated vehicle, that their pipeline (SN 9347), which was the suspected source of the leak, showed no physical damage nor evidence of any leaking oil.

As the initial standup test on the SP 49 system was unsuccessful in identifying the leak source, another more detailed pressure test procedure was developed on October 3 with the assistance of MMS.

On October 4, the second standup test was conducted on the SP 49 pipeline system. The pressure test medium was water, which was injected at SP 49. Pressure readings at MC 109, SP 45, MC 20, and SP 49 Onshore once again remained at 0 psi throughout the test. Pressure readings recorded by SCADA at SP 49 were:

Time (hours)	Pressure (psi)	Comment
1000	72	
1100	103	Injected 141 barrels of water. Stopped pumping. Aerial surveillance started. No pressure increase at SP 49 Onshore.
1145	-	No slicks sighted
1200	102	
1300	100	
1315	-	No slicks sighted.
1400	99	
1500	99	
1530	-	Oil observed coming to surface in SP Block 38
1600	68	
1700	69	
1800	0	

On October 5, divers confirmed that oil was coming from a depression on the seafloor in the SP 38 area. The depression, located in a water depth of 110 feet, measured 8 feet in diameter and 6 feet deep. The leak location was recorded at coordinates X = 107,143 and Y=2,656,428. Following jetting operations on October 13, the pipeline was found approximately 20 feet below the mud line (see Attachment 5). The pipeline was found totally parted, with the ends being approximately 3 to 4 feet apart and out of alignment. The north end of the pipeline had a 20–foot mud plug, while the south end of the pipeline had a 4–foot mud plug. Shortly after pipeline discovery, the ends of the pipeline were capped pending repair operations.

The pipeline repair entailed the installation of 10–inch ANSI 600 flexiforge end connectors and the fabrication and installation of a spool piece

16 feet 5 1/16 inches in length (see Attachment 6). Photographs of the surface preparations for the pipeline repair can be found in Attachment 7.

Failure Analysis

When pipeline SN 5625 was installed in 1980, MMS regulations required the pipeline (at the leak location) to be buried a minimum of 3 feet below the mud line. On October 5, during attempts to locate the pipeline leak location, divers found the pipeline to be buried approximately 20 feet below the mud line, indicating that a subsea mudslide had occurred. The pipeline was found completely parted, with pipe ends separated by approximately 3 to 4 feet and out of alignment.

Visual inspection of the pipeline rupture point revealed total failure of the pipeline where two pipeline sections had been joined by welding (see Attachment 8). To ascertain the cause of failure, a 6-foot section of pipe that contained the failure was cut from the pipeline by CPL and was forwarded to the Chevron Research and Technology Center (CRTC) for analysis.

On January 14, 1999, CRTC forwarded a report entitled "South Pass Crude Oil Pipeline – Material Failure Analysis," which detailed results of visual inspections of the failure surfaces and metallographic testing (see Attachment 9). The CRTC scientists determined that "the pipeline failed by propagation of a crack along the weld heat affected zone (HAZ). A combination of high stress generated by a mudslide and low fracture toughness of the pipe resulted in a rapid catastrophic fracture."

Both ends of the failed pipeline section contained a primary fracture along their HAZ that transitioned through the weld to the HAZ of the adjoining pipe. The failure propagated circumferentially along the weld as this area has a lower fracture toughness than the pipe. Neither of the primary fractures began or ended at the weld buttons, which are oriented 180° from each other. Inspections indicated that there was "no obvious initiation site or evidence of a preexisting flaw . . ." in the pipe or weld.

Two additional secondary cracks were also found on the pipeline. The cracks were approximately ¾ inches in length and oriented 180° from each other, possibly a result of "cyclic bending stress." The cracks "did not follow the HAZs but propagated into the base metal. The crack faces were covered with corrosion products and one of the cracks had grown thru-wall." The cracks were determined to be "a result of corrosion-fatigue."

Panel Investigation and Findings

Investigated Aspects

The investigation panel members reviewed and analyzed the following aspects of the pipeline leak incident:

- The cause of the pipeline failure
- System measurement balance data
- Factors affecting the appearance and observation of leaked oil
- The most probable oil spill volume
- Startup chronology and procedures
- Leak detection methodologies
- Modeling of the pipeline system's safety devices

Cause of Pipeline Failure

As noted earlier, the 10–inch pipeline suffered a rapid catastrophic failure. The failure is assumed to have occurred between 0200 hours on September 27, the time at which SP 49 was shut down, and at 1530 hours on September 29, the time at which SP 45 was allowed to resume production. The failure was due to high stress induced by a mudslide, coupled with a low pipe fracture toughness, and occurred along a weld that joined two lengths of pipe.

A review of historical pipeline repair records shows that this is the first reported occurrence of a mudslide of such magnitude that the SP 49 pipeline system was subjected to sufficient forces to result in damage. With a reported seafloor slope of approximately two to three feet per 500-foot distance in this SP location, seafloor movement would not appear to be a problem. Still, a survey conducted shortly after Hurricane Georges shows that, in addition to the mudslide that parted the 10–inch pipeline, a number of other mass movements had also occurred in the same vicinity in the SP area, at least one of which crossed over SN 5625 (see Attachment 10).

System Measurement Balance

The average daily production measured through MC 109 for the 8–month period prior to September 1998 was 9,901 BPD. According to CPL reports, the MC 109 LACT unit accounted for nearly all of the oil pumped after coming back on line after the hurricane; MC 109 pumped for over 25 hours after coming back on line before being shut in by the CSC because of the suspicion of a leak. At an average startup rate of 333 barrels per hour, it was possible to have pumped up to a maximum of 8,400 barrels of oil during the subject operational period.

The latest pipeline balance receipts for the SP 49 system indicate that the deliveries at the terminal were short approximately 9,677 barrels of oil for September 1998. Review of the system receipts before and after the pipeline spill (January 1998 thru December 1998) shows that the pipeline system had shortages as great as 5,683 barrels (1.1 % of receipts) and overages up to 6,742 barrels (1.5 % of receipts). For 1998, the SP 49 system showed a shortage of 11,115 barrels (0.21 % of receipts). These imbalances may be caused by such factors as:

1. Meter factors on the LACT units entering the system
2. Meter prover tolerances
3. Meter readings not taken precisely at seven each morning on the first of each month.

Following are the overage/shortage figures for the SP 49 system for 1998:

SOUTH PASS 49 SYSTEM RECEIPTS FOR 1998

Month	Receipts (barrels)	Over/Short (barrels)	% Over/Short
January	449,640	(67)	- 0.01
February	413,517	(100)	- 0.02
March	470,790	(683)	- 0.15
April	465,389	(577)	- 0.12
May	549,819	(663)	- 0.12
June	541,045	411	0.08
July	497,556	(5,683)	- 1.10
August	455,402	6,742	1.50
September	398,104	(9,677)	- 2.40
October	160,572	1,135	0.71
November	477,259	(1,228)	- 0.26
December	527,524	(725)	- 0.14
Year-to-Date	5,406,617	(11,115)	- 0.21

It should be noted that prior to the pipeline leak, CSC performed line balances on a monthly basis.

Factors Affecting the Surface Appearance and Observation of Oil

Estimates of the spill volume, based on aerial surveillance during the early phases of spill response, indicated a total volume of 3,700 barrels of oil. This is contrasted with the initial estimated volume of approximately 7,500 barrels of oil that was recorded pumped into the SP 49 system and presumed spilled into the Gulf of Mexico beginning on September 29. The variance in spill versus observed oil volume and the time that passed before released oil reached the surface pose a number of questions for which general theories are posited and scientific fact are presented below.

It has been observed that not all oil that is released from subsea locations comes to the surface in the immediately vicinity of the release point. Studies have shown that oil "plumes" can remain in the water column for periods of time without surfacing. Additionally, it has been found that plumes do not necessarily move in the same direction as a surface slick because of opposing water currents or eddies near river outflows.

After oil that is released from a subsea location reaches the surface of the water, natural forces such as gravity and surface tension immediately work to cause the oil to form a thin layer on the water. This thinning of the oil then facilitates the commencement of other dispersive processes, such as evaporation, dissolution, emulsification, chemical reaction, biological degradation, and formation of tar lumps.

As oil begins to disperse and to "weather," efforts to obtain an accurate estimate of the spill volume are impacted. Light hydrocarbons can rapidly evaporate, oxidize, or be mixed with seawater and dispersed in the water column. Heavier hydrocarbons can weather in much the same manner and can also form emulsions or tar lumps. Surface winds and chop can break oil into streamers and tar balls which are difficult to identify during aerial surveillance because of size, reflection of light, and a process called over-washing.

All of these factors make spill volume determination based on visual observation somewhat problematic, and often, as in this case, can result in underestimation of the severity of the spill.

Oil Spill Volume Determination

Calculation of the exact amount of oil released during the post-hurricane startup phase of the SP 49 pipeline system is not feasible. A review of overages and shortages during the previous 12-month period shows major fluctuations in the system, thus making application of factors to this event irrelevant. For example, July showed a shortage of 5,683 barrels, while August showed an overage of 6,742 barrels, indicating a tendency for significant variances to balance out over time, but only when production levels are essentially the same.

When 6–month running averages of the overages and shortages for 1998 are calculated, including the reported 9,677 barrel shortage that occurred in September, variances range from -76 to -1,573 barrels. A review of the data for the same time period, assuming that September showed a shortage of 131 barrels (the 11–month average excluding the September reported value), produced variances ranging from +302 to -1,216 barrels. The reported shortage figure of 9,677 barrels for September could therefore range from 8,461 to 9,979 barrels using these averaged figures, if production levels had remained constant, which they did not. Still, the figures generally correlate to the volume calculated by CPL and help establish the upper-end limits of oil loss.

A gross approximation of a spill volume has been calculated below, given review of the production tickets from affected platforms, consideration of startup practices, timing of events, and estimation of pipeline residual leakage after the pipeline failure. Another assumption critical to the approximation is that the pipeline was parted at the time SP 45 resumed production on September 29.

The total volume that is expected to have spilled during the subject pipeline leak is 8,212 barrels. The volume is based upon the following assumptions:

	Volume Description	Volume (bbls)
a.	Volume pumped after startup	8,066
b.	Volume to fill lines for pressure test	122
c.	Volume lost during pressure tests	85
d.	Volume recovered to tank	(61)
	TOTAL	8,212

Startup Procedures and Chronology

The CPL does have operating procedures that dictate actions to be taken following an "other than normal circumstance," as in the case of Hurricane Georges. The CPL procedures excerpted from the *Chevron Pipe Line Company – Gulf Coast Region – West Bay Pipeline System Manual*, presented below, deal with planned startup procedures that must be followed for system startup following normal or other than normal circumstances:

a) "Start-up of the system or a segment of the system will be coordinated by CSCC [customer service center controller], CSR [customer service representative], and the FTL.

b) "After system integrity has been verified and a segment of the system is ready for start-up, the Venice FTL will coordinate system start-up with the various field producers. Coordination includes verifying that Empire/Ostrica is ready to receive deliveries. A PL OP [pipeline operations] order may be issued, if appropriate, to affected FTL advising time and start-up and flow rates.

c) "The CSCC and field personnel will keep accurate records during the start-up and advise the appropriate FTL of any unusual events that may have occurred during the start-up.

d) "If the system is being restarted after being shut down for reasons other than normal, volume in vs. volume out checks will be made after the first 15 minutes of operation and at 30 minute intervals until it is evident that the line is operating normally.

e) "If the flow rate deviates from the established rate during start-up, the CSC will shut the system down following established shut down procedures and notify the appropriate FTL."

Thus, while CPL stated that they do not have established guidance on which platform should begin pumping first following a major system upset, they do provide for a system of checks and cross-checks to ensure that leaks can be identified quickly.

As operator of MC 109, BP indicates that following severe weather ". . . under no circumstances should deliveries commence without the consent of the pipeline company." Further, they indicated that their ". . . guidelines are not to start up if we have not established voice communication." BP correctly followed internal procedures, establishing voice contact and obtaining consent from CPL to pump into the SP 49 system. It is unclear, however, if CPL gave instructions to BP on the need for continued voice communications during startup regarding production rates.

SP 45 (OXY) ". . . does not have specific procedures for restarting a platform after a hurricane although damage assessment is carried out first." Similar to BP, "OXY USA. Inc. requires approval from respective pipeline prior to commencement of sales following hurricane evacuation." SP 45 personnel did contact CPL to pump into the pipeline but indicated that "No specific start-up instructions from Chevron Pipeline were noted after hurricane evacuation."

In conjunction with post-hurricane startup of the SP 49 pipeline, CPL stated that they advised MC 109 to resume production at 1630 hours with the condition that startup occur during daylight hours only to allow overflights. MC 109 was also instructed to look around the platform for slicks. BP indicates that CPL advised MC 109 to resume production at 1845 hours and provided ". . . no restrictions on rates or daylight hours or any requirement for stand-up tests or overflights . . .". MC 109 reported that production started at 1900 hours. A review of production charts for MC 109 shows that pumping resumed at approximately 2200 hours.

A review of actions taken by the pipeline operating company showed that CPL staff did not adhere to appropriate company "other than normal" procedures regarding volume tracking.

Two additional problems contributed to the failure to identify the pipeline leak promptly. First, recording of tank levels by CSC and the field representative was inconsistent, with measurements being reported in feet and inches versus feet and tenths of feet, e.g. tank level = 5 feet 6 inches versus 5.5 feet. Second, the failure of CPL to have backup phone numbers of producers prevented them from maintaining real-time communications regarding actual production startup and pump rates.

Leak Detection Methodology

The primary leak detection system on this 156,288–foot long pipeline is that provided by the use of PSLs on pipelines that depart oil production facilities and connect via subsea tie-ins to the subject transportation pipeline system. In addition, the SP 49 system is equipped with SCADA, which captures pressure and flow rate data at both delivery and receiving points in the system and is monitored in Houston. At the time of the pipeline spill, CSC used SCADA data primarily for monthly line balancing and did not have procedures established to continuously monitor SCADA data or trend SCADA data to assist in the identification of shortages that might indicate a pipeline leak.

Through the use of the PSLs, coupled with SCADA information, pipeline leaks should be quickly identified and isolated. Identification of a potential leak, however, is generally predicated on proper operation and settings of the PSLs as well as adherence to established operating procedures that help define what type of operational data need be collected to detect the presence of a leak and at what intervals such data should be collected.

During normal operations, MC 109 pumps into the SP 49 pipeline as needed for tank management. During pumping operations, the pipeline pressure approaches 150 psi. The PSL to detect low pressure on the pipeline is located on the transfer pump and is set at 46 psi, with a 45-second delay after pump startup. This represents an approved departure from MMS regulations. When the pumps are shut down, the pipeline pressure is 0 psi or on a vacuum.

SP 45 also pumps into the SP 49 pipeline system based on tank management. During pumping operations, the pipeline pressure ranges from approximately 0 to 200 psi, with the PSL set at 5 psi. The PSL has a 15-second delay, to allow pump startup.

In both cases, sufficient back pressure remained at the departing platforms to prevent the PSLs from sensing a leak. It is assumed that MC 109 did not shut in on low pressure because of the leak location and system hydraulics. Modeling of the system to support this conclusion is provided in the following section. The SP 45 PSL did not shut-in the platform since pressure did not drop below the 5 psi setting as a result of restrictions in the pipeline. (Following the spill incident, OXY personnel are reported to have found a partial paraffin plug that restricted flow through the pipeline.) The restriction allowed the producer to pump into the pipeline at pressures above the PSL setting in spite of a nearby catastrophic pipeline failure. Simulations indicate that the PSL would have tripped on low pressure with a pipeline rupture located in SP 38 had the inside diameter of the pipe not been reduced by the buildup of paraffin.

Many pipeline oil spills are discovered through visual observation by personnel stationed on platforms, planned flyovers during pipeline inspections, or chance identification by personnel traveling through the area. Efforts extended to identify oil spills and their origins assume that the oil released from a subsea location will surface in the immediate vicinity of the pipeline leak. This may not have been the case in the SP 38 spill.

Daylight overflights of the SP 49 pipeline system during the initial startup phase did not identify the release of oil, suggesting that oil plumes may have moved laterally subsea away from the leak location. Given the proximity of the pipeline leak location to the mouth of the Mississippi River, it is argued that during the initial spill riverine currents pushed the oil plume to deeper water. At the time of its initial discovery the slick was described as oriented from northeast to southwest.

During the secondary spill that occurred during the pressure–testing sequence, surfacing and the subsequent sighting of oil were as expected, near the actual leak location in SP 38. Within four hours of the initiation of the pressure test, oil was sighted through aerial surveillance. This finding disputes the previous theory on subsea oil plume movement; however, such observations should be considered while attempting to sight spills from specific pipeline systems.

Standup tests of pipeline systems are another method used to ascertain if a system can maintain a static pressure for a given length of time. After the hurricane, CPL staff made the determination that a standup test did not have to be conducted on the offshore component of the pipeline system because SCADA was operational at the time of their decision. Even though SCADA operations malfunctioned early in the startup process, the decision to conduct a standup test was not revisited.

During the post-spill pipeline leak identification phase, pressure tests were conducted on the pipeline system from SP 49 to SP 49 Onshore. Throughout the initial pressure test, pressure at SP 49 Onshore remained at 0 psi, pressure on the pipeline appeared stable, and no slicks were observed. Several factors contributed to the appearance that the pipeline system was intact.

First, a pressure buildup should have been observed at SP 49 Onshore during the test. However, during an inspection of a pig trap located on SP 49 Onshore on October 1, it was discovered that the trap contained an 8–inch and a 10–inch utility pig and approximately 200 pounds of wax, which probably account for the lack of pressure at SP 49 Onshore.

During normal operations, MC 109 runs their 8–inch pig each week on Monday and SP 49 runs their 10–inch pig on Tuesday. This is done to ensure that the 10–inch pig will push the 8–inch pig into the trap at SP 49 Onshore. Operations personnel failed to recall that pigs had been run prior to the cessation of operations before the hurricane.

During the initial pressure test, gas was used as the test medium. Pressure was held at 165 psi for two hours at SP 49. It is hypothesized that, given the compressibility of gas, the volume of fluid in the pipeline, the depth of the pipeline, and the relative depth of the leak location, that the initial test pressure was inadequate. The test verified the integrity of the riser of SP 49 but was of insufficient pressure to push fluids through the pipeline system to the rupture point.

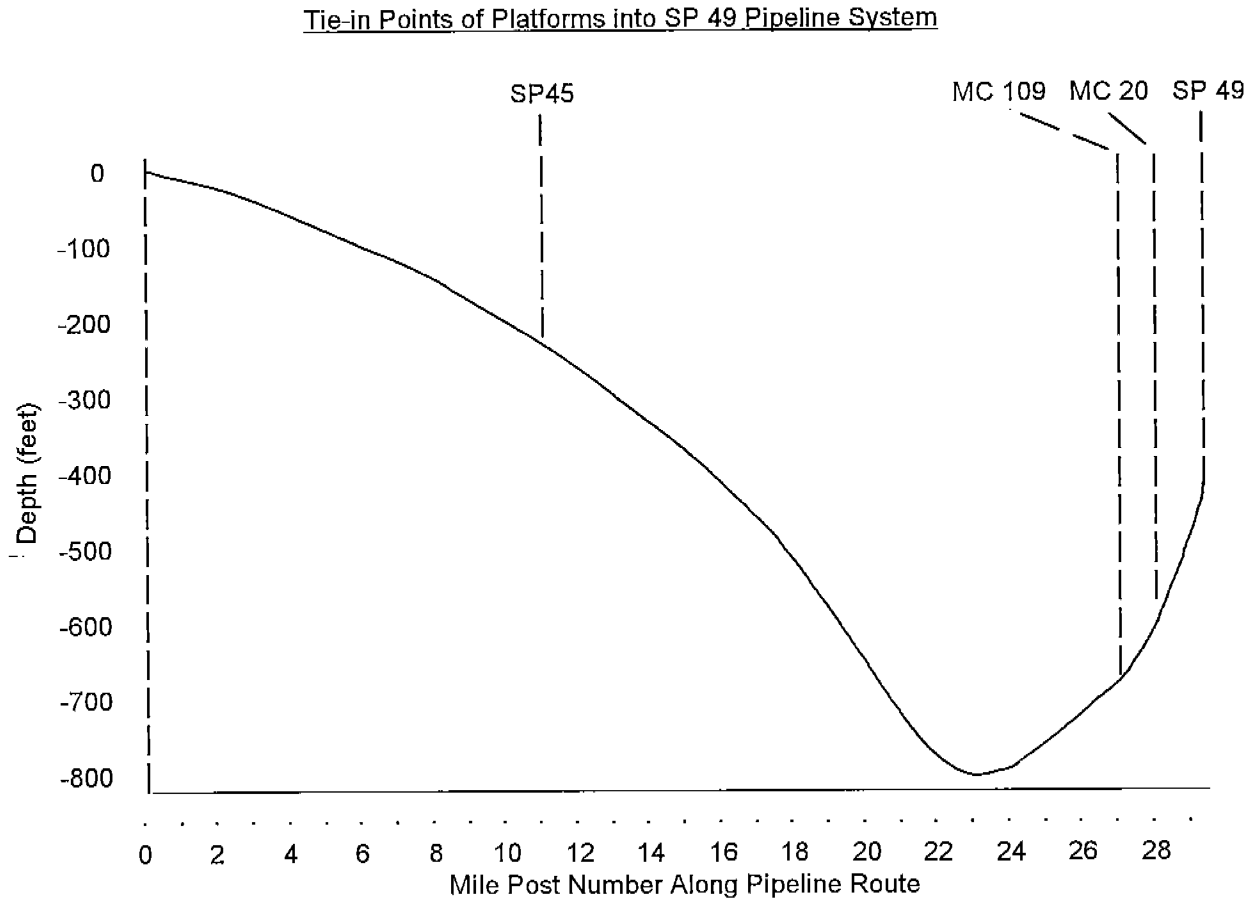
Analytical Pipeline Leak Model

Settings on PSLs to detect pipeline leaks are established according to MMS guidelines, which require a pressure setting of 15 percent below the normal operating pressure but no lower than 5 psi. Theoretically, pressure losses in the pipeline resulting from a breach in line integrity should be sensed by the PSLs at the producing facilities, and shutdown valves should be activated to stop fluid flow into the pipeline. It has long been assumed that catastrophic pipeline failures would produce sufficient pressure losses to trip the PSLs. Empirical evidence, however, has shown that the pressure loss from a minor pipeline leak is inadequate to reduce the pipeline operating pressure below the PSL setting, allowing the leak to go undetected.

The PSL settings for SP 45, MC 109, MC 20, and SP 49 A during post-hurricane startup were 20 psi, 46 psi, 10 psi, and 5 psi, respectively. At these approved settings neither of the two producers that were brought back on stream (SP 45 and MC 109) shut in due to low pressure, even though the SP 49 pipeline was completely parted and the platforms were effectively pumping into an open-ended pipeline buried approximately 20 feet below the seafloor.

To analyze the SP 49 pipeline system hydraulics and safety system operations, CPL used a pipeline model to simulate the system under various configurations. The primary objective of the analysis was to determine why the PSLs had failed to shut in the producing platforms. The simulations involved review of the effectiveness of PSLs on the basis of pipeline ruptures at different locations, operating pressures, pumping rates, groupings of producers pumping at the same time, water depths, and theoretical back pressures at SP 49 Onshore. The report, "South Pass 49 Pipeline System Pressure Safety Low Setting Evaluation," may be found in its entirety in Appendix 11. An example of model results follows.

Leak Detection Effectiveness Modeling - SP 49 Pipeline System



	Platforms			
	SP 45	MC 109	MC 20	SP 49
Current PSL Setting[a] (psig)	20	46	10	5
Scenario 1 - Rupture at Milepost 6.5 (SP 38)				
Theoretical Operating Pressure[b] (psig)	-8	150	51	71
Would PSL Shut in Pipeline[c]?	Yes	No	No	No
Scenario 2 - Rupture at Milepost 23.1 (-780')				
Theoretical Operating Pressure[b] (psig)	14	131	89	65
Would PSL Shut in Pipeline[c]?	Yes	No	No	No
Scenario 3 - Rupture at Milepost 27.1 (MC 109)				
Theoretical Operating Pressure[b] (psig)	5	102	77	35
Would PSL Shut in Pipeline[c]?	Yes	No	No	No
Scenario 4 - Rupture at Milepost 27.9 (MC 20)				
Theoretical Operating Pressure[b] (psig)	0	90	70	23
Would PSL Shut in Pipeline[c]?	Yes	No	No	No

[a] - Actual current pressure setting of PSL at respective pipeline departing point.

[b] - Theoretical operating pressure with only one producer pumping at a time, with a rupture in the pipeline at the noted location.

[c] - Comparison of theoretical operating pressure to current PSL setting and the determination if PSL is set sufficiently to detect pipeline rupture and initiate shutdown of flow to pipeline.

As the preceding graph and scenarios show, hydrostatic pressure at the modeled leak locations was found in many cases to emulate the back pressure associated with a producer pumping into tankage at the SP 49 Onshore facility. This occurs as pressure losses associated with leaks are offset by the pressure of seawater at the given depth of the leak location below sea level. The operating pressure at the PSL sensing location at the producing facility thus showed little if any change, giving no indication that the pipeline integrity was no longer intact.

The report included a number of significant conclusions that bring into question current policies affecting pipeline safety systems and the use of PSLs as the primary leak detection methodology. Notably, CPL indicated that, "The current PSL settings for each of the producers will not automatically shut-in flow to the 10" SP 49 Pipeline System for a rupture at all points in the system." Further, modeling showed that reducing PSL settings to 15 percent below the lowest operating pressure still would not shut in flow from producers for a rupture at all points in the pipeline system. The reduced setting, however, was found to shut in more producers than at currently prescribed PSL settings in a number of scenarios.

Setting a nominal back pressure at SP 49 Onshore in conjunction with reduced PSL settings proved to provide better pipeline protection than currently approved PSL setting levels. Still, this improvement was only marginally better and was highly dependent on the water depth at the leak location as well as the number of producers pumping into the system at the same time.

Simulations did show, however, that installing a back–pressure valve at SP 49 onshore with a valve setting of 410 psi, coupled with setting PSLs at 15 percent below the lowest operating pressure, would protect the pipeline system in the event of a failure at the onshore facility water line (the worst-case rupture scenario) even when all facilities were producing simultaneously. All facilities would not shut down immediately on low pressure, but would follow a domino effect as the operating pressure of the pipeline was continually reduced as each facility dropped from the system. Alternatively, it was found that an SP 49 Onshore back pressure of 525 psi, coupled with setting PSLs at 15 percent below the lowest operating pressure, produced a simultaneous shutdown of all facilities under the worst-case rupture scenario.

As a result of the analysis, CPL has developed a recommended two-phase approach for improving operational safety and the ability to identify pipeline leaks quickly on the SP 49 pipeline system. The approach calls for the simultaneous use of PSLs and SCADA as the primary method for leak detection. The recommendation suggests that producers reset PSLs to 15 percent below their normal operating pressure and that SCADA be configured to provide line balance information that can be trended.

Conclusions

Following a thorough review of relevant information related to the oil spill that occurred in South Pass Block 38, the investigation panel arrived at the following conclusions:

1. The damage to the pipeline occurred as a result of a natural hazard, specifically a mudslide that was precipitated by a hurricane.
2. The most probable total volume of oil that was spilled during the primary and secondary releases was 8,212 barrels.
3. Deviations from established other-than-normal startup operating procedures contributed to the failure to identify the pipeline leak promptly.
4. Poor communications during system start-up contributed to the failure to identify the pipeline leak promptly.
5. Responsible personnel failed to recognize, verify, or take appropriate action upon critical indicators that pointed to a significant system imbalance during post-hurricane startup.
6. The primary leak detection system, i.e.. PSLs, was ineffective in sensing the pipeline leak because of the negligible pressure drop measured at the pressure sensors.

Recommendations

The initial oil spill that occurred as a result of the rupture of the SP 49 system pipeline during the hurricane was unforeseeable and unavoidable. The additional loss of oil into the environment during system startup, however, could have been prevented had information on mudslide risks, post-hurricane startup procedures, and safety system inadequacies been available to the pipeline operating company.

As a result of the findings and conclusions of this investigation panel, the following recommendations, designed to prevent a reoccurrence of an incident similar to the SP 38 spill, are offered for approval and immediate implementation by the respective agencies or companies noted therein.

1. The MMS should undertake a study to identify areas throughout the Gulf of Mexico where pipeline damage has occurred as a result of mudslides and should make the data available to interested parties.

2. The MMS Gulf of Mexico Region should advise operators of pipelines in mudslide-prone areas to review and, where appropriate, revise post-hurricane startup procedures to address additional steps that will be taken to ensure pipeline integrity prior to resumption of operations

3. The MMS should advise pipeline operators of the need to assess the effectiveness of PSLs in pipeline leak detection and the need for consideration of alternate and/or supplementary leak detection methods if PSLs are deemed potentially inadequate on individual pipelines and/or pipeline networks.

4. The MMS should undertake a study to determine the effectiveness of PSLs on pipelines under various pipeline operating conditions.

5. Chevon Pipe Line Company should establish leak detection determination protocol on the SP 49 pipeline system using data collected through the supervisory control and data acquisition system, reviewing the data at such a frequency so as to identify promptly system imbalances that would indicate a potential leak.

6. The MMS Gulf of Mexico Region should issue a safety alert to operators throughout the GOMR area instructing them to adhere to established post-hurricane pipeline operations startup procedures, and if no procedures are in place, to develop and implement them.

Attachments

1. Memorandum Establishing Accident Investigation Panel
2. West Bay Pipeline System
3. 10" South Pass 49 Pipeline System
4. October '98 Chevron Pipeline Oil Spill Environmental Impact and Response Evaluation
5. Chevron 10" Pipeline Repair/South Pass 38 – Pipeline Profile Information as of October 15, 1998
6. Spool Piece Design
7. Photographs – Pipeline Repair
8. Photographs – Pipeline Damage
9. South Pass 49 Crude Oil Pipeline Material Failure Analysis
10. Sidescan Sonar Survey – Mass Movement Features
11. Chevron Pipe Line Company – South Pass 49 Pipeline System - Pressure Safety Low Setting Evaluation – March 25, 1999

Attachment 1

OCT 2 9 1998

UNITED STATES GOVERNMENT
MEMORANDUM

To: David Moore, Pipeline Section, Field Operations, GOM OCS Region (MS 5232)
Frank Torres, Pipeline Section, Field Operations, GOM OCS Region (MS 5232)
Mike Joseph, Surface Commingling and Production Measurement Section, Production and Development (MS 5312)

From: Regional Director, Gulf of Mexico OCS Region (MS 5000)

Subject: Accident Investigation Panel

To confirm prior verbal communication, and pursuant to Minerals Management Service Manual, Part 640, Chapter 3, Accident Investigations, you are hereby appointed to serve as the accident investigation panel to investigate the break that occurred on or about September 28, 1998, in the 10-inch gas/oil pipeline, Segment No. 5625, Right-of-Way OCS-G 7561, permitted to Chevron Pipeline Company and constructed between Platform A, South Pass Block 49, Lease OCS-G 2177, and the Federal-State boundary in South Pass Block 27, Lease OCS-0693, off the Louisiana coast.

David Moore is designated as the panel chairman.

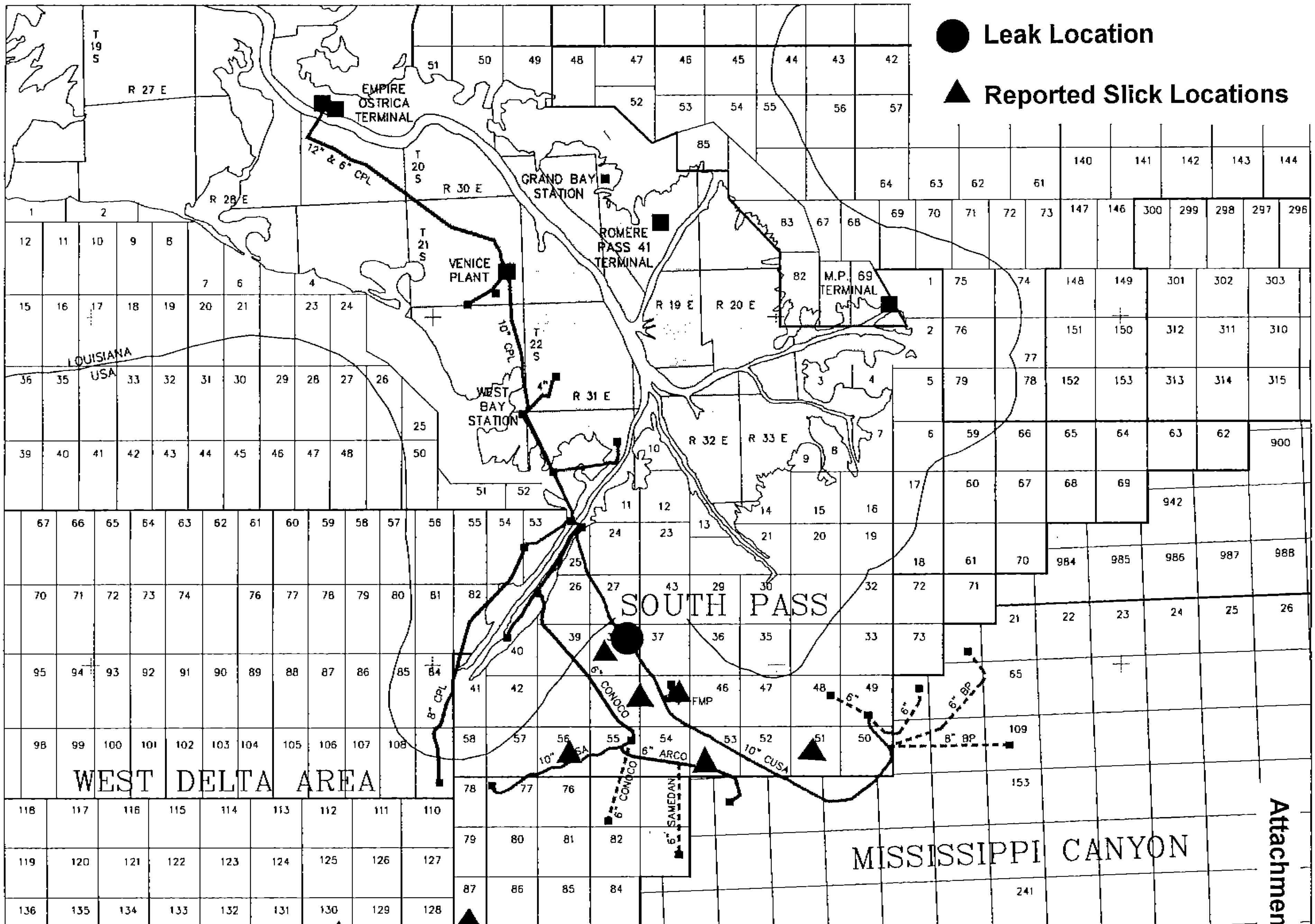
Please convene the panel as soon as possible and coordinate the investigation with the Department of Transportation, Office of Pipeline Safety, and the U. S. Coast Guard.

for Chris C. Oynes

cc: 1401-01a (MS 5232)
MS 5000 Reading File

JRHennessey:amm:10/27/98:acinvpnl.mem

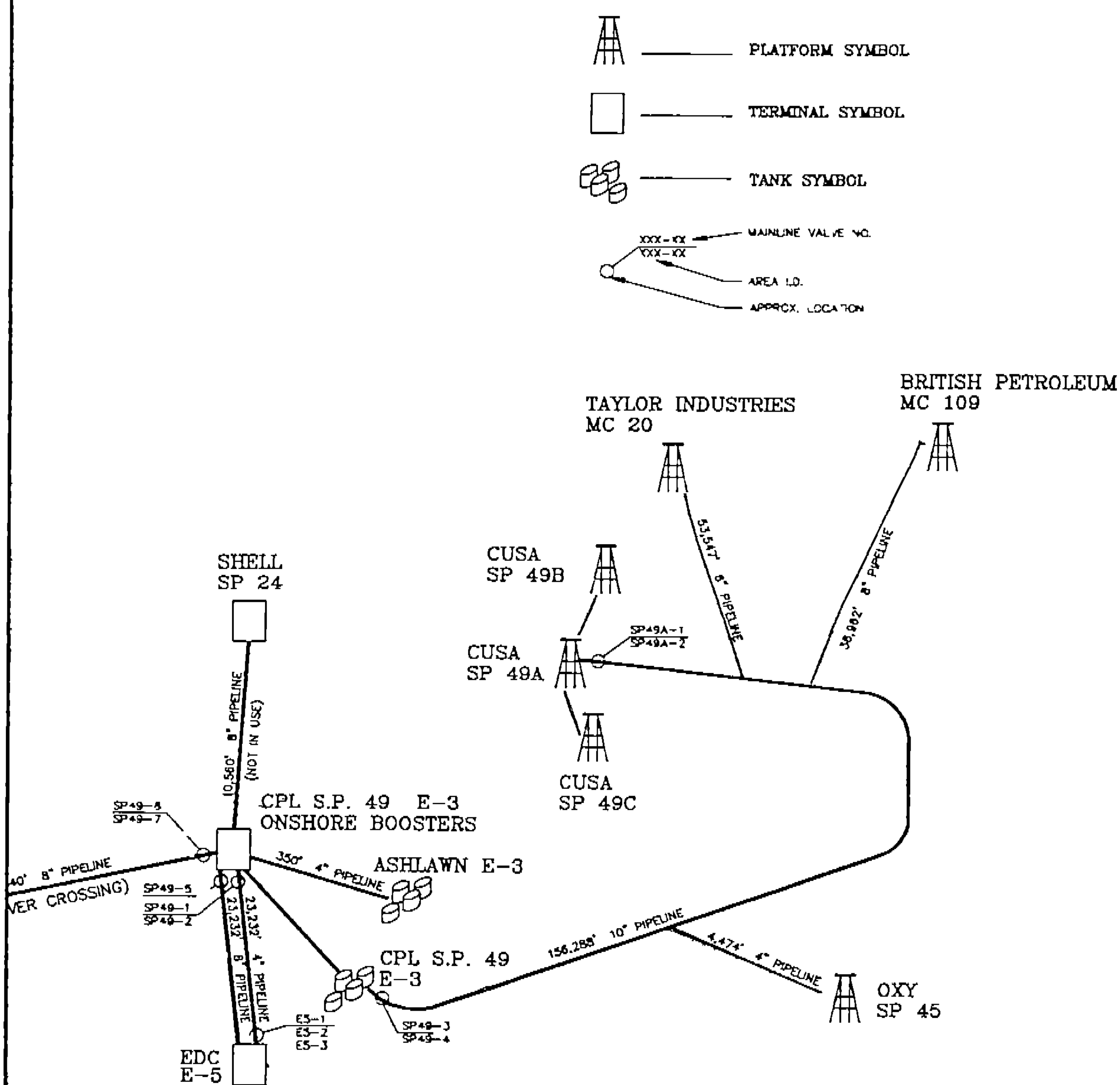
Attachment 2



WEST BAY PIPELINE SYSTEM

SCALE: 1" = 7.2 MILES

Attachment 3



Chevron

Chevron Pipe Line Co.
Gulf Coast Corridor

10" South Pass 49 Pipeline System

SCALE: NONE
DR: WJH
CK: DEW
OPR'G. DEPT: T/S
DATE: 4/26/96
ENGINEER: DEW
ENG'R. DEPT: T/S
APPROVED
W.O. 8A300003
B.O.

61-YD-13374

FILE NAME: 460-112
DATE: 11-28-94

Attachment 4

UNITED STATES GOVERNMENT
MEMORANDUM

February 1, 1999

To: Regional Director, Gulf of Mexico OCS Region (MS 5000)

From: Regional Supervisor, Field Operations, Gulf of Mexico OCS Region (MS 5200)
Regional Supervisor, Leasing and Environment, Gulf of Mexico OCS Region (MS 5400)

Subject: October '98 Chevron Pipeline Oil Spill Environmental Impact and Response Evaluation

Summary

- An oil slick developed from a leak in Chevron Pipeline's 10" pipeline at South Pass 50, on September 29, 1998.
- Favorable weather and currents kept the initial oil spill (3700 - 7500 bbls) offshore resulting in no shoreline or wildlife impacts. The second release (85 bbls) was largely recovered or naturally dispersed prior to impacting the shoreline.
- The spill response was appropriate, fast, efficient, effective.
- Shoreline impact from the October 4, 1998 oil spill (85 bbls) was minimal, with light sheens along the eastern gulf side of Southwest Pass, from the Burrwood Cut southward to the rock jetties. No wildlife impacts were observed.
- NRDA will likely not be pursued.

Background

After the passing of Hurricane Georges on September 28, 1998, BP Exploration started producing into their 8" pipeline at 1900 hours on September 29, 1998. BP Exploration's 8" pipeline (seg # 9347) ties into Chevron Pipeline's 10" pipeline (seg # 5625) through a subsea tie-in at South Pass Block 50. At approximately 2000 hours on September 30, 1998, Chevron Pipeline called BP Exploration and informed them that they were receiving no oil at the pipeline terminal. They had pumped an estimated 7500 bbls of oil into the 8" pipeline; the observed slick size volume estimate is 3700 bbls according to all the information reviewed. BP Exploration started their initial response on October 1, 1998. Chevron Pipeline assumed responsibility for the response on October 6, 1998, after it was discovered the leak was in their segment of the pipeline system.

Because of the inability to identify the leak location and confirm system integrity, a plan was developed to pressure test the BP Exploration 8" pipeline from Mississippi Canyon 109 to Chevron Pipeline's 10" pipeline in South Pass 50. During the pressure test of the pipeline on October 4, they noticed an oil sheen from the initial release, near South Pass Block 24/37. Response equipment on-site for the test immediately began skimming operations. Fresh oil bubbles were observed at approximately 1500 hours; this second release was estimated at 85 bbls. This release was from Chevron Pipeline's 10" pipeline.

<u>Response Activities</u>

Oil was first discovered on the water at approximately 1030 hours October 1, 1998. BP Exploration immediately mobilized personnel and equipment to respond to the spill. The first response to the spill location was dispersants. During the first two days they applied 3700 gallons of dispersant to the slick. This dispersed approximately 1,138 bbls of oil.

Skimming operations on the initial release recovered approximately six barrels of oil. Skimming recovered approximately 60 - 65 barrels of the second release. The difference between the two amounts recovered is timing. For the first spill it took more than 20 hours to get a skimmer onsite. The skimmers for the second release were pre-positioned near the location and started skimming in just a few hours.

Mass Balance - After 5 days (barrels)

Oil Spilled	Evaporated	Naturally Dispersed	Chemically Dispersed	Recovered	Remaining
3700	1221	185	1138	70	1086
7500	2475	375	1138	70	3442

The oil continued to degrade and has naturally dispersed into the water column.

<u>Shoreline Impacts</u>

Favorable weather and currents kept the initial oil spill offshore (See Attachment A) resulting in no shoreline or wildlife impacts. The second release was driven N/NW towards the Mississippi River Delta by strong southerly winds up to 20 - 25 knots. The leading edge of this slick was within state waters at 1800 hours CDT on 10/4/98 and according to teams onsite, the first shoreline contact occurred on the afternoon of October 5. Shoreline impact was minimal, however, with light sheens extending several miles along the eastern gulf side of Southwest Pass, from the Burrwood Cut southward to the rock jetties (see Attachment B). Small bands of a slightly heavier mousse were observed just offshore at the convergence line of fresh and salt water. While estimates vary, USCG onsite representative Chief Petty Officer Bill Hudgens estimated the oil washed ashore at less than 10 gallons.

Although shoreline impact was minimal, one State of Louisiana natural resource damage assessment trustee suggested cleanup of the most heavily impacted sections of the beach. By the afternoon of October 6, prior to actual deployment of cleanup equipment/crew, increasing seas dissipated the minimal oil along the shoreline and made beach cleanup no longer necessary. Pass a Loutre State Wildlife Management Area was not impacted by this spill.

<u>Wildlife Impacts</u>

Shoreline resources (marshes and tidal flats) and biological resources at risk (fish, shellfish, birds, mammals, reptiles, habitats) were identified as part of the oil spill response effort. BP Exploration and Chevron Pipeline contracted and staged wildlife response professionals from International Bird Rescue and Rehab Center. Clean Gulf's Wildlife Rehabilitation Trailer was pre-staged in the Venice area in the event of any wildlife impact. However, no impacted animals of any kind were observed during this spill incident.

Natural Resource Damage Assessment (NRDA)

Throughout the oil spill response effort contractors specializing in NRDA assessments, hired by both BP Exploration and Chevron Pipeline, conducted sampling and shoreline impact surveys in anticipation of NRDA proceedings. The consensus among these contractors was: the shoreline impact was not heavy enough to warrant a cleanup effort. Analysis of the samples taken has not been conducted, based on the low likelihood that NRDA would be pursued.

NRDA trustees from state agencies (Louisiana Governor's Office - Oil Spill Coordinator, Department of Environmental Quality, Department of Natural Resources, Department of Wildlife and Fisheries) and federal agencies (MMS, United States Coast Guard, Department of the Interior, NOAA) were also actively involved during the oil spill response effort. According to Chevron Pipeline, the trustees indicated that NRDA would probably not be pursued based on the minimal impact on the shore and no observed wildlife impacts. The Louisiana Department of Environmental Quality (DEQ) has indicated they may still conduct a follow up visual observation of the impacted shoreline. If DEQ determines this trip is necessary, MMS representatives plan to attend.

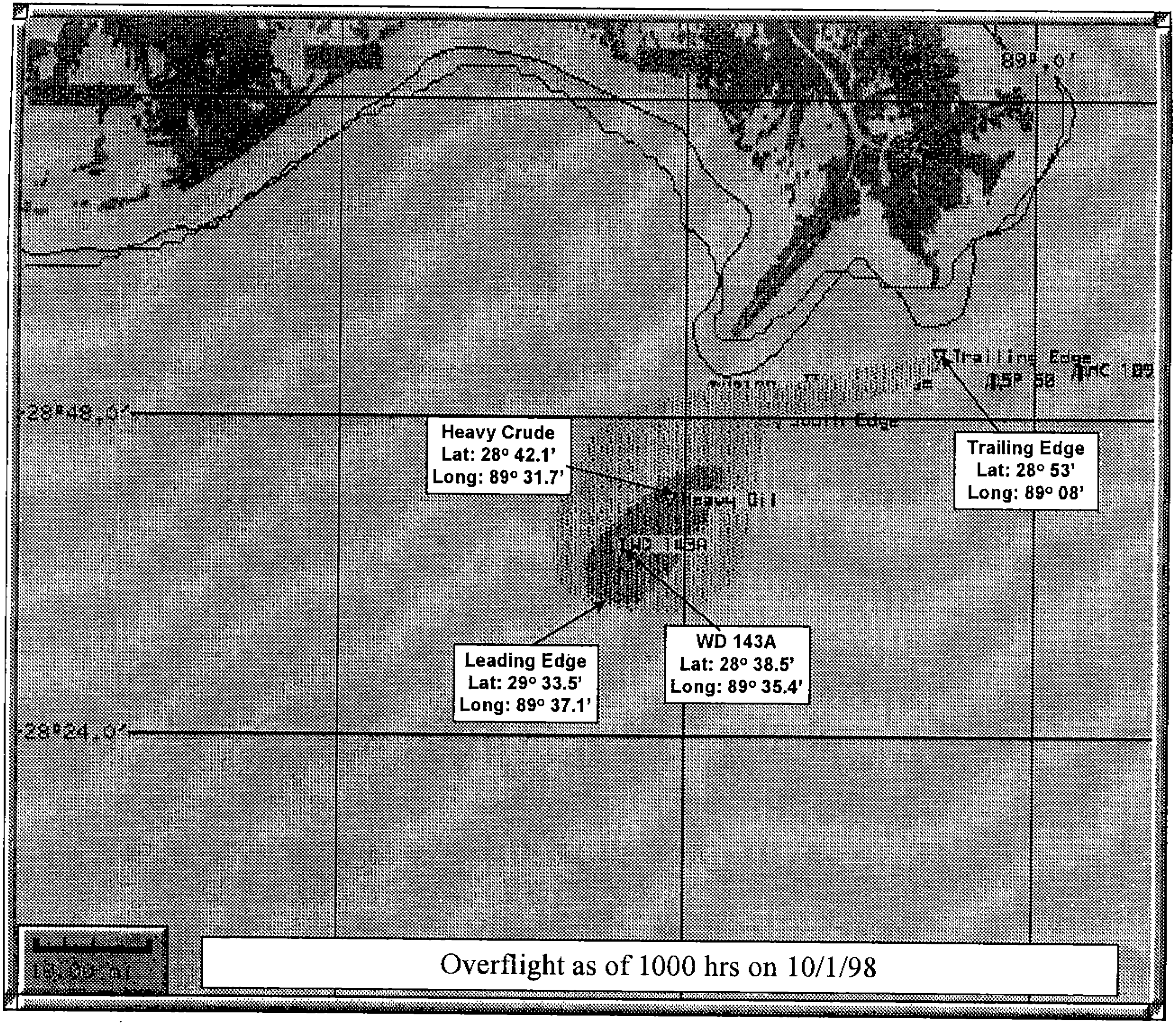
Orig. Sgnd William H. Martin
for Donald C. Howard

(Orig. Sgd.) J. Hammond Eve
Hammond Eve

Attachments

cc: Howard w/attachs (MS 5200)
Eve w/attachs (MS 5400)
Wright w/attachs (MS 5231)
Pilie w/attachs (MS 5442)
MS 5000 Reading File

HWright:kmd:02/01/99:g:\wordperf\rwright\chev-eva.wpd

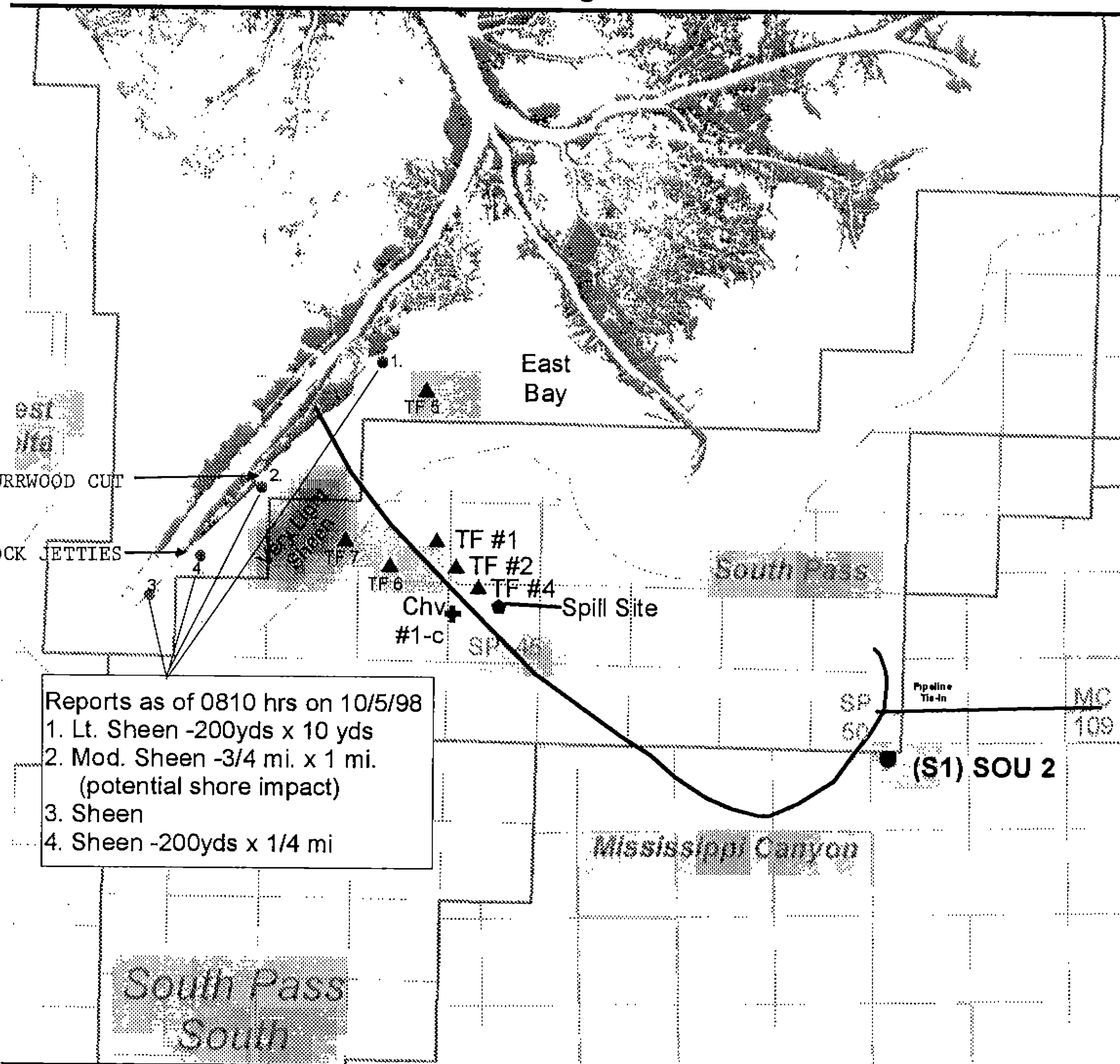


ATTACHMENT A

Situation Map (0810- 10/5/98)

Overflight as of 0810hrs. on 10/5/98

Prepared by
Morris Environmental



LEGEND

Lease Block (S1) ● Source Control
Lease Area (N) ▲ Near Shore
Heavy Oil (O) ▲ On water
Sheen ✚ Chevron Vessel
Light Streamers ⬟ Spill Site

SOURCE CONTROL

Task Force	Name	Status
SOU2	ROV	OL

OPEN WATER DIVISION

Task Force	Name	Status
1	NRC Sentry	OL
2	Edison G	OL
3	David G	Released
4	LA Resp.	OL
5	TX Resp.	Released
6	GC Resp.	Released
7	Dispersant	
	PK Air Spotter	
	Airborne Support DC3	
	Airborne Support DC4	
8.	SROMP Team	Released
Chv #1-c	Ensco Chief (FRU)	OL

NEAR SHORE DIVISION

Task Force	Name	Status
4	Jackie G	Released
5	Cavalier ETA	OL
6	Damon Chouest	OL
7	Ryan Chouest	OL
8	Deck Barges	OL
9	Miss Pearl	Released
10	Willie McCall	OL
11	Cenac (Boom/Crew)	OL

AIR OPERATIONS

Task Force	Name	Status
(A) 1	Helo #416	OL
(A) 2	Navajo	Released
(A) 3	Helo #174	OL
(A) 4	Helo #152	Released
(A) 5	Helo #BP1	OL
(A) 6	Helo #298	OL
(A) 7	Helo #N7077B	Released
(A) 8	Baron	Released
(A) 9	Baron	OL

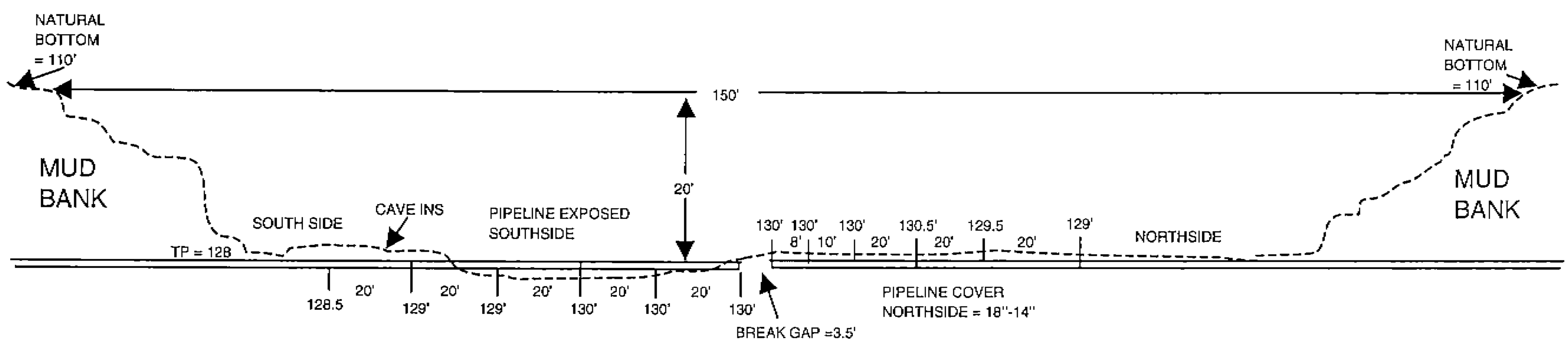
OL-On Location; ER-En Route; ST-Staging

Attachment 5

CHEVRON 10" PIPELINE REPAIR / SOUTH PASS 38

PIPELINE PROFILE INFORMATION AS OF OCTOBER 15, 1998

DATA OBTAINED BY GLOBAL INDUSTRIES AND JOHN E. CHANCE /
DATA COMPLIED BY MAGELLAN MARINE INC / A. CRAMPTON



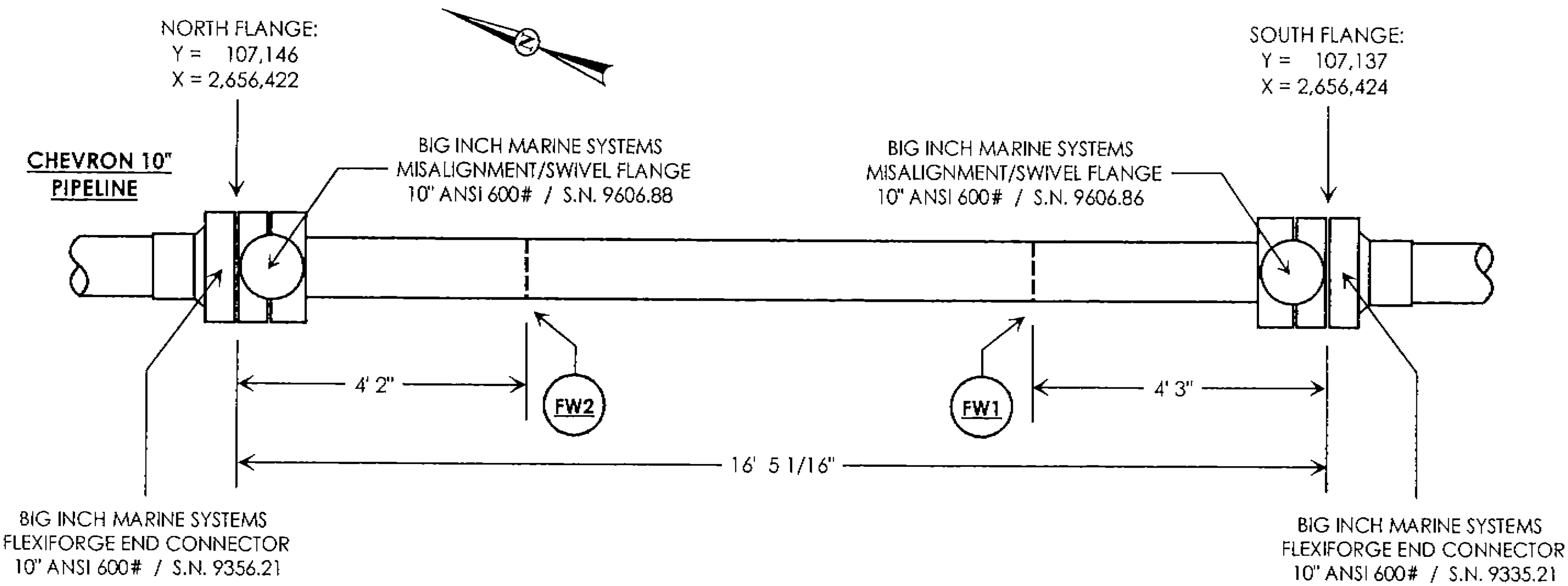
Attachment 6

MAGELLAN MARINE, INC.
PROJECT DOCUMENTATION

Chevron

PROJECT TITLE	CHEVRON 10" REPAIR
PROJECT ENGINEER	KEVIN GAUDET
INSPECTOR NAME	L. WHITED / A. CRAMPTON
PROJECT DESCRIPTION	LEAK REPAIR FOR 20' BURIED
	CHEVRON 10" OIL PIPELINE
	--- SPOOLPIECE AS-BUILT ---

DATE / DRAWING #	10/20/98	81008S01
CLIENT JOB NUMBER	PWREM-00264-410	
AREA	SOUTH PASS 38	
CONTRACTOR	GLOBAL INDUSTRIES (SENECA)	
CONSULTING FIRM	MAGELLAN MARINE, INC.	
FOR ILLUSTRATION ONLY -- NOT TO SCALE		



NATURAL BOTTOM = 110 FSW
TOP OF PIPE @ REPAIR = 130 SFW

FLANGES & SPOOLPIECE WERE SANDBAGGED AS REQUIRED FOR FULL SUPPORT.

FIELD WELDS MADE ON BARGE SENECA:

FW1 DAVID PEARSON, DERRELL BIRMINGHAM

FW2 ROBERT DAY, JAMES ELKINS

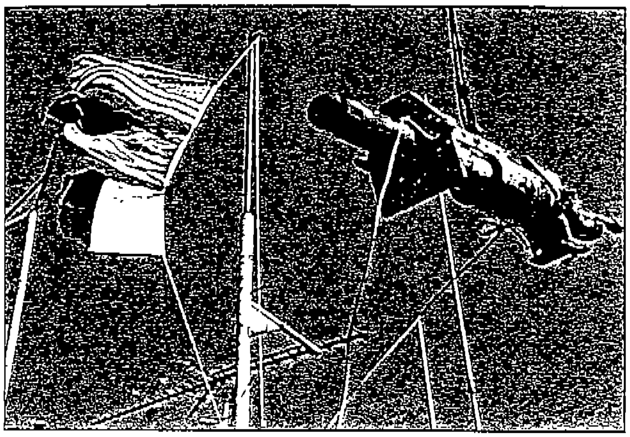
NOTICE: ALL SURVEY ISSUES SHOULD BE DIRECTED TO THE CONTRACTOR OR JOHN E. CHANCE.

SURVEY SYSTEM IN USE:
US STATE PLANE 1927
LOUISIANA SOUTH 1702
NAD 1927

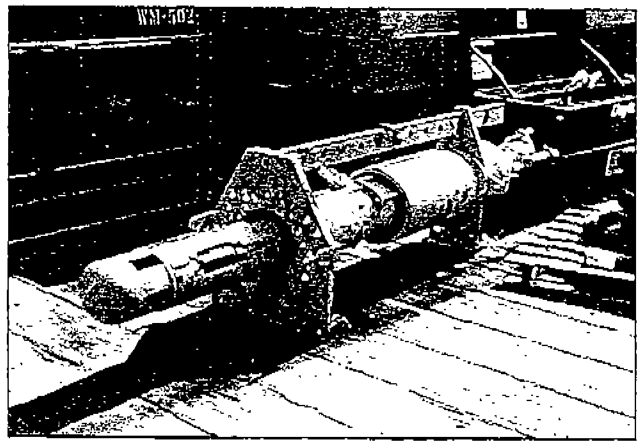
Attachment 7

CHEVRON 10" PIPELINE REPAIR -- SOUTH PASS 38 -- OCTOBER 1998

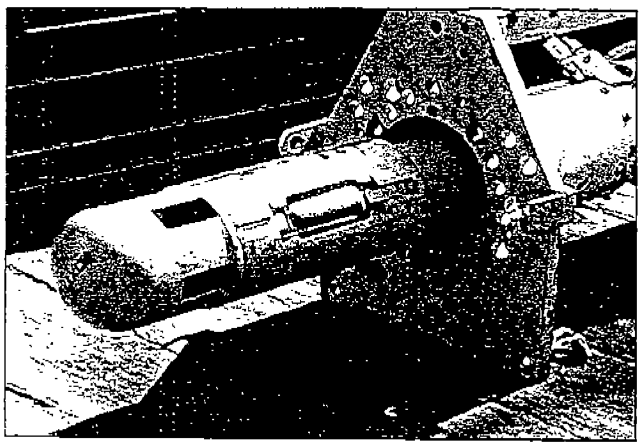
BIMS FORGING TOOL



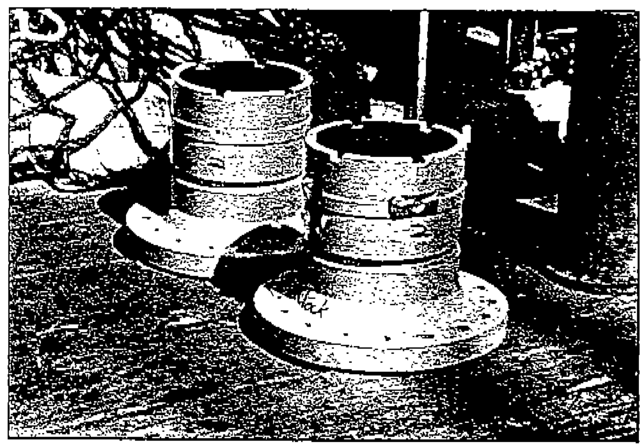
BIMS FORGING TOOL



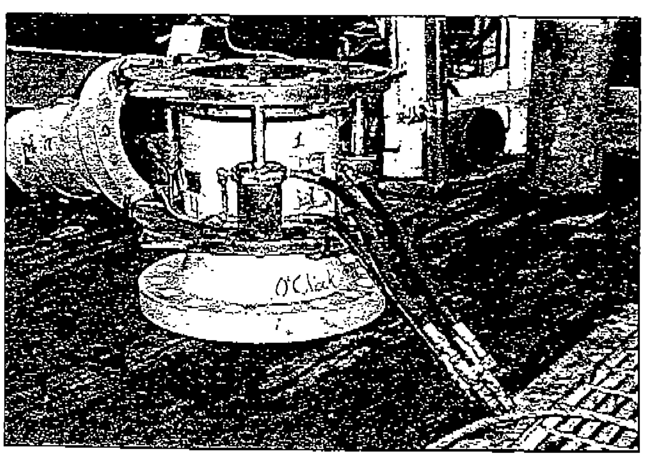
BIMS FORGING TOOL



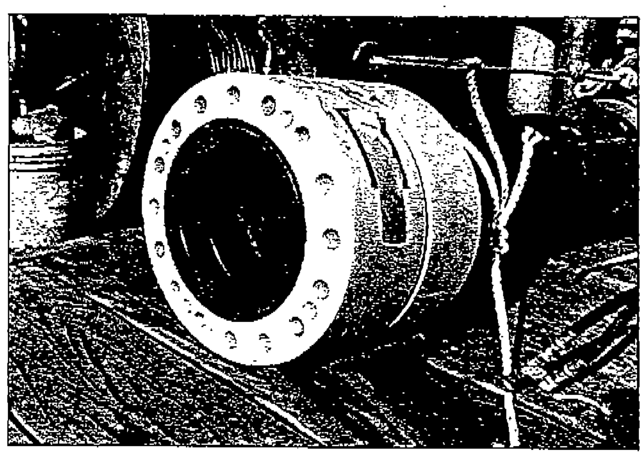
BIMS END CONNECTORS



BIMS COUNTER-TORQUE MOUNTED

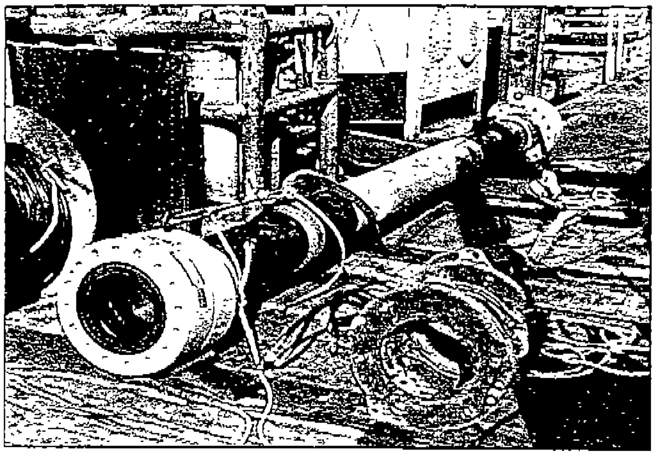


BIMS MISALIGNMENT BALL FLANGE

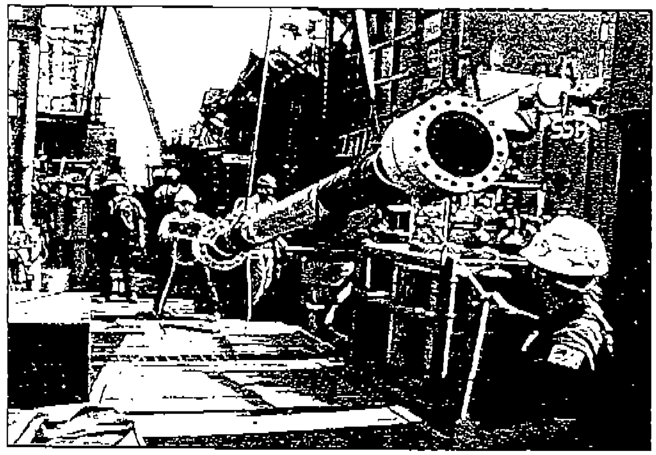


CHEVRON 10" PIPELINE REPAIR -- SOUTH PASS 38 -- OCTOBER 1998

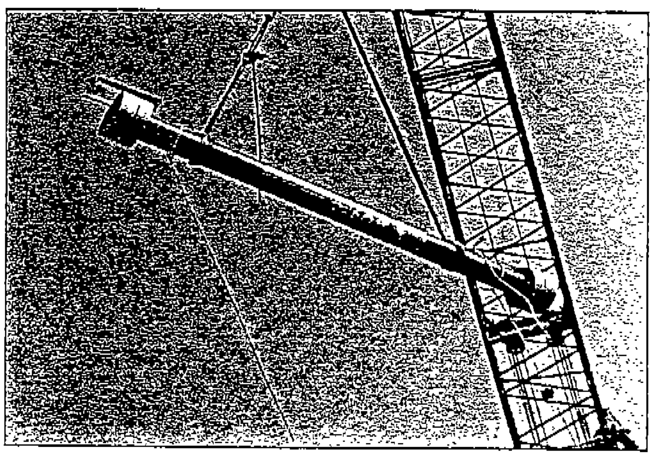
REPAIR SPOOLPIECE (10" X 16' 5-1/16")



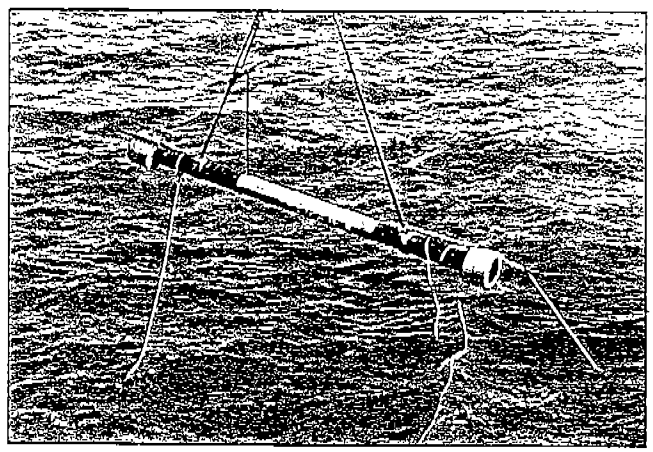
RIGGING SPOOLPIECE



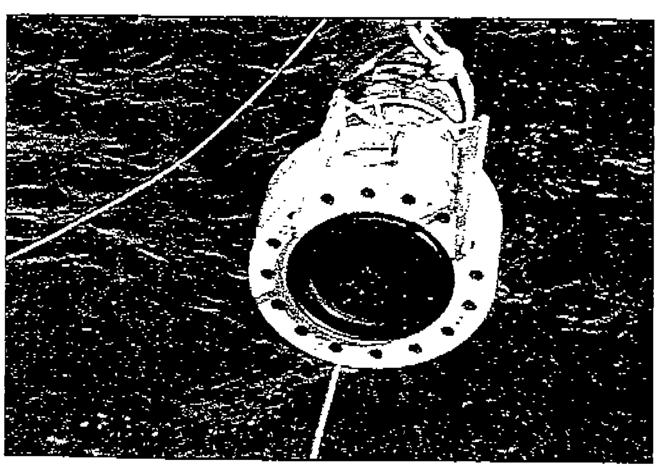
LAUNCHING SPOOLPIECE



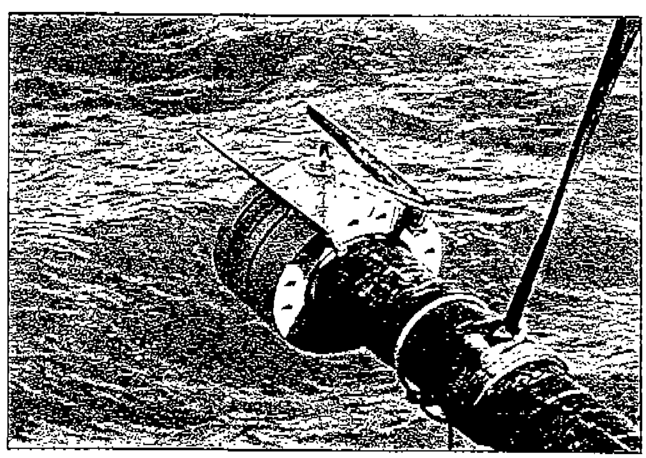
LAUNCHING SPOOLPIECE



INSTALLATION FORKS TO ASSIST DIVERS



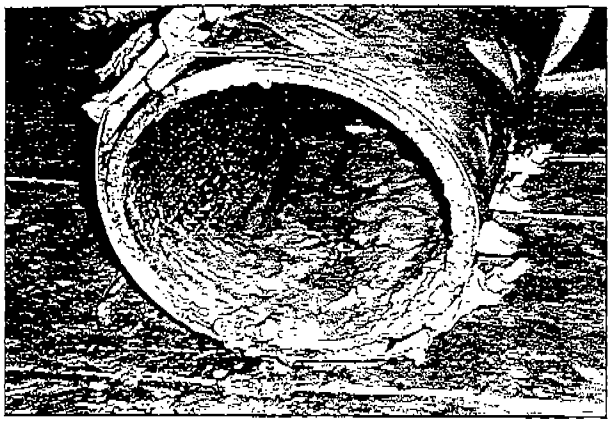
INSTALLATION FORKS TO ASSIST DIVERS



Attachment 8

CHEVRON 10" PIPELINE REPAIR -- SOUTH PASS 38 -- OCTOBER 1998

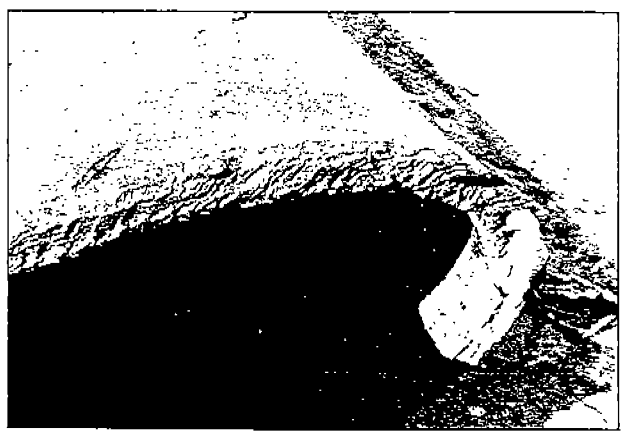
OIL SEPARATING IN SOUTH END



NORTH END (NO OIL)

BROKEN WELD (NORTH END)

SEPARATED WELD (NORTH END)



Chevron

Research and Technology

Richmond, California
January 14, 1999

Attachment 9

SOUTH PASS 49 CRUDE OIL PIPELINE
MATERIAL FAILURE ANALYSIS

Kevin Gaudet
Keith Bergeron

Summary

MATERIAL FAILURE:

A failure occurred in a 10" pipeline that carries crude oil from the SP49A platform to the SP 49 onshore tank battery. The line had been shut-in upon approach of hurricane "Georges". When the line was put back into service, an oil slick was discovered and ultimately traced to a failure at a weld in the line. Failed sections of the line were removed and sent to CRTC for analysis.

CAUSE OF FAILURE

The pipeline failed by propagation of a crack along the weld heat affected zone. A combination of high stresses generated by a mudslide and low fracture toughness of the pipe resulted in a rapid catastrophic fracture.

Background

A failure occurred in a 10" pipeline that carries crude oil from the SP49A platform to the SP 49 onshore facility. The line had been shut-in upon approach of hurricane "Georges". After initial start-up, and subsequent pressure tests of the pipeline, oil was detected on the surface and traced back to this line. The leak was located approximately 23 miles from the SP49A platform (7 miles from the onshore facility) in 110 ft. of water. The line was buried under 20 ft. of mud. The pipe had been completely severed at a butt weld in the line and the ends had separated by 3-4 feet.

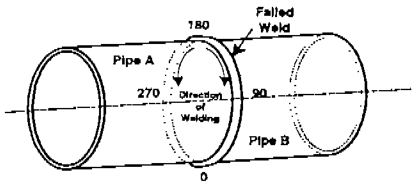
The line is located in an area prone to mudslides and runs parallel to the prevailing slope of the sea bottom. After the storm, a side scan sonar survey indicated a slide in the area. A depth of coverage survey of the line was attempted, however, the survey was unsuccessful due to the mud composition. A six-foot section of the line containing the failed weld was removed and sent to CRTC for analysis.

Fracture Surface Examination

For ease of explanation in describing the fracture surface, a schematic of the fracture surfaces is shown in Figures 1 & 2. The orientation of 0° was arbitrarily assigned to one of the weld buttons. If a downhill welding direction is assumed (which is most common in pipeline welding), the 0° orientation would correspond to the bottom of the pipe as oriented during welding. This orientation is shown in the upper left-hand corner of Figures 1 & 2. The 180° orientation would then correspond to the start of welding and 0° would be the stop. Note that this was not necessarily the orientation of the pipe while in service. The numbers on the figures (98-377, etc) correspond to metallographic samples taken from the pipe for further analysis.

C. N. Dykstal

File: 04.15.05, 18.10, 70.33



South Pass 49 Pipeline
Pipe A

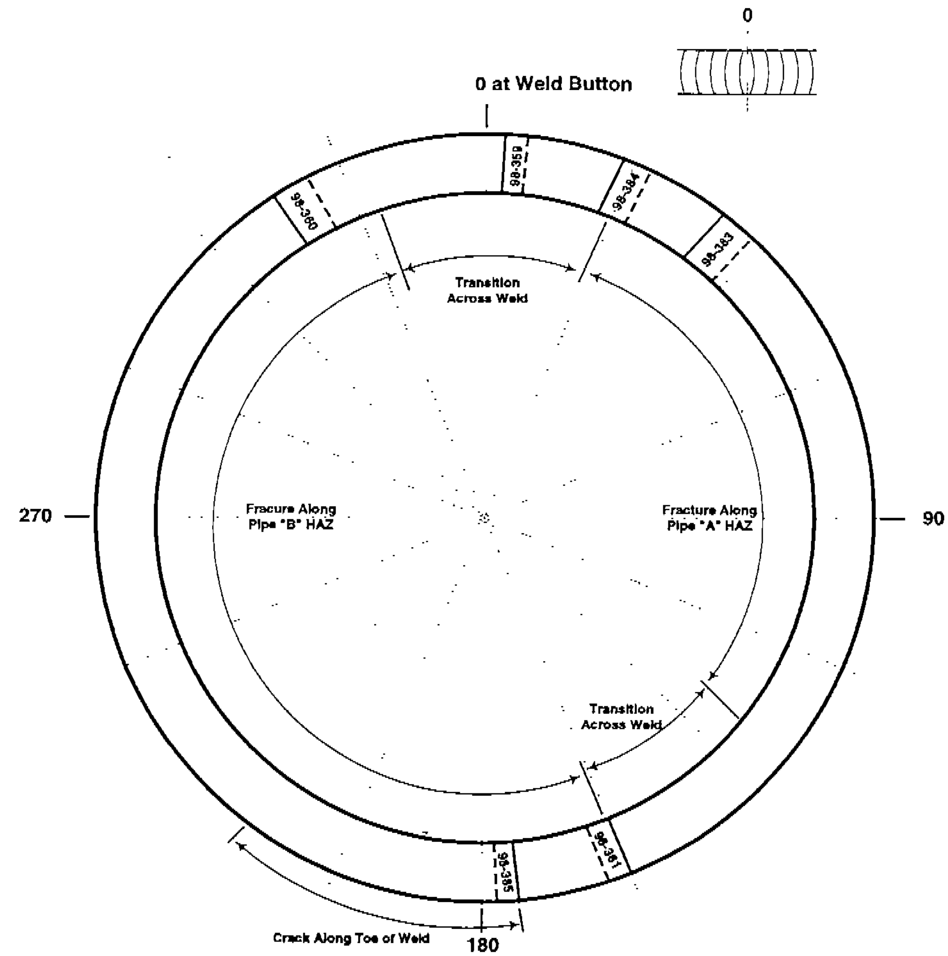


Figure 1 **Schematic of pipe "A" side of fracture surface indicating location of fracture, secondary cracks, and metallographic samples.**

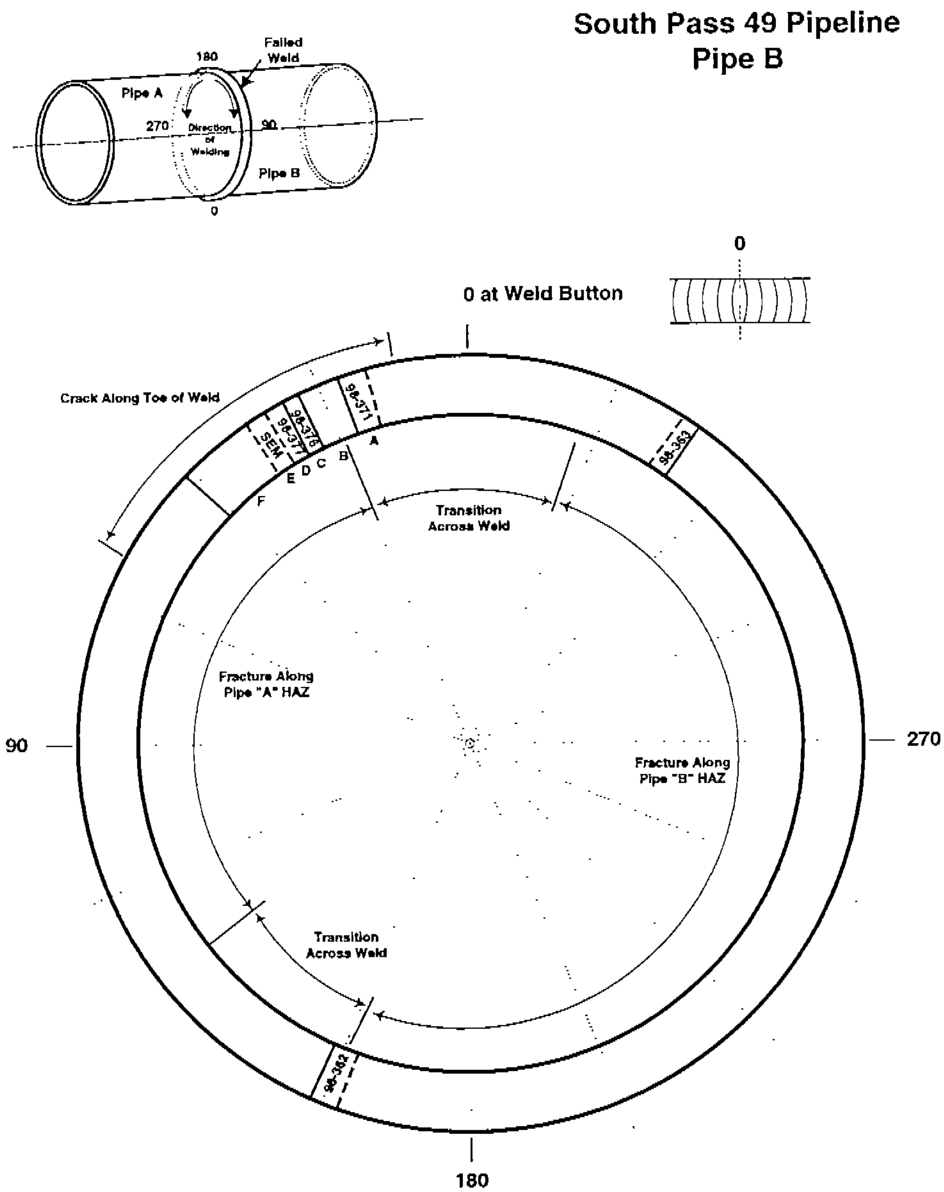


Figure 2 Schematic of pipe "B" side of fracture surface indicating location of fracture, secondary cracks, and metallographic samples.

The fracture occurred primarily along the weld heat affected zones (HAZ). Approximately 50% of the fracture surface propagated along the pipe "B" HAZ, transitioned across the weld, and then followed the pipe "A" HAZ (Figures 1 & 2). The surfaces were covered with rust in the as-received condition. Upon light chemical cleaning to remove the corrosion products, no obvious initiation site or evidence of a preexisting flaw was apparent. Diameter measurements at the fracture revealed a 0.125 in. difference between major and minor dimensions. Appreciable plastic deformation at the failure was not apparent. Metallographic cross sections indicated that crack propagation during fracture was primarily along the weld HAZs (except where the crack transitioned across the weld). The crack was transgranular and little secondary cracking was observed.

Two secondary cracks, on the opposite side of the weld cap from the fracture surface were also observed. These cracks were each approximately 3-4" in length, ran along the toe of the weld, and were oriented 180° from each other (See Figs 1 & 2). In contrast to the failure, these cracks did not follow the HAZ's but propagated into the base metal. The crack faces were covered with corrosion products and one of the cracks had grown through-wall.

Pipe Chemistry and Mechanical Properties

Table 1

	Pipe A	Pipe B	API 5L Grade B
Al	<0.005	<0.005	
C	0.26	0.26	0.27 max
Cr	0.02	0.02	
Cu	<0.005	<0.005	
Mn	0.92	0.93	1.15 max
Mo	<0.005	<0.005	
Ni	0.01	0.01	
P	0.010	0.010	0.030 max
Si	<0.005	<0.005	
S	0.014	0.015	0.030 max
Ti	<0.005	<0.005	
V	<0.005	<0.005	

Base metal samples from each side of the weld were analyzed for chemical composition with the results contained in Table 1. Pipe chemistry was consistent with API 5L Grade B pipe.

Table 2

Specimen	Absorbed Energy (ft-lbs)	Lateral Expansion (mils)	% Shear
A	7	9	9
	13	16	14
	8	10	14
B	5	6	9
	6.5	8	9
	5	7	9

Base metal transverse impact testing was conducted at 32° F and the results are contained in Table 2. While the impact values are low when compared against present standards, these values are not atypical for pipe manufactured approximately 18 years ago.

Table 3

Location	Knoop Microhardness (500g)
Base Metal	190-200
HAZ	215-227
Weld Metal	205-215

Microhardness traverses across the weld were taken on several samples. Results are contained in the Table 3. A slight increase in hardness along the HAZ was apparent but not significant.

Discussion

The failure of the pipeline weld was due to a combination of high pipeline stresses generated by the mudslide and the fracture toughness of the material. Fracture toughness is the ability of a material to tolerate flaws or stress concentrations without failing. As fracture toughness decreases, the stress at which a flaw of given size becomes unstable is reduced. Once this "critical" stress level is reached, the flaw propagates in an uncontrolled manner resulting in rapid fracture. Likewise, for a given level of stress, the lower the fracture toughness, the smaller the flaw size at which it becomes unstable and propagates catastrophically. In either case, the stress level at failure is often much less than the yield stress of the material and therefore the amount of plastic deformation at the fracture surfaces is minimal.

Charpy impact values are often used as an indicator for the fracture toughness of a material. Based on the low values reported in Table 2, poor base metal fracture toughness would have been expected. In addition, weld HAZ typically exhibit values less than that of the base metal. Under normal operational stresses, the fracture toughness was sufficient so that the existing stress concentrations and/or flaws along the weld were stable. However, when the mudslide occurred, stresses on the pipe increased above normal levels to a point where the flaws were rendered unstable and rapid fracture occurred. The fact that the cracked propagated primarily along the weld heat affected zone is consistent with the fracture toughness being a minimum at this location and provided a path of least resistance for crack propagation. Likewise, as characteristic of these "brittle" fractures, significant plastic deformation at the fracture surfaces was not present.

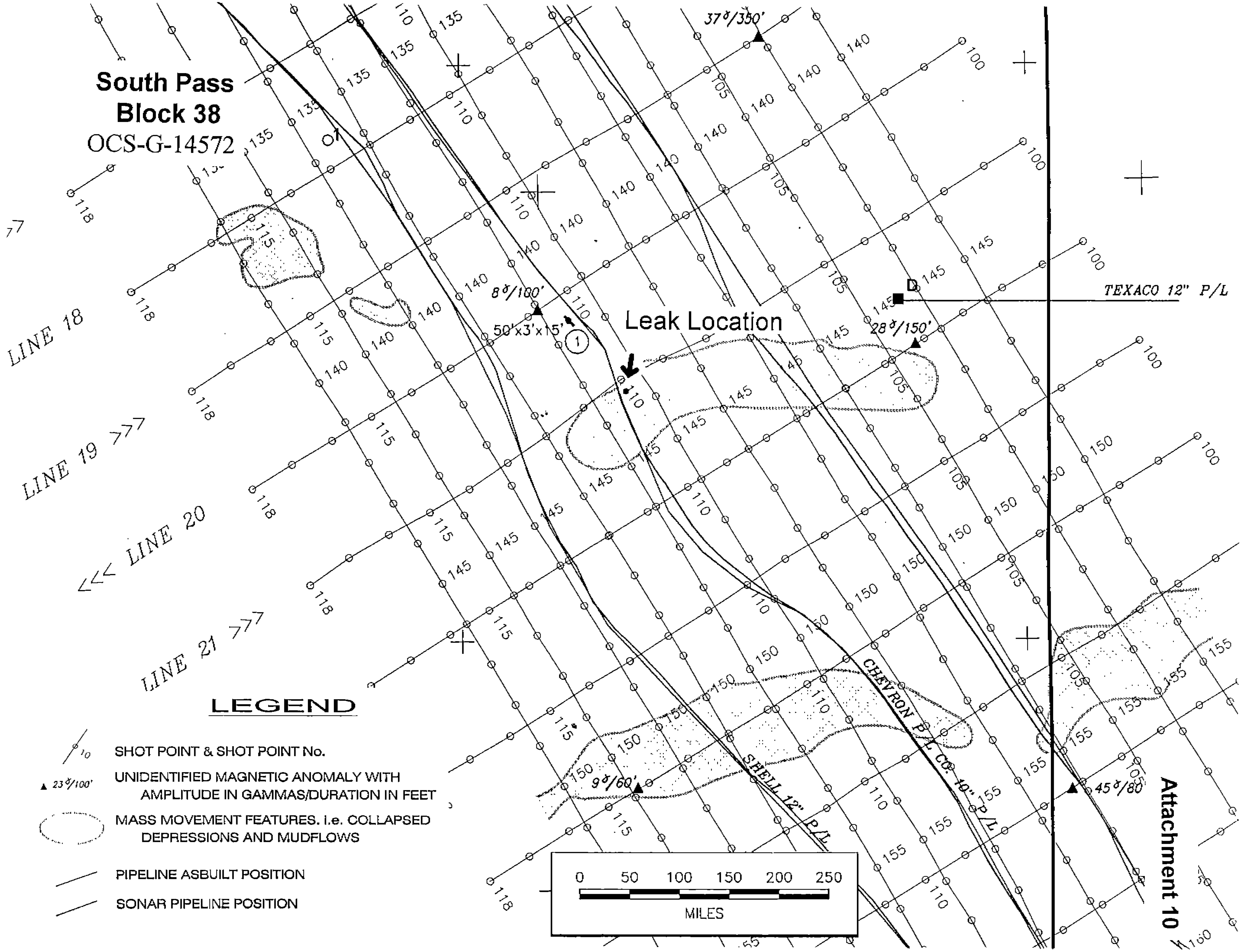
The two cracks observed along the toe of the weld were formed as a result of corrosion-fatigue. They had existed for some time as evidenced by the amount of corrosion products present in the cracks. Their orientation, with respect to each other, 180° apart and on opposite sides of the weld, and propagation normal to the pipe surface suggests the possibility of a cyclic bending stress in the line at this location. Nevertheless, the stresses generated from the mudslide were in a direction such that propagation of these cracks did not occur.

C. N. Dykstal

K. Gaudet-1
R. W. Sweenyey-1
G. Kohut-1
LNWatson-1
C. N. Dykstal-1

File-1

Attachment 10



ORIGINAL - REC'D
3/29/99

Attachment 11

Chevron Pipe Line Company
South Pass 49 Pipeline System
Pressure Safety Low Setting Evaluation
March 25, 1999

This hydraulic analysis was performed by Chevron Pipe Line Company in response to the pipeline failure that occurred in the South Pass 38 area near Milepost 6.5 on the 10" South Pass 49 Pipeline System. The desired outcome of the analysis is to determine why the Pressure Safety Low (PSL) settings for British Petroleum's Mississippi Canyon 109 Platform and Occidental's South Pass 45 platform did not activate the shutdown valves (SDV's) on the respective platforms.

Other desired outcomes of the hydraulic analysis are:

Determine the theoretical operating pressures for each producer.

Investigate the effectiveness of the actual PSL settings if the pipeline were to rupture at predetermined locations.

Investigate the effectiveness of calculated PSL settings for the producers if the pipeline ruptured at predetermined locations.

Investigate the pressure increase and corresponding calculated PSL settings for the producers if CPL installed a 60 psi back pressure valve at South Pass 49 Onshore and the pipeline ruptured at predetermined locations.

SUMMARY OF CONCLUSIONS

Current PSL and Pump Rate Configuration

- The current PSL settings for each of the producers will not automatically shut in-flow to the 10" SP 49 Pipeline System for a rupture at all points in the system.

Revised PSL Setting at Current Pump Rate Configuration

If the PSL setting for each producer is changed to point that is 15% below the lowest operating pressure as calculated by individual pumping rates, then:

- producers will not shut-in for a pipeline rupture at all points in the system.

If, in addition to changing the PSL settings, a back pressure valve is installed at the South Pass 49 Onshore Facility, then:

- at a back pressure of 60 psi, all points in the system are protected by PSL's when a single producer is on-line; however, the system is not always protected when multiple producers are online.
- at a back pressure of 525 psi, all points in the system are protected by PSL's even if all producers are on-line.

ANALYTICAL APPROACH

The hydraulic analysis of the 10" South Pass 49 (SP 49) Pipeline System included the following:

Operating Scenarios

- Producers pumping at current pump rates.
- Producers pumping ratably.

Rupture Locations

Determine the operating pressures of the producers for the following rupture locations using the above operating scenario:

- Pipeline system in the current configuration.
- Rupture in the 10" pipeline at Milepost 6.5 (SP 38 area).
- Rupture in the 10" pipeline at Milepost 23.1 in 780 feet of seawater (deepest point).
- Rupture in the 10" pipeline at the MC 109 tie-in (Milepost 27.1 in 640 feet of seawater).
- Rupture in the 10" pipeline at the MC 20 tie-in (Milepost 27.9 in 540 feet of seawater).
- Rupture in the 10" SP 49 Pipeline riser at the SP 49 Onshore Facility.

PSL Settings

Determine if the following PSL settings will shutdown the producers at each rupture location.

- Current PSL setting.
- Theoretical pressure safety low (PSL) settings for each producer based upon 15% below the lowest calculated operating pressure of each producer pumping individually at current pump rates.
- Theoretical PSL setting for each producer based upon 15% below the lowest calculated operating pressure of each producer pumping individually at current pumping rates and if a 60 psi back pressure valve is installed at the SP 49 Onshore Facility.

RESULTS

1.0 Static Conditions (no flow conditions)

The following table summarizes the elevation of the tanks' liquid level at SP 49 Onshore, the producers' SDV elevations (all referenced to sea level) and the corresponding calculated static pressures based on the respective crude oil gravities.

Location	Elevation referenced to sea level (feet)	Static Pressure (psi)
SP 49 Onshore Tank Liquid Level	+10	0
SP 45	+60	-17
MC 109	+65	-23
MC 20	+60	-18
SP 49 "A"	+75	-17

Table 1.0. Elevations of SP 49 Onshore tanks' liquid level, producers' SDV elevations and corresponding static pressure.

The elevations of the producers' SDV's and associated pressure pilots are much higher than the elevations of the tanks' liquid level at the SP 49 Onshore Facility. This results in vacuum pressures at the producers' platform when the pipeline is at static conditions.

The following table summarizes the elevation of the producers' SDV elevations and the corresponding calculated static pressures based on the respective crude oil gravities with a 60 psi back pressure valve installed at SP 49 Onshore

Location	Elevation referenced to sea level (feet)	Static Pressure (psi)
SP 45	+60	29
MC 109	+65	26
MC 20	+60	30
SP 49 "A"	+75	30

Table 1.01. Elevations of SP 49 Onshore tanks' liquid level, producers' SDV elevations and corresponding static pressure with a 60 psi back pressure valve installed at the SP 49 Onshore Facility.

2.0 Operating Scenario - Current Pumping Rates

The following table summarizes the theoretical operating pressure if a single producer were pumping into the onshore storage tanks on the 10" SP 49 pipeline at current pumping rates. This would give the lowest operating pressure for each producer. However, it should be noted that the producer's daily production levels dictate the pumping schedule and only one producer pumping at a time is not the normal operation for the pipeline system. Based upon current production levels, MC 109 is pumping the majority of a 24 hour day, SP 49 "A" pumps on an intermittent schedule and MC 20 and SP 45 pump approximately two – four times a day. The operating pressure for each producer is significantly higher than the results below when two, three or all four producers are pumping.

Producer	Lowest Theoretical Operating Pressure (psi)
SP 45	-10.3*
MC 109	173
MC 20	50
SP 49 "A"	90

Table 2.0. Theoretical operating pressure for a single producer pumping into tankage at SP 49 Onshore.

* In theory, SP 45 does not pump at a rate that will generate head loss in the system to create positive pressure at SP 45.

The following table summarizes the theoretical operating pressure if a single producer were pumping into the onshore storage tanks and a 60 psi back pressure valve was installed at the SP 49 Onshore Facility. This would be the lowest operating pressure for each producer.

Producer	Lowest Theoretical Operating Pressure (psi)
SP 45	50
MC 109	233
MC 20	110
SP 49 "A"	150

Table 2.01. Theoretical operating pressure for a single producer pumping into tankage with a 60 psi back pressure valve installed at SP 49 Onshore.

2.1 Pipeline Rupture at Milepost 6.5 (SP 38 Incident point):

At Milepost 6.5, the water depth is approximately 100 fsw. The hydrostatic pressure at this water depth is approximately 45 psi.

Current PSL Settings:

The following table summarizes the actual PSL setting for each producer, the theoretical operating pressure with only one producer pumping at a time at current pumping rates and whether the producer's shutdown valve would close on a PSL command with a rupture in the 10" pipeline at Milepost 6.5 (SP 38 area).

Producer	Current PSL setting (psi)	Operating Pressure (psi)	PSL protection
SP 45	20	-8	Yes*
MC 109	46	150	No
MC 20	10	51	No
SP 49 A	5	71	No

Table 2.10. Comparison of current PSL setting vs. operating pressures for each producer with a pipeline rupture at Milepost 6.5 (SP 38 area).

As indicated in the table above, MC 109, MC 20 and SP 49"A" would be able to pump as a single producer without shutting down on PSL commands at the current set points. This is a result of the head loss in the system and the hydrostatic head of the –100 fsw at the rupture location acting as back pressure on the system. The back pressure nearly emulates a producer pumping into tankage at the SP 49 Onshore Facility. With all four producers pumping into the pipeline at current pumping rates, the pressure at SP 45 would be about 54 psi, assuming a fully open 4" schedule 80 pipeline. SP 45 would not shutdown on a PSL command in this scenario.

* Explanation of SP 45:

Theoretical calculations for a fully open 4" schedule 80 pipeline indicate SP 45 should have shutdown on PSL; however, SP 45 was able to flow into the pipeline as a single producer. After the repairs to the 10" pipeline, the 4" SP 45 pipeline would shutdown on high pressure. An investigation by the producer indicated a paraffin plug in the 4" pipeline that prohibited flow. The paraffin build up on the walls of the 4" pipeline increased the back pressure at SP 45 allowing them to pump at pressures above the PSL setting during the SP 38 incident.

Effects of Changing PSL Settings to a Theoretical Value

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 2.0 and if a single producer, pumping at current pumping rates would shutdown on a PSL command with a pipeline rupture at Milepost 6.5 (SP 38 area).

The theoretical PSL setting is a calculated value that was obtained from the operating pressures of the producers in Table 2.0. This was calculated for each producer as shown in the following example.

Example 1: Theoretical PSL setting for MC 109.

MC 109 Operating Pressure from Table 2.0:	173 psi
Subtract 15% (operating range)	- 26 psi
Theoretical PSL set point:	147 psi

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 2.0. (psi)	Operating Pressure (psi)	PSL protection
SP 45	5**	-8	Yes
MC 109	147	150	No
MC 20	43	51	No
SP 49 "A"	77	71	Yes

Table 2.11. Comparison of theoretical PSL setting vs. operating pressure for a single producer with a pipeline rupture at Milepost 6.5 (SP 38 area).
** 5 psi is the lowest PSL setting allowed by the MMS.

Theoretically changing the PSL setting for each producer does not provide PSL protection to the 10" pipeline system with only MC 109 or MC 20 pumping as a single producer. With MC 109 and SP 49 pumping at the same time, the pressure at SP 49 "A" would be about 263 psi; therefore, PSL protection would not shutdown SP 49 "A" in this scenario. Also, with all four producers pumping at the same time the pressure at SP 45 would be approximately 54 psi; therefore, PSL protection would not shutdown SP 45.

Effects of Installing a 60 psi Back Pressure Valve

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 2.01 and if a single producer, pumping at current pumping rates would shutdown on a PSL command with a pipeline rupture at Milepost 6.5 (SP 38 area).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 2.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	43	-8	Yes
MC 109	198	150	Yes
MC 20	94	51	Yes
SP 49 "A"	128	71	Yes

Table 2.12. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer with a rupture at Milepost 6.5 (SP 38 area).

Theoretically, installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection to a single producer pumping into the 10" pipeline. However, if multiple producers, such as MC 109 and SP 49"A", are pumping simultaneously, they would not shutdown on a PSL command until one producer completed the normal pumping cycle.

2.2 Pipeline Rupture at Greatest Depth of the 10" Pipeline

The greatest water depth the 10" SP 49 pipeline operates in is approximately 780 fsw and occurs at Milepost 23.1. The hydrostatic pressure at this water depth is approximately 351 psi.

For this rupture location, SP 45 is located downstream of the leak site and MC 109, MC 20 and SP 49"A" is located upstream of the leak site.

Current PSL Settings

The following table summarizes the actual PSL setting for each producer, the theoretical operating pressure with only one producer pumping at a time at current pumping rates and whether the producer's shutdown valve would close on a PSL command with a rupture in the 10" pipeline at Milepost 23.1 (-780 fsw).

Producer	Current PSL setting (psi)	Operating Pressure (psi)	PSL protection
SP 45	20	14	Yes
MC 109	46	131	No
MC 20	10	89	No
SP 49 A	5	65	No

Table 2.20. Comparison of current PSL setting vs. operating pressures for each producer with a pipeline rupture at Milepost 23.1 (-780 fsw).

As indicated in the table above, MC 109, MC 20 and SP 49"A" would be able to pump as a single producer without shutting down on PSL commands at the current set points. This is a result of the head loss in the system and the hydrostatic head of the –780 fsw at the rupture location acting as back pressure on the system.

Effects of Changing PSL Settings to a Theoretical Value

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 2.0 and if a single producer, pumping at current pumping rates, would shutdown on a PSL command with a pipeline rupture at Milepost 23.1 (-780 fsw).

Producer	**Theoretical PSL setting based on 15% below the operating pressure of Table 2.0. (psi)**	**Operating Pressure (psi)**	**PSL protection**
SP 45	5**	14	No
MC 109	147	131	Yes
MC 20	43	89	No
SP 49 "A"	77	65	Yes

Table 2.21. Comparison of theoretical PSL setting vs. operating pressure for a single producer with a pipeline rupture at Milepost 23.1 (-780 fsw).

** 5 psi is the lowest PSL setting allowed by the MMS.

Theoretically changing the PSL setting for each producer does not provide PSL protection to the 10" pipeline system with only MC 20 pumping as a single producer. Also, SP 45 would not shutdown on PSL command until the pipeline reaches equilibrium. Equilibrium will occur when seawater stops flowing into the pipeline and displaces the oil into the tanks at SP 49 Onshore. At this point, the operating pressure at SP 45 would be approximately –2 psi and would shutdown on PSL. With MC 109 and SP 49 "A" pumping at the same time, the pressures would be about 177 psi and 110 psi respectively; therefore, PSL protection would not shutdown MC 109 and SP 49 "A" in this scenario until one producer completed a pumping cycle.

Effects of Installing a 60 psi Back Pressure Valve

The following table summarizes a theoretical PSL setting based upon the lowest operating pressures from Table 2.01 and if a single producer, pumping at current pumping rates, would shutdown on a PSL command with a pipeline rupture at Milepost 23.1 (-780 fsw).

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure of Table 2.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	43	43	Yes
MC 109	198	131	Yes
MC 20	94	89	Yes
SP 49 "A"	128	65	Yes

Table 2.22. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer with a rupture at Milepost 23.1 (-780 fsw).

Theoretically, installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection to a single producer operating on the upstream and downstream side of the rupture. Also, if MC 109, MC 20 and SP 49"A" are pumping simultaneously on the upstream side of the rupture, their pressures would be about 194 psi, 175 psi and 128 psi respectively. MC 109 would shutdown on PSL, and the operating pressure at MC 20 and SP 49"A" would decrease to 123 psi and 75 psi respectively. SP 49 "A" would shutdown on PSL then the operating pressure at MC 20 would decrease to 89 psi and shutdown on PSL.

2.3 Pipeline Rupture at MC 109 Tie-In (Milepost 27.1)

At the MC 109 tie-in, the water depth is approximately 640 fsw. The hydrostatic pressure at this water depth is approximately 288 psi.

For this rupture location, SP 45 is located downstream of the leak site and MC 109, MC 20 and SP 49"A" is located upstream of the leak site.

Current PSL setting

The following table summarizes the actual PSL setting for each producer, the theoretical operating pressure with only one producer pumping at a time at current pumping rates and whether the producer's shutdown valve would close on a PSL command with a rupture in the 10" pipeline at the MC 109 tie-in. (-640 fsw)

Producer	Current PSL setting (psi)	Operating Pressure (psi)	PSL protection
SP 45	20	5	Yes
MC 109	46	102	No
MC 20	10	77	No
SP 49 A	5	35	No

Table 2.30. Comparison of current PSL setting vs. operating pressures for each producer with a pipeline rupture at the MC 109 tie-in. (Milepost 27.1 and -640 fsw).

As indicated in the table above, MC 109, MC 20 and SP 49"A" would be able to pump as a single producer without shutting down on PSL commands at the current set points. This is a result of the head loss in the system and the hydrostatic head of the –640 fsw at the rupture location acting as back pressure on the system.

Effects of Changing PSL Settings to a Theoretical Value

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 2.0 and if a single producer, pumping at current pumping rates, would shutdown on a PSL command with a pipeline rupture at the MC 109 tie-in. (Milepost 27.1 and -640 fsw).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 2.0 (psi)	Operating Pressure (psi)	PSL protection
SP 45	5**	5	Yes
MC 109	147	102	Yes
MC 20	43	77	No
SP 49 "A"	77	35	Yes

Table 2.31. Comparison of theoretical PSL setting vs. operating pressure for a single producer with a pipeline rupture at the MC 109 tie-in (Milepost 27.1 and -640 fsw).

** 5 psi is the lowest PSL setting allowed by the MMS.

Theoretically changing the PSL setting for each producer does not provide PSL protection to the 10" pipeline system with only MC 20 pumping as a single producer. However, if MC 109, MC 20 and SP 49 "A" are pumping at the same time, the pressures would be about 102 psi, 84 psi and 37 psi respectively; therefore, PSL protection would shutdown MC 109 and SP 49 "A" in this scenario and not MC 20.

Effects of Installing a 60 psi Back Pressure Valve

The following table summarizes a theoretical PSL setting based upon the lowest operating pressures from Table 2.01 and if a single producer, pumping at current pumping rates, would shutdown on a PSL command with a pipeline rupture at the MC 109 tie-in (Milepost 27.1 and-640 fsw).

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure of Table 2.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	43	32	Yes
MC 109	198	102	Yes
MC 20	93	77	Yes
SP 49 "A"	127	35	Yes

Table 2.32. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer with a rupture at MC 109 tie-in (Milepost 27.1 and -640 fsw).

Theoretically, installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection to a single producer operating on the upstream and downstream side of the rupture. Also, if MC 109, MC 20 and SP 49"A" are pumping simultaneously on the upstream side of the rupture their pressures would be about 102 psi, 84 psi and 37 psi respectively. Therefore, all three producers would shutdown on PSL.

2.4 Pipeline Rupture at MC 20 Tie-In (Milepost 27.9)

At the MC 20 tie-in, the water depth is approximately 540 fsw. The hydrostatic pressure at this water depth is approximately 243 psi.

For this rupture location, SP 45 and MC 109 is located downstream of the leak site and MC 20 and SP 49"A" is located upstream of the leak site.

Current PSL setting

The following table summarizes the actual PSL setting for each producer, the theoretical operating pressure with only one producer pumping at a time at current pumping rates and whether the producer's shutdown valve would close on a PSL command with a rupture in the 10" pipeline at the MC 20 tie-in. (-540 fsw)

Producer	Current PSL setting (psi)	Operating Pressure (psi)	PSL protection
SP 45	20	0	Yes
MC 109	46	90	No
MC 20	10	70	No
SP 49 A	5	23	No

Table 2.40. Comparison of current PSL setting vs. operating pressures for each producer with a pipeline rupture at the MC 20 tie-in. (Milepost 27.9 and -540 fsw).

As indicated in the table above, MC 109, MC 20 and SP 49"A" would be able to pump as a single producer without shutting down on PSL commands at the current set points. This is a result of the head loss in the system and the hydrostatic head of the –540 fsw at the rupture location acting as back pressure on the system.

Effects of Changing PSL Settings to a Theoretical Value

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 2.0 and if a single producer, pumping at current pumping rates, would shutdown on a PSL command with a pipeline rupture at the MC 20 tie-in. (Milepost 27.9 and -540 fsw).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 2.0. (psi)	Operating Pressure (psi)	PSL protection
SP 45	5**	0	Yes
MC 109	147	90	Yes
MC 20	43	70	No
SP 49 "A"	77	23	Yes

Table 2.41. Comparison of theoretical PSL setting vs. operating pressure for a single producer with a pipeline rupture at the MC 20 tie-in (Milepost 27.9 and -540 fsw).

** 5 psi is the lowest PSL setting allowed by the MMS.

Theoretically changing the PSL setting for each producer does not provide PSL protection to the 10" pipeline system with only MC 20 pumping as a single producer.

Effects of Installing a 60 psi Back Pressure Valve

The following table summarizes a theoretical PSL setting based upon the lowest operating pressures from Table 2.01 and if a single producer, pumping at current pumping rates, would shutdown on a PSL command with a pipeline rupture at the MC 20 tie-in (Milepost 27.9 and -540 fsw).

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure of Table 2.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	43	25	Yes
MC 109	198	93	Yes
MC 20	94	70	Yes
SP 49 "A"	128	23	Yes

Table 2.42. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer with a rupture at the MC 20 tie-in (Milepost 27.9 and -540 fsw).

Theoretically, installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection to all producers pumping as single units on both the upstream and downstream side of the rupture. Also, if SP 45 and MC 109 were pumping simultaneously on the downstream side of the rupture, their pressures would be about 30 psi and 94 psi respectively. Both producers would shut down on PSL. If MC 20 and SP 49 "A" were pumping simultaneously on the upstream side of the rupture, there pressures would be approximately 70 psi and 23 psi respectively; therefore both producers would shutdown on PSL.

2.5 Conclusions for Section 2

- The current PSL settings for each of the producers do not automatically shut-in flow on the 10" SP 49 Pipeline System for a pipeline rupture at Milepost 6.5, Milepost 23.1, Milepost 27.1 and Milepost 27.9. The current PSL settings for SP 45, MC 109 and MC 20 may provide protection to the lateral pipelines if a rupture were to occur close to their respective platforms. Also, current PSL setting for SP 49 "A" may shutdown SP 49 "A" if a pipeline rupture were to occur close to the platform.

- Changing the PSL settings for each of the producers to 15% below the lowest operating pressure as calculated by individual pumping rates does not automatically shut-in flow on the 10" SP 49 Pipeline System for a pipeline rupture at Milepost 6.5, Milepost 23.1, Milepost 27.1 and Milepost 27.9.

- The installation of a back pressure valve at the South Pass 49 Onshore facility set at 60 psi and changing the PSL levels to 15% below the lowest operating pressures, automatically shuts-in flow on the 10" South Pass 49 Pipeline System at current pumping rates for an operating pumping as a single producer. However, as noted in Section 2.1, Pipeline Rupture at Milepost 6.5, if multiple producers are pumping simultaneously, they will not shutdown on PSL until one of the producers completed their normal pumping cycle.

- If all four producers are pumping simultaneously and a rupture occurred at the SP 49 Onshore Facility riser at the water line (worst case rupture scenario), there are two back pressure valve settings that will shutdown the producers on the 10" SP 49 pipeline. First a set pressure of 410 psi will start a chain of shutdowns on the system. The results are in the following table.

Producer	Lowest Theoretical Operating Pressure for a single producer with 410 psi back pressure valve (psi)	Theoretical PSL setting based on 15% below the lowest operating pressure if a 410 psi back pressure valve is installed at SP 49 Onshore. (psi)	Theoretical Operating Pressure for all four producers pumping simultaneously with a rupture at SP 49 Onshore riser (psi)
SP 45	400	340	157
MC 109	583	495	506
MC 20	460	391	488
SP 49 "A"	500	425	441

Table 2.50. Comparison of theoretical PSL settings with a 410 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure if all four producers are pumping with a rupture at the SP 49 Onshore facility riser at the waterline

SP 45 would shutdown on a PSL command first and the pressures at MC 109, MC 20 and SP 49 "A" would decrease to approximately 490 psi, 472 and 425 psi respectively. MC 109 and SP 49 "A" would shutdown on a PSL command and the pressures MC 20 would decrease and shutdown on PSL.

A back pressure valve setting of 525 psi will shut down all producers on a PSL command without waiting for other producers to shutdown and decrease the operating pressure on the pipeline system. The results are in the following table.

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure if a 525 psi back pressure valve is installed at SP 49 Onshore. (psi)	Operating Pressure with a rupture at the SP 49 Onshore facility (all 4 producers pumping) (psi)	PSL protection
SP 45	437	157	Yes
MC 109	594	506	Yes
MC 20	488	488	Yes
SP 49 "A"	522	441	Yes

Table 2.51. Comparison of theoretical PSL settings with a 525 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure if all four producers are pumping with a rupture at the SP 49 Onshore facility riser at the waterline.

The installation of a back pressure valve set at 410 psi or 525 psi will shutdown the 10" pipeline if all four producers are pumping simultaneously and a pipeline rupture occurred on the riser at the SP 49 Onshore Facility. However, creating 410 psi or 525 psi of back pressure on the system will most likely have serious economic impacts on the producers for changing or resizing pumps and motors or engines. Also, this will increase the emissions generated and the power consumption for each producer thereby increasing each producers' operating expense.

3.0 Operating Scenario - Ratable System

The following table summarizes the theoretical operating pressure if a single producer were pumping ratably into the onshore storage tanks on the 10" SP 49 Onshore. This would give the lowest operating pressure for each producer. Chevron Pipe Line Company defines ratable pumping for a producer as a pump rate not greater than 120% of the producer's daily production. While this is the "ideal" operating scenario, it is not always economical or feasible for the producers to modify their pumps.

In this operating scenario, ratable pumping for SP 45, MC 20 and SP 49 "A" is 20 BPH, 50 BPH and 250 BPH respectively. MC 109 pumping rate is the same used in Section 2. The operating pressure for each producer will be significantly higher than the results below when two, three or all four producers are pumping. Also, this operating scenario will require the producers to reset their current PSL settings to 15% below the lowest operating pressure; therefore, at the pipeline rupture locations studied, a theoretical PSL setting is compared against a theoretical operating pressure.

Producer	Lowest Theoretical Operating Pressure (psi)
SP 45	-17
MC 109	173
MC 20	-7
SP 49 "A"	7

Table 3.0. Theoretical operating pressure for a single producer pumping ratably into tankage at SP 49 Onshore.

SP 45 and MC 20 would not be able to pump as a single producer, since the operating pressure for each platform is below the minimum PSL setting of 5 psi. SP 45 would require both MC 109 and SP 49 "A" to be pumping to achieve an operating pressure above the 5 psi PSL setting. MC 20 would require either MC 109 or SP 49 "A" to be pumping to achieve and an operating pressure above the 5 psi PSL setting.

The following table summarizes the theoretical operating pressure if a single producer were pumping ratably into the onshore storage tanks and a 60 psi back pressure valve was installed at the SP 49 Onshore Facility.

Producer	Lowest Theoretical Operating Pressure (psi)
SP 45	42
MC 109	233
MC 20	53
SP 49 "A"	67

Table 3.01. Theoretical operating pressure for a single producer pumping ratably into tankage with a 60 psi back pressure valve installed at SP 49 Onshore.

3.1 Pipeline Rupture at Milepost 6.5 (SP 38 Incident point):

At Milepost 6.5, the water depth is approximately 100 fsw. The hydrostatic pressure at this water depth is approximately 45 psi.

Effects of Ratable Pumping

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 3.0 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at Milepost 6.5 (SP 38 area).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 3.0. (psi)	Operating Pressure (psi)	PSL protection
SP 45	5***	-15	Yes
MC 109	147	150	No
MC 20	5***	-5	Yes
SP 49 "A"	6	5	Yes

Table 3.10. Comparison of theoretical PSL setting vs. operating pressure for a single producer pumping ratably with a pipeline rupture at Milepost 6.5 (SP 38 area).
*** 5 psi is the lowest PSL setting allowed by the MMS

Theoretically, with a ratable system, MC 109 pumping as a single producer would not shutdown on a PSL command with a rupture at Milepost 6.5. Also, if all four producers are pumping simultaneously, none of the producers would shutdown on PSL. In this scenario, with MC 109 not shutting down on PSL, allows MC 20 and SP 49 "A" to pump without shutting down.

Effects of Ratable Pumping and Installing a 60 psi Back Pressure Valve

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 3.01 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at Milepost 6.5 (SP 38 area).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 3.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	36	-15	Yes
MC 109	198	150	Yes
MC 20	45	-5	Yes
SP 49 "A"	57	5	Yes

Table 3.12. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer pumping ratably with a rupture at Milepost 6.5 (SP 38 area).

Theoretically, a ratable system and installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection a single producer pumping into the 10" pipeline. However, if MC 109 and SP 49 "A" were pumping simultaneously, they would not shutdown on a PSL command until one producer completed their normal pumping cycle.

3.2 Pipeline Rupture at Greatest Depth of the 10" Pipeline

The greatest water depth the 10" SP 49 pipeline operates in is approximately 780 fsw and occurs at Milepost 23.1. The hydrostatic pressure at this water depth is approximately 351 psi.

In the following scenarios, SP 45 is located downstream of the leak site and MC 109, MC 20 and SP 49"A" is located upstream of the leak site.

Effects of Ratable Pumping

The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 3.0 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at Milepost 23.1 (-780 fsw).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 3.0. (psi)	Operating Pressure (psi)	PSL protection
SP 45	5***	8	No
MC 109	147	131	Yes
MC 20	5***	39	No
SP 49 "A"	6	40	No

Table 3.20. Comparison of theoretical PSL setting vs. operating pressure for a single with a pipeline rupture at Milepost 23.1 (-780 fsw).
*** 5 psi is the lowest PSL setting allowed by the MMS

Theoretically, with a ratable system, SP 45, MC 20 and SP 49"A", pumping as a single producer, would not shutdown on a PSL command with a rupture at Milepost 23.1. Also, SP 45 would not shutdown on PSL command until the pipeline reaches equilibrium. When equilibrium is achieved the operating pressure at SP 45 would be approximately –8 psi and would shutdown on PSL.

Effects of Ratable Pumping and Installing a 60 psi Back Pressure Valve
The following table summarizes a theoretical PSL setting based upon the lowest operating pressures from Table 3.01 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at Milepost 23.1 (-780 fsw).

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure of Table 3.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	36	40	No
MC 109	198	131	Yes
MC 20	45	39	Yes
SP 49 "A"	57	40	Yes

Table 3.21. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer pumping ratably with a rupture at Milepost 23.1 (-780 fsw).

Theoretically, a ratable system and installing a 60 psi back pressure valve at SP 49 Onshore would not provide PSL protection to SP 45 operating on the downstream side of the rupture. However, if MC 109, MC 20 and SP 49"A" are pumping simultaneously on the upstream side of the rupture, their pressures would be about 154 psi, 84 psi and 78 psi respectively. MC 109 would shutdown on PSL, and the operating pressure at MC 20 and SP 49"A" would decrease to 48 psi and 42 psi respectively. SP 49 "A" would shutdown on PSL then the operating pressure at MC 20 would decrease to 39 psi and shutdown on PSL.

3.3 Pipeline Rupture at MC 109 Tie-In (Milepost 27.1)

At the MC 109 tie-in, the water depth is approximately 640 fsw. The hydrostatic pressure at this water depth is approximately 288 psi.

For this rupture location, SP 45 is located downstream of the leak site and MC 109, MC 20 and SP 49"A" is located upstream of the leak site.

Effects of Pumping Ratably
The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 3.0 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at the MC 109 tie-in. (Milepost 27.1 and -640 fsw).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 3.0. (psi)	Operating Pressure (psi)	PSL protection
SP 45	5***	-1	Yes
MC 109	147	102	Yes
MC 20	5***	30	No
SP 49 "A"	6	25	No

Table 3.30. Comparison of theoretical PSL setting vs. operating pressure for a single producer pumping ratably with a pipeline rupture at the MC 109 tie-in (Milepost 27.1 and -640 fsw).
*** 5 psi is the lowest PSL setting allowed by the MMS

Theoretically, with a ratable system, MC 20 and SP 49"A", pumping as a single producer, would not shutdown on a PSL command.

Effects of Ratable Pumping and Installing a 60 psi Back Pressure Valve
The following table summarizes a theoretical PSL setting based upon the lowest operating pressures from Table 3.01 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at the MC 109 tie-in (Milepost 27.1 and-640 fsw).

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure of Table 3.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	36	28	Yes
MC 109	198	102	Yes
MC 20	45	30	Yes
SP 49 "A"	57	25	Yes

Table 3.31. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer pumping ratably with a rupture at MC 109 tie-in (Milepost 27.1 and -640 fsw).

Theoretically, installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection to a single producer operating on the upstream and downstream side of the rupture. Also, if MC 109, MC 20 and SP 49"A" are pumping simultaneously on the upstream side of the rupture their pressures would be about 102 psi, 32 psi and 25 psi respectively. Therefore, all three producers would shutdown on PSL.

3.4 Pipeline Rupture at MC 20 Tie-In (Milepost 27.9)

At the MC 20 tie-in, the water depth is approximately 540 fsw. The hydrostatic pressure at this water depth is approximately 243 psi.

For this rupture location, SP 45 and MC 109 is located downstream of the leak site and MC 20 and SP 49"A" is located upstream of the leak site.

Effects of Pumping Ratably
The following table summarizes a theoretical PSL setting based upon the operating pressures from Table 3.0 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at the MC 20 tie-in. (Milepost 27.9 and -540 fsw).

Producer	Theoretical PSL setting based on 15% below the operating pressure of Table 3.0. (psi)	Operating Pressure (psi)	PSL protection
SP 45	5***	-4	Yes
MC 109	147	89	Yes
MC 20	5***	22	No
SP 49 "A"	6	16	No

Table 3.40. Comparison of theoretical PSL setting vs. operating pressure for a single producer pumping ratably with a pipeline rupture at the MC 109 tie-in (Milepost 27.9 and -540 fsw).
*** 5 psi is the lowest PSL setting allowed by the MMS

Theoretically changing the PSL setting for each producer does not provide PSL protection to the 10" pipeline system with MC 20 and SP 49 "A" pumping as a single producer.

Effects of Ratable Pumping and Installing a 60 psi Back Pressure Valve

The following table summarizes a theoretical PSL setting based upon the lowest operating pressures from Table 3.01 and if a single producer, pumping ratably, would shutdown on a PSL command with a pipeline rupture at the MC 20 tie-in (Milepost 27.9 and -540 fsw).

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure of Table 3.01. (psi)	Operating Pressure (psi)	PSL protection
SP 45	36	21	Yes
MC 109	198	93	Yes
MC 20	45	22	Yes
SP 49 "A"	57	16	Yes

Table 3.41. Comparison of theoretical PSL settings with a 60 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure of a single producer pumping ratably with a rupture at the MC 20 tie-in (Milepost 27.9 and -540 fsw).

Theoretically, installing a 60 psi back pressure valve at SP 49 Onshore would provide PSL protection to all producers pumping as single units on both the upstream and downstream side of the rupture. Also, if SP 45 and MC 109 were pumping simultaneously on the downstream side of the rupture, their pressures would be about 25 psi and 93 psi respectively. Both producers would shut down on a PSL command. If MC 20 and SP 49 "A" were pumping simultaneously on the upstream side of the rupture, there pressures would be approximately 22 psi and 16 psi respectively; therefore both producers would shutdown on a PSL command.

3.5 Conclusions for Section 3

- If the system was ratable and the PSL settings for each of the producer were set to 15% below the lowest operating pressure as calculated by individual pumping rates, the PSL's do not automatically shut-in flow on the 10" SP 49 Pipeline System for a pipeline rupture at Milepost 6.5, Milepost 23.1, Milepost 27.1 and Milepost 27.9.

- If a 60 psi back pressure valve was installed on a ratable system at the South Pass 49 Onshore facility and the PSL set points were set to 15% below the lowest operating pressures, the producers on the 10" South Pass 49 Pipeline System will not automatically shut in with ruptures at the deepest operating point of the pipeline (Milepost 23.1).

- If all four producers are ratably pumping simultaneously and a rupture occurred at the SP 49 Onshore Facility riser at the water line (worst case rupture scenario), there are two back pressure valve settings that will shutdown the producers on the 10" SP 49 pipeline. First a set pressure of 165 psi will start a chain of shutdowns on the system. The results are in the following table.

Producer	Lowest Theoretical Operating Pressure for a single producer with 245 psi back pressure valve (psi)	Theoretical PSL setting based on 15% below the lowest operating pressure if a 245 psi back pressure valve is installed at SP 49 Onshore. (psi)	Theoretical Operating Pressure for all four producers pumping simultaneously with a rupture at SP 49 Onshore riser (psi)
SP 45	147	125	63
MC 109	338	287	289
MC 20	158	134	219
SP 49 "A"	172	146	212

Table 3.50. Comparison of theoretical PSL settings with a 165 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure if all four producers are pumping with a rupture at the SP 49 Onshore facility riser at the waterline

SP 45 would shutdown on a PSL command first and the pressures at MC 109, MC 20 and SP 49 "A" would decrease to approximately 285 psi, 215 and 209 psi respectively. MC 109 would shutdown on a PSL command and the pressures at MC 20 and SP 49 "A" would decrease to 21 psi and 15 psi respectively and both producers would shutdown on PSL.

A back pressure valve setting of 270 psi will shut down all producers on a PSL command without waiting for other producers to shutdown and decrease the operating pressure on the pipeline system. The results are in the following table.

Producer	Theoretical PSL setting based on 15% below the lowest operating pressure if a 270 psi back pressure valve is installed at SP 49 Onshore. (psi)	Operating Pressure with a rupture at the SP 49 Onshore facility (all 4 producers pumping) (psi)	PSL protection
SP 45	214	63	Yes
MC 109	375	289	Yes
MC 20	223	219	Yes
SP 49 "A"	235	212	Yes

Table 3.51. Comparison of theoretical PSL settings with a 270 psi back pressure control valve installed at SP 49 Onshore versus the operating pressure if all four producers are pumping with a rupture at the SP 49 Onshore facility riser at the waterline.

The installation of a back pressure valve set at 165 psi or 270 psi will shutdown the 10" pipeline if all four producers are operating and a pipeline rupture occurred on the riser at SP 49 Onshore above the waterline.

4.0 SYSTEM RECOMMENDATION

The recommendation for safely operating the 10" SP 49 Pipeline can be obtained as follows:

- Keep the producers at current pumping rates and have the producers reset their PSL settings to 15% below their respective operating pressures when pumping. Although, the change in PSL setting will not shutdown all the producers at the pipeline rupture locations studied, the change will increase the number of producers that will shutdown versus the current PSL settings.

- Configure the monitored SCADA points (offshore LACT meters SP 49 Onshore tank levels and SP 49 Onshore meters) to provide line balance information that can be trended. SCADA monitoring will be able to detect a leak on the system better than the capabilities of the PSL's for a leak at or near the SP 49 Onshore Facility. Chevron Pipe Line Company has initiated the work to provide our Customer Service Center controllers with this capability for the SP 49 Pipeline System.

EXAMPLE OF HYDRAULIC CALCULATIONS

Complete SP 49 Pipeline system

P (psi)	59.1477	P (psi)	408.7968	P (psi)	343.5396
PSL (psi)	20	PSL (psi)	46	PSL (psi)	5
API =	28.3	API =	27.5	API =	33.2
SG =	0.885482	SG =	0.889937	SG =	0.859138
Q (BPH)	70	Q (BPH)	550	Q (BPH)	535
EL (ft) =	60	EL (ft) =	65	EL (ft) =	75
SP45 [illegible]		[illegible]		SP 49A	

P(psi)	50
EL (ft) =	-100
Break out	

Pipe diamter change	
EL (ft)	-620
P (psi)	439.8873

P (psi)	390.5119
PSL (psi)	10
API =	28.6
SG =	0.883823
Q (BPH)	150
EL (ft) =	60

MC 20

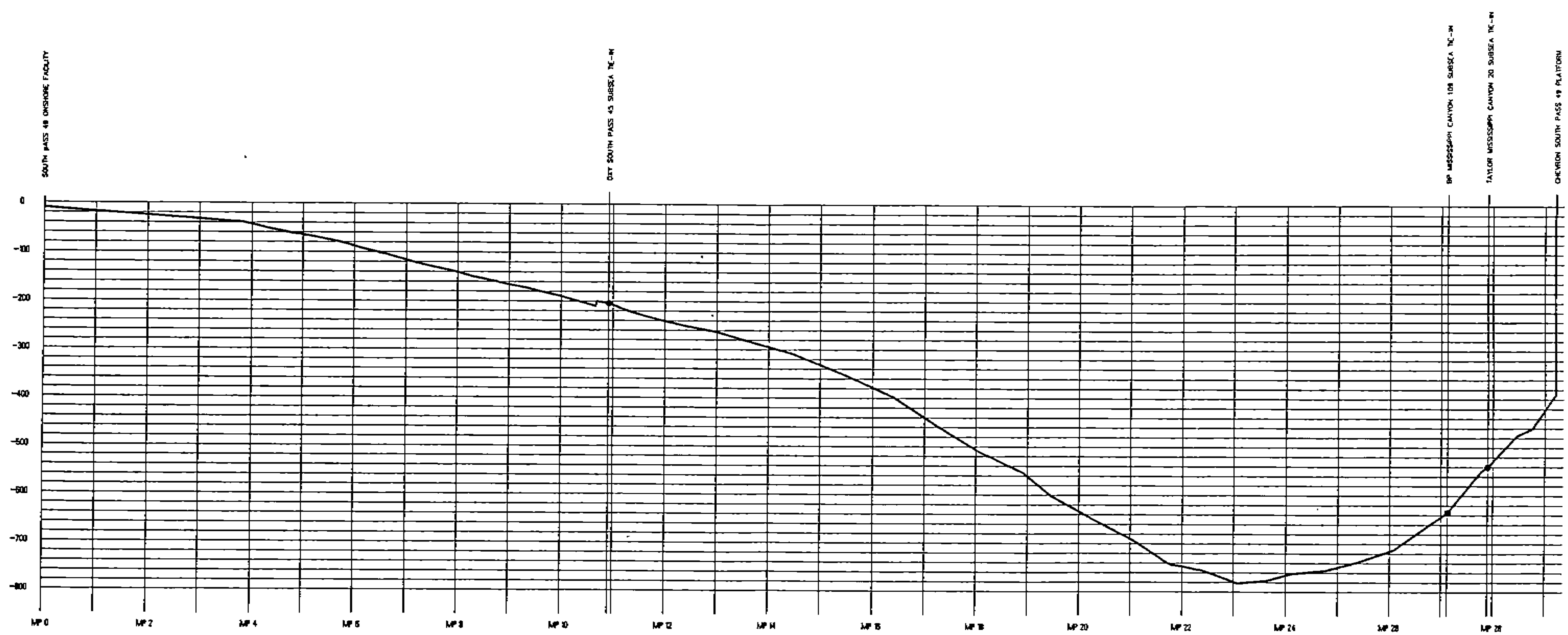
SP 45 TI [illegible]		Deepest Point		[illegible]		MC 20 Tie-in	
EL (ft) =	-200	EL (ft) =	-780	EL (ft) =	-640	EL (ft) =	-540
P (psi)	151.3867	P (psi)	566.4198	P (psi)	594.7619	P (psi)	563.3777

10" x .500" SP 45 Tie In to Onshore		10" x .500" SP 45 TI to .894" wall		10" x .894" to deepest point	
fluid density (lbm/ft^3)	54.68541	fluid density (lbm/ft^3)	54.65318	fluid density (lbm/ft^3)	54.65318
viscosity (cp)	15	viscosity (cp)	15	viscosity (cp)	15
fluid velocity (ft/sec)	3.926042	fluid velocity (ft/sec)	3.715449	fluid velocity (ft/sec)	4.30103
pipe id (in)	9.75	pipe id (in)	9.75	pipe id (in)	9.062
pipe roughness (ft)	0.00015	pipe roughness (ft)	0.00015	pipe roughness (ft)	0.00015
pipe length (ft)	21120	pipe length (ft)	47358	pipe length (ft)	17058
Leq (ft)	0	Leq (ft)	0	Leq (ft)	0
friction factor	0.026839	friction factor	0.027224	friction factor	0.026722
head loss (ft)	166.9757	head loss (ft)	340.1405	head loss (ft)	173.3872

10" x .894" Deepest to MC 109		10" x .894" MC 109 to MC 20 TI		10" x .894" MC 20TI to SP 49 A	
fluid density (lbm/ft^3)	54.65318	fluid density (lbm/ft^3)	53.9475	fluid density (lbm/ft^3)	53.6102
viscosity (cp)	15	viscosity (cp)	15	viscosity (cp)	15
fluid velocity (ft/sec)	4.30103	fluid velocity (ft/sec)	2.385591	fluid velocity (ft/sec)	1.863199
pipe id (in)	9.062	pipe id (in)	9.062	pipe id (in)	9.062
pipe roughness (ft)	0.00015	pipe roughness (ft)	0.00015	pipe roughness (ft)	0.00015
pipe length (ft)	21120	pipe length (ft)	4424	pipe length (ft)	10198
Leq (ft)	0	Leq (ft)	0	Leq (ft)	0
friction factor	0.026722	friction factor	0.031345	friction factor	0.033659
head loss (ft)	214.6757	head loss (ft)	16.22748	head loss (ft)	24.50242

4" x .337" SP 45 TI to SP 45		8" x .406" MC 109 TI to MC 109		6" x .432 MC 20 to MC 20	
fluid density (lbm/ft^3)	55.25407	fluid density (lbm/ft^3)	55.53208	fluid density (lbm/ft^3)	55.15053
viscosity (cp)	15	viscosity (cp)	15	viscosity (cp)	15
fluid velocity (ft/sec)	1.367608	fluid velocity (ft/sec)	2.5768	fluid velocity (ft/sec)	1.292555
pipe id (in)	3.826	pipe id (in)	7.813	pipe id (in)	5.761
pipe roughness (ft)	0.00015	pipe roughness (ft)	0.00015	pipe roughness (ft)	0.00015
pipe length (ft)	4474	pipe length (ft)	36960	pipe length (ft)	53547
Leq (ft)	0	Leq (ft)	0	Leq (ft)	0
friction factor	0.048123	friction factor	0.031719	friction factor	0.042808
head loss (ft)	19.6121	head loss (ft)	222.7746	head loss (ft)	148.6413

20
45



10" SOUTH PASS 49 PIPELINE PROFILE

DRAWING ISSUED

- ____ FOR REVIEW
- ____ FOR APPROVAL
- ____ FOR REFERENCE
- ____ FOR PERMIT REQUEST
- ____ FOR BID
- ____ FOR CONSTRUCTION
- ____ FOR AS-BUILT

REFERENCE DRAWINGS

REVISIONS

Chevron Pipe Line

SCALE ____ DATE ____
DR ____ CH ____ DR APP ____ ENGR ____
OPR'G DEPT ____ ENG DEPT. ____

APPROVED | COST CODE

SHT

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Royalty Management Program** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.

Minerals Management Service
Gulf of Mexico OCS Region

Managing America's offshore energy resources

Protecting America's coastal and marine environments