Reliability of Pressure Signals in Offshore Pipeline Leak Detection

Final Report to Dept. of the Interior, MMS TA&R Program
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EXECUTIVE SUMMARY

This report details industry use of pressure safety low (PSL) alarms in identifying leaks from single and multi-phase flow pipelines. The investigation includes:

- A technical survey of the current pipeline system in the Pacific Region and the US Gulf of Mexico.
- A review of discrete pressure measurements and the configuration of the PSLs on offshore pipelines.
- A review of PSL setting methods.
- An analysis of representative PSL alarms registered in the past 2-3 years (or longer).
- An assessment of the reliability of PSL systems in detecting leaks in offshore pipelines.

The investigation was performed in order to determine the current use of pressure safety low alarms offshore, and their reliability in detecting oil, gas or multiphase leaks in offshore pipelines. Important outcomes of this study include

1. Practices and procedures of PSL alarms that may be controlled or altered to improve system performance
2. Elements of the production system inherent to the manner in which offshore wells/platform/pipeline systems are operated, and which limit the operation of the PSL in leak detection
3. Elements of the general environment that may limit the operation of PSLs
4. A reliability assessment of mass flow, PSL and combination leak detection systems used offshore

The reliability of three types of leak detection systems (mass flow only, PSL only, and combination of PSL and mass flow) for oil pipelines, gas pipelines and multiphase lines was compared using probabilistic risk assessment (PRA). Fault trees for each case were constructed to show the effect of contributing events on system-level reliability. Probabilistic methods provide a unifying method to assess physical faults, contributing effects, human interactions, and other events having a high degree of uncertainty. The probability of various events leading either to a PSL false alarm or a PSL failure to detect a leak is calculated from the probabilities of the basic initiating events.

The probability of basic failure events (e.g. sensor failure, communication link failure) was determined mainly from OREDA (SINTEFF, 1997). Some reliability data was inferred from the pipeline risk point system given by Mulbauher (1999). PSL leak data and false alarm information was also collected in the study and included in the fault tree analysis (FTA).

Based on the findings of this study, recommendations are given concerning alternatives for improved leak detection offshore. The specific recommendations include formal reporting of PSL events, improved coordination and communication between platform and pipeline operators, closer setting of PSLs (where operations permit), and further study on the potential for expanding mass flow leak detection in the United States Outer Continental Shelf (OCS).

1.0 BACKGROUND

In the U.S. Gulf of Mexico (GOM), pipelines are the facilities that spill the largest volume of hydrocarbons. Minerals Management Service information indicates that more than 2000 pipeline incidents have been noted since 1969. (MMS, 2001)

From a regulatory standpoint, pipeline leak detection focuses on the use of pressure safety lows (PSLs). PSLs are low-pressure alarms used to monitor oil and gas production facilities. The PSL pipeline alarms are intended to shut-in the producing facility in the event of a system leak or catastrophic event.

PSL alarms typically operate with discrete pressure sensors, linked to local controllers, or linked to supervisory, control and data acquisition systems (SCADA). For an offshore pipeline, pressure alarms are placed on the platform immediately upstream of the pipeline junction, and on the fluid receiving facility at the downstream end of the pipeline.

From a leak detection standpoint, three possible outcomes exist:

1. A leak occurs and the PSL alarm is triggered
2. A leak occurs and no PSL alarm is triggered
3. No leak occurs and a PSL alarm is triggered

Case 1 is the outcome expected. Case 2 is of greatest concern, from a regulatory, safety and an environmental standpoint, particularly as operations move into deeper water. Case 3 is a concern to operators because repeated false alarms undermine the trustworthiness of the leak detection method.

It has been observed that many pipeline leaks are not detected by a PSL alarm. Further, operators have reported frequent false alarms if the PSL alarm is set within a narrow margin of the system operating pressure. For these reasons, the Minerals Management Service (MMS) has initiated this PSL study to address the following questions,

- When do PSLs function correctly to identify a leak in an offshore pipeline?

- What conditions may create false alarms with PSLs?

- Under what conditions do PSLs fail to detect a leak?

The project addresses these questions by examining the occurrences of PSL alarms, the occurrences of leaks, and the operation of offshore pipelines. PSL reliability is determined based on frequency of occurrence, using probabilistic risk methods and fault tree analysis. Modeling of the PSL release is not included in this study.

2.0 OFFSHORE PIPELINES AND PRODUCTION FACILITIES

Offshore pipelines can be infield pipelines, gathering lines or transmission lines. Infield lines are typically smaller diameter lines that connect facilities within the same field. For example, infield lines may connect two platforms, a subsea template to a platform, or a production manifold to a production facility. Figure 2.1 illustrates a subsea complex tied back to a host platform.

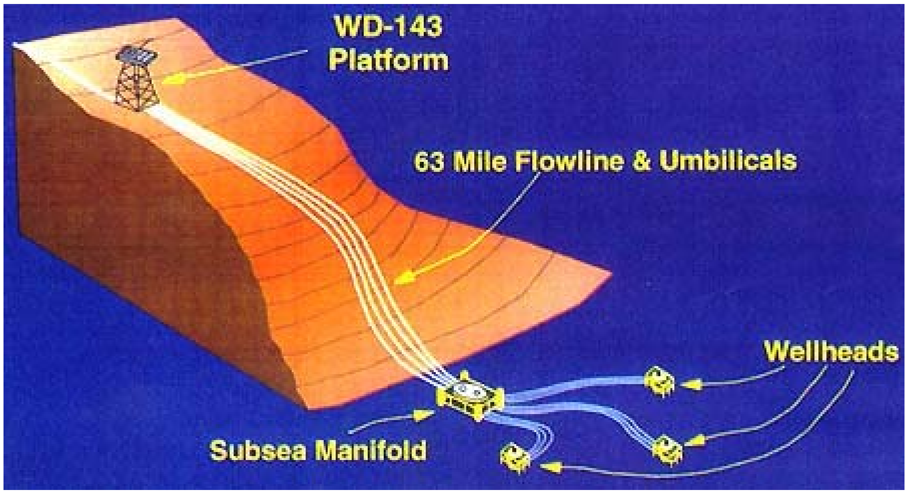


Figure 2.1 Subsea Production Facility Tied-back to Host Platform with Flowlines (offshore-technology.com)

Gathering lines refer to pipelines that connect fluids from multiple facilities, or lines that connect the field production to the major transmission line. Gathering lines may be small to medium diameter (Palmer and King, 2004).

Transmission lines, or trunk lines, are larger diameter pipelines used to transport production to the processing facility onshore. Transmission lines typically carry combined production from multiple offshore production facilities. The production is most frequently combined through gathering lines that route the fluids to a single platform. The transmission line then transports the fluids from the collection hub to the processing facility on shore. Figure 2.2 illustrates the concept of transmission pipelines.

It is common practice to provide a subsea tap for a subsea tie-in along transmission or gathering pipelines. If one pipeline is connected to another pipeline in this manner the fluids are commingled at the point of the subsea tie-in. No pressure or flow measurement is taken subsea at this juncture.

Frequently, the operator of the transmission pipeline is not the operator of the system platforms. This presents a challenge in communications. The platform operators must coordinate their operations with that of the transmission pipeline, and provide information as needed.

Transmission pipelines differ from other offshore lines because the transmission line connects the final production facility to shore. The U.S. Department of Transportation (DOT) has jurisdiction over the pipeline or pipeline segments downstream (landward) of the last valve and associated safety equipment (e.g. pressure safety sensors) on the last production facility on the outer continental shelf (OCS). Hence, the PSL alarm onshore is governed by DOT regulations (49 CFR parts 192, 195) and the PSL at the offshore platform is under the jurisdiction of the MMS. (DOT, 2000)

Transmission pipelines are typically either oil or gas pipelines. Multiphase flow introduces complexities in operation and pressure loss and, for this reason, industry has preferred to construct separate oil and gas transmission lines to shore in the shallow OCS. Deepwater pipelines may include multiphase flow in the future, but those constructed to date have also been single-phase flow.

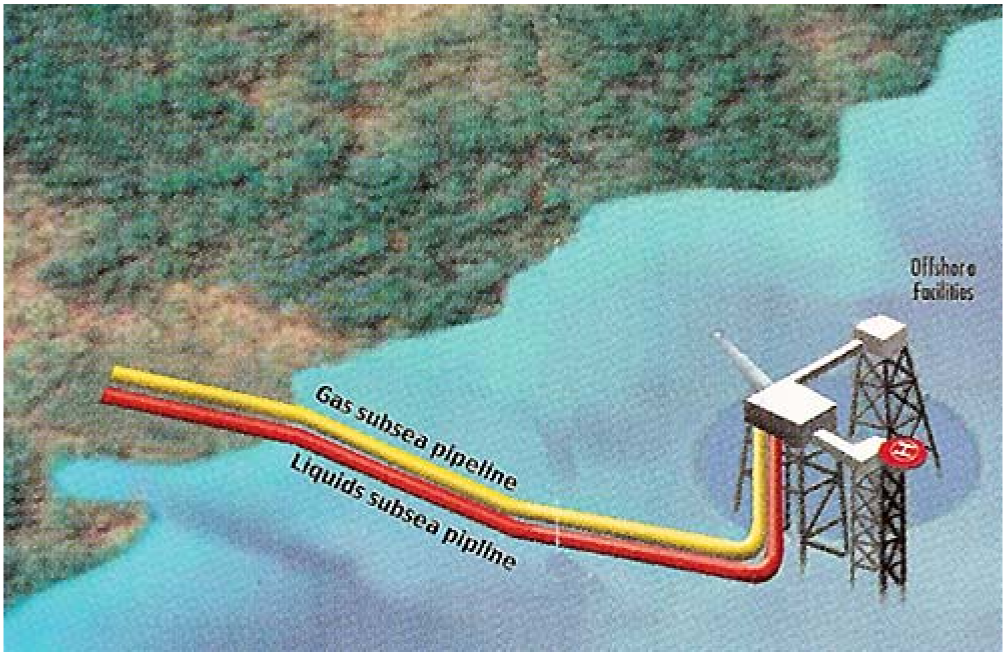


Figure 2.2 Transmission Pipelines (offshore-technology.com)

Subsea flowlines typically carry multiphase flow (oil, water, gas) because the fluids have not yet reached separation facilities. Subsea wells typically include a pressure sensor at the wellhead, but most subsea systems do not include multi-phase subsea flow monitoring. A notable exception is the Canyon Express pipeline system.

The Canyon Express Pipeline System (Figure 2.3) produces three fields, under different operating regimes and varying production rates from multiple zone completions. To accomplish this without any field taking on the performance risk of another field, accurate flow allocation was deemed essential, and subsea multi-phase flow meters were included on each of the subsea wells.

The gas from the three fields will be transported along a gathering system consisting of dual 12-inch pipelines (Figure 2.3).

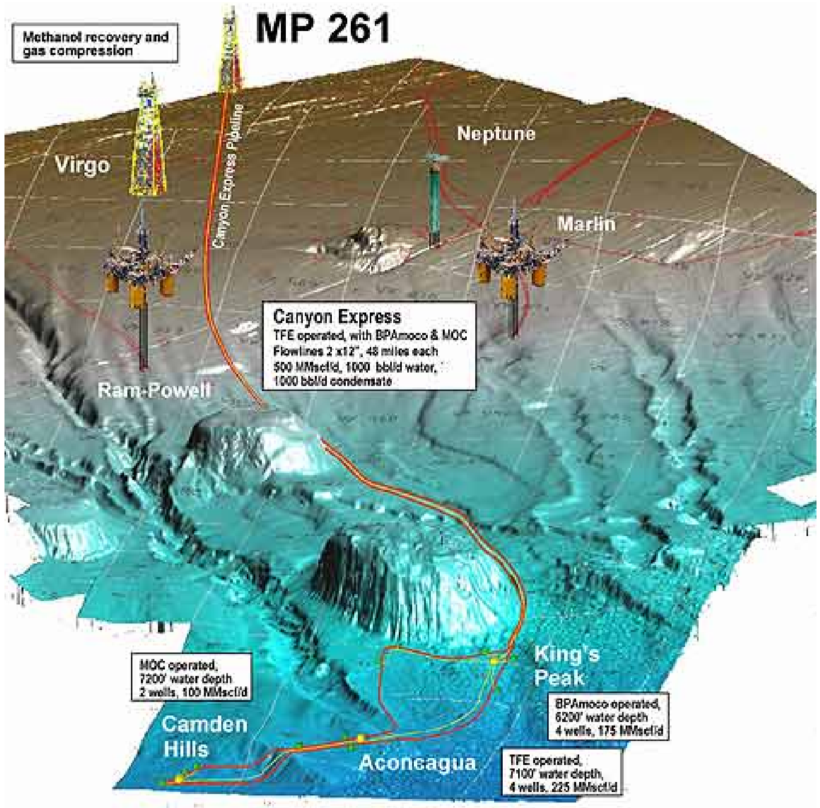


Figure 2.3 Canyon Express Pipeline System (offshore-technology.com)

Supervisory Control and Data Acquisition (SCADA) systems are employed extensively offshore. Gathering pipelines and transmission pipelines are included in such monitoring systems where they exist. Pipeline pressure sensors and flowmeters are linked directly to the platform central processing unit (CPU) via direct connections or through subsea umbilicals.

The existence of SCADA capabilities offshore has implications for offshore leak detection, because certain methods of leak detection require periodic data polling. A complete review of SCADA systems offshore is provided by Erickson et. al, 2000.

3.0 OFFSHORE PIPELINE LEAK DETECTION

Multiple methods of leak detection exist and are being applied offshore. The methods frequently applied include visual inspection, pressure monitoring (PSLs), and computational pipeline monitoring.

3.1 Visual Inspection

Visual inspection refers to manually looking for a release, by having a helicopter (or a seaplane) fly over the pipeline route and examine the ocean for a hydrocarbon sheen or a similar indication of a release. This method of leak detection is performed routinely, by major pipeline operators (particularly on transmission lines). Many other leaks are seen and reported by offshore personnel, either while flying to a platform or while working on a platform offshore. Remotely operated vehicles (ROVs) may also aid in visual inspection of pipelines.

The MMS requires periodic visual inspection (CFR 250.1004 (a)) and notes that visual inspection is a major method of leak detection offshore.

3.2 Pressure Monitoring (PSLs)

Pressure changes are commonly used as a means of leak detection offshore. Pressure sensors are included on the production platform, as the fluids exit the platform into the pipeline or gathering line. A second pressure sensor is located either at the inlet of the next platform, or onshore in the case of a transmission pipeline.

The pressure sensors are set lower than the normal operating pressure of the pipeline. If a leak occurs, then the pipeline pressure drops below the normal operating pressure. If the pressure drops below the level of the PSL, and alarm is registered and production is shut-in.

Operators who do not employ SCADA monitoring of their production facilities tend to rely on PSLs for their principal leak detection method.

3.3 Monitoring Flow Volumes

PSL alarm information can also be combined with monitoring flow volumes to ascertain whether an alarm event is actually a release. In this method, the pipeline operator monitors the volume received into the pipeline over a period of time and checks this against the volumes produced at the pipeline terminus. If the volumes produced are less than those entering the line, a leak is confirmed.

‘Rate of change’ in system pressure or flow can also be monitored to yield the same result.

This method can work well in liquid filled pipelines provided there is no significant line pack to account for. Simple monitoring of volumes would not be reliable for two phase flow or gas pipelines.

3.4 Computational Pipeline Monitoring

Computational pipeline monitoring (CPM) is a term that refers to algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a release (leak). API publications 1130 (October 1995), 1149 (November 1993) and 1155 (February 1995) summarize various aspects of CPM.

The use of a computational pipeline monitoring system infers that the pipeline operator will employ a SCADA system that polls the pressure sensors and flow meters on a frequent basis. CPM methods cannot be employed unless an operator has this monitoring infrastructure in place.

CPM systems, as well as the other methods of release detection, each have a detection threshold below which commodity release detection cannot be expected. Figure 3.1 indicates that even CPM methods only address commodity releases above some practical detection limit.

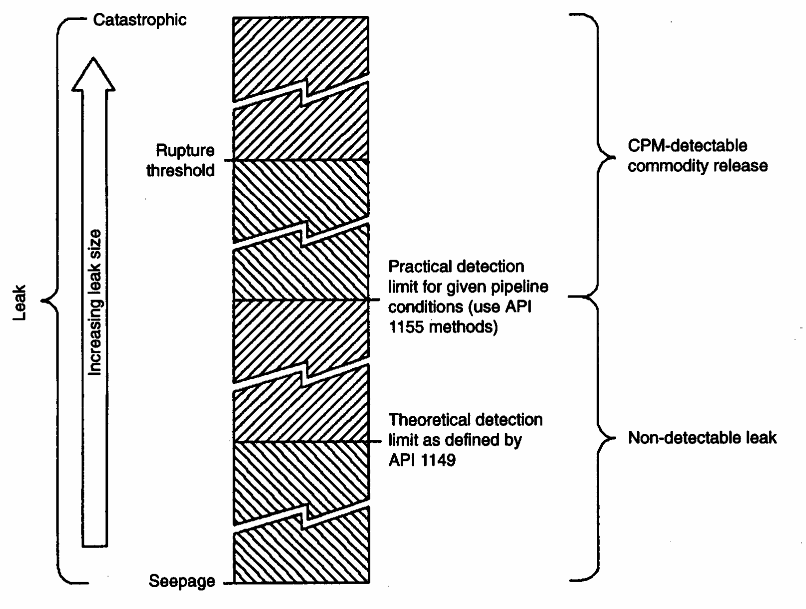


Figure 3.1 Relative Scale of Leak Detection (API 1130)

The following leak detection method descriptions are taken from API 1130.

3.4.1 Line Balance

Line balance is a meter-based method that determines the measurement imbalance between the incoming (receipt) and outgoing (delivery) volumes. The imbalance is compared against a predefined alarm threshold for a select time interval (time window). There is no compensation for the change in pipeline inventory due to pressure, temperature or composition. Imbalance calculations are typically performed from the receipt and delivery meters, but less timely and less accurate volumes can be determined from tank gauging.

This method of CPM is the same a manual volume monitoring noted above, but is performed with an algorithm.

3.4.2 Volume Balance

This method is an enhanced line balance technique with limited compensation for changes in pipeline inventory due to temperature and/or pressure. Pipeline inventory correction is accomplished by taking into account the volume increase or decrease in the pipeline inventory due to changes in the system's pressure and/or temperature. It is difficult to manually compensate for changes in pipeline inventory because the complexity of the imbalance computation. There is usually no correction for the varying inventory density. A representative bulk modulus is used for line pack calculation.

3.4.3 Modified Volume Balance

This is a meter-based enhanced volume balance technique. Line pack correction is accomplished by taking into account the volume change in the pipeline inventory utilizing a dynamic bulk modulus. This modulus is derived from the bulk moduli of the various commodities as a function of their percentage of line fill volume.

3.4.4 Real Time Transient Model

The real time transient model approach is perhaps the most sophisticated CPM method. The fundamental improvement that RTTM provides over the MVB method is that it models all the fluid dynamic characteristics (flow, pressure, temperature). Extensive configuration of physical pipeline parameters (length, diameter, thickness, pipe composition, route topology, internal roughness, pumps, valves, equipment location, etc.) and commodity characteristics (accurate bulk modulus value, viscosity, etc.) are required to design a pipeline specific RTTM. The application software generate a real time transient hydraulic model by this configuration with field inputs from meters, pressure, temperatures, densities and strategic receipt and delivery locations, referred to as software boundary conditions. Fluid dynamic characteristic values are modeled throughout the pipeline, even during system transients.

3.4.5 Pressure/Flow Monitoring

Three approaches to using pressure or flow information can be used. Pressure/flow values that exceed a predetermined alarm threshold are classified as excursion alarms. Initially, excursion thresholds are set out of range of the system operating fluctuations. After the system has reached a steady-state condition, it may be appropriate to set thresholds close to operating values for early anomaly recognition.

Pressure/flow trending is the representation of current and recent historical pressure or flow rate or both. These trends may be represented in a tabular or graphical format on the control center monitor to enable a controller to be cognizant of these parameter fluctuations. This method can be used to display operating changes that can infer commodity releases.

Rate-of-change (ROC) calculates the variation in a process variable with respect to a defined time interval. The rate at which line pressure or flow or both changes with respect to time are the two most common forms of ROC for pipeline operation. The intent of this approach is to identify rates of change in pressure or flow or both aside from normal operating conditions, thereby inferring a commodity release if operating anomalies cannot be explained.

3.4.6 Acoustic/Negative Pressure Wave

The acoustic/negative pressure wave technique takes advantage of the rarefaction waves produced when the commodity breaches the pipe wall. The release produces a sudden drop in pressure in the pipe at the leak site that generates two negative pressure or rarefaction waves, traveling upstream and downstream. High response rate/moderate accuracy pressure transmitters at select locations on the pipeline continuously measure the fluctuation of the line pressure. A rapid pressure drop and recover will be reported to the central facility. At the central facility, the data from all monitored sites will be used to determine whether to initiate a CPM alarm.

3.4.7 Statistical Analysis

The degree of statistical involvement varies widely with the various methods in this classification. In a simple approach, statistical limits may be applied to a single parameter to indicate an operating anomaly. Conversely, a more sophisticated statistical approach may correlate the averaging of one or more parameters over short and long time intervals in order to identify an anomaly.

The statistical process control (SPC) approach includes statistical analysis on pressure or flow or both. SPC techniques can be applied to generate sensitive CPM alarm threshold from empirical data for a select time window. A particular method of statistical process control may use line balance ‘over/short’ data from normal operations to establish upper and lower volume balance imbalance limits. If the volume imbalance for the evaluated time window violates the statistical process control tests, the CPM system will alarm.

All of the API 1130 CPM methods described are applicable only in liquid filled pipelines. Highly volatile liquids, multi-phase, and gas lines are not included in the analysis. However, CPM methods are currently employed in multiphase lines offshore.

Other methods of leak detection, such as clamp on ultrasonics and multi-phase metering are not discussed in this report, because the methods have limited applicability or acceptance offshore. RTTM has been applied to multi-phase flow through subsea flowlines (e.g., Troika Field and Gemini Field) but has not been widely adopted as a leak detection method for multi-phase flow offshore. CPM is the most prevalent method of leak detection, coupled with PSLs.

4.0 SURVEY OF EXISTING PIPELINE SYSTEMS

The United States Outer Continental Shelf (OCS) includes over 33,000 miles of oil and gas pipelines. Currently, 32,900 miles of these lines are located in the Gulf of Mexico (GOM). The majority of the remaining pipelines are concentrated off the coast of Southern California. A few other offshore pipelines are evolving off the coast of Florida, the northeast US and Alaska. For the purposes of this study, only pipelines in the US GOM and Pacific region have been investigated.

The following is a summary of pipelines investigated the U. S. Pacific Region, and a review of the pipeline and data systems for the Gulf of Mexico.

4.1 Pacific Region Summary

The Pacific Region includes platforms and pipelines located off the coast of Southern California. Four principal pipeline systems exist in the area, which include 20 lines transporting either oil or oil/water, 20 lines carrying gas (four of these convey sour gas), and 10 lines conveying produced water or water used for field pressure maintenance. These lines are summarized in Table 4.1.

The offshore platforms in the Pacific region are facilities that, for the most part, are operated by smaller independent producing companies. The facilities have been in place since the late 1960s or early 1970s. While the trend is toward upgrading these facilities to include SCADA systems, not every system currently included SCADA controls at the time of this study.

Pipeline leak detection methods were found to vary among the systems examined. Where operators had not upgraded platform systems to include SCADA, the trend was to rely solely on PSL alarms for leak detection, or a combination of PSL alarms and line balance (meter based method determining the imbalance between the incoming and outgoing delivery volumes). However, these systems are currently being upgraded to include some method of computational pipeline monitoring (CPM).

One larger operator surveyed currently utilizes CPM and SCADA for pipeline leak detection in the Pacific Region.

Two major pipeline leaks in the Pacific Region were noted in meetings with operators and the MMS. In one case, the PSL alarms failed to detect the leak, and in the second case the PSL functioned correctly. In the latter case, the operator reset the alarm and resumed operations, and the leak continued.

In discussion with operators, essentially all surveyed believed that PSL alarms could not correctly identify small, leaks in pipeline systems, but that the alarms would shut-in a facility in the event of a catastrophe. One operator shared an underwater picture from an extremely small leak in their gas transmission line. The leak was not detected by a pressure safety low. Rather, the operator noticed an increase in produced water at the shore facility. A salinity check verified that a line was experiencing seawater influx.

OCS PIPELINES

FROM	PIPELINE			TO		PIPELINE OPERATOR
PLATFORM	I.D."	TYPE	FLOW	PLATFORM	ONSHORE FACILITY	
C	8" 6" 6"	OIL/WATER GAS WATER(INJ)	→ → ←	B		NUEVO
B	12" 12" 6"	OIL/WATER GAS WATER	→ → →		RINCON	
A	12" 12" 6"	OIL/WATER GAS WATER	→ → →	REFERENCE NOTE (2)		
HILLHOUSE	8" 8" 6"	OIL GAS SPARE	→ → →	A		
HENRY	8" 6" 8"	OIL GAS WATER	→ → →	HILLHOUSE		
HOUCHIN	10" 10" 12" 4"	OIL/WATER GAS LIFT GAS WATER	→ → → →	HOGAN		PACIFIC OFFSHORE OPERATORS INC.
HOGAN	10" 10" 12" 4"	OIL/WATER GAS LIFT GAS WATER	→ ← → ←		LA CONCHITA	
GAIL	8" 8" 8"	GAS OIL GAS	→ → →	GRACE		VENOCO
GRACE	10"	GAS	→	HOPE *		
	12"	OIL	→			VENOCO
HABITAT	12"	GAS	→		CARPINTERIA	NUEVO
GINA	10" 6"	OIL/WATER GAS	→ →		MANDALAY	NUEVO
GILDA	12" 10" 6"	OIL/WATER GAS WATER	→ → ←		MANDALAY	
EDITH	6" 6"	GAS OIL	→ →	EVA * ELLEN/ELLY		NUEVO
EUREKA	12" 10" 6"	OIL/WATER WATER (INJ) GAS	→ ← →	ELLEN/ELLY		AERA ENERGY
ELLEN/ELLY	16"	OIL	→		SAN PEDRO	
HERITAGE	20"	OIL/WATER	→	HARMONY		EXXONMOBIL CORPORATION
HARMONY	20" 12"	OIL WATER	→ ←		LAS FLORES CANYON	
	12"	GAS	→	HONDO		
HONDO	14"	OIL/WATER	→	HARMONY		
	12"	GAS	→		LAS FLORES CANYON	PACIFIC OFFSHORE PIPELINE CO.
HIDALGO	16" 10"	OIL/WATER SOUR GAS	→ →	HERMOSA		ARGUELLO INC
HARVEST	12" 8"	OIL/WATER SOUR GAS	→ →	HERMOSA		ARGUELLO INC
HERMOSA	24" 20"	OIL/WATER SOUR GAS	→ →		GAVIOTA	POINT ARGUELLO PIPELINE COMPANY
IRENE	20" 8"	OIL/WATER WATER	→ ←		ORCUTT	TORCH
	8"	SOUR GAS	→			TORCH

(1) * DENOTES STATE PLATFORM

(2) PIPLINES FROM PLATFORM "A" TIE-IN WITH PIPELINES PLATFORM "B" TO ONSHORE FACILITY.

Table 4.1 Summary of Pacific Region Pipelines (courtesy MMS)

4.2 Gulf of Mexico Region Summary

The US Gulf of Mexico (GOM) presents a greater challenge in characterizing pipeline systems for leak detection. At the outset of the study, a database containing pipeline segments for the GOM was obtained and summarized to identify the most significant pipeline operators. Example pages from this database are included in Appendix A. Table 4.2 summarizes the top 38 companies by length (footage) of line operated.

Table 4.2 shows that for several of the larger companies, there is more than one listing. For example, Shell operates offshore lines under Shell Offshore, U.S.A., Shell Gas Gathering Company, Shell Deepwater Development, Inc., and Equilon Pipeline Company, LLC. Apart from the lines acquired through Equilon, Shell pipelines are managed according to their size, product type and water depth. This segregation of lines poses challenges in collecting PSL data from such companies.

At the outset of the research it was intended to develop a complete database of all GOM pipeline systems according to pipeline segments. After initial discussions in the Pacific Region, and meeting with one operator in the GOM it became apparent that a better approach would be to describe pipeline systems, since pipelines including CPM methods must be closed systems for leak detection. Figure 4.1 depicts a closed system of platforms and pipelines for the Timbalier Area.

The Minerals Management Service (MMS) Pipeline section was contacted to identify pipeline systems in the GOM. After meeting with the MMS, it was understood that the only method of identifying pipeline systems relies on systems identified for royalty purposes. This approach was deemed reasonable since product sales should track system flow exactly.

A listing of oil systems and gas systems were provided and maps from selected systems were printed and reviewed. All pipeline royalty systems for the US GOM could be identified using this approach, but not all systems are complete (include all pipeline segments) in the current MMS royalty system database. Figure 4.2 provides an example royalty pipeline system in the Vermillion area.

While the royalty systems identified in the Gulf of Mexico form a basis for soliciting information regarding systems that potentially employ CPM, it was determined that most of the royalty systems do not employ CPM because there are multiple operators involved. Hence, it was decided to examine the GOM pipelines by asking companies to provide information on any leak incident or false alarm, regardless of its location.

Several operators were questioned with respect to their system operations. Responses given were similar to those obtained in the Pacific Region. Larger operators have either installed or are in the process of initiating CPM methods for leak detection on their pipeline systems, while smaller operators may still rely solely on PSL alarms. Some small operators do not have SCADA capability in the US GOM.

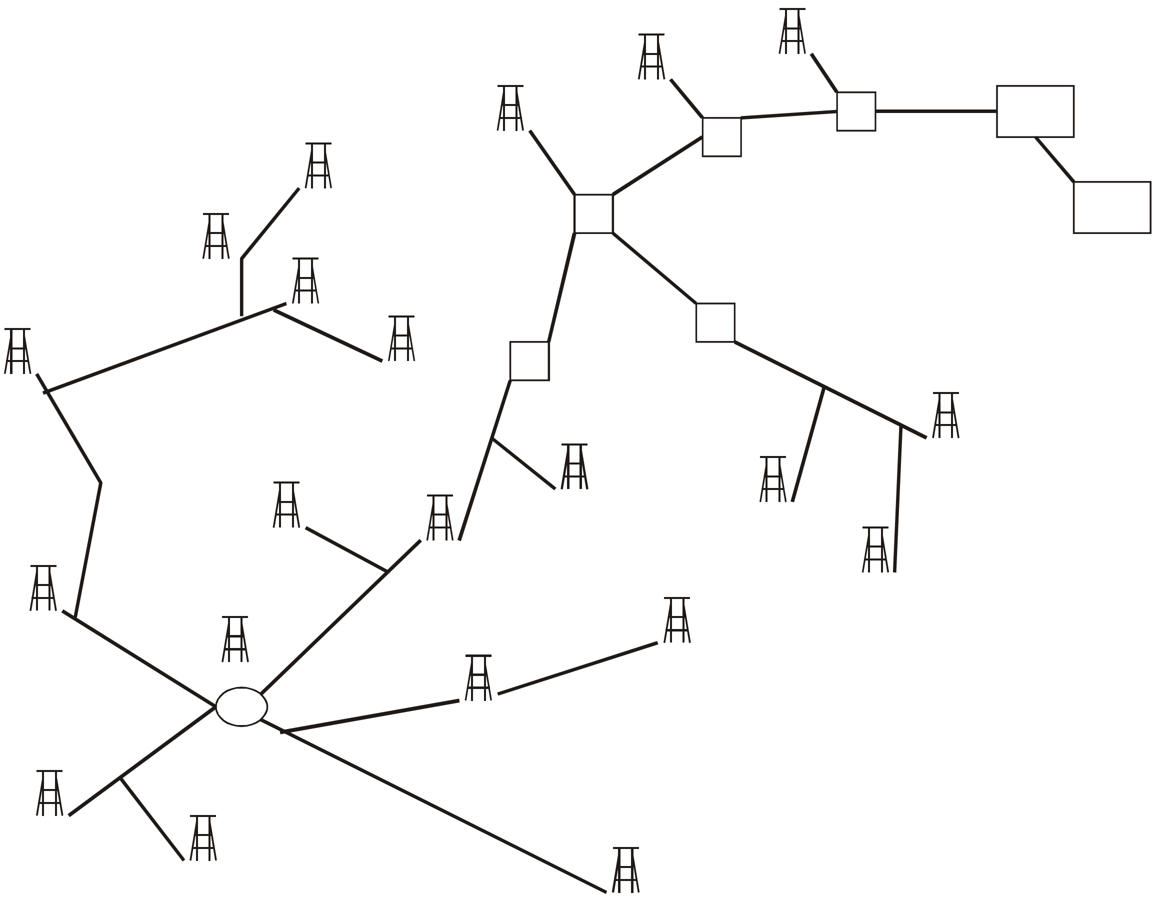


Figure 4.1 Timbalier Example Platform and Pipeline System

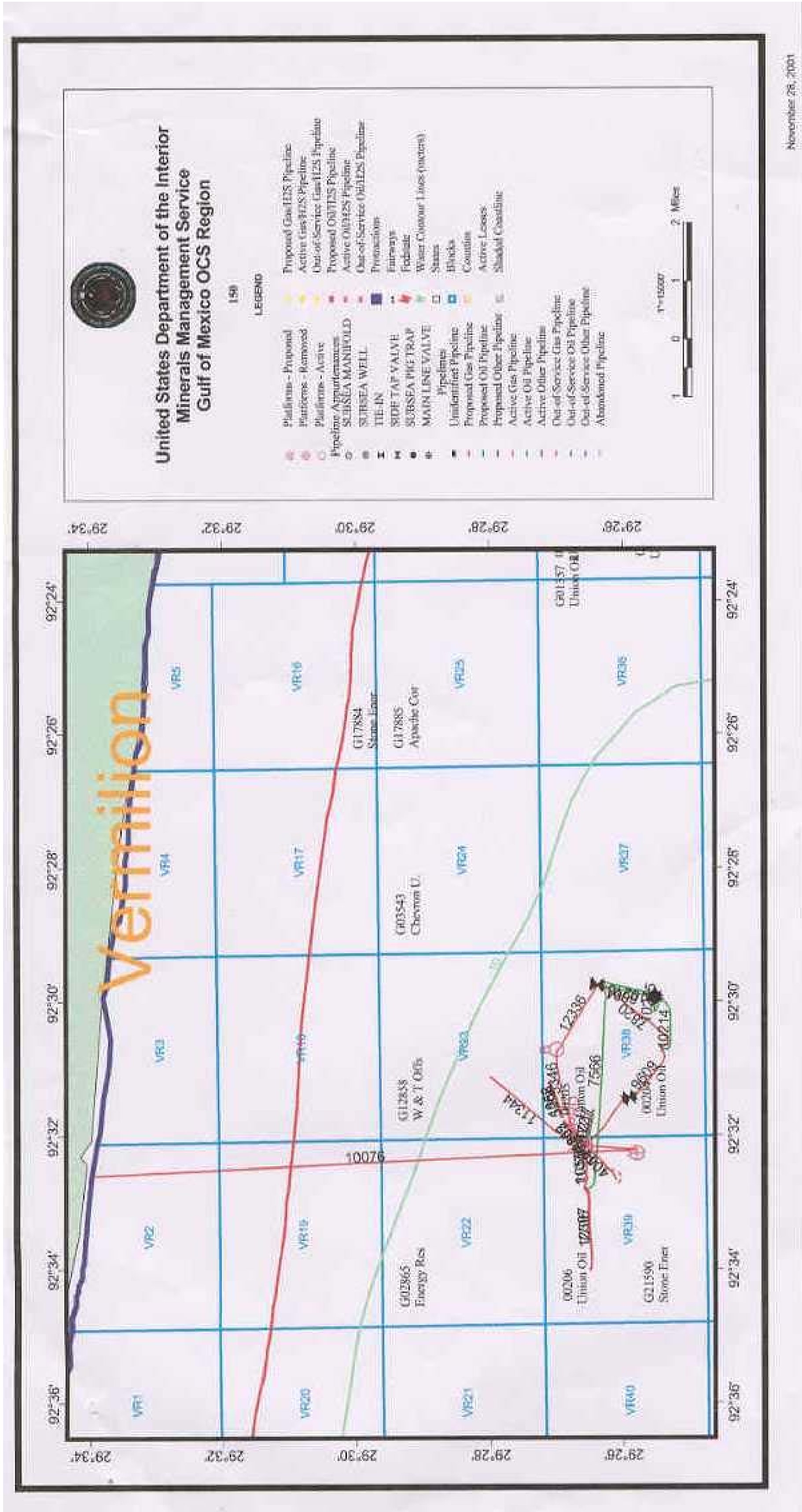


Figure 4.2 Vermillion Area Royalty System (courtesy MMS)

No.	Operating Company	Total Length (ft)
1.	Transcontinental Gas Pipeline Corporation.	8965007
2.	Chevron U.S.A. Inc.	6876330
3.	Equilon Pipeline Company LLC.	6822029
4.	Tennessee Gas Pipeline Company	6108838
5.	ANR Pipeline Company	3475716
6.	Texas Eastern Transmission Corporation	3176532
7.	Shell Deepwater Development Inc.	3001144
8.	Petrocom Communications, Inc.	2480000
9.	Exxon Mobil Pipeline Company.	2416092
10.	Murphy Exploration & Production Company	2366908
11.	Newfield Exploration Company	2363580
12.	Sea Robin Pipeline Company	2235415
13.	Exxon Mobil Corporation	2214420
14.	Trunkline Gas Company	2206177
15.	Columbia Gulf Transmission Company.	2138330
16.	Mobil Oil Exploration & Producing South	2131212
17.	Amoco Pipeline Company	2107666
18.	Texaco Inc.	2094776
19.	Union Oil Company Of California	2072522
20.	Walter Oil & Gas Corporation	2011071
21.	Manta Ray Gathering Company, L.L.C.	1962963
22.	Shell Gas Gathering Company	1934638
23.	Chevron Pipeline Company	1925897
24.	Southern Natural Gas Company	1893281
25.	Shell Offshore Inc.	1867593
26.	Vastar Resources, Inc.	1839031
27.	Exxon Mobil Corporation	1810189
28.	Samden Oil Corporation.	1611068
29.	Apache Corporation	1486547
30.	Marathon Pipeline Co.	1418188
31.	RME Petroleum Company	1398260
32.	TotalFinaElf E&P USA, Inc.	1339261
33.	Williams Field Services-Gulf Coast Com.	1260744
34.	Kerr-McGee Oil & Gas Corporation	1185677
35.	Mariner Energy, Inc.	1143951
36.	High Island Offshore System	1079521
37.	Dauphin Island Gathering Company Partners	1069223
38.	El Paso Production GOM Inc.	1061872

Table 4.2 Top 38 Pipeline Operators in GOM by Footage (MMS, 2002)

5.0 PRESSURE SAFETY LOWS (PSL)

The pressure data from an actual PSL event is plotted in Figure 5.1. This line was shut-in due to a PSL trip from an upstream platform. This figure also shows the operating fluctuations in the normal line pressure.

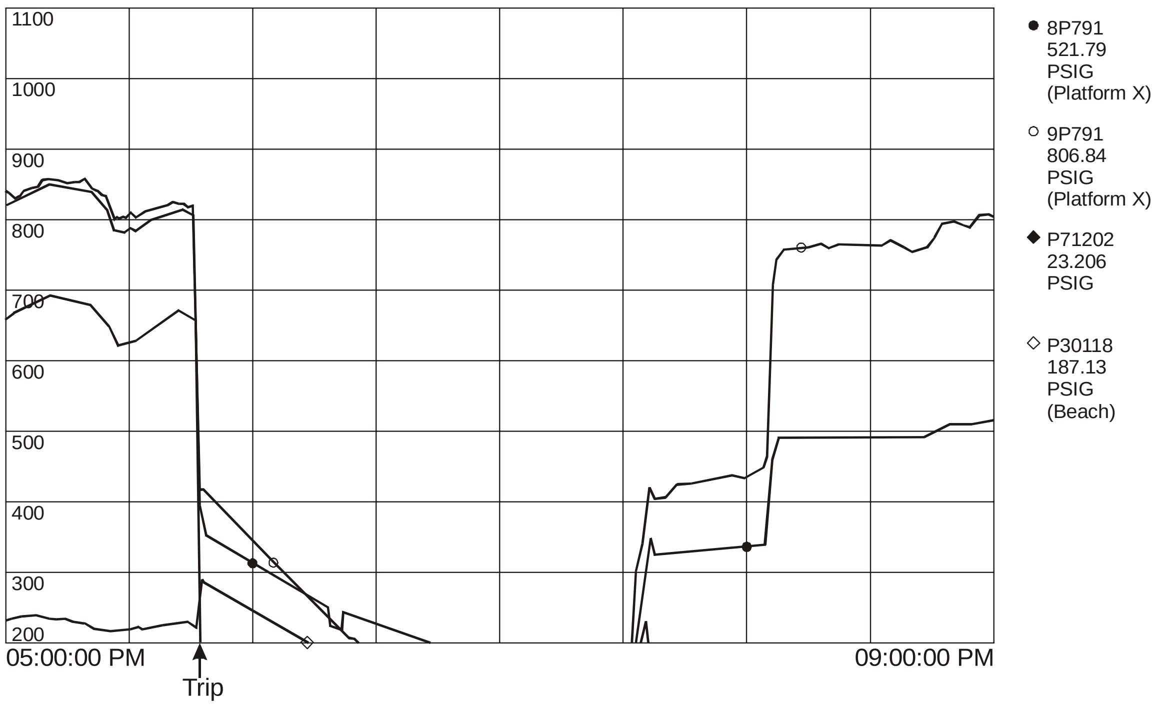


Figure 5.1 Pipeline Pressures During PSL Shut-in and Subsequent Recovery

5.1 Sensor Operation

A typical pressure sensor and its connection to a gas pipeline are shown in Figure 5.2. The primary sensing element is the differential capacitance between the sensing diaphragm and the two capacitor plates. Both sides of the sensing diaphragm are coupled to isolating diaphragms with oil. One side of the sensing diaphragm is coupled to the low-pressure side, open to the ambient environment, and one side is coupled to the high pressure side, the pipeline. Often, the electronics package simply converts the differential capacitance to a 4 to 20 mA signal representing the actual pressure over the calibrated range. This 4 to 20 mA signal is transmitted to a distributed control system (DCS) or programmable logic controller (PLC) where the actual pressure alarm is generated. The typical accuracy is ±0.25% of the calibrated span and the response to an abrupt change in pressure has a time constant on the order of 50 to 100 milliseconds. However, some operators have replaced the simple pressure sensor with a microprocessor-based converter that can average the sensor readings. The microprocessor changes the typical accuracy to about ±0.05% of the calibrated span, but adds 50 to 100 milliseconds to the response time. Any averaging of the pressure signal further increases the response time.

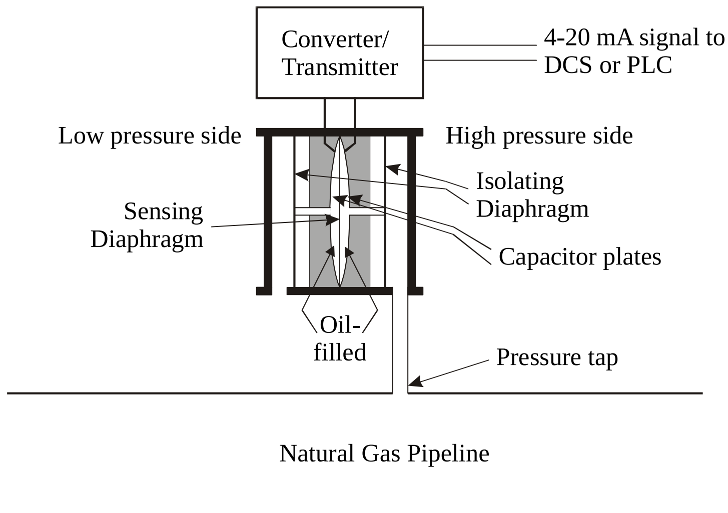


Figure 5.2 Typical Pressure Sensor

5.2 Sensor Manufacturer and Failure Rate

A summary of pressure sensor manufacturers is provided by Erickson et al (2000). No operator questioned in this study indicated particular problems associated with one type of pressure sensor, nor was sensor failure rate indicated as a concern. For these reasons, specific instances of sensor failure data were not collected in this study.

5.3 Configuration of Typical PSL Platform/Pipeline System

5.3.1 PSL Location

In the case of gathering lines connecting two platforms, or in the case of a transmission line connecting a production hub to shore, one PSL sensor is located on the platform where the fluid enters the pipeline. A second PSL sensor is located at the point where the pipeline terminates, which is either another platform or a shore facility. This is shown in Figure 5.3.

No operator questioned in the study indicated use of PSL alarms at the point of subsea tie-ins, or at any intermediate point along the pipeline. Similarly, no operator indicated use of interemediate pumps along a pipeline, unless the pipeline was routed over an intermediate small platform.

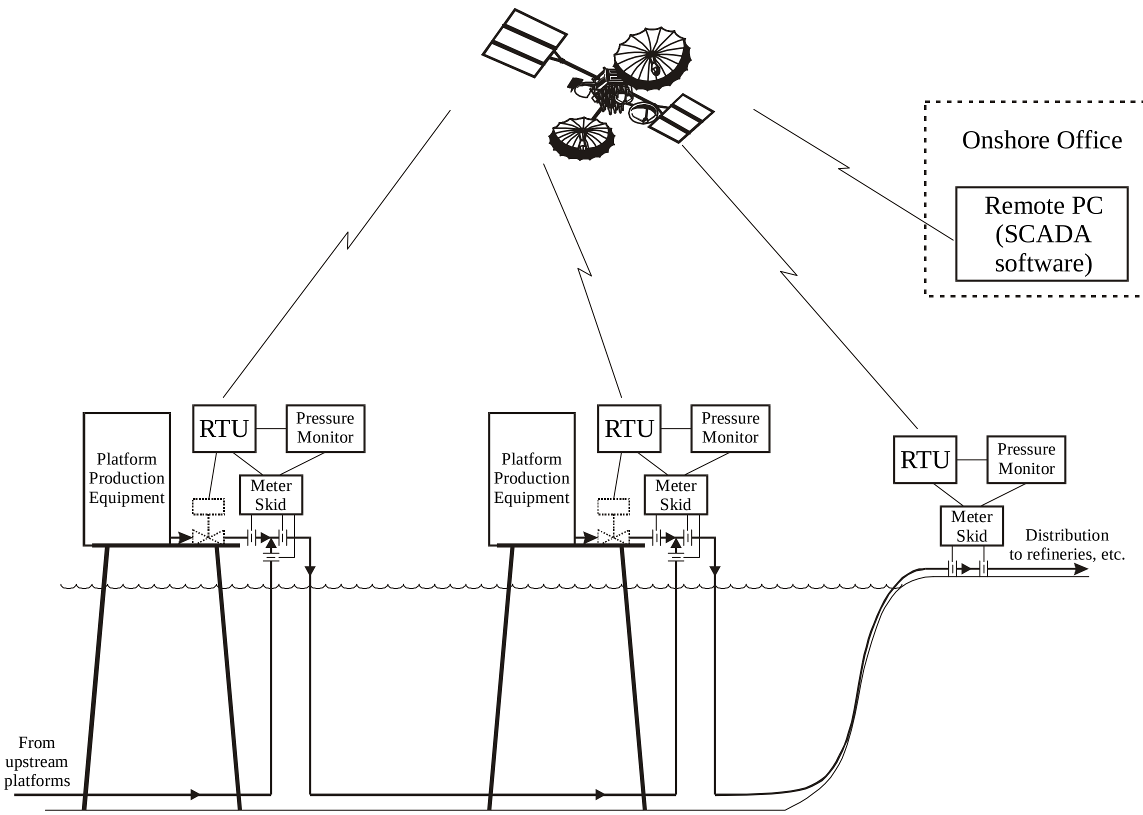


Figure 5.3 Platforms and Pipeline – Location of Pressure Monitoring

5.3.2 Operational Considerations

Figure 5.4 details the placement of the PSL sensor relative to the pipeline pumps, valves, and pig launcher (Tiratsoo, 1992). As shown, the PSL is downstream of the pipeline pump.

One operator questioned indicated that a principal difficulty in setting PSL alarms was the nature of the pipeline pump. Offshore pipeline pumps tend to be piston or reciprocating type pumps, which by their nature create more pressure surging in the line. Coupling producing well fluctuations on multiple platforms with the periodic cycling of the pipeline pumps, means that the system pressures fluctuate widely.

Once a PSL causes a line to shut-in, if the operator is uncertain as to the cause of the shutdown and/or integrity of the pipeline, an arerial survey of the line is made.

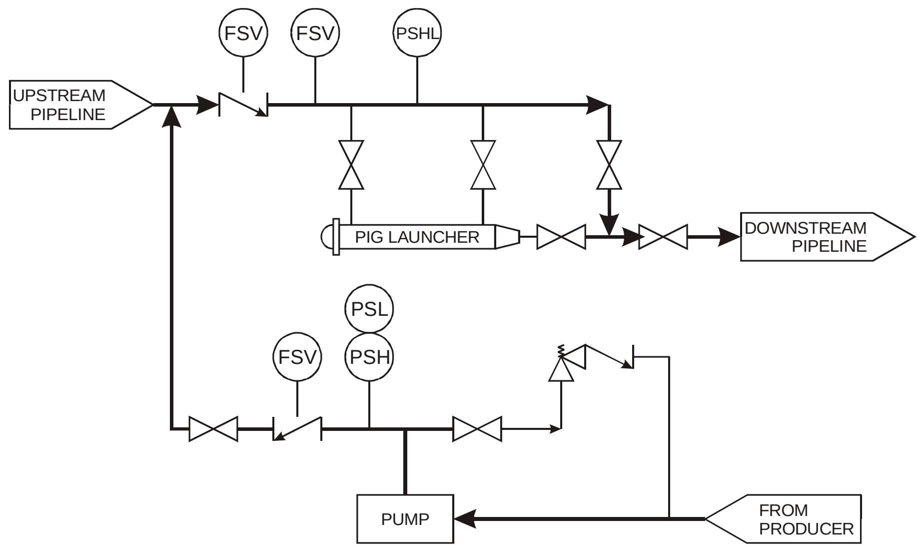


Figure 5.4 Detail of an Offshore Pipeline/ Platform Junction Showing Alarm Locations

Operators surveyed indicated that PSLs on in-field lines do not generally detect leaks. Operators usually notice an oil slick on the water before any PSLs trip.

One operator indicated that rate-of-change (ROC) alarms are an important indication of a leak. However, if a ROC alarms happens, the operators monitor the pipeline pressure at various points to determine the likelihood of a leak.

Another operational consideration is reservoir depletion, and the impact of declining reservoir pressures on pipeline operation. As reservoir pressures decline, pipeline operation pressures must also decrease unless additional pumping equipment is specified. In the older facilities in the shallow OCS, system operating pressures may fall below the hydrostatic pressure of the sea at points along the pipe route. For example, if a pipline is located in 400 feet of water, and the seawater gradient is 0.465 psi/ft, then the external pressure on the line would be

$$p_{HYDRO} = (0.465\, psi/\ ft)(400\, ft) = 186\, psi$$

If the pipline operating pressure falls to this level, it is unlikely that the PSL could detect a leak. Several instances of this phenomena were found in the study. This pheonema has more widespread implications for deepwater operations. For example, if the water depth increases to 6000 ft, the operating pressure of the line must fall below

$$p_{HYDRO} = (0.465\, psi/\ ft)(6000\, ft) = 2790\, psi$$

for a leak to go undetected. This example shows that PSLs on deepwater pipelines will be likely affected by hydrostatic pressure.

5.4 Regulatory Aspects of the PSLs

The US Department of Interior Minerals Management Service regulates oil and gas operations offshore. The regulations concerning pipelines safety equipment and PSLs are found in CFR 250.1004 paragraph b parts (2) through (9):

Parts (2) through (9) of CFR 250.1004 paragraph (b) also describe requirements for pipelines:

(2) Incoming pipelines boarding to a production platform shall be equipped with an automatic shutdown valve (SDV) immediately upon boarding the platform. The SDV shall be connected to the automatic – and remote-emergency shut-in systems.

(3) Departing pipelines receiving production from production facilities shall be protected by high and low-pressure sensors (PSHL) to directly or indirectly shut in all production facilities. The PSHL shall be set not to exceed 15 percent above and below the normal operating pressure range. However, high pilots shall not be set above the pipelines MAOP.

(4) Crossing pipelines on production or manned non-production platforms which do not receive production from the platform shall be equipped with an SDV immediately upon boarding the platform. The SDV shall be operated by a PSHL on the departing pipelines and connected to the platform automatic- and remote-emergency shut-in system.

(5) The Regional Supervisor may require that oil pipelines be equipped with a metering system to provide a continuous volumetric comparison between the input to the line at the structure(s) and the deliveries onshore. The system shall include an alarm system and shall be of adequate sensitivity to detect variations between input and discharge volumes. In lieu of the foregoing, a system capable of detecting leaks in the pipeline may be substituted with the approval of the Regional Supervisor.

(6) Pipelines incoming to a subsea tie-in shall be equipped with a block valve and FSV. Bi-directional pipelines connected to a subsea tie-in shall be equipped with only a block valve.

(7) Gas-lift or water-injection pipelines on unmanned platforms need only be equipped with an FSV installed immediately upstream of each casing annulus of the first inlet valve on the christmas tree.

(8) Bi-directional pipelines shall be equipped with a PSHL and an SDV immediately upon boarding each platform.

(9) Pipeline pumps shall comply with Section A7 of API RP 14C. The setting levels for the PSHL devices are specified in [3] of this section.

The remainder of 250.1004 requires that if the safety equipment is removed or rendered inoperative, it must be replaced by a similar level of protection.

5.5 Methods of Setting PSLs

Figure 5.5 is an example pressure chart recorded for an offshore liquids pipeline. In this example the system pressure varies from 300 psi to1496 psi over a 4 hour period. This wide pressure fluctuation is common in offshore production facilities.

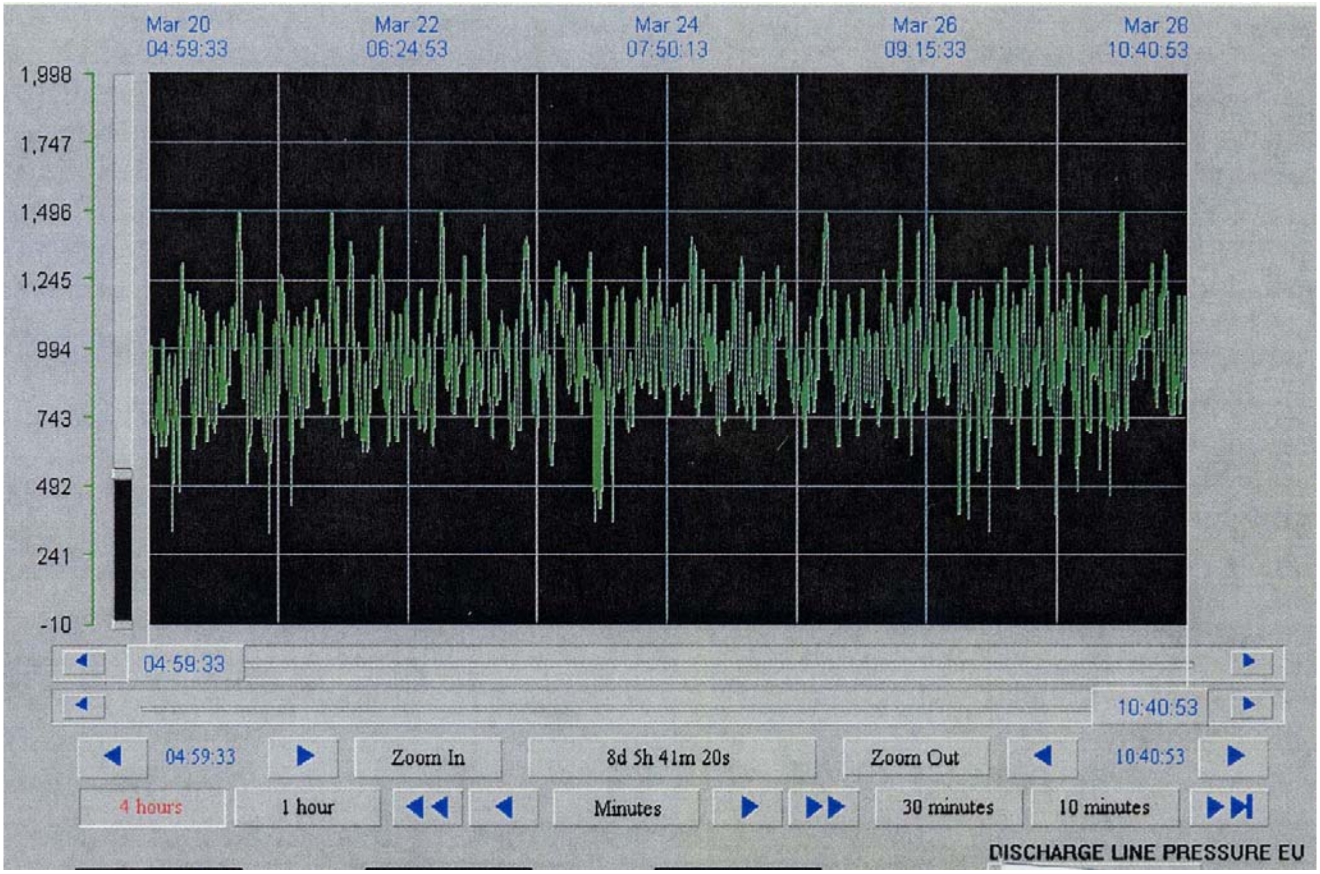


Figure 5.5 Example Pipeline Pressure Chart

The operator must review pressure charts such as the one shown in Figure 5.5, to determine the PSL setting threshold. Federal law prescribes setting PSL alarms on pipelines within 15% of the system operating pressure *range*, so the PSL can be set 15% below the lowest operating pressure of the pipeline. The federal code does not explicitly detail operational methods for determining what the lowest system operating pressure is.

In the study, operators were asked how they determined their pipeline system operating pressure and set their PSLs. Almost uniformly, their first response was an explanation of the significant pressure fluctuations that occur in an offshore pipeline. Widely varying operating pressures occur when wells go on and off production, and if entire platforms are shut in. In addition, the operating pressure of the line varies according to the pipeline pumps in operation at the time. The pipeline operator is clearly challenged to determine average pressures across the fluctuations.

Typically, operators run charts for 2-3 days, taking the lowest pressure that occurs over a period of time to set the PSL. This is estimated (visually) across the chart.

One other practice was revealed. An operator had three platforms all operating at different pressures. To set the PSL on the pipeline, the operator used the lowest of the three platform operating pressures as the average system pressure. This practice would almost certainly reduce the effectiveness of leak detection relying strictly on PSL alarms. However, this operator also relied on CPM methods for monitoring the line.

6.0 DATA ACQUISITION

Sixteen (16) oil and gas operators and 2 gas pipeline transmission companies were invited to contribute pipeline leak incident data and PSL information to the study. A letter of support from the MMS was distributed to a number of companies in an effort to solicit the widest possible support for the project.

Companies that responded favorably and contributed to the study include

- ExxonMobil
- Nuevo
- ChevronTexaco
- BP (Hipps)
- Marathon Oil Company
- Texas Eastern Transmission Co.
- Duke Energy

6.1 Approaches Utilized

At the outset of the project it was believed that PSL alarms could be readily identified in operator's SCADA data, and the incidents of interest could be extracted from those records. Following discussions with several operators it became apparent that some companies did not have SCADA systems (or were in the process of implementing such systems) and that PSL alarm data for these companies would need to be extracted manually, by working through platform records.

Another company indicated that while the alarm events did exist in their SCADA records, the PSL alarms were not labeled or annotated, and it would be very difficult to extract or draw conclusions from those records. One E&P operator indicated that their pipeline company would need to extract the PSL information from their SCADA records.

After these initial discussions it was decided to survey the operators for alarm data rather than to request SCADA records. Table 3 depicts the type of information sought. Surveys requests were followed by telephone contact or personal visits.

While the royalty systems identified in the Gulf of Mexico form a basis for soliciting information regarding systems that potentially employ CPM, it was decided to ask companies to provide information on any leak incident or false alarm, regardless of its location.

The MMS also provided over 2000 pages of incident data. Those data were reviewed to identify pipeline leak events that reported information regarding the PSL.

6.2 Challenges in Data Collection

The principal challenge in collecting data was the reluctance or inability of operators to provide information on pipeline leak events and PSL false alarms. Some operators approached did not have electronic SCADA data. Others either could not provide access to data or did not have data annotated, which meant it would not be possible to tell what triggered the alarm.

In general, false alarm data was more difficult to obtain than PSL event data associated with a leak. This was likely due to the fact that false trips are an operational annoyance, and do not necessarily merit documentation.

Pipelin Leak or EVENT	Year	Pip Diamet	Operati Pressur	Flow Rate	Type Line[1]	PS Setting	Relativ Leak [2]	PSL tripped (Yes or No)	Distance of from platform	Distance of from pressure	Wate Dept	Remark
1	200	6	80	1400	PT	60	VS	No	.3	.3	22	noticed by sheen on
2	200	8	100	4	PT	75	VS	No	.5	.5	17	bubbles detected at
3	200	4	80	1000	PT	70	VS	No	.2	.2	20	detected by mass
4	200	12	120		TT	97	SM	No	8	4 miles to	14	
PSL												
1	200	10	100		PT	80	PSL	YE	na	na	17	PSL tripped due to press
2	200	6	80		PT	50	PSL	YE	na	na	28	False
3	200	12	100		TT	80	PSL	YE	na	na	35	False

Footnotes
1. Type of line refers to line connecting well to platform (WTP), platform to gathering line (PTG) or
2. Relative size of leak refers to very minor (VSM), small (SM), significant and reported

Table 6.1. Example PSL Alarm Data

7.0 PSL DATA SUMMARY

PSL event data from MMS incident reports, MMS databases, and operator information are reviewed and summarized in this section.

7.1 PSLs Identified in MMS Incident Reports

At the outset of the study, all pipeline related incidents reported in the MMS incident database were provided for analysis (MMS, 2001). These data comprised over 2000 pages of reports on incidents recorded since 1969. In addition to data from the MMS incident database, pipeline incident reports for the Pacific Region were also provided.

Eleven events were identified and are summarized as follows:

1. South Pass 65, Shell Pipeline Leak, December, 1996

   No report of cause of the leak. No information on pressure sensors.

2. High Island Pipeline, Galveston Block A-2, February, 1988

   The leak involved a 14-inch segment of High Island pipe system. The operating pipeline pressure at the departing platform ranged from a high of 1228 psig to a low of 8 psig. The high and low-pressure sensors were set at 1350 psig and 770 psig respectively. At the time of the leak, the pipeline operating pressure was 1050 psig. The size of the leak was not large enough to drop the operating pressure below 770 psig, thus activating the low-pressure sensor that would have shut in the pipeline.

3. Exxon, Eugene Island Block 314, May, 1990

   No report of cause of the leak. No information on pressure sensors.

4. Trunkline Gas Company, Ship shoal 90, November, 1992

   The probable cause of the leak was that the 1,070 psig at which the pipeline was operating exceeded the pressure that the pipeline could withstand at the point or origin of the rupture. The equipment that could shut-in the pipeline at the T-25 platform was not in service. This allowed the flow in the pipeline to continue until the pipeline was manually shut in.

5. Hobbit Pipeline, Ship Shoal 281

   At the time of the spill, the primary means of leak detection was the pipeline pressure safety low (PSL) sensor. It was determined that pressure fluctuations within the pipeline system (20 to 500 psig) and hydrostatic pressure of the sea water at the SST leak point (92 psig) as well as the psig setting at the SOI platform in Ship Shoal Block 249 (34 psig) made the detection of a leak of any size impossible.

6. Chevron Pipeline, South Pass Block 38, September, 1998

The leak involved a split rupture in the 10" South Pass 49 Pipeline System. This pipeline serviced multiple platforms. The rupture occurred due to a subsea mudslide following Hurricane George. All platforms were shut in for the oncoming Hurricane. The pipeline rupture was not detected by PSL alarms when production was resumed. A subsequent hydraulic analysis of the pipeline system revealed that the current PSL settings for each of the producers will not automatically shut in flow to the 10" SP pipeline system for all points in the system. The report also indicated a practice of setting PSL alarms based on 15% of the lowest operating pressure rather than an average pressure.

7. Elf Exploration Inc., South Timbalier, Block 38, October, 1991

No report of cause of the leak. No information on pressure sensors.

8. Aera Energy, LLC, Bulk Production Line, June, 1999

Seven small leaks had developed in the bulk production line connecting two platforms. These leaks developed due to internal corrosion. A PSL based leak detection system failed to detect these leaks. While the leak detection system was tested and found adequate to identify small leaks at the time it was installed, company employees stated that efforts to fine-tune the system over the years proved unsuccessful. After many false alarms the system was considered to be an unreliable source of information and, although left on, monitoring the system was more or less abandoned.

9. Torch Operating Company, Platform Irene OCS P0441, December, 1997

A rupture occurred in the 20-inch emulsion pipeline that transports oil and water to shore. The cause of the spill was a broken flange connecting a spool piece to the 20-inch pipeline. Simultaneous with the PSL alarm and alarm was registered for the pig launcher. Since pigging was in progress, the operator focused on the pigging operation rather than suspecting a line leak. The operator reset alarms and resumed production. Subsequent alarms and no product delivery onshore caused attention to be focused on a release, and a sheen was then observed. In this case, the PSL alarm functioned properly but circumstances led the operator to overlook the alarm.

10. Conoco, Inc., East Cameron, March, 1996

A pipeline riser rupture and flashed fire occurred on the 6-inch departing bulk gas pipeline. Analysis of the pipe determined that the failure was due to tensile overload consistent with creep failure. Failure was due to gradual thinning of the pipe wall from corrosion due to breaches in the pipe coating. Fire damage was limited to a charred floatation life ring and a charred section of the CLX electric cable. The PSL sensor actuated and isolated the JB-3 well shut off flow.

11. Chevron USA, East Cameron, July, 1996

The operator noticed pollution near the platform and called it in as a sighting. The pipeline pump shipping oil through a departing pipeline was operating. The operator then noticed an increase in the slick size and stopped the pipeline pump immediately. The pipeline was bled to zero pressure, the pollution stopped, and the riser was repaired. The leak was too small for the pressure safety low to detect.

7.2 MMS Pipeline Database

In addition to the specific incident reports, a number of records in the MMS pipeline database indicated possible PSL events with a pipeline leak. Of the data provided, six records indicated the term “PSL” or “psi”. These records were from pipeline incidents in the 1990s. This supports the fact that prior to recent time, the term PSL was not widely used in incident reporting.

Of the six records identified, the PSL or pressure sensor was reported to have tripped or detected the leak. Some examples of these leaks include:

1. In 1996, a work boat snagged a line and when the operator went to put the line back into service it was reported that the PSL would not allow the line come back on because it had been split open. This leak was 1500 ft from the riser. The pressure setting of the PSL was not given.

2. A jackup derrick barge installing a pipeline set up on top of a pipeline. Bubbles were seen and the PSL on the gas lift line shut in flow to the pipeline. In this case it is not clear whether the main line was oil and whether the main PSL also tripped. The distance of the crushed pipe from the PSL was not reported, nor was the pressure setting reported.

3. A leak was correctly detected in the riser on a platform and was shut in. No details regarding operating pressure or shut in pressure were given.

4. In 1998 an 8” riser shut in on pressure after the line burst at 2750 psig. There were no further details given about this incident.

5. In 2001, there was a gas leak from a gas lift pipeline located about 30 feet from a platform in 17 feet of water. The leak was successfully detected by the PSL and was confirmed visually. There was no report of the pressures at the time of the incident.

6. In 2001 another incident occurred where a MODU snagged a 3” gas lift line between two structures. The PSL on one structure shut-in everything. The pipeline was severed approximately 2500 feet from each structure. There were no details regarding the pressure at the time of the incident.

The databases maintained by the MMS contain extensive records of pipeline leaks and pipeline incidents. Results from this study indicate that very few of the records provide any information regarding the setting of the PSL at the time, whether the PSL activated properly, the system operating pressure at the time of the incident, or the distance between the PSL and the leak.

7.3 Other PSL Alarm Data

Pipeline operators were also surveyed in the study to identify other accidents, related to pipeline leaks or alarms, and the response of associated PSLs. As noted, most operators were reluctant to participate in the study and provide actual PSL data. Only a limited amount of data was obtained from industry and this is recognized as a limitation of this work. Yet, sufficient industry data were available to see trends, and to draw conclusions in the study.

Table 7.1 provides example data obtain from an operator in the Pacific Region. With the exception of the platform Irene incident, these data are all false alarms on oil pipelines. The recurrence of the false alarms in the same line underscores the sensitivity of the PSL to pipeline pressure fluctuations.

Table 7.1 PSL Alarm Data

Event	Length	Diameter	Operating Pressure	PSLSD	
1	22 miles	20”	700 psig	302 psi	*Irene Incident
2	11.8 miles	12”	150 psig	77 psig	
3	6 miles	10”	350 psig	89 psig	
4	11.8 miles	12”	150 psig	77 psig	
5	10.5 miles	12”	220 psig	68 psig	
6	11.8 miles	12”	150 psig	77 psig	

Table 7.2 summarizes operator data for offshore GOM liquid pipeline releases without PSL activation (failure to trip); Table 7.3 summarizes offshore liquid pipeline releases with correct PSL operation and Table 7.4 summarizes offshore liquid pipelines with false alarm data. Table 7.5 and 7.6 summarize offshore GOM gas pipelines with failure to trip and correct PSL operation, respectively.

In some cases, operators were willing to indicate that a PSL event had occurred, but were not willing to share the details of the event. These events are included in the tables with an asterisk (*) even though data were not provided for the event.

Many of the PSL events summarized in Tables 5-9 lack information such as the PSL setting at the time of activation, distance from the PSL, or operating pressure at the time of the event. This incomplete information precluded any statistical analysis of the data.

TABLE 7.2 OFFSHORE LIQUID PIPELINE RELEASES WITHOUT PSL ACTIVATIONS (FAILURE TO TRIP)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	SCADA	CPM	WATER DEPTH
1	2001	11/19/2001	8	600psi	7000	PTG	5 gal	No	143	On Riser			+5 ft
2	2001	10/20/2001	8	800psi	6000	PTG	very small	No	45	1MILE			-220 ft
3	1997	3/24/1997	8	600psi	7000	PTG	very small	No	?	9 miles			-190 ft
4	1988	Feb-88	14	1050psi	3080	PTG	?	No	770	22 mi	Yes		
5	1986	Dec-86	8	not reported	10000	PTG	~23000 bbls	No	no report	0.5 mi		No	-300 ft
6	1990	May-90	8	not reported	12000	PTG	4569 bbls	No	no report	1.2 mi		No	
7	1990	Jan-90	4	20-500	1000	PTG	14423 bbls	No	34 psi	6 mi	Yes		(92 psi)
8	1994	Nov-94	4	20-500	?	PTG	4533 bbls	No	33 psi	6 mi			
9	1998	Sep-98	10	51-150 psi (*)	9901 (*)	T	7765 bbls	No	20-46 psi (*)		Yes		up to -780 ft
10	1991	Oct-91	?	?	?	?	?	?					
11	1999	Jun-99	12	?	?	PTG	small	No	6.5 mi ?	.28-.93 mi			-300 to 500 ft
12	1996	Jul-96	?	?	?		4.7 bbls	No	?	On Riser			-175 ft
13	no details given												
14	no details given												
15	1996	Sep-96	10	956	?	PTG	very small	No	474	riser flange	Yes		-183 ft

TABLE 7.3. OFFSHORE LIQUID PIPELINE RELEASES WITH PSL ACTIVATIONS (CORRECT PSL OPERATION)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	SCADA	CPM	WATER DEPTH
1	1997	12/24/1997	8	750psi	10,000	PTG	large	Yes	?	On Platform			+50 ft
2	1997	Dec-97	20	695	67,800	T	large	Yes	302	5.9 miles			-122 ft
(*)	2000												

TABLE 7.4. OFFSHORE LIQUID PIPELINES WITH FALSE PSL ACTIVATIONS (FALSE ALARMS)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	SCADA	CPM	WATER DEPTH
1	2001		12	150	?	PTG	na	Yes	77	11.6 mi			
2	2001		10	350	?	PTG	na	Yes	89	6 mi			
3	2001		12	150	?	PTG	na	Yes	77	11.8 mi			
4	2001		12	220	?	PTG	na	Yes	68	10.5 mi			
5	2001		12	150	?	PTG	na	Yes	77	11.8 mi			
(*)	no details given												
(*)	no details given												

TABLE 7.5. OFFSHORE GAS PIPELINE RELEASES WITHOUT PSL ACTIVATIONS (FAILURE TO TRIP)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	SCADA	CPM	WATER DEPTH
(*)	no details given												
2	1992	Nov-92		1070		T	large						

TABLE 7.6. OFFSHORE GAS PIPELINE RELEASES WITH PSL ACTIVATIONS (CORRECT PSL OPERATION)

EVENT	YEAR	DATE	NOMINAL PIPE DIAMETER	OPERATING PRESSURE	FLOWRATE (B/D)	TYPE OF LINE	RELATIVE LEAK SIZE	PSL TRIPPED (YES/NO)	PSL Setting psi	DISTANCE FROM PLATFORM	SCADA	CPM	WATER DEPTH
1	1996	Mar-96	6	?	?	PTG	large	Yes	?	on riser			

7.4 Discussion of Other Alarm Data

At the outset of the work it is expected that sufficient PSL data would be made available by industry, and that the data would be analyzed to determine the statistical occurrence of an event (PSL alarm, or failure to alarm), as a function of a particular physical situation (e.g. distance of PSL sensor from the leak). The lack of sufficient PSL incident data precluded such statistical analysis. Nevertheless several observations can be made from the data collected.

Data for the case where a PSL failed to correctly identify leak in liquid lines (Table 7.2) show that the alarms were typically set at only 5-25% of the pipeline operating pressure. This is certainly a contributing factor in the failure of PSLs to correctly detect the leak.

The data in Table 7.2 and 7.3 also suggest that when a leak is greater than seepage and is located on the riser, the PSL will function correctly. Similarly, when an oil leak is sufficiently large, and when pipeline pressure is high relative to the hydrostatic head of the seawater, the leak can be detected by a PSL even if the leak is a significant distance from the PSL.

The data collected also suggest that when there is seepage, for example from the leaking flange on a riser, such a leak cannot be detected by a PSL alarm. Small leaks (pinhole or a minimum size relative to the pressure difference between operating and hydrostatic head) are also unlikely to be detected by a PSL sensor, regardless of their distance from the pressure sensor.

Operator data also supports the belief that PSLs are not reliable for detecting leaks in highly compressible flow, unless the leak is located on the riser and very near the PSL sensor (Tables 7.5 and 7.6).

One instance of flow in a gas line provided evidence that PSLs cannot detect a leak when the hydrostatic head of the seawater exceed the pipeline operating pressure at the point of the system leak.   In this case, the seawater came into the lower pressure gas line, and the influx was only noticed by increase watercut and water salinity at the production facility.

8.0 RELIABILITY ASSESSMENT OF PSL ALARMS

8.1 Fault Tree Analysis

A fault tree analysis is a logical, structured process that can help identify potential causes of system failure before the failures actually occur. It can predict the most likely causes of system failure in the event of system breakdown (Centinkaya, 2001)

In this study fault tree diagrams have been developed for liquid, gas and multiphase to calculate a probability of failure to trip and false trip. Fault tree diagrams are chosen because of the sensitivity of pressure safety lows. Since any small error in hardware or software leads to failure to trip or false trip, analysis should focus on one particular system failure at a time. Fault tree analysis (FTA) is restricted only to the identification of the system events that lead to one particular undesired failure or accident

8.1.1 Fault Tree Construction

The goal of fault tree construction is to model the system conditions that can result in the undesired event. Before the construction of the fault tree can proceed, the analyst must acquire a thorough understanding of the system. In fact, a system description should be part of the analysis documentation. The analyst must carefully define the undesired event under consideration, called the “top event” (Stanek, 1980)

8.1.2 Symbols

Gate symbols are used to connect events according to their casual relations. A gate may have one or more input events but only one output event. Table 8.1 illustrates different types of gate symbols. Event symbols show specific types of fault and normal events in fault tree analysis. Table 8.2. summarizes event symbols. (Stanek, 1980; Henley and Kumamoto, 1981).

8.1.3 Construction Methodology

A fault tree is structured so that the sequence of events that lead to the undesired event are shown below the top event and are logically related to the undesired event by OR and AND gates. Figure 8.1 shows how a fault tree grows from the top event to basic events or vice versa. The input events to each logic gate that are also outputs of other logic gates at a lower level are shown as rectangles. These events are developed further until the sequence of events lead to basic causes of interest, called “basic events”. The basic events appear as circles and diamonds on the bottom of the fault tree and represent the limit of resolution of the fault tree.

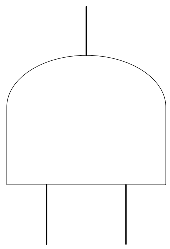
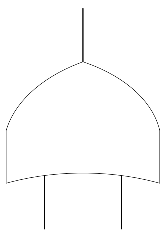
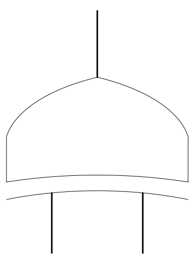
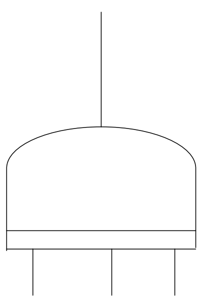
Fault Tree Symbol	Name	Definition
	AND gate	Output event occurs if all input events occur simultaneously.
	OR gate	Output event occurs if any one of the input events occur.
	Exclusive OR gate	Output event occurs if one, but not both, of the input events occur.
	Priority AND gate	The output event occurs when all of the input events occur and in proper sequence.

Table 8.1 Gate symbols and their description (Henley and Kumamoto, 1981, 1985)

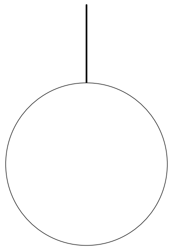
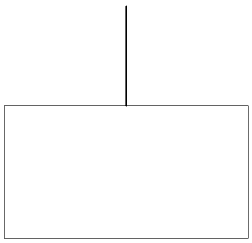
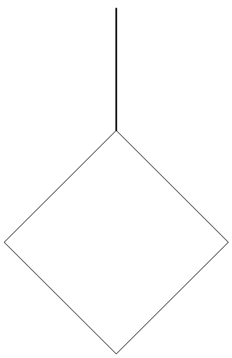
Fault Tree Symbol	Name	Definition
	Circle	Basic component or system failure event. The circle defines a basic inherent failure of a system element when operated within its design specifications. It is therefore a primary failure, and is also referred to as a generic failure.
	Rectangle	State of system or component event .The rectangle defines an event that is the output of a logic gate and is dependent on the type of logic gate and the inputs to the logic gate.
	Diamond event	This is an undeveloped event due to lack of information, money or time. The diamond represents a failure, other than a primary failure that is purposely not developed further.

Table 8.2 Event symbols and their description (Henley and Kumamoto, 1981, 1985)

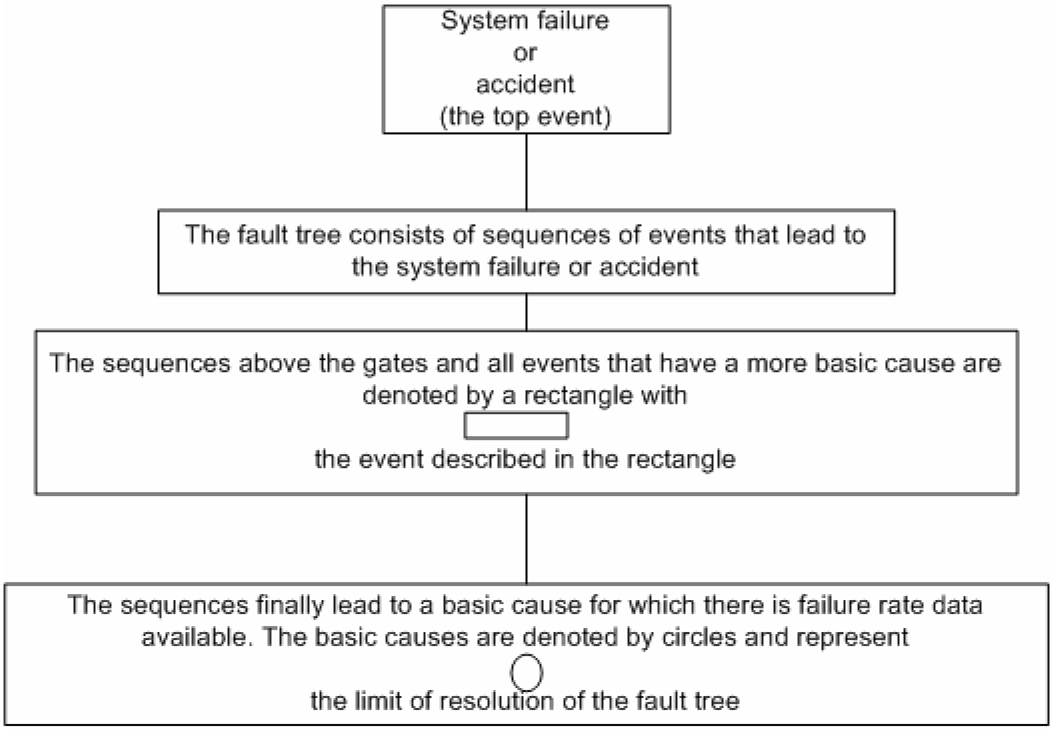


Figure 8.1 Fundamental structures of fault tree (Centinkaya, 2001)

8.1.4 Structuring Process

The structuring process is used to develop fault flows in a fault tree when a system is examined on a functional basis, i.e., when failures of system elements are considered. At this level, schematics, piping diagrams, process flow sheets, etc., are examined for cause and effect types of relationships to determine the subsystem and component fault states that can contribute to the occurrence of the undesired event (Centinkaya, 2001)

The structuring process identifies three failure mechanism or causes that can contribute to a component being in a fault state.

1. A primary failure is a failure due to the internal characteristics of the system element under consideration.
2. A secondary failure is a failure due to excessive environmental or operational stress placed on the system element

8.2 Reliability Theory

In performing the reliability analysis of a complex system, it is almost impossible to treat the system in its entirety. The logical approach is to divide the system into functional entities composed of units, subsystems, or components. The subdivision generates a fault tree diagram of system operation. Models are then formulated to fit this logical structure, and the probability theory is used to find the system reliability. Series and parallel structures often occur, and their reliability can be described very simply (Shooman, 1968; Stanek, 1980; Barlow et. al, 1993).

The random variable **t** is defined as the failure time of the item in question. Thus, the probability of failure as a function of time is given as

$$P(t \leq t) = F(t) \qquad (1)$$

which is simply the definition of failure distribution function. We can define reliability, which is a probability of success in terms of F (t), as

$$R(t) = P_S(t) = 1 - F(t) = P(t \leq t) \qquad (2)$$

The simplest and most common reliability function is an exponential,

$$R(t) = e^{-\lambda t} \qquad (3)$$

where R stands for system reliability**.** **λ** is failure rate defined as the ratio of the number of failures per unit time to the number of components that are exposed to failure.

Series Reliability

Any system in which the system success depends on the success of all its components is a series system.

The event signifying the success of nth unit will be x_n , and $\bar{x}_n$ will represent the failure of the *n*th unit. The probability that unit *n* is successful will be P (x_n). The probability of system success is denoted by P_S . In keeping with definition of reliability, P_S = R. The probability of system failure is

$$P_f = 1 - P_S \qquad (4)$$

Since the series system requires that all units operate successfully for system success, the event representing system success is intersection of $x_1, x_2, \ldots, x_n$ .The reliability of this structure is given by

$$R(t) = P(x_1, x_2, \cdots, x_n) = P(x_1)P(x_2 / x_1)P(x_3 / x_1 x_2) \cdots P(x_n / x_1 x_2 \cdots x_{n-1})$$

If the *n* items $x_1, x_2, \ldots x_n$ are independent, then

$$R(t) = P(x_1, x_2, \ldots, x_n) = \prod_{i=1}^{n} P(x_i) \qquad (6)$$

If each component exhibits a constant hazard, then the appropriate component model is $e^{-\lambda_i t}$, and Eq. (6) becomes

$$R(t) = \prod_{i=1}^{n} e^{-\lambda_i t} = \exp\left(-\sum_{i=1}^{n} \lambda_i t\right) \tag{7}$$

Eq. (3) is the most commonly used and the most elementary system reliability formula.

Parallel Reliability

If the system is such that failure of one or more paths still allows the remaining path to perform properly, the system can be represented by a parallel model. The reliability expression for a parallel system may be expressed in terms of the probability of success of each component or, more conveniently in terms of probability of failure.

$$R(t) = P(x_1 + x_2 + \cdots + x_n) = 1 - P(\overline{x}_1 \overline{x}_2 \cdots \overline{x}_n) \tag{8}$$

In the case of constant –hazard components, $P_f = P(\overline{x}_i) = 1 - e^{-\lambda_i t}$, and Eq.(8) becomes

$$R(t) = 1 - [\prod_{i=1}^{n} (1 - e^{-\lambda_i t}) \tag{9}$$

In general case, the system reliability function is

$$R(t) = 1 - [\prod_{i=1}^{n} (1 - e^{-Z_i t}) \tag{10}$$

Now one can find the reliability of a simple system with a knowledge of fault tree analysis and reliability. As an example, Figure 8.2 shows a circuit controlling a motor. The top event is a failure of the motor to start. The causes are named A, B, C and D and represent the following.

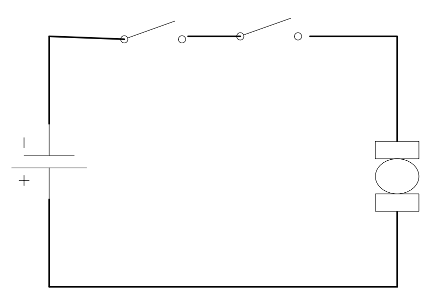


Figure 8.2 Description of circuit controlling motor (Centinkaya, 2001)

A – Motor fails to start
B- Circuit fails to supply current to motor
C- Motor seizure due to inadequate lubrication of bearings
D- Motor casing cracks due to excess temp or external vibration

Either one of the above events will lead to top event. Now using the FTA method, the fault tree is shown in Figure 8.3.

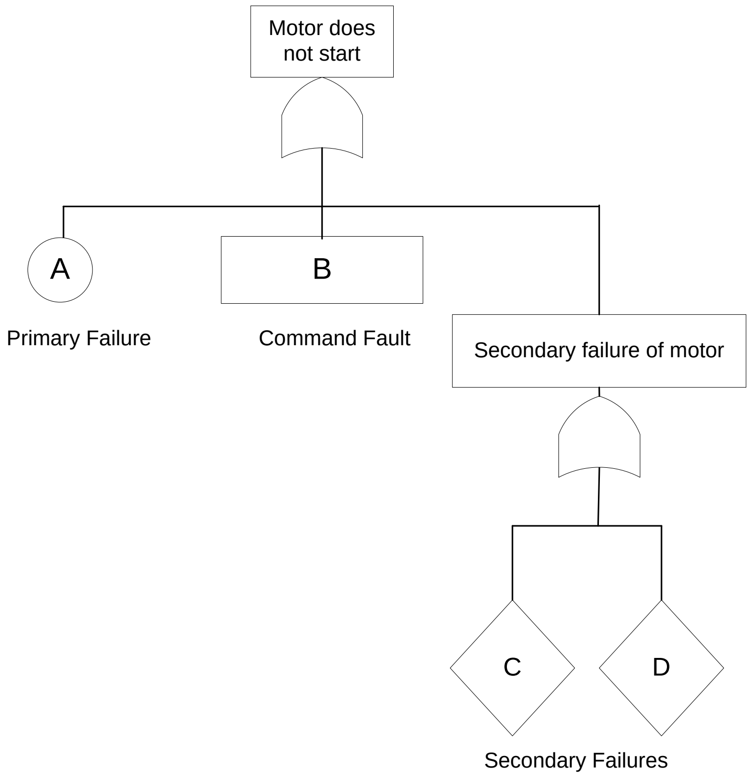


Figure 8.3 Fault tree showing development of state-of-component fault event

Failure probability values were taken from Henley and Kumamoto, (1981, 1985, 1992) and used to compute the total system reliability. The probability of the motor failing to start is:

$$q_{system} = (1 - P_A) \times ((1 - P_C) \times (1 - P_D)) \times (1 - P_B)$$

which is 0.00015. The same principles are used to calculate failure probabilities for PSLs in pipeline leak detection.

Basic events	Probability of failure(q) Unreliability	Reliability (p) (1- unreliability)
A	0.3	0.7
B	0.2	0.8
C	0.05	0.95
D	0.05	0.95

Table 8.3 Reliabilities of components of a simple motor system

8.3 Reliability Analysis of PSLs

Eighteen fault tree analyses (FTA) were performed to predict the probabilities of either a failure to trip a PSL alarm in the presence of a leak or a PSL trip when no leak was present (false alarm). Each case is considered for liquid flow, gas flow and multiphase flow with three possible leak monitoring systems - PSL only, mass flow system only or a combination of mass flow and PSL. Table 8.4 summarizes these cases.

Monitoring System:	**Flow Type:**					
	Gas	Liquid	Multi	Gas	Liquid	Multi
PSL	X	X	X	X	X	X
MFS	X	X	X	X	X	X
PSL/MFS	X	X	X	X	X	X
Malfunction:	← Failure to trip →			← False trip →		

Table 8.4 Matrix of FTA Pipeline Cases

It can be seen that nine cases are examples of failure to trip with a leak present and nine cases are examples of false trips. The nine fault tree diagrams for failure to trip will have many similarities. The same can be said of the nine fault tree diagrams for false trips.

8.3.1 Basic Events

The eighteen fault tree diagrams will share a great many basic events. It is useful to define all of the basic events before examining the fault tree diagrams. Table 8.5 has a list of the 22 basic events with a definition of the event, the Mean Time To Failure (MTTF) and the Mean Time To Repair (MTTR), the unavailability (Q) plus the source of the data.

Fault tree diagram symbols are shown in Tables 8.1 and 8.2 with definitions of each symbol.

Mean time to failure is defined as the expected value of the time to failure. In the case of the exponential distribution this is equal to the reciprocal of the failure rate. If a failure occurs in every one million hours for a component, it is said that the component has a failure of 1*10^-6 failures/hour. The MTTF is reciprocal of failure rate. The failure rates used in this thesis have constant failure rates. If the failure rates have different distributions, then the MTTF is found according to the corresponding distribution.

$$MTTF = \frac{1}{\lambda}$$

Mean time to repair is the expected value of the time to repair.

$$MTTR = \frac{1}{\mu}$$

Availability is the probability of finding the component/device/system in the operating state at some time in the future.

$$Availability = \frac{MTTF}{MTTF + MTTR} = \frac{\mu}{\mu + \lambda}$$

Unavaibality is the probability of finding a component or system in the non-operating state at some time in the future.

$$Unavailability(q) = \frac{MTTR}{MTTR + MTTF} = \frac{\lambda}{\lambda + \mu}$$

Event #	Definition	MTTF (hrs)	MTTR (hrs)	q	Source
1	Pipeline leak due to corrosion	4.09*10^9	72	1.75*10^-8	a,c
2	Pipeline leak due to third party	4.09*10^9	72	1.75*10^-8	a,c
3	Pipeline leak due to earth movement	0	72	0	d
4	Pipeline leak due to weld failure	3.31*10^9	72	2.16*10^-8	a,c
5	Pipeline leak due to valve failure	17.52*10^9	72	4.109810^-9	a,c
6	Pipeline leak due to material failure	0	72	0	d
7	Pressure sensors fail to detect low (gas) pressure in pipeline	87600	11.6	1.32*10^-4	a,d
8	Communications link failure between PSL and control computer	0		0.01	a
9	Safety shut off valve (SSV) fails to close	292000	0.8	2.74*10^-6	a
10	Computer fails to trip SSV	8156	4.1	5.02*10^-4	a
11	Communications link failure between computer and SSV			0.01	a
12	Failure of (gas) Mass Flow Sensor 1 (MFS 1)	7684	11.6	1.507*10^-3	a,c
13	Failure of (gas) Mass Flow Sensor 2 (MFS 2)	7684	11.6	1.507*10^-3	a,c
14	Communication link failure between MFS 1 and computer			0.01	a
15	Communication link failure between MFS 2 and computer			0.01	a
16	Pressure sensor signal goes low	876000	11.6	1.32*10^-5	a,c
17	Pressure sensor fails to detect low (liquid) pressure in pipeline	4000	11.6	0.00289	a
18	Pressure sensor fails to detect low pressure (multiphase) in pipeline	800	11.6	0.143	a
19	Failure of (liquid) mass flow sensor 1 (MFS 1)	7684	11.6	1.507*10^-3	a,c
20	Failure of (liquid) mass flow sensor 2 (MFS 2)	7684	11.6	1.507*10^-3	a,c
21	Failure of (multiphase) mass flow sensor 1 (MFS 1)	7684	11.6	1.507*10^-3	a,c
22	Failure of (multiphase) mass flow sensor 2 (MFS 2)	7684	11.6	1.507*10^-3	a,c

a) OREDA: 1977 Offshore Reliability Data.
b) Mulbauer: Pipeline Risk Management Manual.
c) Henley & Kumamoto: Probabilistic Risk Assessment.
d) Estimated

Table 8.5 Basic Event Data

Table 8.5 gives the basic events that must be considered within the various fault tree diagrams. In this list of failures, events one to six are the various causes for a leak in pipeline. Events 7, 12, 13 and 16 are sensor failures. Events 8, 14 and 15 are communications link failures between sensors and the control computer. Events 9, 10 and 11 relate to failure to close safety shut-off valves (SSV's) due to SSV, communications link or computer failures.

8.3.2 Development of the Fault Trees for Gas Flow Pipelines

Fault tree diagrams have been developed for a gas pipeline for three different systems [3]: Pressure Sensor Low (PSL only), Mass Flow System (MFS only) and Dual PSL and MSF leak protection. For each type of system a pair of fault trees is developed, one for a top event where a leak occurs but it is not detected, and one for top event where no leak has occurred but a false trip takes place.

Figure 8.4 shows a fault tree diagram for a gas pipeline protected by a mass flow or line balance system (MFS) in which the top event is a failure to trip with a leak present. The top event occurs when there is a leak AND either the system fails to detect the leak, OR the safety shut- off valves fail to close.

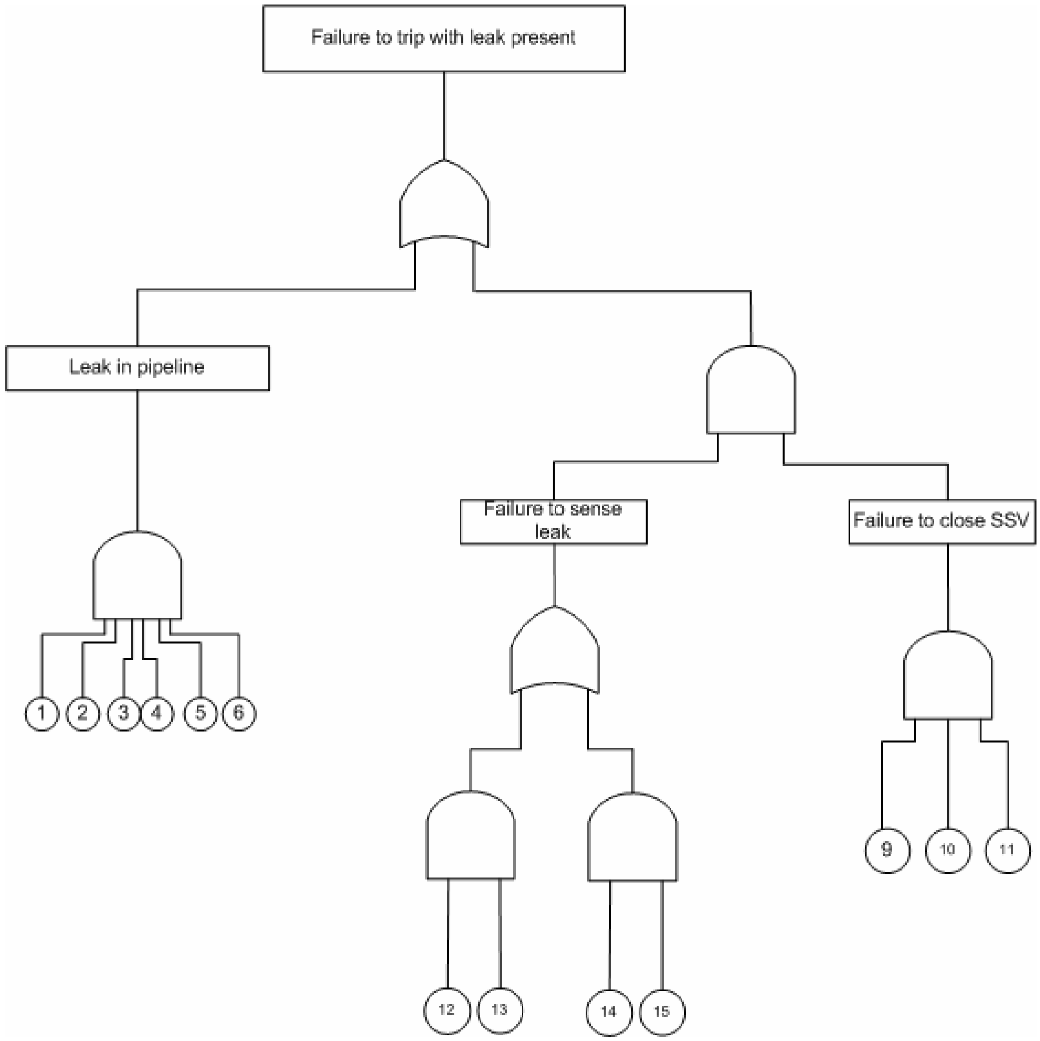


Figure 8.4 Gaseous Flow – Failure to trip with leak present – MFS only

The system will fail to sense a leak if there is a simultaneous loss of mass flow signals either due to sensor failures OR communication links from the computer to the SSV fail to causing the top event.

Figure 8.5 shows a fault tree diagram for a gas flow pipeline protected by a mass flow system (MFS). The top event is a false trip. The top event occurs when either mass flow sensor (MFS1) OR mass flow sensor 2 (MFS2) OR the communications links between MFS1 and the computer OR the communication link between MFS2 and the computer fails

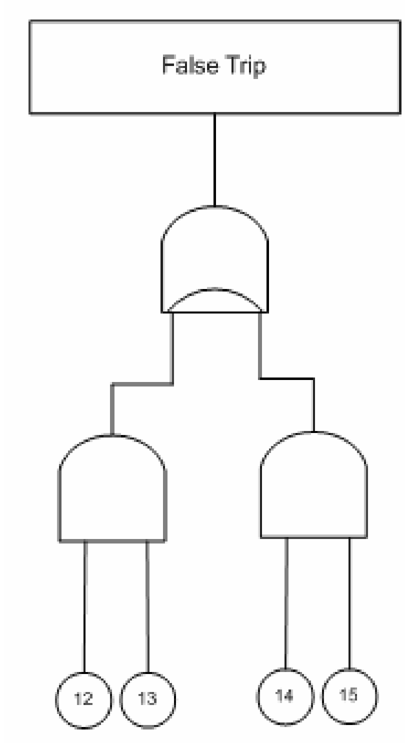


Figure 8.5 Gaseous Flow-False Trip –MFS only

Figure 8.6 shows a fault tree diagram for a gas pipeline protected by a pressure sensor (safety) low (PSL) in which the top event is a failure to trip with a leak present. The top event occurs when there is a leak present AND either the system fails to detect a leak OR the safety shut-off valve(s) fail to close.

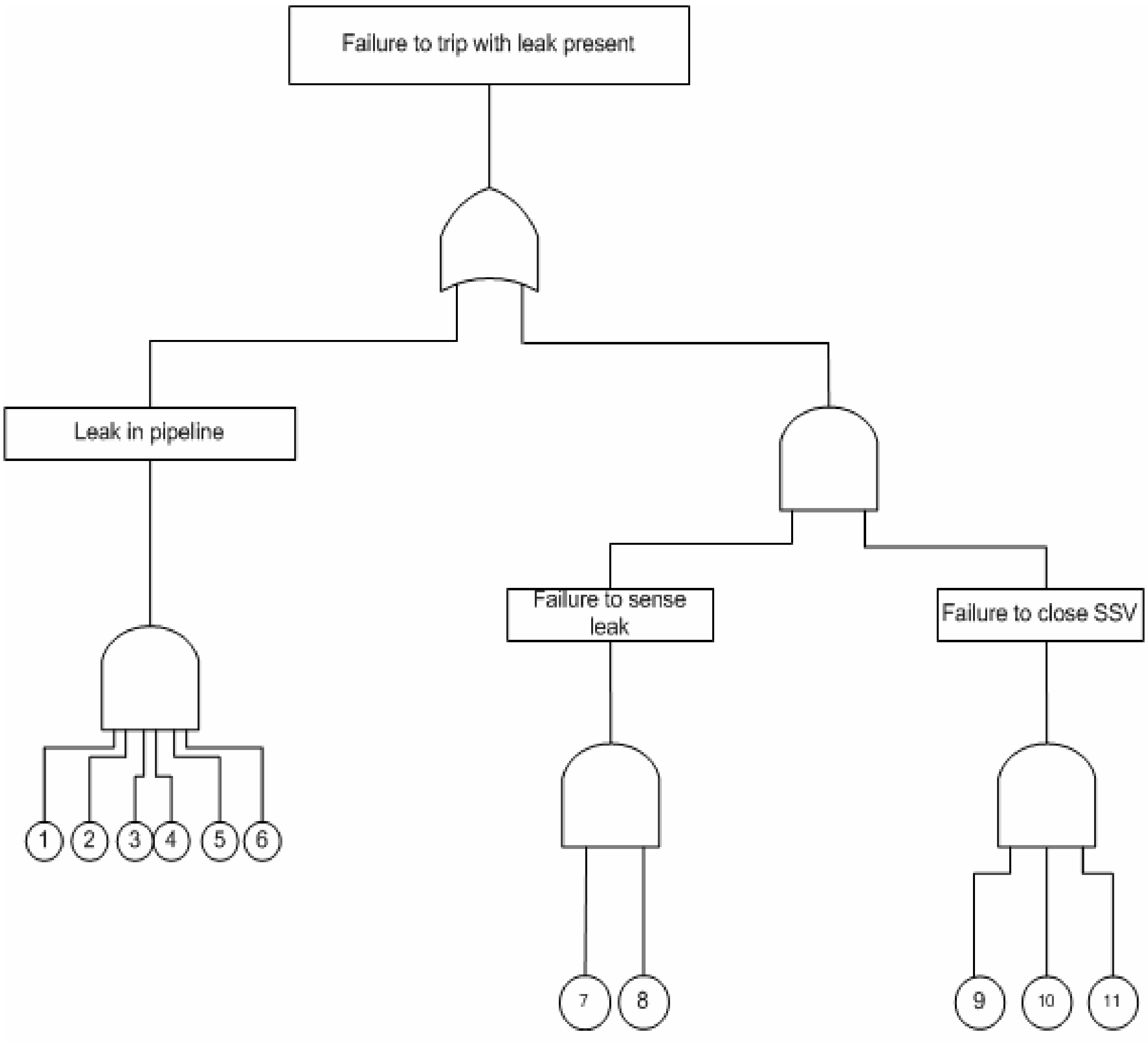


Figure 8.6 Gaseous Flow – Failure to trip with leak present – PSL only

The system will fail to sense a leak if the PSL fails to detect low pressure in the pipeline OR the communication link from the PSL to the computer fails in an unsafe mode OR the safety shut-off valves fail to close for one of the reasons outline above. It is assumed that either of these two scenarios can occur in conjunction with a leak in the pipeline to cause the top event.

Figure 8.7 shows a fault tree diagram for a gas flow pipeline protected by a pressure sensor low (PSL) system. The top event is a false trip. The top event occurs when either the pressure sensor low OR the communication link between the PSL and the computer fails.

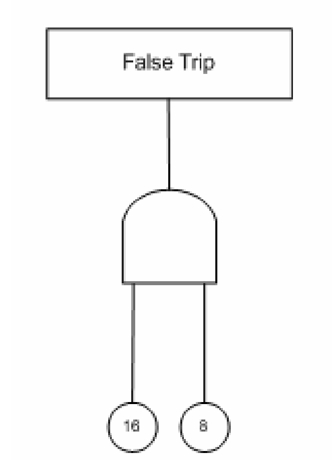


Figure 8.7 Gaseous Flow-False Trip –PSL only

Figure 8.8 shows a fault tree diagram for a gas flow pipeline protected by a combination of a mass flow system (MFS) and a pressure sensor low (PSL) system. Either system can sense a leak and trip the SSV's. The top event is a failure to trip with a leak present. The top event occurs when there is a leak present AND either the MFS/PSL system fail to detect a leak, OR the safety shut-off valves fail to close.

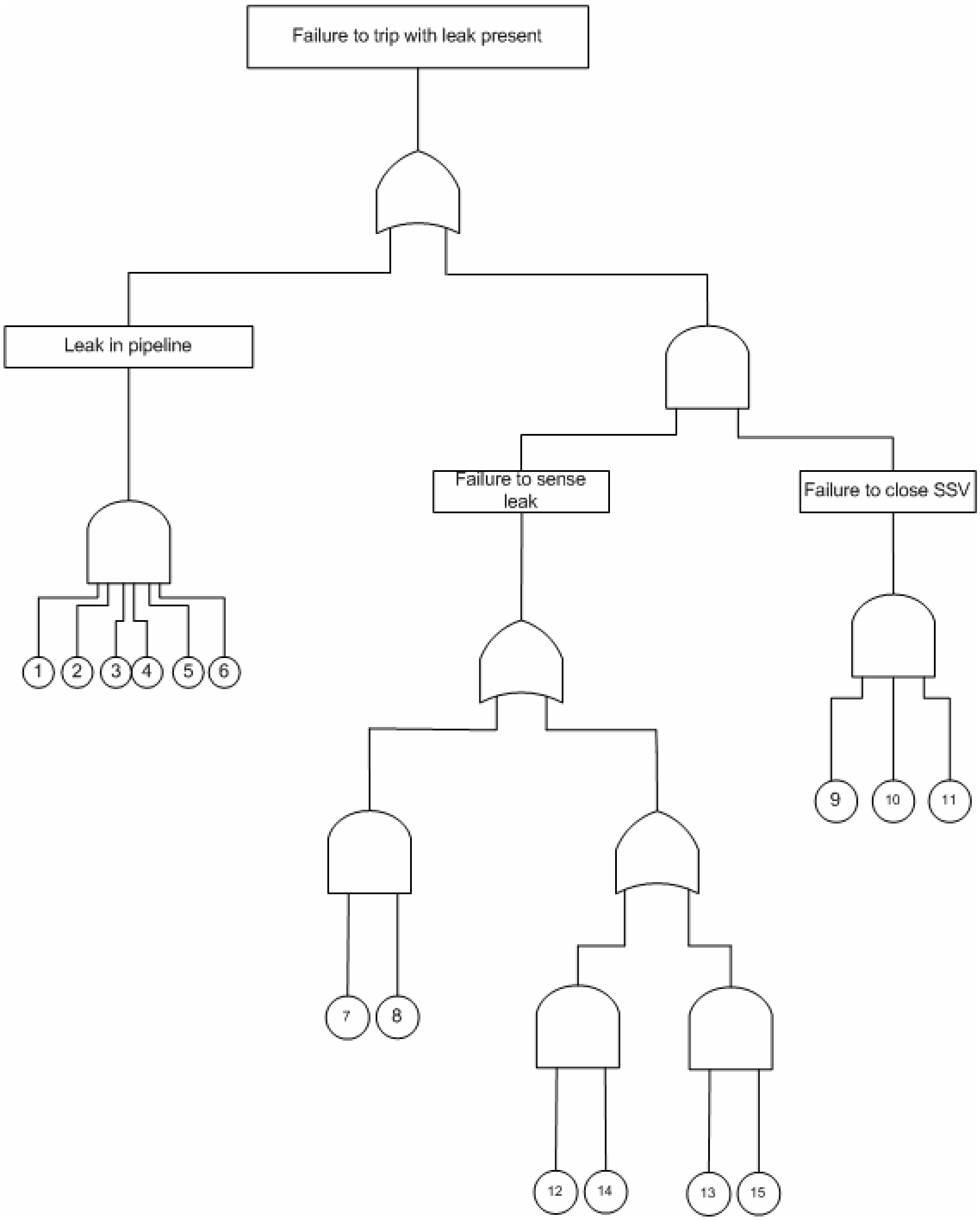


Figure 8.8 Gaseous Flow – Failure to trip with leak present – PSL/MFS only

The system will fail to sense a leak if both the MFS and PSL systems fail as outlined for the fault trees of Figures 8.4 and 8.5. The system will also fail if the safety shut-off valve(s) fail to close for one of the reasons outlined above. Either of these two scenarios can occur in conjunction with a leak in the pipeline to cause the top event.

Figure 8.9 shows a fault tree diagram for a gas flow pipeline protected by a combination of an MFS and a PSL system. The top event is a false trip. The top event occurs when either the MFS OR the PSL causes a trip without a leak present. The top event will occur when either the PSL fails OR the communication link from the PSL to the computer OR the mass flow sensor1 OR the mass flow sensor 2 OR the communication link between MFS1 and the computer OR the communication link between MFS2 and the computer fails.

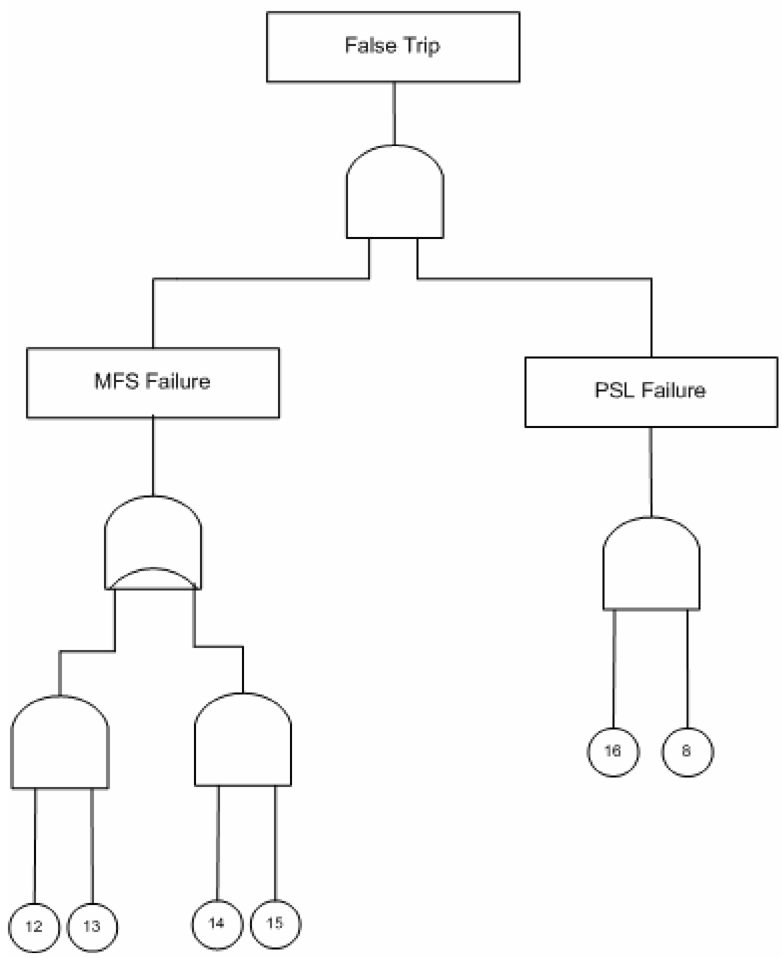


Figure 8.9 Gaseous Flow-False Trip –PSL/MFS

Basic probabilities for each of the failure events will be used to calculate probability of the top event occurring in Figures 8.4 through 8.9

8.3.3 Development of the Fault Trees for Liquid Flow Pipelines

Fault tree diagrams have been developed for a liquid flow pipeline for three different systems: Pressure Sensor Low (PSL only), Mass Flow System (MFS only) and Dual PSL and MSF leak protection. For each type of system a pair of fault trees is developed, one for a top event where a leak occurs but it is not detected, and one for top event where no leak has occurred but a false trip takes place.

Within the various fault tree diagrams, the basic events that must be considered are given in Table 8.5.

Figure 8.10 shows a fault tree diagram for a liquid pipeline protected by a mass flow or line balance system (MFS) in which the top event is a failure to trip with a leak present. The top event occurs when there is a leak AND either the system fails to detect the leak, OR the safety shut- off valves fail to close.

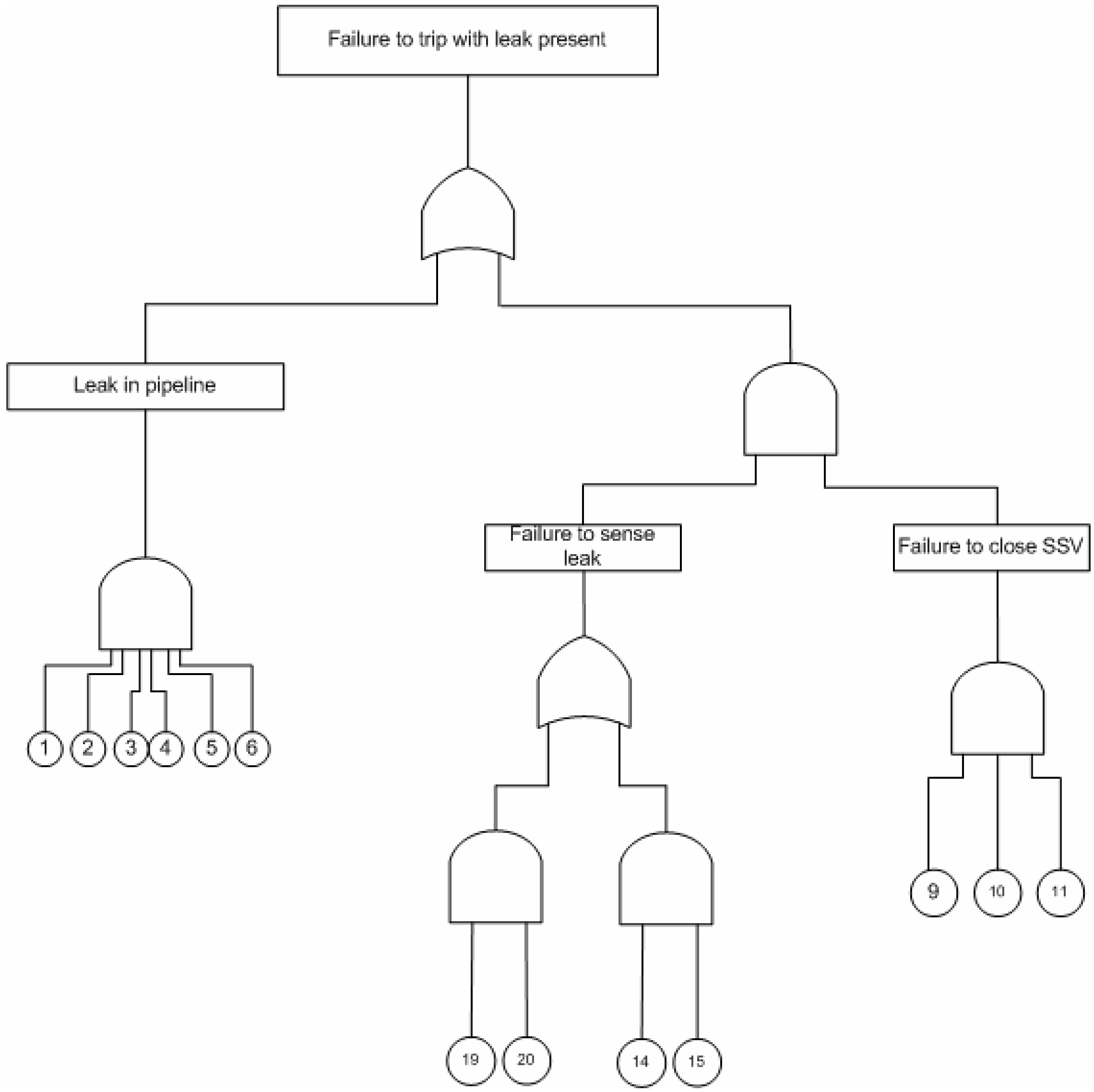


Figure 8.10 Liquid Flow – Failure to trip with leak present – MFS only

The system will fail to sense a leak if there is a simultaneous loss of mass flow signals either due to sensor failures OR communication link from the computer to the SSV fail, resulting in the top event.

Figure 8.11 shows a fault tree diagram for a liquid flow pipeline protected by a mass flow system (MFS). The top event is a false trip. The top event occurs when either mass flow sensor (MFS1) OR mass flow sensor 2 (MFS2) OR the communications links between MFS1 and the computer OR the communication link between MFS2 and the computer, fails.

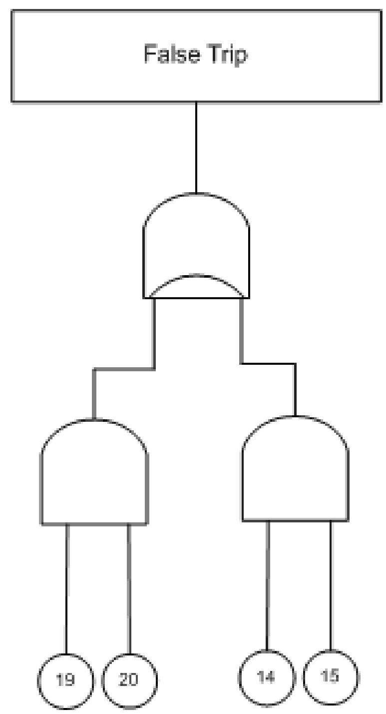


Figure 8.11 Liquid Flow-False trip –MFS only

Figure 8.12 shows a fault tree diagram for a liquid flow pipeline protected by a pressure sensor (safety) low (PSL) in which the top event is a failure to trip with a leak present. The top event occurs when there is a leak present AND either the system fails to detect a leak OR the safety shut-off valve(s) fail to close.

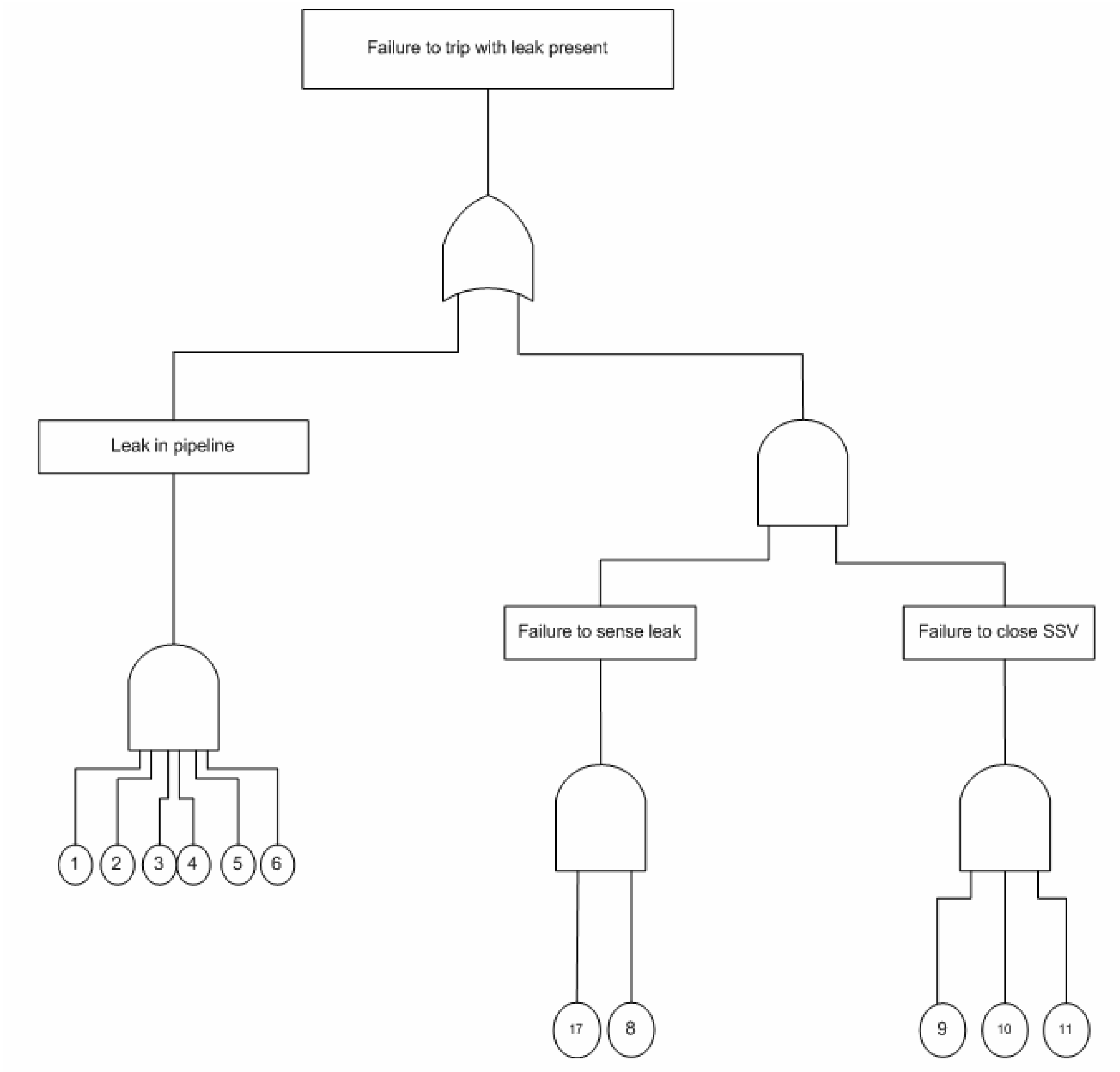


Figure 8.12 Liquid Flow – Failure to trip with leak present – PSL only

The system will fail to sense a leak if the PSL fails to detect low pressure in the pipeline OR the communication link from the PSL to the computer fails in an unsafe mode OR the safety shut-off valves fail to close for one of the reasons outline above. It is assumed that one of these three scenarios can occur in conjunction with a leak in the pipeline to cause the top event.

Figure 8.13 shows a fault tree diagram for a liquid flow pipeline protected by a pressure sensor low (PSL) system. The top event is a false trip. The top event occurs when either the pressure sensor low OR the communication link between the PSL and the computer fails.

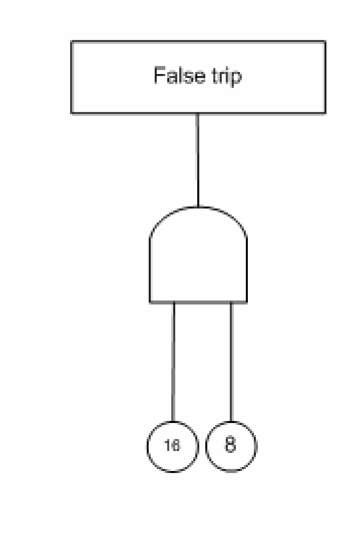


Figure 8.13 Liquid Flow-False trip –PSL only

Figure 8.14 shows a fault tree diagram for a liquid flow pipeline protected by a combination of a mass flow system (MFS) and a pressure sensor low (PSL) system. Either system can sense a leak and trip the SSV’s. The top event is a failure to trip with a leak present. The top event occurs when there is a leak present AND either the MFS/PSL system fails to detect a leak, OR the safety shut-off valves fail to close.

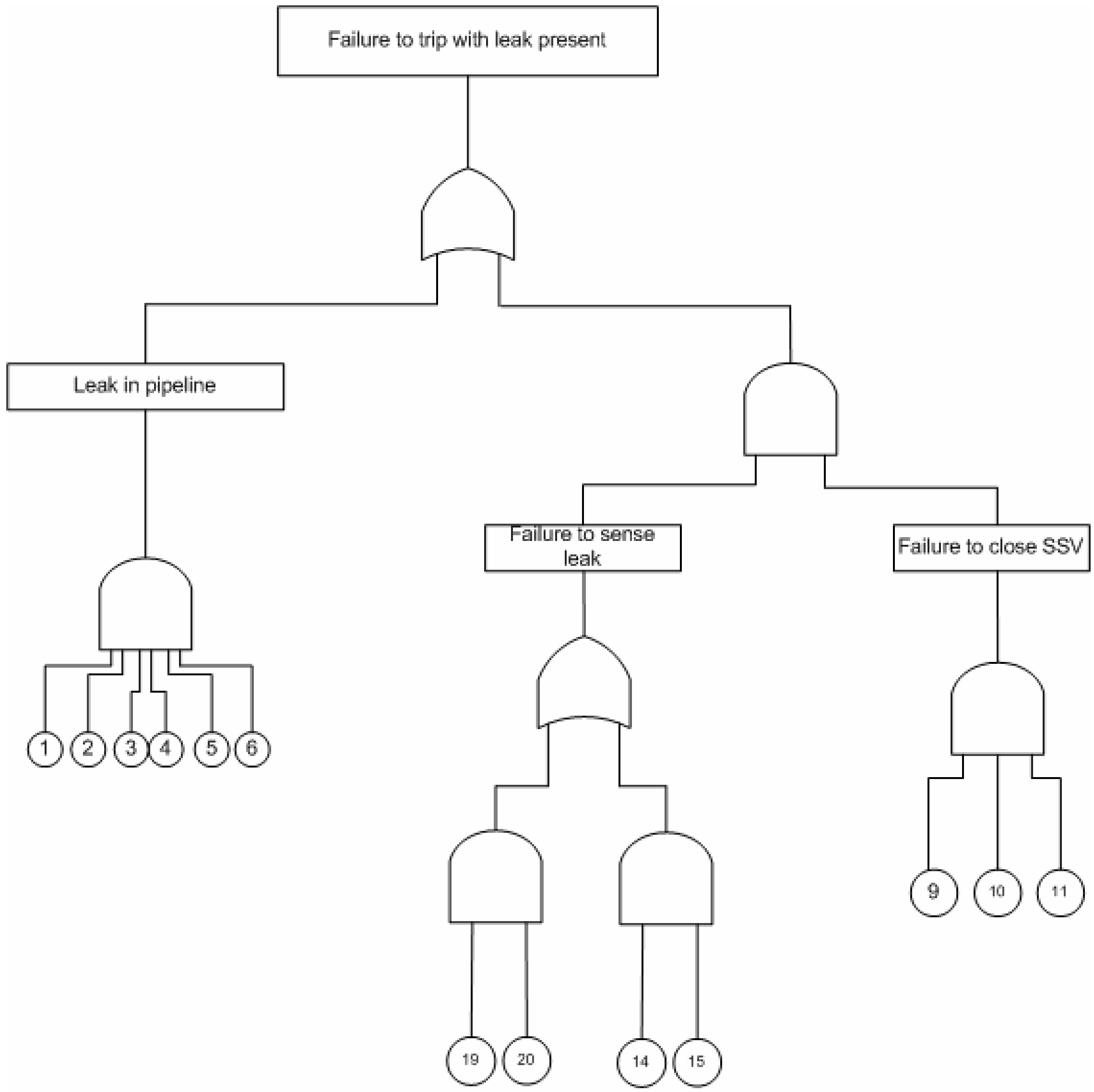


Figure 8.14 Liquid Flow – Failure to trip with leak present –PSL/ MFS only

The system will fail to sense a leak if both the MFS and PSL systems fail as outlined for the fault trees of Figures 8.10 and 8.11. The system will also fail if the safety shut-off valve(s) fail to close for one of the reasons outlined above. Either of these two scenarios can occur in a conjunction with a leak in the pipeline to cause the top event.

Figure 8.15 shows a fault tree diagram for a liquid flow pipeline protected by a combination of an MFS and a PSL system. The top event is a false trip. The top event occurs when either the MFS fails OR the PSL fails. The top event will also occur when either the PSL fails OR the communication link form the PSL to the computer OR the mass flow sensor1 OR the mass flow sensor 2 OR the communication link between MFS1 and the computer OR the communication link between MFS2 and the computer, fails.

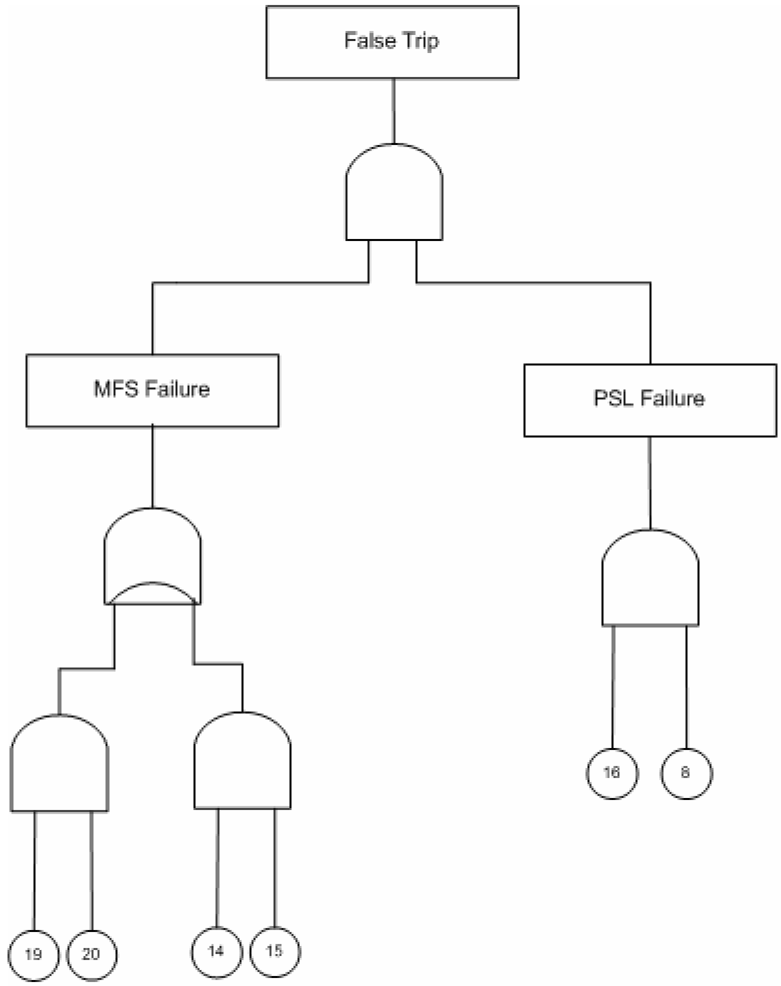


Figure 8.15 Liquid Flow-False trip –PSL/MFS

Basic probabilities for each of the failure events will be used to calculate probability of the top event occurring in Figures 8.10 through 8.15.

8.3.4 Development of the Fault Trees for Multiphase Flow Pipelines

Fault tree diagrams have been developed for a multiphase flow pipeline for three different systems: Pressure Sensor Low (PSL only), Mass Flow System (MFS only) and Dual PSL and MSF leak protection. For each type of system a pair of fault trees is developed, one for a top event where a leak occurs but it is not detected, and one for top event where no leak has occurred but a false trip takes place.

Within the various fault tree diagrams, the basic events that must be considered are given in Table 8.5.

Figure 8.16 shows a fault tree diagram for a multiphase flow pipeline protected by a mass flow or line balance system (MFS) in which the top event is a failure to trip with a leak present. The top event occurs when there is a leak AND either the system fails to detect the leak, OR the safety shut- off valves fail to close.

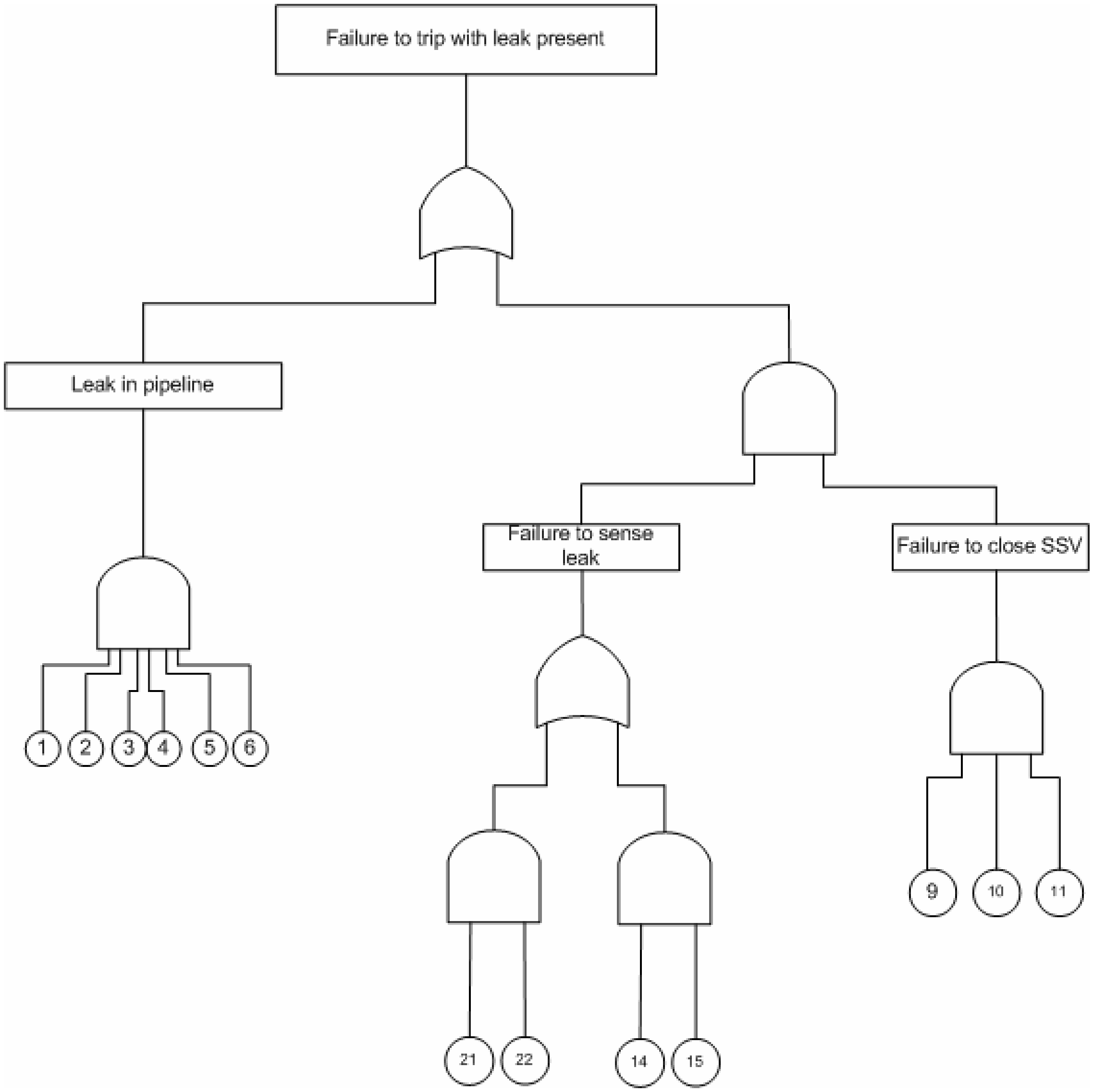


Figure 8.16 Multiphase Flow – Failure to trip with leak present – MFS only

The system will fail to sense a leak if there is a simultaneous loss of mass flow signals either due to sensor failures or failures in the communication link between the sensors and the computer. The system will also fail if the communication link from the computer to the SSV fails; either scenario will result in the top event.

Figure 8.17 shows a fault tree diagram for a multiphase flow pipeline protected by a mass flow system (MFS). The top event is a false trip. The top event occurs when either mass flow sensor

(MFS1) OR mass flow sensor 2 (MFS2) OR the communications links between MFS1 and the computer OR the communication link between MFS2 and the computer fails.

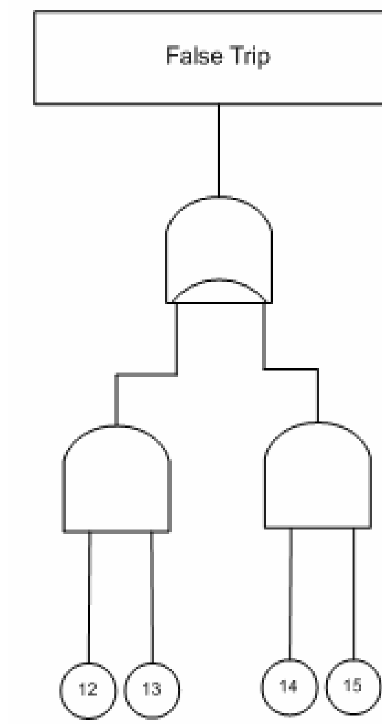


Figure 8.17 Multiphase Flow-False trip –MFS only

Figure 8.18 shows a fault tree diagram for a multiphase flow pipeline protected by a PSL in which the top event is a failure to trip with a leak present. The top event occurs when there is a leak present AND either the system fails to detect a leak OR the safety shut-off valve(s) fail to close.

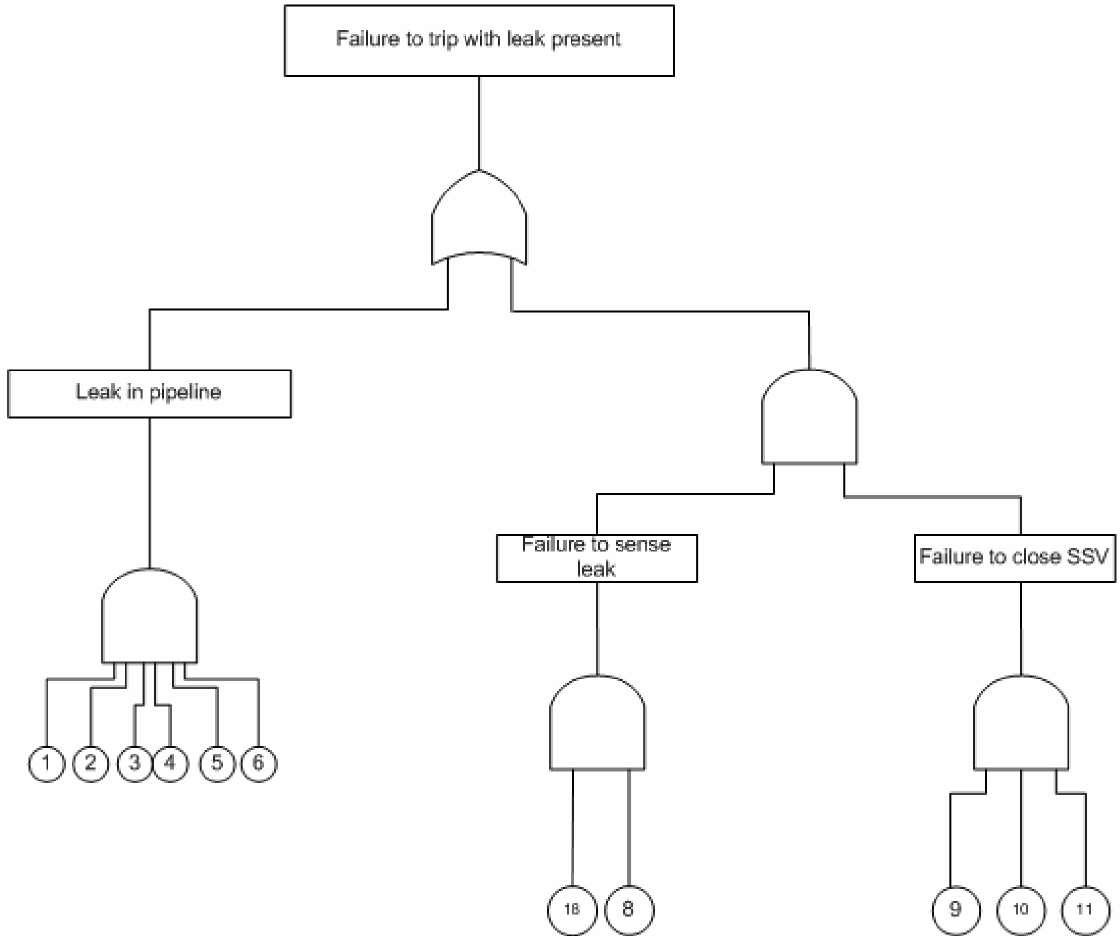


Figure 8.18 Multiphase Flow – Failure to trip with leak present – PSL only

The system will fail if the PSL fails to detect low pressure in the pipeline OR the communication link from the PSL to the computer fails in an unsafe mode OR the safety shut-off valves fail to close for one of the reasons outline above. It is assumed that one of these three scenarios can occur in conjunction with a leak in the pipeline to cause the top event.

Figure 8.19 shows a fault tree diagram for a multiphase flow pipeline protected by a pressure sensor low (PSL) system. The top event is a false trip. The top event occurs when either the pressure sensor low OR the communication link between the PSL and the computer, fails.

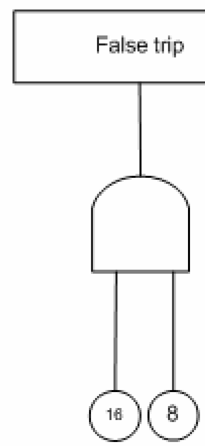


Figure 8.19 Multiphase Flow-False trip –PSL only

Figure 8.20 shows a fault tree diagram for a multiphase flow pipeline protected by a combination of a mass flow system (MFS) and a pressure sensor low (PSL) system. Either system can sense a leak and trip the SSV's. The top event is a failure to trip with a leak present. The top event occurs when there is a leak present AND either the MFS/PSL system fails to detect a leak, OR the safety shut-off valves fail to close.

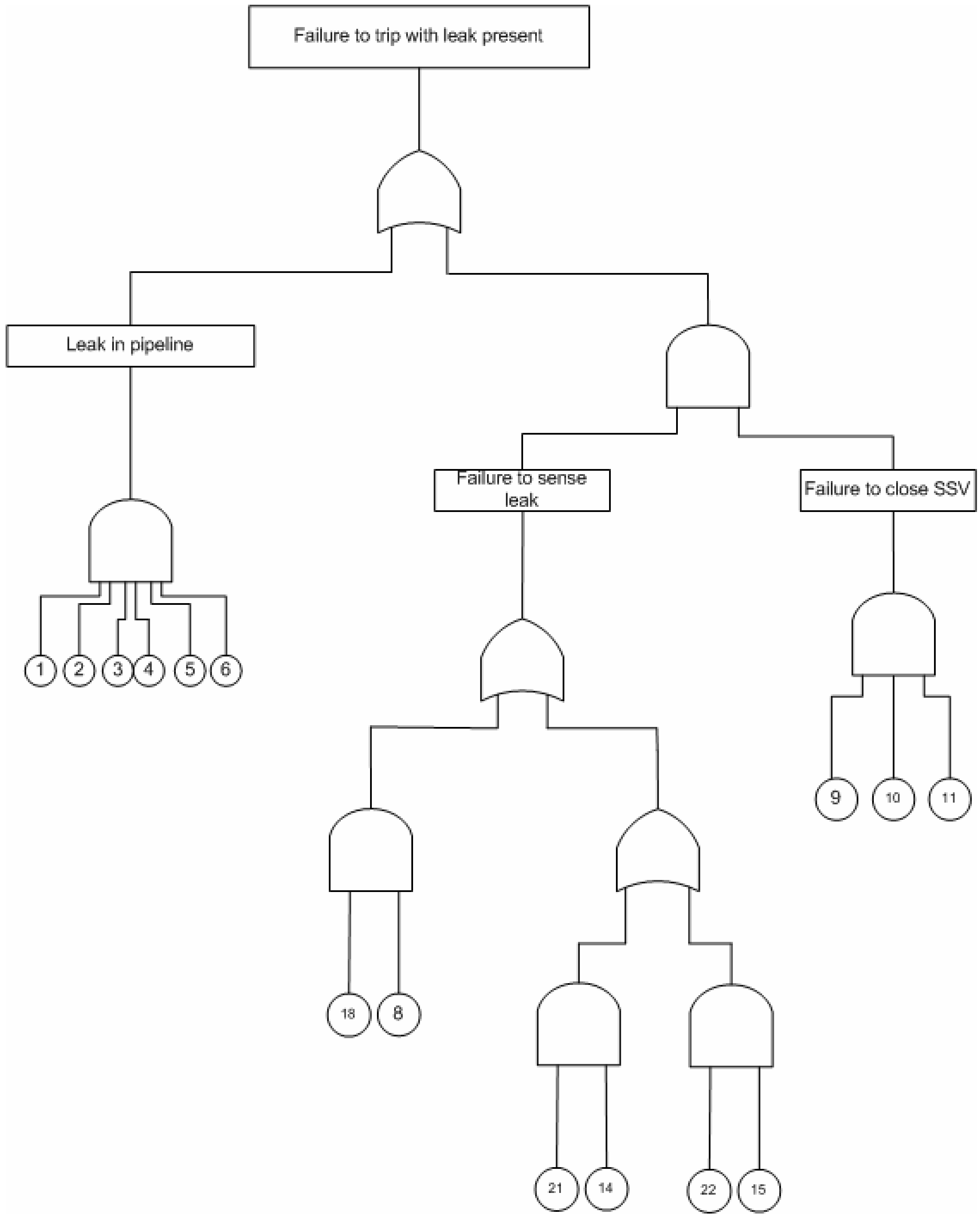


Figure 8.20 Multiphase-Failure to trip with leak present-PSL/MFS

The system will fail to sense a leak if both the MFS and PSL systems fail as outlined for the fault trees of Figures 8.16 and 8.17. The system will also fail if the safety shut-off valve(s) fail to close for one of the reasons outlines above. Either of these two scenarios can occur in a conjunction with a leak in the pipeline to cause the top event.

Figure 8.21 shows a fault tree diagram for a multiphase flow pipeline protected by a combination of an MFS and a PSL system. The top event is a false trip. The top event occurs when either the MFS fails OR the PSL fails. The top event will also occur when either the PSL fails OR the communication link from the PSL to the computer OR the mass flow sensor1 OR the mass flow sensor 2 OR the communication link between MFS1 and the computer OR the communication link between MFS2 and the computer, fails.

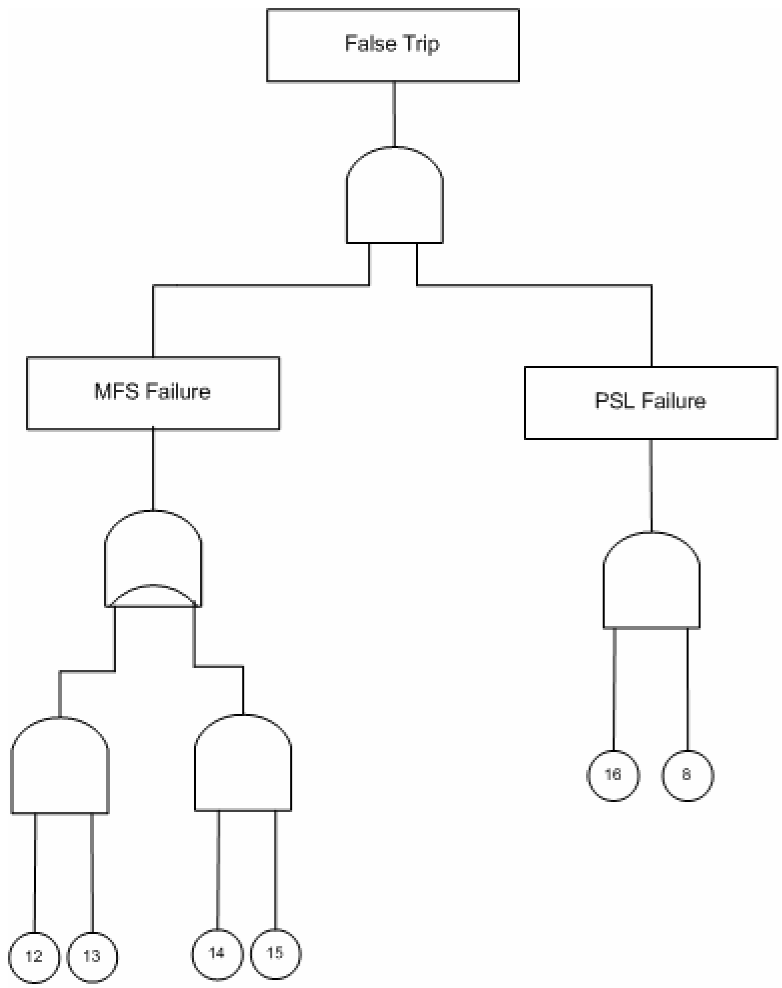


Figure 8.21 Multiphase Flow-False trip –PSL/MFS

Basic probabilities for each of the failure events will be used to calculate probability of the top event occurring in Figures 8.16 through 8.21.

9.0 RESULTS

Table 9.1 summarizes the probabilities of the top events for the eighteen pipeline cases considered in section 8 of this study.

Monitoring System:	**Flow Type:**					
	Gas	**Liquid**	**Multi**	**Gas**	**Liquid**	**Multi**
PSL	$13.66*10^{-6}$	$14.80*10^{-6}$	$127.0*10^{-6}$	$1 *10^{-2}$	$1 *10^{-2}$	$1*10^{-2}$
MFS	$8.39*10^{-6}$	$5.95*10^{-6}$	$8.368*10^{-6}$	$2.273*10^{-2}$	$2.273*10^{-2}$	$2.273*10^{-2}$
PSL/MFS	$8.368*10^{-6}$	$5.6*10^{-6}$	$5.6614*10^{-6}$	$3.26*10^{-2}$	$3.26*10^{-2}$	$3.26*10^{-2}$
Malfunction	Failure to trip			False trip		

Table 9.1 Probabilities of Top Events

As shown, the monitoring system using PSL in conjunction with MFS has the lowest values of failure to trip but the highest values of false trip. This is typical of redundant monitoring systems.

The mass flow system has consistent values for failure to trip or false tripping regardless of flow type. The reason for this is that the mass flow system is capable of accurately sensing leakages for any type of flow and it has the same propensity to false trip for all types of flow.

Generally, it can be seen that false tripping is the predominant failure mode, usually by three or four orders of magnitude. This prediction is consistent with historical records. These higher values of false tripping for the MFS and MFS/PSL monitoring systems than the PSL monitoring system are due to the additional complexity of these systems and a greater number of ways to signal a leak when none exists.

10.0 CONCLUSIONS AND RECOMMENDATIONS

Several conclusions can be drawn from the PSL data collected, the reliability analysis of MSF/PSL systems, the known leak incidents in which PSLs are considered, and the general comments of operators surveyed.

The principal conclusions of this study are

1. PSLs can detect leaks of a certain size in both liquid and gas pipe flow. Liquid data suggests leaks above a critical size can be detected at a significant distance from the PSL sensor, provided the PSL is set high (with respect to pipeline operating pressure) and the leak is large.

2. PSLs can be triggered when no leak is present. Operators are less likely to register, analyze and remember false alarms unless they occur repeatedly, for example, when a new leak system is installed or an existing system is recalibrated.

3. Offshore pipeline systems linking multiple platforms operate at widely fluctuating system pressures, as production from wells come on/off line. Piston style pipeline pumps also contribute to pressure surges. Pressure surging is a principal cause of false alarms where PSLs are set high relative to the line operating pressure.

4. PSL trip pressures appear to be low with respect to system operating pressure at the time of a leak, but are not excessively low with respect to the operating pressure range of the pipeline systems.

5. PSLs cannot protect pipeline systems where the hydrostatic head of the seawater exceeds the PSL trip pressure, or the operating pressure of the line. This is a concern in deepwater, but may also be a concern in shallow water. Mature reservoirs in the shallow OCS have declining reservoir pressures, which translate to lower pipeline operating pressures.

6. Historical MMS leak incident data has limited information on PSLs. PSL data are not currently tracked or reported in any way. Operators should be encouraged to track and report PSL information.

7. MMS Royalty systems are not necessarily related to the use of computation pipeline monitoring systems. CPM may be found more frequently where one operator dominates ownership within a particular system.

8. Operators using CPM methods indicated fewer false alarms. CMP methods appear to be more reliable for leak detection, but again not for seepage.

9. Volume balance is useful to combine with PSL alarm information in determining if a pipeline leak exists (if no CPM system is available).

10. Operators of transmission pipelines may not actually know the setting of each platform PSL, particularly if the pipeline is under the control of a pipeline company and the platforms are under an exploration and production (E&P) company.

11. Some operators do not employ SCADA systems. This limits the use of CPM methods.

12. Based on the data collected, the frequency of a leak that goes undetected is 0.003 leak/yr/mile.

13. Gas pipelines cannot rely on PSLs for leak detection due to gas compressibility. The data collected indicate that unless the leak is on the riser (very near the PSL alarm) it cannot be detected on a gas pipeline.

14. CPM or MFS leak detection systems coupled with PSLs are increasing in the GOM. This method requires a ‘closed system’ of platforms and lines that are part of the computational algorithm. Reliability analysis indicates that such systems are more reliable than PSLs in detecting pipeline leaks.

Recommendations

The following suggestions or recommendations are made based on observations of the study:

1. Operators should track and report their PSL settings in some manner. It appears that there has been more interest in tracking PSL settings since 1990, but there is currently no formal requirement for tracking or reporting PSL settings, even on incident report forms.

2. Pipeline operators responsible for transmission of flow from a system of platforms should perform hydraulic analysis on the entire system and be cognizant of how platform PSL alarm settings on their systems may need to be adjusted to operate against the hydrostatic head at various points along the line.

3. Whenever possible, PSLs should be augmented with volume balance methods (either through the MMS royalty system information of CPM). Historical leak incident data suggests that small system losses registered by comparing royalty input to pipeline system output may help identify leaks.

4. The use of PSLs as the principal regulatory mechanism for pipeline leak detection should be reviewed. Sufficient data indicate that PSLs, alone, simply cannot function reliably to detect even large leaks in many pipelines.

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APPENDIX

Operator Summary – Pipeline Segments Database (MMS,2002)

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UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO REGION

Segment List in Operator Order

Start District: 1
End District : 8
Start Operator Name: 1400 CORP.
End Operator Name : Williams Field Services - Gul

	Authority Code	Approval Code	Total Segments	Total Length
1400 CORP.	DOI	ROW	1	578
AEDC (USA) INC.	DOI	ROW	1	93528
ANR Central Gulf Gathering Company, Inc	DOT	ROW	1	180083
ANR PIPELINE COMPANY	DOI	ROW	3	23137
ANR PIPELINE COMPANY	DOT	ROW	109	3475716
ARCO Pipe Line Company	DOT	ROW	5	48270
ATP Oil & Gas Corporation	DOI	Lease	11	98896
ATP Oil & Gas Corporation	DOI	ROW	20	644598
Agip Petroleum Co. Inc.	DOI	Lease	21	70746
Agip Petroleum Co. Inc.	DOI	ROW	12	451948
Allied Natural Gas Corporation	DOI	Lease	1	11847
Amerada Hess Corporation	DOI	Lease	49	458353
Amerada Hess Corporation	DOI	ROW	25	725693
Amerada Hess Corporation	DOT	ROW	3	2802
American Exploration Company	DOI	Lease	2	7510
American Exploration Company	DOT	Lease	1	1930
Amoco Pipeline Company	DOT	ROW	27	2107666
Amoco Production Company	DOI	Lease	91	775816
Amoco Production Company	DOI	MMS	4	102808
Amoco Production Company	DOI	ROW	18	651154
Amoco Production Company	DOT	Lease	1	22143
Anadarko Petroleum Corporation	DOI	Lease	9	79795
Anadarko Petroleum Corporation	DOI	ROW	2	33270
Apache Corporation	DOI	Lease	117	761553
Apache Corporation	DOI	ROW	72	1486547
Apache Oil & Gas Transmission, Inc.	DOT	ROW	1	32909
Apache Oil Corporation	DOI	Lease	1	7957
Apache Oil Corporation	DOT	Lease	1	4829
Apex Oil & Gas, Inc.	DOI	Lease	3	19391
Apex Oil & Gas, Inc.	DOI	ROW	1	9034
Aquila Energy Corporation	DOI	Lease	1	5454
Aquila Energy Corporation	DOT	Lease	1	1177
Aquila Energy Corporation	DOT	ROW	1	3569
Aquila Energy Resources Corporation	DOI	Lease	4	13754
Aquila Energy Resources Corporation	DOT	ROW	1	14382
Ashland Exploration Holdings, Inc.	DOI	Lease	1	13323

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	Authority Code	Approval Code	Total Segments	Total Length
Ashland Exploration Holdings, Inc.	DOI	ROW	1	12492
Atlantic Richfield Company	DOI	Lease	44	232290
Atlantic Richfield Company	DOI	ROW	2	22493
Atlantic Richfield Company	DOT	Lease	5	50172
Atlantic Richfield Company	DOT	ROW	3	46076
Aviara Energy Corporation	DOI	Lease	7	31735
Aviara Energy Corporation	DOI	ROW	2	31700
Aviva America, Inc.	DOT	Lease	1	1496
B T Operating Co.	DOI	Lease	4	25908
B T Operating Co.	DOI	ROW	2	34085
BHP Petroleum (Americas) Inc.	DOI	ROW	3	78682
BP Amoco Corporation	DOI	Lease	7	84103
BP Exploration & Oil Inc.	DOI	Lease	15	138221
BP Exploration & Oil Inc.	DOI	ROW	10	495676
BP Exploration & Production Inc.	DOI	ROW	13	888761
Barcoo Exploration Inc.	DOT	ROW	1	8117
Barrett Resources Corporation	DOI	Lease	2	15574
Barrett Resources Corporation	DOI	ROW	3	45003
Bayou City Pipelines, Inc.	DOT	ROW	2	57345
Bellwether Exploration Company	DOI	Lease	4	14296
Bellwether Exploration Company	DOI	ROW	1	14491
Bellwether Exploration Company	DOT	ROW	1	61079
Black Marlin Pipeline Company	DOT	ROW	3	186859
Blue Dolphin Exploration Company	DOI	Lease	5	13000
Blue Dolphin Pipe Line Company	DOI	ROW	3	124903
Blue Dolphin Pipe Line Company	DOT	ROW	10	421681
Bois d'Arc Offshore Ltd.	DOI	Lease	46	313115
Bois d'Arc Offshore Ltd.	DOI	ROW	6	111786
British-Borneo USA, Inc.	DOI	Lease	4	6227
British-Borneo USA, Inc.	DOI	ROW	5	141306
Broussard Brothers, Inc.	DOT	ROW	1	12613
Buccaneer Gas Pipeline Company, L.L.C.	DOT	ROW	1	198934
Burlington Resources Offshore Inc.	DOI	Lease	87	490297
Burlington Resources Offshore Inc.	DOI	ROW	18	447039
Burlington Resources Offshore Inc.	DOT	Lease	1	
Burlington Resources Offshore Inc.	DOT	ROW	1	38214

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	Authority Code	Approval Code	Total Segments	Total Length
CBL Capital Corporation	DOT	ROW	5	228590
CNG Transmission Corporation	DOI	MMS	1	1923
CNG Transmission Corporation	DOT	ROW	4	76017
CSP Pipeline, L.L.C.	DOT	ROW	1	7624
Cairn Energy USA, Inc.	DOI	Lease	1	2062
Cairn Energy USA, Inc.	DOI	ROW	1	13879
Callon Petroleum Operating Company	DOI	Lease	20	144428
Callon Petroleum Operating Company	DOI	ROW	8	205734
Calpine Natural Gas Company	DOI	Lease	4	22388
Calpine Natural Gas Company	DOI	ROW	2	21801
CanadianOxy Offshore Production Co.	DOI	Lease	3	26181
Centana Gathering Company	DOT	ROW	2	327439
Century Exploration Company	DOI	Lease	15	68158
Century Exploration Company	DOI	ROW	7	164626
Century Offshore Management Corporation	DOI	Lease	9	36325
Century Offshore Management Corporation	DOI	ROW	1	11457
Century Offshore Management Corporation	DOT	Lease	2	8584
Century Offshore Management Corporation	DOT	ROW	6	80839
Challenger Minerals Inc.	DOI	ROW	1	15924
Chandeleur Pipe Line Company	DOT	ROW	5	384318
Chevron Pipe Line Company	DOI	ROW	1	29941
Chevron Pipe Line Company	DOT	Lease	2	11575
Chevron Pipe Line Company	DOT	MMS	1	15000
Chevron Pipe Line Company	DOT	ROW	55	1925897
Chevron U.S.A. Inc.	DOI	Lease	1481	6876330
Chevron U.S.A. Inc.	DOI	MMS	15	379541
Chevron U.S.A. Inc.	DOI	ROW	84	2008235
Chevron U.S.A. Inc.	DOT	Lease	19	65573
Chevron U.S.A. Inc.	DOT	MMS	2	145458
Chevron U.S.A. Inc.	DOT	ROW	6	191179
Chieftain International (U.S.) Inc.	DOI	Lease	8	44439
Chieftain International (U.S.) Inc.	DOI	ROW	14	177644
Coastal Oil & Gas Corporation	DOI	Lease	40	404739
Coastal Oil & Gas Corporation	DOI	ROW	35	779149
Coastal Oil & Gas Resources, Inc.	DOI	ROW	1	11406
Coastal Oil & Gas USA, L.P.	DOI	ROW	6	94169

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	Authority Code	Approval Code	Total Segments	Total Length
Coastal States Gas Transmission Company	DOI	ROW	1	9332
Coastal States Trading, Inc.	DOT	ROW	1	90958
Cockrell Oil Corporation	DOI	Lease	7	25987
Cockrell Oil Corporation	DOI	ROW	6	85483
Columbia Gulf Transmission Company	DOI	ROW	1	7698
Columbia Gulf Transmission Company	DOT	Lease	1	9790
Columbia Gulf Transmission Company	DOT	MMS	2	13128
Columbia Gulf Transmission Company	DOT	ROW	77	2138330
Comstock Offshore, LLC	DOI	Lease	3	13899
Comstock Offshore, LLC	DOI	ROW	3	10416
Conn Energy, Inc.	DOI	Lease	1	9200
Conoco Inc.	DOI	Lease	61	426273
Conoco Inc.	DOI	MMS	2	146648
Conoco Inc.	DOI	ROW	11	433569
Conoco Inc.	DOT	Lease	1	18800
Consolidated Gas Supply Corporation	DOT	Lease	1	4200
Corpus Christi Oil and Gas Company	DOI	Lease	1	
Corpus Christi Oil and Gas Company	DOT	ROW	1	11666
Coscol Marine Corporation	DOT	ROW	1	16000
Cowboy Pipeline Company	DOI	ROW	2	0
Cronus Offshore, Inc.	DOI	ROW	2	21891
DALEN Resources Oil & Gas Co.	DOT	ROW	1	17847
Dauphin Island Gathering Company, L.P.	DOT	ROW	2	93564
Dauphin Island Gathering Partners	DOT	ROW	20	1069223
Davis Oil Company	DOT	ROW	1	11226
Delos Offshore Company, L.L.C.	DOT	ROW	2	139485
Denbury Resources Inc.	DOI	ROW	2	70082
Department of Energy	DOI	ROW	1	19008
Department of Energy	DOT	ROW	1	26449
Destin Pipeline Company, L.L.C.	DOT	ROW	7	606802
Devon Energy Corporation	DOI	Lease	1	18205
Devon Energy Corporation	DOT	ROW	2	37632
Devon Energy Operating Corporation	DOT	ROW	1	18466
Devon Energy Petroleum Pipeline Company	DOT	ROW	6	310602
Devon Energy Production Company, L.P.	DOI	Lease	112	877770
Devon Energy Production Company, L.P.	DOI	MMS	1	9400

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	Authority Code	Approval Code	Total Segments	Total Length
Devon Energy Production Company, L.P.	DOI	ROW	14	734698
Devon Energy Production Company, L.P.	DOI		1	15671
Devon Energy Production Company, L.P.	DOT	Lease	1	52653
Devon Energy Production Company, L.P.	DOT	ROW	2	22480
Devon SFS Operating, Inc.	DOI	Lease	23	159058
Devon SFS Operating, Inc.	DOI	ROW	27	728275
Devon SFS Operating, Inc.	DOT	Lease	3	20966
Discovery Gas Transmission LLC	DOI	ROW	2	50375
Discovery Gas Transmission LLC	DOT	ROW	4	596924
Discovery Producer Services LLC	DOT	ROW	4	195068
Domain Energy Production Corporation	DOI	Lease	1	5148
Dominion Exploration & Production, Inc.	DOI	Lease	29	274838
Dominion Exploration & Production, Inc.	DOI	ROW	26	362823
Duke Energy Field Services, LP	DOI	Lease	2	7075
Duke Energy Field Services, LP	DOI	ROW	7	138674
Duke Energy Field Services, LP	DOT	ROW	9	171661
Dynegy Energy, Inc.	DOT	ROW	3	80500
Dynegy Midstream Services, Limited Part	DOT	ROW	13	627219
EEX Corporation	DOI	Lease	15	165618
EEX Corporation	DOI	ROW	21	926007
ENSTAR Corporation	DOI	Lease	2	4262
EOG Resources Omega LLC	DOI	ROW	2	35490
EOG Resources, Inc.	DOI	Lease	12	117942
EOG Resources, Inc.	DOI	ROW	17	390831
EP Operating Limited Partnership			1	
EPEC Offshore Gathering Company	DOT	ROW	1	46893
EPL Pipeline, L.L.C.	DOT	ROW	1	24945
East Breaks Gathering Company, L.L.C.	DOI	ROW	1	454203
El Paso Energy Development I Company	DOI	ROW	1	24353
El Paso Energy Oil Transmission, Inc.	DOT	ROW	3	112611
El Paso Natural Gas Company	DOT	ROW	2	28899
El Paso Offshore Gathering & Transmissi	DOI	ROW	1	30789
El Paso Offshore Gathering & Transmissi	DOT	ROW	25	623964
El Paso Production Company	DOI	Lease	56	276137
El Paso Production Company	DOI	ROW	15	419755
El Paso Production GOM Inc.	DOI	Lease	20	125020

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	Authority Code	Approval Code	Total Segments	Total Length
El Paso Production GOM Inc.	DOI	ROW	53	1061872
Elf Aquitaine, Inc.	DOT	Lease	1	10054
Energen Resources MAQ, Inc.	DOI	Lease	5	23166
Energen Resources MAQ, Inc.	DOI	MMS	1	13780
Energen Resources MAQ, Inc.	DOT	ROW	2	65563
Energy Development Corporation	DOI	Lease	2	12313
Energy Development Corporation	DOT	Lease	2	3707
Energy Partners, Ltd.	DOI	Lease	468	609816
Energy Partners, Ltd.	DOI	ROW	1	5457
Energy Partners, Ltd.	DOI	State	56	27115
Energy Partners, Ltd.	DOT	Lease	6	
Energy Partners, Ltd.	DOT	State	1691	11200
Energy Resource Technology, Inc.	DOI	Lease	28	173248
Energy Resource Technology, Inc.	DOI	ROW	16	443514
Energy Resources Corporation	DOT	ROW	1	65764
Enron Corp.	DOT	ROW	5	93845
Enserch Exploration, Inc.	DOI	Lease	1	8289
Enserch Exploration, Inc.	DOT	ROW	1	9553
Enserch Exploration, Inc.			3	
Enterprise Oil Gulf of Mexico Inc.	DOI	ROW	1	14771
Equilon Pipeline Company LLC	DOI	ROW	2	183969
Equilon Pipeline Company LLC	DOT	ROW	72	6822029
Equitable Production Company	DOI	Lease	1	5250
Ewing Bank Gathering Company	DOI	ROW	1	34340
Ewing Bank Gathering Company	DOT	ROW	1	605
Ewing Bank Gathering Company, L.L.C.	DOI	ROW	3	103155
Exxon Mobil Corporation	DOI	Lease	244	2214420
Exxon Mobil Corporation	DOI	ROW	27	1810189
Exxon Mobil Corporation	DOT	Lease	2	9200
Exxon Mobil Corporation	DOT	MMS	2	22200
Exxon Mobil Corporation	DOT	ROW	2	19194
ExxonMobil Pipeline Company	DOT	ROW	30	2416092
ExxonMobil Pipeline Company	DOT	State	1	2500
Fairways Specialty Sales & Service, Inc	DOI	Lease	4	15809
Fairways Specialty Sales & Service, Inc	DOI	ROW	3	117688
Falcon Offshore Operating Company	DOT	Lease	1	9076

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Start District: 1
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	Authority Code	Approval Code	Total Segments	Total Length
Falcon Offshore Operating Company	DOT	ROW	1	4972
Flash Gas & Oil Southwest, Inc.	DOI	Lease	2	5068
Flash Gas & Oil Southwest, Inc.	DOT	ROW	1	35522
Flextrend Development Company, L.L.C.	DOI	Lease	8	600
Flextrend Development Company, L.L.C.	DOI	ROW	7	146500
Flextrend Development Company, L.L.C.			1	
Florida Gas Transmission Company	DOT	ROW	6	85690
Forcenergy GOM Inc.	DOI	Lease	3	38425
Forcenergy GOM Inc.	DOI	ROW	3	59018
Forcenergy Gas Exploration, Inc.	DOI	Lease	1	7200
Forcenergy Inc.	DOI	ROW	2	25388
Forcenergy Inc.	DOT	Lease	1	2034
Forest Oil Corporation	DOI	Lease	113	601540
Forest Oil Corporation	DOI	MMS	1	13758
Forest Oil Corporation	DOI	ROW	30	758242
Forest Oil Corporation	DOT	Lease	1	9000
Four Star Oil & Gas Company	DOI	Lease	43	91780
Freeport Interstate Pipeline Company	DOT	ROW	2	6430
Freeport Minerals Company	DOT	MMS	3	9645
Freeport-McMoRan Sulphur LLC	DOI	Lease	5	17155
Freeport-McMoRan Sulphur LLC	DOI	ROW	9	39023
GOM Shelf LLC	DOI	Lease	2	17561
GOM Shelf LLC	DOI	ROW	11	365689
Garden Banks Gas Pipeline, L.L.C.	DOT	ROW	6	278341
Gas Transportation Corp.	DOI	Lease	5	14500
Gas Transportation Corp.	DOT	Lease	3	18776
Gasdel Pipeline System Incorporated	DOT	ROW	1	27108
Gateway Offshore Pipeline Company	DOI	ROW	1	1153
Gateway Offshore Pipeline Company	DOT	ROW	5	69845
Gateway Offshore Pipeline Company		ROW	1	23206
General Atlantic Resources, Inc.	DOI	Lease	9	42688
General Atlantic Resources, Inc.	DOI	ROW	1	2919
General Atlantic Resources, Inc.	DOT	Lease	1	5163
General Atlantic Resources, Inc.	DOT	ROW	1	12897
Genesis Crude Oil, L.P.	DOT	ROW	1	8827
Global Marine Oil & Gas Company	DOI	ROW	2	41190

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	Authority Code	Approval Code	Total Segments	Total Length
Green Canyon Pipe Line Company, L.P.	DOT	ROW	5	358062
Gryphon Exploration Company	DOI	ROW	1	10973
Gulfstar Energy, Inc.	DOI	Lease	1	5680
Gulfstar Energy, Inc.	DOI	ROW	2	88018
Gulfstream Natural Gas System, L.L.C.	DOT	ROW	1	
HI-BOL Pipeline Company	DOT	ROW	6	189040
Hall-Houston Oil Company	DOI	Lease	21	150561
Hall-Houston Oil Company	DOI	ROW	30	693754
Hall-Houston Oil Company	DOT	ROW	1	53343
High Island Offshore System	DOT	ROW	7	1079521
Houston Oil & Minerals Corporation	DOI	Lease	13	45463
Houston Oil & Minerals Corporation	DOT	Lease	1	2264
Houston Oil & Minerals Corporation	DOT	MMS	1	37500
Howell Petroleum Corporation	DOI	Lease	51	151461
Howell Petroleum Corporation	DOT	Lease	2	9190
Howell Petroleum Corporation	DOT	ROW	1	63
Hughes Eastern Petroleum, Inc.	DOT	ROW	1	0
Hunt Oil Company	DOI	Lease	24	150011
Hunt Oil Company	DOI	MMS	1	0
Hunt Oil Company	DOT	ROW	1	49985
IP Petroleum Company, Inc.	DOI	Lease	1	5903
IP Petroleum Company, Inc.	DOI	ROW	7	93783
Ivory Production Co.	DOI	Lease	28	138894
Ivory Production Co.	DOT	Lease	2	20590
J. M. Huber Corporation	DOI	Lease	185	471907
J. M. Huber Corporation	DOI	ROW	5	238588
J. Ray McDermott Technology, Inc.	DOI	Lease	3	21233
J. Ray McDermott Technology, Inc.	DOI	ROW	1	16672
Juniper Energy L.P.	DOI	Lease	1	1714
Juniper Energy L.P.	DOI	ROW	2	48406
Jupiter Energy Corporation	DOI	ROW	1	10732
Jupiter Energy Corporation	DOT	ROW	6	78211
KERR-McGEE PIPELINE CORP.	DOI	ROW	3	60796
KERR-McGEE PIPELINE CORP.	DOT	MMS	1	89594
KERR-McGEE PIPELINE CORP.	DOT	ROW	5	91381
KIRBY EXPLORATION COMPANY OF TEXAS	DOT	ROW	1	23350

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Kelley Oil Corporation	DOI	Lease	4	33080
Kerr-McGee Corporation	DOI	Lease	144	536847
Kerr-McGee Corporation	DOI	MMS	1	7837
Kerr-McGee Corporation	DOI	ROW	3	43481
Kerr-McGee Oil & Gas Corporation	DOI	Lease	161	1185677
Kerr-McGee Oil & Gas Corporation	DOI	ROW	23	896276
Koch Exploration Company	DOI	Lease	8	93266
Koch Gateway Pipeline Company	DOT	MMS	2	1839
Koch Gateway Pipeline Company	DOT	ROW	36	715130
Koch Industries, Inc.	DOI	ROW	3	43395
Koch Industries, Inc.	DOT	ROW	3	91708
LLECO Holdings, Inc.	DOI	Lease	5	23928
LLECO Holdings, Inc.	DOT	Lease	1	4200
LLECO Holdings, Inc.	DOT	ROW	2	36021
LOOP, LLC.			6	215986
Legacy Resources Co., L.P.	DOI	ROW	1	19755
Leviathan Oil Transport Systems, L.L.C.	DOT	ROW	1	34831
Levinson Partners Corporation	DOT	ROW	1	21566
Linder Oil Company, A Partnership	DOI	Lease	18	94667
Linder Oil Company, A Partnership	DOI	MMS	2	14520
Linder Oil Company, A Partnership	DOI	ROW	8	165861
Louis Dreyfus Natural Gas Corp.	DOI	Lease	1	7898
Louis Dreyfus Natural Gas Corp.	DOI	ROW	8	138261
MEGS, L.L.C.	DOI	ROW	1	150303
MOBIL OIL EXPLORATION & PRODUCING SOUTH	DOI	Lease	497	2131212
MOBIL OIL EXPLORATION & PRODUCING SOUTH	DOI	MMS	4	81781
MOBIL OIL EXPLORATION & PRODUCING SOUTH	DOI	ROW	14	404897
MOBIL OIL EXPLORATION & PRODUCING SOUTH	DOT	Lease	3	26600
MOBIL OIL EXPLORATION & PRODUCING SOUTH	DOT	MMS	1	24800
Magellan Exploration, LLC	DOI	Lease	1	8037
Magnum Hunter Production, Inc.	DOI	Lease	6	78986
Magnum Hunter Production, Inc.	DOI	ROW	1	18113
Main Energy, Inc.	DOI	Lease	1	48377
Manta Ray Gathering Company, L.L.C.	DOT	ROW	19	1962963
Manta Ray Offshore Gathering Company, L	DOT	ROW	2	97509
Mantaray Pipeline Company	DOT	ROW	1	22687

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	Authority Code	Approval Code	Total Segments	Total Length
Marathon Oil Company	DOI	Lease	41	247577
Marathon Oil Company	DOI	ROW	6	275020
Marathon Petroleum Company	DOI	Lease	1	5650
Marathon Pipe Line Company	DOT	MMS	1	57559
Marathon Pipe Line Company	DOT	ROW	2	10448
Marathon Pipe Line LLC	DOT	ROW	14	843897
Mariner Energy, Inc.	DOI	Lease	12	211079
Mariner Energy, Inc.	DOI	ROW	21	1143951
Maritech Resources, Inc.	DOI	ROW	4	35415
Mark Producing, Inc.	DOT	ROW	1	15040
Matrix Oil & Gas, Inc.	DOI	Lease	1	1406
Matrix Oil & Gas, Inc.	DOI	Lease	31	116434
Matrix Oil & Gas, Inc.	DOI		1	41143
Matrix Oil & Gas, Inc.	DOT	Lease	2	5600
McMoRan Oil & Gas Co.	DOI	Lease	27	104092
McMoRan Oil & Gas LLC	DOI	Lease	7	45522
McMoRan Oil & Gas LLC	DOI	ROW	5	135805
McMoRan Pipeline Company	DOT	ROW	1	15972
Mesa Operating Limited Partnership	DOI	Lease	2	18172
Mesa Operating Limited Partnership	DOT	ROW	1	22035
Mid Louisiana Gas Company	DOT	ROW	1	6388
MidCon Exploration Company - Gulf Coast	DOI	Lease	2	9274
MidCon Exploration Company - Gulf Coast	DOT	MMS	1	85852
Midcon Offshore, Inc.	DOT	Lease	2	6000
Millennium Offshore Group, Inc.	DOI	Lease	1	3008
Millennium Offshore Group, Inc.	DOI	ROW	1	10516
Mississippi Canyon Gas Pipeline, LLC	DOT	ROW	1	178436
Mitchell Energy Corporation	DOT	Lease	1	4011
Mobil Eugene Island Pipeline Company	DOT	ROW	3	222600
Mobil Exploration and Producing North A	DOI	Lease	2	12188
Mobil Exploration and Producing North A	DOT	ROW	1	64608
Mobil Producing Texas & New Mexico Inc.	DOI	Lease	4	36547
Murphy Exploration & Production Company	DOI	Lease	882	2366908
Murphy Exploration & Production Company	DOI	ROW	29	591880
NCX Company, Inc.	DOI	Lease	3	21002
NCX Company, Inc.	DOI	ROW	5	98603

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	Authority Code	Approval Code	Total Segments	Total Length
Natural Gas Pipeline Company of America	DOT	Lease	1	5710
Natural Gas Pipeline Company of America	DOT	MMS	3	32118
Natural Gas Pipeline Company of America	DOT	ROW	40	997147
Nautilus Pipeline Company, L.L.C.	DOT	ROW	1	358603
Nemo Gathering Company, LLC	DOT	ROW	1	124420
Newfield Exploration Company	DOI	Lease	138	769641
Newfield Exploration Company	DOI	ROW	79	2363580
Nexen Petroleum Offshore U.S.A. Inc.	DOI	Lease	56	380970
Nexen Petroleum Offshore U.S.A. Inc.	DOI	ROW	3	14336
Nexen Petroleum U.S.A. Inc.	DOI	Lease	4	18445
Nippon Oil Exploration U.S.A. Limited	DOI	Lease	2	1935
Norcen Explorer, Inc.	DOI	Lease	3	14010
Norcen Explorer, Inc.	DOT	Lease	2	7234
Norcen Offshore Properties, Ltd. Co.	DOT	Lease	2	9600
North Central Oil Corporation	DOI	ROW	1	20925
Northern Natural Gas Company	DOT	ROW	28	793726
OEDC Exploration & Production, L.P.	DOI	Lease	5	24061
OEDC Exploration & Production, L.P.	DOI	ROW	6	212276
ORYX ENERGY COMPANY	DOI	Lease	1	2400
ORYX ENERGY COMPANY	DOI	ROW	2	45818
ORYX ENERGY COMPANY	DOT	ROW	1	86003
OXY USA Inc.	DOI	Lease	31	235485
OXY USA Inc.	DOI	MMS	1	7180
OXY USA Inc.	DOI	ROW	1	21000
OXY USA Inc.	DOT	Lease	1	4750
Ocean Energy, Inc.	DOI	Lease	257	946922
Ocean Energy, Inc.	DOI	ROW	31	564492
Ocean Energy, Inc.	DOI	State	1	
Ocean Energy, Inc.	DOI		1	27557
Ocean Energy, Inc.	DOT	Lease	1	10135
Ocean Energy, Inc.	DOT	ROW	1	25552
Ocean Energy, Inc.	DOT	State	10	0
Odeco Oil & Gas Company	DOI	Lease	11	16291
Offshore Energy Development Corporation	DOI	ROW	1	10293
Offshore Resources, LLC	DOT	ROW	1	28777
Omega Pipeline Company	DOT	ROW	2	4662

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	Authority Code	Approval Code	Total Segments	Total Length
Quintana Offshore, Inc.	DOI	Lease	5	7255
Quintana Petroleum Corporation	DOI	Lease	1	4281
Quintana Petroleum Corporation	DOT	Lease	1	9909
Quintana Petroleum Corporation	DOT	MMS	1	9125
Quintana Petroleum Corporation	DOT	ROW	1	19098
RME Petroleum Company	DOI	Lease	74	575173
RME Petroleum Company	DOI	ROW	41	1398260
Range Energy Ventures Corporation	DOI	ROW	2	31311
Reading & Bates Development Co.	DOI	ROW	1	17380
Remington Oil and Gas Corporation	DOI	ROW	5	129862
SCANA Petroleum Resources, Inc.	DOI	Lease	4	22418
SOCO Offshore, Inc.	DOI	Lease	10	33191
SOCO Offshore, Inc.	DOI	ROW	6	90239
SOCO Offshore, Inc.	DOT	Lease	1	3701
SOCO Offshore, Inc.	DOT	ROW	2	4410
Sabine Corporation	DOT	ROW	1	4551
Sabine Pipe Line Company	DOT	ROW	4	100272
Samedan Oil Corporation	DOI	Lease	94	706333
Samedan Oil Corporation	DOI	MMS	1	0
Samedan Oil Corporation	DOI	ROW	63	1611068
Sea Robin Pipeline Company	DOT	ROW	60	2235415
SeaCrest Company, L.L.C.	DOI	ROW	1	29294
SeaCrest Company, L.L.C.	DOT	ROW	19	691049
Seagull Energy E&P Inc.	DOI	Lease	16	127686
Seagull Energy E&P Inc.	DOI	ROW	1	0
Seagull Energy E&P Inc.	DOT	Lease	3	48735
Seagull Energy E&P Inc.	DOT	ROW	3	53448
Seagull Energy E&P Inc.	DOI	Lease	15	127280
Seagull Energy E&P Inc.	DOI	ROW	2	52795
Seagull Energy E&P Inc.	DOT	ROW	2	44593
Seneca Resources Corporation	DOI	Lease	37	154538
Seneca Resources Corporation	DOI	ROW	17	395997
Shell Deepwater Development Inc.	DOI	Lease	26	305669
Shell Deepwater Development Inc.	DOI	ROW	15	849839
Shell Deepwater Production Inc.	DOI	ROW	32	3001144
Shell Gas Gathering Company	DOT	ROW	23	1934638

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	Authority Code	Approval Code	Total Segments	Total Length
Tejas Gas Corp.	DOT	ROW	1	20705
Tenneco Oil Company	DOI	Lease	1	1517
Tenneco Oil Company	DOT	Lease	1	1517
Tenneco Oil Company	DOT	ROW	1	9653
Tennessee Gas Pipeline Company	DOI	Lease	2	5919
Tennessee Gas Pipeline Company	DOI	ROW	2	38946
Tennessee Gas Pipeline Company	DOT	MMS	20	142183
Tennessee Gas Pipeline Company	DOT	ROW	267	6108838
Texaco Exploration and Production Inc.	DOI	Lease	134	871542
Texaco Exploration and Production Inc.	DOI	ROW	17	1028570
Texaco Inc.	DOI	Lease	379	2094776
Texaco Inc.	DOI	MMS	5	42576
Texaco Inc.	DOT	Lease	13	49079
Texaco Inc.	DOT	MMS	2	28079
Texaco Pipeline Inc.	DOT	MMS	2	24721
Texaco Pipelines LLC	DOT	ROW	1	160200
Texas Eastern Transmission Corporation	DOT	MMS	1	4398
Texas Eastern Transmission Corporation	DOT	ROW	80	3176532
Texas Gas Transmission Corporation	DOI	ROW	1	37467
Texas Gas Transmission Corporation	DOT	ROW	35	583292
The Houston Exploration Company	DOI	Lease	32	176028
The Houston Exploration Company	DOI	ROW	11	180787
The Louisiana Land and Exploration Comp	DOI	Lease	21	187352
The Louisiana Land and Exploration Comp	DOI	ROW	25	578326
The William G. Helis Company, L.L.C.	DOI	Lease	3	22338
The William G. Helis Company, L.L.C.	DOI	ROW	2	22246
Torch Operating Company	DOI	Lease	18	117686
Torch Operating Company	DOI	ROW	1	14946
TotalFinaElf E&P USA, Inc.	DOI	Lease	14	36082
TotalFinaElf E&P USA, Inc.	DOI	ROW	26	1339261
TransAtlantic Petroleum (USA) Corp.	DOI	Lease	1	3524
Transco Exploration and Production Comp	DOT	Lease	1	793
Transcontinental Gas Pipe Line Corporat	DOI	Lease	1	13143
Transcontinental Gas Pipe Line Corporat	DOI	ROW	2	8147
Transcontinental Gas Pipe Line Corporat	DOT	MMS	22	141287
Transcontinental Gas Pipe Line Corporat	DOT	ROW	292	8965007

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	Authority Code	Approval Code	Total Segments	Total Length
Transworld Exploration and Production,	DOI	Lease	18	133376
Transworld Exploration and Production,	DOI	ROW	2	35900
Tri-Union Development Corporation	DOI	Lease	4	23478
Tri-Union Development Corporation	DOI	ROW	10	175051
Trunkline Gas Company	DOT	ROW	79	2206177
U-T Offshore System	DOT	ROW	1	131700
Union Exploration Partners, Ltd.	DOI	Lease	7	22541
Union Oil Company of California	DOI	Lease	376	2072522
Union Oil Company of California	DOI	MMS	1	3900
Union Oil Company of California	DOI	ROW	46	958787
Union Texas Petroleum Corporation	DOI	MMS	2	5500
Union Texas Petroleum Corporation	DOT	Lease	1	986
Union Texas Petroleum Corporation	DOT	MMS	1	170
Union Texas Petroleum Corporation	DOT	ROW	2	14545
Unocal Exploration Corporation	DOI	Lease	1	12400
Unocal Pipeline Company	DOT	ROW	9	503622
VK-Main Pass Gathering Company, L.L.C.	DOT	ROW	1	32420
Vastar Offshore, Inc.	DOI	Lease	70	465260
Vastar Offshore, Inc.	DOI	ROW	1	5936
Vastar Pipeline, LLC	DOI	ROW	7	126587
Vastar Pipeline, LLC	DOT	ROW	1	35000
Vastar Resources, Inc.	DOI	Lease	271	1839031
Vastar Resources, Inc.	DOI	MMS	2	60459
Vastar Resources, Inc.	DOI	ROW	56	1418188
Vastar Resources, Inc.	DOT	Lease	1	13095
Vastar Resources, Inc.			1	5530
Venice Energy Services Company, L.L.C.	DOT	ROW	22	1160068
Vintage Petroleum, Inc.	DOI	Lease	7	64142
Vintage Petroleum, Inc.	DOI	ROW	6	173152
Viosca Knoll Gathering Company	DOT	ROW	9	710289
W & T Offshore, Inc.	DOI	Lease	6	27499
W & T Offshore, Inc.	DOI	ROW	17	338079
WFS - Offshore Gathering Company	DOI	ROW	1	1979
WFS - Offshore Gathering Company	DOT	ROW	21	973866
Walter Oil & Gas Corporation	DOI	Lease	63	376248
Walter Oil & Gas Corporation	DOI	ROW	70	2011071

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Walter Oil & Gas Corporation	DOT	Lease	2	17838
Walter Oil & Gas Corporation	DOT	ROW	3	38061
Wayman W. Buchanan, Inc.	DOI	Lease	2	12784
West Lake Arthur Corporation	DOT	ROW	1	24625
Westport Resources Corporation	DOI	Lease	29	198067
Westport Resources Corporation	DOI	ROW	10	275528
White Shoal Pipeline Corporation	DOT	ROW	2	17000
Williams Field Services - Gulf Coast Co	DOI	ROW	3	17649
Williams Field Services - Gulf Coast Co	DOT	ROW	10	1260744
Williams Field Services - Gulf Coast Co			1	5890