UNDERWRITING MARKETING REPORT - EXAMPLE

EXAMPLE CORPORATION
EXAMPLE Refinery
Example, Texas, USA

Address:	Example Corporation Example Refinery 123 ABC Street Example, TX, USA
Survey Date:	March 1-3, 2011
Consultant(s):	Jesse Wilson, Risk Engineer Mark Frazier, Reliability Specialist.

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ABSTRACT

This refinery has a total feedstock throughput of 100,000 barrels/day. Process Units consist of a Crude Oil Unit, a Vacuum Unit, a Fluidized Catalytic Cracking Unit, a Catalytic Reformer, a Continuous Regenerative Catalytic Reformer (CCR), a Hydrocracker, a Light Ends Unit, an HF Alkylation Unit, a DOT (deasphalted oil treater), a DHT (diesel hydrotreater) Unit, two Naphtha Hydrodesulferizers, a Hydrogen Unit, a POT Unit (lube oil hydrotreating) and a BTX (benzene/toluene/xylene) Unit. Other operating units are Merox Units for extraction of mercaptans and LPG's. The main products are gasoline, diesel fuel, jet fuel, and lube oil stock. All process areas in the refinery are constantly attended. The main entrance is manned 24 hours a day. External exposures are light.

Building construction is heavy and light noncombustible consisting of blast resistive control buildings and metal office buildings, warehouses and sheds. Building are one story high. Process structures have multiple levels of open steel construction with mostly good fireproofing. Numerous fire divisions are achieved by separation of process areas and diking of tank farms.

Site Perils include those normally associated with petroleum refineries, namely fired heaters, reactors, the storage and handling of flammable liquids, liquid fixed flammable gases, toxic materials, and exothermic reactions. They are well arranged.

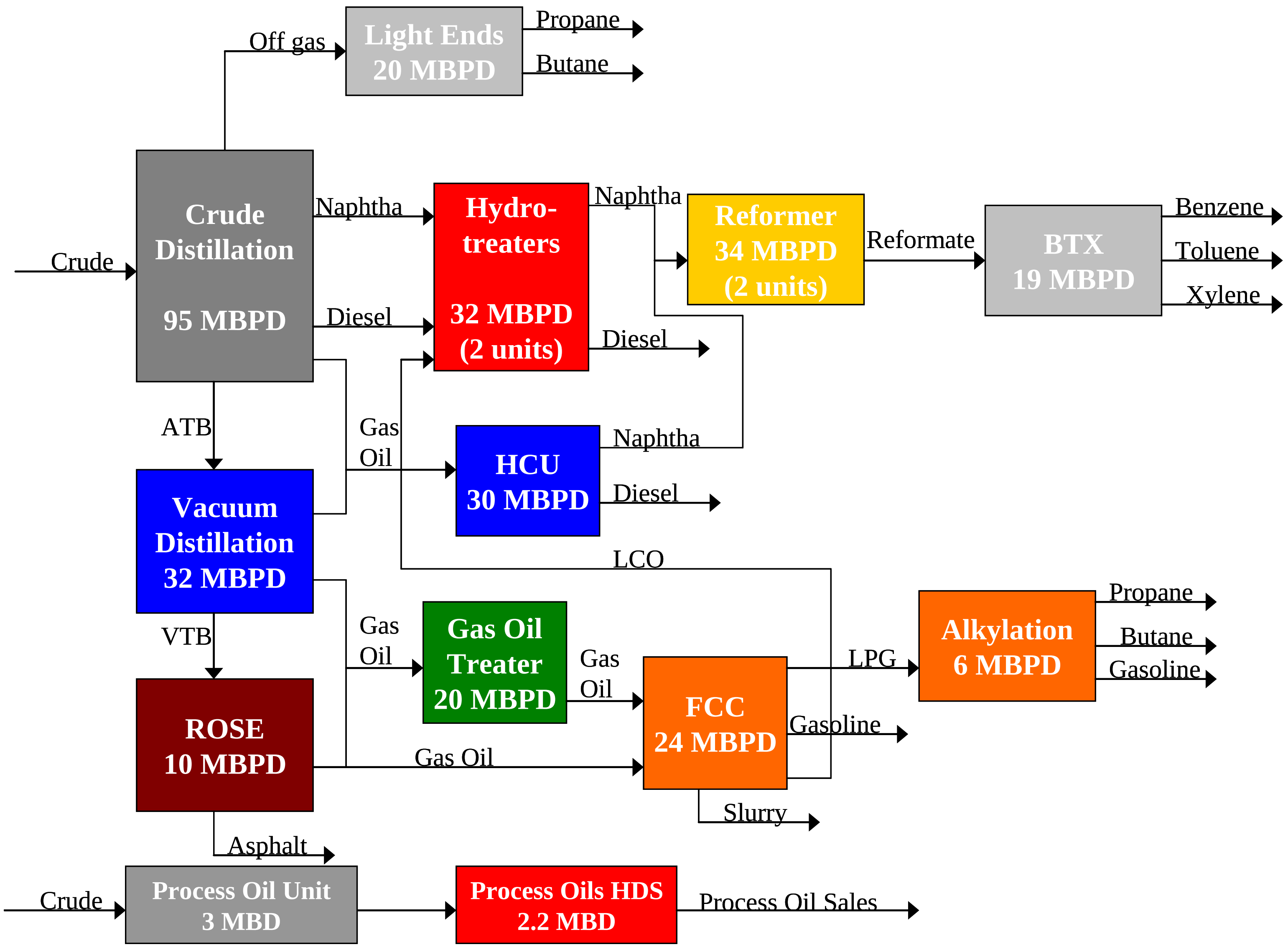
The services at this facility consist of boilers and associated oil storage, electrical systems, refrigeration systems, cooling towers and industrial gases. They well arranged.

Standard safeguards for the petroleum industry are provided such as hydrant and monitor nozzle coverage. There are a 20 automatic and manual deluge waterspray systems over process pumps and manual deluge water weir coverage over LPG Spheres. Fire protection water is supplied by four diesel engine driven fire pumps. Two automatic, 2500 gpm at 140 psig, vertical turbine diesel fire pumps take suction from a 4.0 MM gallon pond. The HF waterspray mitigation system is cross connected to the fire protection water supply. It consists of two 4000 gpm @164 psig fire pumps connected to a 2.5 mm gallon pond. A well looped underground system of 12", and 14" mains exists throughout the refinery and supplies an adequate number of yard and monitor nozzles. Adequate sectional control valves are provided. The site has a mature PSM program. This is an OSHA VPP Star Site.

An ample complement of portable fire equipment is provided throughout the refinery. The fire pumps are inspected weekly, with adequate records maintained. In addition to plant hydrants, the plant cooling tower basins could be used as a firewater suction source in an emergency or the fire pumper trucks could draft directly from the firewater pond.

The refinery has a structural fire fighting brigade on each shift (10-15 members per shift). They have several pieces of mobile equipment including a 3500 gpm foam pumper truck. The professional Refinery Terminex Fire Company in Coastas Texas will respond if requested, with up to three large fire trucks and 20,000 gallons of foam concentrate in three hours.

GENERAL FLOW DIAGRAM



FINANCIAL REVIEW

INSURABLE VALUES

Property Damage is based upon current replacement costs. Business Interruption is a projection for 2010.

Property Damage:	**$**	**1,465.1**	**MM**
Business Interruption:	**$**	**189.0**	**MM**
Total:	**$**	**1,654.1**	**MM**

Plant P.D. Breakdown

Unit/Area/Equipment	Capacity (BPD)	Total PD (MM)
West Plant - Crude Unit	96,600	69.3
West Plant - Vacuum Unit	35,000	28.1
West Plant - Reformer (Semi-Regen)	10,500	25.7
West Plant - Hydrogen Generation (MMSCF/D) Mostly idle	2 to 4	-
West Plant - Hydrogen Purification	4,500	2.3
West Plant – Rose Unit	10,000	21.3
West Plant – Special Fractionation (LEU/Sat Gas)	27,000	12.5
West Plant – Sulfur Unit	100 LTD	9.6
West Plant – DOT (VGO Desulphurizer)	17,000	49.5
West Plant – BTX Unit (aromatics solvent extraction)	18,000	36.3
West Plant – No. 1 HDS (Distillate Hydrotreater)	33,000	66.5
West Plant - Tail Gas Unit (LTD)	20	9.1
East Plant – Sulfur Unit (LTD)	70 -100	9.5
East Plant – Special Fractionation (LEU)	26,500	12.4
East Plant- No. 2 HDS (Naphtha Hydrotreater)_	24,000	29.6
East Plant - FCC Unit	24,500	121.7
East Plant - Hydrocracker Unit	30,000	171.1
East Plant - Reformer (CCR)	23,500	73.6
East Plant - HF Alkylation	6,500	52.9
Other Process Units (incl. Cryogenic & Lube Oil)		13.7
Utilities		16.0
Total Process Units		**830.7**
Process Related Off-Sites (electrical, pipe racks, cooling towers, etc.)		367.4
Other Off-Sites (Tankage, Loading Racks, etc..)		235.5
Catalyst		20.8
Spare Parts		10.7
Total Off-Sites and Other		**634.4**
Total Refinery		**1,465.1**

INSURABLE VALUES - continued

Plant BI Breakdown

Product Line	Approximate Share of BI
Gasoline	42%
Diesel	23%
Jet Fuels	10%
Specialty Sales	15%
LPG	4%
Heavy Oils & Lube Oils	6%

LOSS ESTIMATES

The Maximum Foreseeable Loss estimate is based upon a vapor cloud explosion at the FCC Unit, which destroys the local units and effectively shuts down the Refinery.

There are five types of Loss Estimates are included in this report. Three are in regards to Fire and Associated Perils and two in regards to Boiler and Machinery Perils

NLE = Normal Loss Expectancy
EML = Engineered Maximum Loss
MFL = Maximum Foreseeable Loss

Loss Estimate Table

Loss Estimates	P.D. ($MM)	B.I. ($MM)	I.B.I./E.E. ($MM)	TOTAL ($MM)
NLE-Fire	24.3	47.3	0.0	71.6
EML– Fire	73.0	189.0	0.0	262.0
MFL– Fire	**556.4**	**330.8**	**0.0**	**887.1**
EML – BM	0.5	1.5	0.0	2.0
MFL – BM	10	283.5	0.0	293.5

LOSS ESTIMATES - continued

Fire and Associated Perils - Normal Loss Expectancy

Definition:

The expected economic loss resulting from a significant release of flammable materials and ensuing fire or deflagration. All fixed loss prevention systems and emergency response organizations are expected to respond normally. The amount of direct damage is assumed to be proportional to the characteristics of the process unit and its loss prevention systems. Typical initiating events: catastrophic pump seal failure, site glass failure or spill fire in tank farm dike.

Scenario:

Under this scenario a fire in the Reactor Area of the FCC Unit would spread quickly throughout the area. This is primarily due to process congestion, exposed cable trays and the lack of complete deluge waterspray protection for the process equipment. The fire would be contained to the Gas Con areas by the plant emergency response brigade. Reinforced concrete and fire proofed steel process supports would prevent wide spread collapse and heavy damage to the unit.

The refinery would not be able to meet specification requirements without the FCC Unit and would not be able to store or transport out the excess vacuum gas oil for an extended interruption.

Physical Damage:			
Area	**PD Value**	**Damage**	**Loss**
FCC Gas Con	$ 121.7 MM x 40%	50%	$ 24.3 MM

Business Interruption:			
Line	**BI / month**	**Interruption**	**Loss**
Refinery	$ 15.8 MM	3 mo's @ 100%	$47.3 MM

IBI/Extra Expense:			
Material(s)	**Amount**	**Extra Cost**	**Loss**
N/A			

GRAND TOTAL			**$ 71.6 MM**

LOSS ESTIMATES – continued

Fire and Associated Perils - Engineered Maximum Loss

Definition:

The expected economic loss resulting from a large release of flammable materials and ensuing fire or low order explosion. Partial failure of the fixed loss prevention systems is assumed. Normal performance from the emergency response organizations is expected. The amount of direct damage is assumed to be proportional to the characteristics of the process unit and the loss prevention systems remaining in service. Typical initiating events: catastrophic compressor failure, opening in piping of 1 inch or large in diameter, etc.

Scenario:

A large release of hydrocarbons in the FCC Unit Reactor Area and an ensuing low order explosion and/or ensuing fire with one fixed fire protection system out of service. The fire would spread rapidly and be difficult to contain due to process congestion, exposed cable trays and the lack of automatic deluge waterspray protection on process equipment. Plant fire fighting efforts would be primarily devoted to preventing BLEVEs (boiling liquid expanding vapor explosions) and limiting the damage to other units. The fire would not be extinguished until the unit could be shutdown and blocked in. There would be heavy damage to the FCC Unit.

It would take approximately 12 months to repair the FCC Unit and bring it back to full production. The refinery would not be able to meet specification requirements without the FCC Unit and would not be able to store or transport out the excess vacuum gas oil for an extended interruption.

Physical Damage:			
Area	**PD Value**	**Damage**	**Loss**
FCC Unit	$ 121.7 MM	60%	$ 73.0 MM

Business Interruption:			
Line	**BI / month**	**Interruption**	**Loss**
All Lines	$ 15.8 MM	12 mo's @ 100%	$189.0 MM

IBI/Extra Expense:			
Material(s)	**Amount**	**Extra Cost**	**Loss**
N/A			

GRAND TOTAL			**$ 262.0 MM**

LOSS ESTIMATES – continued

Fire and Associated Perils - Maximum Foreseeable Loss

Definition:

The worst case loss resulting from a catastrophic incident such as a vapor cloud explosion with and ensuing fire, or some other type of explosion and ensuing fire. A total failure of loss prevention systems is generally assumed along with a lack of effective response from emergency response organizations. The extent of fire damage will depend upon the nature of the process affected by the incident and the passive loss prevention features associated with the facility. Examples: total release of the contents of a process circuit or short duration releases from pipelines and storage tanks.

Vapor clouds can be drifted up to 120 meters to maximize the loss estimate *provided* that the new assumed center of the explosion can provide the confinement and obstacle density needed for a VCE event. All material in a cloud is assumed to be in the flammable range. The amount of material in a cloud is calculated using the super heated flashing liquid formula. An adjustment is made for the expected aerosol effect. A maximum cloud size of 60 metric tons is assumed. The TNT equivalency method is used to approximate the damage caused by a vapor cloud explosion. The Swiss Re Ex-Tool Software is used to calculate the overpressures of the VCE.

Scenario:

The MFL for this facility would be caused by an unconfined vapor cloud explosion, which is possible upon the release of a large quantity of liquefied flammable gas or flammable liquid heated above its atmospheric boiling point. Large releases are possible from the HF Alkylation Unit; the Light ends Unit in the East Plant, and the LPG bullets and butane spheres at the south end of the facility. Because of the Alkylation Unit's central location in the East Plant, it is likely that the worst case scenario would involve a release of isobutane from the high pressure receiver (160 psig & 200°F). This 50,000 gallon vessel normally contains about 20,000 gallons of C4 and lighter components. Thus, based on a 20,000 gallon release and total vaporization, the cloud weight would be approximately 83,000 lbs. or 37.7 metric tons.

Based on a heat of combustion of 49,600 KJ/KG, and an explosive yield factor of 4%, the equivalent energy of an exploding 37.7 metric ton cloud of butane would be approximately 16.6 metric tons of TNT. This will create overpressure waves with radii of approximately 117 meters (384 ft.) for the 5 psi/345 mbar circle, 209 meters (685 ft.) for the 2 psi/138 mbar) circle, and 332 meters (1090 ft.) for the 1 psi/73 mbar circle. No drift is needed to maximize the loss estimate.

The FCC, Hydrocracker and Alkylation Unit would be heavily damaged by this event. The other units at the East Plant (the CCR, HDS, a Sulfur Unit and the Light Ends Unit) would suffer moderate damage. The West Plant would be largely unaffected due to its separation from the East Plant. HF contamination could be a major problem.

It is expected that the Refinery would be effectively shut down for three months after the incident for initial HF decontamination and the loss investigation. The FCC and HF Alkylation Unit are expected to take another 18 months to rebuild. The other units could be repaired sooner, however, the Refinery as a whole is not expected to be a feasible operation without the FCC and Alkylation Units.

LOSS ESTIMATES – continued

Fire and Associated Perils - Maximum Foreseeable Loss – continued

PD Loss Breakdown Table

Area/Unit/Category	P.D. Value ($MM)	Damage	P.D. Loss ($MM)
West Plant - Crude Unit	69.3	0%	-
West Plant - Vacuum Unit	28.1	0%	-
West Plant - Reformer (Semi-Regen)	25.7	0%	-
West Plant - Hydrogen Generation (MMSCF/D)	-	0%	-
West Plant - Hydrogen Purification	2.3	0%	-
West Plant – Rose Unit	21.3	0%	-
West Plant – Special Fractionation (LEU/Sat Gas)	12.5	0%	-
West Plant – Sulfur Unit	9.6	0%	-
West Plant – DOT (VGO Desulphurizer)	49.5	0%	-
West Plant – BTX Unit (aromatics solvent extraction)	36.3	0%	-
West Plant – No. 1 HDS (Distillate Hydrotreater)	66.5	0%	-
West Plant - Tail Gas Unit (LTD)	9.1	0%	-
East Plant – Sulfur Unit (LTD)	9.5	80%	7.6
East Plant – Special Fractionation (LEU)	12.4	70%	8.7
East Plant- No. 2 HDS (Naphtha Hydrotreater)_	29.6	60%	17.8
East Plant - FCC Unit	121.7	90%	109.5
East Plant - Hydrocracker Unit	171.1	60%	102.7
East Plant - Reformer (CCR)	73.6	60%	44.1
East Plant - HF Alkylation	52.9	100%	52.9
Other Process Units (incl. Cryogenic & Lube Oil)	13.7	10%	1.4
Utilities	16.0	50%	8.0
Process Related Off-Sites (electrical, pipe racks,	367.4	25%	91.9
Other Off-Sites (Tankage, Loading Racks, etc..)	235.5	10%	23.6
Catalyst	20.8	50%	10.4
Spare Parts	10.7	50%	5.4
Sub Total			**$ 483.8**
T.A.F.* (15% of Subtotal)			**$ 72.6**
Total			**$ 556.4**

* The TAF or Technical Adjustment Factor, includes the following surcharges.

Debris Removal/Decontamination:	2%	Inflation (3% over 3 year adjustment period)	10%
Modernization Fees	2%	Engineering and Permitting Fees	1%

Production Lines	B.I. /month ($MM)	Loss	Months	Loss ($MM)
All Product Lines	15.8	100%	21	330.8

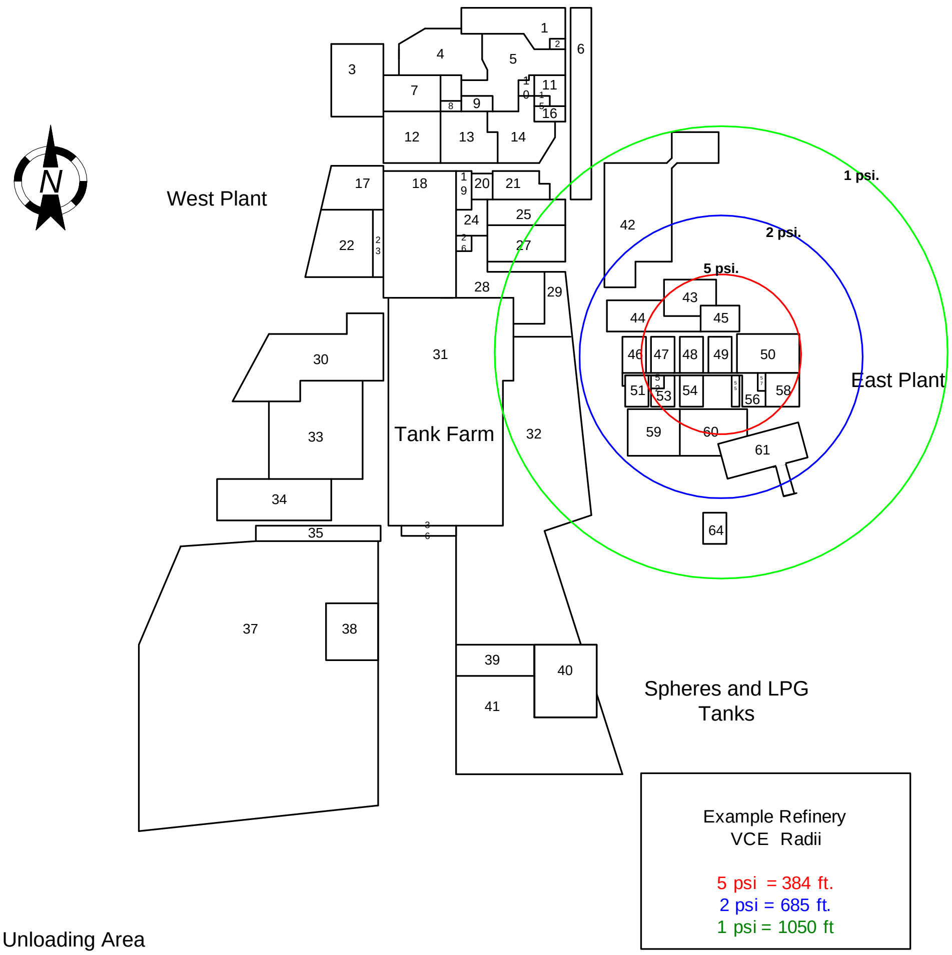
Direct Business Interruption **$ 330.8 MM**

Extra Expenses **$ - MM**

GRAND TOTAL = $ 556.4 MM PD + $ 330.8 MM BI + $ - MM EE = $ 887.1 MM

LOSS ESTIMATES – continued

VCE DIAGRAM



2 - Unloading Area
3 - Bullet Tanks
4 – Storage Tanks
5 - Storage Tanks
6 - Railcar Loading
7 - Rose Unit
8 - Vacant
9 - Crude Desalter
10,11,15,16 Mirando & LO
12 -Vacuum Unit
13 - HDS Reformer 1
14 - Crude Unit
17 - Bullet Tanks
18 - Storage Tanks
19 - Storage Tanks
20 - Storage Tanks
21 - 4300 Hydrogen Unit and West Plant Control Room
22 - Storage Tanks
23 - Storage Tanks

24 - Storage Tanks
25 -26 DOT Unit
27 - BTX/Aromatics Unit
28 - 36 Storage Tanks
37 - Idle Ponds
38 - Fire Water Pond
39 -41 Butane/Propane Storage and loading
42 - Main Office, Fire Station, Maintenance, Warehouse, New Lab
43 - CCR Unit
44 - Naptha Hydrotreater
45 - East Plant MCC & Control Room

46 - Cooling Tower
47- Light Ends Unit
48,54 Alkylation Unit
49 - 50 FCC Unit
51 - Sulfur Recovery Unit
52 - Light Ends Unit
53 - Sour Water Recovery Unit
56 - FCC Gas Con Area
58 - Hydrocracker Fractionator Unit
59 -Main Sub Station
60 - Utilities
61 - Hydrocracker Unit
64 - HF Mitigation Pumps

LOSS ESTIMATES – continued

Boiler & Machinery Perils - Engineered Maximum Loss

Definition:

The maximum amount of sudden and accidental loss that can occur to an object.

Scenario:

The event chosen is a stator winding failure on one of the large motors serving the booster compressor serving the Hydrocracker. The occurrence would require a shutdown of the compressor during motor repairs. Repairs to the synchronous motor could be completed in a period of three weeks at an estimated cost of $500,000.

The loss of one compressor in the Hydrocracker Unit would cause a 40% reduction in the Hydrocracker charge capacity and a 12,000 BPD reduction (13%) in Refinery output.

Physical Damage:			
Equipment	**Repair Replacement**	**Other Fees**	**Loss**
Hydrocracker Compressor	$ 0.5 MM	$ -	$ 0.5 MM

Business Interruption:			
Line	**BI / month**	**Interruption**	**Loss**
All Lines	$ 15.8 MM	0.75 mo's @ 13%	$ 1.5 MM

IBI/Extra Expense:				
Product		**Product Loss**	**Extra Cost**	**Loss**
N/A				

GRAND TOTAL			**$ 2.0 MM**

LOSS ESTIMATES – continued

Boiler & Machinery Perils - Maximum Foreseeable Loss

Definition:

The maximum amount of sudden and accidental loss that can occur to an object, without any credit to spare equipment or expediting efforts which may reduce the loss.

Scenario:

The event chosen is a total loss of the FCC Reactor due to a mechanical failure. The occurrence assumes damages could not be repaired and fabrication of a new reactor would be required. The reactor would take approximately 18 months to replace and install. Loss of the reactor virtually eliminates gasoline production.

Physical Damage:			
Equipment	**Repair Replacement**	**Other Fees**	**Loss**
FCC Reactor	$ 9.0 MM	$ 1.0 MM	$ 10.0 MM

Business Interruption:			
Line	**BI / month**	**Interruption**	**Loss**
Refinery Output	$ 15.8 MM	18 mo's @ 100%	$ 283.5 MM

IBI/Extra Expense:			
Product	**Supplier**	**Extra Cost**	**Loss**
N/A			

GRAND TOTAL			**$ 293.5 MM**

LAYOUT AND CONSTRUCTION

SITE LAYOUT

The Example Refinery is located near the intersection of US Highway 1 and State Route 2 on the edge of the town of Example, Texas on a 400 acre site. There are no immediate industrial or residential neighbors.

The refinery is divided into two integrated but well separated Plants: the East Plant and the West Plant. The West Plant consists of the Crude Unit, Vacuum Unit, Demex Unit, Lube Oil Units, Naphtha Splitter Unit, No. 1 Naphtha Hydrotreater,Gas Oil Hydrotreater, Hydrogen Unit and the Benzene/Toluene/Xylene (BTX) Splitter.

The East Plant consists of a CCR/Naphtha Hydrotreater Unit, FCC Unit, Hydrocracker Unit, HF Alkylation Unit, Merox Treating and Light Ends Separation Unit.

The tank farm is large and is located south of the West Plant and extends southwards. The tank farm contains both finished and raw materials. There is also a small tank farm for the Lube Oil Units located on the north side of the West Plant.

PROCESS UNITS

The process units are open, outdoor design with steel frames and supports. The structural steel supports are fireproofed 25 to 35 ft. above grade. Fire proofing is mostly 2 and 3 hours rated per UL 1709. Secondary piping supports are not generally fire proofed.

Spacing between process units varies from 25 ft to 100 ft.

Each process unit is provided with chemical spill and storm water run off drains. Large scale application of fire fighting water will tend to pool and drain away from the immediate process areas.

CONTROL BUILDINGS

Each Plant has its own dedicated Control Building. The buildings are blast resistant and pressurized. IO equipment is located within these buildings and in secondary buildings. These secondary buildings are masonry structures and have been provided with smoke detection systems.

OPERATIONS

The Example Example refinery is a continuously operating petroleum refinery with a total feedstock throughput of 100,000-BPD. The refinery is capable of producing a wide variety of products including fuel gas, LPG's, propylene, gasoline, kerosene, jet fuel, diesel fuel, No. 6 fuel oil, benzene, toluene, xylene and sulfur.

Although there have been operations at the location since the 1960's, the refinery construction began in 1964 with the Crude Unit. The first major expansion was in 1978 and 1979 when the Catalytic Reformer and Vacuum Distillation units were added. in 1985 an FCC unit and Alkylation unit were added. In 1992 and 1993 the Crude Unit was expanded again. The CCR reformer was added in 1994. The Hydrocracker unit was built in 1999. The Gas Oil Hydrotreater, and Hydrogen Plant were moved to the plant site in 1998 and 1996 and the BTX Unit was grassroots construction in 1996. Sulfur recovery operations are provided for both plants although there operation is integrated.

WEST PLANT

<u>Crude Unit:</u> The crude oil is desalted in a two-stage process with preheating done by a gas fired vertical heater. A pre-flash column followed by an atmospheric distillation column obtains naphtha, kerosene, diesel fuel, and gas oil as the side stream fractions, with reduced crude oil as the bottoms product. The atmospheric column is equipped with light ends strippers that serve each side stream withdrawal. These side cut strippers are stacked columns in a single shell. T he unit uses four fin fan condensers and receives cooling water from the cooling tower serving the West Plant.

<u>Vacuum Unit:</u> The Vacuum Unit is a 32,000-BPD unit. The vacuum column produces the gas oil feed for the FCC and the Hydrocracker. Its feed stock is the atmospheric distillation bottoms from the Crude Unit. The vacuum column bottoms goes to the ROSE Unit.

<u>Rose Unit</u>: The 10,000-BPD Residual Oil Solvent Extraction (ROSE) Unit removes asphaltines from the resid. The process uses normal butane as a solvent to accomplish this recovery. A separator and stripping column are used to obtain a heavy gas oil, which is fed to the Gas Oil Hydrotreater before going to the FCC Unit. The heavy bottoms product from the ROSE Unit is a blend stock for asphalt and No. 6 fuel oil.

<u>Mirando Lubes</u>: The 3,000-BPD Lube Oil Unit and 2,200-BPD Lube Oil HDS were built in 1980 and 1976 respectively. A heavy naphthanic crude stream is processed to produce kerosene, gas oil and lube stock. The hydrotreater uses hydrogen to desulfurize and improve the color and stability of the lube oil cuts. The bottoms off the tower go to the Vacuum Unit.

<u>No. 1 Reformer / Naphtha Hydrotreater:</u> This is a combined unit with the Reforming section and a capacity of 10,500-BPD. The Naphtha Hydrotreating portion was completed in 1978 with a capacity of 14,000-BPD. The unit is equipped with three spherical reactors and is located in the south-central area of the West Plant. It takes Naphtha and rearranges its molecular structure to form a higher octane aromatic reformate. Because dehydrogenation occurs during reforming, hydrogen is liberated and becomes a useful byproduct that can be consumed in hydrotreating operations. T his unit is equipped with two identical process gas compressors powered by electric motors. The naphtha stream feed for the reformer is hydrotreated to remove sulfur. The hydrotreating equipment has excess capacity and can provide treated naphtha to the other reformer. T he No. 1 Reformer is also equipped with a Cryogenic LPG recovery unit that uses two MAFI turbine expanders to recover heavier products from the off-gases emanating from the HDS and the FCC Unit.

BTX Unit: The Benzene, Toluene, Xylene (BTX) Unit has one solvent extraction tower with a fired reboiler followed by three columns in series that separate benzene, toluene, and xylene streams from light reformate. The finished products are sent out by rail car from a dedicated loading spot.

Naphtha Splitter Column: This atmospheric distillation column receives the overhead products of the Crude Unit and yields undebutanized light straight run gasoline as the top product, with the bottoms stream serving as feed stock for reforming.

Deasphalting Oil Treater (DOT) Unit: Heavy gas oils are hydrotreated to reduce concarbon, nitrogen, and sulfur levels prior to being fed to the FCC Unit.

Hydrogen Plant: Natural gas is reformed with super heated steam in a single furnace. The product gas is compressed and purified in a pressure swing adsorption unit. The hydrogen is used by the various hydro treating operations within the refinery.

EAST PLANT

No. 2 Reformer / Naphtha Hydrotreater: This is also a combined unit. The No. 2 Reformer is a Continuous Catalyst Regeneration (CCR) process unit. It has four reactors, preceded by the hydrotreater reactor, that produce mixed LPG's and a reformate stream used for gasoline blending. This combined processing area has several heaters and towers and is physically separated into two sections by a pipe rack.

FCC Unit: The Fluid Catalytic Cracker (FCC) produces LPG, gasoline, light cycle oil, and slurry oil. An 8,000 HP electric motor driven blower supplies combustion air to the catalyst regenerator. The two-stage wet gas compressor is powered by a 3,075 HP steam turbine. The unit has a Belco Scrubber.

Alkylation Unit: The HF Alkylation Unit, has a feed throughput capacity of 6,000-BPD. This unit receives isobutane and olefins from the light ends distillation section of the FCC Unit as well as purchased feed received via truck. The unit produces alkylate (a high octane stream) which goes to the gasoline blending pool. The unit is also protected by a HF mitigation system consisting of both a water curtain ring and elevated remotely operated monitors.

HCU Unit: The Hydrocracker takes gas oil streams from the Crude and Vacuum Units are catalytically cracked in the presence of hydrogen to form lighter products such as mixed LPG's, LSR, naphtha, kerosene, and diesel. This is a high pressure vapor phase exothermic reaction that has two reactors in series. This unit is well detached from the other units. Its fractionation equipment is located in a separate process block near the FCC Unit.

LEU Unit: The Light Ends Unit takes liquids from the Crude Unit, mixed LPG's from the Reformers and the Hydrocracker, and externally supplied natural gas liquids are separated into fuel gas, ethane, propane, normal and iso-butane and light straight run gasoline. This is accomplished by a series of skid mounted columns/fin fans/pumps served by a common pipe rack.

Merox Unit: Merox is a proprietary process for extracting easily removed mercaptans and converting the remaining mercaptans in naphthas to disulfides. It employs caustic soda, which is regenerated by lowering with air in the presence of a special catalyst to oxidize the mercaptans to disulfides. These are used to treat LPG, lower boiling fractions, gasoline streams and kerosene streams.

Sulfur Recovery: Sulfur recovery is accomplished by MDEA Units as well as Tail Gas Recovery Units.

TANKAGE, PIPELINES AND LOADING

Crude oil is received primarily by pipeline from the Example terminal. The finished products are sent out by pipeline to the Example terminals, as well as some truck and rail traffic.

The tank farm is large and is located south of the West Plant and extends southwards. The tank farm contains both finished and raw materials. There is also a small tank farm for the Lube Oil Units located on the north side of the West Plant. The tank farms are provided with earthen diking. The large (south) tank farm has cone roof tanks, external floating roof tanks, bullet tanks and spheres. Both finished and raw materials are stored in the tanks. Most of the cone roof and floating roof tanks have semi-fixed foam systems. Monitors and hydrants have been provided as well. The spheres have remote actuated water weir systems and fire proofed legs. The bullet tanks have been provided with remote actuated deluge systems. The smaller tank farm has only small cone roof tanks. The Tank Farm Project (a Long Term Project) has been completed. The dike walls have been refurbished and the NFPA 30 intermediate diking has been completed.

A Tank Farm list has been included in the appendices of this report.

The truck loading rack uses a Scully bottom loading emergency shutdown system and an automatic water spray system over the area. Gasoline, Jet fuel and diesel fuel are the main products of this rack. LPG's are loaded at two locations on the south side of the refinery near the butane spheres. A fire detection system has been interlocked with the LPG loading system. The rail loading for benzene and other products is near the entrance to the West Plant. Monitor nozzles are available for this area.

CRITICAL EQUIPMENT

HEATERS

All new heaters have a modern BMS and process control system meeting the Example Corporate Standard. The BMS includes a double SSV, pressure regulators, a permissive based purge system, high stack temperature and oxygen interlocks. Approximately 33% of the sites 31 Heaters will have been upgraded by the end of 2009.

Progress continues on the Heater Controls Standardization Project. The heaters are being upgraded as part of the TA cycles. Triconex equipment is being used to operate the SIS loops. SIL ratings of 1 and 2 are in the design standard.. New equipment is being installed such that on-line testing of the SIS can be done. Older controls are being retrofitted over time with on line testing capability.

ROTATING EQUIPMENT

Critical rotating equipment at this refinery includes the following:

The FCC Main Air Blower is an Elliot axial flow compressor driven by an 8,000 HP motor. The blower train is fully instrumented including a continuous vibration monitoring and shutdown system and state of the art surge protection. Major spare parts stocked on site include rotors, gears for the gear set, and a motor.

The FCC Wet Gas Compressor is an Elliot steam turbine driven centrifugal compressor with a Philadelphia gear box. 450 psi steam drives the machine with an air cooled surface condenser. The turbine has been upgraded to an electronic speed control system. Both turbine and compressor are provided full instrumentation including a continuous vibration monitoring and shutdown system. Major spares stocked on/off site include a turbine rotor, compressor rotor, bearings and seals.

The Hydrocracker Booster Compressors are reciprocating machines driven by 5,000 synchronous motors.

REACTORS AND TOWERS

Critical reactors and towers include the FCC Reactor and Regenerator and the Hydrocracker Reactor.

The FCC reactor and regenerator have been in operation since 1981. Both are fabricated of carbon steel and are UOP design. The flue gas cooler is a box type heat recovery steam generator critical to FCC operations. Without the heat sink of the flue gas cooler, the FCC unit would shut down from high temperature in the belco. The boiler produces 45,000 lb/hr of 450 psi steam that is used to drive the wet gas compressor through a steam turbine.

The R-2 Hydrocracker Reactor is a thick walled, forged vessel operating in the 2,800 psi range. There are no spare reactor vessels or alternate means to hydrocrack. The vessels are typically not available in the United States and this particular vessel was manufactured in Japan. Delivery time can approach 18 months.

UTILITIES

Many of the utilities at this site are divided by the East Plant (Complex 1) and the West Plant (Complex 2)

STEAM

The refinery's steam system consists of three main headers: 450 psig superheated, 150 psig saturated and 50 psig saturated. The 450 psig superheated steam is produced by six fuel gas fired boilers, the FCC flue gas waste heat boiler, the CCR heaters convection sections and the sulfur plants thermal reactors. The 150 psig saturated steam is produced a numerous waste heat boilers, let down from the 450 psig header and turbine exhaust and a single fuel gas fired boiler. All the 50 psig steam is produced from waste heat boilers, sulfur condensers, turbine exhaust and letdown from the 150 psig header. Approximately 500,000 lb/hr 450 psig steam is consumed, 330,000 psig lb/hr 150 psig steam is consumed and 190,000 lb/hr 50 psig steam. The steam headers are connected to both complexes. The system typically operates at around 85 to 90% capacity.

ELECTRICITY

All electrical power to the site is provided by three separate 138 kV utility feeds that supply a modern ring bus arrangement at the main substation. Any one feed would be adequate for site electrical demand. Incoming voltage is stepped down to 12.5 kV by four 20 MVA three phase, oil filled transformers that power four 1200 A switchgear lineups. Two of the four transformers are required for operation. The main 12.5 kV gear, as well as the various process substations and motor control centers, feature double ended main tie main designs. Switchgear consists of a mix of current limiting fuses and relay breakers. The 8,000 HP FCC Main Air Blower is supplied from the Main Substation by a 7.5 MVA 138 KV – 4.16 KV transformer which is spared. Average electrical demand for the site is about 64 MW. There are a number of diesel emergency generators and uninterruptable power supplies for critical process controls. Feeder cables are a mix of aerial and underground lines.

PROCESS & COOLING WATER

Process water comes from the municipal supply and private wells. The city source is through a single connection that normally provides 700 gpm. The well water is supplied by three wells (total 650 gpm) located about five miles from the plant. Each well has a submersible pump, driven by motors. The well water is pumped into a 5,000 barrel tank located near the wells. One pair of pumps is used to transfer the water from this tank to a 10,000-barrel tank in the West Plant. One pump is a spare. Another pair of pumps delivers water from this tank to a surge tank in the East Plant. One pump is a spare. Another leased well is to be installed for reliability purposes.

The West Plant cooling water system is comprised of two cooling towers with associated pumps, piping and heat exchange equipment.

Cooling Tower #1 provides approximately 40% of the WPLT cooling water needs. It has three cooling towers structures over a single basin containing approximately 40,000 gallons. There are four cooling water circulation pumps that have a design rate of 9000 GPM @ 173 feet of head. This cooling tower system typically operates at approximately 80% of design capacity when the crude charge rate is at 90,000 B/D during the summer season.

Cooling Tower #2 provides approximately 60% of the WPLT cooling water needs. It has a one cooling tower structure over a single basin containing approximately 35,000 gallons. There are four cooling water circulation pumps that have a design rate of 14,000 GPM @ 132 feet of head. This cooling tower system typically operates at approximately 85% of design capacity when the crude charge rate is at 90,000 B/D during the summer season.

Piping and exchangers are almost all exclusively carbon steel. There are several small brass coolers associated with various compressors.

The East Plant cooling water system consists of two cooling towers and associated circulating equipment. The two cooling water systems are designated the South system and the North system. The design parameters for the two systems are listed in the table below.

	South System	North System
Configuration	Crossflow	Crossflow
Processing Units Serviced	FCC, UnSat Gas Plant, HF Alky, Hydrocracker Main Fract, Utilities, Sour Water Strpr, ATS	CCR, Hydrocracker, Sulfur Recovery Unit, Sat Gas Plant (LEU)
Number of Cells	two	three
Number of Pumps	2 motor driven, 1 steam turbine driven	5 motor driven (1 pump as standby spare)
Circulation Capacity, gpm	15000	20000
Heat Removal, MMBtu/Hr	120	160

The circulating systems include cross connects on the supply and return headers to enable contingency operations.

COMPRESSED AIR

The East Plant instrument air and plant utility air are supplied by three identical centrifugal, three stage compressors operated in parallel. Each compressor has a capacity of 1,500 SCFM. Two compressors are steam turbine driven and one compressor is motor driven. Two compressors are operated continuously with one compressor in auto start, standby service. Each compressor is equipped with suction filtration, interstage coolers, discharge coolers and automatic surge protection controls. The common discharge header routes to an air receiver vessel. Instrument air from the receiver vessel passes thru a filter coalescer, regenerative dryers, and fine particulate filters prior to routing to the instrument air distribution system. The regenerative dryers consist of two dryer systems operating in parallel. Each dryer system consists of two vessels with one vessel in drying service and one vessel in regeneration. The dryer regeneration is automated with control room monitoring and alarming functions to include dry air moisture content monitoring and alarming.

The West Plant instrument air system is comprised of two reciprocating air compressors and their associated after-coolers, air receivers and air dryers. Instrument air compressor 630-C-64 is rated to deliver 720 SCFM at 125 psig. Instrument air compressor 630-C-74 is rated to deliver 820 SCFM at 100 psig. Both air compressors are adjusted to deliver instrument air into the system at 80 psig. The instrument air are pressure swing design. The dryers achieve a dew point of -50 deg F or better.

A common line exists between both complexes that can allow flow between each. This line is normally closed. The air systems include control instrumentation to automatically throttle the flow to the plant utility air system to insure that the instrument air system demand is always satisfied.

REFRIGERATION

The LPG Recovery unit in the No. I Reforming area is a cryogenic operation that uses one MAFI turbine expander. Two external Freon chillers can also be used to pre-cool the off-gases before they enter the turbine suction during the summer. This unit currently processes FCC off-gas as its primary feed.

INDUSTRIAL GASES

Natural gas delivered into the plant by two suppliers, AEP and Duke Energy. AEP is supplied at 450 to 500 psig. Duke Energy gas is supplied at 800 psig. The gas pressure is regulated and routed to three fuel mix drums. The East Plant and Main West Plant mix drums operate at 70 to 80 psig. The hydrogen plant fuel gas mix drum operates at 25 psig.

Fuel mix drum 6-V-20 is located in the East Plant area and natural gas is supplied by Duke Energy. Fuel mix drum 6-V-4 is located in the West Plant area and natural gas is supplied by AEP. Fuel mix drum D-2507 is located in the West Plant Hydrogen Plant area and natural gas is supplied by either AEP or Duke Energy.

Suitable process gases are amine treated to remove the sulfur and then are routed to the appropriate fuel mix drum. The resulting natural gas/process gas mixture is then used to fire various heaters and boilers throughout the plant.

The refinery's nitrogen is supplied by Air Liquide. The system consists of an on-site air separation nitrogen plant that produces up to 35,000 SCFH of 99.999 % pure nitrogen. Liquid nitrogen is available in (2) 11,000 gallon nitrogen tanks and is used for back up to the nitrogen plant and for refinery's consumption that exceeds that of the nitrogen plants production. Recent liquid nitrogen usage, on average, has been 25,000 SCFH. The nitrogen plant is centralized to distribute nitrogen at a normal operating pressure of 150 psig, however up to 250 psig can be supplied, to the refinery's East Plant, West Plant, and Tank Farm.

Supplemental (24 MM SCFD max) Hydrogen is obtained from the Air Liquide site in Corpus Christi via an 8" pipeline.

FLARES

Flare studies are done on a regular basis to verify that the Refinery Flares and their headers can handle a high demand event such as a fire or a utility failure. The East and West Plant have dedicated flares and flare headers with knock out pots. Process vessel PRVs are connected to the flare headers.

WASTE WATER

All chemical spills and storm water effluent are captured on site in ponds and treated prior to being released. The site also has an underground injection well.

PROCESS AUTOMATION

BASIC PROCESS CONTROL SYSTEMS

The process control systems are being upgraded from Honeywell TDC 3000 systems to Experion. Gas fire heaters are provided with automatic shutdown systems interlocked with emergency isolation valves on the fuel train and manual steam snuffing systems.

Per a corporate standard the reliability of all PLCs is being improved by providing them with redundant, hot standby configuration and dual ether-net communication system capabilities.

EMERGENCY SHUTDOWN SYSTEMS

There are unit-specific emergency shutdown systems as well as equipment specific shutdown systems. Emergency shutdown systems are mostly hardwired although some dedicated programmable logic controllers (PLC) are being employed. Triconex systems have been installed for the FCC WGC and the Main Air Blower.

Example is implementing Corporate Guideline on the application of SIS type interlocks for Reactors and other high hazard equipment The FCC and the HCU are to be evaluated next.

Progress continues on the Heater Controls Standardization Project. The heaters are being upgraded as part of the TA cycles. Triconex equipment is being used to operate the SIS loops. SIL ratings of 1 and 2 are in the design standard. New equipment is being installed such that on-line testing of the SIS can be done. Older controls are being retrofitted over time with on line testing capability.

ALARM AND INTERLOCK MANAGEMENT

Alarm Management improvements are expected as the refinery moves to the Honeywell Experion Control System. The full Alarm System rationalization process is expected to take five years to complete. The East Plant has set up an Alarm Management Team to identify critical alarms and interlocks.

There is an administrative protocol in effect to manage alarm by-passing by the operators. Interlocks can only be by-passed by an I&E engineer using an MOC.

EMERGENCY ISOLATION VALVES

Thirty six (36) emergency isolation valves have been installed across the refinery. Another twenty (20) are planned for using the new Example EIV specification, 17 GS-30. Eight (8) are expected to be installed during the next group of Turn Arounds in the fall of 2009.

The EIVs are provided with local and remote controls in the control rooms.

FIRE PROTECTION

FIRE PROTECTION WATER SUPPLY

The primary source of fire protection water is a 6,000,000 gallon fire water pond on the south side of the site that supplies two vertical turbine fire pumps with diesel engine drivers. The pumps are rated for 2500 gpm at 140 psi. The water supply for the HF mitigation system for the Alkylation Unit is connected into the fire water system via a normally closed 12 inch line. This water supply consists of two 4800 gpm at 150 psi diesel engine drive fire pumps taking suction from a 3,000,000 gallon lined pond.

A fire protection contractor conducts quarterly inspections and testing of the deluge systems (22 total), monitor nozzles, hydrants, the HF mitigation system and the fire trucks. Area operators conduct monthly visual inspections of the fire protection equipment in their units. The fire pumps are run tested for 30 minutes on a weekly basis by the Safety or Operations Department and have a quarterly PM program directed by the rotating equipment group.

Fire pump nos. 2 & 3 can be started remotely form the West Plant Control Room. They are Vertical Turbine Pumps with Right Angle Gears.

Where available fire pump curves and the latest data are included in the appendicies.

Fire Pump Data:

PUMP	RATING	DRIVER	SOURCE	ARRANGEMENT
No. 2 South Pump	2500 gpm @ 140 psi 1750 rpm	Diesel Engine 2100 rpm	6 MM Gallon Pond	Automatic start 75 psi.
No. 3 North Pump	2500 gpm @ 140 psi 1750 rpm	Diesel Engine 2100 rpm	6 MM Gallon Pond	Automatic start 65 psi.
No. 4 (HF)	4000 gpm @ 164 psi 1750 rpm	Diesel Engine 1750 rpm	3 MM Gallon Pond	Automatic Starting w/HF Mitigation System
No. 5 (HF)	4000 gpm @ 164 psi 1750 rpm	Diesel Engine 1750 rpm	3 MM Gallon Pond	Automatic Starting w/HF Mitigation System

FIXED FIRE PROTECTION SYSTEMS

A gridded network of 12” and 14” mains exists throughout the refinery. Adequate sectional valving has been provided. An adequate supply of hydrants and monitor nozzles has been provided. A large number of large diameter pumper connections have also been provided for expediting manual fire fighting efforts.

Automatic deluge water spray systems are being installed in congested processing areas such as the Crude Unit and over LPG service pumps on a program basis. The BTX unit has automatic water spray protection over its pumps and accumulators. The bullet tanks and spheres have remote actuated deluge systems. There is also a smaller manually actuated deluge systems in the FCC Unit. Steam snuffing systems are provided for heaters.

Hydrofoam stations (monitors and small hose lines) are provided in most of the process areas.

FIRE AND GAS DETECTION SYSTEMS

Smoke detections systems have been provided in most electrical rooms. The automatic deluge systems are activated by pilot head heat detection systems. Combustible Gas Detectors are provided in the LPG Tank Farm Area. HF Detectors are provided in the Alkylation Unit. All detectors alarm in a local Control Room or Satellite Control Room.

EMERGENCY RESPONSE

The Emergency Response Team has approximately 100 members. Off duty responders are notified in the event of an emergency by a pager system. Each team member is provided with an individual set of fire fighting bunker gear. Annual hands-on and classroom training is provided for all team members. All members receive 64 hours per year of training of which 32 is done off-site at a fire training ground. All ERT members are certified as Level 1 External Structural Fire Fighters as a minimum. Preplans have been developed for handling storage tank fires as well as types of fires such as compressors, fired heaters, pumps, etc..

The facility has a 1,500 gpm National Foam Pumper that carries 2,000 gallons of foam and 500 gallons of water. It also has large amounts of 5” hose as well as several other pieces of mobile equipment including a 4,000 gallon foam concentrate trailer. There are several thousand gallons of foam concentrate kept on site. A 3,500 gpm pumper truck was purchased in 2007.

An Emergency Operations Center is provided in the new Security Building. It is provided with an Emergency Generator. An Emergency Operations Center may also be setup at the Main Office. An Emergency Generator is also provided for the Main Office.

MANAGEMENT SYSTEMS

EQUIPMENT MAINTENANCE AND RELIABILITY

Maintenance and reliability programs continue to improve at this location. Work processes, planning and scheduling functions continue to improve. Advance reliability tools are being introduced (Weibull and Pareto analysis, Crowe AMSAA reliability growth charts, criticality ranking, root cause failure analysis, etc.). The site maintenance and reliability groups are involved in the corporate sponsored technical networks. The maintenance program includes regularly scheduled routine maintenance and inspections that are recorded and documented in the in-plant computerized maintenance system. SAP is used as the computerized maintenance management system. Maintenance is performed by an in-house maintenance supplemented as necessary by outside contractors and specialists. Large construction projects are contracted out. There is an excellent critical spares inventory.

Recently completed reliability improvements include:
- Electrical power system studies
- West Plant underground electrical service
- DCS reliability improvements

Near term reliability improvement highlights:
- Rotating equipment monitoring system upgrades including control room displays and trendability, axial vibration trips (2002 voting) and redundant instrumentation.
- Main Substation protective relay upgrade
- FCC Main Air Blower and Wet Gas Compressor instrumentation and surge controller upgrades
- Improved ground fault protection and motor protection relays

Reliability improvement highlights planned through 2012:
- Substation HVAC improvements
- New Refinery Main Substation at West Plant
- Underground electrical feeder replacements

<u>Fixed Equipment (Pressure Vessels, Tanks and Piping)</u>: The fixed equipment inspection and reliability programs at this site have improved significantly. Fixed equipment inspection compliance has improved dramatically. Overdue pressure vessel inspections have been reduce from 142 (Nov. 2007) to 60 (ytd) and should be near 0 following the February 2009 turn around. Overdue storage tank inspections have been reduce from 12 (Nov. 2007) to 2 (ytd). Overdue pressure relief device inspections have been reduce from 104 (Nov. 2007) to 52 (ytd) and should be near 0 following the February 2009 turn around. Overdue piping thickness measurements are only 0.06% of the total thickness measurements.

The fixed equipment program follows internationally recognized standards and good engineering practices such as ASME, API, ANSI, etc. Inspection programs have been developed for fired and unfired pressure vessels, above ground storage tanks and piping systems. Ultrapipe is currently used as the inspection data base management system. On stream piping inspection programs include ultrasonic thickness testing and corrosion under insulation assessments. Well developed positive materials identification and on stream leak repair procedures have been implemented. The overall number of process leak clamps has been reduced significantly. Positive materials identification is performed in accordance with best practices. The cathodic protection program has been improved.

Risk Based Inspection (RBI) methodologies and the use of Plant Condition Monitoring System for fixed equipment inspection data management are now Example corporate standards.

Electrical Maintenance: Electrical maintenance and testing activities include transformer oil and gas analysis, thermography, circuit breaker maintenance, relay calibration and testing, insulation resistance testing, and a battery inspection program. Transformer dielectric testing is conducted annually in the main substation and prior to shutdowns in operating units. Thorough shutdown transformer maintenance (insulation resistance tests, dialectic watts loss power factor testing) have been implemented. Insulation resistance and polarization index testing is conducted on the large motors during unit turnarounds. A Doble power factor testing program (windings and bushings) has been established for critical transformers. Transformer oils receive annual chemical and physical analysis including gas chromatography. UPS's and battery banks are PM'd quarterly. A site wide infrared thermographic survey is performed annually.

Rotating Equipment: Rotating equipment reliability programs continue to improve at this site. A long term service agreement has been established with John Crane to improve pump seal reliability. Oil mist systems have been installed on new units and other priority units. Rotating machinery programs include manual vibration monitoring on a routine basis using CSI equipment and RBI spectrum analysis software. Beta analysis is performed on critical reciprocating machines. Lube oil analysis is regularly conducted on large and critical equipment. Spectrographic analysis of lube oil is normally completed after oil samples are taken and before oils are changed. If problems are suspected following spectrographic analysis, wear particle analysis may be performed. There is a significant amount of expertise in laser alignment at this facility. Turbines are over speed trip tested annually. Currently, the mean time between failure for rotating equipment is about 47 months.

Instrumentation and Controls: There is a major effort at this site to bring all safety instrumented systems up to highly reliable, triple modular redundant, best in class world standards in compliance with ISA S84.01, "Application of Safety Instrumented Systems for the Process Industries" and IEC 61511 "Functional Safety: Safety Instrumented Systems for the Process Industry Sector." Online instrumentation checks are routinely performed and full function loop tests are performed during unit turnarounds. Safety instrumented system calibration and functional testing compliance at this site is 100%.

Critical Equipment Sparing & Contingency Plans: A formal contingency plan does not exist for the high valued or critical equipment in the plant, but reasonable steps could be taken to mitigate a loss involving one or more of the plant critical equipment. The plant processes are very flexible through adjustment of feed rates, purchase of intermediate products, and possible sale of semi-finished products. For each of the critical equipment exposures there are numerous ways to sustain operations in the event of an occurrence. The plant process engineers are continuously reviewing market conditions, production efficiencies, available intermediates, and available markets for finished and semi finished products.

Spare parts inventory for critical rotating equipment at the plant is very good. The plant stocks all rotating elements for critical equipment with the exception of some motors that could be rewound in a short period of time. All critical compressors, gear sets, expanders, and turbines have major spare parts stocked on site.

PROCESS HAZARDS ANALYSIS

The Refinery follows the Example Corporate Guidelines on PHAs. This guideline includes a set Risk Ranking Matrix. Each process unit has undergone a comprehensive PHA that included a full HazOp Analysis, an MOC and Incident Review (local and corporate) revalidation of the previous PHA, a Reliability Overview, an Inherently Safety Technology Review and a PSI update. The Site Process Safety Manager leads all of the PHAs.

The PHA program will conduct complete "ground up" PHAs during the next cycle as opposed to "revalidations", which are more limited in scope. All PHA Action Items are tracked to completion.

MANAGEMENT OF CHANGE

There is a mature MOC program in place. All engineers and operators are trained in the MOC process. There are three types of MOC: Emergency, Temporary, and Permanent. They currently use a paper based system but will be moving to an electronic E-moc system in 2010.

A separate MOC system has been implemented for process control changes.

There is a monthly audit of the MOC data base by Process Safety. A Site Risk Management Committee reviews all high risk action items or consequences identified in the PHA or MOC programs.

INCIDENT INVESTIGATION

The refinery uses the corporate software program IMPACT to manage their Incident Investigation Program and Recommendations. The program captures about 100 incidents per year, of which about 20% are near misses. Incidents are tracked by Severity and Type using pull down menus. There are sub-categories for type of production equipment involved. Anyone in the refinery can enter an incident into the system.

“Tap Root” is used for high level investigations. There are six trained Tap Root Facilitators.

Incidents are reviewed daily, monthly and annually by management.

SAFE WORK PERMITS

There is a Permit to Work procedure that follows OSHA VPP Star guidelines. A formal safe work permit system is used for confined space entry situations, hot work, lock-out/tag-out and other hazardous procedures. Cold work permits are issued by operations for all other maintenance work. Blind flanges are used for isolating equipment on all hot work or confined space entry jobs. Operations are responsible for preparing all equipment for maintenance work. Copies of all permits are kept in the local control room and in the field. These permits have specific requirements in regards to precautions that must be taken, and who is allowed to issue them. The plant safety department writes all hot work and confined space permits. A permit can last up to one shift. The permit system is audited weekly by pant personnel on a random basis. Job Safety analyses are done on all jobs involving high voltage and must be approved by the Safety Manager and the Refinery Manager. LEL monitoring is done prior to all Hot Work and Confined Space Entry

OPERATIONS

There are approximately 300 employees and 40 permanent contractors.

There is a formal operating training program in use with a Plant Training Coordinator responsible for writing all exams and monitoring operator development. In addition to class room exams the operators must also pass field proficiency exams done under the supervision of the shift supervisor. Certification normally takes three years. The API continuing education system is being used to give each operator 54 hours of training per year in addition to the Unit specific training they receive on safety and operating procedures. CBT training is being developed. The entire training process is being updated per a corporate directive in 2010.

The SOPs in each unit are being reformatted as part of a larger program to improve the Operator Training Program. Operators are tested on SOPs tri-annually via computer based training. Emergency Operating Procedure testing is done annually. Detailed SOPs and EOPs are maintained electronically with a copy kept in paper form in the Control Rooms.

CONTRACTOR MANAGEMENT

Contractors are prequalified and monitored by the Safety Department who analyses the contractors safety organizations and safety records. All contractors must have the proper certifications and insurance to work on Site.

RECOMMENDATION TRACKING

All internally generated Process Safety, Occupational Safely and Insurance Recommendations are tracked to completion on a corporate data base with quarterly updates submitted by the refinery managers. A monthly internal audit of the recommendations is done by each refinery as well.

PHA recommendations are completed within 6 months unless they are Turn Around Items.

Recommendations	Description	Ranking	Status
08-PROP-01	Initiate a Fire Proofing Program	B	In progress
08-PROP-02	Post hard copies of the EOPs in the Control Rooms	C	In progress
08-PROP-03	Expand the PHA process to include a LOPA of Reactor alarms and interlocks.	B	In progress
08-PROP-04	Disconnect idle equipment in the West Plant	C	In progress
08-PROP-05	Install EIVs upstream of pumps serving the Debutanizer….	B	In progress
05-PROP-01	Tank Farm 300 Pipe Rack and Tanks	B	To do - 2010
05-PROP-2	Install automatic deluge water spray protection for the LEU and CCR Units ….	C	To do - 2011
05-PROP-3	Computer/IO Room Protection	B	To do - 2009
05-PROP-4	Motor Control Center & Substation Protection	C	To do by 2013
05-BM-5	Revalidate the Fault Current and Short Circuit Coordination Study.	C	To do - 2009
05-BM-02	Review the Adequacy of Protective Relaying ….	C	To do - 2009

Rankings:	A	Loss Exposure > $50MM Major Management System issue Fire or Building Code Issue	B	Loss Exposure <$50MM Moderate Management System Issue
	C	Loss Exposure < $10MM Minor Management System issue	D	Loss Exposure <$1MM Minor Maintenance type issues

Categories:
PROP Fire Protection or Process Safety Recommendation
BM Mechanical Integrity Recommendation (Equipment/system reliability and protection issues).

MAJOR FIRE AND EXPLOSION PERILS

Most process pumps handling light ends are provided with supervised tandem seals, however, this is not a site standard. Older pumps are changed out on an opportunistic basis. Many of the process pumps are not accessible to monitor coverage; however, most of them are protected by manually activated deluge waterspray systems. The design of the waterspray systems varies from one nozzles to two nozzles per pump to a boxed in approach with nozzles on four sides

Atmospheric storage tanks are provided with semi-fixed foam systems. Pressurized storage tanks have remote actuated monitors or deluge systems. Detailed fire fighting plans have been developed for the larger storage tanks. Similar plans for the process units are under development.

The maximum process Unit fire water demand is estimated at 7500 gpm.

Emergency Isolation Valves, with a few exceptions, are used to isolate leaks from pumps fed by vessels containing at least 5 metric tons or more of LPGs. They can be arranged to fail as is. They are actuated by operators at local stations 50 ft. away.

Process areas with large amounts of LPGs includes the Rose Unit, the HF Alkylation Unit, the Crude Unit the FCC Reaction and Gas Plant.

The FCC Reaction Area has a large unit volume with medium obstacle density and 2D confinement. The HF Unit also has a large unit volume and medium obstacle density with slightly less 2D confinement.

The other process units containing light ends are much smaller, are not centrally located and have much less obstacle density and confinement in addition to having smaller amounts of light ends.

NATURAL CATASTROPHE PERILS

LATITUDE, LONGITUDE & ELEVATION

The Refinery is located at XXº 27’28.57 N and xxº11’14.82 W.

It is approximately 174 ft. above sea level.

PROTECTION FEATURES

The Example River borders the perimeter of the plant. The U.S. Army Corps of Engineers has built a levee 22 ft high which diverts any flooding around the plant and the town of Example. Portions of the outer areas of the site are in a 100 year flood plain.

It is far enough inland as not to be exposed directly to high winds or storm surges from Gulf Coast hurricanes.

BUSINESS INTERRUPTION FEATURES

PRODUCTION BOTTLENECKS

There are no unusual production bottlenecks associated with this refinery.

INTERDEPENDENT BUSINESS INTERRUPTION

There are no interdependencies with other Example Refineries. There are some opportunistic relationships with the Example Refinery.

CONTINGENT BUSINESS INTERRUPTION

Aside from Industrial Gases there are no critical 3rd party suppliers.

RECOMMENDATIONS

OPEN RECOMMENDATIONS

08-INS-PROP-1 Initiate a Fire Proofing Program (B)

Assessment

There are several areas within the Refinery that would benefit from additional fire proofing. A list of these areas is included in this report. A multi-year program to fire proof critical load bearing structural steel supports and certain cable trays should be included in the CapEx planning progress.

Justification

Fire proofing has proven to be an excellent investment for Example refineries.

The new Example Fire Proofing Specification, 17 GS-20, offers detailed advice on how and where to apply fire proofing.

Alternatives

The new Example Fire Proofing Guideline does not *currently* address the fire proofing needs of secondary piping supports and cable trays. Regardless, these are critical loss exposures and should be addressed in the Fire Proofing Program.

Automatic deluge waterspray protection can be provided on structural steel and cable trays in lieu of fire proofing.

Thermolag 3000 is a good fire proofing retrofitting material. It is light weight, easy to install and virtually maintenance free once installed.

Action Plan

This recommendation was discussed during the Exit Conference with Management.

OPEN RECOMMENDATIONS – continued

08-INS-PROP-2 Post Hard Copies of the EOPs in the Control Rooms (C)

Assessment

The Emergency Operating Procedures, EOPs, are kept as “controlled’ copies on PCs in the Control Rooms. Paper “controlled” copies are only available in the PSM Clerk and Shift Supervisors offices. Per ISO requirements paper copies of procedures should be avoided

Justification

A Hard Copy of these procedures; clear labeled as *non-controlled*, is considered the most reliable way of keeping these procedures readily available to operators in an emergency.

In the event of a power outage; or just PLC or printer problems, a hard copy of the emergency operating procedure with detailed check lists that can be quickly accessed by board operators could be very useful for many different emergency scenarios.

Alternatives

The procedures should be kept in a separate, color coded binder in the control room near the operators.

Action Plan

This recommendation was discussed during the Exit Conference with Management.

OPEN RECOMMENDATIONS – continued

08-INS-PROP-3 Expand the PHA Process to Include a LOPA of Reactor Alarms and Interlocks (B)

Assessment

The Heaters and critical pieces of rotating equipment are being evaluated for SIS requirements via the PHA process or by a separate engineering reliability review. No such program is actively underway for the refinery reactors. These reactors are controlled directly by the DCS process control system. Past PHAs have added alarms and interlocks to the DCS process control system to mitigate certain identified risks.

Justification

The current PHA process does not specifically evaluate the reliability requirements/needs of the alarms and interlocks used to mitigate the risks associated with operating reactors such as the Hydrocracker and FCC Reactors.

Alternatives

An Engineering Standard, similar to the Heater Control Standard, can be implemented for the different reactors. This standard would lay out what alarms and interlocks would be needed for a given type of reactor.

“Critical alarms and interlocks” can be pulled off the DCS process control system and set up on dedicated PLCs as “SIS” type loops. This is the Example Refinery Practice.

Action Plan

This recommendation was discussed during the Exit Conference with Management.

OPEN RECOMMENDATIONS – continued

08-INS-PROP-4 Disconnect the idle equipment in the West Plant (C)

Assessment

There is a significant amount of process equipment that has been tagged out and labeled as “idle” in the West Plant (Rose & Cryogenic Gas Recovery Units). It was not obvious where or how this equipment has been disconnected from active process equipment.

Justification

Idle equipment that is physically connected to active equipment poses a variety of mechanical integrity and process safety risks. Isolation valves or blind flanging, alone, is not sufficient. Loss history shows that idle equipment should be physically disconnected as a minimum. Complete removal of this equipment is even better.

Alternatives

Physically remove all equipment once it has been permanently shut down.

Action Plan

This recommendation was discussed during the Exit Conference with Management.

OPEN RECOMMENDATIONS – continued

08-INS-PROP-5 Install EIVs Upstream of the FCC Debutanizer and the High Pressure Receiver Pumps (B)

Assessment

These process vessels pose the largest Vapor Cloud Explosion (VCE) potential to the Site given their large hold up of C4 and lighter components and their locations within this process unit. The liquid discharge outlet off of these vessels supply several transfer pumps. None of these transfer pumps has a motor rated for 100 hp or more. Therefore, per the *current* Example EIV specification, 17GS-30, Emergency Isolation Valves are not required on these vessels. Therefore, they are not on the EIV installation list to be implemented by Refinery Engineering.

Justification

The current EIV selection guideline focuses primarily on the leak potential associated with pumps. It requests that EIVs be installed upstream of pumps that meet ALL of the following criteria: A) have mechanical seals, B) have a driver HP greater than 100; C) have a liquid release potential more than 100 gpm assuming a 1 inch hole at normal pump suction pressure; D) have a suction vessel inventory greater than 2500 gallons and E) the pump is in moderate or high process fire hazard service.

Criteria (B) *have a driver HP greater than 100*, *eliminates previously planned EIVs installations* - including the ones noted above in this recommendation. Both of these EIV candidates meet all of the EIV criteria EXCEPT (B).

Pump driver power requirements are an inherently poor measure of the explosion, fire or leak risk associated with a pump failure. Flow rates, piping or case diameter, material pressure, temperature, and vapor pressure are the normal way of assessing the risks associate with LPG releases.

These vessels pose a significant Vapor Cloud Explosion exposure to the Refinery.

EIVs on the liquid discharge lines of process vessels containing more than 2500 gallons is a property insurer key performance indicator.

Alternatives

An EIV can be placed upstream of each pump or on the main discharge line coming off the vessels.

Action Plan

This recommendation was discussed during the Exit Conference with Management.

OPEN RECOMMENDATIONS – continued

05-INS-PROP-01 Tank Farm 300 (B)

Protect the large pipe rack and the adjacent product storage tanks in Tank Farm 300.

A) Fireproof (UL 170 – 2 hours) the pipe rack to 30 ft. above grade.

B) Provide manual deluge waterspray protection for the sides of the storage tanks next to the pipe rack.

Assessment

The *main transfer pipe rack between the process units and the tank farm* runs along the inside of the dike wall of the Tank Farm containing the 300 series tanks. The pipe rack is as tall as the vertical storage tanks (nos. 313, 312, 310, 306 and 308) which are used to store light ends and intermediates.

Justification

The pipe rack blocks access to the storage tanks from one side and prevents the application of cooling water to roughly half their surface area. This limits the fire brigade from aggressively attacking one of these tanks if it is on fire.

The pipe rack is in turn exposed to both a dike fire and a tank fire. The loss of this pipe rack could shutdown operations until it could be repaired or replaced.

Alternatives

The exact arrangement of the water piping and its support structure is not set. One idea is to run a 12 inch, dry fire water line in the pipe rack itself and install branch lines and nozzles off it such each tank is sprayed with water once a main control valve is opened. Other more traditional options are also possible.

Action Plan

This recommendation, and it alternatives, were discussed with the Safety Department during the survey and with Management during the exit conference. It is scheduled for completion in 2010.

OPEN RECOMMENDATIONS - CONTINUED

05-INS-BM-02 Review The Adequacy Of Protective Relaying For The 12.5 Kv New Main Sub No. 2 Switchgear Line Up (BUS 4 AND 5). (A)

Assessment

During the March 2005 turn around, a significant amount of electrical maintenance work was performed by an outside contractor. The contractor reported hardware deficiencies in the protective relaying for the 12.5 kv new main sub no. 2 switchgear line up (bus 4 and 5). Based on current design, there is some concern that this protective relaying is not highly reliable to perform.

It is suggested that the site determine the validity of the electrical reliability findings. If these deficiencies exist, the site should assess the risks to site operations should this equipment fail to perform on demand and develop a plan to restore this protection at the earliest opportunity.

Justification

The protective relaying scheme for the electrical distribution system at this site is a critical system essential for the safe and reliable operation of the site. Deficiencies in the protective relaying should be identified and resolved at the earliest opportunity.

Alternatives

There are no practical alternatives to ensuring the reliability of the electrical protective relay system.

Action Plan

Re-studies have been completed. Work scopes have been developed and most of the work is scheduled for completion during the next turn around.

OPEN RECOMMENDATIONS – continued

05-INS-BM-05 Revalidate the Site Fault Current and Short Circuit Coordination Study.

Assessment

Several improvements are under way in association with the new DHT unit. A ring bus and new No. 5 Transformer are being installed in the main substation. The site is assuming responsibility for all major substation equipment previously owned and operated by the utility. A revalidation of the 1996 power study is planned and resolution of outstanding reliability and protection deficiencies is planned. During our next visit, we would like to review the revalidation power study and verify the resolution of protection deficiencies.

Over the years, the electrical distribution system for this location has grown as new process units have been added. However, many of these electrical system additions have not always been designed to optimize reliability and maintenance. Several substations providing power for critical process units appear to be single ended substations powered with single feeders.

Justification

Improvements in system design will enhance reliability and access for maintenance in accordance with industry recognized standards.

Alternatives

There appear to be no practical alternatives to improving system reliability and access for maintenance.

Separation of the 7.5 MVA Transformers by fire barrier walls would prevent both of them being damaged by a single fire mitigating the need for an emergency replacement contingency plan.

Relocate the 7.5 MVA transformer (FCC Main Air Blower).

Action Plan

Re-studies have been completed. Work scopes have been developed and most of the work is scheduled for completion during the next turn around.

OPEN RECOMMENDATIONS – continued

05-INS-PROP-02 **Install automatic deluge water spray protection for the LEU and CCR Units per the drawings and calculations already generated by Plant Engineering. (C)**

Assessment

In-depth assessments of each Process Unit have already been done by Plant Engineering and Safety personnel to determine the areas and the equipment needing this protection.

Justification

The unit has significant hold-ups of liquefied flammable materials and superheated flammable liquids in several process vessels. These vessels in turn are connected to pumps many of which are not accessible to monitor coverage. The ERT group is limited on initial response. Therefore, aggressive fire fighting tactics cannot be employed until secondary responders arrive. This could take 15-30 minutes.

Alternatives

Dramatically improving monitor protection and installing additional EIVs is a potential alternative to this recommendation.

Action Plan

Scheduled for completion in 2011.

OPEN RECOMMENDATIONS – continued

05-INS-PROP-03 Computer/IO Room Smoke Detection Systems.

Install supervised smoke detection systems in:

1. The underfloor area of the East Plant Control Room (**Done 2005)**
2. The underfloor area of the New West Plant Control Room.
3. The New West Plant Computer Room.

Assessment

These rooms contain equipment and wiring critical to the efficient operation of the refinery. These rooms are largely unattended. The equipment in the room could be replaced fairly easily, however, rewiring the equipment and the marshalling panels could take more than 15 days in many cases.

Justification

A 15+-day process interruption could be caused by a small fire in a computer or IO room that causes very light property damage.

Alternatives

If the operations of a room and its equipment can be readily transferred to another area then it can be considered non-critical and therefore left as is.

In the case of underfloor areas the verification of extremely light combustible loading coupled with low amperage wiring (or metallic conduit) could eliminate the need for smoke detection.

Action Plan

To be done in the next 24 months.

OPEN RECOMMENDATIONS – continued

05-INS-PROP-04 Motor Control Center & Substation Protection

A) Risk Rank all MCCs and Substations not having smoke detectors – assuming a 10 day outage is possible assuming an undiscovered fire occurs in the room.

B) Initiate a program to install supervised NFPA 72 compliant smoke detection systems in the MCCs and substations on a Risk Ranking basis over a five year time period.

C) Initiate a program to identify Motor Control Centers and Substations in process areas classified as Class I Division I or II electrically and provide over a five year time period with:

1. Supervised pressurizations systems capable of maintaining 0.1 inches of positive pressure in the enclosures.
2. Hydrocarbon detectors in the air intake stack interlocked at 60% of the LEL to shutdown the local pressurization system.

Assessment

Many (but not all) of the MCCs are provided with smoke detectors and pressurization systems.

Most of the pressurization systems do not have hydrocarbon detectors.

If the loss of the equipment in an MCC would cause a Property and Business Interruption loss of less than $1.0 MM it can be considered as not critical.

Justification

A fire in an MCC or substation is very difficult to extinguish if it is not caught early.

These small buildings can be destroyed if hydrocarbon vapors enter them and are ignited by electrical equipment.

Alternatives

Determine which MCCs are not essential to production or can be easily by-passed and do not provide them with smoke detectors.

Move or rearrange those operations that are in electrically classified areas.

Action Plan

This is being done on a scheduled basis. Completion expected in 2013.

CLOSED RECOMMENDATIONS

02-INS-BM-02 Improve the Onstream Leak Repair program (B)

A) Improve documentatiom requirements for mechanical integrity assessments.
B) Establish risk classes for leak clamps.
C) Establish an OSLR inspection program.
D) Define responsibilities for Operations, Inspection and Reliability.
E) Develop tracking procedures.
F) Define the maximum number of repumps permitted.
G) Define strong back requirements.
H) Restrict multiple OSLR's installations on a piping circuit.

Assessment

This location features a well developed and implemented mechanical integrity program for fixed equipment. However, some opportunities for improvement were discovered during this visit, in particular with the management of leak clamps and "onstream leak repairs".

Justification

Every effort should be made to ensure that temporary leak clamps are mechanically sound. Every practical effort should be made to ensure that these temporary repairs are permanently repaired at the appropriate time.

Action Plans

A formal, written MI procedure for Onstream Leak Repairs has been developed and implemented. The procedure includes all of the important issues associated with a best practice leak clamp procedure.

CLOSED RECOMMENDATIONS – continued

05-INS-PROP-02 Emergency Isolation Valves (B)

Incorporate an Emergency Isolation Valve (EIV) review into the PHA Revalidation Program

Assessment

The Site has over 50 EIVs already installed. No new EIVs have been installed at this refinery since the ROSE project over three years ago.

Justification

EIVs are critical part of a Refineries risk mitigation strategy and should be retroactively installed on older units if they have not already been provided.

There is a Example Corporate guideline on the selection and installation of EIVs.

Alternatives

Conduct a Site wide assessment of each process unit to identify candidates for EIV installations and begin installing them on a program basis.

Action Plan

The initial plan is to evaluate refinery vessels based on the current Example EIV Protocol and then install the EIVs during the Unit Turn Arounds. Therefore, this recommendation has been closed and a new FCC Unit specific EIV recommendation submitted.

APPENDIX A – FIRE PUMP CURVES AND TEST DATA

Location: Example
File No.: 0
Pump No.: 103A
Driver: Diesel
Driver Rating: Satisfactory
Pump Rating: Good

Pump Data (horizontal centrifugal)		Rated Flow (gpm)	Shop Head (psi)	NFPA Head (psi)
Rated Flow (gpm)	**4000**	0	185.0	185
Rated Pressure (psi)	**164**	4000	164.0	164
Rated Speed (RPM)	**1750**	6000	120.0	107

Field Test Results: **Test Curve** **Adjusted for speed**

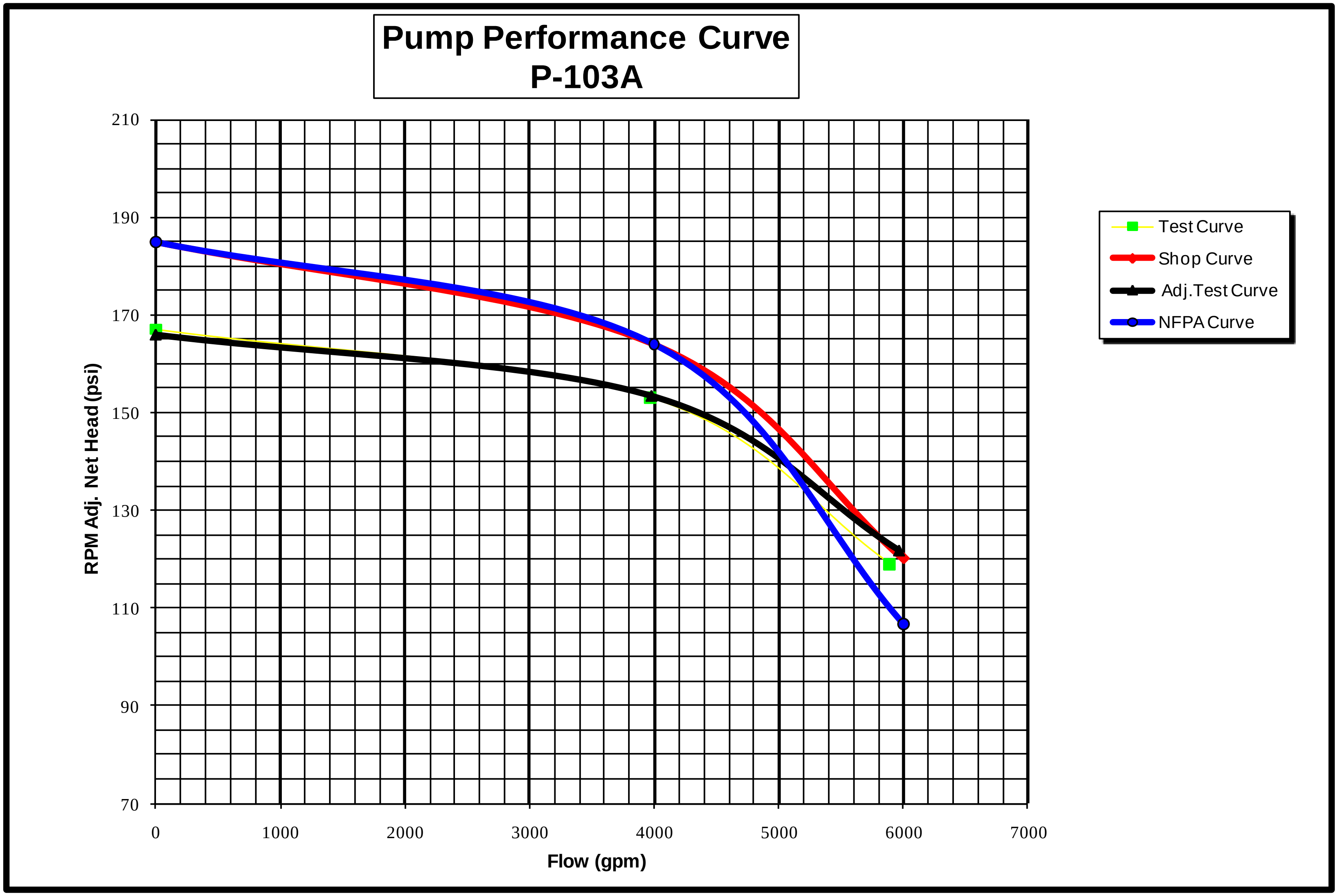
RPM	Disch. P (psi)	Suct. P (psi)	Net Head (psi)	Flow (gpm)	RPM Adj. Net Head (psi)	RPM Adj. Flow (gpm)	Rated Pressure (%)	Rated Flow (%)
1756	**170**	**3**	167	0	166	0	101%	0%
1748	**156**	**3**	153	3971	153	3975	94%	99%
1730	**122**	**3**	119	5892	122	5960	74%	149%

Pump Rating Guideline
1) Excellent - within 95% of shop curve or above the NFPA curve
2) Good - within 95% of NFPA curve
3) Fair - within 90% of NFPA curve
4) Poor - anything less than that.

Driver Rating Guideline
Satisfactory if RPM drop less than 10%

PRV set at ~ 105 psig

APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued



APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued

Location: Example
File No.: 0
Pump No.: 103B
Driver: Diesel
Driver Rating: Satisfactory
Pump Rating: Good

Pump Data (horizontal centrifugal)		Rated Flow (gpm)	Shop Head (psi)	NFPA Head (psi)
Rated Flow (gpm)	**4000**	0	185.0	185
Rated Pressure (psi)	**164**	4000	164.0	164
Rated Speed (RPM)	**1750**	6000	120.0	107

Field Test Results: **Test Curve** **Adjusted for speed**

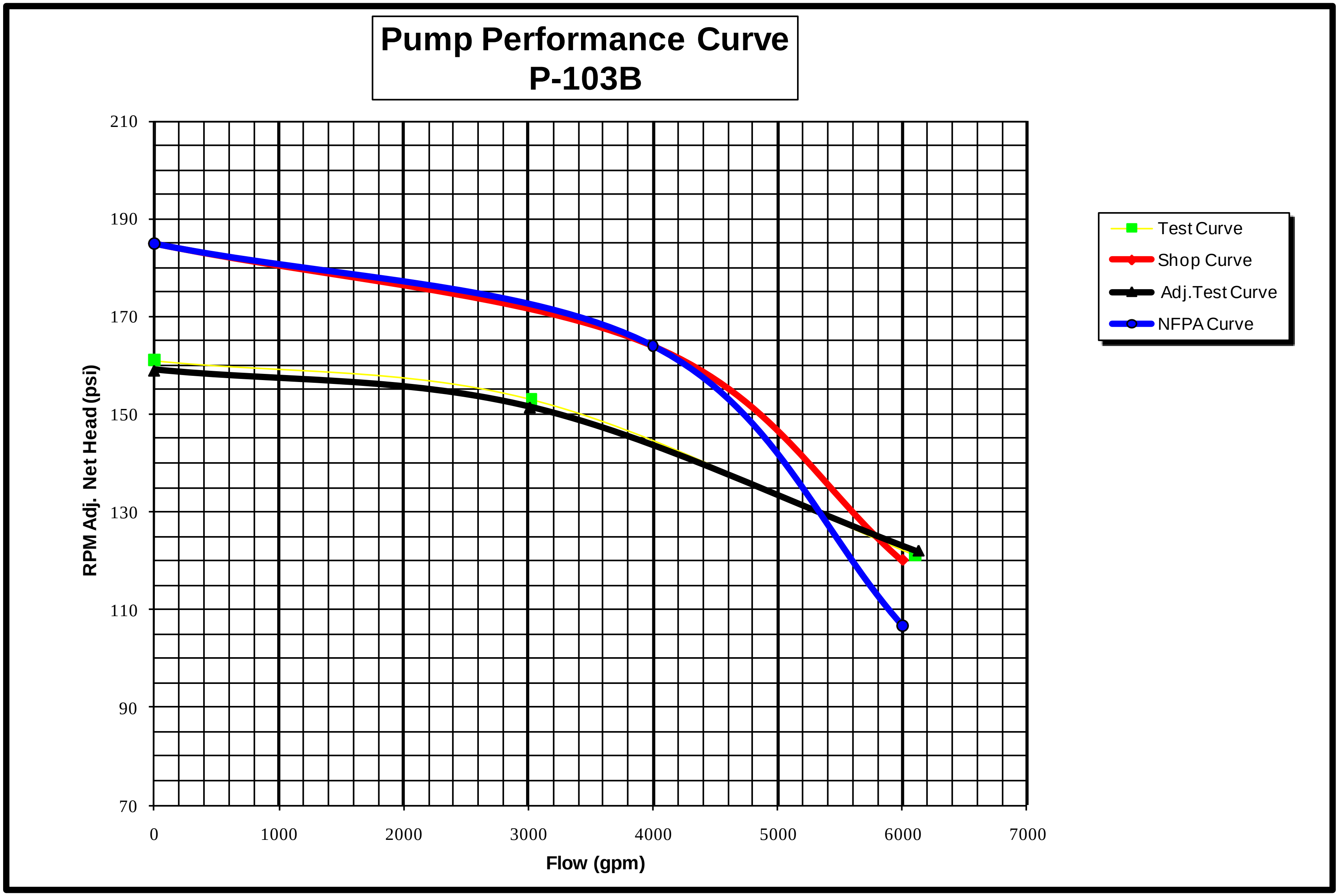
RPM	Disch. P (psi)	Suct. P (psi)	Net Head (psi)	Flow (gpm)	RPM Adj. Net Head (psi)	RPM Adj. Flow (gpm)	Rated Pressure (%)	Rated Flow (%)
1761	**164**	**3**	161	0	159	0	97%	0%
1759	**156**	**3**	153	3028	151	3013	92%	75%
1743	**124**	**3**	121	6105	122	6130	74%	153%

Pump Rating Guideline
1) Excellent - within 95% of shop curve or above the NFPA curve
2) Good - within 95% of NFPA curve
3) Fair - within 90% of NFPA curve
4) Poor - anything less than that.

Driver Rating Guideline
Satisfactory if RPM drop less than 10%

PRV set @ 150 psig

APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued



APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued

Location: Example
File No.: 0
Pump No.: North
Driver: Diesel
Driver Rating: Satisfactory
Pump Rating: Good

Pump Data (horizontal centrifugal)		Rated Flow (gpm)	Shop Head (psi)	Good Curve (psi)
Rated Flow (gpm)	**2500**	0	170.0	162
Rated Pressure (psi)	**140**	2500	140.0	133
Rated Speed (RPM)	**1770**	3750	93.0	86

Field Test Results: **Test Curve** **Adjusted for speed**

RPM	Disch. P (psi)	Suct. P (psi)	Net Head (psi)	Flow (gpm)	RPM Adj. Net Head (psi)	RPM Adj. Flow (gpm)	Rated Pressure (%)	Rated Flow (%)
1828	**166**	**-2**	168	0	158	0	113%	0%
1810	**129**	**-2**	131	2791	125	2730	89%	109%
1807	**80**	**-2**	82	3877	79	3798	56%	152%

Pump Rating Guideline

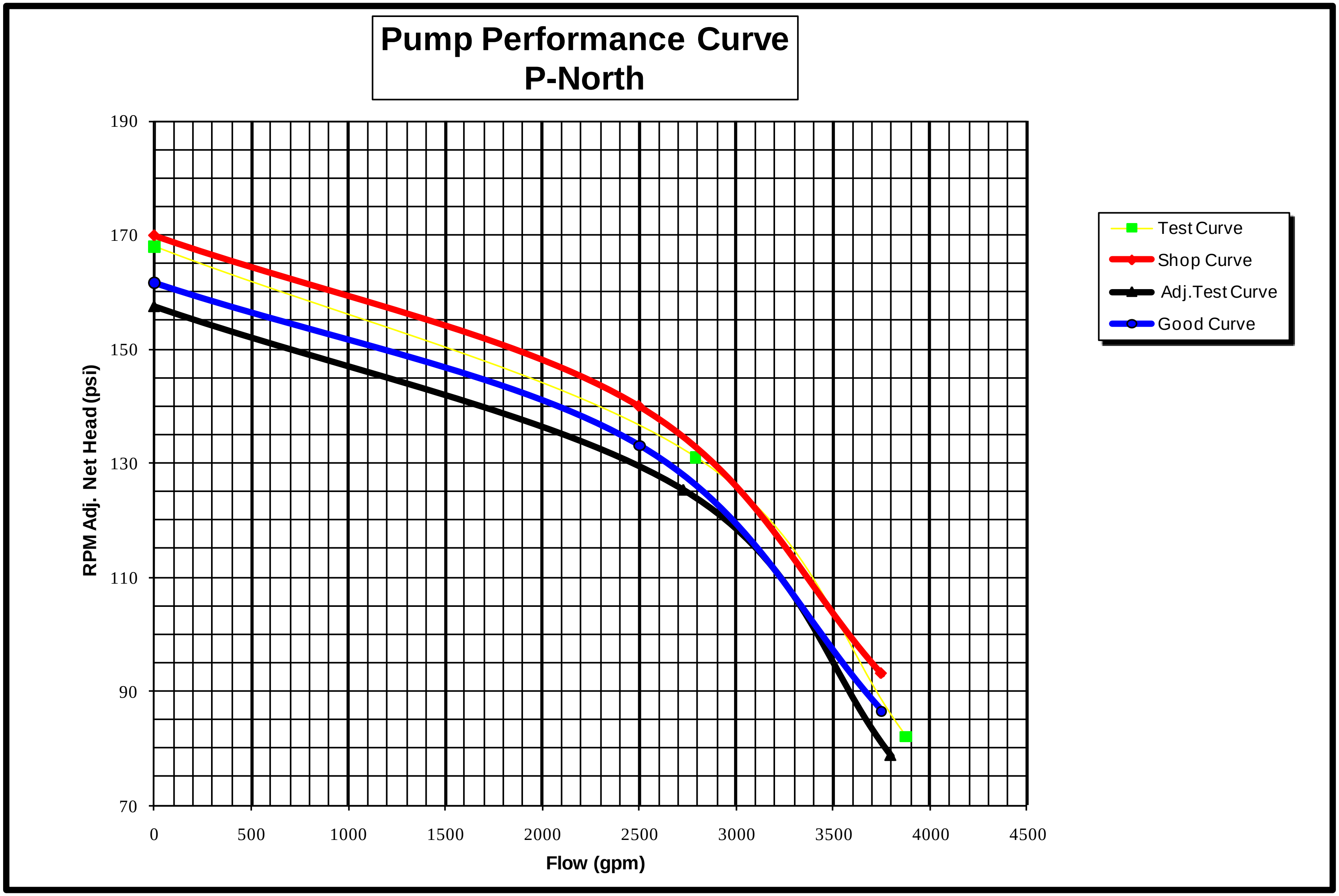
1) Excellent - within 95% of shop curve or above the NFPA curve
2) Good - within 95% of NFPA curve
3) Fair - within 90% of NFPA curve
4) Poor - anything less than that.

Driver Rating Guideline

Satisfactory if RPM drop less than 10%

PRV set at 150 psig

APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued



APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued

Location: Example
File No.: 0
Pump No.: South
Driver: Diesel
Driver Rating: Satisfactory
Pump Rating: Good

Pump Data (horizontal centrifugal)		Rated Flow (gpm)	Shop Head (psi)	Fair Curve (psi)
Rated Flow (gpm)	**2500**	0	170.0	153
Rated Pressure (psi)	**140**	2500	140.0	126
Rated Speed (RPM)	**1770**	3750	93.0	82

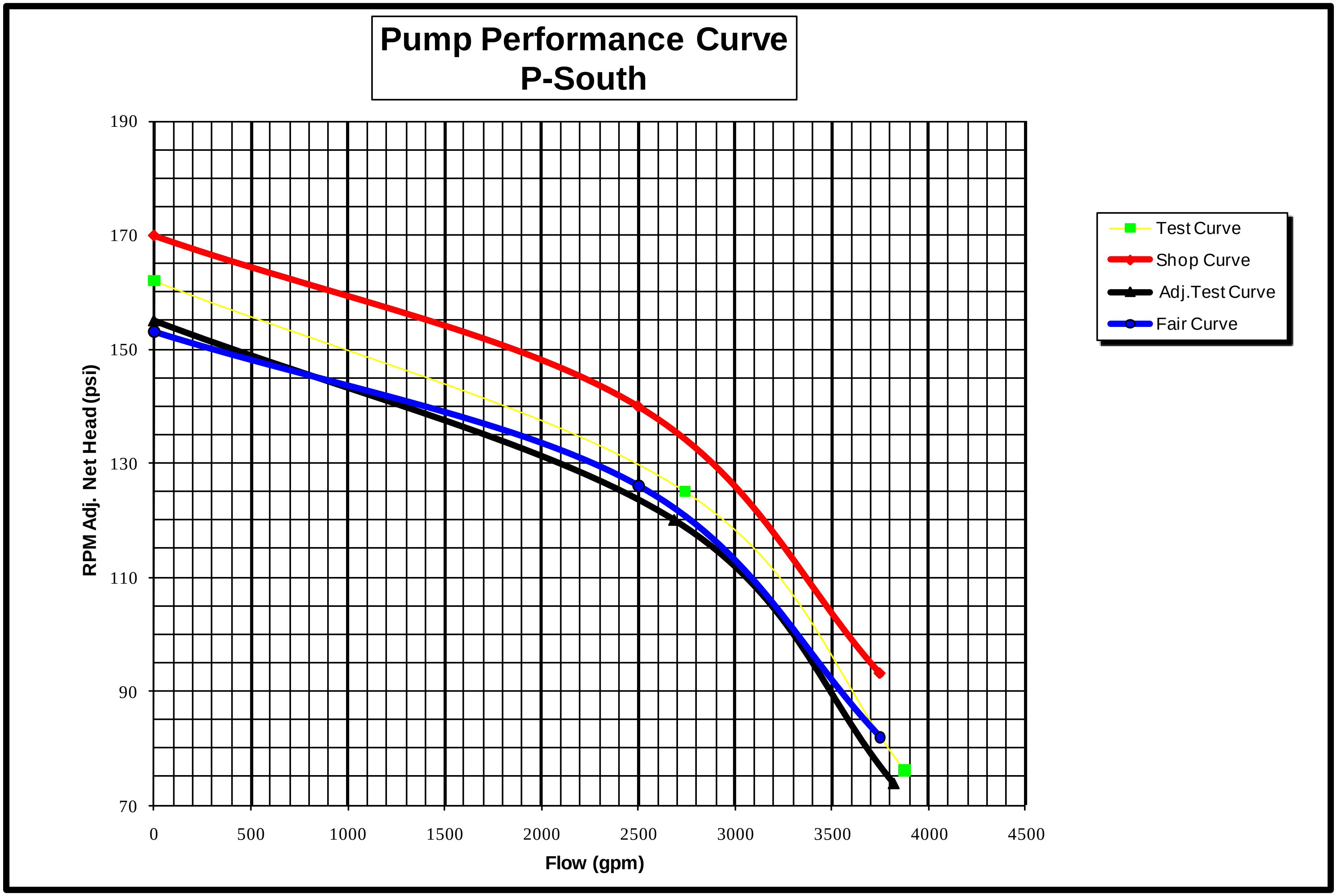
Field Test Results: **Test Curve** **Adjusted for speed**

RPM	Disch. P (psi)	Suct. P (psi)	Net Head (psi)	Flow (gpm)	RPM Adj. Net Head (psi)	RPM Adj. Flow (gpm)	Rated Pressure (%)	Rated Flow (%)
1810	**160**	**-2**	162	0	155	0	111%	0%
1807	**123**	**-2**	125	2742	120	2685	86%	107%
1797	**74**	**-2**	76	3877	74	3819	53%	153%

Pump Rating Guideline
1) Excellent - within 95% of shop curve or above the NFPA curve
2) Good - within 95% of NFPA curve
3) Fair - within 90% of NFPA curve
4) Poor - anything less than that.

Driver Rating Guideline
Satisfactory if RPM drop less than 10%

APPENDIX A – FIRE PUMP CURVES AND TEST DATA - continued



APPENDIX B – STORAGE TANK LIST

Tank ID	Product Description	Roof Type	Cap (BBLS)	Diam (ft)	Ht (ft)
31	Slurry	Cone	5,000	35	28-1
32	Slurry	Cone	10,000	45	34-3
33	*Av Gas*	External Floating	10,000	45	39-6
34	LCO	Cone	10,000	45	39-0
35	Gas Oil	Cone	40,000	90	34-6
36	Sour Water	Cone	10,000	45	33-3
37	Reformate	External Floating	20,000	60	35-0
38	Reformate	External Floating	20,000	60	35-0
40	Raffinate	External Floating	67,000	110	40-0
41	Gasoline	External Floating	67,000	110	40-0
42	Gas Oil	Cone	100,000	142	34-6
43	Gasoline	External Floating	40,000	85	36-0
100	Benzene	External Floating	5,000	34	29-2
101	Benzene	External Floating	5,000	34	29-2
102	Benzene	External Floating	5,000	34	29-2
127	Diesel	Cone	25,000	45	37-0
128	Diesel	Cone	25,000	45	37-0
129	Diesel	Cone	20,000	60	40-0
130	Diesel	Cone	20,000	60	40-0
200	Crude	Internal Floating	60,000	106	37-4
201	VTBs	Cone	25,000	67	39-7
300	Gasoline	Internal Floating	96,000	120	45-1
301	Toluene	Internal Floating	10,000	48	29-6
302	Toluene	Internal Floating	10,000	48	29-6
303	JP Make & Sales	Internal Floating	10,000	48	29-6
304	JP Make & Sales	Internal Floating	10,000	48	29-6
305	Xylene	Internal Floating	10,000	48	29-6
31	Slurry	Cone	5,000	35	28-1
32	Slurry	Cone	10,000	45	34-3
33	*Av Gas*	External Floating	10,000	45	39-6
34	LCO	Cone	10,000	45	39-0
35	Gas Oil	Cone	40,000	90	34-6
36	Sour Water	Cone	10,000	45	33-3
37	Reformate	External Floating	20,000	60	35-0
38	Reformate	External Floating	20,000	60	35-0
40	Raffinate	External Floating	67,000	110	40-0
41	Gasoline	External Floating	67,000	110	40-0
42	Gas Oil	Cone	100,000	142	34-6
43	Gasoline	External Floating	40,000	85	36-0
100	Benzene	External Floating	5,000	34	29-2
101	Benzene	External Floating	5,000	34	29-2
102	Benzene	External Floating	5,000	34	29-2
127	Diesel	Cone	25,000	45	37-0
128	Diesel	Cone	25,000	45	37-0
129	Diesel	Cone	20,000	60	40-0
130	Diesel	Cone	20,000	60	40-0

APPENDIX B – STORAGE TANK LIST – continued

Tank ID	Product Description	Roof Type	Cap (BBLS)	Diam (ft)	Ht (ft)
306	Xylene	Internal Floating	10,000	48	29-6
308	Xylene	Internal Floating	24,000	67	37-6
309	Carom Extract	Internal Floating	10,000	48	30-0
310	API Oil	Internal Floating	10,000	48	30-0
311	JP Make & Sales	Internal Floating	10,000	48	30-0
312	Reformate	Internal Floating	10,000	48	30-0
313	Naphtha	Internal Floating	24,000	67	37-6
314	JP Make & Sales	Internal Floating	10,000	48	29-6
315	None	Internal Floating	10,000	48	29-6
316	Av Gas	Internal Floating	10,000	48	29-6
317	Av Gas	Internal Floating	5,000	35	29-6
318	Gasoline	Internal Floating	5,000	35	29-6
331	Jet A - (pipeline)	Internal Floating	55,000	100	37-6
332	Naphtha	Internal Floating	55,000	100	37-6
333	Diesel	External Floating	100,000	125	45-0
334	Reformate	External Floating	55,000	100	37-6
335	Gasoline	External Floating	55,000	100	37-6
336	Toluene	Internal Floating	24,000	67	37-0
337	Gasoline	External Floating	200,000	180	47-6
338	Crude	External Floating	200,000	180	47-6
339	Gasoline	Internal Floating	100,000	122	42-9
340	Diesel	Internal Floating	67,000	100	42-5
401	No. 6 Fuel Oil	Cone	55,000	100	37-0
402	VTB	Cone	55,000	100	37-0
206	Process Oils	Cone	10,000	48	31-0
207	Process Oils	Cone	10,000	48	31-0
208	Process Oils	Cone	10,000	48	31-0
209	Process Oils	Cone	10,000	48	31-0
314	JP Make & Sales	Internal Floating	10,000	48	29-6
315	None	Internal Floating	10,000	48	29-6
316	Av Gas	Internal Floating	10,000	48	29-6
210	Process Oils	Cone	10,000	48	31-0
211	Process Oils	Cone	1,000	18	23-0
212	Process Oils	Cone	1,000	18	23-0
213	Process Oils	Cone	1,000	18	23-0
214	Process Oils	Cone	1,000	18	23-0
215	Process Oils	Cone	1,000	18	23-0
216	Process Oils	Cone	1,000	18	23-0
217	Process Oils	Cone	5,100	34	31-0
218	Process Oils	Cone	5,100	34	31-0
219	Process Oils	Cone	5,100	34	31-0
220	Process Oils	Cone	1,000	16	29-0
221	Process Oils	Cone	1,000	16	29-0
222	Process Oils	Cone	400	16	19-6
210	Process Oils	Cone	10,000	48	31-0
211	Process Oils	Cone	1,000	18	23-0
212	Process Oils	Cone	1,000	18	23-0

APPENDIX B – STORAGE TANK LIST – continued

Tank ID	Product Description	Roof Type	Cap (BBLS)	Diam (ft)	Ht (ft)
223	Process Oils	bullet	400	16	-
224	Process Oils	bullet	1,000	16	-
225	Process Oils	bullet	1,000	16	-
V-1	Propane	bullet	1,670	12	-
V-2	Propane	bullet	1,670	12	-
V-4	Butane	bullet	1,670	12	-
V-13	Propane	bullet	1,670	12	-
V-14	Propane	bullet	1,670	12	-
V-15	Propane	bullet	1,670	12	-
V-16	Propane	bullet	1,670	12	-
V-29	Propane	bullet	2,000	12	-
V-30	Propane	bullet	2,000	12	-
V-7	Isobutane	sphere	11,000	50	-
V-8	Isobutane	sphere	11,000	50	-
V-12	Butane	sphere	11,000	50	-
V-23	Olefins	bullet	714	10	-
V-24	Olefins	bullet	714	10	-
V-25	Olefins	bullet	714	10	-
V-26	Olefins	bullet	714	10	-
V-27	Olefins	bullet	714	10	-
V-28	Olefins	bullet	714	10	-
V-17	LPG	bullet	714	10	-
V-18	LPG	bullet	714	10	-
V-19	LPG	bullet	714	10	-
V-20	LPG	bullet	714	10	-
V-21	LPG	bullet	714	10	-
V-22	LPG	bullet	714	10	-
D-329	Solvent	bullet	712	10	-
D-330	Solvent	bullet	719	10	-
D-331	Solvent	bullet	853	10	-
223	Process Oils	bullet	400	16	-
224	Process Oils	bullet	1,000	16	-
225	Process Oils	bullet	1,000	16	-
V-1	Propane	bullet	1,670	12	-
V-2	Propane	bullet	1,670	12	-
V-4	Butane	bullet	1,670	12	-

APPENDIX C – SITE PHOTO