Revisions to the Point Arguello Field Development and Production Plans to Include the Rocky Point Unit Development

Supporting Information Volume

Submitted to:
The Minerals Management Service
Pacific OCS Region

Submitted by:
Arguello Inc.

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ARGUELLO

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Attachment A – Typical Well Control Equipment

Attachment A – Typical Well Control Equipment

Well control equipment will provide for prevention, detection and control of undesired formation fluid entry into the wellbore. What is described below is a typical well control equipment.

A 20” diverter BOP system will be used as described in the following section. The BOP schematics are given in Figure 1 and 2. The diverter, BOP stack and choke manifold will be designed in accordance with API RP 53” Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells.

I. Blowout Prevention Equipment

1. 20" Diverter Blowout Prevention System

A. Hydril 21-1/4" MSP 2,000 psi WT with H_2S trim studded top x hubbed down (CIW hub) RX73 ring groove.

B.	1	Diverter Spool 20-3/4" 3000-lb with CIW hubbed end connections and with 2 each 13-5/8” 3000-lb (12" bore) flanged outlets, manufactured to API 6A PSL-1, tempered class U, material class DD, by Woodco U.S.A.
C.	2	Blind Flange 13-5/8" 3000-lb manufactured to API 6A PSL-1 tempered class U, material class DD, Woodco U.S.A.
D.	2	Adapter Spool 13-5/8" 3000-lb x 12" ANSI 300-LB (12" bore) API flanges can be manufactures to 6A specification's but this spool cannot be monogrammed.
E.	1	Woodco Clamp
F.	2	Stud set for 13-5/8" 3000-lb
	2	API ring gasket R-57
	3	300-lb SS knife valves

G. One (1) drilling spool, 20-3/4 ", 3,000 psi WP hub, RX73 top and bottom, with one (1) 3" 5,000 psi side outlet flange, and one (1) 4" 5,000 psi side outlet flange.

H. One (1) 20-3/4" 3,000 psi WP riser spool, 30' long with hub RX73 up x 3,000 psi 20-3/4" flange down, with API stamp.

I. 20" 3,000 psi WP Hydril single gate preventer, hub x hub, CIW #17, RX73, H_2S trim with 3" side outlets (blind flanged), manual locking.

J. Double gate, 20-3/4" 3,000 psi WP Hydril double gate preventer, CIW #18 hub up, CIW #17 hub down, RX73 up and down, H_2S trim with 3" side outlets (blind flanged), manual locking.

K. Rams for 20-3/4" 3,000 psi stack:
   1. One (1) set of blind rams.
   2. Two (2) sets of 5" rams.
   3. One (1) set of 13-3/8" rams.

L. Diverter Valves
   Four (4) each SS 12" x 3000-lb knife valves hydraulic actuated with hose and valving.

M. 12" pipe and fittings to divert flow away from rig in two directions in compliance with AOGC rules. All flanges to be 12" ANSI 300

2. 13-5/8" BOP

A. Annular BOP (Hub)

Hydril, GK, 13-5/8" ID, 5,000 psi WP, with top 13-5/8" - 5,000 psi stud connection and bottom 13-5/8" - 5,000 psi, hub connection complete with screw top bonnet connection. Includes:

1. One (1) HS trim chain sling lifting assembly.
2. Two (2) eyebolts to lift piston assembly.
3. Two (2) eyebolts to lift latched bonnet assembly.

B. Single Gate (Hub)

One (1) Hydril, 13-5/8" ID 5,000 psi WP, MPL (Multi-position Lock), 13-5/8" hub, 5,000 psi connection top and bottom, 4-1/16", 5,000 psi flanged side outlets H_2S trim.

C. Double Gate (Hub)

One (1) Hydril, 13-5/8" ID 5,000 psi WP, MPL (Multi-Position Lock), 13-5/8" hub 5,000 psi connection top and bottom, 4-1/16", 5,000 PSI flanged side outlets, H_2S trim.

D. Drilling Spool (Hub)

One (1) 13-5/8", 5,000 psi, top and bottom flanged side outlet and one (1) 3-1/16", 5,000 psi flanged side outlet 29" high.

E. Rams
1. One (1) set blind rams.
2. Two (2) sets 5" pipe rams.
3. Two (2) set variable bore rams 3 ½" to 6".
4. One (1) set 2-7/8" pipe rams.
5. One (1) set 9-5/8" pipe rams.
6. One (1) set 7" pipe rams.
7. One (1) set 3 ½" pipe rams.
8. One (1) set 3 ½" dual pipe rams.
9. One (1) set spare VBR element.

F. One (1) 13-5/8" 5,000 psi riser spool, approximately 27' long, flange x flange, with API stamp.

3. BOP Stack Handling System

A. One (1) each overhead crane system capable of picking either stack up while landing casing.

B. One (1) BOP platform which is capable of stumping up both the 13-5/8" stack and the 20" stack simultaneously for moving or other activity.

C. BOP work platform to facilitate ram changes, nipple up and nipple down. Platform height can be moved up and down easily.

4. Kill and Choke Lines System

A. Kill line valves to consist of two (2) 3-1/6" 10,000 psi, McEvoy type E gate valve, with one valve being manually operated and one being hydraulically activated.

B. Kill line is 3-1/6" 5,000 psi Coflexquip Hose 30' which comes off the standpipe manifold, all connections flanged.

C. Choke valves to consist of two (2) 4-1/6" 10,000 psi, McEvoy type E gate valve, one (1) valve being manually operated and one (1) being hydraulically activated.

D. Choke line is 4-1/6" 5,000 psi Coflexquip hose 30', which connects from choke line valves to floor mounted choke manifold. All hose connections flanged.

5. Degasser Vessel and Vent Line

A. Primary degasser built as per drawing, specifications.

B. Primary degasser vent line to be 10", extends to crown.

C. Straight through vent line 4", connects into degasser vent and proceeds to crown.

6. Blowout Preventer Control System

NL Koomey Model T40280-3S blowout preventer control unit with 375 gallon volume tank, main energy provided by a 40 HP electric motor driven triplex plunger pump rate at 20.2 GPM at 3,000 psi charging twenty-eight (28) each 11-gallon bladder-type separate accumulator bottles. Second energy charging system consists of Model FA-42 air pumps rated at a combined volume of 23 GPM at 1,200 psi, or 12 GPM at 3,000 psi. Above two energy systems BACKED UP by 12 - 220 cubic feet nitrogen bottles connected to the manifold system. All above system controlled by a Model SU2KB7S"S" series manifold with eight (8) manual control stations at the unit.

A. Includes two (2) Model MGBK7EH electrically operated remote control panel with two manifold pressure gauges and nine push button controls with lights. One (1) mounted on rig floor, one (1) mounted in pipe rack module.

Controls for:

One (1) annular BOP with pressure regulator control to decrease or increase annular pressure.

Three (3) gates BOP.

One (1) kill line HCR valve.
One (1) choke line HCR valve.
One (1) diverter flow selector valve.

B. BOP mounted in subbase module such that 1" coflexip, hoses can remain connected when skidding the rig and picking the stack up.

7. Upper Kelly Cocks

Two (2) each. One for top drive, one for conventional kelly drilling Hydril kelly guard, 10,000 psi W.P.

8. Lower Kelly Cocks and D.P. Floor Valve

A. One (1) for Varco Top Drive 4 ½ IF
B. One (1) for conventional drilling 4 ½ IF
C. Two (2) for floor valve-one (1) 4 ½ IF, one (1) 3 ½ IF
D. All to be Hydril Kelly Guard, 10,000 psi W.P.

9. Inside BOP

One (1) Flocon inside BOP 4 ½ IF
One (1) Flocon inside BOP 3 ½ IF

10. BOP Test Pump

Triton Model 3075 triplex plunger pump rated at 5000 psi working pressure at 6 GPM, driven by a top-mount 20 BP electric motor complete with make-up tank, adjustable relief pressure bypass valve, system gauges with four each 50-ft of 3/8" 5000 psi working pressure test hose with snap-type couplers. This unit is also designed to act as a low volume wash-down pump. Included with the unit are two each NGC 200-2 cleaning lances.

Figure 1 Example Class III BOPE Installation, API Arrangement SRRA or SRdA

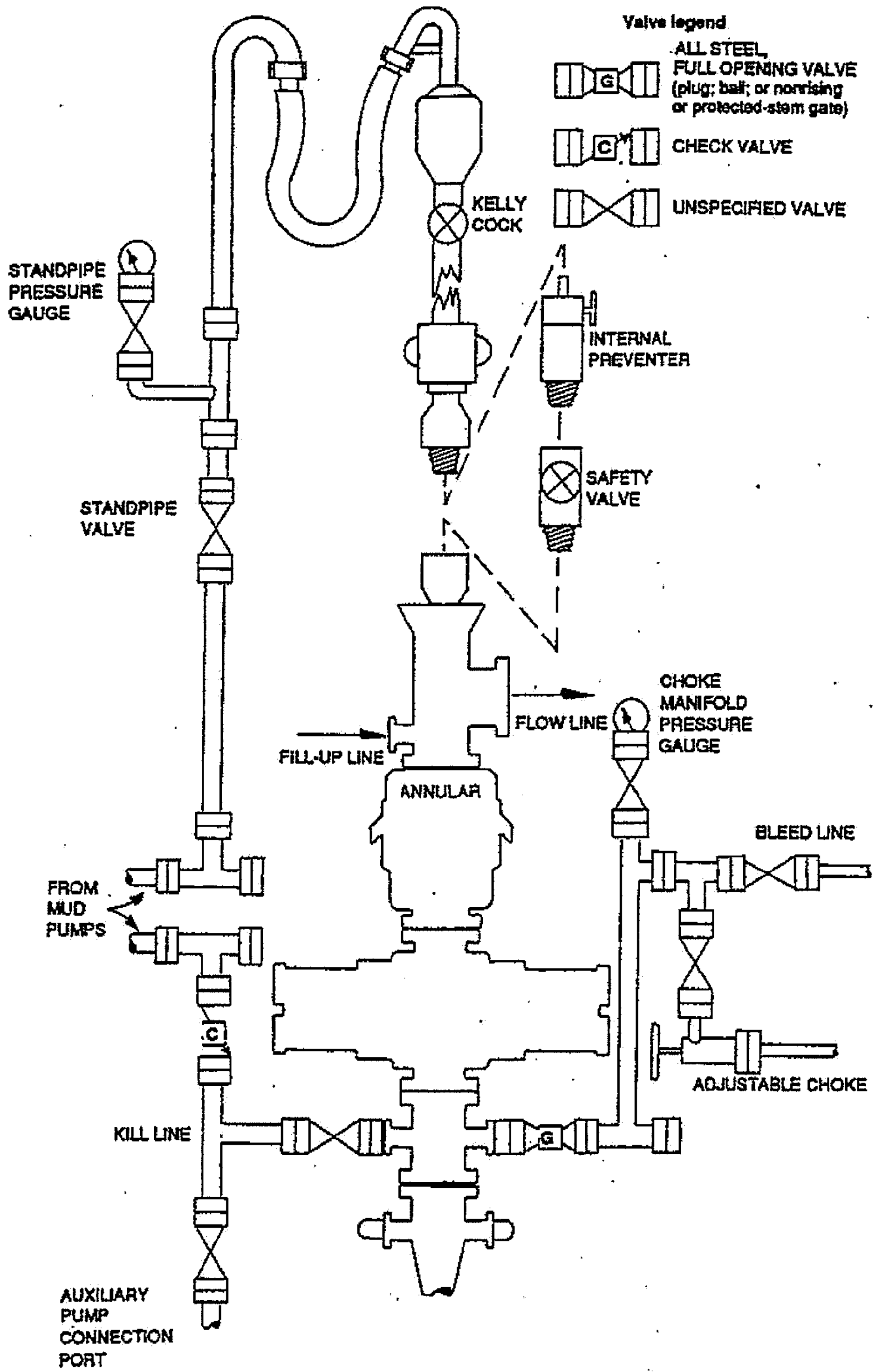
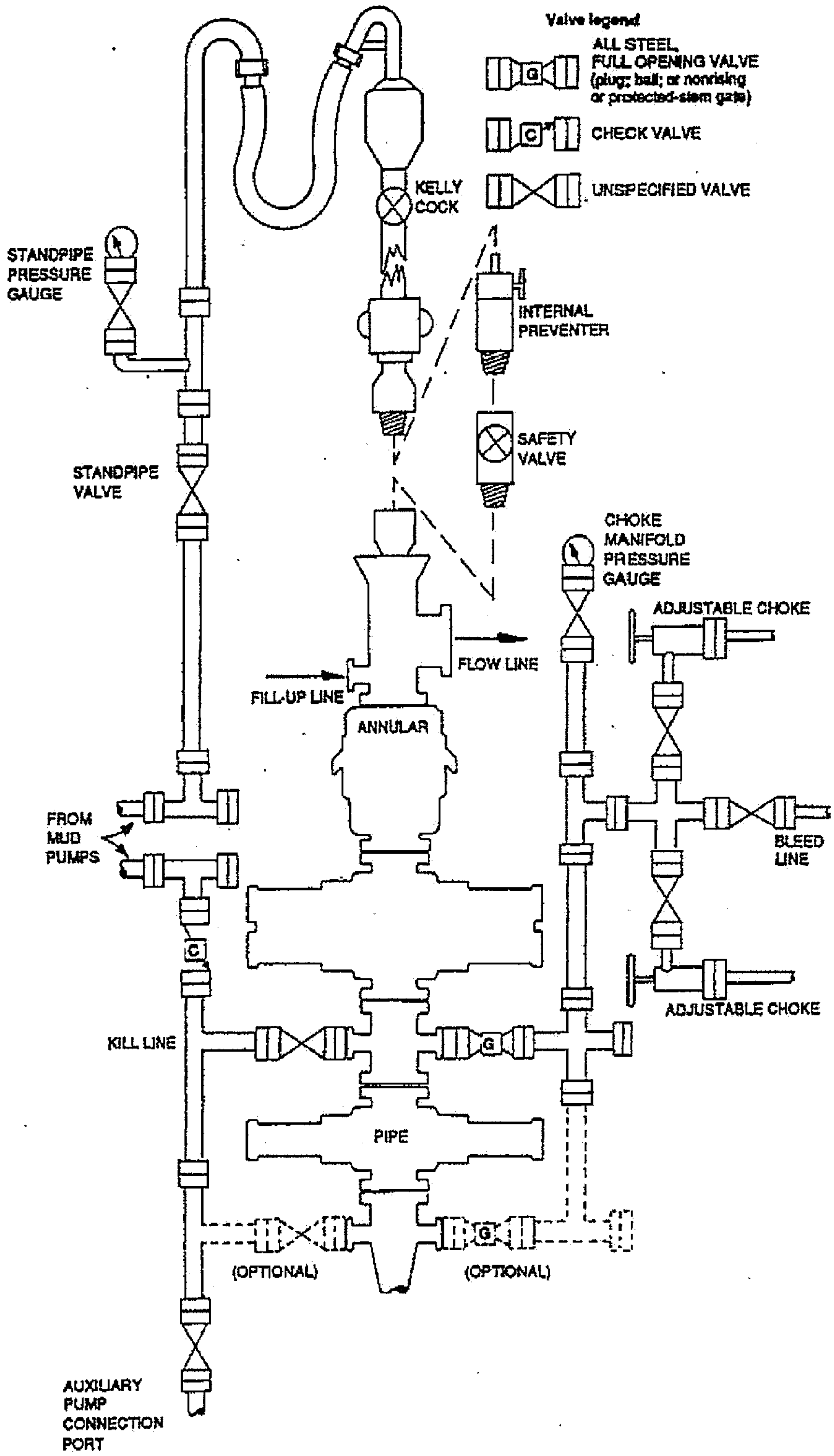


Figure 2 Example Class IV BOPE Installation, API Arrangement RSRRA or RSRdA



Attachment B – Typical Mud System

Attachment B – Typical Mud System

What is described below is a typical mud system.

I. Mud Pumps and Equipment

1. Pumps

Two (2) Oil well, A- 1700-PT (triplex, single acting pistons), 7-3/4" bore and 12" stroke x 5,000 PSI fluid end discharge manifold system. Gear end equipped with electric-driven lube oil pump, filtration, Glycol heat exchanger thermostat controlled cooling system. Pistons and. liners are flushed cooled by electric suction charging pumps, engage a few moments prior to the pistons. Pumps are driven by two (2) each traction motors and torque team belts designed to stroke pumps at a maximum of 120 SPM under fall load. Fluid ends are equipped with 611 liners and pistons which produce a nominal 530 GPM at a maximum of 120 rpm up to a nominal of 3,900 PSI.

A. 3 " Demco pressure relief valves.

B. 2" Oteco 0-6,000 psi mud gauge.

2. Pulsation Dampeners

Two (2) Hydril K20-5,000 pulsation dampeners.

3. Suction Dampeners

Oilwell 10" suction stabilizer.

4. Suction Strainers

Suction strainers mounted on mud tank suction piping, basket type, shop made.

5. Centrifugals

All pumps are 6" x 8" x 14" mission magnum with 12 ½ " impellers, 17/8 diameter shaft. Rated at 900 gpm at 65 feet: of head. Mud system complete with the following charging pumps:

A. Two (2) pumps for charging two (2) triplex pumps - 1,200 rpm each.
B. One (1) pump for desander - 1,800 rpm.
C. One (1) pump for mud cleaner - 1,800 rpm.
D. One (1) pump for hopper and gun lines - 1,800 rpm.
E. One (1) pump for transfer to mud storage and back up for hopper and gun lines - 1,800 rpm.

F. All pumps powered by one (1) each 100 HP explosion-proof, 460 volt, three-phase, 60 Hz, electric motor with Dodge Paraflex coupling.

6. Trip Tank

Trip tank mounted in substructure tank, 40 bbl capacity, with one (1) 3" x 4" x 13" mission magnum pump with 10" impeller, rated at 300 gpm at 48 feet of head with 25 HP explosion proof motor.

7. Drains

Mud module constructed with integrated drains to consolidate all waste fluids from mud pump, processing area.

II. Mud Pits and Related Equipment

1. Active Tank

Processing tank 430 bbl nominal volume which consists of:

A. 30 bbl sand trap.
B. 105 bbl degasser tank.
C. 80 bbl desander tank.
D. 80 bbl mud cleaner tank.
E. 80 bbl centrifuge tank.
F. 55 bbl slugging and pill tank.

2. Auger

All solids control equipment located such that all solids can be easily consolidated, and moved to the center of the platform using a 16" auger. This system can be utilized on any leg by changing the screw direction. An 8" auger takes the mud cleaner underflow to the main 16' auger.

3. Solids Control Equipment

A. Three (3) each Derrick Model 58 Flow Line Cleaners #L60-96F-3 AWD screen angle adjustment +5° uphill to -15° downhill. 129" long x 91-1/4" wide x 84" high.

B. One (1) Pioneer Model T 86 Sandmaster Desander with eight (8) each 6" cones.

C. One (1) Derrick Mud Cleaner, combination silt separator [sixteen (16) each 4" cones]. When required, the underflow from the cones passes onto the pretensioned screens and the majority of the desired Barite passes through the screens and returns to the mud system. Undesirable solids are discarded. Unit is rated at a nominal flow of 800 gpm each.

D. Degasser - One (1) Drillco See-Flow Degasser, vented to outside at the mud module nominally rated at 800 gpm.

E. Agitators

One (1) 5-HP Brandt agitator for pill pit 24" impeller.
Four (4) each 15 HP Brandt mud agitators for active mud tank, 32" impellers.

F. Mud Hopper - Geosource Model 8900 Sidewinder, rated at 900 gpm at 70' of head without back pressure. Hopper conveniently mounted on mud dock so that mud pallets can be placed by the crane and moved to the hopper with mud module in any drilling leg location.

4. Mud Logging

Mud logging unit to be set on platform main deck.

5. Cuttings Chute

16" x 50' auger incorporated into first floor of mud module, which allows the system to be run in a dry mode. This allows cuttings to be diverted to cuttings chute with rig over any leg.

III. Logging

Oil muds do not conduct electric current, therefore, do not use logging tools that require electric conductance to measure resistivity (i.e., short-normal resistivity). Table 1 provides guidelines for logging in oil muds.

Table 1 Logging and Formation Evaluation Guidelines

Objective	Tool	Notes
Depth control correlation and lithology	Induction/gamma ray log Formation density log Neuton log Dipmeter	Use the gamma ray log to determine sand and shale sequences. Use the other logs for identifying complex lithology.
Percent shale in shaley sands	Gamma ray log	The gamma ray log method replaces the sand/shale index found in fresh waters from the SP log.
Net sand (sand count)	Formation density log Gamma ray log	Use the formation density log and/or the caliper log to determine sand count when the sand and shale densities differ.
Detect hydrocarbon-bearing formations	Induction/gamma ray log Sonic log Neuton log	High resistivity values indicate hydrocarbon pore saturation. Use a formation density log in conjunction with neuton and sonic logs to identify hydrocarbons.
Interpretation - Water saturation - Porosity - Permeability - Structural formation - Productivity	 - Induction, sonic, density, and neutron logs - Formation density, sonic, and neutron logs; sidewall cores - Sidewall cores - Continuous dipmeter - Formation tester	 - Use Archie's equation to compute water saturation.

Attachment C – Estimated Mud Composition for RP-4 Well

Attachment C - Estimated Drilling Mud Composition (RP-4 Well)

Water Based Mud

INTERVAL (FT)	PRODUCTS	PACKAGE		UNITS sx	TOTAL Pounds
0 - 1285'	DUROGEL	50	lb/sx	1054	52700
1800 bbl Starting Volume	Soda Ash	50	lb/sx	43	2150
307 bbl of mud build for interval	Sodium Bicarbonate	50	lb/sx	30	1500
	MI-BAR	100	lb/sx	200	20000
1285' - 1535'	DUROGEL	50	lb/sx	253	12650
	Soda Ash	50	lb/sx	69	3450
900 bbl Starting Volume	POLYPAC	50	lb/sx	12	600
478 bbl of mud build for interval	DRIL XT	55	gal	3	1169
	GELITE	50	lb/sx	366	18300
	M-I GEL	100	lb/sx	90	9000
	Sodium Bicarbonate	50	lb/sx	30	1500
	MI-BAR	100	lb/sx	200	20000
1535' - 3958'	DUROGEL	50	lb/sx	9	450
	Soda Ash	50	lb/sx	84	4200
4190 bbl of mud build for interval	POLYPAC	50	lb/sx	21	1050
	DRIL XT	55	gal	3	1169
	GELITE	50	lb/sx	252	12600
	M-I GEL	100	lb/sx	126	12600
	Chrome-Free Desco	25	lb/sx	20	500
	Sodium Bicarbonate	50	lb/sx	30	1500
	MI-BAR	100	lb/sx	200	20000
3958' - 14,825'	SP-101	50	lb/sx	387	19350
	Soda Ash	50	lb/sx	411	20550
800 bbl Starting Volume	POLYPAC	50	lb/sx	44	2200
8657 bbl of mud build for interval	GELITE	50	lb/sx	334	16700
	M-I GEL	100	lb/sx	167	16700
	LUBE-167	55	gal	39	17251
	XCD	25	lb/sx	292	7300
	MI-BAR	100	lb/sx	2447	244700
	Sodium Bicarbonate	50	lb/sx	30	1500
14,825' - 19,315'	FLO-VIS	25	lb/sx	246	6150
	GREEN-CIDE	55	gal	2	963
800 bbl Starting Volume	SAFECARB F	50	lb/sx	692	34600
1657 bbl of mud build for interval	SAFECARB M	50	lb/sx	692	34600
	DUALFLO	50	lb/sx	92	4600

Estimated Drilling Mud Composition (RP-4 Well)

Synthetic Based Mud

INTERVAL (FT)	PRODUCTS	PACKAGE		UNITS sx	TOTAL Pounds
3958' - 14,825'	VG PLUS	50	lb/sx	1026	51300
	LIME	50	lb/sx	1232	61600
800 bbl Starting Volume	NOVA-MUL	55	gal	417	175849
9469 bbl of mud build for interval	NOVA-WET	55	gal	48	20462
	NOVA-MOD	55	gal	40	15585
	VERSA-HRP	55	lb/sx	292	16060
	M-I BAR	100	lb/sx	2447	244700
	Calcium Chloride	80	lb/sx	3465	277200
14,825' - 19,315'	VG PLUS	50	lb/sx	597	29850
	LIME	50	lb/sx	716	35818
800 bbl Starting Volume	NOVA-MUL	55	gal	243	102663
5171 bbl of mud build for interval	NOVA-WET	55	gal	28	12076
	NOVA-MOD	55	gal	22	8406
	VERSA-HRP	55	lb/sx	170	9338
	M-I BAR	100	lb/sx	1423	142283

Estimated Drilling Mud Composition (RP-4 Well)

Oil Based Mud

INTERVAL (FT)	PRODUCTS	PACKAGE		UNITS sx	TOTAL Pounds
3958' - 14,825'	VG PLUS	50	lb/sx	616	30800
	LIME	50	lb/sx	1232	61600
800 bbl Starting Volume	VERSA-MUL	55	gal	146	61568
9469 bbl of mud build for interval	VERSA-COAT	55	gal	50	21314
	VERSA-HRP	55	gal	36	14026
	ECOTROL	50	lb/sx	410	20500
	M-I BAR	100	lb/sx	2447	244700
	Calcium Chloride	80	lb/sx	3465	277200
14,825' - 19,315'	VG PLUS	50	lb/sx	358	17909
	LIME	50	lb/sx	716	35818
800 bbl Starting Volume	VERSA-MUL	55	gal	85	35845
5171 bbl of mud build for interval	VERSA-COAT	55	gal	28	11936
	VERSA-HRP	55	gal	21	8182
	ECOTROL	55	lb/sx	238	13090
	M-I BAR	100	lb/sx	1423	142300

Attachment D – Air Emissions

Rocky Point Unit
Summary of Total Peak Emissions by Platform and Activity

Activity/Platform/Emission Source	NO_x				ROC				CO				SO_x				PM				PM_{10}			
	lbs/hr	lbs/day	tons/qr	tons/yr	lbs/hr	lbs/day	tons/qr	tons/yr	lbs/hr	lbs/day	tons/qr	tons/yr	lbs/hr	lbs/day	tons/qr	tons/yr	lbs/hr	lbs/day	tons/qr	tons/yr	lbs/hr	lbs/day	tons/qr	tons/yr
1. Drilling[A]																								
Platform Harvest																								
Drilling Rig	6.52	156.43	7.14	28.55	0.12	2.98	0.14	0.54	1.74	41.65	1.90	7.60	0.21	5.02	0.23	0.92	0.07	1.76	0.08	0.32	0.07	1.76	0.08	0.32
Other Drilling Equipment	50.93	287.04	6.05	24.21	6.91	38.96	0.82	3.29	18.37	103.54	2.18	8.73	1.27	7.18	0.15	0.61	6.06	34.17	0.72	2.88	6.06	34.17	0.72	2.88
Mud System	0.00	0.00	0.00	0.00	0.04	1.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Platform Harvest	***57.45***	***443.47***	***13.19***	***52.76***	***7.08***	***42.94***	***0.97***	***3.87***	***20.11***	***145.19***	***4.08***	***16.33***	***1.48***	***12.20***	***0.38***	***1.52***	***6.14***	***35.94***	***0.80***	***3.20***	***6.14***	***35.94***	***0.80***	***3.20***
Platform Hermosa																								
Drilling Rig	5.14	123.36	5.63	22.51	0.54	12.89	0.59	2.35	3.39	81.28	3.71	14.83	0.21	5.01	0.23	0.91	0.07	1.79	0.08	0.33	0.07	1.79	0.08	0.33
Other Drilling Equipment	50.93	287.04	6.05	24.21	6.91	38.96	0.82	3.29	18.37	103.54	2.18	8.73	1.27	7.18	0.15	0.61	6.06	34.17	0.72	2.88	6.06	34.17	0.72	2.88
Mud System	0.00	0.00	0.00	0.00	0.04	1.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Platform Hermosa	***56.07***	***410.40***	***11.68***	***46.72***	***7.49***	***52.85***	***1.42***	***5.67***	***21.76***	***184.82***	***5.89***	***23.57***	***1.48***	***12.19***	***0.38***	***1.52***	***6.14***	***35.96***	***0.80***	***3.21***	***6.14***	***35.96***	***0.80***	***3.21***
Platform Hidalgo																								
Drilling Rig	5.14	123.36	5.63	22.51	0.54	12.89	0.59	2.35	3.39	81.28	3.71	14.83	0.21	5.01	0.23	0.91	0.07	1.79	0.08	0.33	0.07	1.79	0.08	0.33
Other Drilling Equipment	50.93	287.04	6.05	24.21	6.91	38.96	0.82	3.29	18.37	103.54	2.18	8.73	1.27	7.18	0.15	0.61	6.06	34.17	0.72	2.88	6.06	34.17	0.72	2.88
Mud System	0.00	0.00	0.00	0.00	0.04	1.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Platform Hidalgo	***56.07***	***410.40***	***11.68***	***46.72***	***7.49***	***52.85***	***1.42***	***5.67***	***21.76***	***184.82***	***5.89***	***23.57***	***1.48***	***12.19***	***0.38***	***1.52***	***6.14***	***35.96***	***0.80***	***3.21***	***6.14***	***35.96***	***0.80***	***3.21***
Supply Boats[B]																								
Port Hueneme to Ventura County Line	127.18	385.63	3.37	13.49	5.20	13.34	0.17	0.69	19.79	56.45	0.73	2.94	9.13	27.92	0.36	1.45	7.79	23.08	0.30	1.20	7.48	22.16	0.29	1.15
SB County Line to Platforms	127.18	1,245.97	11.04	44.18	5.20	44.70	0.58	2.32	19.79	184.74	2.40	9.61	9.13	90.05	1.17	4.68	7.79	74.93	0.97	3.90	7.48	71.93	0.94	3.74
2. Drill Rig Mobilization																								
From Port Hueneme[C]																								
Port Hueneme to Ventura County Line	127.18	385.63	2.60	2.60	5.20	13.34	0.13	0.13	19.79	56.45	0.56	0.56	9.13	27.92	0.28	0.28	7.79	23.08	0.23	0.23	7.48	22.16	0.22	0.22
SB County Line to Platforms	127.18	1,245.97	8.50	8.50	5.20	44.70	0.45	0.45	19.79	184.74	1.85	1.85	9.13	90.05	0.90	0.90	7.79	74.93	0.75	0.75	7.48	71.93	0.72	0.72
Interplatform[D,E]	127.18	288.34	2.16	2.16	5.20	13.17	0.13	0.13	19.79	46.90	0.47	0.47	9.13	20.58	0.21	0.21	7.79	17.97	0.18	0.18	7.48	17.25	0.17	0.17
3. Fugitive Emissions (20 wells)																								
Platform Harvest (7 wells)	0.00	0.00	0.00	0.00	0.57	13.65	0.62	2.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Platform Hermosa (7 wells)	0.00	0.00	0.00	0.00	0.57	13.65	0.62	2.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Platform Hidalgo (6 wells)	0.00	0.00	0.00	0.00	0.49	11.70	0.53	2.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fugitive Emissions	**0.00**	**0.00**	**0.00**	**0.00**	**1.63**	**39.00**	**1.78**	**7.12**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes:

A. Assumes drilling occurs at each platform for 12 calendar months.

B. Assumes 2 supply boat round trips per week from Port Hueneme to the platforms for 12 calendar months.

C. Assumes 20 supply boat round trips between Port Hueneme and the platforms over a 30-day period.

D. Assumes 20 supply boat round trips between two platforms over a 30-day period.

E. Emissions associated with interplatform moves are all within Santa Barbara County and part of the ESE and PTO.

Comparison of Peak Annual Rocky Point Emissions to Total Permitted Facility Emissions

Platform/Emission Category	NO_X	ROC	CO	SO_X	PM	PM_{10}
Platform Harvest[A]						
Total Permitted Emissions (tons/yr) [PTO 9103]	341.64	78.38	180.33	46.34	18.02	17.90
2000 Actual Emissions (tons/yr)	125.14	49.58	72.71	38.29	3.34	3.31
Estimated Peak Rocky Point Emissions (tons/yr)[B]	52.76	3.87	16.33	1.52	3.20	3.20
Excess Permitted Emissions (tons/yr)[C]	163.74	24.93	91.28	6.53	11.48	11.38
Platform Hermosa[A]						
Total Permitted Emissions (tons/yr) [PTO 9104]	109.35	69.00	90.46	40.04	9.42	9.23
2000 Actual Emissions (tons/yr)	52.57	40.11	41.20	23.84	4.02	3.97
Estimated Peak Rocky Point Emissions (tons/yr)[B]	46.72	5.67	23.57	1.52	3.21	3.21
Excess Permitted Emissions (tons/yr)[C]	10.05	23.21	25.69	14.68	2.19	2.05
Platform Hidalgo[A]						
Total Permitted Emissions (tons/yr) [PTO 9105]	111.19	50.35	69.76	31.32	9.31	9.16
2000 Actual Emissions (tons/yr)	52.99	27.41	35.37	26.35	5.14	5.10
Estimated Peak Rocky Point Emissions (tons/yr)[B]	46.72	5.67	23.57	1.52	3.21	3.21
Excess Permitted Emissions (tons/yr)[C]	11.48	17.27	10.82	3.45	0.96	0.85
Supply Boats						
Total Permitted Emissions (tons/yr) [PTOs 9103, 9104, 9105]	76.24	3.99	16.67	8.18	6.79	6.51
2000 Actual Emissions (tons/yr)	21.85	1.32	5.25	2.49	2.16	2.04
Estimated Peak Rocky Point Emissions (tons/yr)[D,E]	44.18	2.32	9.61	4.68	3.90	3.74
Excess Permitted Emissions (tons/yr)[C]	10.21	0.35	1.81	1.00	0.73	0.73

Notes:

A. Supply, Crew and Emergency Response vessel emissions not included.

B. Assumes drilling for 12 months and that muds are injected at the platform.

C. The excess permitted emissions = total permitted emissions-2000 actual emissions-estimated peak Rocky Point emissions. For Platform Harvest and Hidalgo, the peak Rocky Point emissions occur well in the future when the actual Point Arguello emissions should be lower. Therefore, the excess permitted emissions will most likely be greater for these two platforms.

D. Boat emissions are from SB County line to the platforms, consistent with Total Permitted Emissions from the PTOs.

E. Assumes 2 supply boat trips per week in addition to what is currently occurring for the Point Arguello Field operations. It is likely that supply boat trips would be shared between the two projects. This would serve to reduce the estimated Rocky Point emissions.

Rocky Point Unit Development
Drilling Emission Estimates - Turbines

Estimated Quantity, Size and Load Factors for Electrical Driven Drilling Equipment

Rocky Point Drill Rig Data	Quantity	Load (hp)	Load (kW)	Load Factor
Draw Works	2	1,000	1,492	0.25
Mud Pumps	2	1,000	1,492	0.6
Rotary Table	1	1,000	746	0.6
Top Drive	1	1,000	746	0.5

Notes:

Estimated data. Actual data for rig will not be known until a contract has been issued.

Platform Turbine Data

Platform Turbine Data	Turbine #	Fuel	%S	Size (kW)
Platform Harvest	300-G-700(A-E)	Produced Gas	0.005	3,695
Platform Hermosa	G92/G93	Produced Gas	0.005	2,800
Platform Hidalgo	G92/G93	Produced Gas	0.005	2,800

Notes:

These turbines are permitted and fully offset with the SBCAPCD.

Platform Harvest has a total of 5 turbines that are permitted to operate 8,760 hrs/yr.

Platform Hidalgo and Hermosa have a total of 4 turbines, 3 of which are permitted to operate 8,760 hrs/yr.

Platform Turbine Emission Factors

Turbine Emission Factors	lbs/kW-hr					
	NO_X	ROC	CO	SO_X	PM	PM_{10}
Harvest Emission Factors	3.120433E-03	5.953992E-05	8.308525E-04	1.001353E-04	3.518268E-05	3.518268E-05
Hermosa Emission Factors	2.460714E-03	2.571429E-04	1.621429E-03	1.000000E-04	3.571429E-05	3.571429E-05
Hidalgo Emission Factors	2.460714E-03	2.571429E-04	1.621429E-03	1.000000E-04	3.571429E-05	3.571429E-05

Notes:

The highest emission turbines on each platform was chosen in estimating the turbine emissions.

Emission factors taken from PTO 9104 for Hermosa, PTO 9105 for Hidalgo, and PTO 9103 for Harvest (April 19, 2001)

PTO turbine emission factors are in lbs/hr. These were converted to lbs/kW-hr by dividing by the rating on each turbine.

Peak Turbine Emissions from Rocky Point Drilling

Rocky Point Peak Turbine Drilling Emissions	NO_X	ROC	CO	SO_X	PM	PM_{10}
Platform Harvest						
lbs./hr	6.52	0.12	1.74	0.21	0.07	0.07
lbs./day	156.43	2.98	41.65	5.02	1.76	1.76
tons/qr	7.14	0.14	1.90	0.23	0.08	0.08
tons/yr[A]	28.55	0.54	7.60	0.92	0.32	0.32
Platform Hermosa						
lbs./hr	5.14	0.54	3.39	0.21	0.07	0.07
lbs./day	123.36	12.89	81.28	5.01	1.79	1.79
tons/qr	5.63	0.59	3.71	0.23	0.08	0.08
tons/yr[A]	22.51	2.35	14.83	0.91	0.33	0.33
Platform Hidalgo						
lbs./hr	5.14	0.54	3.39	0.21	0.07	0.07
lbs./day	123.36	12.89	81.28	5.01	1.79	1.79
tons/qr	5.63	0.59	3.71	0.23	0.08	0.08
tons/yr[A]	22.51	2.35	14.83	0.91	0.33	0.33
Total Drilling Emissions (tons)						
Phase 1[B,E]	69.18	5.81	39.05	2.67	0.95	0.95
Phase 2[C,E]	28.03	2.22	15.20	1.07	0.38	0.38
Phase 3[D,E]	46.44	2.01	17.52	1.60	0.57	0.57
Total for all Phases	***143.65***	***10.03***	***71.77***	***5.34***	***1.90***	***1.90***

Notes:

A. Tons/yr assumes drilling occurs for 12 consecutive calendar months.

B. Phase 1 is 4 wells at Hidalgo, 4 at Hermosa and 2 at Harvest.

C. Phase 2 is 3 wells at Hermosa and 1 at Harvest.

D. Phase 3 is 4 well at Harvest and 2 at Hidalgo.

E. Assumes each well takes 3.5 months to complete.

Rocky Point Unit Development
Drilling Emission Estimates - Other Equipment

Rocky Point Drill Rig Data	Quantity	Load (hp)	Fuel	Note
Well Logging Unit	1	100	Diesel	1
Acidizing Pump	1	100	Diesel	2
Emergency Generator	1	1,350	Diesel	3
Cement Pump	1	200	Diesel	4
Slurry Pump	1	1,000	Diesel	5

Notes

Estimated data. Actual data for rig will not be known until a contract has been issued.

1. Well logging unit operates 10 days per month.
2. Each acidizing pump is operated 5 days per well, 8 hours per day.
3. Each emergency generator tested 2 hours per month.
4. Cement pump operates 2 days per month, 8 hours per day.
5. Slurry Pump operates for 8 hrs per day, 70 days per well. This pump would only be needed if oil/synthetic based muds are injected offshore.

Emission Factors	g/hp-hr					
	NO_X	ROC	CO	SO_X	PM	PM_{10}
Well Logging Unit	8.4	1.14	3.03	0.21	1	1
Acidizing Pump	8.4	1.14	3.03	0.21	1	1
Emergency Generator	8.4	1.14	3.03	0.21	1	1
Cement Pump	8.4	1.14	3.03	0.21	1	1
Slurry Pump	8.4	1.14	3.03	0.21	1	1

Notes

Diesel I.C. Engines raw factors from AP-42, Table 3.3-1. NO_x reduced by 40% to reflect optimum injection timing retard.
SO_2 adjusted for 0.05% sulfur in fuel. HC assumed to be 100% ROC. PM assumed to be 100% PM_{10}.

Rocky Point Drilling Emissions	NO_X	ROC	CO	SO_X	PM	PM_{10}
		lbs/hr				
Well Logging Unit	1.85	0.25	0.67	0.05	0.22	0.22
Acidizing Pump	1.85	0.25	0.67	0.05	0.22	0.22
Emergency Generator	25.00	3.39	9.02	0.63	2.98	2.98
Cement Pump	3.70	0.50	1.34	0.09	0.44	0.44
Slurry Pump	18.52	2.51	6.68	0.46	2.20	2.20
Total Hourly Emissions	***50.93***	***6.91***	***18.37***	***1.27***	***6.06***	***6.06***
		lbs/day				
Well Logging Unit	44.45	6.03	16.03	1.11	5.29	5.29
Acidizing Pump	14.82	2.01	5.34	0.37	1.76	1.76
Emergency Generator	50.00	6.79	18.04	1.25	5.95	5.95
Cement Pump	29.63	4.02	10.69	0.74	3.53	3.53
Slurry Pump	148.15	20.11	53.44	3.70	17.64	17.64
Total Daily Emissions	***287.04***	***38.96***	***103.54***	***7.18***	***34.17***	***34.17***
		tons/qr				
Well Logging Unit	0.67	0.09	0.24	0.02	0.08	0.08
Acidizing Pump	0.04	0.01	0.01	0.00	0.00	0.00
Emergency Generator	0.08	0.01	0.03	0.00	0.01	0.01
Cement Pump	0.09	0.01	0.03	0.00	0.01	0.01
Slurry Pump	5.19	0.70	1.87	0.13	0.62	0.62
Total Quarterly Emissions	***6.05***	***0.82***	***2.18***	***0.15***	***0.72***	***0.72***
		tons/yr				
Well Logging Unit	2.67	0.36	0.96	0.07	0.32	0.32
Acidizing Pump	0.15	0.02	0.05	0.00	0.02	0.02
Emergency Generator	0.30	0.04	0.11	0.01	0.04	0.04
Cement Pump	0.36	0.05	0.13	0.01	0.04	0.04
Slurry Pump	20.74	2.81	7.48	0.52	2.47	2.47
Total Annual Emissions	***24.21***	***3.29***	***8.73***	***0.61***	***2.88***	***2.88***
		Total Drilling Emissions (tons)				
Phase 1	70.62	9.58	25.47	1.77	8.41	8.41
Phase 2	28.25	3.83	10.19	0.71	3.36	3.36
Phase 3	42.37	5.75	15.28	1.06	5.04	5.04
Total for all Phases	***141.23***	***19.17***	***50.95***	***3.53***	***16.81***	***16.81***

Notes

Assumes seven wells drilled at Harvest, seven drilled at Hermosa, and six drilled at Hidalgo.
Phase 1 is 4 wells at Hidalgo, 4 at Hermosa and 2 at Harvest.
Phase 2 is 3 wells at Hermosa and 1 at Harvest.
Phase 3 is 4 wells at Harvest and 2 at Hidalgo.
Assumes each well takes 3.5 months to complete.
The slurry pump would only be needed if the oil/synthetic based muds are injected at the platforms.

Rocky Point Unit Development
Drilling Emission Estimates - ROC Emissions from Mud System

Assumptions

Volume of gas in drilling mud from one well = 85,000 scf
Density of gas =0.0056 lbs/scf
Fraction of gas that is reactive organic compounds=20.5%
Density of reactive organic compound gas = 0.00115 lbs/scf
Time required to drill one well = 105 days
Time when gas may be present in mud per well =20 days
The mud-gas separator and mud degasser removal efficiency = 98%
Mud-gas separator and mud degasser are vented at the top of the derrick

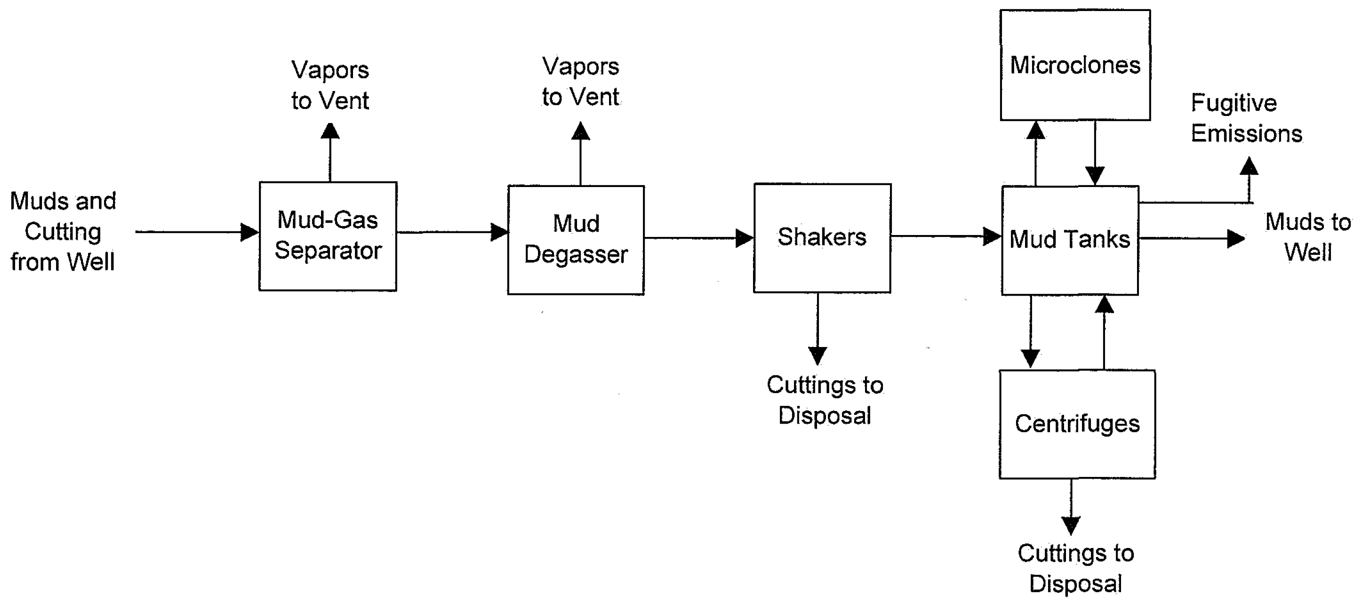
Emissions Estimates per Well

				ROC Emissions						
Source	SCF/hr	SCF/day	% ROC	lbs/hr	lbs/day	lbs/well	lbs/yr	Phase 1 (lbs)	Phase 2 (lbs)	Phase 3 (lbs)
Mud-gas Separator/Mud Degasser Vent	174	4165	20.5%	0.041	0.980	19.590	68.099	198.622	79.449	119.173
Fugitives from Mud Tanks	4	85	20.5%	0.001	0.020	0.400	1.390	4.054	1.621	2.432
Total	177	4250		0.042	0.999	19.990	69.489	202.675	81.070	121.605

Notes

Assumes 7 wells drilled at Harvest, 7 drilled at Hermosa, and 6 drilled at Hidalgo.
Phase 1 is 4 wells at Hidalgo, 4 at Hermosa and 2 at Harvest.
Phase 2 is 3 wells at Hermosa and 1 at Harvest.
Phase 3 is 4 wells at Harvest and 2 at Hidalgo.

Process Flow Diagram of Typical Mud Handling System



Rocky Point Unit Development
Supply Boat Emission Estimates

Supply Boat Engine Data

Engine	Fuel	%S	Size (bhp)	Fuel Usage (gals/bhp-hr)	Load Factor	gals/hr
Main Engines-Controlled	D2	0.29	5,000	0.055	0.65	178.75
Main Engines-Uncontrolled	D3	1.29	5,000	0.055	0.65	178.75
Generator Engines	D3	1.29	600	0.055	0.5	16.5
Bow Thruster	D4	2.29	515	0.055	1.0	28.325

Notes:

Data taken from PTO 9104 for Hermosa, PTO 9105 for Hidalgo, and PTO 9103 for Harvest (April 19, 2001).

Supply Boat Emission Factors

Emission Source	lbs/1,000 gals					
	NO_X	ROC	CO	SO_X	PM	PM_{10}
Main Engines-Controlled	337	16.80	78.30	40.85	33.00	31.68
Main Engines-Uncontrolled	561	16.80	78.30	40.85	33.00	31.68
Generator Engines	600	48.98	129.26	40.85	42.18	40.49
Bow Thruster	600	48.98	129.26	40.85	42.18	40.49

Notes:

Emission factors taken from PTO 9104 for Hermosa, PTO 9105 for Hidalgo, and PTO 9103 for Harvest (April 19, 2001).

Supply Boat Fuel Usage

Fuel Usage	gals/hr	Port Hueneme to Platforms		InterPlatform Transfer[D] (gals/round trip)
		Total[A]	SBC[B]	
Main Engines-Controlled	178.75	2,591.88	1,966.25	357.50
Main Engines-Controlled	178.75	2,591.88	1,966.25	357.50
Generator Engines	16.50	239.25	181.50	33.00
Bow Thruster	28.33	56.65	56.65	113.30

Notes:

A. Total is from Port Hueneme to the platforms (round trip assumes 14.5-hrs main engines and generator engines, 2-hrs bow thrusters).

B. SBC is from SB County line to the platforms (round trip assumes 11-hrs main engines and generator engines, 2-hrs bow thrusters).

C. PTO is within 25 miles of the platforms (round trip assumes 4-hrs main engines and generator engines, 2-hrs bow thrusters).

D. Interplatform transfer (round trip assumes 2-hrs main engines and generator engines, 4-hrs bow thrusters).

Rocky Point Unit Development
Supply Boat Emission Estimates

Total Supply Boat Emissions for Rocky Point (Port Hueneme to the Platforms)

Estimated Supply Boat Emissions	NO_X	ROC	CO	SO_X	PM	PM_{10}
Drill Rig Transport from Port Hueneme to the Platforms [C]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	1,631.60	58.04	241.19	117.97	98.01	94.09
tons/qr[E]	11.09	0.58	2.41	1.18	0.98	0.94
tons/yr[E]	11.09	0.58	2.41	1.18	0.98	0.94
Drill Rig Transport Between Platforms [C]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	288.34	13.17	46.90	20.58	17.97	17.25
tons/qr[E]	2.16	0.13	0.47	0.21	0.18	0.17
tons/yr[E]	2.16	0.13	0.47	0.21	0.18	0.17
Drilling Operations [D]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	1,631.60	58.04	241.19	117.97	98.01	94.09
tons/qr[E]	14.42	0.75	3.14	1.53	1.27	1.22
tons/yr[E]	57.67	3.02	12.54	6.13	5.10	4.89

Notes:

A. lbs/hr maximum based on all engines running simultaneously, and assumes uncontrolled main engines.
B. Assumes one round trip per day, and assumes uncontrolled main engines.
C. Drill rig transport based on 20 round trips total over one month, once per year.
D. Supply boat trips for operations assume 2 round trips per week for 52 weeks per year.
E. Assumes that uncontrolled main engines are used 10% of the time. (Same assumption as PTOs 9103, 9104, and 9105.)

Santa Barbara County Supply Boat Emissions for Rocky Point (SB County Line to the Platforms)

Estimated Supply Boat Emissions	NO_X	ROC	CO	SO_X	PM	PM_{10}
Drill Rig Transport from Port Hueneme to the Platforms [C]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	1,245.97	44.70	184.74	90.05	74.93	71.93
tons/qr[E]	8.50	0.45	1.85	0.90	0.75	0.72
tons/yr[E]	8.50	0.45	1.85	0.90	0.75	0.72
Drill Rig Transport Between Platforms [C]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	288.34	13.17	46.90	20.58	17.97	17.25
tons/qr[E]	2.16	0.13	0.47	0.21	0.18	0.17
tons/yr[E]	2.16	0.13	0.47	0.21	0.18	0.17
Drilling Operations [D]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	1,245.97	44.70	184.74	90.05	74.93	71.93
tons/qr[E]	11.04	0.58	2.40	1.17	0.97	0.94
tons/yr[E]	44.18	2.32	9.61	4.68	3.90	3.74

Notes:

A. lbs/hr maximum based on all engines running simultaneously, and assumes uncontrolled main engines.
B. Assumes one round trip per day, and assumes uncontrolled main engines.
C. Drill rig transport based on 20 round trips total over one month, once per year.
D. Supply boat trips for operations assume 2 round trips per week for 52 weeks per year.
E. Assumes that uncontrolled main engines are used 10% of the time. (Same assumption as PTOs 9103, 9104, and 9105.)

Rocky Point Unit Development
Supply Boat Emission Estimates

Ventura County Supply Boat Emissions for Rocky Point (Port Hueneme to SB County Line)

Estimated Supply Boat Emissions	NO_X	ROC	CO	SO_X	PM	PM_{10}
Drill Rig Transport from Port Hueneme to the Platforms [C]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	385.63	13.34	56.45	27.92	23.08	22.16
tons/qr[E]	2.60	0.13	0.56	0.28	0.23	0.22
tons/yr[E]	2.60	0.13	0.56	0.28	0.23	0.22
Drill Rig Transport Between Platforms [C]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	0.00	0.00	0.00	0.00	0.00	0.00
tons/qr[E]	0.00	0.00	0.00	0.00	0.00	0.00
tons/yr[E]	0.00	0.00	0.00	0.00	0.00	0.00
Drilling Operations [D]						
lbs/hr (max.)[A]	127.18	5.20	19.79	9.13	7.79	7.48
lbs/day[B]	385.63	13.34	56.45	27.92	23.08	22.16
tons/qr[E]	3.37	0.17	0.73	0.36	0.30	0.29
tons/yr[E]	13.49	0.69	2.94	1.45	1.20	1.15

Notes:

A. lbs/hr maximum based on all engines running simultaneously, and assumes uncontrolled main engines.

B. Assumes one round trip per day, and assumes uncontrolled main engines.

C. Drill rig transport based on 20 round trips total over one month, once per year.

D. Supply boat trips for operations assume 2 round trips per week for 52 weeks per year.

E. Assumes that uncontrolled main engines are used 10% of the time. (Same assumption as PTOs 9103, 9104, and 9105.)

Rocky Point Unit Development
Fugitive Emission Estimates

Component Type	Quantity[A]	Emission Factor[B] (lbs/day-clp)	ROC Emissions			
			lbs/hr	lbs/day	tons/qr	tons/yr
		Phase 1[C]				
Oil - controlled	1,250	0.0009	0.047	1.125	0.051	0.205
Oil - unsafe	0	0.0044	0.000	0.000	0.000	0.000
Gas - controlled	1,250	0.0147	0.766	18.375	0.838	3.353
Gas - unsafe	0	0.0736	0.000	0.000	0.000	0.000
Total Phase 1	***2,500***		***0.813***	***19.500***	***0.890***	***3.559***
		Phase 2[D]				
Oil - controlled	500	0.0009	0.019	0.450	0.021	0.082
Oil - unsafe	0	0.0044	0.000	0.000	0.000	0.000
Gas - controlled	500	0.0147	0.306	7.350	0.335	1.341
Gas - unsafe	0	0.0736	0.000	0.000	0.000	0.000
Total Phase 2	***1,000***		***0.325***	***7.800***	***0.356***	***1.424***
		Phase 3[E]				
Oil - controlled	750	0.0009	0.028	0.675	0.031	0.123
Oil - unsafe	0	0.0044	0.000	0.000	0.000	0.000
Gas - controlled	750	0.0147	0.459	11.025	0.503	2.012
Gas - unsafe	0	0.0736	0.000	0.000	0.000	0.000
Total Phase 3	***1,500***		***0.488***	***11.700***	***0.534***	***2.135***
Total for All Phases			***1.625***	***39.000***	***1.779***	***7.118***

Notes:

A. Component counts are estimates only. Actual counts will be developed when wells are installed.

B. Emission Factors from SBCAPCD PTOs 9103, 9104, and 9105.

C. Phase 1 is 4 wells at Hidalgo, 4 at Hermosa and 2 at Harvest.

D. Phase 2 is 3 wells at Hermosa and 1 at Harvest.

E. Phase 3 is 4 well at Harvest and 2 at Hidalgo.

Attachment E – Risk Assessment for the Chevron Point Arguello Field Gas Injection Feasibility Study

Risk Assessment For The Chevron Point Arguello Field Gas Injection Feasibility Study

Prepared for
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October 10, 1997

Reference 34595

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Glossary

CO_2	carbon dioxide
DEA	diethanolamine
DGA	diglycolamine
EIR	Environmental Impact Statement
EIS	Environmental Impact Report
FTA	fault tree analysis
GRS	Gas Re-injection Study
H_2S	hydrogen sulfide
HAZOP	hazard and operability study
IDLH	Immediately Dangerous to Life and Health
kW/m^2	kilowatt per square meter
LFL	lower flammability limit
LOC	levels of concern
m/s	meters per second
MMSCFD	million standard cubic feet per day
PANGL	Point Arguello Natural Gas Line
PANGLCO	Point Arguello Natural Gas Line Company
PHA	Process Hazards Analysis
ppm	parts per million
psig	pounds per square inch absolute
SEIR	Supplemental Environmental Impact Report
UVCE	Unconfined Vapor Cloud Explosion
yr	year

Executive Summary

This document has been prepared to evaluate potential risk on the Point Arguello platforms that would result from the gas re-injection activities proposed by Chevron. Rapidly declining oil and gas production rates from the Point Arguello Field have caused Chevron to re-evaluate the method of handling and processing of crude oil and produced gas. Based upon current and projected oil and gas production rates, it has become feasible to process oil offshore and re-inject gas back into the reservoir at Platform Harvest.

In 1994, Chevron conducted a gas re-injection study for the Point Arguello Field. This study was required as part of the Tri-Party Agreement between Chevron, the Minerals Management Service and the County of Santa Barbara. This study showed that, for the full gas re-injection case, there was a significant safety impact associated with a possible fitting break on the gas re-injection wellhead system (Scenario FGR-2). Chevron asked Arthur D. Little to re-evaluate this scenario based upon the proposed Gas Injection Project.

The proposed Gas Injection Project differs significantly from the system originally proposed as part of Chevron's Gas Re-injection Feasibility Study. The changes result from the lower than expected gas production rates, which have allowed Chevron to utilize existing compressors and piping on Platform Harvest. Table ES-1 provides a summary of the differences between the original gas re-injection project, evaluated in the Gas Re-Injection Study (1994), and the currently proposed gas injection program.

Table ES-1 Changes in Design Basis for Point Arguello Field Gas Re-Injection

Parameter	Gas Re-injection Study (1994)	Proposed Gas Injection Project (1997)
Gas Production Rates	60+ MMSCFD for remainder of field life.	Currently 10 to 15 MMSCFD declining to 5 to 10 MMSCFD.
New Injection Equipment Requirements	Power turbines, injection compressors, gas lift compression and flare tip.	None. Injection would utilize existing compressor and injection line.
Platform Injection Equipment Operating Conditions	3,500 psig	2,700 psig
Platform Injection Equipment Design	Pipe sizes ranging from 2 to 6 inches.	Utilizes existing 2 inch collection and injection piping.
Platform Injection Equipment Location	Wellhead level.	Below 70' Mezzanine level, protected by overhead grating and decking, and away from overhead levels.

MMSCFD = million standard cubic feet per day; psig = pounds per square inch absolute

Figure ES-1 shows the risk matrix for the offshore hazard scenarios which was evaluated in the 1994 Gas Re-Injection Study and Chevron's proposed Gas Injection Project. In Figure ES-1, the base case scenarios (i.e., current operations) are presented by code PFB, the 1994 full gas re-injection scenarios are presented by code FGR; and the 1997 gas injection scenarios are presented by code RFR, which cover Chevron's proposed gas injection project.

Figure ES-1 Offshore Platform Hazard Scenario Risk Ranking Matrix

LIKELIHOOD	Negligible	Minor	Major	Severe	Disastrous
Frequent					
Likely					
Unlikely				FGR-2	
Rare			PFB-2 PFB-3 RFR-2		
Extraordinary		RFR-1	PFB-1	PFB-4 FGR-1	FGR-3 RFR-3
			SEVERITY		

NOTE: SEE TABLE 6.2 IN SECTION 6 FOR A DESCRIPTION OF THE RELEASE SCENARIOS.

SIGNIFICANT IMPACT

INSIGNIFICANT IMPACT

As Figure ES-1 shows, the base case (i.e., current operations) scenarios do not have any impacts that would be classified as significant, based upon the County of Santa Barbara risk matrix. The 1994 full gas re-injection alternative does have one impact (FGR-2) that would be classified as significant. However, under the current Gas Injection Project, this scenario would have a lower potential failure rate, as well as lower consequences. As a result, potential impacts associated with proposed gas injection scenario (RFR-2) would be less than significant.

The reductions in failure rates and consequences for injection scenario RFR-2 are a result of the following:

1. Lower gas injection pressures than previously required.
2. Lower gas injection volume than originally proposed.
3. Smaller and less piping required for gas injection.
4. Gas re-injection will occur at only one platform.
5. The existing gas compressor is located below the mezzanine level, which is more remote from the location of the crew and other activities that could lead to a release and/or exposure.

The results of this study have shown that Chevron's proposed full Gas Injection Project for the Point Arguello Field would result in no new significant safety impacts as defined by the County of Santa Barbara risk matrix.

1.0 Introduction

In 1984, an Environmental Impact Statement/Environmental Impact Report (EIS/EIR) was completed for the Point Arguello Field Project. As part of this document, a safety risk assessment was developed that covered the sour gas pipeline and the gas plant at Gaviota. In 1987, the County of Santa Barbara determined that an Supplemental EIR (SEIR) was needed to address potentially higher hydrogen sulfide (H_2S) concentrations in the produced gas from the Point Arguello Field. The SEIR was necessary for the County of Santa Barbara to determine if the anticipated higher levels of H_2S were in substantial conformity with the initial permit issued for the Point Arguello Field Project. The SEIR was completed and certified in 1988, and the County of Santa Barbara found the higher levels of H_2S to be in substantial conformity with the initial permit.

As part of the substantial conformity determination, Chevron developed an operating plan to limit the pipeline operating pressure as a function of the H_2S concentration in the Point Arguello Natural Gas Line Company (PANGLCO) gas pipeline. This operating plan was included in a tri-party agreement between the Point Arguello Partners, the County of Santa Barbara, and the Minerals Management Service. Section 4 of this agreement addresses the gas re-injection feasibility study. The gas re-injection feasibility study was required as part of the agreement because the SEIR identified this as a possible alternative to the approved existing project, in lieu of the higher than anticipated H_2S levels. However, this alternative could not be evaluated at the time of the SEIR, because there was insufficient information available on the reservoir to allow a feasibility determination. As such, the study was scheduled to be completed two and a half years from the start-up date of the Point Arguello Project.

In developing the Gas Re-injection Study (GRS), one factor that Chevron was required to address was the potential impacts to safety and the environment. As such, they asked Arthur D. Little, Inc. to assist with the development of the safety and environmental portions of the study. A considerable amount of the data developed in the original 1984 EIS/EIR and the 1988 SEIR was still applicable to this study. In particular, some of the pipeline work done in the 1988 SEIR was used. Data contained in the original 1984 EIS/EIR was also used with regard to the gas plant.

Results of the GRS found that full gas re-injection offshore, as well as re-injection of an acid gas stream, posed a significant risk to platform workers, as well as the environment. Several release scenarios were identified that were considered to have significant safety and/or environmental risks. As a result, re-injection of produced gas offshore, as well as gas treatment and acid gas re-injection offshore, were dropped from further consideration.

However, rapidly declining Point Arguello Unit oil and gas production rates have caused Chevron to reevaluate their handling and processing of crude oil and produced gas. Based on current and projected oil and gas production rates, it has become feasible to process the oil and gas offshore, thus bypassing most of the onshore facilities (i.e., the Gaviota oil and gas plants).

Figure 1-1 illustrates the proposed configuration of the Point Arguello Unit for oil and gas processing. Crude oil from Platforms Hidalgo, Harvest and Hermosa would be stabilized at Platform Hermosa where it would be subsequently transported to shore to the All American Pipeline (Figure 1-2). Produced gas would be sent to Platform Harvest where it would be injected. Under this configuration, sour gas would no longer be transported to the Gaviota Gas Plant via the Point Arguello Natural Gas Line (PANGL), thus idling this pipeline. However, utility gas, necessary for platform operations, may need to be transported from onshore to the platforms in the future should produced gas production decrease to a point where offshore demands can no longer be met with produced gas.

This analysis has been prepared to evaluate the potential risk on the platforms that would result from gas injection activities, and to evaluate this risk in light of existing operations. Key elements of this analysis include an evaluation of existing equipment and how this equipment would be operated under re-injection conditions, differences in failures between the original re-injection and the new gas injection projects, differences in release scenarios and potential hazard zones, and the potential risk associated with the proposed gas injection project.

Figure 1-1 Project Overview

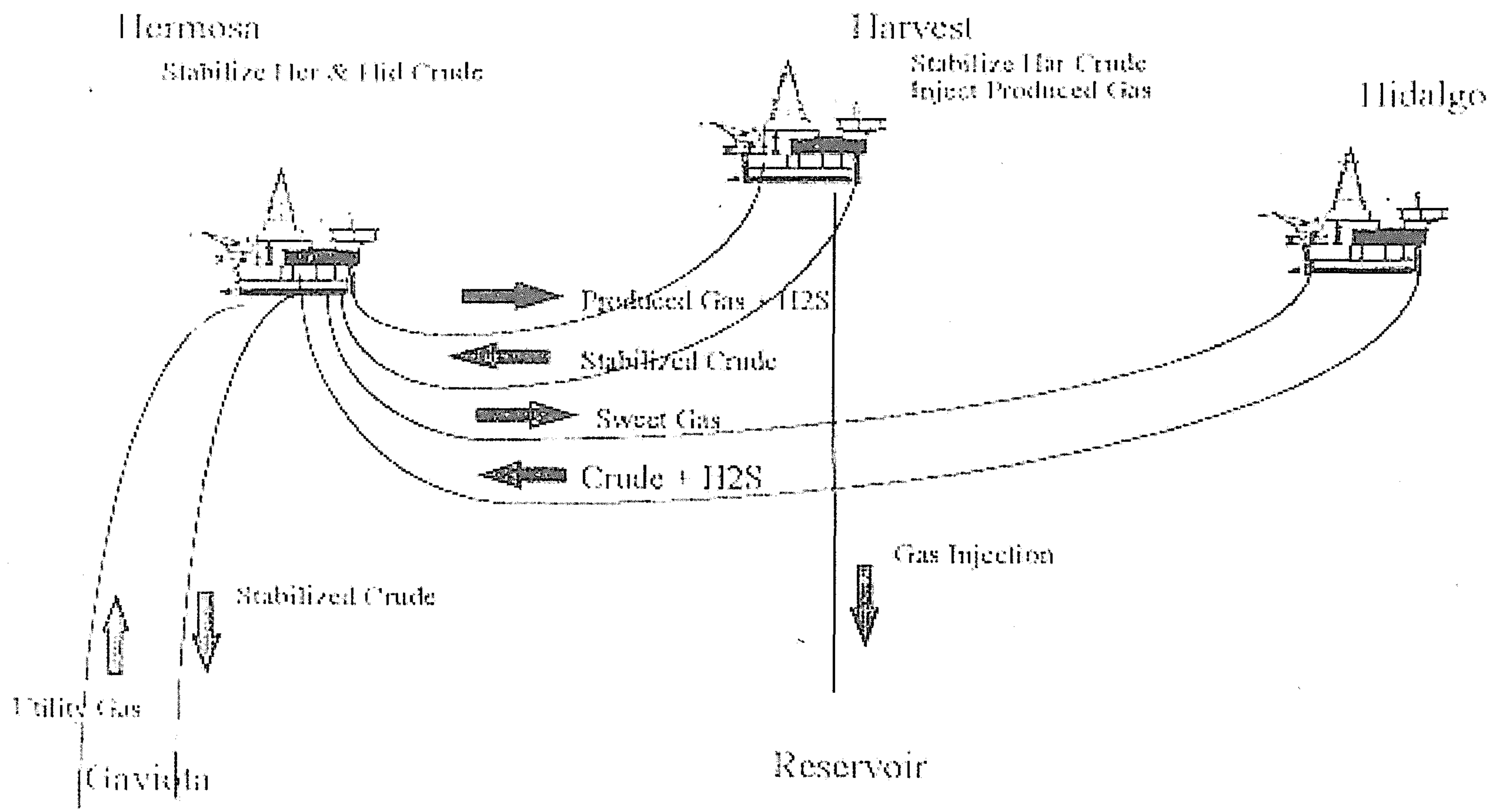
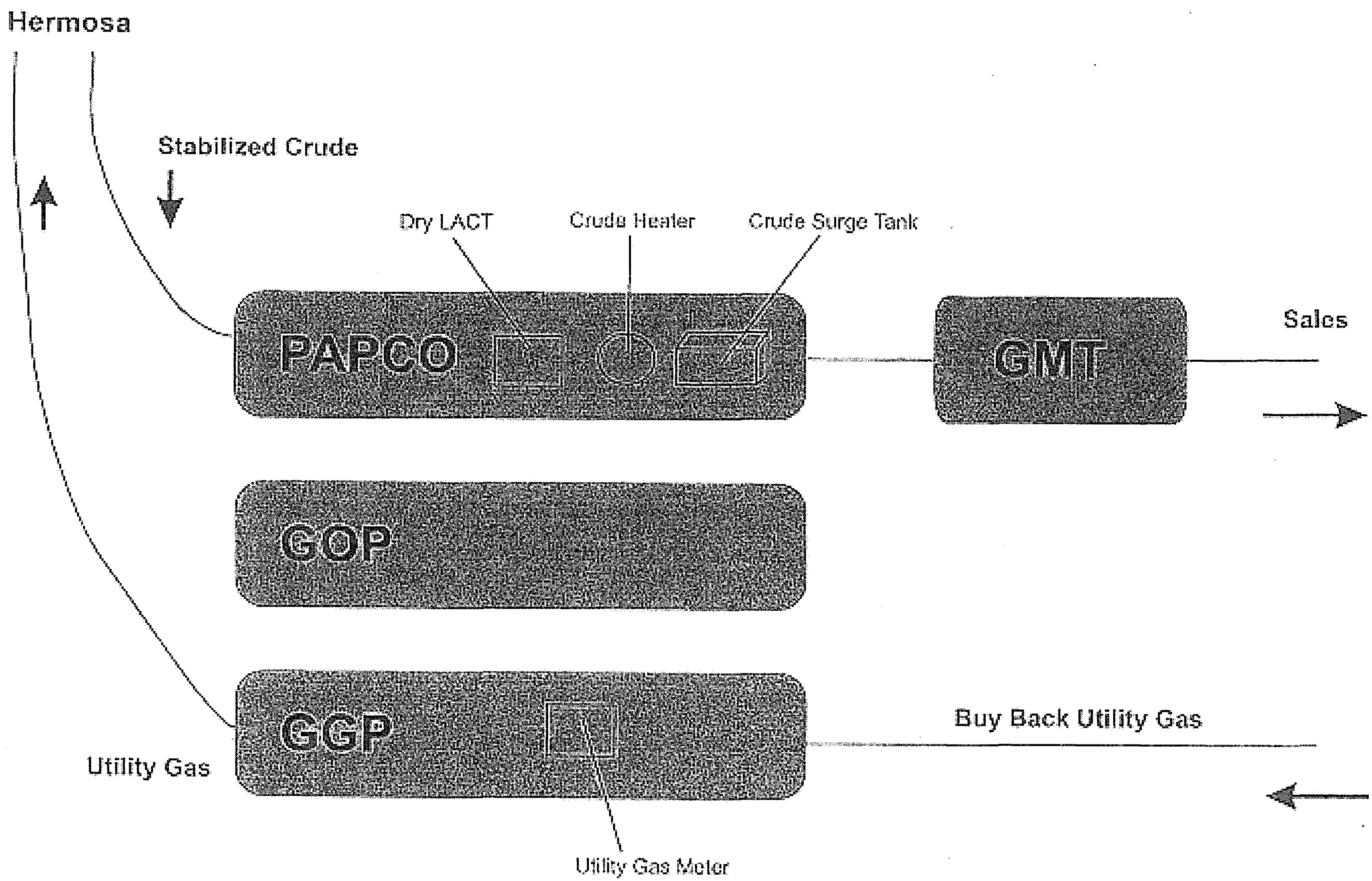


Figure 1-2 Crude Oil Stabilization



2.0 Revised Operating Parameters

The proposed produced gas injection system differs significantly from the system originally proposed as part of Chevron's Gas Re-injection Feasibility Study. These differences mainly result from rapidly declining oil and gas production rates, which in turn increase the feasibility of using existing equipment on the platform for gas injection.

Due to lower than expected gas production rates, existing compressors and piping can be used to handle the gas to be re-injected into the reservoir. Given the declining production rates and availability of existing equipment for gas injection, the following differences between the original gas re-injection project and the proposed gas injection study can be summarized as follows:

Parameter	Gas Re-injection Study	Proposed Gas Injection Project
Gas Production Rates	60+ MMSCFD for rest of field life.	Currently 10-15 MMSCFD declining to 5 to 10 MMSCFD.
New Injection Equipment Requirements	Power turbines, injection compressors, gas lift compression and flare tip.	None - injection would utilize existing compressor and injection line.
Platform Injection Equipment Operating Conditions	3,500 psig	2,700 psig
Platform Injection Equipment Design	Pipe sizes ranging from 2 to 6 inches.	Utilizes existing 2 inch collection and injection piping.
Platform injection equipment location	Wellhead level.	Below 70' Mezzanine level, protected by overhead grating and decking, and away from overhead levels.
Changes in Onshore Operating Conditions	Shutdown of second amine and sulfur trains.	Complete shutdown of Gaviota oil and gas processing plants.
Potential Shutdown Year	2002 to 2004	1998 to 2000

MMSCFD = million standard cubic feet per day; psig = pounds per square inch absolute

Release scenarios identified in the GRS have been reevaluated in this study to reflect the changes listed above. The following sections discuss the release scenarios that have been evaluated, revisions to potential failure rates resulting from changes in the gas injection project, consequences associated with the gas injection release scenarios and the significance of the potential risk associated with the platform release scenarios.

3.0 Gas Injection Release Scenarios

Based on the differences in the design and operating parameters that were examined in the gas re-injection study and the proposed injection project, failure rates were reevaluated for the injection project. Since the injection equipment exists it could be considered as part of the baseline risk. However, the increase in equipment utilization warrants evaluating the additional risk associated with full-time utilization.

Base Case (i.e., Existing Conditions)

Four release scenarios were examine in the GRS to evaluate existing hazards on the offshore platforms. These release scenarios were used to formulate baseline hazard conditions on the platforms. The four release scenarios included:

Pipeline Compressor Seal Failure. The existing compressor seal design allows the gas to be vented to the flare in the event of a failure. In the event of a leak to the atmosphere, the compressor areas are provided with both hydrocarbon and hydrogen sulfide detectors. The compressor seals are included in an inspection and maintenance program, and are routinely replaced when the compressor is shut down for servicing. In the event of a seal leak, the pressure of the gas could be as high as 1,200 psig. This scenario applies to both Platforms Hermosa and Harvest.

Pipeline Rupture At Platform Hermosa. Under this scenario there would be a full line rupture of the gas pipeline at the platform. This scenario is similar to the full rupture case of the gas pipeline at landfall. The scenario has assumed a double ended break of the pipeline. Further information on this scenario is provided in the pipeline section below. The operating pressure of the pipeline could be as high as 1,200 psig.

Pipeline Leak At The Platforms. This scenario assumes that there is a two inch hole in the gas pipeline. For Platform Harvest, this was assumed to occur at the discharge of the compressor on the pipeline between Platforms Harvest and Hermosa. For Platform Hermosa, the leak was assumed to occur at the compressor discharge on the gas pipeline leaving Platform Hermosa to the Gaviota Gas Plant. The operating pressure of the gas pipeline could be as high as 1,200 psig.

Rich Amine Line Rupture. This scenario assumes full rupture of a rich amine line coming from the bottom of the absorption towers. Amine solution is used on platforms to remove H_2S from a portion of the produced gas, which is, in turn, used as fuel for the offshore turbines and compressors. Rich amine solutions (i.e., spent amine solution) contain relatively large amounts of H_2S, which would be released to the atmosphere in the event of a spill. Platform Harvest uses a diglycolamine (DGA) solution for removing the H_2S from the gas. DGA solution is equally selective at removing H_2S and carbon dioxide (CO_2) from the gas and therefore produces an acid gas stream with a 50/50 mix of H_2S and CO_2. Platform Hermosa uses a diethanolamine (DEA) solution for removing the H_2S from the gas. The DEA solution is less selective at removing H_2S and, therefore, produces an acid gas stream that is a 25/75 mix of H_2S and CO_2.

Full Gas injection - GRS Alternative and Proposed Gas Injection Project

Three release scenarios were originally identified and evaluated as part of the Gas Re-injection Study that potentially could have occurred on Platforms Harvest and Hermosa. These scenarios are also applicable to the proposed gas injection project on Platform Harvest and include:

Re-injection Compressor Seal Failure (FGR-1). Compressor seal design allows the gas to be vented to the flare in the event of a failure. Compressor seals are included in an inspection and maintenance program and are routinely replaced when the compressor is shut down for servicing. To detect a leak to the atmosphere, both hydrocarbon and hydrogen sulfide detectors are installed in the compressor areas. In the event of a seal failure to the atmosphere, the pressure of the gas would be around 2,700 psig for the existing equipment. A pressure of 3,500 psig was used in the GRS.

Fitting Break On Gas Re-injection Wellhead System (FGR-2). In the designed re-injection wellhead area, fittings were examined which could be vulnerable to impact from associated well work. As many as ten fittings could be located on the wellhead. In the event of a break on one of these fittings, production gas would be released to the atmosphere. The pressure of this gas could be as high as 2,700 psig for the existing equipment. A pressure of 3,500 psig was used in the GRS.

Re-injection Wellheader Pipe Failure (FGR-3). This scenario would involve a full rupture of the gas re-injection wellheader pipe. The re-injection wellhead allows for the re-injection of the gas back into the reservoir. These wellheads serve as the pipeline system that would allow the gas to be sent back to the reservoir. In the event that the re-injection wellhead failed, produced gas would be released to the atmosphere. The normal operating pressure of the re-injection headers would be around 2,700 psig for the existing equipment. A pressure of 3,500 psig was used in the GRS.

Based on the current configuration of the gas injection project, these release scenarios would still apply, but only at Platform Harvest, where gas injection would take place. In addition, the gas injection is located in a safer location on the platform (i.e., more remote location) and operated at a lower pressure.

Therefore, the following release scenarios were evaluated as part of the gas injection safety analysis:

1. RFR-1 → Injection compressor seal failure (Platform Harvest),
2. RFR-2 → Fitting break on the injection wellhead system (Platform Harvest), and
3. RFR-3 → Injection wellheader pipe failure (Platform Harvest).

These scenarios were chosen because they represented a wide range of release conditions and covered all possible types of hazard scenarios. These scenarios also represent credible and unique events which could result from each respective design. Table 3.1 provides a list of the initial release conditions used for each platform releases scenario.

Table 3.1 Summary of Platform Release Conditions

Description	Code # *	Release Type	Release Composition	H_2S Concentration (ppm)	Initial Temperature (°F)	Initial Pressure (psig)	Initial Volume (ft^3)	Release Diameter (inches)
Pipeline Compressor Seal Failure	PFB-1	Vapor Jet	Produced Gas	14,900	99	1,200	113,000	13
Pipeline Rupture at Platform Hermosa	PFB-2	Vapor Jet	Produced Gas	14,900	99	1,200	113,000	20
Pipeline Leak at Platforms	PFB-3	Vapor Jet	Produced Gas	14,900	99	1,200	113,000	2
Rich Amine Line Rupture	PFB-4	Flashing Liquid Spill	Rich Amine Solution	13,830	105	1,150	157	3
Re-injection Compressor Seal Failure	FGR-1	Vapor Jet	Produced Gas	14,900	200	3,500	550	13
Fitting Break on the Re-injection Wellhead System	FGR-2	Vapor Jet	Produced Gas	14,900	90	3,500	500	2
Re-injection Wellheader Pipe Failure	FGR-3	Vapor Jet	Produced Gas	14,900	90	3,500	500	4
Re-injection Compressor Seal Failure	RFR-1	Vapor Jet	Produced Gas	20,000	200	2,700	550	2
Fitting Break on the Re-injection Wellhead System	RFR-2	Vapor Jet	Produced Gas	20,000	90	2,700	500	2
Re-injection Wellheader Pipe Failure	RFR-3	Vapor Jet	Produced Gas	20,000	90	2,700	500	2

* These code numbers are used throughout the document to reference the various release scenarios.
GPR = Gaviota Plant Release

4.0 Revised Failure Rates

This chapter presents the methodology and results for the frequency evaluation conducted for injection of produced gas on the offshore platforms.

4.1 Methodology

The basic methodology employed for the offshore platforms was fault tree analysis, which is described in this section.

4.1.1 Fault Tree Overview

Fault tree analysis (FTA) is a tool employed in the analysis of complex systems. It provides a graphical representation of the relationships between initiating events and the ultimate undesired outcome. A well-constructed fault tree allows the recognition of failure combinations, which would not normally be discovered.

As opposed to other methods which start with the failure of a component and seek the consequences, FTA starts with the effect or undesired outcome and seeks the causes. FTA does not cover all possible failures or all causes of system failure; instead, it focuses on only the credible means by which an undesired event may occur. The undesired outcome, most often called the "top event" of a fault tree, can be identified based on experience, imagination, checklists and historical occurrences. Alternatively, fault trees can be constructed for events identified by other methods such as a hazard and operability study (HAZOP) or "What-If" studies which may have been conducted as part of a Process Hazards Analysis (PHA).

For this analysis, a "What-If" type PHA was conducted to identify hazard scenarios for the offshore platforms, and these scenarios were then used as top events and failure combinations in the fault trees. The top events and fault trees for the gas plant were previously determined in the 1984 EIR/EIS, and were updated to reflect changes in design and operating conditions.

4.1.2 Fault Tree Construction

Fault tree analysis begins with a particular undesired top event, such as a compressor seal failure or toxic gas release. The analysis next breaks down the causes of such an accident into all the identifiable contributing sequences. Each sequence is separated into all its necessary components or events. In this study, the trees are not developed to the greatest level of detail possible, but, rather, to the level necessary to quantify the events of concern.

The sequences form pathways, along which are found logical "AND" or "OR" gates. Figure 4-1 shows the major logic symbols used in developing fault trees. These gates connect the basic initiating and contributing events to the higher order events. When the occurrence of all of a set of lower-order events is necessary for the higher-order event to occur, they are joined by an "AND" gate. By multiplying together the probabilities of each event in the set, the probability of the next higher event is obtained. When the occurrence of any one event of the set of lower-order events is sufficient for the next event to take place, the events are joined by an "OR" gate, and the probabilities are added. Probabilities of the top events are expressed as yearly rates - e.g., 1×10^{-4} chance of occurrence. (This event would be expected to recur once every 10,000 operating years.)

Since the probability of each top event is to be expressed as a yearly rate, no more than one event leading into an "AND" gate can have a probability expressed as a frequency. Otherwise, the overall failure rates will be in terms of something similar to "occurrence rate per year squared" - a meaningless unit. Thus, at most, one lower event leading into an "AND" gate can be expressed as a frequency; the remaining events are expressed as conditional probabilities, or probabilities per demand. At "OR" gates, it is essential that all the events entering the gate be quantified in the same units (either frequencies or probabilities) because they are to be added. The next higher-order event will be in the same units as the events immediately preceding.

4.1.3 Quantification Of Failure Rates

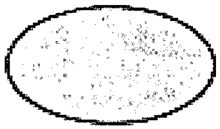
The failure rates for human error and equipment failure, which may be used in a given study, are based either on information reported in the literature or on estimates that combine information specific to the selected application with information from other sources of literature. The sources used in developing the failure rates for this study are listed in Section 7, References. The tables at the end of this section provide the rationale for each selected failure rate, and also provide information on the data sources.

For each fault tree, all initiating events have a numeric code in the fault tree box. These codes provide a reference number to the tables at the end of this chapter. In all cases, it has been assumed that properly designed construction materials would be available for the gas injection alternatives. This assumption was necessary in order to use historical failure rate data. This is the typical approach used for a conceptual design analysis.

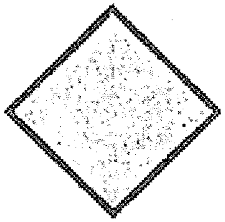
4.2 Offshore Platforms

From the PHA conducted for the alternative platform designs and the base case, the following ten release scenarios for the base case and full gas injection alternative were selected for fault tree analysis:

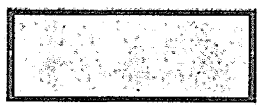
Figure 4-1 Fault Tree Logic Symbols



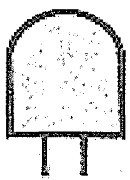
Circles or Ovals Represent Initiating Events and Therefore Have Yearly Rates of Occurrence



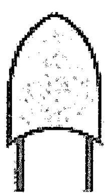
Diamonds Represent Contributing Events and Therefore Have Rates of Occurrence per Demand, i.e. Conditional on the Prior Initiating and Contributing Events Having Taken Place



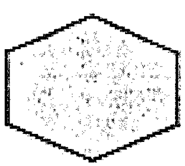
Rectangles Represent States Which are the Product of Several Initiating and/or Contributing Events Through an "AND" or "OR" Gate and May Therefore Have Rates of Occurrence Either Yearly or per Demand.



"AND" Gate - the Rates of Occurrence on the Incoming Branches are Multiplied



"OR" Gate - the Rates of Occurrence on the Incoming Branches Are Added



Hexagons Represent Numbers of Components and Serve as Multipliers

Base Case (i.e., Existing Operations)

1. Compressor Seal Failure At Platform Hermosa/Harvest
2. Pipeline Rupture At Platform Hermosa
3. Pipeline Leak At Platform Hermosa/Harvest
4. Sustained Rich Amine Line Rupture At Platform Hermosa/Harvest

Full Gas Re-injection

1. Compressor Seal Failure At Platform Hermosa/Harvest
2. Fitting Break On The Gas Re-injection Wellhead System At Platform Hermosa/Harvest
3. Re-injection Wellheader Pipe Failure At Platform Hermosa/Harvest

Produced Gas Injection

1. Compressor Seal Failure At Platform Harvest
2. Fitting Break On The Gas Injection Wellhead System At Platform Harvest
3. Injection Wellheader Pipe Failure At Platform Harvest

While a number of other scenarios were identified in the PHA, these were chosen as the scenarios for further evaluation.

4.2.1 Base Case (i.e., Existing Operations)

The base case scenarios were selected to provide a similar set of scenarios to the gas injection alternatives. As such, the failure rates for these scenarios will be the same as that for the representative cases in the alternatives.

Compressor Seal Failure

The failure rate would be the same as for the compressor seal failure covered as part of the full re-injection alternative discussed below. The major compressor seal failure ($1x10^{-1}$/yr) dominates the mechanical equipment failures. However, in order for a compressor seal failure to cause sufficient personnel exposure, both the area detectors must fail, and the inspection and maintenance program which would catch deteriorating seals must also have not been implemented. This results in a total failure frequency of $1.9x10^{-7}$/yr (or one chance in 5,300,000 per year). See Section 4.2.2 below for a more detailed discussion of the failure rate associated with this hazard scenario.

Pipeline Rupture At Platform Hermosa

This scenario would be expected to have the same frequency as the onshore pipeline rupture case which is discussed in the GRS. The failure rate for this event was estimated to be 2.44×10^{-6}/yr (one chance in 410,000 per year). The failure rate for a pipeline rupture is dominated by an outside force impact and material defects. The reader is referred to the original GRS for additional information on how the frequency of this scenario was developed.

Pipeline Leak At Platform
This scenario would be expected to have the same frequency as the onshore pipeline rupture case which is discussed in the GRS. The failure rate for this event was estimated to be 6.3 x 10^{-5}/yr (one chance in 15,900 per year). The failure rate for a pipeline leak is dominated by an outside force impact and material defects. The reader is referred to the original GRS for additional information on how the frequency of this scenario was developed.

Sustained Rich Amine Line Rupture
The mechanisms for failure of this line are an external pipe impact or pipe corrosion. However, this must be a sustained release, which can only occur if there is inadequate detection of the line failure. This would require the failure of a number of safety systems as well as a number of detectors. The overall failure rate for this fault tree is $2.4x10^{-7}$/yr, or one chance in 4,200,000 per year.

4.2.2 Full Gas Re-injection From GRS Study

Three hazard scenarios were evaluated for the full gas re-injection alternative. All these scenarios would apply to Platforms Hermosa and Harvest. Each scenario is discussed in detail below.

Compressor Seal Failure
The compressor seal allows the full re-injection gas to be vented to the flare in the event of a failure. A vent line piping failure or a major compressor seal failure are mechanical defects which can cause a compressor seal leak sufficient for personnel exposure.

As shown in Figure 4-2, the major compressor seal failure ($1x10^{-1}$/yr) dominates the mechanical equipment failures. However, in order for a compressor seal failure to cause sufficient personnel exposure, both the area detectors must fail, and the inspection and maintenance program, which would catch deteriorating seals, must also have not been implemented. This results in a total failure frequency of $1.9x10^{-7}$/yr (or one chance in 5,300,000 per year).

Fitting Break On Gas Re-injection Wellhead System
Venting of the wellhead gas can result from a fitting break caused by an external impact or a small pipe break. Although the fittings are robust in design, there is a high level of activity involved in moving heavy pipework and well head components in the confined wellhead area.

Pipe leaks due to corrosion as well as the selection of improper material may also cause venting of the wellhead gas. A corrosion monitoring program should find areas of corrosion and inhibit corrosion and replace the piping and fittings as required. Proper material selection is also critical. In this case, the pipe failure rate is $1.4x10^{-4}$/yr based on typical piping data. Should the corrosion program not be implemented, the failure rate would increase dramatically. Since it is unlikely that the program would be omitted, the failure rate is only increased one order of magnitude. As shown in Figure 4-3, each of the two event probabilities which cause venting of the wellhead gas are relatively equal giving a total frequency of $2.9x10^{-3}$/yr (or one chance in 340 per year).

Figure 4-2 Fault Tree for Release Scenario FGR-1

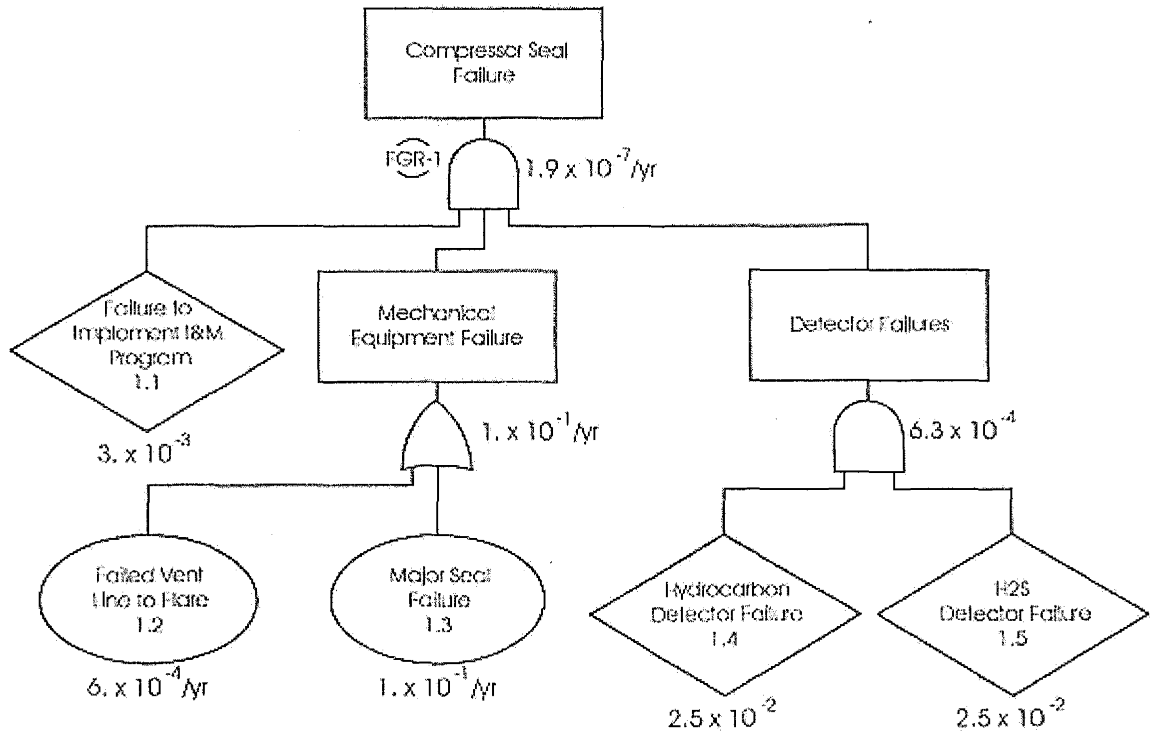
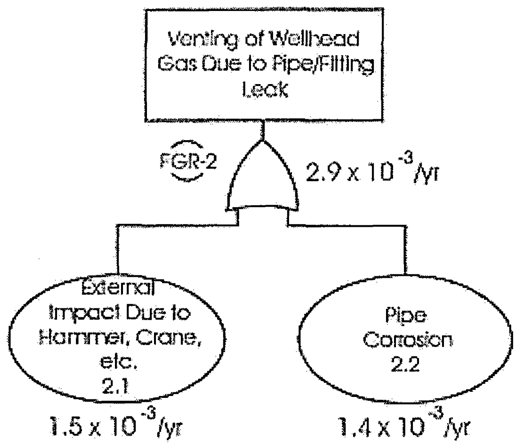


Figure 4-3 Fault Tree for Release Scenario FGR-2



Re-injection Wellheader Pipe Failure
A re-injection wellheader pipe failure could be caused by the same two mechanisms as were described above for the small pipe break on gas re-injection wellhead. The line is approximately the same length, but has a larger diameter. This reduces the pipe failure rate to 6.8×10^{-5}/yr.

In addition, there are protective features to detect a line failure. These include a low pressure alarm, a hydrocarbon detector and a hydrogen sulfide detector. The operator also periodically checks the condition of the hardware by a passive inspection. Failure of the alarm and detectors as well as failure of the operator to check the condition of the hardware would result in inadequate line failure detection. Figure 4-4 shows that no one event dominates this fault tree which has a top event failure frequency of 3.2×10^{-7}/yr (or one chance in 3,100,000 per year).

4.2.3 Proposed Gas injection Project

The same three hazard scenarios were evaluated for the proposed gas injection project. All these scenarios would apply to Platform Harvest. Each scenario is discussed in detail below.

Compressor Seal Failure
The compressor seal allows the full re-injection gas to be vented to the flare in the event of a failure. A vent line piping failure or a major compressor seal failure are mechanical defects which can cause a compressor seal leak sufficient for personnel exposure.

As shown in Figure 4-5, the major compressor seal failure (1×10^{-1}/yr) dominates the mechanical equipment failures. However, in order for a compressor seal failure to cause sufficient personnel exposure, both the area detectors must fail, and the inspection and maintenance program, which would catch deteriorating seals, must also have not been implemented. This results in a total failure frequency of 1.9×10^{-7}/yr (or one chance in 5,300,000 per year).

Fitting Break On Gas Re-injection Wellhead System
Venting of the wellhead gas can result from a fitting break caused by an external impact or a small pipe break. Although the fittings are robust in design, activity in the vicinity of the well head components in the confined wellhead area could result in a failure.

Pipe leaks due to corrosion as well as the selection of improper material may also cause venting of the wellhead gas. A corrosion monitoring program should find areas of corrosion and inhibit corrosion and replace the piping and fittings as required. Proper material selection is also critical. In this case, the pipe failure rate is 1.4×10^{-4}/yr based on typical piping data. Should the corrosion program not be implemented, the failure rate would increase dramatically. Since it is unlikely that the program would be omitted, the failure rate has not been increased. As shown in Figure 4-6, mechanical damage to the well head would have the highest probability of causing a release and giving a total frequency of 4.0×10^{-5}/yr (or one chance in 25,000 per year).

Figure 4-4 Fault Tree for Release Scenario FGR-3

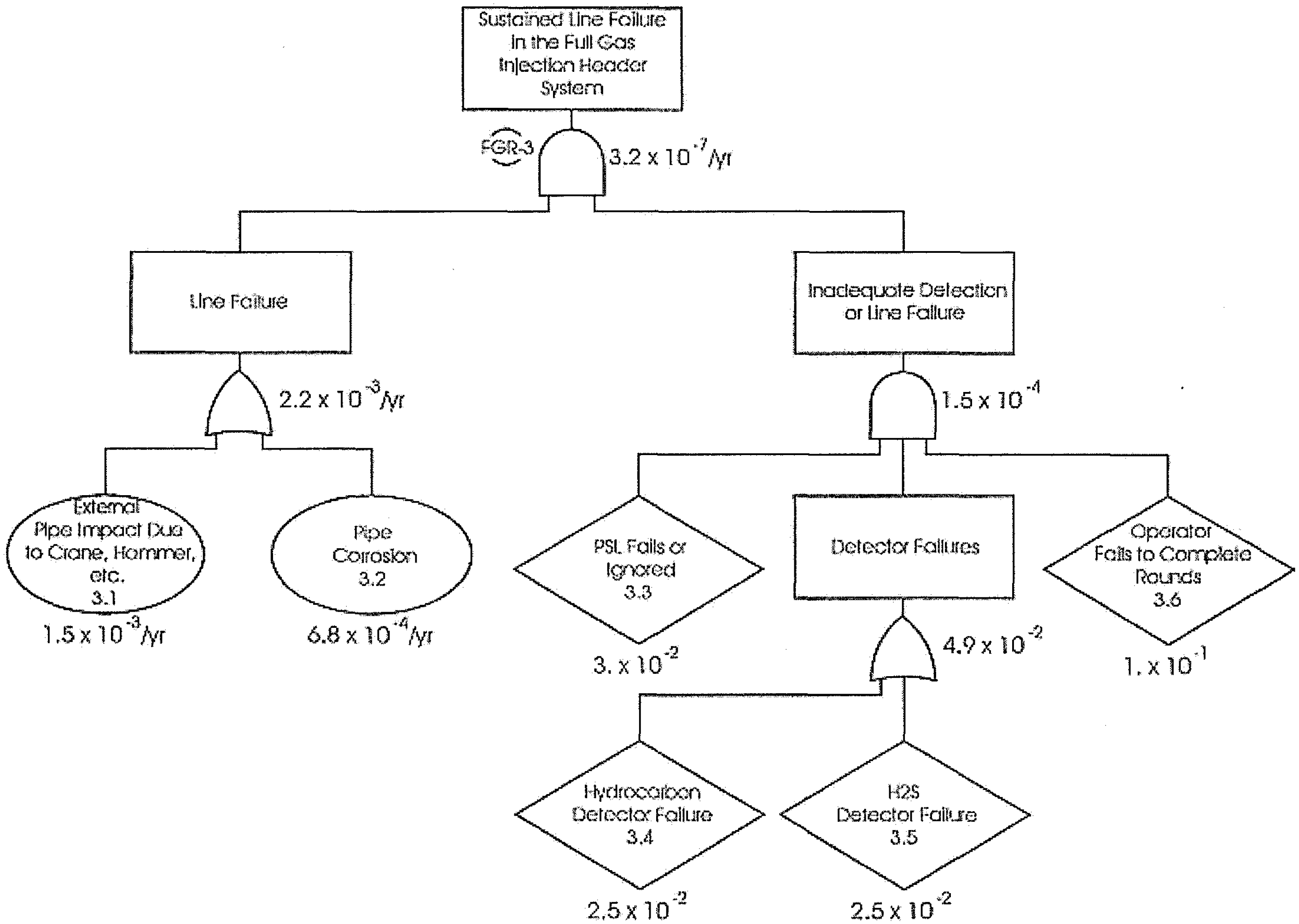


Figure 4-5 Fault Tree for Release Scenario RFR-1

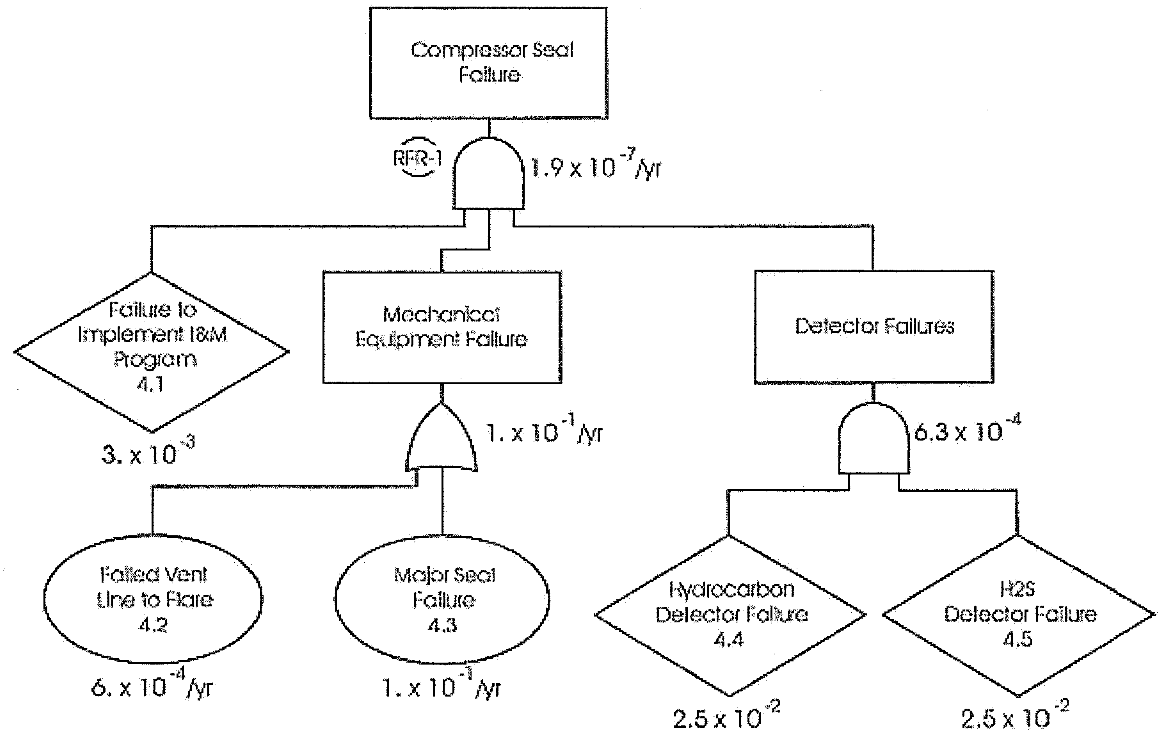
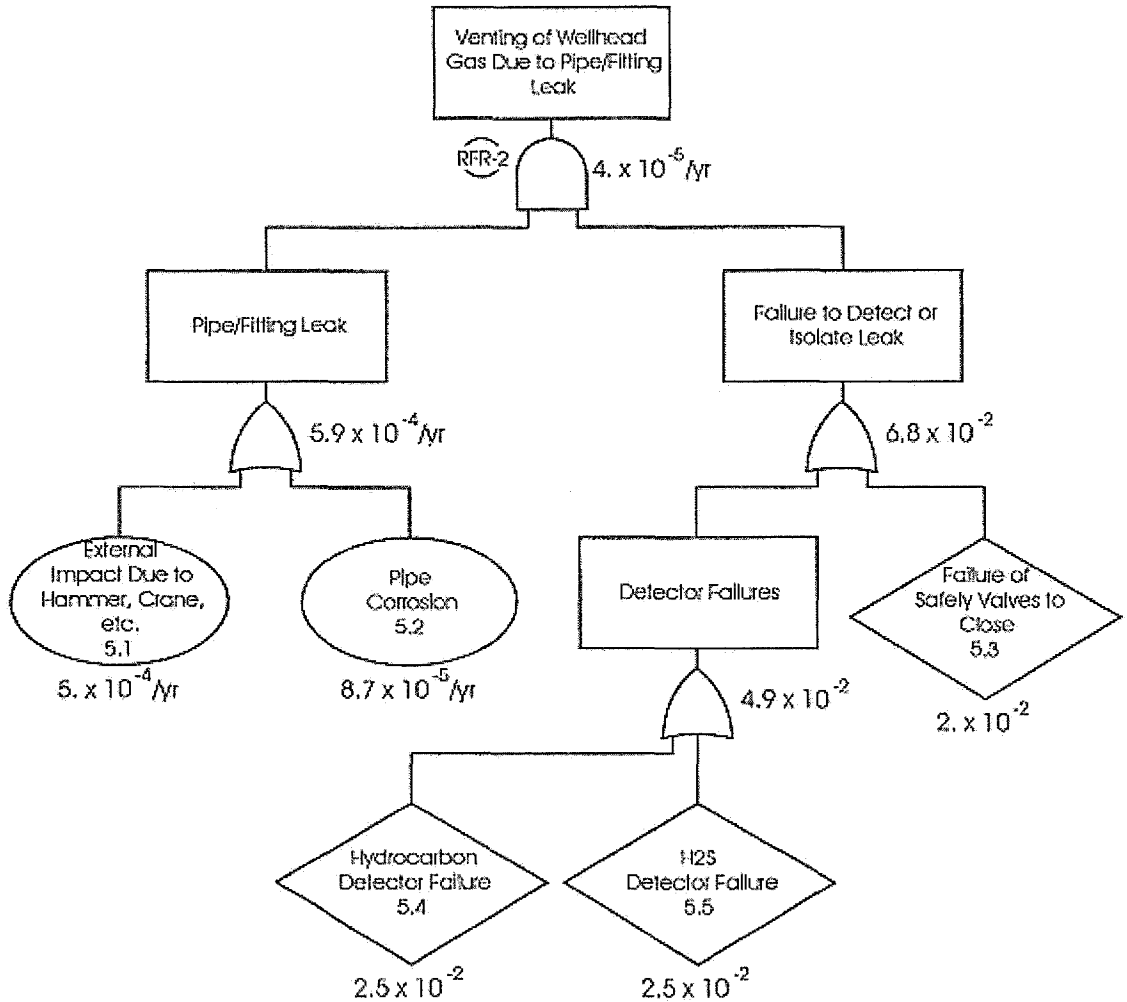


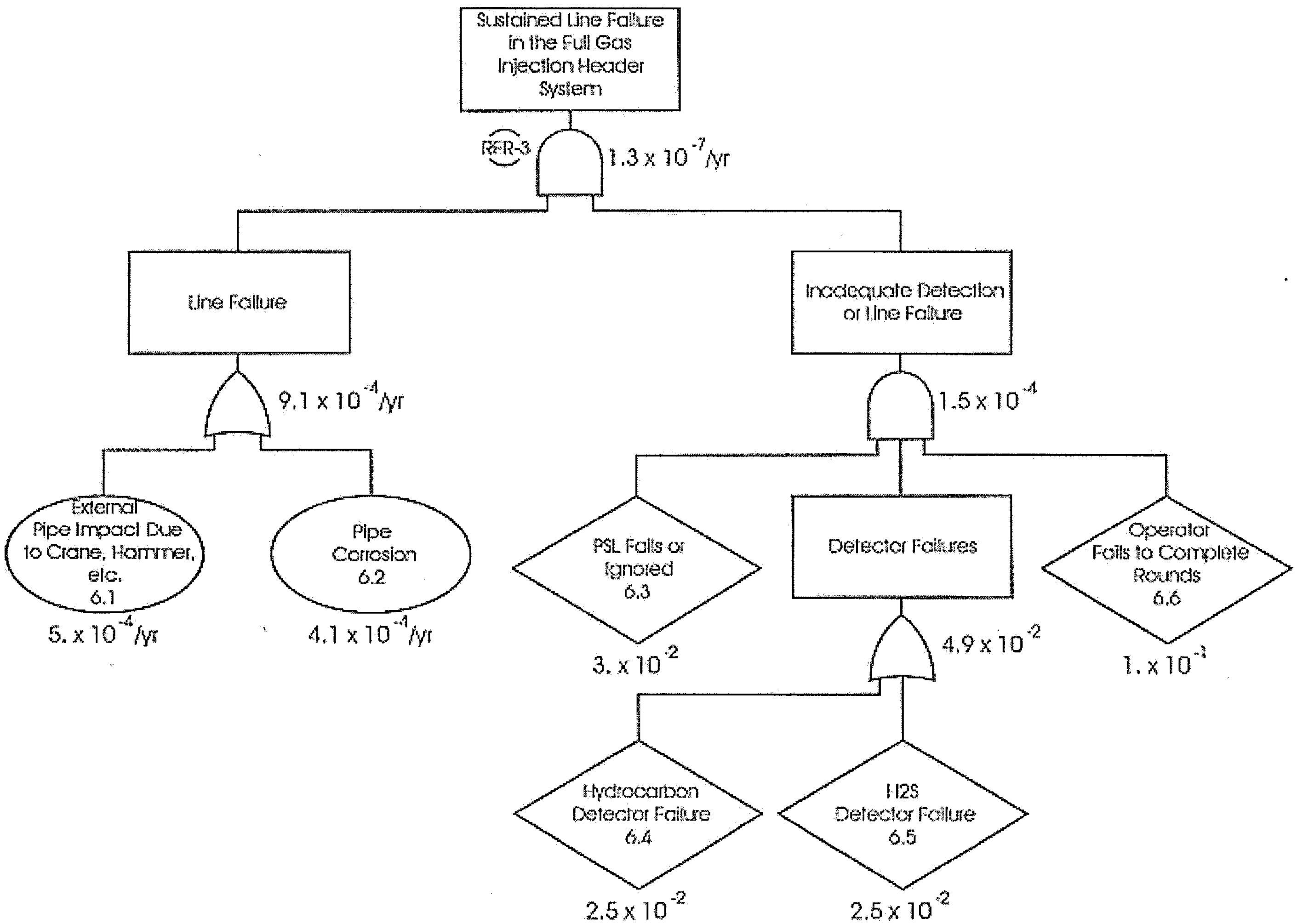
Figure 4-6 Fault Tree for Release Scenario RFR-2



Re-injection Wellheader Pipe Failure
An injection wellheader pipe failure could be caused by the same two mechanisms as were described above for the small pipe break on gas re-injection wellhead. The line is longer and has the same diameter. However, the wellheader has additional safety mechanisms (equipment and operator checks).

In addition, there are protective features to detect a line failure. These include a low pressure alarm, a hydrocarbon detector and a hydrogen sulfide detector. The operator also periodically checks the condition of the hardware by a passive inspection. Failure of the alarm and detectors as well as failure of the operator to check the condition of the hardware would result in inadequate line failure detection. Figure 4-7 shows that no one event dominates this fault tree which has a top event failure frequency of 8.4×10^{-8}/yr (or one chance in 11,900,000 per year).

Figure 4-7 Fault Tree for Release Scenario RFR-3



Rationale For Initiating Events In Offshore Platform Fault Trees

Event	Frequency or Probability	Source/Discussion
1.1 Failure to implement inspection and maintenance program	3×10^{-3}	CONCAWE states a probability of 3×10^{-3} for errors of omission embedded in a procedure.
1.2 Failed vent line to flare	6×10^{-4}/yr	Rijnmond states a leakage rate of 1×10^{-5}/m-yr for pipe less than 2 inches in diameter. There are approximately 60 m of pipe.
1.3 Major seal failure	1×10^{-1}/yr	No data is available for compressor seal failure rates. However, SRS, EPRI and others state pump failure rates ranging from less than l/yr to several per year. We use l/yr. SRS also states that 60% of all pump failures are due to seals. This yields a 0.6/yr failure rate. However, because compressor seals are subject to a harsher environment, we use l/yr. Ten percent of the seal failures are considered to be major.
1.4 Hydrocarbon detector failure	2.5×10^{-2}	OREDA states a failure rate of 1.8/yr for hydrocarbon gas detectors. Assume 1/3 fail-to-danger and monthly inspection with failure occurring between inspections yields 2.5×10^{-2}.
1.5 H_2S detector failure	2.5×10^{-2}	Because the H_2S detectors are similar in design and operation to the hydrocarbon detectors, we will use the same probability of failure.
2.1 External impact due to hammer, crane, etc.	1.5×10^{-3}/yr	Because of the relatively high level of activity involved in the movement of heavy pipework and wellhead components in a confined area, it is estimated that the failure rate will be 3×10^{-4}/yr per fitting, or three times the rate typically used, despite the robustness of these fittings. There are 5 fittings.
2.2 Pipe corrosion	1.4×10^{-3}/yr	Rijnmond states a leakage rate of 6×10^{-6}/m-yr for pipe 2 to 6 inches in diameter. There are approximately 90 m of pipe. Department of Transportation data indicate that for gas pipelines approximately 25% of pipe failures result from corrosion or material failures that might be attributed to improper material selection. This yields a failure rate of 1.4×10^{-4}/yr. Given the fact that the material flowing through the pipe is of a highly-corrosive nature, the implementation of a corrosion monitoring program to detect problem areas is necessary to attempt to achieve the typical pipe failure rate. Should the program implementation be compromised, this failure rate would increase dramatically. Therefore, we have increased the base failure rate by one order of magnitude.

Rationale For Initiating Events In Offshore Platform Fault Trees

Event	Frequency or Probability	Source/Discussion
3.1 External impact due to crane, hammer, crane, etc.	1.5×10^{-3}/yr	See 2.1
3.2 Pipe corrosion	6.8×10^{-4}/yr	Rijnmond states a leakage rate of 3×10^{-6}/m-yr for pipes greater than 6 inches in diameter. See 2.2 for pipe length and further discussions.
3.3 PSL fails or ignored	3×10^{-2}	Lees states a failure rate of 1.41/yr for pressure measurement. Assuming 1/3 are fail to danger and monthly inspections with failure occurring at the midpoint between inspection yields 2×10^{-2}. Further, Lees states a probability of 3×10^{-2} that the operator will ignore the action while Rijnmond states 3×10^{-4}. We use 1×10^{-2} for a total probability of 3×10^{-2}.
3.4 Combustible Gas detector failure	2.5×10^{-2}	See 1.4
3.5 H_2S detector failure	2.5×10^{-2}	See 1.5
3.6 Operator fails to complete rounds	1×10^{-1}	Operator fails to check condition of hardware (Swain and Guttman), or passive inspection from same source.
4.1 Failure to implement inspection and maintenance program	3×10^{-3}	See 1.1
4.2 Failed vent line to flare	6×10^{-4}/yr	See 1.2
4.3 Major seal failure	1×10^{-1}/yr	See 1.3
4.4 Hydrocarbon detector failure	2.5×10^{-2}	See 1.4
4.5 H_2S detector failure	2.5×10^{-2}	See 1.5
5.1 External impact due to hammer, crane, etc.	5.0×10^{-4}/yr	Because the level of activity near the well head injection system will be relatively low and protected from external forces, it is estimated that the normal failure rate will be 1×10^{-4}/yr per fitting. There are 5 fittings.
5.2 Pipe corrosion	8.7×10^{-5}/yr	Rijnmond states a leakage rate of 6×10^{-6}/m-yr for pipe 2 to 6 inches in diameter. There are approximately 58 m of pipe. Department of Transportation data indicate that for gas pipelines approximately 25% of pipe failures result from corrosion or material failures that might be attributed to improper material selection. This yields a failure rate of 8.7×10^{-5}/yr. Since the gas will be injected dry with a water dew point well below operating temperatures and with 23%

Rationale For Initiating Events In Offshore Platform Fault Trees

Event	Frequency or Probability	Source/Discussion
		lower partial pressures of H2S and CO2, internal corrosion would be minimal. Therefore, no additional adjustments have been made to this failure rate for corrosive gas service.
5.3 Valve Failure	2.0×10^{-2}	Lees states a failure rate of 1.0×10^{-2} per demand for spurious valve operation or failure to change position on demand. The failure of one of two safety valves would result in a sustained release.
5.4 Hydrocarbon detector failure	2.5×10^{-2}	See 1.4
5.5 H_2S detector failure	2.5×10^{-2}	See 1.5
6.1 External impact due to crane, hammer, crane, etc.	1.5×10^{-3}/yr	See 2.1
6.2 Pipe corrosion	4.1×10^{-4}/yr	See 5.2 for corrosion for pipe specifications and adjustments.
6.3 PSL fails or ignored	3×10^{-2}	See 3.3
6.4 Combustible gas detector failure	2.5×10^{-2}	See 1.4
6.5 H_2S detector failure	2.5×10^{-2}	See 1.5
6.6 Operator fails to complete rounds	1×10^{-1}	See 3.6
6.7 Valve Failure	2.0×10^{-2}	See 5.3

5.0 Revised Consequence Modeling

The consequence analysis and hazard modeling is the part of the risk assessment which considers the physical effects and the damage caused by these physical effects. It is performed in order to judge the seriousness of potential hazards associated with accidents and their possible consequences.

The types of hazards that are generally considered in any risk assessment include fire, flammability, explosion, and toxicity. Fire and flammability hazards are of significance for flammable vapors with relatively low flash points, such as propane and methane; their hazard is usually in the form of thermal radiation from vapor jet or pool fires. In addition, larger vapor jet fires can also lead to loss of structural integrity of other storage or process vessels. The temperature in flame jets is usually high and flame impingement onto nearby equipment is of the greatest concern. The release and ignition of flammable vapors may also result in an explosion. The blast overpressure hazard is dependent on the nature of the chemical, the strength of the ignition source and the degree of confinement. Finally, toxic chemicals can produce adverse effects to humans. The degree of the effects are dependent upon the toxicity of the material and the duration of the exposure.

5.1 Methodology

Performing state-of-the-art hazard assessment requires the combination of sophisticated analytical techniques and extensive professional experience. The models that were used in this analysis are the result of over two decades of development, and have been validated using large-scale field tests. They have also been computerized for ease of use and operate on both mainframe and personal computer. While a large number of consequence models are available, only a few specific models were needed to assess the hazards identified as part of this study.

The hazard assessment models used as part of this analysis can be grouped into the following categories:

- Release rate models, and
- Vapor dispersion models.

The general characteristics for each model used in this analysis are discussed in the following sections. Specific models used in the analysis were based on the scenarios identified in the hazard identifications task.

5.1.1 Release Rate Models

Several models were utilized to simulate potential releases of sour and acid gas, amine spills and vapor/liquid releases from pipes and vessels. These models are discussed below.

Release Rate Characterization

One of the first steps in consequence modeling is to establish the release rate associated with each scenario. The release rate is the rate at which the material is released from the pipe and/or vessel to the atmosphere. Before the release rates can be estimated for each scenario identified in the hazard analysis, the thermodynamic and physical properties of each hydrocarbon stream need to be characterized. Estimation of the thermodynamic and physical properties of the hydrocarbon streams was accomplished using the Arthur D. Little, Inc. SuperChems™ and PropertEASE™ models, which utilize numerous thermodynamic and physical property estimation techniques.

The SuperChems™ model has been updated to simulate the release of multi-component liquid/vapor streams which are characteristic of potential releases associated with the Point Arguello Field. For this study, these models are useful in assessing the effect of multi-component streams on vapor cloud flammability characteristics, especially where inert compounds are involved (i.e., CO_2).

Two-Phase Flashing Flow Model

This is a critical two-phase flashing flow multi-component liquid discharge model based on methodology validated by experimental data in the recent literature. The data has demonstrated that, for a pipe length exceeding about four inches, irrespective of pipe diameter, there is enough residence time for a discharging flashing liquid to establish thermal equilibrium in a pipe. Using an established method known as the Slip Equilibrium Method, the model does a friction calculation based on average vapor/liquid mixture properties and sequentially solves the equilibrium and mechanical energy balance equations, accounting for the pressure reduction and adiabatically recalculating the mixture properties. The output of the model gives a mass release rate and properties of the exiting hydrocarbon aerosol mixture.

This model was used to estimate release rate characteristics for the scenarios where potential aerosol formation could occur as a result of rapid vessel/pipeline decompression and cooling.

Steady/Non-Steady Release From A Pressurized Vessel/Pipeline

These numerical steady and non-steady state flow models are used to compute multi-component liquid/vapor release rate from a ruptured valve or pipeline. The steady choked and unchoked flow models compute a single release rate assuming uniform pressure and temperature in the vessel; in most blowdown processes from pressure vessels, the pressure inside is sufficiently high that choked flow (i.e., releases that occur at sonic velocity) conditions exist during most of the blowdown period. However, in smaller pressure vessels, or for relatively larger release rates, the conditions inside the vessel are not steady. The pressure drop influences the flow velocity and thus the mass flow rate. In addition, the density and temperature inside the vessel are also changing. The unsteady state models compute a time-dependent release rate profile based on the chemical component properties.

5.1.2 Dispersion Models

Among the models required for hazard assessment, vapor dispersion models are perhaps the most complex. This is due to the varied nature of release scenarios, as well as the varied nature of chemicals that may be released into the environment. The exposure limit must be selected carefully by the user, to reflect both the impact of interest (fatality, serious injury, injury, etc.) and the scenario release conditions (especially duration of release).

In dispersion analysis, gases and two-phase vapor-liquid mixtures are divided into three general classes, materials which are:

1. Positively buoyant
2. Neutrally buoyant
3. Negatively buoyant

These classifications are based on density differences between the released material and its surrounding medium (air), and are influenced by release temperature, molecular weight, ambient temperature, relative humidity, and the presence of aerosols.

Initially, density of the release affects the dispersion process. A buoyant release may increase the effective height of the source. By the same token, a heavier-than-air release will slump towards the ground. For heavier-than-air releases at or near ground level, the initial density determines the initial spreading rate. This is particularly true for large releases of liquefied or pressurized chemicals, where flashing of vapor and formation of liquid aerosols contributes very significantly to the initial effective vapor density and therefore to the density difference with air. This was particularly true for the onshore gas pipeline releases.

Results of recent research programs dramatically indicate the importance of heavy gas dispersion in the area of chemical hazard assessment.

- The initial rate of spreading (often termed slumping) is significant, and is dependent on the differences between the effective mean vapor density and the air density.

- The rapid mixing with ambient air due to slumping leads to lower concentrations at shorter distances than those predicted using neutral density dispersion models.

- There is very little mixing in the vertical direction, and, thus, a vapor cloud hugging the ground is generated.

- When the mean density difference becomes small, the subsequent dispersion is governed by prevailing atmospheric conditions.

Since heavy gas dispersion occurs near the release, it is particularly important when considering large releases of pressurized flammable chemicals, such as the onshore gas pipeline.

In addition, dispersion analysis is also a function of release modes. They are usually divided into the following categories:

- Instantaneous release (puff)
- Continuous release (plume)
- Momentum-dominated continuous release (jet)
- Time-dependent continuous releases (jet/plume)

For instance, a momentum-dominated jet will dilute much faster than a plume due to increased entrainment of air caused by the jet. This is especially important when simulating the release of compressed gases.

In addition to the effects of initial release density, the presence of aerosols, release rate/quantity, release duration, and release mode, dispersion analysis also depends on:

- Prevailing atmospheric conditions
- Limiting concentration
- Elevation of the source
- Surrounding terrain
- Source geometry

Prevailing Atmospheric Conditions include a representative wind speed and an atmospheric stability class. Less stable atmospheric conditions result in shorter dispersion distances than more stable weather conditions. Wind speed affects the dispersion distance inversely. Because weather conditions at the time of an accident cannot be determined *a priori*, it is usually prudent to exercise the model for at least typical and worst case weather conditions for hazard analysis purposes.

Limiting Concentration affects the dispersion distance inversely. Lower concentrations leads to a larger dispersion distances. As with source release rate, the effect is non-linear; for example, for steady state releases, a factor of 100 reduction in the limiting concentration results in an increase in the dispersion distance by a factor of about 10.

Elevation Of The Source is attributed to its physical height (such as a tall stack). In general, the effect of source height is to increase dispersion in the vertical direction (since it is not ground restricted), and to reduce the concentration at ground level.

Surrounding Terrain affects the dispersion process greatly. For example, rough terrain involving trees, shrubs, buildings and structures usually enhance dispersion, and lead to a shorter dispersion distance than predicted using a flat terrain model. Building and terrain effects are site-specific and cannot be considered in a generalized dispersion model.

Source Geometry refers to the actual size and geometry of the source emission. For example, a release from a safety valve may be modeled as a point source. However, an evaporating pool may be very large in area and may require an area source model. The source geometry effects are significant when considering near-field dispersion (less than the ten times the characteristic dimensions of the source). At farther distances, the source geometry effects are smaller and eventually become negligible.

Plume Dispersion Models (Atmospheric)

In the estimation of hazard zones for low velocity releases involving flammable or toxic materials, a set of neutrally-buoyant Gaussian plume models are available. The effects of initial density are usually small in the computation of far-field dispersion zones. The most relevant release characteristics affecting the extent of vapor dispersion are the release rate (or quantity), the release duration, the limiting concentration, and the ambient conditions.

Several mathematical variations are included in our models. They have also been computerized as part of Arthur D. Little's SuperChems™ modeling package for ease of use. Additional models, which are available in the public domain and have been rigorously evaluated, are also available. These models have also been validated using large-scale field tests and wind tunnel experiments. The variations in these models consider the details of the source effects (as opposed to the virtual source method). They include a continuous line/plane source model (to approximate finite size source effects from evaporating pools, overflowing dikes, etc.); a continuous point-source plume model (isolated stack) including effects of buoyancy and momentum; a finite duration point-source model for concentration; a finite-source duration and receptor duration to model dose effects from a point-source; and a finite duration "Probit" model which accounts for a non-linear dose response relationship. As a function of downwind distance, each model evaluates concentration and cloud width at source and ground level.

Jet Dispersion Model

The turbulent free jet dispersion models (including a modification of the Ooms model) are based on widely accepted entrainment theory and are supported by vast laboratory scale experimental data. For momentum-dominated jets of flammable materials, dispersion to limiting concentrations is generally completed in the jet regime. The models, which also incorporate buoyancy effects, include circular jets in co-flowing air, planar jets in co-flowing air, and circular jets in the presence of a crossflow. The exit conditions and geometry are corrected for choked flow. The models compute concentration and velocity profiles as a function of axial distance. In addition, ground level hazards for elevated jets are evaluated.

This model was used to estimate the initial dispersion for all the vapor jet releases examined in this analysis. In many instances, plume concentrations were observed to drop below the levels of concern (LOC) within the jet as a result of the high entrainment related to high velocity jets. When the jet reaches ground level, results from the jet dispersion model were transition into the appropriate heavy gas or passive (i.e., Gaussian) dispersion model. The jet dispersion model was used for all above-ground high pressure releases.

Flame Jet Model

This model is designed to simulate turbulent diffusion flames (flame jets) and can characterize the turbulent flame length, diameter, temperature, and thermal radiation effects. This model is capable of simulating inclined turbulent jets, radiation fields, and the aerodynamic effects on radiant energy and flame stability. This model was used for all scenarios where potential flammable vapor releases were identified.

Unconfined/Partially Confined Vapor Cloud Explosion Model

A partially confined deflagration model was used to estimate overpressure levels for each flammable vapor release considered. This model is a theoretical 1-dimensional model for the prediction of overpressures within several geometric configurations, and accounts for the non-ideal behavior of burnt and unburnt gaseous components during high pressure venting and multi-reaction chemical equilibrium. The pressure-time histories within the explosion chamber (i.e., confined space and/or vapor cloud) are calculated by the model and are in generally good agreement with small and large scale experimental data on methane-air, propane-air, and hydrocarbon mixture vented and unvented explosions. Explosion potential is expressed in terms of a TNT equivalence, and well known shock wave propagation relationships are used to estimate overpressure levels at specified distances from the explosion.

The potential for unconfined vapor cloud fires and explosions were also assessed using the SuperChems™ model. The potential for a vapor cloud explosion versus a vapor cloud fire were assessed based on the physical characteristics of the hydrocarbon stream. Parameters that influence the potential for, and consequences of a vapor cloud explosion include:

- Characteristics of ignition sources,
- Flame acceleration mechanisms,
- Deflagration to detonation transitions,
- Direct initiation of detonations,
- Overpressure levels within the combustion zone,
- Effects of pressure rise time dependency on structures vs. TNT curves,
- Minimum amount of mass sufficient to sustain an Unconfined Vapor Cloud Explosion (UVCE),
- Partial vapor cloud confinement and flame reflection characteristics, and
- Explosion efficiencies.

This model was used to assess whether or not enough flammable mass could accumulate to sustain a UVCE (a relatively large amount of flammable mass is required for the flame front in the vapor cloud to gain sufficient speed to result in a significant pressure wave within the vapor cloud). In most cases, the amount of flammable mass was not sufficient to sustain a UVCE. In other cases, modeling results showed that vapor cloud ignition would be characterized by a deflagration (i.e., sub-sonic flame velocity) and would not transition to a full detonation (i.e., super sonic flame velocity). In addition, the composition of the hydrocarbon streams, which contained significant amounts of non-flammable gases such as nitrogen and carbon dioxide, inhibited flame propagation speed and potential pressure wave intensity.

5.1.3 Meteorological Data

Meteorological data were summarized as part of the 1984 EIS/EIR and 1988 SEIR and were also utilized in this consequence analysis. Based on the stability/wind frequency distributions for the region, two meteorological conditions were selected for the consequence modeling analysis. Atmospheric stability classes D and F were selected for worst-case day and night stability conditions, respectively. Based on wind speed conditions for these stability classes, a wind speed of 5.0 meters per second (m/s) was selected for stability class D neutral atmospheric stability), while a wind speed of 2.0 meters per second (m/s) was selected for stability class F (stable atmospheric conditions).

5.1.4 Damage Criteria

Several potential hazards exist in the event of an accidental release of the hydrocarbon streams identified in the hazards analysis. Since these streams are extremely flammable, releases could potentially result in thermal radiation exposure from a fire, and also presents a significant explosion hazard in confined areas. Hydrogen sulfide concentrations in some of the gas streams also pose a potential hazard. Damage criteria were developed in order to quantify the potential consequences of an accidental release.

Hydrogen Sulfide Damage Criteria

A consistent set of criteria for adverse consequences, referred to as levels of concern (LOC), have been used in modeling the consequences of the various releases. The LOCs are presented as concentrations of the hazardous material (in this case H_2S) in the atmosphere in parts per million (ppm). The justification for selecting these LOCs are described below. Momentary concentration is used in place of dosage because preliminary release rate calculations have shown that for the severe releases, the hazard zones based on dosage are smaller than that for a one breath concentration hazard zone. This is because the maximum release rate and plume length for the severe releases are relatively small and would pass over a receptor (a person exposed to the hazardous plume) in a short time (thus, low dosage). Many of the scenarios are characterized by high initial release rates that gradually decrease until the release ceases. Therefore, the initial concentration is relatively high, but the total dosage is low.

Two basic concentration levels are employed to present the hazard zones for the hydrogen sulfide. These are "extensive" and "major" A value of 1,000 ppm has been used to define extensive health effects, which is consistent with the SEIR analysis. The Immediately Dangerous to Life and Health (IDLH) was used to define major health effects, which is also consistent with the 1988 SEIR analysis. Extensive is defined as "one breath can lead to collapse, unconsciousness, or death," and Major is defined as "extended exposure can lead to irreversible injury." These concentrations, presented in Table 5.1, are based on a review of reported concentrations and dosages that have been used in experiments with animals and have been estimated in accident investigation cases involving humans. The justification for selecting these LOCs are further described below.

Table 5.1 Hydrogen Sulfide Toxic Damage Criteria

Toxic Concentration (ppm)	*Damage Criteria*	*Averaging Time (min)*
1,000	Extensive	<10
300	Major	30

Hydrogen Sulfide Inhalation Toxicology

Acute intoxication from hydrogen sulfide exposure usually occurs from a single exposure to elevated concentrations and refers to systemic effects involving both the central nervous system and respiratory system. Effects of acute exposures include eye irritation, respiratory tract irritation, headache, dizziness, excitement, staggering gait, and gastroenteric disorders. Exposure to concentrations of 1,000 to 2,000 ppm causes respiratory paralysis after a breath or two, due to inhibition of the respiratory center of the brain. Death due to sulfide toxicity is believed to result from respiratory arrest attributed to a direct depressant effect on the respiratory centers of the brain stem.

For consequence analysis purposes, it is desired to estimate those concentrations in air capable of causing deaths in at least some small fraction of exposed populations within the two time periods of 10 minutes (or less) and 30 minutes. These represent two distinct classes of release:
1) instantaneous loss of contents or a continuous discharge that is rapidly isolated; and 2) a continuous discharge that requires a longer time to isolate or which continues until available inventory is depleted.

Table 5.2 presents the physiologic response to various concentrations of hydrogen sulfide. NIOSH (1985) reports the IDLH (Immediately Dangerous to Life and Health) level for this chemical as 300 ppm for 30 minute exposure. Table 5.3 provides summaries of relevant data, reported by key sources of information regarding the potential exposures capable of causing fatalities among exposed members of the public in the event of an accident.

Table 5.2 Physiologic Effects of Human Exposure to Various Levels of Hydrogen Sulfide (page 1 of 2)

Concentration (ppm)	*Physiologic Effects*
<1	Some level of odor
3--5	Offensive, moderately intense
10	Obvious and unpleasant odor
10	Threshold limit value-time weighted average
10	"Sore eyes"
20	Maximum allowable concentration for daily 8-hour exposure
20--30	Strong and intense odor, but not intolerable
50--100	Mild irritation to the respiratory tract and especially to the eyes after 12 hour of exposure
100	Loss of smell in 3 to 15 minutes, may sting eye and throat
200	Kills smell quickly, stings eyes and throat
300-500	Pulmonary edema, imminent threat to life (short-term exposure)
500	In 0.5-1 hour it will cause excitement, headache, dizziness, and staggering, followed by unconsciousness and respiratory failure
500--1000	Acts primarily as a systemic poison causing unconsciousness and death through respiratory paralysis (short term exposure)

Table 5.2 Physiologic Effects of Human Exposure to Various Levels of Hydrogen Sulfide (page 2 of 2)

Concentration (ppm)	*Physiologic Effects*
700	Unconscious quickly, death will result if not rescued promptly
700--900	Rapidly produces unconsciousness, cessation of respiration and death (short-term exposure)
1000	Rapidly produces unconsciousness, cessation of respiration and death
1000	Nervous system paralysis
5000	Imminent death

* Most of these are for short-term acute exposures.

Source: Modified from Beauchamp (1984)

Table 5.3 Summary of Acute Inhalation Toxicity Data for Hydrogen Sulfide

Exposure	*Observed Effect*	*References*
>700 ppm (30 min)	Death	Baskin (1972)
500 ppm (30 min)	Headache, Dizziness, Excitement, Staggering, and Gastroenteric disorders possibly followed by bronchitis or bronchial pneumonia	Braker (1977)
>600 ppm (30 min)	Death from respiratory paralysis	Braker (1977)
1000 ppm (single breath)	Convulsions, coma and rapid death	Proctor, Hughes (1978)
500 ppm (30 min)	Headache, dizziness, excitement, staggering gait, diarrhea and dysuria followed by bronchitis or bronchopneumonia	Sax (1989)
800-1,000 ppm (30 min)	Death due to respiratory paralysis	Sax (1989)
1,000-2,000 ppm (single breath)	Convulsions, coma, and rapid death	Matkinson, et al., (1989)
600 ppm (30 min)	Death	NIOSH (1983)
700 ppm (>30 min)	Death	Air Products and Chemicals, Inc. (1985)

The data in Tables 5.2 and 5.3 reveals that the majority of references agree that concentrations of 600 to 700 ppm of hydrogen sulfide in air are required to cause fatalities among human populations exposed for 30 minutes. However, in order to be consistent with the 1988 SEIR and to provide some level of conservatism, a value of 300 ppm for 30 minutes has been used to represent the "major" injury level (Table 5.1). From the information provided in these tables we have concluded that fatalities could occur from one breath exposure. Given that there is some degree of contradiction, however, and (more importantly) that toxicity data of this sort usually contains some degree of uncertainty, we have selected 1,000 ppm to represent limiting concentrations for the "extensive" injury levels (Table 5.1). This values is considered the peak (10 minutes or less) exposure concentrations. As needed both of these values were scaled to the appropriate exposure time using the "Probit" equation method.

Thermal Radiation Damage Criteria

The potential concern associated with large-scale compressed gas vapor jet fires is thermal radiation intensity and its effects surrounding structures, process and fire suppression equipment. Table 5.4 and 5.5 present an overview of thermal radiation intensity and observed effects. Data presented in these tables show that no significant physical effect would result from exposure to a radiation intensity of 1.6 kW/m^2 over extended periods. Exposure to a radiation intensity of 4 kW/m^2 would result in pain if the exposure period were to exceed 20 seconds. Exposure to a radiation intensity of 9.5 kW/m^2 would result in pain (8 seconds) and second degree burns after short exposure periods (i.e., 20 seconds).

Data on the exposure time necessary to reach pain thresholds is presented in Table 5.5. This information indicates that relatively high thermal radiation levels can be tolerated without significant pain or injury. The time required to reach the pain threshold can be used to indicate a reasonable evacuation time that would result in little or no significant physical injury. Exposure to a thermal radiation level of 5 kW/m^2 would not likely result in any significant injury, based on the assumption that a person could leave the immediate area of the fire within the approximately 15 seconds required to reach the pain threshold. Exposure to a thermal radiation level of 10 kW/m^2 would likely result in some pain, but evacuation would be possible before second degree burns would be incurred. Based on the data in these tables and other sources, thermal radiation levels of 5 and 10 kW/m^2 were selected to represent minor (first degree burn) and moderate (second degree burn) physical injury levels.

Damage to surrounding structures and equipment could potentially also occur in the immediate vicinity of a hydrocarbon vapor jet fire. Based on the data presented in Table 5.4, a thermal radiation level of 37.5 kW/m^2 was selected to characterize potential damage to surrounding structures and equipment. This thermal radiation level represents the minimum level that could cause damage to structures and equipment; however, prolonged exposure would be required before significant damage could occur.

Table 5.4 Observed Effects Of Thermal Radiation Intensity

Thermal Radiation Intensity (kW/m^2)	Observed Effect
37.5	Sufficient to cause damage to process equipment
25.0	Minimum energy required to ignite wood at indefinitely long exposures (non-piloted)
12.5	Minimum energy required for piloted ignition of wood, melting of plastic tubing
9.5	Pain threshold reached after 8 seconds; second degree burns after 20 seconds
4.0	Sufficient to cause pain to personnel if unable to reach cover within 20 seconds; however blistering of the skin (second degree burns) is likely; 0 percent lethality
1.6	Will cause no discomfort for long exposure

Source: Center for Chemical Process Safety, 1989.

Table 5.5 Thermal Radiation Intensity And Time To Pain Threshold

Thermal Radiation Intensity (kW/m^2)	Time To Pain Threshold (seconds)
1.74	60
2.33	40
2.90	30
4.73	16
6.94	9
9.46	6
11.67	4
19.87	2

Source: Center for Chemical Process Safety, 1989.

Explosion/Overpressure Criteria

Several process vessels would contain flammable/explosive vapors and potential ignition sources would likely be abundant in the vicinity. The possibility of ignition and an UVCE is unlikely for many scenarios. The consequences of flammable vapor ignition were quantified by estimating the distance to several overpressure levels (shock waves) that represent different damage criteria.

Several biological and structural explosion damage criteria were reviewed (Table 5.6). Four overpressure levels were selected to be representative of light (0.5 psi), moderate (1.0 psi), heavy (3.0 psi), and extensive (5.0 psi). An overpressure level of 0.5 psi would likely result in broken windows and some potential for minor injury. Some structural damage and injury would likely occur as a result of exposure to an overpressure level of 1.0 psi. An overpressure level of 3.0 psi would likely result in significant damage to nearby buildings. An overpressure level of 5.0 psi would result in structural damage to nearby structures; however, overpressure levels of 15-50 psi would be required to cause significant damage to surrounding vessels and equipment. Significant biological damage would also potentially result from exposure to an overpressure level of 5.0 psi.

5.2 Consequence Modeling Results

To assess the potential impact of produced gas injection on the platforms, several base case (i.e., existing operations) and produced gas injection scenarios were examined as shown in Table 5.7. This table provides a description of the scenarios along with their initial release conditions. Current applicable operations include produced gas compression for pipeline transport to shore and acid gas scrubbing for fuel gas requirements.

Toxic hazards (hydrogen sulfide exposure) associated with baseline operations and under the full gas injection cases are summarized in Table 5.8. Results of the consequence analysis indicate that toxic hazards would not change appreciably over baseline conditions, and would decrease over the conditions originally proposed for gas re-injection (i.e., GRS), mainly as a result of the lower operating pressures required for the proposed gas injection project. The maximum baseline toxic hazard zone is approximately 840 feet associated with a spill of rich amine solution. This hazard zone would remain the same under the gas injection alternative while the gas compression system failure hazard zone associated with gas injection would be approximately 140 feet. A subsea rupture of the pipeline could result in a sour gas release for the gas injection project. In the event of this type of release the release rate of the gas would be substantially less than for a rupture on the platform given the higher outside pressures. At a depth of 600 feet the pressure on the outside of the pipeline would be approximately 270 psig. This reduced release rate combined with the higher diffusion and solubility of H_2S in the seawater would cause the gas to be dissolved into the water, as it ascends to the surface. This would result in eliminating the toxic hazard associated with a subsea rupture.

Flammable vapor hazards associated with baseline operations and under the produced gas injection cases are summarized in Table 5.9. These results indicate that flammable vapor hazard zones would not change substantially when compared to baseline conditions.

Table 5.6 Biological And Structural Damage Criteria From Explosions

Overpressure (psi *)	Biological Damage	Structural Damage
70	99% Fatality	Total structural damage
50	50% Fatality	Total structural damage
35	1% Fatality	Total structural damage
15	Lung Damage	Severe structural damage
7-8		Shearing and flexure failure of brick wall panel 8 to 12 inches thick (not reinforced)
5	Eardrum rupture	Shattering of concrete wall panels, 8 to 12 inches thick (not Reinforced)
2-4		Non-reinforced cinder block walls shattered; 50 percent destruction of brick buildings; steel frame building distorted; light industrial buildings ruptured
1-2		Failure of wood siding panels. Shattering of asbestos siding and corrugated steel and aluminum panel failure
0.5-1		Shattering of glass windows

Source: Center for Chemical Process Safety, 1989.

* The total overpressure may be achieved by reflection of an incident wave of about half of the stated values.

Table 5.7 Summary of Platform Release Conditions

Description	Code #	Release Type	Release Composition	H_2S Concentration (ppm)	Initial Temperature (°F)	Initial Pressure (psig)	Initial Volume (ft^3)	Release Diameter (inches)
Pipeline Compressor Seal Failure	PFB-1	Vapor Jet	Produced Gas	14,900	99	1,200	113,000	13
Pipeline Rupture at Platform Hermosa	PFB-2	Vapor Jet	Produced Gas	14,900	99	1,200	113,000	20
Pipeline Leak at Platforms	PFB-3	Vapor Jet	Produced Gas	14,900	99	1,200	113,000	2
Rich Amine Line Rupture	PFB-4	Flashing Liquid Spill	Rich Amine Solution	13,830	105	1,150	157	3
Re-injection Compressor Seal Failure	FGR-1	Vapor Jet	Produced Gas	14,900	200	3,500	550	13
Fitting Break on the Re-injection Wellhead System	FGR-2	Vapor Jet	Produced Gas	14,900	90	3,500	500	2
Re-injection Wellheader Pipe Failure	FGR-3	Vapor Jet	Produced Gas	14,900	90	3,500	500	4
Re-injection Compressor Seal Failure	RFR-1	Vapor Jet	Produced Gas	20,000	200	2,700	550	2
Fitting Break on the Re-injection Wellhead System	RFR-2	Vapor Jet	Produced Gas	20,000	90	2,700	500	2
Re-injection Wellheader Pipe Failure	RFR-3	Vapor Jet	Produced Gas	20,000	90	2,700	500	2

Table 5.8 Point Arguello Field Platforms - H_2S Toxicity Hazard Zones (page 1 of 2) (Meteorological Conditions - D stability/5 meters per second wind speed)

Scenario	Distance to 1,000 ppmV Instantaneous (feet)		Distance to 300 ppmV for 30 minutes (feet)	
	Downwind Distance	Crosswind Distance	Downwind Distance	Crosswind Distance
1. Base Case (i.e., existing operations)				
Pipeline Compressor Seal Failure (Hermosa/Harvest)	46	7	7	3
Pipeline Rupture at Platform Hermosa	72	13	167	33
Pipeline Leak at Platforms (Hermosa/Harvest)	43	7	167	23
Rich Amine Line Rupture (Hermosa/Harvest)	200	39	26	20
2. Full Gas Re-injection Alternative				
Re-injection Compressor Seal Failure (Hermosa/Harvest)	66	13	7	3
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	79	13	23	3
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	689	39	26	7
3. Gas Injection Project				
Re-injection Compressor Seal Failure (Harvest)	13	2	4	1
Fitting Break on the Re-injection Wellhead System (Harvest)	16	3	4	1
Re-injection Wellheader Pipe Failure (Harvest)	108	18	19	3

Table 5.8 Point Arguello Field Platforms - H_2S Toxicity Hazard Zones (page 2 of 2)
(Meteorological Conditions - F stability/2 meters per second wind speed)

Scenario	Distance to 1,000 ppmV Instantaneous (feet)		Distance to 300 ppmV for 30 minutes (feet)	
	Downwind Distance	Crosswind Distance	Downwind Distance	Crosswind Distance
1. Base Case (i.e., existing operations)				
Pipeline Compressor Seal Failure (Hermosa/Harvest)	59	10	7	3
Pipeline Rupture at Platform Hermosa	95	16	230	39
Pipeline Leak at Platforms (Hermosa/Harvest)	56	10	230	30
Rich Amine Line Rupture (Hermosa/Harvest)	843	125	420	43
2. Full Gas Re-injection Alternative				
Re-injection Compressor Seal Failure (Hermosa/Harvest)	89	13	10	3
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	95	16	26	3
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	597	46	36	10
3. Gas Injection Project				
Re-injection Compressor Seal Failure (Harvest)	16	2	5	1
Fitting Break on the Re-injection Wellhead System (Harvest)	19	3	5	1
Re-injection Wellheader Pipe Failure (Harvest)	138	21	23	4

Table 5.9 **Point Arguello Field Platforms - Flammable Vapor Hazard Zones (Meteorological Conditions - D stability/5 meters per second wind speed)**

Scenario	Distance to Lower Flammability Limit (feet)		Distance to 1/2 Lower Flammability Limit (feet)	
	Downwind Distance	Crosswind Distance	Downwind Distance	Crosswind Distance
Meteorological Conditions - D stability/5 meters per second wind speed				
1. Base Case (i.e., existing operations)				
Pipeline Compressor Seal Failure (Hermosa/Harvest)	82	13	194	23
Pipeline Rupture at Platform Hermosa	125	23	269	49
Pipeline Leak at Platforms (Hermosa/Harvest)	75	13	174	23
2. Full Gas Re-injection Alternative				
Re-injection Compressor Seal Failure (Hermosa/Harvest)	121	20	289	36
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	144	20	341	36
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	902	62	1292	82
3. Gas Injection Project				
Re-injection Compressor Seal Failure (Harvest)	16	3	32	6
Fitting Break on the Re-injection Wellhead System (Harvest)	20	4	41	8
Re-injection Wellheader Pipe Failure (Harvest)	141	22	335	40

Table 5.9 **Point Arguello Field Platforms - Flammable Vapor Hazard Zones (Meteorological Conditions - F stability/2 meters per second wind speed)**

Scenario	Distance to Lower Flammability Limit (feet)		Distance to 1/2 Lower Flammability Limit (feet)	
	Downwind Distance	Crosswind Distance	Downwind Distance	Crosswind Distance
Meteorological Conditions - F stability/2 meters per second wind speed				
1. Base Case (i.e., existing operations)				
Pipeline Compressor Seal Failure (Hermosa/Harvest)	108	16	262	30
Pipeline Rupture at Platform Hermosa	171	30	377	59
Pipeline Leak at Platforms (Hermosa/Harvest)	102	16	233	30
2. Full Gas Re-injection Alternative				
Re-injection Compressor Seal Failure (Hermosa/Harvest)	164	23	394	46
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	180	26	436	49
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	784	59	1112	89
3. Gas Injection Project				
Re-injection Compressor Seal Failure (Harvest)	21	3	43	7
Fitting Break on the Re-injection Wellhead System (Harvest)	25	4	5	9
Re-injection Wellheader Pipe Failure (Harvest)	180	26	427	51

In addition, flammable hazard zones would be substantially less than those for the full gas re-injection alternative that was examined in the GRS due to the lower injection pressures and smaller injection pipe size. The maximum baseline flammable vapor hazard zone to the lower flammability limit (LFL) is approximately 170 feet, and would increase to 180 feet under the gas injection project due to higher pressures.

Thermal radiation hazards associated with flame jets are summarized in Table 5.10. These hazards would remain essentially unchanged for the cases involving gas transport to shore. Thermal radiation hazards associated with the gas injection would be negligible when compared to baseline conditions.

The potential for vapor cloud explosions would not change appreciably on the platforms when compared to baseline conditions as shown in Table 5.11. The maximum baseline 5 psi explosion overpressure hazard zone of 85 feet is roughly the same as the 79 feet for the gas injection project.

Model output files for the three gas injection release scenarios are presented in Appendix A. The GRS (Arthur D. Little, 1994) contains the model output files for the baseline and re-injection alternatives, as well as for the onshore sour gas pipeline and Gaviota Gas Plant.

Table 5.10 **Point Arguello Field Platforms - Thermal Radiation Hazard Zones (Meteorological Conditions - D stability/5 meters per second wind speed)**

Scenario	Flame Length (ft)	Distance to 5 kW/m^2 (ft)	Distance to 10 kW/m^2 (ft)
Meteorological Conditions - D stability 5 meters per second wind speed			
1. Base Case (i.e., existing operations)			
Pipeline Compressor Seal Failure (Hermosa/Harvest)	52	98	85
Pipeline Rupture at Platform Hermosa	164	243	220
Pipeline Leak at Platforms (Hermosa/Harvest)	52	95	85
2. Full Gas Re-injection Alternative			
Re-injection Compressor Seal Failure (Hermosa/Harvest)	75	134	118
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	75	128	115
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	85	141	128
3. Full Gas Injection			
Re-injection Compressor Seal Failure (Harvest)	10	22	18
Fitting Break on the Re-injection Wellhead System (Harvest)	7	25	20
Re-injection Wellheader Pipe Failure (Harvest)	35	75	66

Table 5.10 Point Arguello Field Platforms - Thermal Radiation Hazard Zones (Meteorological Conditions - F stability/2 meters per second wind speed)

Scenario	Flame Length (ft)	Distance to 5 kW/m² (ft)	Distance to 10 kW/m² (ft)
Meteorological Conditions - F stability 2 meters per second wind speed			
1. Base Case (i.e., existing operations)			
Pipeline Compressor Seal Failure (Hermosa/Harvest)	59	102	89
Pipeline Rupture at Platform Hermosa	216	276	259
Pipeline Leak at Platforms (Hermosa/Harvest)	59	102	89
2. Full Gas Re-injection Alternative			
Re-injection Compressor Seal Failure (Hermosa/Harvest)	89	144	128
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	92	141	128
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	102	154	138
3. Full Gas Injection			
Re-injection Compressor Seal Failure (Hermosa/Harvest)	11	23	19
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	10	25	21
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	38	79	67

Table 5.11 Point Arguello Field Platforms - Explosion Overpressure Hazard Zones
(Meteorological Conditions - D stability/5 meters per second wind speed)

Scenario	Distance to 0.5 psi (ft)	Distance to 1.0 psi (ft)	Distance to 3.0 psi (ft)	Distance to 5.0 psi (ft)
Meteorological Conditions - D stability 5 meters per second wind speed				
1. Base Case (i.e., existing operations)				
Pipeline Compressor Seal Failure (Hermosa/Harvest)	600	298	98	59
Pipeline Rupture at Platform Hermosa	856	426	141	85
Pipeline Leak at Platforms (Hermosa/Harvest)	577	289	95	59
2. Full Gas Re-injection Alternative				
Re-injection Compressor Seal Failure (Hermosa/Harvest)	787	394	131	79
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	738	371	125	72
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	3893	1948	649	387
3. Gas Injection Project				
Re-injection Compressor Seal Failure (Harvest)	201	101	33	20
Fitting Break on the Re-injection Wellhead System (Harvest)	208	104	35	21
Re-injection Wellheader Pipe Failure (Harvest)	794	397	131	79

Table 5.11 Point Arguello Field Platforms - Explosion Overpressure Hazard Zones

(Meteorological Conditions - F stability/2 meters per second wind speed)

Scenario	Distance to 0.5 psi (ft)	Distance to 1.0 psi (ft)	Distance to 3.0 psi (ft)	Distance to 5.0 psi (ft)
Meteorological Conditions - F stability 2 meters per second wind speed				
1. Base Case (i.e., existing operations)				
Pipeline Compressor Seal Failure (Hermosa/Harvest)	702	351	118	69
Pipeline Rupture at Platform Hermosa	604	302	102	59
Pipeline Leak at Platforms (Hermosa/Harvest)	676	338	112	69
2. Full Gas Re-injection Alternative				
Re-injection Compressor Seal Failure (Hermosa/Harvest)	905	453	151	89
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	512	256	85	52
Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	3241	1620	541	321
3. Gas Injection Project				
Re-injection Compressor Seal Failure (Harvest)	227	113	38	23
Fitting Break on the Re-injection Wellhead System (Harvest)	235	117	39	23
Re-injection Wellheader Pipe Failure (Harvest)	617	308	102	62

6.0 Revised Risk Rankings

Consistent with the GRS, potential hazards associated with a release on one of the offshore platforms was evaluated using the risk matrix approach. The risk matrix methodology involves plotting the failure rate frequency and consequence into a risk ranking matrix. The risk ranking matrix used in this study is shown in Figure 6-1. Table 6.1 provides the descriptions of the various likelihood and severity classifications. This matrix is from the County of Santa Barbara's Significance Criteria Guidelines, and is used to assess the significance of system safety impacts for CEQA documents.

The frequency of the identified offshore platform hazards have been developed in Section 4. In order to estimate the consequences of the offshore hazards in terms of fatalities, the consequence modeling results were combined with population distribution data on the platforms. The typical population on Platforms Hermosa and Harvest averages between 35 and 40 people on each platform. Most of these people are normally inside the crew quarters or the control room. It has been assumed that, on average, about 10 to 15 people are outside an enclosed area on the platforms at any given time.

Considering factors such as the limited space on the platforms, the type of enclosure construction and the climate, the likelihood's of fatality (conditional impact probabilities) used for each hazard type were:

- **Flammable Vapor Dispersion.** 30 percent of the population that is indoors, and 100 percent of the population that is outside and exposed directly to the flammable vapor cloud.

- **Overpressure.** 30 percent of the population that is within the over pressure zones.

- **Toxic Vapor Dispersion (300 ppm/30 min).** 30 percent fatality (indoors or outdoors as there is time for vapors to penetrate if a building is not well sealed or windows are open).

- **Toxic Vapor Dispersion (1,000 ppm).** Due to the instantaneous impact of this concentration, a very high value is appropriate. However, the clouds may pass very quickly at some of the further downwind distances and those who are indoors may be protected. Hence, a value of 25 percent has been used for populations indoors and 100 percent for populations outside.

Using these conditional probabilities along with the consequence modeling results, an estimate of the number of fatalities was made for each scenario at all the platforms. The results were then plotted on the risk matrix. This was done for the base case, as well as for each re-injection alternative.

Figure 6-2 shows the risk matrix for the offshore hazard scenarios, which are listed in detail in Table 6.2.

Figure 6-1 Severity and Frequency Matrix of Significance

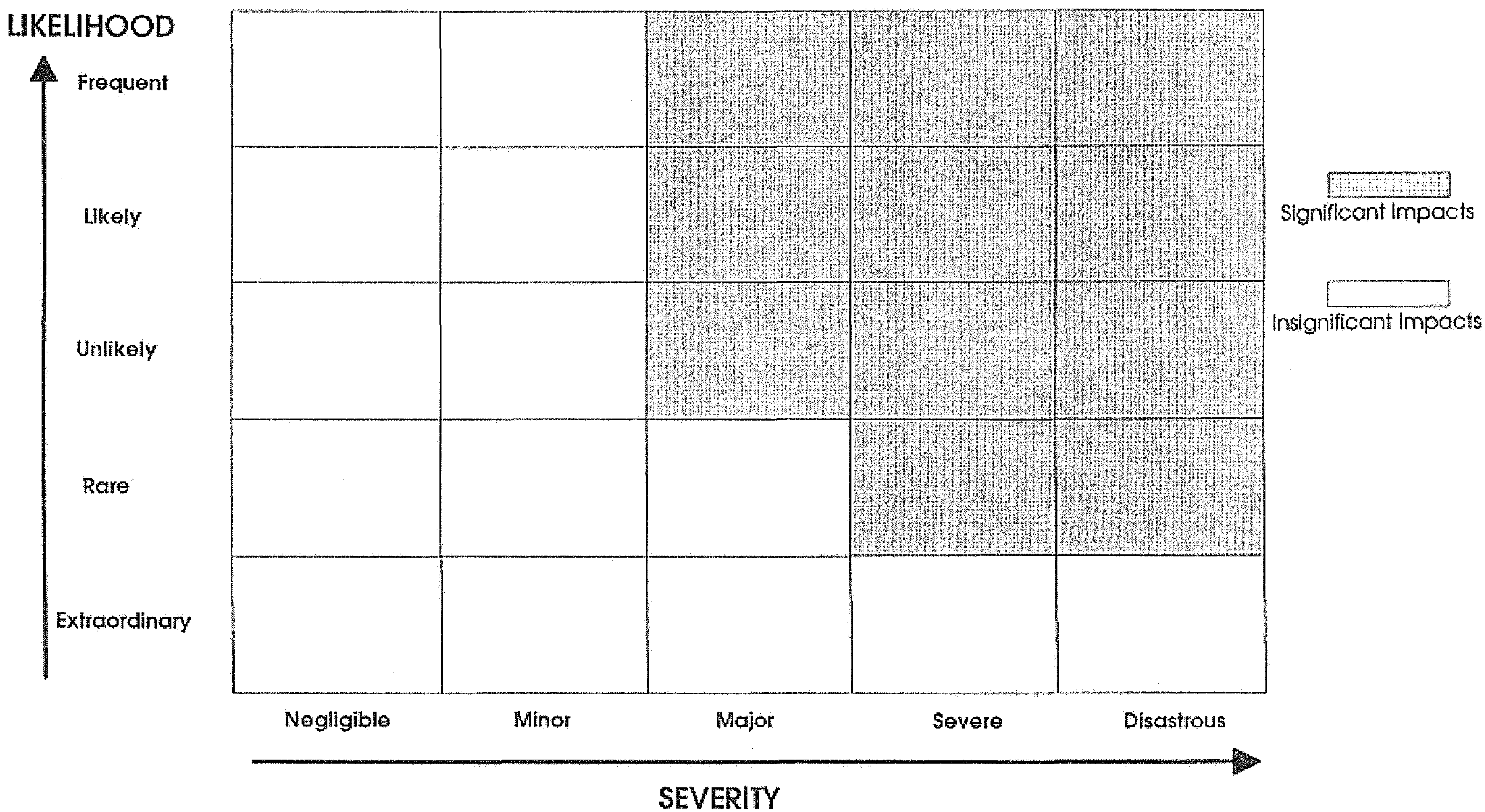


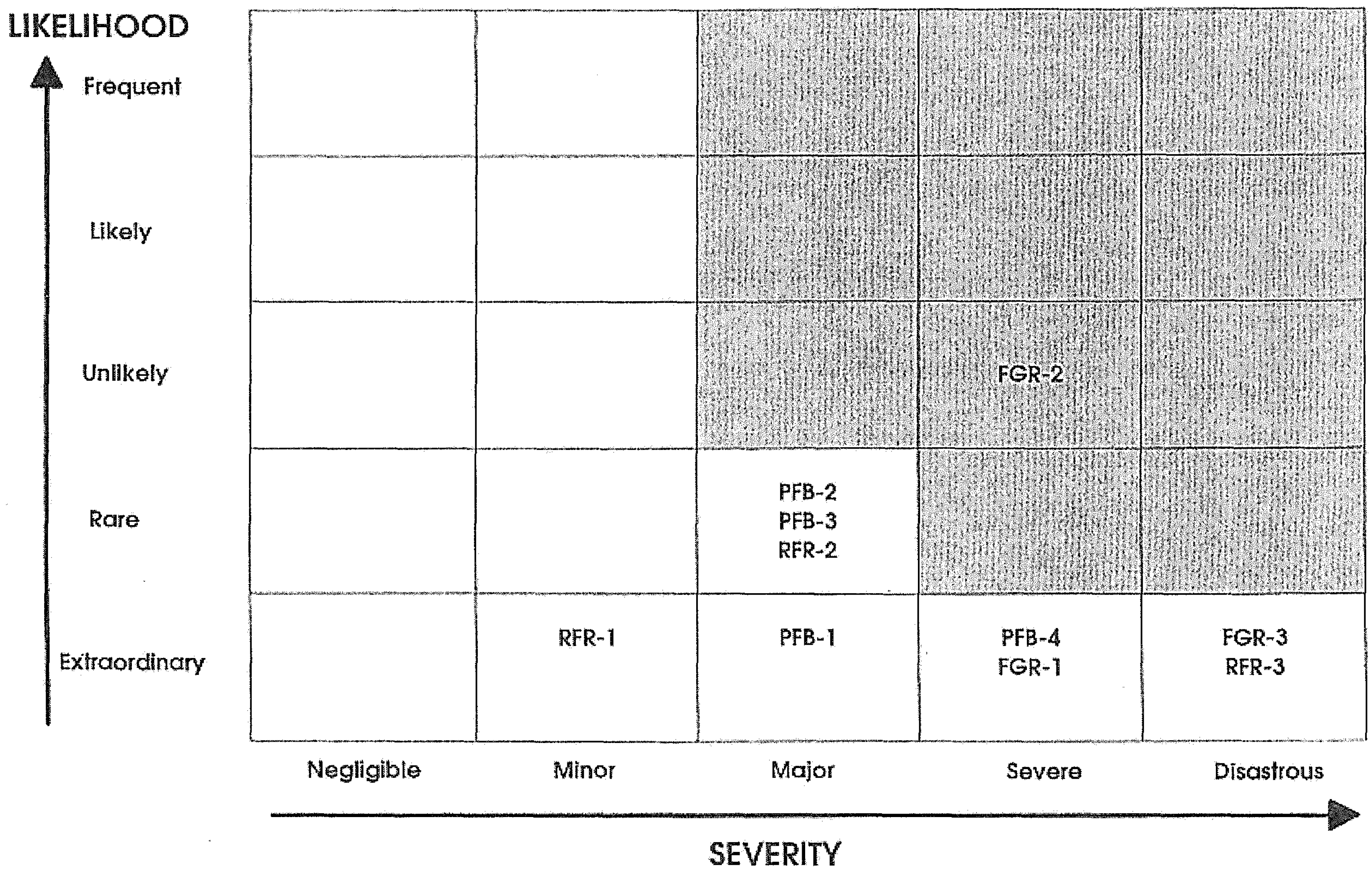
Table 6.1 Criticality And Frequency Classifications

(a) Criticality Classification

Classification	Description of Public Safety Hazard
Negligible	No significant risk to the public, with no minor injuries.
Minor	Small level of public risk, with at most a few minor injuries.
Major	Major level of public risk with up to 10 severe injuries.
Severe	Severe public risk with up to 100 severe injuries or up to 10 fatalities.
Disastrous	Disastrous public risk involving more than 100 severe injuries or more than 10 fatalities.

Type	Frequency	Description
Extraordinary	Less than once in one million years.	An event whose occurrence is extremely unlikely.
Rare	Between once in ten thousand years and once in one million years.	An event which almost certainly would not occur during the project lifetime.
Unlikely	Between once in a hundred and once in ten thousand years.	An even which is not expected to occur during the project lifetime.
Likely	Between once a year and once in one hundred years.	An event which probably would occur during the project lifetime.
Frequent	Greater than once a year.	An event which would occur more than once a year on average.

Figure 6-2 Offshore Platform Hazard Scenario Risk Ranking Matrix



Note: See Table 6.2 for a description of the release scenarios.

Significant Impact

Insignificant

Table 6.2 Summary of Offshore Hazard Scenario Failure Rates and Consequence Modeling Results (page 1 of 2)

Scenario Description	Code	Failure Rate	Downwind Distance @ D/5 (feet)			
			H2S (1,000 ppmV)	LFL	5 psi	10 kW/m^2
Pipeline Compressor Seal Failure (Hermosa/Harvest)	PFB-1	1.9 x 10^{-7}/yr	46	82	59	85
Pipeline Rupture at Platform Hermosa	PFB-2	2.44 x 10^{-6}/yr	72	125	85	220
Pipeline Leak at Platforms (Hermosa/Harvest)	PFB-3	5.0 x 10^{-6}/yr	43	75	59	85
Rich Amine Line Rupture (Hermosa/Harvest)	PFB-4	2.4 x 10^{-7}/yr	200	N/A	N/A	N/A
Compressor Seal Failure (Hermosa/Harvest)	FGR-1	1.9 x 10^{-7}/yr	66	121	76	118
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	FGR-2	2.9 x 10^{-3}/yr	76	144	72	115
The Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	FGR-3	3.2 x10^{-7}/yr	689	902	387	128
Compressor Seal Failure (Harvest)	RFR-1	1.9 x 10^{-7}/yr	13	16	20	18
Fitting Break on the Re-injection Wellhead System (Harvest)	RFR -2	4.0 x 10^{-5}/yr	16	20	21	20
The Re-injection Wellheader Pipe Failure (Harvest)	RFR -3	1.3 x10^{-7}/yr	108	141	79	66

NA Not applicable under these scenarios, however, the base case hazard distances would still apply.

Table 6.2 **Summary of Offshore Hazard Scenario Failure Rates and Consequence Modeling Results (page 2 of 2)**

Scenario Description	Code	Failure Rate	Downwind Distance @ F/2 (feet)			
			H2S (1,000 ppmV)	LFL	5 psi	10 kW/m^2
Pipeline Compressor Seal Failure (Hermosa/Harvest)	PFB-1	1.9 x 10^{-7}/yr	59	108	69	89
Pipeline Rupture at Platform Hermosa	PFB-2	2.44 x 10^{-6}/yr	95	171	59	259
Pipeline Leak at Platforms (Hermosa/Harvest)	PFB-3	5.0 x 10^{-6}/yr	56	102	69	89
Rich Amine Line Rupture (Hermosa/Harvest)	PFB-4	2.4 x 10^{-7}/yr	843	N/A	N/A	N/A
Compressor Seal Failure (Hermosa/Harvest)	FGR-1	1.9 x 10^{-7}/yr	89	164	89	128
Fitting Break on the Re-injection Wellhead System (Hermosa/Harvest)	FGR-2	2.9 x 10^{-3}/yr	95	180	52	128
The Re-injection Wellheader Pipe Failure (Hermosa/Harvest)	FGR-3	3.2 x10^{-7}/yr	597	784	321	138
Compressor Seal Failure (Harvest)	RFR-1	1.9 x 10^{-7}/yr	16	21	23	19
Fitting Break on the Re-injection Wellhead System (Harvest)	RFR -2	4.4 x 10^{-5}/yr	19	25	23	21
The Re-injection Wellheader Pipe Failure (Harvest)	RFR -3	8.4 x10^{-8}/yr	138	180	62	67

NA = Not applicable under these scenarios, however, the base case hazard zones would still apply.

In Figure 6-2, the base case scenarios are presented by code PFB, while the original full gas re-injection scenarios are presented by code FGR, and the revised gas re-injection scenarios are presented by code RFR. Table 6.2 provides a listing of these scenarios along with their respective failure rates and consequence modeling results.

As Figure 6-2 shows, the base case scenarios do not have any impacts that would be classified as significant based upon the County of Santa Barbara's Matrix. However, the original full gas re-injection alternative does have one impact (FGR-2) that would be classified as significant. However, under the current gas injection proposal, this scenario would have a lower potential failure rate, as well as lower consequences. As a result, potential impacts associated with RFR-2 and the revised gas injection project would be less than significant.

The reductions in failure rates and consequences for this injection scenario are a result of the following:

1. Lower gas injection pressures than previously required.

2. Lower gas injection volume than originally proposed.

3. Smaller and less piping required for gas injection.

4. Gas re-injection will occur at only one platform.

5. The existing gas compressor is located below the mezzanine level which is more remote from the location of the crew and other activities that could lead to a release and/or exposure.

7.0 References

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(Note: Although objections have been raised regarding the WASH-1400 report, the source of disagreement or dissatisfaction is generally the treatment of uncertainty and not the methodology as a whole. The data set collected and compiled for the study is considered to be reliable and accurate, and it is not subject to the same criticisms as the overall study. The failure rates and probabilities given by the report are based on information from operating industrial facilities such as chemical plants, refineries, power plants and manufacturing facilities.)

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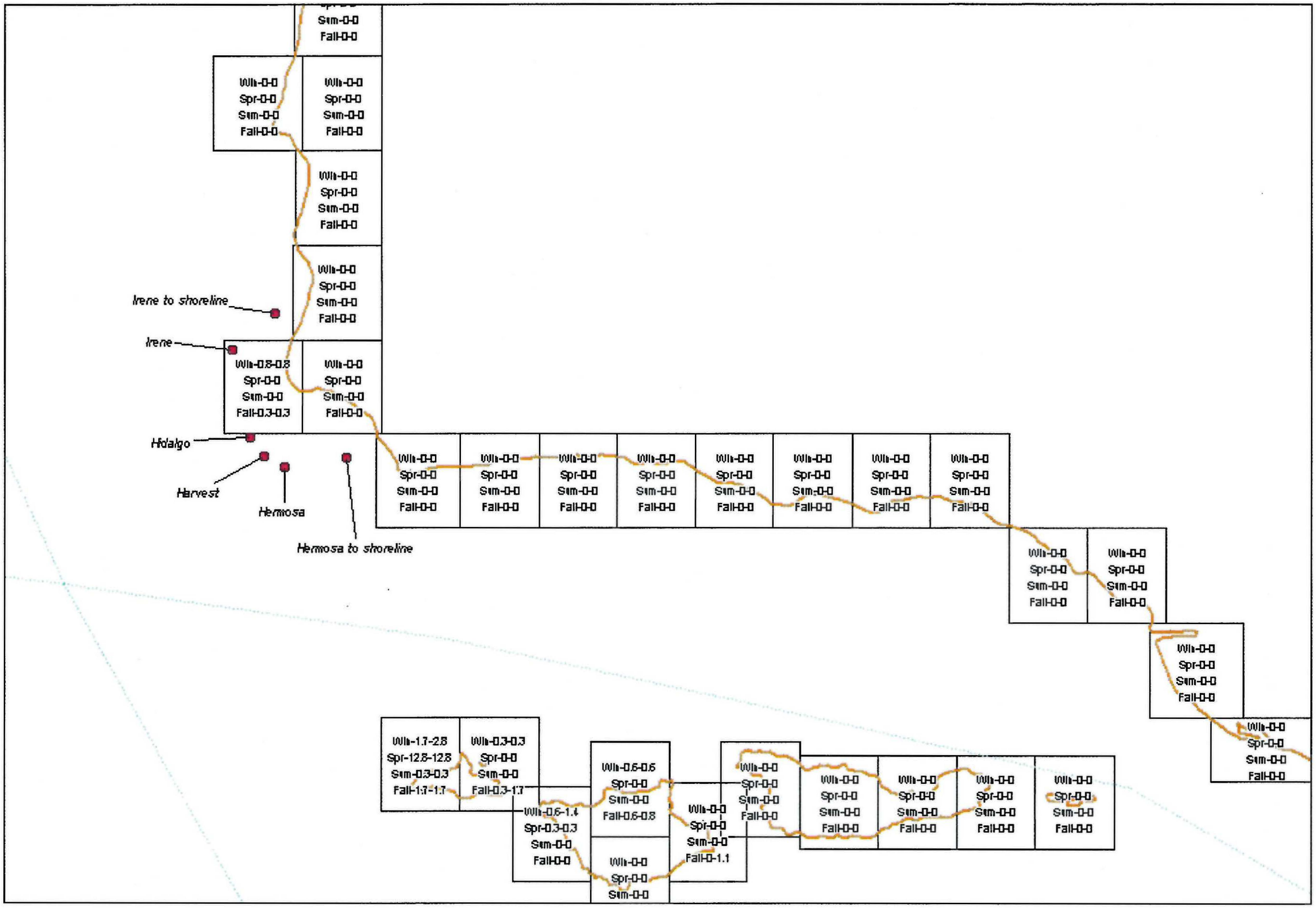
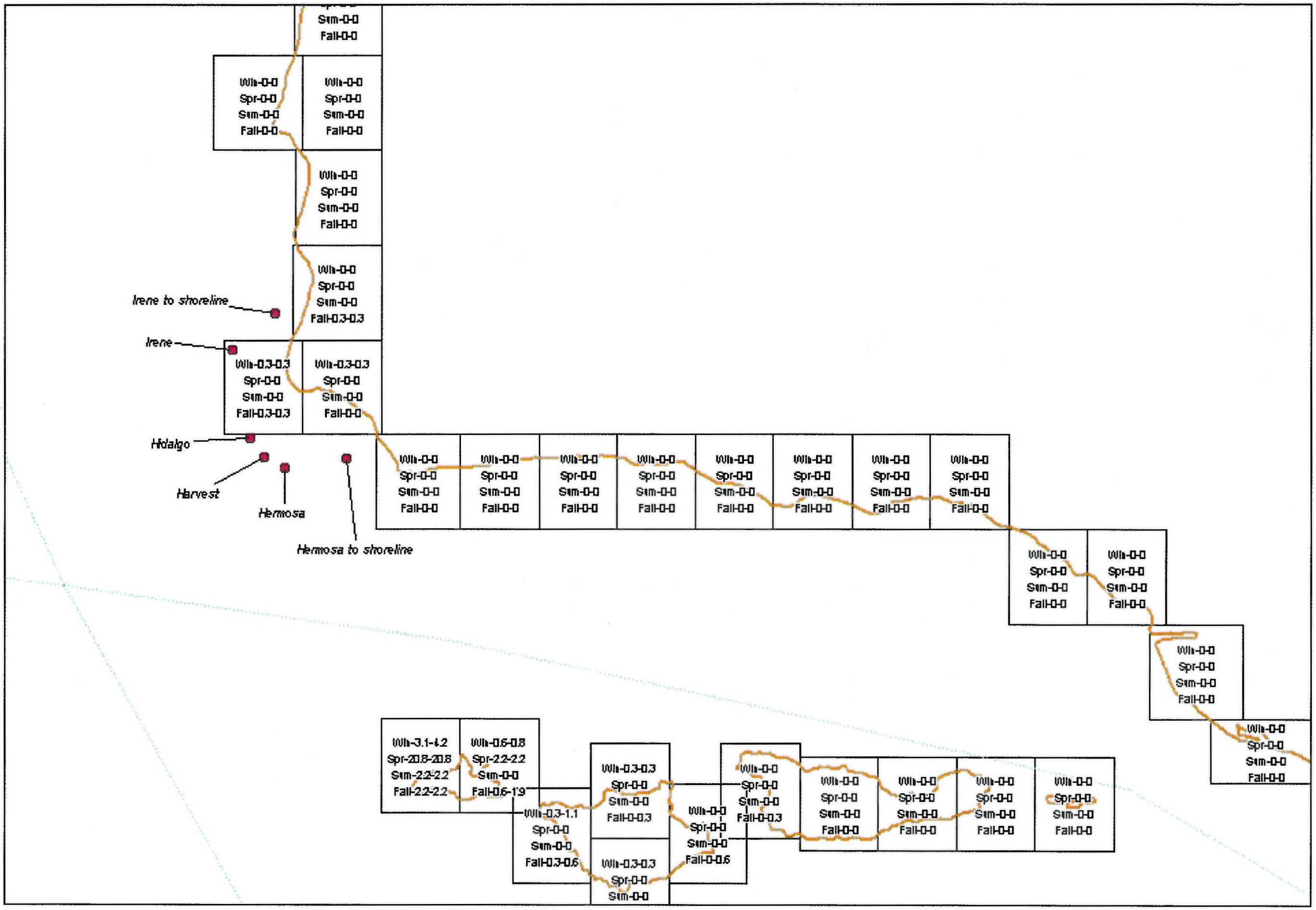
Attachment F – OSRA Oil Spill Trajectories



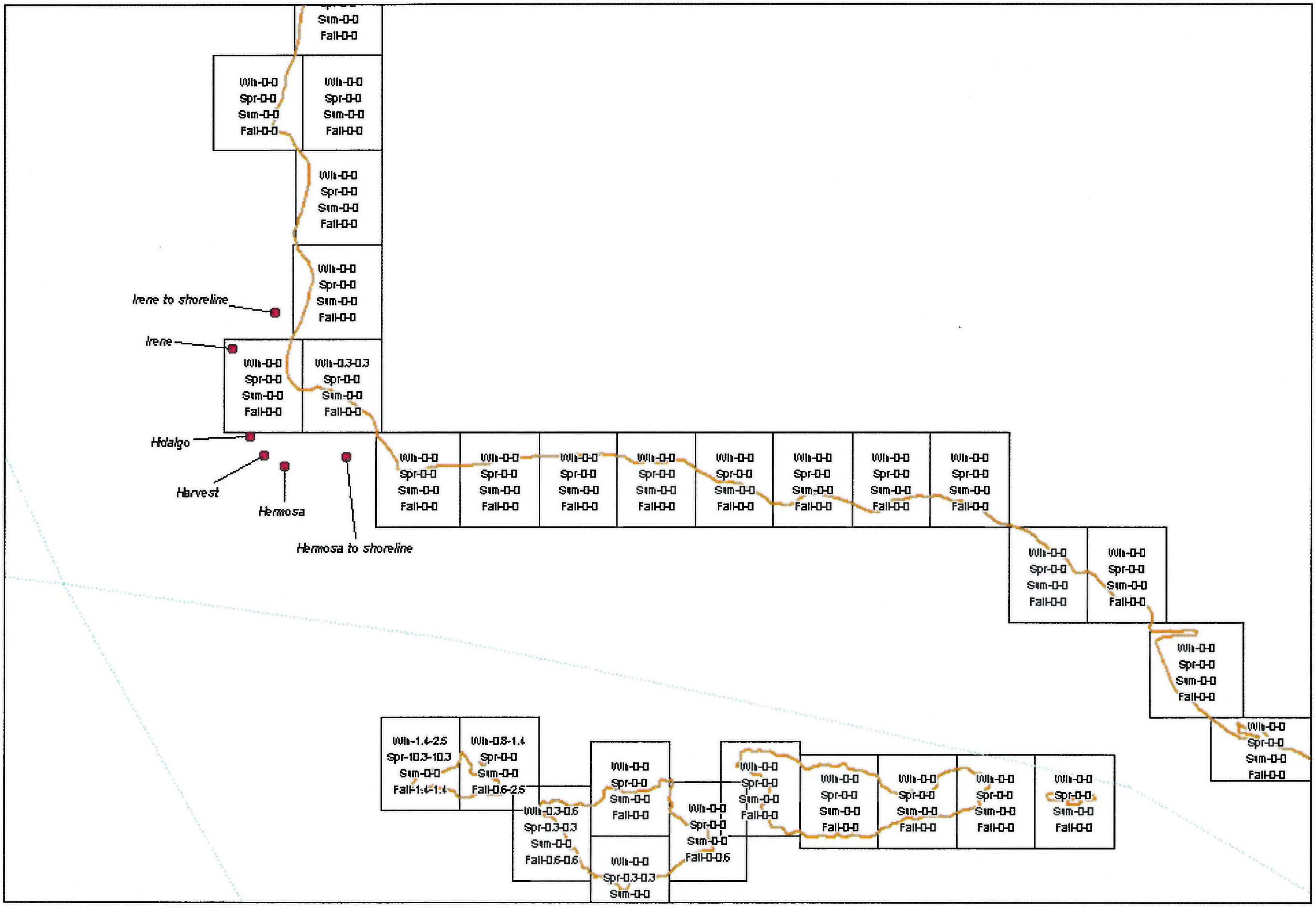
MMS OSRA Conditional Probabilities: Harvest

Text values in each box indicate conditional probabilities for the following sources:
Winter, Spring, Summer and Fall (as labeled) followed by the 10-day and 30-day levels



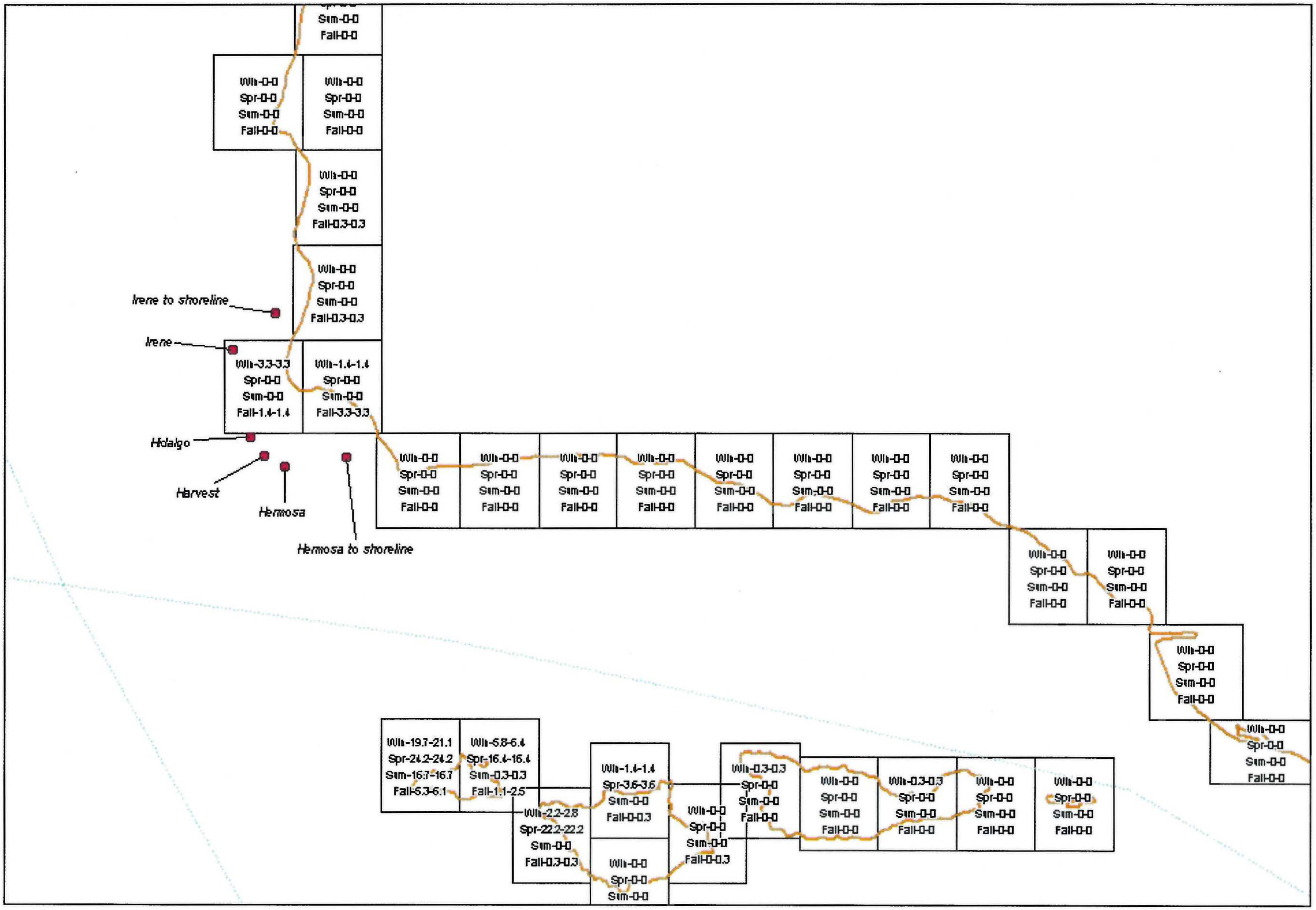
MMS OSRA Conditional Probabilities: Hermosa

Text values in each box indicate conditional probabilities for the following sources:
Winter, Spring, Summer and Fall (as labeled) followed by the 10-day and 30-day levels



MMS OSRA Conditional Probabilities: Hidalgo

Text values in each box indicate conditional probabilities for the following sources:
Winter, Spring, Summer and Fall (as labeled) followed by the 10-day and 30-day levels



MMS OSRA Conditional Probabilities: Point Arguello Pipeline

Text values in each box indicate conditional probabilities for the following sources:
Winter, Spring, Summer and Fall (as labeled) followed by the 10-day and 30-day levels

Attachment G – Worst Case Spill Calculations

Pt Arguello Area
Worst Case Discharge

Worst Case Spill Volumes for Point Argeullo Unit Only

Item	Description	Units	Hermosa	Hidalgo	Harvest
V_1	Vessel and Piping Discharge	BBL	2,509	1,336	2,908
V_2	Pipeline Discharge	BBL	2,217	500	292
V_3	Well Blowout Discharge	B/D	1,070	973	5,000
V_{wcd}	Total Worst-Case Spill Volumes	B/D	5,796	2,809	8,199

Worst Case Spill Volumes for Point Argeullo Rocky Point Units

Item	Description	Units	Hermosa	Hidalgo	Harvest
V_1	Vessel and Piping Discharge	BBL	2,509	1,336	2,908
V_2	Pipeline Discharge	BBL	2,217	500	292
V_3	Well Blowout Discharge	B/D	2,500	2,500	5,000
V_{wcd}	Total Worst-Case Spill Volumes	B/D	7,226	4,336	8,199

Pt Arguello Platforms
Vessel and Piping Discharge Calculations

Item	Description	Units	Hermosa	Hidalgo	Harvest
Vessel			V-03	V-03	V-102A
D	Diameter	ft	5.0	5.5	10.0
L	Length	ft	20.0	24.0	35.0
h_1	Top of oil layer	ft	3.0	3.8	8.0
h_2	Bottom of oil layer	ft	1.0	1.0	2.0
%	Oil cut	%	95.0	95.0	95.0
V	**Volume of oil**	**BBL**	**32.2**	**58.1**	**332.9**
Vessel			V-04	V-04	V-102B
D	Diameter	ft	3.5	4.0	10.0
L	Length	ft	15.0	16.0	35.0
h_1	Top of oil layer	ft	2.5	2.8	8.0
h_2	Bottom of oil layer	ft	1.0	1.0	2.0
%	Oil cut	%	95.0	95.0	95.0
V	**Volume of oil**	**BBL**	**12.9**	**18.3**	**332.9**
Vessel			V-05	V-05	V-100A
D	Diameter	ft	3.5	4.0	6.0
L	Length	ft	15.0	16.0	15.0
h_1	Top of oil layer	ft	2.5	2.8	4.8
h_2	Bottom of oil layer	ft	1.0	1.0	1.0
%	Oil cut	%	95.0	95.0	95.0
V	**Volume of oil**	**BBL**	**12.9**	**18.3**	**54.1**
Vessel			V-09	V-09	V-100B
D	Diameter	ft	6.0	6.0	6.0
L	Length	ft	19.5	19.5	15.0
h_1	Top of oil layer	ft	13.0	13.0	4.8
h_2	Bottom of oil layer	ft	0.0	0.0	1.0
%	Oil cut	%	70.0	70.0	95.0
V	**Volume of oil**	**BBL**	**45.8**	**45.8**	**54.1**
Vessel			V-01	V-01	V-101
D	Diameter	ft	7.5	7.5	12.0
L	Length	ft	35.0	30.0	80.5
h_1	Top of oil layer	ft	4.5	5.0	12.0
h_2	Bottom of oil layer	ft	1.0	1.0	2.0
%	Oil cut	%	95.0	95.0	98.0
V	**Volume of oil**	**BBL**	**143.3**	**141.2**	**1416.2**

Pt Arguello Platforms
Vessel and Piping Discharge Calculations

Item	Description	Units	Hermosa	Hidalgo	Harvest
Vessel			V-02	V-02	V-900
D	Diameter	ft	7.5	7.5	3.5
L	Length	ft	35.0	30.0	52.0
h_1	Top of oil layer	ft	4.5	5.0	6.0
h_2	Bottom of oil layer	ft	1.0	1.0	0.0
%	Oil cut	%	95.0	95.0	98.0
V	**Volume of oil**	**BBL**	**143.3**	**141.2**	**10.1**
Vessel			V-06	---	V-103A
D	Diameter	ft	12.0		8.0
L	Length	ft	32.0		30.0
h_1	Top of oil layer	ft	12.0		6.3
h_2	Bottom of oil layer	ft	2.0		0.0
%	Oil cut	%	98.0		98.0
V	**Volume of oil**	**BBL**	**563.0**		**223.6**
Vessel			V-07	---	V-103B
D	Diameter	ft	12.5		8.0
L	Length	ft	30.0		30.0
h_1	Top of oil layer	ft	12.0		6.3
h_2	Bottom of oil layer	ft	2.0		0.0
%	Oil cut	%	98.0		98.0
V	**Volume of oil**	**BBL**	**568.1**		**223.6**
Vessel			V-67	---	V-800
D	Diameter	ft	3.5		6.0
L	Length	ft	52.0		25.0
h_1	Top of oil layer	ft	6.0		4.5
h_2	Bottom of oil layer	ft	0.0		0.0
%	Oil cut	%	98.0		80.0
V	**Volume of oil**	**BBL**	**10.1**		**81.1**
Vessel			V-08	V-08	V-801
D	Diameter	ft	10.0	10.0	6.0
L	Length	ft	26.0	24.0	15.0
h_1	Top of oil layer	ft	8.0	8.3	11.5
h_2	Bottom of oil layer	ft	0.0	0.0	0.0
%	Oil cut	%	98.0	98.0	70.0
V	**Volume of oil**	**BBL**	**305.9**	**290.6**	**40.6**

Pt Arguello Platforms
Vessel and Piping Discharge Calculations

Item	Description	Units	Hermosa	Hidalgo	Harvest
Vessel			V-70	V-70	---
D	Diameter	ft	5.0	5.0	
L	Length	ft	15.5	15.5	
h_1	Top of oil layer	ft	4.5	4.5	
h_2	Bottom of oil layer	ft	0.0	0.0	
%	Oil cut	%	80.0	80.0	
V	**Volume of oil**	**BBL**	**41.1**	**41.1**	
Vessel			V-71	V-71	---
D	Diameter	ft	11.5	11.5	
L	Length	ft	18.5	18.5	
h_1	Top of oil layer	ft	17.3	17.5	
h_2	Bottom of oil layer	ft	0.0	0.0	
%	Oil cut	%	80.0	80.0	
V	**Volume of oil**	**BBL**	**255.4**	**259.1**	
Vessel			V-72	V-72	---
D	Diameter	ft	11.5	11.5	
L	Length	ft	18.5	18.5	
h_1	Top of oil layer	ft	17.3	17.5	
h_2	Bottom of oil layer	ft	0.0	0.0	
%	Oil cut	%	80.0	80.0	
V	**Volume of oil**	**BBL**	**255.4**	**259.1**	
Piping	**Volume of oil**	**BBL**	**119.5**	**63.6**	**138.5**

V_1	**Volume of oil discharged from vessels and piping**	**BBL**	**2508.83**	**1336.41**	**2907.54**

Notes:

The top of oil layer level for vessels which operate at a constant level (Gross separators, coalescers, etc.) is the normal operating level. For vessels in which the level varies (shipping vessel, sump tanks, etc.), the LSH level was used.

The bottom of oil layer level for vessels which operate at constant interface (gross separators, coalescers, etc.) is the normal interface level. For vessels in which the interface level varies (well clean up vessels, sump tanks, etc.), 0 was used.

The volume of oil in the flow lines was estimated to be 5% of the total vessel volume

Pt Arguello Pipelines
Pipeline Discharge Calculations

Item	Description	Units	Harvest to Hermosa	Hidalgo to Hermosa	Hermosa to Shore	Total to Shore from Hermosa
Q	Flow rate of shipping pump	B/D	27840	12926	19200	
t	Time to shut down pump and close valve	min	5.75	5.75	5.75	
%	Oil cut	%	99	97.5	98.5	
V_{pump}	**Discharge volume from time to shut down**	**BBL**	**110**	**50**	76	**186**
P_D	Design pipeline pressure (PSV set point)	psi	1320	700	1300	
D_{ID}	Nominal inside diameter	in	11.5	15.062	22.75	
D_{OD}	Nominal outside diameter	in	12.75	16	24	
D_{ID}	Nominal inside diameter	ft	*0.9583333*	*1.255167*	*1.8958333*	
D_{OD}	Nominal outside diameter	ft	*1.0625*	*1.333333*	2	
s	Hoop stress	psi	*25608*	*23180.6*	*48620*	
E	Young's modulus		30000000	30000000	30000000	
D_P	Inside diameter during pumping	ft	*0.9591514*	*1.256137*	*1.8989058*	
API	API gravity		20	21	20	
SG	Specific Gravity		*0.9339934*	*0.927869*	*0.9339934*	
RO_s	Static density of oil	lb/ft^3	*58.281188*	*57.89902*	*58.281188*	
DRO	Difference in oil density due to compressibility from GPSA data book	lb/ft^3	0.24	0.19	0.24	
RO_d	Dynamic density of oil	lb/ft^3	*58.521188*	*58.08902*	*58.521188*	
L	Pipeline length	ft	18691	29515	57552	
V_{RO}	**Discharge volume from density change**	**BBL**	**10**	**21**	118	**128**
V_D	**Discharge volume from diameter change**	**BBL**	**4**	**10**	92	**97**
L_1	Length above water line on inlet end	ft	265	270	395	
L_2	Length above water line on discharge end	ft	105	160	315	
V_H	**Discharge volume from hydrostatic head**	**BBL**	**47**	**92**	352	**352**
V_P	**Discharge volume from perculation due to density difference between oil and sea water**	**BBL**	**121**	**327**	**1455**	**1455**
V_2	**Volume of oil calculated to leak from a rupture of a subsea pipeline**	**BBL**	**292**	**500**	**2093**	**2217**

Notes:
Total to shore from Platform Hermosa volumes include volume due to density change and diameter change of the Harvest to Hermosa Pipeline

Pt Arguello Platforms
Well Blowout Discharge Calculations

Pt Arguello Wells

Platform	Units	Hermosa	Hidalgo	Harvest
Oil discharge rate of highest capacity flowing well	**B/D**	**1,070**	**973**	**5,000**

Rocky Point Wells

Platform	Units	Hermosa	Hidalgo	Harvest
Oil discharge rate of highest capacity flowing well	**B/D**	**2,500**	**2,500**	**2,500**

Notes:

For Pt Arguello, only wells on Platform Harvest will flow without gas lift.

For Rocky Point wells, the rate is the highest of the drill stem tests.
drilling from both platforms, take the highest of the two wells

Attachment H – Oil Spill Risk Calculations, Point Arguello and Rocky Point Units

Oil Spill Risk Calculations
Point Arguello and Rocky Point Units

Table 1 US OCS Spill Historical Spill Data

US OCS Spills	Number of Spills	Median Spill Size (bbls)	Spill Rate (spills per 10^9 bbls)
Spills Greater Than or Equal to 1,000 bbls			
Platforms	11	7,000	0.45
Pipelines	12	5,600	1.35
Spills Greater Than or Equal to 10,000 bbls			
Platforms	4	41,500	0.16
Pipelines	4	17,700	0.44

Source: Comparative Occurrence Rate for Offshore Oil Spills, Anderson and La Belle, MMS.

Table 2 Calculation of Spill Probabilities for Point Arguello Field Only

Location	Spill Rate (spills per 10^9 bbls)	Total Oil Production (10^9 bbls)	Duration of Total Oil Production (years)	Estimated Number of Spills During the Duration	Probability of Zero Spills Occurring (P(0))	Probability of One or More Spills Occurring
Spills Greater Than or Equal to 1,000 bbls						
Platform Hermosa	0.45	0.018	15	0.008	99.2%	0.8%
Platform Harvest	0.45	0.028	15	0.013	98.7%	1.3%
Platform Hidalgo	0.45	0.0095	15	0.004	99.6%	0.4%
Total Platforms	*0.45*	*0.0555*	*15*	*0.025*	*97.5%*	*2.5%*
PAPCO Pipeline	1.35	0.0555	15	0.075	92.8%	7.2%
Spills Greater Than or Equal to 10,000 bbls						
Platform Hermosa	0.16	0.018	15	0.003	99.7%	0.3%
Platform Harvest	0.16	0.028	15	0.004	99.6%	0.4%
Platform Hidalgo	0.16	0.0095	15	0.002	99.8%	0.2%
Total Platforms	*0.16*	*0.0555*	*15*	*0.009*	*99.1%*	*0.9%*
PAPCO Pipeline	0.44	0.0555	15	0.024	97.6%	2.4%

Notes:
The platform numbers may not add-up due to rounding.
Duration of production is from the beginning of 2000 through the end of 2015.
Estimated number of spills during the duration=spill rate*total oil production.
P(0)=(number of spills during duration^0 *e^-number of spills during duration)/1
The probability of one or more spills=1-P(0).

Table 3 Calculation of Spill Probabilities for Rocky Point Unit (35 million barrels of production)

Location	Spill Rate (spills per 10^9 bbls)	Total Oil Production (10^9 bbls)	Duration of Total Oil Production (years)	Estimated Number of Spills During the Duration	Probability of Zero Spills Occurring (P(0))	Probability of One or More Spills Occurring
Spills Greater Than or Equal to 1,000 bbls						
Platform Hermosa	0.45	0.01211	12	0.005	99.5%	0.5%
Platform Harvest	0.45	0.01211	12	0.005	99.5%	0.5%
Platform Hidalgo	0.45	0.01038	12	0.005	99.5%	0.5%
Total Platforms	*0.45*	*0.0346*	*12*	*0.016*	*98.5%*	*1.5%*
PAPCO Pipeline	1.35	0.0346	12	0.047	95.4%	4.6%
Spills Greater Than or Equal to 10,000 bbls						
Platform Hermosa	0.16	0.01211	12	0.002	99.8%	0.2%
Platform Harvest	0.16	0.01211	12	0.002	99.8%	0.2%
Platform Hidalgo	0.16	0.01038	12	0.002	99.8%	0.2%
Total Platforms	*0.16*	*0.0346*	*12*	*0.006*	*99.4%*	*0.6%*
PAPCO Pipeline	0.44	0.0346	12	0.015	98.5%	1.5%

Notes:
The platform numbers may not add-up due to rounding.
Duration of production is from third quarter 2002 through the end of the third quarter 2014.
Estimated number of spills during the duration=spill rate*total oil production.
P(0)=(number of spills during duration^0 *e^-number of spills during duration)/1
The probability of one or more spills=1-P(0).

Table 4 Calculation of Spill Probabilities for Rocky Point Unit (50 million barrels of production)

Location	Spill Rate (spills per 10^9 bbls)	Total Oil Production (10^9 bbls)	Duration of Total Oil Production (years)	Estimated Number of Spills During the Duration	Probability of Zero Spills Occurring (P(0))	Probability of One or More Spills Occurring
Spills Greater Than or Equal to 1,000 bbls						
Platform Hermosa	0.45	0.0175	12	0.008	99.2%	0.8%
Platform Harvest	0.45	0.0175	12	0.008	99.2%	0.8%
Platform Hidalgo	0.45	0.015	12	0.007	99.3%	0.7%
Total Platforms	0.45	*0.05*	*12*	*0.023*	*97.8%*	*2.2%*
PAPCO Pipeline	1.35	0.05	12	0.068	93.5%	6.5%
Spills Greater Than or Equal to 10,000 bbls						
Platform Hermosa	0.16	0.0175	12	0.003	99.7%	0.3%
Platform Harvest	0.16	0.0175	12	0.003	99.7%	0.3%
Platform Hidalgo	0.16	0.015	12	0.002	99.8%	0.2%
Total Platforms	0.16	*0.05*	*12*	*0.008*	*99.2%*	*0.8%*
PAPCO Pipeline	0.44	0.05	12	0.022	97.8%	2.2%

Notes:
The platform numbers may not add-up due to rounding.
Duration of production is from third quarter 2002 through the end of the third quarter 2014.
Estimated number of spills during the duration=spill rate*total oil production.
P(0)=(number of spills during duration^0 *e^-number of spills during duration)/1
The probability of one or more spills=1-P(0).

Attachment I – Environmental Justice Data

CENSUS Information on Port Huenene, US Census Bureau, 1990 Data

Category	All of California		Ventura County CA		1 Mile radius		2 mile radius		5 mile radius	
	Data	Percent	Data	Percent	Data	Percent	Data	Percent	Data	Percent
Total Population	29,760,021		669,016		12,686		36,819		144,862	
Population/square mile	191		362		3,533		6,113		4,169	
Persons living in households	29,024,579	97	655,603	97	11,521	90	35,276	95	141,815	97
Persons in group quarters	735,442	2	13,413	2	1,165	9	1,543	4	3,047	2
Male	14,881,551	50	337,491	50	6,993	55	19,427	52	74,567	51
Female	14,878,470	49	331,525	49	5,693	44	17,392	47	70,295	48
Average age	34		33		29		29		31	
White	20,555,653	69	529,878	79	9,817	77	25,528	69	88,216	60
Black	2,198,766	7	15,741	2	722	5	1,961	5	7,546	5
American Indian/Eskimo/Aleut	248,929	0	5,041	0	100	0	508	1	1,423	0
Asian/Pacific Islander	2,847,835	9	34,293	5	774	6	2,403	6	11,436	7
Other race	3,908,838	13	84,063	12	1,273	10	6,419	17	36,241	25
Total Minority	9,204,368	31	139,138	21	2,869	23	11,291	31	56,646	39
Hispanic origin (any race)	7,557,550	25	175,414	26	3,069	24	15,527	42	75,012	51
Persons 15+ years	23,164,593		514,242		9,453		27,003		107,467	
Not presently married	10,353,344	44	202,470	39	4,530	47	11,931	44	46,459	43
Now married	12,811,249	55	311,772	60	4,923	52	15,072	55	61,008	56
Persons 3+ years	28,317,687		636,389		11,948		34,711		136,776	
In preprimary/elemen./high sch.	5,707,835	20	136,727	21	2,353	19	7,911	22	31,559	23
In college	2,592,211	9	51,565	8	825	6	2,382	6	9,343	6
Not enrolled in school	20,017,641	70	448,097	70	8,770	73	24,418	70	95,874	70
Public school	7,177,045	25	160,617	25	2,793	23	9,375	27	36,992	27
Private school	1,123,001	3	27,675	4	385	3	918	2	3,910	2
Persons 25+ years	18,695,499		415,551		7,072		20,181		82,247	
By Educational Attainment:										
Less than complete high school	4,450,528	23	85,778	20	1,452	20	6,708	33	31,177	37
High school graduate	4,167,897	22	91,704	22	1,716	24	4,274	21	17,376	21
Some college/college degree	10,077,074	53	238,069	57	3,904	55	9,199	45	33,694	40
Persons 16+ years	22,786,281		504,674		9,287		26,467		105,240	

CENSUS Information on Port Huenene, US Census Bureau, 1990 Data

Category	All of California		Ventura County CA		1 Mile radius		2 mile radius		5 mile radius	
	Data	Percent	Data	Percent	Data	Percent	Data	Percent	Data	Percent
By Employment Status:										
In Armed Forces	270,089	1	5,511	1	1,822	19	2,062	7	3,231	3
Civilian participation rate %	67		71		71		72		70	
Male civilian part. rate %	76		81		81		82		80	
Female civilian part. rate %	58		61		61		62		60	
Employed	13,996,309	61	336,772	66	4,959	53	16,449	62	66,425	63
Unemployed	996,502	4	16,841	3	324	3	1,148	4	4,908	4
Unemployment rate %	7		5		6		7		7	
Male unemployment rate %	7		5		5		6		6	
Female unemployment rate %	7		5		7		8		8	