EXHIBIT 1

THE PLAYA DEL REY

MONITORING PROGRAM

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I. Storage Zone Problems

A. Possible source of gas migration to surface

There are at least five different possible sources of gas to the surface at Playa del Rey:

1. Casing leaks due to tubing/drill pipe wear, corrosion, stage collars, squeeze holes or metal failure.

2. Casing shoe leaks in active and abandoned wells.

3. Leaks from lower to upper zones outside the casing through uncemented or poorly cemented well bore in either active or abandoned wells.

4. Abandonment plug leaks inside the casings of abandoned wells.

5. Wellhead seal leaks.

B. Three incidents of shallow casing leaks at Playa del Rey

Since Playa del Rey was converted to gas storage in 1942 for the war effort, there have been three incidents of shallow casing leaks. Two of these leaks had surface shows of gas and oil: 12-1 and 24-2, respectively.

1. In 1964, a casing leak was reported in Big Ben at about 150'. Repaired leak in 6-5/8" casing with Baash Ross casing bowl to 269'. The leak was determined to be at a depth of 269'.

2. On August 9, 1974, a gas leak was reported in the 13-1 block. The well 12-1 was determined to have a casing leak at between 700 and 800 feet. Bar hole surveys around the well and over the pipelines in the area indicated gas was appearing at the surface. The well was killed on August 15, 1974. From this time on, no gas was injected into the 13-1 block.

3. On April 30, 1975 at about 11:00 a.m., oil and gas surfaced on the east side of cellar wall. The well was producing through a leak in 7" casing at an unknown depth. They found corrosion in the

casing from 108' - 157'. Six weeks later well was returned to service. Currently, this well has an Otis subsurface safety valve located at 92'.

II. Overview of Field

A. Introduction

Playa del Rey oil field is about eleven miles west of Los Angeles, between Venice and Playa del Rey. Wildcatting was carried on in the vicinity of Playa del Rey for over eight years before the field was finally discovered. Drilling activities in the vicinity of Playa del Rey date back to May 14, 1921, at which time Del Rey 1 was spudded. This well was drilled to depth of 2785' without encountering any oil or gas showings, and was abandoned because of mechanical problems.

The first well drilled into the storage zone was on August 2, 1929. The Ohio Oil Company spudded the "Recreation Gun Club" 1. This well was drilled to a depth deeper than 6200'. A poorly sorted conglomerate, showing gas and oil, from 6114 to 6199 was discovered. While preparing to run a "water witch" to determine the nature and point of entry of the fluid, the well suddenly came in December 18, 1929, and flowed through the casing at an estimated rate of 2500 barrels of oil and 1,500,000 cubic feet of gas per day with the oil having an API of 21.6°.

On August 4, 1942, the Commission decided that Playa del Rey appeared feasible for Underground Storage from an engineering and economic standpoint. The goverment decided that Union Oil Company of California was to act as the operating contractor for Defense Plants Corporation, and the Southern California Gas Company as the gas utility to store and withdraw gas. From that time, the storage zone has increased from a field deliverability of approximately 10 MMcf/hr to about 25 MMcf/hr. Currently, Southern California Gas Company has 72 active wells in Playa del Rey.

B. Well Lists

There are 72 active wells in this field. These wells are divided into four groups:

1.	Injection/withdrawal wells Storage wells	28
2.	Flowing wells migration Return	2
3.	Pumping wells:	10
	a. Fluid removal b. Pressure relief	
4.	Observation wells	32

These wells comprise the Playa del Rey storage operation.

C. Storage Areas

There are five distinct areas in the Playa del Rey storage field. Each of these areas has distinct operating functions.

1. 13-1 Fault Block
2. 24-1 Fault Block
3. Del Rey Main Area
4. Del Rey Gas Cap
5. Venice Townlot area

13-1 Fault Block

The 13-1 fault block has not been used for injection/withdrawal operations since 1974 when a shallow leak at well 12-1 brought gas to the surface at nearby houses. This block includes wells 12-1, 13-1, Colly 2, Colly 10, Harper, Hisey, Kelly and Merrill. Should this block be determined feasible to return to operations, other factors need to be considered. All of the wells in this block are in a residential area and will require subsurface safety valves with which they are already equipped. These wells have not been operated for some time; and thus the question is whether or not the neighbors will tolerate the increased noise level required to operate these wells.

The 13-1 fault block is geologically connected but not pressure connected. This block is an upthrown fault block, gas can migrate in, but the block holds pressure indicating that gas accumulates.

24-1 Fault Block

This fault block is used in tandem with the main storage area. It has no other purpose other than to remove fluid from this east flank.

Del Rey Main Area

This is the storage zone area. The operating guidelines are to withdraw from low structure wells first and work towards the higher structures. There are twenty-eight injection/withdrawal wells located in this area.

Del Rey Gas Cap

The wells located in this area of the field are primarily used for observation. Two of these wells are also used for gas migration return Del Rey 15 and Del Rey 18.

Venice Townlot Area

The wells in this area have a dual purpose: pressure relief (fluid removal) and gas migration (observation).

Early in the usage of Playa del Rey as a gas storage reservoir, it was discovered that certain oil productive areas, previously considered to be structurally separate deposits were really pressure connected. The areas in question were the Del Rey Gas Cap, Del Rey Hills Area, Del Rey Main Area and the Venice Townlot area. Parts of this reservoir are apparently geologically connected but not pressure connected.

Block 10R, Block 11, Townsite 2, Townsite 3, Townsite 11 and Troxel are located in this part of the field. Troxel, however, is on the other side of a fault block. Helium tests have indicated storage gas production from this area of the field.

III. Monitoring Program

A. Temperature, Noise and Tracer Surveys

All of the wells at Playa del Rey with the exception of tire pumping wells have temperature surveys are run on a quarterly basis. These surveys provide the information needed to determine well leaks. When a well leaks, the expanding gas from the leak cools both the pipe and surrounding formation. On a temperature survey, the leak appears as a cooling anomaly on a temperature survey.

Gas storage technicians run temperature surveys quarterly using company-owned wireline units. If a cooling anomaly appears on the temperature survey, a noise survey is run to verify the leak. If indicated, a radioaoctive tracer survey (R/A) is run which pinpoints the exact location of the leak and provides data necessary to estimate the rate of gas loss. During the 1st five years, only two R/A tracer surveys were run. They were on Big Ben and 12-1. Big Ben had a casing leak at 1065', and well 12-1 had a leak between 168' and 230'.

B. Surface Observation

All active well cellar areas are inspected each month for indications of near surface gas migration by station personnel. Any bubbles are analyzed for hydrocarbon and helium content. The resident reservoir engineer requests the analysis, and reviews and maintains records of the results. If storage gas is forced, the senior petroleum engineer is notified.

Once a month at Playa del Rey, the station personnel survey the four permanent bar holes that are near all active wells with a gas scope or flame ionization unit.

Twice a year, the station surveys the bar holes in the vicinity of abandoned wells with the flame ionization unit to detect any near surface gas migration under the direction of the South Basin Pipeline Superintendent.

Once a year, all storage field pipelines are surveyed using the flame ionization unit to detect any near surface gas migration.

C. Storage Zone

1. Surface pressures in each well are measured and recorded weekly using a calibrated test gauge. The data recorded for each well are:

   Tubing pressure
   Casing pressure
   Annuli pressure
   Safety valve control-line pressure
   Mode of operation

2. A plot of weekly surface casing and innerstring annuli pressures versus time is maintained for each well.

3. Wellhead inspections are performed once a month.

4. Subsurface temperature survey are performed on a quarterly basis.

D. Gas Cap Observation Well

Vidor 6 is Playa del Rey's GCOW used to observe gas bubble pressures. This well is not used for injection and is used for withdrawal only for peak load conditions. The surface pressure measurements on the tubing and casing of Vidor 6 is recorded and plotted daily.

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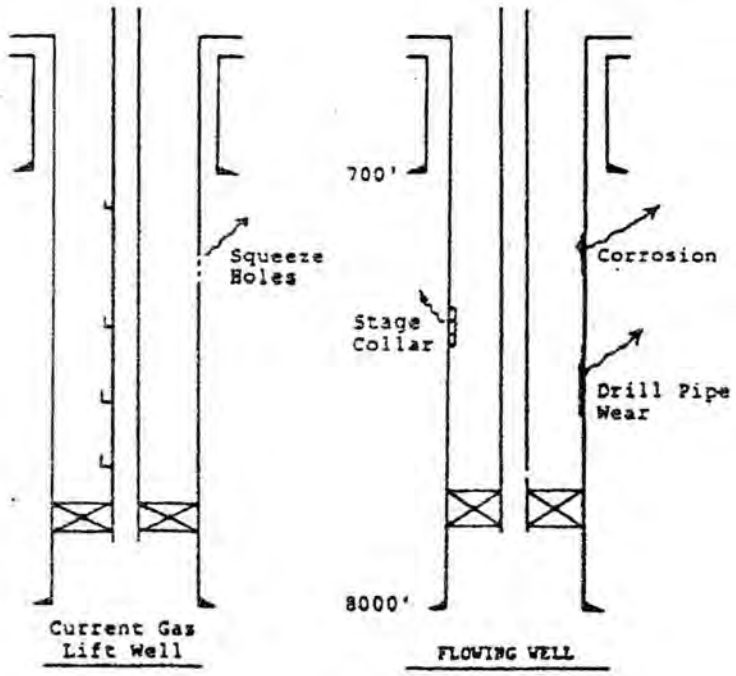
April 25, 1985

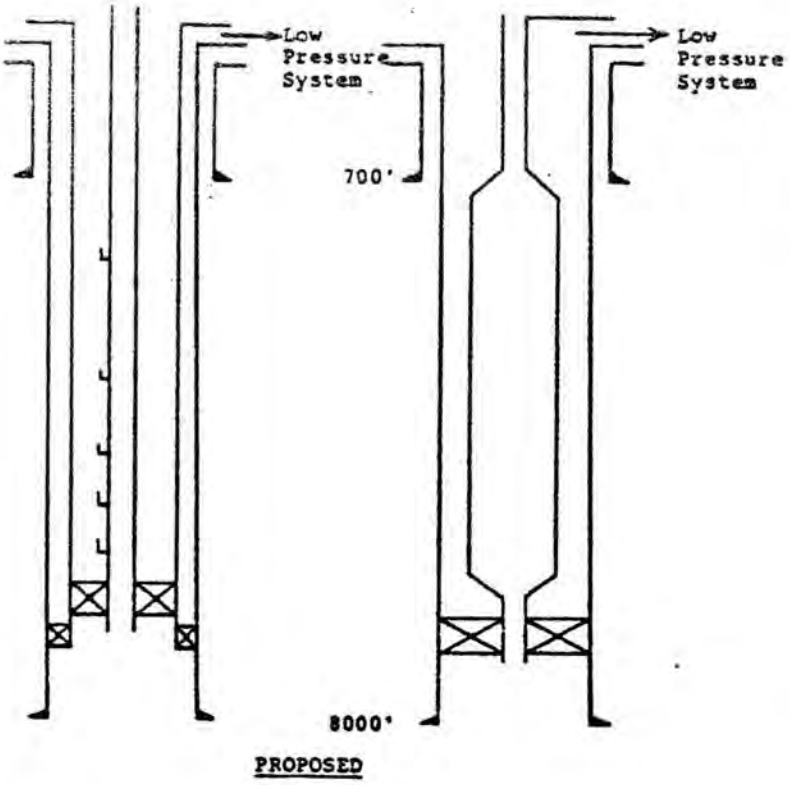
EXHIBIT I

CASING LEAKS: TYPE 1



PROBLEM:

Casing leaks that allow high pressure gas into low pressure, shallow zones.



SOLUTION:

Use innerstrings and/or tubing to confine all high gas pressure. Keep innerstring or tubing annulus pressure lower than that required to force gas into acquifer sand at shoe of surface casing by venting gas to atmosphere or to low pressure system. Withdrawal wells' deliverability can be kept high by using large tubing.

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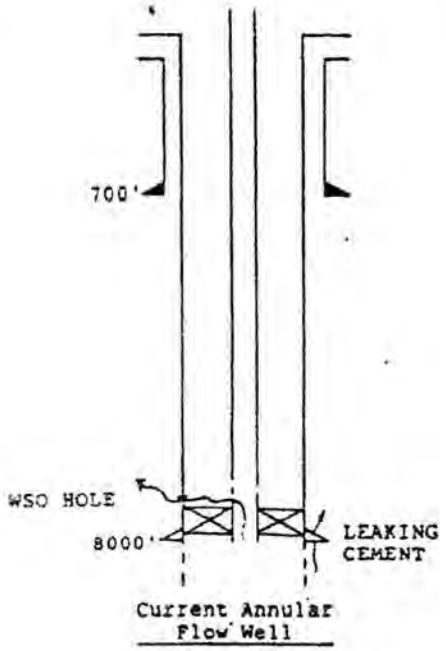
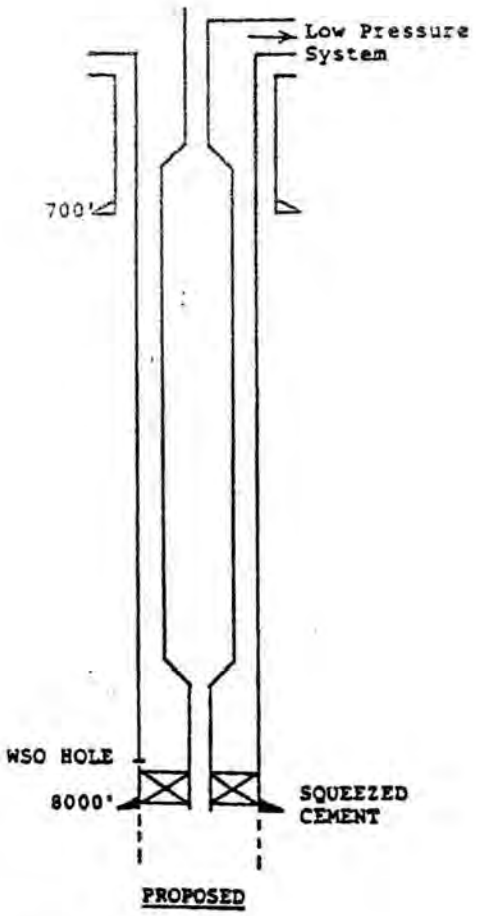
EXHIBIT I

CASING SHOE LEAKS: TYPE 2



Current Annular Flow Well

PROBLEM:
Casing shoe leaks due to poor, deteriorated cement or to leakage through WSO holes in active or abandoned wells.



PROPOSED

SOLUTION, ACTIVE WELLS:
Squeeze cement into shoe area. Place tubing packer below WSO holes where possible.

ALTERNATE SOLUTION, ACTIVE WELLS:
Do not repair if leak is into 7th zone but no higher. Collect all free gas from the 7th zone by activating more collection wells.

SOLUTION, ABANDONED WELLS:
Collect all free gas from overlying zones. Repair work not possible.

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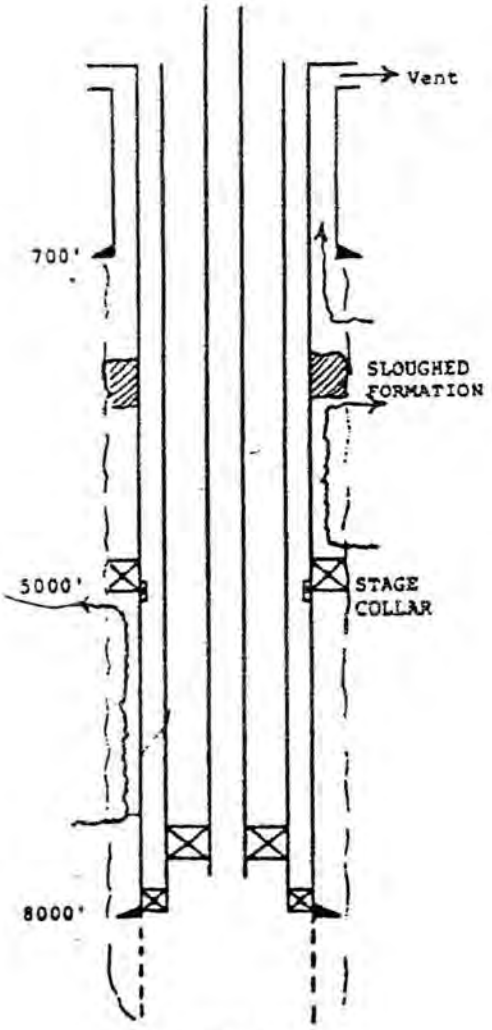
EXHIBIT I

UNCEMENTED WELLBORE LEAKS: TYPE 3



CURRENT AND FUTURE WELL

PROBLEM:
All wells have some uncemented segments. Few wells have any cement above 2000'. Formation sloughing may have filled in some of these wellbores but most remain the most permeable upward path for gas migration.

SOLUTION:
Noise and TDT monitor active wells to find areas of increasing activity. Continually produce shallow zones. Vent to atmosphere all gas coming from surface casing shoe aquifer.

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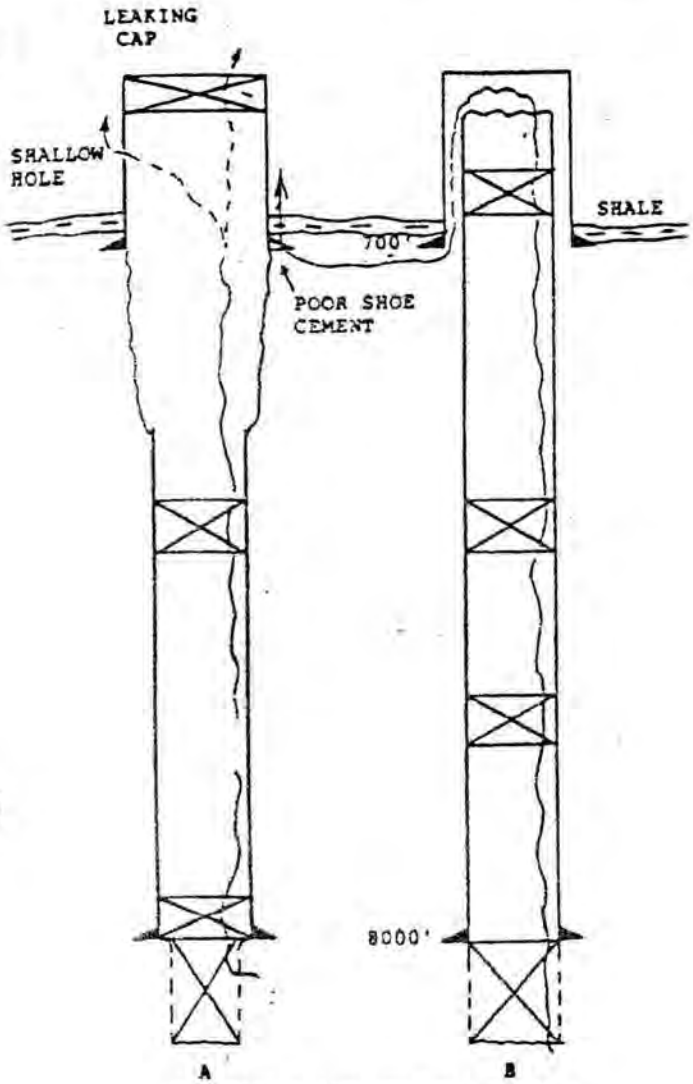
EXHIBIT I

ABANDONMENT PLUG LEAKS: TYPE 4



EXISTING ABANDONED WELL TYPES

PROBLEM, TYPE A ABANDONMENT:
Cement plugs inside casing allow some gas to migrate upwards. Because its casing was cut off below the surface string, water will continue to fill casing as gas leaks out. Leak will therefore be sporadic and low rate.

PROBLEM, TYPE B ABANDONMENT:
Cement plugs inside casing allow some gas to migrate upwards. Because the casing stub is cut off within 100' of surface, the entire surface casing fills with gas. No liquid enters the well. The gas leak unloads fluid from the well and the rate increases with time. Eventually all of the fluid unloads and the leak rate stabilizes at a near constant daily rate.

PROBLEMS, BOTH TYPE ABANDONMENTS:

1. Casing cap, surface casing and casing shoe cement competent. Gas will build up inside surface casing and force its way into shallow aquifer sand. Gas will surface at a non-leaking well that has the following problems.
2. Casing cap not competent. Gas will surface near well.
3. Surface casing or shoe cement not competent. Gas will spread over large area as it rises to surface lethargically.

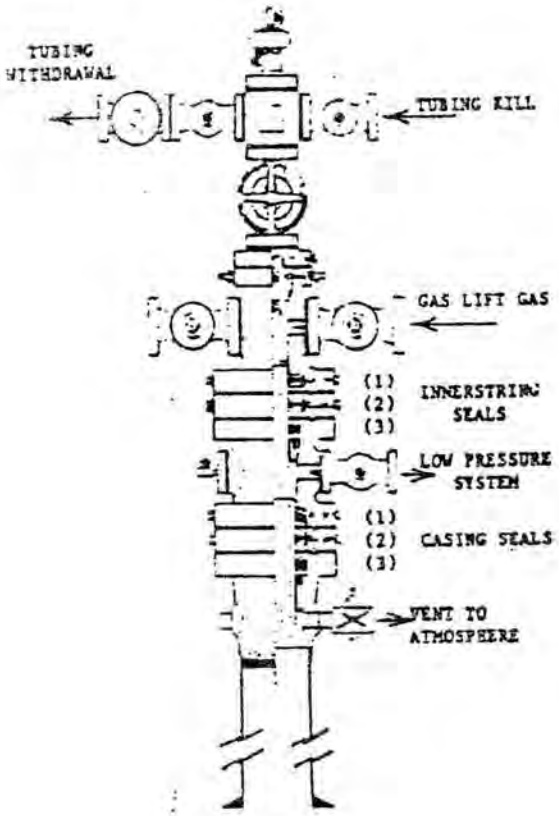
SOLUTION, PROBLEM 1:
Direct repair of leaking well not possible because source well is unknown. Other wells where gas appears are continually vented to surface.

SOLUTION, PROBLEM 2:
Unearth well and recap or place collection funnel over it. Rig work not required. Vent all gas to atmosphere.

SOLUTION, PROBLEM 3:
Unearth well, move in rig, attempt to enter and repair old casing. Produce gas through casing into low pressure system. Vent surface annulus to atmosphere.

EXHIBIT I

WELLHEAD LEAKS: TYPE 5



CURRENT AND PROPOSED WELLHEAD FOR WELLS WITH INNERSTRINGS

PROBLEM:
Wellhead seal leaks allow high pressure gas to leak into the innerstring, tubing or surface casing annulus. Gas then enters shallow zones at the surface casing shoe or through casing holes.

SOLUTION:
Keep all annular pressures below that required to force gas into shallow zones either by connecting them to low pressure system or venting them to atmosphere. Install new wellheads with triple seals (as illustrated) on wells with obsolete equipment when other well work is performing or when wellhead is leaking badly.

(1) Inject sealant to energize seal in head

(2) Inject sealant to energize seal in sealing flange

(3) Set down weight on slips to energize seal

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EXHIBIT 2

CHRONOLOGY OF WELL COMPLETIONS

Operator	*Well No.*	*Date of completion*
Union Oil Co. of California	"King Vidor" 1	May 23, 1931
Union Oil Co. of California	"Del Rey" 4	May 8, 1932
Union Oil Co. of California	"King Vidor" 2	Dec. 4, 1932
Union Oil Co. of California	"King Vidor" 3	May 10, 1933
Union Oil Co. of California	"Del Rey" 5	July 19, 1933
Union Oil Co. of California	"King Vidor" 5	April 17, 1934
Chas. W. Fourl	"Fourl" 1	Nov. 16, 1934
Union Oil Co. of California	"King Vidor" 6	Jan. 24, 1935
Union Oil Co. of California	"King Vidor" 7	Feb. 26, 1935
D. D. Dunlap Oil Co.	"Del Rey" 1	Feb. 26, 1935
McAdams Oil Co.	"Del Rey" 1	Mar. 14, 1935
D. W. Elliott	"Del Rey" 1	Mar. 21, 1935
Union Oil Co. of California	"King Vidor" 8	Mar. 26, 1935
Royalty Service Corp., Ltd.	"Del Rey" 1	Mar. 30, 1935
Pacific Drilling Corp.	"Del Rey" 1	April 20, 1935
Chas. W. Fourl	"Fourl" 8	April 24, 1935
Dunlap Petroleum Co.	1	May 11, 1935
Rite-Lube Oil Co.	"Ray" 1	May 17, 1935
Union Oil Co. of California	"King Vidor" 9	May 19, 1935
Royalty Service Corp., Ltd.	"Pomoc" 1	May 26, 1935
Colly Oil Co.	"Colly" 1	May 31, 1935
Union Oil Co. of California	"King Vidor" 10	June 2, 1935
Red Seal Oil Co., Ltd.	"Big Ben" 1	June 4, 1935
Chas. W. Fourl	"Fourl" 4	June 5, 1935
Coast Petroleum Co.	"Stockburger" 1	June 7, 1935
Thos. Kelly & Laurence C. Kelly	"T. & L." 1	June 13, 1935
Union Oil Co. of California	"Del Rey" 9	June 15, 1935
McAdams Oil Co.	"Del Rey" 2	June 16, 1935
Lor Mar Oil Development Co.	"Lor Mar" 1	June 24, 1935
Colly Oil Co.	"Colly" 2	June 24, 1935
Red Seal Oil Co., Ltd.	"Ben" 2	June 27, 1935
Royalty Service Corp., Ltd.	"Del Rey" 2	July 1, 1935
Embee Oil Co.	"Embee" 1	July 3, 1935
Williams & Harper	"Williams-Harper" 1	July 3, 1935
Royalty Service Corp., Ltd.	"Del Rey" 13-1	July 15, 1935
Union Oil Co. of California	"King Vidor" 11	July 27, 1935
Royalty Service Corp., Ltd.	"Del Rey" 12-1	Aug. 5, 1935
Red Seal Oil Co., Ltd.	"Ben" 3	Aug. 20, 1935
Del Rey Realty Co.	"Herndon Development" 29	Aug. 21, 1935
Union Oil Co. of California	"King Vidor" 12	Sept. 13, 1935
Royalty Service Corp., Ltd.	"Del Rey" 23-1	Sept. 26, 1935
Union Oil Co. of California	"Del Rey" 11	Oct. 18, 1935
Union Oil Co. of California	"King Vidor" 13	Oct. 24, 1935
Birch-Royer Oil Co.	"Hisey-Thrall" 1	Nov. 22, 1935
Otis Hoyt Co.	"Del Rey" 1	Dec. 3, 1935
Union Oil Co. of California	"King Vidor" 14	Jan. 12, 1936
Union Oil Co. of California	"Del Rey" 12	Jan. 27, 1936
G. C. Woodard, Agent	"Milham" 1	Feb. 20, 1936

EXHIBIT 3

APPENDIX A

GAS INVENTORY MONITORING, VERIFICATION, AND REPORTING PROCEDURES

I. GENERAL

Gas Storage Operations require monitoring and inventory verification for safe long-term management of underground gas storage operations. While no single method can be used to precisely monitor and verify the gas inventory in underground storage reservoirs, the three engineering methods in general use are summarized below. Gas volume verification can be obtained only by combining and analyzing available field data. Based on this analysis, gas volume changes or losses are recognized, estimated and reported.

II. DEFINITIONS

When gas storage operations are initiated in an oil or gas reservoir, there is an initial gas content in the reservoir prior to injection. Initial gas content is generally composed of both free gas and solution gas. Additional gas is added to the initial gas content by injection, and the combination comprises the Total Storage Volume. This volume is categorized as follows:

A. Cushion Gas

The base gas is that quantity of gas which must be in the reservoir to maintain the minimum pressure required to exclude fluids from the gas cap and to provide the energy required to deliver the minimum required rate of gas withdrawal at the end of the withdrawal season.

B. Recoverable Cushion Gas

This is defined as the volume of gas that can be economically recovered from the reservoir below the base gas pressure. This volume varies, depending upon economic conditions.

C. Non-Recoverable "Cushion Gas"

This is the volume of gas left in the reservoir after all recoverable gas volumes are removed and is not considered a part of Total Storage Inventory. This gas is capitalized and depreciated over the life of the project.

D. Working Gas

This volume is defined as the gas content which is held in the reservoir between maximum reservoir pressure and the base gas pressure.

E. Effective Working Gas

This volume is defined as the working gas which is withdrawn and re-injected in a complete injection and withdrawal cycle. Ideally, the effective working gas volume is synonymous with the working gas volume. However, limitations by wells, compression facilities, or gas availability may limit effective working gas volume.

F. Total Storage Inventory

This is the sum of all working and recoverable cushion gas volumes.

III. RESPONSIBILITY

The responsibilities for shut-ins, along with analyzing data, verifying gas inventory, and reporting changes or losses are specified in System Instruction 224.0020.

IV. MONITORING

A. Monitoring of the storage reservoir is required to ensure reservoir integrity and field deliverability. The performance review ensures the reservoir functions according to expectations, and integrity tests verify the gas inventory is present and available for delivery. Effective monitoring requires a thorough understanding of the reservoir system. This system is defined as the reservoir rock and wellbores which respond to pressure changes as a result of gas injection and withdrawal. To better understand the system, see System Instruction 224.0035, *Gas Inventory - Summary of Reservoir System.* A successful monitoring program reduces risk of injury, property damage and gas migration.

B. Monitoring of the reservoir system is conducted in both storage and non-storage zone wells and at surface observation points.

1. Storage Zone Wells

a. Performance reviews utilize information collected during individual well and reservoir tests. Back pressure curve shifts, changes in deliverability and field performance are investigated.

b. Tests are conducted on individual wells to prove both well and reservoir integrity.

i. Surface pressures on each well are measured and recorded weekly using a calibrated test gauge. Pressures measured and recorded include tubing pressure, casing pressure, annuli pressures, and, if applicable, safety valve control line pressure. The mode of well operation (injection, withdrawal or shut-in) at the time of pressure measurement is also recorded. Note that the *C.D.O.G.G.R. (California Division Of Oil Gas and Geothermal Resources)* requires a monthly average casing and tubing pressure recorded and submitted as part of the monthly production report.

ii. A plot of the weekly surface casing and the innerstring annuli pressures versus time is maintained or periodically produced for each well. Hardcopy plots are created, marked and filed when an abnormal pressure is

encountered. A pressure is considered abnormal when it may be large enough to force gas into a normally pressured water sand, either at the surface casing shoe or through any other known casing holes or leak-paths.

iii. When abnormally high annular pressures are detected, diagnostic steps are taken to determine the source of pressure build up. This includes tests to eliminate surface valves and downhole tubing as possible sources of leakage. Zero pressure is abnormal in a well that has had a history of annular pressure and is investigated for the possibility of a closed valve.

iv. All wells with continuing zero pressure readings are checked quarterly for closed valves and noted on the pressure plot. Blowdowns are also noted when they occur.

v. Wellhead inspections are performed on a monthly basis. Any leaks from wellhead flanges and valves are reported and corrected.

vi. Subsurface temperature surveys are conducted on each well in according to the following schedule: semi-annually in La Goleta, Montebello, and Playa del Rey storage fields and annually in the Aliso Canyon, and Honor Rancho Storage fields.

vii. Surveys are done in accordance with System Instruction 224.0025, *Standardized Subsurface Temperature and Pressure Surveys*. Wells that have been killed are not exempt from this requirement and must be surveyed according to the schedule. Results of surveys are reported according to Recommended Method 224.001, *Standardized Daily Well Operations Report.*

viii. Additional surveys will be run without regard to this schedule at the first indication of unusual or abnormal well conditions, i.e., anomalous pressure, surface gas emissions or other indications of well problems.

ix. Wireline retrievable tubing obstructions such as tubing plugs, subsurface safety valves, subsurface chokes or tubing stops are removed once each year to perform a temperature survey of the casing shoe and cap rock seal. Ideally, this is done at high reservoir pressure when shoe leaks are most noticeable on temperature surveys.

Under certain conditions it may not be possible or advisable to remove the wireline retrievable obstruction.

x. Subsurface surveys using wireline conductor cable equipment are made to investigate anomalies discovered by temperature surveys.

xi. Conductor cable surveys include temperature surveys, noise logs, spinner surveys, and radioactive tracer surveys.

xii. In the case of well casing leaks above the shoe, radioactive tracer surveys are typically used to verify the location of gas movement through the leak. In the case of shoe or cap rock leaks, these additional surveys are used to verify that a leak exists and as an aid to qualitatively estimate leakage rate.

c. Reservoir integrity tests include:

i. Gas cap observation wells are used to monitor reservoir pressure. If possible one or more wells completed in the gas cap are selected for observation purposes. These wells are not used for injection and are put on withdrawal only for peak load conditions. Surface pressure measurements on the tubing and casing of each gas cap observation well are made and recorded weekly.

ii. A plot of these pressures versus inventory is kept in the office of the Storage Field Engineer and is updated weekly. Anomalous well pressures or behavior are reported to Storage Engineering Staff.

iii. Reservoir shut-ins are generally on a schedule stated in System Instruction 224.0020 or when determined as necessary by the Storage Field Engineer. The

2. Non-storage Zone Wells

a. Non-storage zone wells monitored include both Company wells and wells owned by others in overlying and underlying zones and in other fields within two miles of the storage reservoir boundary, where applicable. These wells are categorized as follows:

i. Pressure observation wells are located in overlying and underlying permeable formations, or adjacent to the storage reservoir but across assumed confining boundaries, such as faults, permeability pinchouts, below the gas-liquid contact or beyond the spill point of the storage zone's confining structure. Although normally static, these wells may have artificial lift mechanisms for removal of gas and fluids.

ii. Gas collection wells are located where known gas migration from the storage zone is intercepted and collected. These wells are normally equipped with operating artificial lift mechanisms so that both liquids and gas can be produced, causing a pressure sink in the reservoir near the wellbore.

iii. In some fields, shallow water observation wells have been drilled into aquifer zones existing in the first permeable sand above the shoe of the surface casing. These wells are closed in at the surface and gas concentrations in the wellbore are measured weekly.

iv. If gas loss is expected, performance reviews of wells operated by other producers in either overlying zones or in adjacent fields may be made by reviewing production reports from these operators.

v. Performance of Company-owned observation and collection wells are also closely monitored. Wellhead inspections and temperature surveys are performed on the pressure observation wells and the gas collection wells.

vi. Pressure observation wells

a. Surface pressures on all tubing and casing strings are measured weekly using a calibrated test gauge.

b. A plot of pressure versus time for each well is kept by the Storage Field Engineer. Bottom-

hole pressure surveys are run as needed on pressure observation wells.

c. If a substantial increase in reservoir pressure is noted or a significant gas buildup occurs, an attempt is made to produce the well. Produced gas is sampled and analyzed for both hydrocarbon and helium content.

vii. Gas collection wells

a. Surface pressures on all casing strings and safety valve control lines are measured weekly using a calibrated test-gauge. The mode of well operation (producing, shut-in) at the time of pressure measurement is also recorded.

b. A plot of pressure vs. time for each surface casing and innerstring annulus is kept by the Storage Field Engineer.

c. Bottom-hole pressure surveys are run on gas collection wells as needed. These surveys follow a shut-in period to allow pressure stabilization after production. If the well is equipped with a standing valve, the valve is pulled prior to the bottom-hole pressure survey and is reinstalled upon completion of the survey.

d. Production schedules are developed by the Storage Field Engineer. The Storage Field Engineer maintains plots of bottomhole pressure versus time and records of produced gas, oil and water.

viii. Shallow water observation wells

a. Shallow water observation wells are closed-in at the surface and gas concentrations in the wellbore measured periodically.

ix. Surface Observations

a. Active well cellar areas are inspected by station personnel each month for indications of near surface gas migration. The Storage Field Engineer requests the analysis if needed and reviews and maintains records of the results.

b. Region personnel survey the location perimeter of four permanent bar holes near all active wells with a gas scope or flame ionization unit. The surveys are performed monthly at Montebello, quarterly at La Goleta, and semi-annually at Aliso Canyon, East Whittier, Honor Rancho and Playa del Rey.

c. The areas in the vicinity of abandoned wells are examined with a flame ionization unit to detect any near surface gas migration under the direction of the Storage Operations Manager. Surveys are performed semi-annually at Montebello, and annually at Aliso Canyon, East Whittier, Honor Rancho, La Goleta and Playa del Rey.

d. Flame ionization surveys to detect any near surface gas migration are performed on all storage field pipelines under the direction of the Storage Operations Manager. These surveys are performed annually at La Goleta, Montebello, and Playa del Rey and every two years at Aliso Canyon, East Whittier and Honor Rancho.

V. BOTTOM-HOLE PRESSURE DETERMINATION

A. Each of the three major methods used to verify gas storage inventory, as explained in Section V, requires the determination of bottom-hole pressures in the field wells. The method used to determine bottom-hole pressure must be consistent from year to year. The most accurate method to determine bottom-hole pressure is to measure the pressure with a pressure bomb. In certain applications the bottom-hole pressure can be calculated from the shut-in wellhead pressure. For wells completed in the gas cap and having full gas columns, the bottom-hole pressure is calculated from the equation:

$$P_{BHP} = P_{WH} \exp\left(\frac{0.01875 \times SG \times D}{Z_{avg} T_{avg}}\right)$$

Where:

P_{BHP} = Bottom-hole pressure, psia.

P_{WH} = Wellhead pressure, psia.

SG = Gas specific gravity.

D = True vertical depth in feet.

T_{avg} = Average wellbore temperature between surface and bottom-hole, degrees Rankin.

Z_{avg} = Average gas compressibility factor from charts, tables or computer programs (dependent on P_{avg}, T_{avg} and gas gravity).

P_{avg} = Average pressure between surface and bottom-hole, psia or

$$P_{avg} = (P_{BHP} + P_{WH})/2$$

NOTE: The above equation could yield incorrect results if the well exhibits abnormally high surface pressure or high fluid levels.

VI. INVENTORY VERIFICATION – SHUT IN

A. Three primary methods for inventory verification of Gas Storage Fields are referenced and summarized below:

1. Calculation of gas content based on volumetric data and average reservoir pressure; Volumetric Determination is explained in Applied Petroleum Reservoir Engineering; by Craft, B. C. and Hawkins, M. F.; Englewood Cliffs, N.J.: Prentice- Hall, 1959.

2. Calculation of effective gas content using the simple gas material balance, hysteresis curve, and P/Z curve methods; Material Balance is explained in Natural Gas Engineering by Ikoku, C. V.; Tulsa, Oklahoma: Penn Well Publishing, 1980.

3. Verification of storage inventory by comparing measured reservoir pressures with calculated pressures obtained using the single cell material balance or reservoir simulation methods; Numerical Simulation or Reservoir Modeling is explained in *Modern Reservoir Engineering —A Simulation Approach* by *Crichlow, H. B.*; Englewood Cliffs, N.J.: Prentice- Hall, 1977 and the *Intercomp Beta II User Manual*.

B. The most common inventory verification method used in mature gas storage projects that are known to have effective geologic closure is the hysteresis curve or P/Z versus inventory plot. Typically, it is adjusted annually for known gas losses and liquid production. Any shift between points plotted at similar pressures following a shut-in is further investigated.

1. Tracking known gas losses and transfers as they occur assist with inventory verification.

2. Recommended Shut-in time durations for effective reservoir stabilization are listed below

- Aliso Canyon -14 days
- Honor Rancho -12 days
- Goleta- 5 days
- Montebello -12 days

C. Data collected during a shut-in period includes accurate measurements of reservoir pressure on each available well. Bottom-hole pressures can be calculated from surface pressures or measured directly. Gas gravity is determined using gas samples from individual, representative wells.

D. The Storage Field Engineer chooses the type and frequency of data to be collected during shut-ins.

E. Calculation of gas content based on volumetric data and average reservoir pressure from shut-in.

1. Average reservoir pressures used in this calculation are obtained during shut-in periods required for reservoir pressure stabilization. Reservoir pore volumes available for gas storage are calculated from either geologic information, material balances using production and pressure information obtained during primary field production, or in some cases from pressure and production data obtained during gas storage operations. Elements of these calculations are described below:

2. Average reservoir pressures are calculated in an appropriate way for each storage reservoir. To be reliable, the method for each field should stay consistent for all years. Various methods of calculation include the following:

a. The average reservoir pressure for Honor Rancho, La Goleta, and Playa del Rey are determined by calculating the arithmetic average of the bottom-hole pressure in the gas cap wells. In these fields the pressure of each well is measured or computed at a specified subsea datum approximately at the midpoint of the zone. The datum and reservoir temperature used for these fields are as follows:

i. Honor Rancho - 8,300 feet subsea, 190°F

ii. La Goleta - 4,200 feet subsea, 150°F

iii. Playa del Rey - 6,100 feet subsea, 210°F

iv. Montebello: An average reservoir pressure is obtained. The pressure points for the average reservoir pressure are generated by converting the bottom-hole pressure to a datum at the top of the 8-2 zone using a reservoir temperature of 187°F.

v. A volumetrically weighted average reservoir pressure is used for Aliso Canyon. The pressures in this field is computed at a specified subsea depth approximately at the midpoint of the zone. The datum depth for this field and the reservoir temperature is as follows:

a. Aliso Canyon - 5,400 feet subsea, 180°F

3. Reservoir pore volume calculated from geologic information utilizes data obtained during the drilling and completion of the well such as electric logs or core information to calculate the total pore volume of the reservoir. These calculations are based on the following equations:

a. Gas reservoirs

i. Equation: $V = Ah\varnothing (1-S_w)$

Where:

V = Reservoir gas pore volume in cubic feet

A = Gas zone area in square feet

h = Average gas zone thickness in feet determined from electric logs or cores

$\varnothing$ = Porosity fraction determined from porosity logs or well test analysis

S_w = Water saturation from log, core, or well test analysis

b. Oil reservoirs

i. Equation: $V = Ah\varnothing(1-S_w) + A_1h_1\varnothing (1-2_w-s_o)$

Where:

A = Primary gas cap area in square feet

A_1 = Secondary gas cap area in square feet

h_1 = Average secondary gas zone thickness in feet

$s_o =$ Residual oil saturation

ii. In most portions of an oil zone storage reservoir, oil saturation is determined from core analysis or can be considered equivalent to residual oil saturation and can be estimated from the 16" normal resistivity curve using the following relationships.

Equation: Residual oil saturation = $(1-s_{xo})$

$$s_{xo} = \sqrt{\frac{Rmf}{R_{xo}\varnothing 2}}$$

Where:

$R_{xo} =$ Resistivity of 16" normal or resistivity of flushed zone.

$S_{xo} =$ Water saturation of mud filtrate within the flushed zone.

$\varnothing =$ Porosity

$Rmf =$ Resistivity of mud filtrate.

4. Gas Reservoir pore volume calculated using material balance equations:

These calculations utilize production and pressure data in the following equations:

a. Equation for constant volume gas reservoirs using primary production:

$$V = \frac{P_{SC} G_P T}{T_{SC}} \left(\frac{1}{P_i / Z_i - P_f / Z_F} \right)$$

Where water production and influx are assumed negligible and where:

$V =$ Gas pore volume in reservoir cubic feet.

$P_{sc} =$ 14.7 psia

$G_p =$ Gas produced in standard cubic feet.

$T =$ Reservoir temperature in degrees Rankin (°R).

$R_{sc} =$ 520°R

P_i = Initial pressure, psia.

P_f = Final pressure, psia.

Z_i = Initial gas compressibility factor.

Z_f = Final gas compressibility factor.

b. Equation for constant volume gas reservoirs using storage production

$$V = \frac{P_{SC} G_P T}{T_{SP}} \left(\frac{1}{P_1 / Z_1 - P_2 / Z_2} \right)$$

Where water production and influx are assumed negligible

G_p = SCF of gas produced or injected between pressure points P1 and P2.

P_1 and P_2 = The first and second stabilized average reservoir pressures bounding the production or injection period considered.

Z_1 and Z_2 = Gas compressibility factors for P1 and P2.

T = Reservoir temperature in degrees Rankin

5. Oil reservoirs pore volume calculations

a. Equation: The 'Reservoir Gas Pore Volume' is equal to the 'Original Gas Cap Pore Volume' plus the 'Secondary Gas Cap Pore Volume' plus the 'Space created by Water Production'.

Or:

$$V = GB_{gi} = \left(NB_{oi} - \left(N - N_p \right) B_o \right) + W_p B_w$$

Where:

G = Original gas pore volume, standard cubic feet (determined from either geologic data or an appropriate form of the material balance equation).

B_{gi} = Gas formation volume factor in reservoir cubic feet per standard cubic feet at discovery pressure.

N = Initial oil in place in stock tank barrels (determined from either geologic data or an appropriated form of the material balance equation).

N_p = Cumulative oil production in stock tank barrels.

B_{oi} = Oil formation volume factor in reservoir cubic feet per stock tank barrel at discovery pressure.

Bo = Oil formation volume factor at existing pressure in reservoir cubic feet per stock tank barrel.

W_p = Water production in stock tank barrels.

B_w = Water formation volume factor, reservoir cubic feet per stock tank barrel (approximates 5.615).

b. Simplifying assumptions used in the above equation are that no storage gas goes into solution in the oil and that there is no water influx into the storage reservoir. These simplifying assumptions are seldom true. However, the equation can be modified based on a judgment of the volume of gas which may go into solution in the reservoir oil and a judgment of aquifer activity surrounding the storage reservoir. When modified by these judgment factors, the equation provides a method for approximating a limit for the reservoir gas pore volume available for storage operations. An upper limit is established when it is assumed that all the residual oil is resaturated with gas. Generally, only a fraction of the oil becomes saturated and so the calculation has little usage beyond setting limits.

c. The values of G and N are not generally expected to be obtained with an accuracy greater than + 20%. However, this is not a major drawback since the methods are used to establish guidelines and set limits.

6. Calculation of gas content.

a. After the gas pore volume has been calculated, or approximated, by one of the methods indicated above, the gas content at the measured reservoir pressure is determined using the gas law as follows:

$$PV = ZNRT$$

Where:

P = Average reservoir pressure, psia

V = Gas pore volume in reservoir cubic feet

T = Temperature of reservoir, (°F + 460) degrees Rankin

Z = Compressibility factor, dependent on P, T, and gas gravity, from charts or tables.

N = pound moles (where one pound mole = 379.41 cubic feet @ 60°F and 14.7 psia).

R = 10.735 universal gas constant for above units.

Solving for gas content;

$$Volume(mscf) = \frac{(0.03533)PV}{ZT}$$

PV = ZNRT

Where:

P = Average reservoir pressure, psia

V = Gas pore volume in reservoir cubic feet

T = Temperature of reservoir, (°F + 460) degrees Rankin

Z = Compressibility factor, dependent on P, T, and gas gravity, from charts or tables.

N = pound moles (where one pound mole = 379.41 cubic feet @ 60°F and 14.7 psia).

R = 10.735 universal gas constant for above units.

Solving for gas content;

$$Volume(mscf) = \frac{(0.03533)PV}{ZT}$$

F. Calculation of effective gas content using the simple gas material balance and hysteresis curve(P/Z curve) methods

1. Pressure changes with rapid gas injection or withdrawal during selected operating periods can show the relationship between effective gas content and the storage inventory. Effective gas content is the gas which, within a given time, causes a measurable pressure response to injection or withdrawal operations. Not all gas in the reservoir yields such a response within the given time interval. The difference between

effective gas content at a given pressure (P_1) and the metered inventory is non-effective gas. Part of this non-effective gas can be due to the lack of pressure equilibrium within the reservoir. Any gas migration out of the storage reservoir also contributes to the non-effective gas. Either one of the two equations, or the graphical solutions presented below are used to calculate the effective gas content.

a. Calculations with negligible water movement are made using the following equation:

$$\text{Effective Gas Content at P1, Q1} = \left(\frac{\Delta Q}{\frac{P_1}{Z_1} - \frac{P_2}{Z_2}}\right)\left(\frac{P_1}{Z_1}\right)$$

Where:

P_1 = Pressure at the first operational point considered.

P_2 = Pressure at the second operational point considered.

Q_1 = Net storage volume at the first operational point considered.

ΔQ = The net change in gas inventory between the two operational points considered.

b. Calculations with significant water movement of a known rate are made using the following equations:

$$Q_1 = \left(\Delta Q - \left(We \times \frac{P_2}{14.7} \times \frac{520}{T_R} \times \frac{1}{Z_R}\right)\right)\frac{\frac{P_1}{Z_1}}{\left(\frac{P_1}{Z_1} - \frac{P_2}{Z_2}\right)}$$

Where terms are defined as above, and where:

We = Water influx in cubic feet.

T_R = Reservoir temperature, degrees Rankin.

Z_R = Z at T_R and P_2.

G. Graphical solutions

1. The hysteresis curve is a plot of reservoir pressure versus storage inventory. This curve utilizes the compressibility factor of non-ideal gas.

It is most effective in a constant volume reservoir since it assumes no water movement into or away from the storage reservoir; and no movement of gas into or out of solution in the reservoir oil. Actually, after sufficient storage history, the hysteresis curve becomes a qualitative tool for inventory verification since with constant operating procedures and a relatively constant storage cycling volume, aquifer movement and movement of gas into and out of solution is relatively constant and effectively drops from the equation.

VII. REPORTING GAS INVENTORY LOSSES

A. Calculated operational losses

1. Gas losses due to compressor, piping system or well blowdowns and wireline surveys are calculated by Storage Field personnel and reported to Measurement monthly. These reports are review by the Storage Field Engineer.

2. Estimates of losses related to workovers and well blowdowns are prepared by the Storage Field Engineer after a well has been killed. These estimated losses are reported monthly to Gas Measurement.

B. Losses from known well and surface facility leaks

1. Some small losses from valves, compressors, field piping, threaded well casing connections and well casing mechanical devices such as cementing stage collars, and some small casing leaks are inherent to Storage Field Operations. These leaks are estimated and reported as follows:

   a. Minor surface facility leakage is surveyed in each storage field periodically. Leakage surveys include wellhead valves and fittings, instrumentation, well piping, field piping, surface production facilities and the compressor station. Surveys are made more frequently if facility modifications are made which might change leakage rates.

   b. During these surveys, measurements are obtained on representative minor atmospheric leaks and then extrapolated to an estimated annual leakage rate for the field.

2. Subsurface leakage from wells is estimated by the Storage Field Engineer and reported to Storage Engineering Staff.

   a. Leakage from well casings is estimated by establishing a leakage rate using the radioactive tracer survey. The number of days of leakage is estimated by using subsurface temperature survey data. Casing shoe or Water Shut-Off (WSO) leakage is estimated by reviewing temperature, noise and radioactive tracer

surveys, pressure draw-down and the overlying wells' gas production during the time of the leak.

b. In cases where leakage rates are not quantifiable, an average rate of 30 Mcf/d may be used. Engineering judgment is then applied and an average daily loss rate selected. The number of days the leak was occurring is determined by taking one-half the difference in the number of days between the last normal and the first abnormal temperature survey.

3. Surface facility leakage and subsurface leakage are quantified annually by the Storage Field Engineer who reports the results to the Storage Engineering Manager and Gas Management.

C. Reservoir losses

1. Reservoir losses are categorized as those associated with Company-operated wells completed in the storage reservoir and general reservoir losses.

a. Losses associated with the Company-operated wells include losses through failures in the cement between the cap rock and well casing. These losses are also known as "shoe leaks," "WSO" leaks and "stage collar" leaks.

b. General reservoir losses include losses through abandoned wells or breakdown of some portion of the trapping mechanism. This type of loss is not directly detected by surveys of Company-operated wells in the storage zone.

c. Quantification of reservoir losses utilizes industry accepted methods of inventory verification.

2. Reservoir losses are quantified annually by the Storage Field Engineer who reports results to the Storage Engineering Manager and Gas Measurement.

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Author's Brief/Summary of Changes:

This FCD was revised by the Storage Engineer Peer Team. The title of the FCD was changed to Gas Inventory - Monitoring, Verification, and Reporting. It was merged with FCD 224.0045 and FCD 224.020 and changed to a Recommended Method.

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