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AN ABSTRACT OF THE THESIS OF Paul Joseph Townley for the Master of Science in Geology presented May 13, 1985.

Title: Preliminary Investigation for Underground Storage of Pipeline Gas in the Bruer and Flora Pools, Mist Gas Field, Columbia County, Oregon.

APPROVED BY MEMBERS OF THE THESIS COMMITTEE:

Gilbert T. Benson, Chairman

Ansel G. Johnson

Michael L. Cummings

Northwest Natural Gas Company has proposed to convert the Bruer and Flora pools of the Mist Gas Field in west-central Columbia County, Northwestern Oregon, to pipeline gas storage reservoirs. Conversion to underground storage of pipeline gas in these depleted gas reservoirs would be the first in the Pacific Northwest. The Bruer and Flora Pools are fault trapped within the Cowlitz Formation. The shales overlying the Cowlitz Formation create a local seal for these gas reservoirs. X-ray diffraction and density log measurements suggest that the clay in these shales is primarily composed of smectite, which provides an excellent caprock seal.

The reservoir rock of the Bruer and Flora Pools is the arkosic Clark and Wilson Sand. An average weighted grain density for the sand

is 2.65 g/cm^3 . The abundance of potassium feldspar in the sand, hence K^{40} , creates a background gamma radiation for the sand roughly equal to that of the shale, making the sand and shale virtually indistinguishable on the gamma ray log.

Bottom Hole Temperatures (BHT), which were recorded on open hole logs, indicate the Bruer Pool is 7°C (20°F) warmer than the Flora Pool, even though the Flora Pool is deeper. This temperature anomaly may be the result of equipment variation. A calibrated temperature survey would remove any discrepancies. A comparison of the thermal gradient determined in a previous study of the Oregon Coast Range and a gradient determined using BHT, suggest that BHT provide a good approximation of formation temperature.

Utilizing the formation water analysis determined from four different wells in the Mist Gas Field, average total dissolved solids was found to be $24,444 \text{ mg/l}$. Of the four analyses, the sample from Well CC#6 R/D2 is considered to be the most representative of the Bruer and Flora Pools formation waters. Analysis of the four samples using the Palmer System suggests that the formation water of the Cowlitz Formation is in the early stages of sea water diagenesis.

Formation water resistivity (R_w) was determined using a chemical and spontaneous potential analysis. R_w derived using chemical analysis averaged 0.175 ohm-meters and is considered the most precise. Water saturation determined using the Archie saturation equation averaged 47.5% and ranged from 26.4 to 80.0% for the zone 814 - 836 meters (2670 - 2742 feet) in CC#10. These results are similar to those determined by the Thermal Time Decay (TDT) log.

Core and geophysical log data from the field are sparse.

Porosities were obtained by analysis of sidewall cores from one well in the Bruer pool, but these values are considered too high. Conventional core analyses were also obtained for one well but it is located 5 km (3 miles) southeast of the proposed storage reservoirs. Therefore, porosities had to be derived from analysis of geophysical logs from boreholes within the Bruer and Flora Pools.

The open-hole log suite for the Bruer and Flora pools normally consisted of an acoustic and induction log, however, a neutron and density log were also run on one well in the Flora pool. TDT logs were run on all completed wells. Porosities determined from the acoustic logs are erroneously high since required compaction, residual gas, and shale correction factors can not be determined. Attempts to develop appropriate correction factors were not successful due to cycle skipping. The construction of neutron-density crossplots provided reasonable porosity values. To determine porosity from any well within the storage reservoirs, a multiple regression analysis was performed using the porosity determined from the neutron-density crossplots and resistivities from the induction logs. The cementation factor (m) and an empirical coefficient (a) from the Archie equation were determined to be 2.56 and 0.46, respectively. A maximum deviation of +5.7% and -5.3%, and an average deviation of +1.6% and -1.8% from neutron-density crossplot porosities was determined.

Using the average porosity for the reservoir and backpressure tests, a deliverability analysis was performed to determine the drainage radius and stabilization times. This analysis indicates that

one additional well is required for the Bruer pool and two additional wells will be required for the Flora pool to meet the deliverability required by Northwest Natural Gas Company. By plotting the values for deliverability on a structural map, the location of future wells may be determined.

PRELIMINARY INVESTIGATION FOR UNDERGROUND STORAGE OF PIPELINE GAS IN
THE BRUER AND FLORA POOLS, MIST GAS FIELD, COLUMBIA COUNTY, OREGON

by
Paul J. Townley

A thesis submitted in partial fulfillment of the
requirements for the degree of

MASTER OF SCIENCE

in

GEOLOGY

Portland State University

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TO THE OFFICE OF GRADUATE STUDIES AND RESEARCH:

The members of the Committee approve the thesis of Paul Joseph Townley presented May 13, 1985.

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I dedicate my work to these people.

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CHAPTER I

INTRODUCTION

When natural gas is produced in one locale and consumed in another, cheap transportation is advantageous. The most economic way to transport natural gas is through pipelines that operate as close to capacity as possible throughout the year. However, there is seldom a steady demand for natural gas, due to seasonal weather variations. Storage of natural gas at or near the point of utilization permits the pipeline to operate at capacity even during periods of low consumption, thus permitting the pipeline to accept a constant supply. This is done by injecting the pipeline gas into a reservoir during periods of low demand and withdrawing it during peak demand.

The practice of storing pipeline gas underground in depleted gas reservoirs has been used since 1915 (Goodman, 1984) and is now a mature industry. Engineering guidelines have been established to aid in the conversion of depleted gas reservoirs to storage. Katz and Tek (1981) have defined several objectives in the design and operation of gas storage reservoirs which are adopted here. They are 1) to know storage capacity for gas as a function of pressure and in some cases, time, 2) to develop a specified gas deliverability rate, and 3) to develop a monitoring system to verify where the gas resides and to ensure that excessive losses from the storage reservoir are not occurring.

Purpose and Scope

Northwest Natural Gas Company plans to develop the Bruer and Flora pools of the Mist Gas Field for pipeline gas storage. In order to ensure a smooth and rapid transition from primary gas production to pipeline gas storage and to achieve maximum storage efficiency, conditions which might affect gas injection, retention and withdrawal must be evaluated before the storage operation is actually begun.

A detailed study of the geologic, geophysical, and primary production data of wells in the Bruer and Flora pools, and wells in the immediate surrounding area provides a means for predicting gas storage behavior and potential problems. Northwest Natural Gas Company has provided access to all primary production data so that a preliminary investigation for underground storage of pipeline gas on the property could be undertaken.

The objectives of this study were to 1) define the reservoir characteristics for use in storage deliverability calculations, 2) provide a preliminary analysis for conversion of the Bruer and Flora pools to storage incorporating the three main engineering and design objectives of Katz and Tek (1981), and 3) to delineate storage characteristics that may be utilized and/or modified by accumulated field data collected throughout the life of the storage field. The well data utilized in this study include present and former producing wells in the Bruer and Flora pools as well as other nearby non-producing wells (Table I). Data were limited to that available from Northwest Natural Gas Company, Reichhold Energy Corporation, and

TABLE I

WELLS IN THE MIST UNDERGROUND STORAGE AREA

<u>WELL NAME</u>	<u>ABBREVIATION</u>
Longview Fibre No. 1	LVF#1
Longview Fibre No. 1 Redrill No. 1	LVF#1 R/D1
Columbia County No. 1	CC#1
Columbia County No. 1 Redrill No. 1	CC#1 R/D1
Columbia County No. 3	CC#3
Columbia County No. 3 Redrill No. 1	CC#3 R/D1
Columbia County No. 5	CC#5
Columbia County No. 5 Redrill No. 1	CC#5 R/D1
Columbia County No. 6	CC#6
Columbia County No. 6 Redrill No. 1	CC#6 R/D1
Columbia County No. 6 Redrill No. 2	CC#6 R/D2
Columbia County No. 32-10	CC#32-10
Columbia County No. 10	CC#10
Columbia County No. 32-3	CC#32-3
Columbia County No. 33-3	CC#33-3
Columbia County No. 44-4	CC#44-4
Columbia County No. 13-2	CC#13-2
Columbia County No. 14-2	CC#14-2

Reichhold Energy Corporation is operator on all wells. See Figure 1 for locations.

Diamond Shamrock Company.

An additional goal of the study was to provide as much information as possible about the reservoir for use in future production evaluation and reservoir engineering problems.

Location

The Mist Gas Field Undergrounds Storage Project (Figure 1) is located approximately 70 km (45 miles) northwest of Portland, Oregon in west-central Columbia County, Oregon. The study area boundaries, which coincide with the permit boundaries for the Mist Underground Storage Project, encompasses 4 square km (2.5 sq miles) approximately 2.4 km (1.5 miles) northwest of the community of Mist, Oregon.

State highway 47, which runs north-south and connects Clatskanie and Mist, is 2.4 km (1.5 miles) east of the Mist Gas Field. State highway 202, which runs east-west and connects Mist and Jewel, is 2.4 km (1.5 miles) south of the field.

Logging roads, presently used in logging operations within the gas field and surrounding lands, are paralleled by natural gas gathering lines and provide access to individual well sites.

Field History

Exploration in the Mist area was initiated in 1943, by The Texas Company (now Texaco Inc.) when a series of shallow rotary core holes were drilled. In 1946, the "Clatskanie" No. 1 (section 36, T.7 N., R.4 W.) was drilled to a depth of 1695 meters (5560 feet), approximately 11 km (7 miles) east-northeast of the Mist field (Figure 2). Very minor

Figure 2. Clatskanie No. 1 and Clark and Wilson No. 6-1 Well location map.

oil and gas shows were reported, and the well was plugged and abandoned. Later in 1946 and 1947, the Clark and Wilson No. 6-1 (section 19, T.6 N., R.4 W.) (Figure 2) was drilled to a depth of 2590 meters (8500 feet), 5 km (3 miles) east-southeast of the proposed storage reservoirs. Again, only minor gas shows were reported, leading to abandonment. It would be 30 years before another exploration program of this magnitude would be attempted in the Mist area.

Between 1977 and 1979, Reichold Energy Corporation as operator, jointly with Diamond Shamrock and/or Northwest Natural Gas, drilled three dry holes in the Mist area; CC#1, LVF#1, and CC#2 (Figure 1). Northwest Natural Gas Company, long interested in underground storage possibilities in Oregon, came in as an equal working interest partner in the Mist lease block with Reichold and Diamond Shamrock. The companies agreed to drill two more holes in the Mist prospect (Bruer, 1980).

In April 1979, CC#1 was re-entered and directionally redrilled updip to the southwest. The redrilled hole was completed May 1, 1979 in the Clark and Wilson sand (Bruer, 1980) as the first commercially producing gas well in the State of Oregon flowing dry gas at a rate of 48,140 m³/day (1700 Mcf/day) through perforations at 1075 to 1080 meters (2448 to 2460 feet).

The discovery pool, the Bruer pool, has now been located by four wells; CC#1 R/D1, CC#3 R/D1, CC#6 R/D2, and CC#32-10. The latter is a deep test well not used for production. The completion of CC#10 in October, 1979 marked the discovery of the Flora pool. CC#33-3 has also penetrated the Flora pool. The chronology of major events for the

Bruer and Flora pools are listed in Table II.

Field production, which began in December 1979 from the Bruer pool and April 1980 from the Flora pool, has not been without problems. Water production began in June 1981 in CC#10. Numerous attempts were made to end this problem by progressively setting bridge plugs up-hole in the well. This proved unsuccessful and the well was shut-in October 1982. CC#6 R/D2 and CC#33-3 have also experienced water problems, however, bridge plugs set in these wells enabled them to be put back into production.

Currently, CC#1 R/D1 and CC#10 are the only wells that have been taken out of production. CC#1 R/D1 was shut-in November 1982, due to reduced pressures. Depletion of the remaining wells is expected in the Spring of 1985 for the Bruer Pool and Winter 1985 for the Flora pool.

Methods of Investigation

First, a literature search was conducted to determine the availability of primary production data, establish the current understanding of the geology of the Mist Gas Field, and to review the current understanding of gas storage technology. Water analyses, geophysical logs, core analyses, and pressure tests were collected from more than 16 wells, including redrills. These data were evaluated and summarized, to identify what data were available for each well. Geophysical logs included: gamma ray, density, neutron, induction, spontaneous potential (SP), sonic, thermal neutron decay time (TDT), and cased reservoir analysis (CHRA); core analyses included: conventional and sidewall; pressure tests included: drill stem tests,

TABLE II

CHRONOLOGY OF THE BRUER AND FLORA POOLS

<u>DATE</u>	<u>WELL</u>	<u>EVENT</u>
5-1-79	CC#1 R/D1	Completion date.
6-8-79	CC#3 R/D1	Completion date.
8-14-79	CC#6 R/D2	Completion date.
10-8-79	CC#10	Completion date.
12-30-79	CC#6 R/D2	First production.
1-16-80	CC#1 R/D1	First production.
2-9-80	CC#3 R/D1	First production.
4-26-80	CC#10	First production.
6-4-80	CC#33-3	Completion date.
7-16-80	CC#33-3	First production.
4-11-81	CC#6 R/D2	First water production 57 LPH (15 GPH).
4-29-81	CC#33-3	First water production 19 LPH (5 GPH).
5-7-81	CC#6 R/D2	Set Schlumberger bridge plug at 713 meters (2340 feet).
6-1-81	CC#10	First water production 4 LPH (1 GPH).
8-3-81	CC#10	Set Welex bridge plug at 713 meters (2700 feet).
8-3-81	CC#33-3	Set Welex bridge plug at 795.5 meters (2610 feet).
8-14-81	CC#33-3	Found Welex bridge plug at 795 meters (2608.5 feet).
9-18-81	CC#6 R/D2	Continued water production 40 LPH (10 GPH)
10-17-81	CC#6 R/D2	Set Welex bridge plug at 708 meters (2324 feet) with continued water

production.

10-29-81	CC#32-10	Completion date.
11-6-81	CC#10	Continued water production.
1-21-82	CC#10	Set Welex bridge plug at 820 meters (2689 feet).
10-5-82	CC#10	Last gas production.
11-2-82	CC#1 R/D1	Last gas production.
12-2-82	CC#10	Installed Otis plunger lift (tubing stop set at 793 meters (2602 feet)).
12-7-82	CC#10	Swabbed 1362 liters (360 gallons) 670.5 meters (2200 feet).
12-8-82	CC#10	Swabbed
2-9-83	CC#6 R/D2	Installed plunger lift (tubing stop at 705.5 meters (2315 feet)).
2-15-83	CC#6 R/D2	Attempt to clean cement bridge at 375 meters (1230 feet) with scratcher.
2-18-83	CC#6 R/D2	Attempt to clean cement bridge at 372-324.5 meters (1220-1240 feet) with 48 mm (1.890 inch) broach.
2-22-83	CC#6 R/D2	Attempt to run BHP. Restricted at 417.5 meters (1370 feet).
3-1-83	CC#6 R/D2	Pull tubing to clean out plugs (no restrictions found).
3-3-83	CC#6 R/D2	Set Welex bridge plug at 700 meters (2298 feet).
3-7-83	CC#6 R/D2	Swab and place into production at 22,654 m ³ /d (800 Mcf/d).

LPH=Liters Per Hour

GPH=Gallons Per Hour

BHP=Bottom Hole Pressure

back pressure tests (four point open flow tests), and semi-annual closed pressure tests.

Next, pertinent geophysical logs and core data were evaluated and the reservoir characteristics of the Bruer and Flora pools determined. These reservoir characteristics were then used to calculate the deliverability and drainage radius, so that well spacing could be determined. Finally, recommendations were made for the containment and observation of the pipeline gas.

CHAPTER II

GEOLOGY

Regional Geology

The proposed storage field is located at the northern end of the Oregon Coast Range (Figure 3), between the Continental shelf to the west and the Willamette Lowland to the east (Armentrout and Suek, 1985). The Fields location is further defined utilizing a Regional Bouguer Gravity Anomaly map (Armentrout and Suek, 1985), in which an Eocene volcanic core is indicated by Bouguer gravity values greater than zero mgals and Cenozoic Sedimentary basin-fill is represented by Bouguer gravity measurements less than zero mgals (Figure 4).

The Nehalem Arch, a segment of the anticlinal trend of the northern Coast Range Uplift and the Willapa Hills Uplift, separates the Astoria Basin to the west, and the Willamette and Centralia-Chehalis Basins to the east. The latter is a sub-basin of the Puget Basin. The Mist Gas Field occurs on a small, highly faulted northwest-southeast-trending anticline in the Nehalem sub-basin of the Willamette Basin (Bruer, 1980; Armentrout and Suek, 1985). Faults in the region strike northwest, northeast, and east forming a conjugate shear pattern. Linear trends defined by analysis of aerial photographs and side-looking radar image data correspond to known fold structures or faults, while others correspond to formation boundaries (Armentrout and Suek, 1985).

Figure 3. Mist Gas Field location map. Modified from Armentrout and Suek (1985).

Figure 4. Regional Bouguer Gravity Anomaly map. Modified from Armentrout and Suek (1985).

Site Geology

The Mist Gas Field reservoirs, including those to be converted to storage of natural gas, are part of the Cowlitz Formation (Bruer and others, 1984; Armentrout and others, 1983). The Cowlitz Formation consists of an eastern deltaic facies grading westward to a marine facies. The Mist Gas Field is entirely within the marine facies.

Three sand intervals were penetrated in the Texaco-Clark and Wilson 6-1 well (C&W#6-1) (Figure 5). They have been previously informally referred to by Newton (1979) as the upper Cowlitz sand, the intermediate "Clark and Wilson sand", and the lower Cowlitz sand. Recently the stratigraphic boundaries of the Cowlitz Formation and Yamhill Formation have been relocated. Bruer (1980), Armentrout and others (1983), and Bruer and others (1984) refer to the lower Cowlitz sands as the "lower Yamhill sand" of the Yamhill Formation. This usage will be employed throughout this study.

The upper Cowlitz sand has not been located within the proposed storage area, suggesting either non-deposition or removal by erosion as proposed by Bruer (1980) and H.J. Meyer (personal communication, 1984). The lower Yamhill sand, which was not intersected by the CC#32-10 well, may occur at depths greater than present drilling, or also may not be present (Bruer and others, 1984). The proposed reservoir storage sand is the intermediate Clark and Wilson sand.

Armentrout and Suek (1985) suggest that the dominance of feldspathic-quartzose grains and relative absence of volcanoclastic grains in the Cowlitz sands result in their being less susceptible to

Figure 5. Subsurface correlation of six Mist Gas Field wells. Modified from Bruer and others (1983).

the diagenetic development of pore-filling authigenic minerals than the more lithic sands of other units and less well-sorted depositional environments in which less sorting of sediment is characteristic. They further suggest that the producibility of the Clark and Wilson sand is directly related to its mineralogy and depositional environment.

Stratigraphy. The following discussion of the stratigraphy of the Columbia County area was taken from the recent publications of Armentrout and others (1983) and Armentrout and Suek (1985). Age assignment and correlations follow the stratigraphic synthesis of Armentrout and others (1983). Stratigraphic correlation and intra-formational facies differentiation, delineation of three-dimensional subsurface volcanic profiles, and complications caused by structure, are a few of the problems encountered in interpreting the stratigraphy of the Mist area.

Armentrout and Suek (1985) have divided the stratigraphic sections of northwestern Oregon into four unconformity-bounded sequences, each representing a tectonically controlled depositional cycle (Figure 6).

Surrounding the Siletz River volcanic core rocks is a belt of Middle Eocene through Lower Miocene marine sedimentary rocks with subordinate interbedded volcanic rocks. This mid-Tertiary unconformity-bounded package consists of fore-arc sedimentary rocks and locally derived arc-related volcanic rocks. These rocks were deposited in a shelf-margin basin where they prograde onto and transgress across the Lower to middle Eocene unconformity-bounded sequence. Rocks of the mid-Tertiary sequence are assigned to the Yamhill Formation, Tillamook

SERIES		WEST COAST FORAMINIFERA	COLUMBIA COUNTY AREA, OREGON
PLEISTOCENE		LOCALLY DEFINED UNITS	FLUVIAL DEPOSITS
PLIOCENE			TROUTDALE FORMATION
MIOCENE	UPPER		PAMONA MEMBER SADDLE MTN. BASALT
	MIDDLE	LUISIAN STAGE	FRENCHMAN SPS. MBR. WANAPUM BASALT
		RELIZIAN STAGE	GRANDE RONDE BASALT
	LOWER	SAUCESIAN STAGE	
OLIGOCENE	UPPER	ZEMORRIAN STAGE	SCAPPOSE FORMATION
	LOWER	REFUGIAN STAGE	PITTSBURG BLUFF FORMATION
EOCENE	UPPER	NARIZIAN STAGE	KEASEY FORMATION
			GOBLE VOLCANICS
			COWLITZ FORMATION
	MIDDLE	ULATIZIAN STAGE AND OLDER	YAMHILL FORMATION
			SILETZ RIVER VOLCANICS

Figure 6. Stratigraphic column of the Columbia County area. Modified from Armentrout and Suek (1985).

Volcanics, Cowlitz Formation, Goble Volcanics, Keasy Formation and Pittsburg Bluff Formation. These formations generally have conformable contacts within depositional lows and unconformable contacts along structural highs. The sand reservoirs of the Mist Gas Field occur within the Cowlitz Formation. Regional deformation during late early to early middle Miocene uplifted this mid-Tertiary sequence, which was subsequently differentially eroded.

The third unconformity-bounded sequence consists of basalt flows, and marine and fluvial sedimentary rocks. These rocks were deposited within topographic and structural lows formed during late early to early middle Miocene deformation. The basalts are flows of the Columbia River Basalt Group. These basalts were extruded in central and eastern Oregon and Washington and flowed westward where they became interbedded with the fluvial and marine sediments along the Miocene coastline. The sedimentary rocks are assigned to the Scappoose and Astoria Formations (Armentrout and Suek, 1985).

Late Miocene deformation folded the older Tertiary rocks of the Coast Ranges of Oregon and Washington restricting deposition during the Pleistocene to local downwarps along river valleys and coastal embayments. The Pliocene-Pleistocene Troutdale Formation consists of fluvial gravels and sands, which were deposited along the Columbia River Valley in the Columbia River downwarp where it crosses the Oregon Coast Range-Willapa Hills uplifts (Armentrout and Suek, 1985).

The differing geologic age assignments by these and other authors reflect the use of different correlation frameworks of local units with the worldwide geologic time scale. The most recent assignment of local

units is provided by Armentrout and others (1983).

CHAPTER III

RESERVOIR CHARACTERISTICS

Introduction

The location of every gas pool is the result of complex interrelated geologic conditions. Each reservoir is unique in its details, but general relations may be seen that permit broad classifications of the major elements that control the location of a reservoir. The first step in converting a depleted gas reservoir to storage is understanding the reservoir in which the gas will be stored. A gas reservoir consists of four essential elements.

1) The reservoir trap is the element that holds the gas in place in the pool. A trap generally consists of an impervious cover overlying and sealing a porous and permeable rock that contains the gas. The lower boundary of the reservoir is, either wholly or partly, the plane of contact of the gas with the underlying body of water upon which the pool rests. It is known as the gas-water contact.

2) The composition, texture, and its continuity or lack of continuity are of prime interest in the reservoir rock, or containing materials.

3) The pore space or void space is expressed as a fraction or percentage of the total volume of rock and it is that portion of the reservoir rock that is available for migration, accumulation, and storage of gas. The measure of the ease with which the fluids may move through the interconnected pores of the rock is permeability. Porosity

and permeability are of special interest because they determine the capacity of the reservoir rock to both hold and yield gas, and control the rate of injection and production.

4) The fluid content consists of the water and gas that occupy the effective pore space within the reservoir rock. The gas is concentrated into pools, but most of the reservoir pore space outside the pool contains water with dissolved gas that is in concentration measured in parts per million. The concentration of gas into pools and the presence of fluid pressure gradients provide evidence of past fluid movements.

These generalizations about the nature of a gas reservoir apply to the Bruer and Flora pools of the Mist Gas Field. The next five sections are concerned with the details of these elements so that deliverability and drainage radius calculations may be performed.

Reservoir Trap

Mist Gas Field traps consist of closure against faults, shale-encased sand stratigraphic traps, and canyon-fill shale seals of erosionally truncated reservoirs (Armentrout and Suek, 1985). The trapping mechanism for the Clark and Wilson sand of the Bruer (CC#1 R/D1, CC#3 R/D1, C#6 R/D2, section 10, T.6 N., R.5 W.) and Flora (CC#10 and 33-3 section 3, T.6 N., R.5 W.) pools is closure against down-to-the-south and down-to-the-northwest faults (Figure 7) (H.J. Meyer, personal communication, 1984). The faults are truncated at the base of the overlying Keasey Formation (Armentrout and Suek, 1985) indicating that they formed as part of an early late Eocene

MIST GAS FIELD CROSS SECTION

REC Col Co 32-3

Projected

S3 T6N R5W

REC Col Co 33-3

S3 T6N R5W

REC Col Co 3

S10 T6N R5W

REC DSC LF #1

S11 T6N R5W

N20W

S20E

Sea Level

Keasey Fm

Refugian

Narizian

Gowittz Fm

Q & W Sand

Narizian Volcanics and Sediments

Water

ONGDC

HJM 5/83

500 FT

162

1000 305
FEET METERS

Figure 7. Geologic cross section of the Bruer and Flora Pools.

deformational phase. Using data from wells CC#6 R/D1, R/D2 and CC#3, and regional subsurface correlations, Bruer (1980) interpreted the Keasey Formation to overlies the Cowlitz Formation unconformably where the Keasey Formation fills topographic lows eroded into the Cowlitz Formation. The Keasey Formation provides a seal where the shale-encased Clark and Wilson sand is truncated by the erosional surface at the top of the Cowlitz Formation.

Overlying the Middle to late Eocene coastal plain and shelf-basin sequence are late Eocene transgressive shales of the upper Cowlitz Formation and Keasey Formation. These shales create a local seal for the gas reservoirs, while the temporal equivalents, such as the Lincoln and Blakely Formations of Washington, constitutes a regional seal (Armentrout and Suek, 1985).

The cuttings of the Cowlitz Formation are brownish gray, micaceous, carbonaceous silty mudstone, laminated mudstone and claystone with some authigenic pyrite, whereas those of the Keasey Formation are gray, tuffaceous, micro-micaceous siltstone and mudstone (Kadri, 1982). The shale of the Keasey Formation in particular is very tuffaceous. Armentrout and Suek (1985) indicated that montmorillonite had been identified by x-ray diffraction and suggested that the Keasey Formation contained abundant expandable clay minerals. Thomas (1984) states that smectite is generally present in abundance in samples derived from volcanic terrains.

The mineral composition of shales varies over a wide range, and shale densities range between 2.20 g/cm³ and 2.85 g/cm³. Typical values for different clay minerals are given in Dresser (1982) (Table

III). By examining the density log of CC#10 (Appendix A) in the shale above the Clark and Wilson sand, shale densities range between 2.20-2.40 g/cm³. This lies between the range of 2.20-2.70 g/cm³ given for the typical values of smectite clays, further suggesting that the clays in the shales overlying the Clark and Wilson sand are smectites. Smectite clays as caprock provide an excellent seal.

Reservoir Rock

The reservoir rock of the Bruer and Flora pools is the Clark and Wilson sand of the middle to late Eocene Cowlitz Formation. In outcrop, the Clark and Wilson sand is a well-sorted, fine to medium-grained friable arkosic sand with some cross-stratification and lignitic clasts (Armentrout and Suek, 1985). In addition, Kadri (1982) states that the Clark and Wilson sand is invariably laminated and that the laminae are entirely composed of large muscovite and biotite flakes, and/or carbonized plant material. Some of the carbonaceous laminae are as much as 3 to 4 mm (0.1-0.15 inch) thick. Van Atta, (personal communication, 1984), stated that the sand is low in clays, and in a scanning electron microphotograph of a core from the Clark and Wilson sand, no clay was found in the pore throats, although, some very small smectite crystals were found on grain surfaces, suggesting that the smectite crystals were authigenic. Kaolinite has been identified in samples collected from outcrops. Van Atta (personal communication, 1984) suggests that the kaolinite is a product of weathering, and that the original kaolinite content in the sand was very low.

Van Atta (1971) constructed a quartz-feldspar-lithic (Q-F-L) plot

TABLE III
TYPICAL DENSITIES OF CLAY MINERALS

<u>MINERAL</u>	<u>DENSITY</u>	<u>REMARKS</u>
Chlorite	2.60-2.96	Low water absorbtive properties
Halloysite	2.55-2.56	Completely evacuated
	2.76-3.00	Muscovite
	2.70-3.10	Biotite
	2.642-2.688	No absorbed water
Kaolinite	2.609	Theoretical density
	2.60-2.68	Extensive literature
	2.63	Most frequently quoted
Palygorskite	2.29-2.36	Limited data
Sepiolite	2.08	Limited data
Smectite	2.20-2.70	Nontronite essentially
	2.24-2.30	Saponite dehydrated
	2.348	
	2.20-2.70	Montmorillonite
	2.53	Low-iron smectite
	2.74	3.6% iron content
Vermiculite	No precise data; oven-dried similar to biotite-mica	

Note. Densities are in g/cm³. Modified from Dresser (1982).

and a sand-clay-silt (S-C-S) plot of the Cowlitz Formation sand from outcrop samples collected within the Nehalem River Basin. These Q-F-L and S-C-S plots are shown in Figures 8 and 9, respectively. Van Atta (1971) divides the framework grains of these samples of the Cowlitz Formation sand into; quartz, feldspars, rock fragments, glass, and micas. Both monocrystalline and polycrystalline quartz are found, with the exception of chalcedony, the abundance of quartz exceeds feldspar by a small amount in the sand. Both potassium and plagioclase feldspar are found, with potassium feldspar slightly more abundant than plagioclase. Potassium feldspar is predominantly orthoclase but microcline is present in all samples. Plagioclase feldspar varies in composition from albite to andesine. Rock fragments are mainly chert and microgranitic rock fragments with some foliated metamorphic rock fragments and minor volcanic porphyries. Volcanic glass is virtually absent (less than one percent). Micas consist of both muscovite and biotite in approximately equal proportions. Minerals with a specific gravity greater than 2.96 g/cm^3 make up from a few tenths of a percent to about 1.5 percent of the Cowlitz Formation sand.

A weighted grain density of the Cowlitz Formation sand was determined using the average percent composition of 12 outcrop samples determined by Van Atta (1981) and the description of individual mineral composition determined by Van Atta (1971). Densities of the individual minerals were obtained from Berry and Mason (1959)(Table IV). The calculations and results are shown in Appendix B. The average grain density was determined to be 2.67 g/cm^3 while the weighted average grain density was 2.65 g/cm^3 . The weighted average grain density is

Figure 8. Size classification, Cowlitz Formation rocks (after Folk, 1954). Modified from Van Atta (1971).

Figure 9. Classification of sandstone, siltstone, and mudstone for the Cowlitz Formation (after Folk, 1968). Modified from Van Atta (1971).

lower than the average grain density, since the low concentrations of the higher density potassium feldspar (2.69 g/cm^3) and micas (2.80 g/cm^3), is taken into account by the weighting.

TABLE IV
COWLITZ FORMATION MINERAL DENSITIES

<u>COMPONENT</u>	<u>AVERAGE</u> ¹	<u>RANGE</u> ¹	<u>DENSITY</u> ²
Rock fragments	11%	4-25%	2.65
Quartz	46%	29-63%	2.65
Potassium Feldspar	21%	6-32%	2.56
Plagioclase Feldspar	22%	11-40%	2.62-2.76 (avg. 2.69)
Glass	---	0-1%	
Mica	9%	3-20%	2.8-2.9 muscovite 2.8-3.4 biotite

(1) Van Atta, 1981

(2) Berry and Mason (1959). Densities given in g/cm^3 .

Further, in the Gamma ray log of CC#10 (Appendix A) it can be seen that gamma ray counts do not decrease when going from shale to sand. This is not a result of the sand being shaley but rather due to the sand being arkosic. Arkose contains significant amounts (approximately 3.32%) of K^{20} , which is contained in the feldspars and micas (Brownlow, 1979). A portion of the potassium in these minerals is generally the unstable isotope K^{40} . Because this isotope naturally emits gamma rays and because of the relatively large amounts of K^{40} , the total background radiation of the sand is roughly equal to that of the shale, therefore, making them indistinguishable with this technique.

Reservoir Temperature

Formation temperature is used to calculate various reservoir parameters, such as water resistivities and gas compressibility factors. Also, temperature variations from the undisturbed condition can be used to detect gas expansion points caused by leaks from the casing or gas flow behind the pipes (Katz and Coats, 1968). Bottom hole temperatures (BHT), measured during logging operations by maximum reading thermometers, are available from the log headings of all geophysical logs in the Mist Gas Field. BHT within the proposed storage area are listed in Table V and plotted in Figure 10. BHT is generally lower than true or static formation temperature due to cooling of the formation while drilling, or the circulating drilling mud prior to logging. The plot (Figure 10) shows that the Bruer pool is approximately 7°C (20° F) warmer than the Flora pool even though the Flora pool is deeper than Bruer pool. This difference may be attributed to Schlumberger logging all Flora pool wells and Welex logging all Bruer pool wells, a calibrated temperature survey would reveal if this difference is a result of equipment error or if this is an actual anomaly. Thus validating all temperature records.

The thermal regime in the Mist area is rather complex, as suggested in Figure 11. The rocks underlying the Cowlitz Formation conduct heat from the mantle. The heat is then absorbed by the waters of the Clark and Wilson sand, which acts as a heat sink (Meyer, personal communication, 1984). As a result convection cells are generated within the sand. Gas overlying the sand acts as an insulator, creating a higher thermal gradient for the gas pools as

TABLE V
BOTTOM HOLE TEMPERATURES

<u>WELL</u>	<u>BHT</u> °C/°F	<u>LOGGER</u>	<u>DATE</u> <u>RECORDED</u>	<u>RECORDED</u> <u>DEPTH</u> meters/feet
LVF#1	47/117	W	10-14-77	939/3081
LVF#1 R/D1	36/96	S	5-9-80	853/2799
CC#1	48/118	W	9-3-77	946/3105
CC#1 R/D1	48/119	W	4-27-79	946/3105
CC#3	47/116	W	5-29-79	894/2932
CC#3 R/D1	48/118	W	6-4-79	912/2993
CC#5	48/119	W	6-28-79	947/3108
CC#5 R/D1	47/117	W	7-7-79	953/3127
CC#6	48/118	W	7-26-79	1055/3462
CC#6 R/D1	45/113	W	8-3-79	900/2955
CC#6 R/D2	46/115	W	8-9-79	798/2620
CC#32-10	46/115	W	9-21-81	851/2792
CC#32-10	56/132	W	10-30-81	2379/7806
CC#10	43/109	W	10-5-79	908/2981
CC#32-3	31/87	S	5-1-80	1031/3384
CC#33-3	33/92	S	6-1-80	846/2777
CC#44-4	32/89	S	5-26-80	933/3060
CC#13-1 R/D1	24/75	S	8-13-81	935/3069
LVF#12-33	41/106	W	9-11-81	731/2399
CC#2	47/116	W	7-16-78	846/2775

W = Welex
S = Schlumberger

Figure 10. Bottom hole temperature versus depth of wells in the underground storage area.

Figure 11. Simplified thermal gradient profile, typical of the underground storage area.

shown in Figure 12. Formations above the sand both insulate and conduct heat from the sand.

Blackwell and others (1978) determined the thermal gradient for the Oregon Coast Range to be $23.6^{\circ} \text{ C/km} + 2^{\circ} \text{ C}$. Meyer (personal communication, 1984) determined the thermal gradient above the Clark and Wilson sand to be 40° C/km and below the Clark and Wilson Sand $18\text{--}19^{\circ} \text{ C/km}$, with an overall gradient of 21° C/km (Figure 11). These gradients were determined from the BHT of open hole logs. The results suggests that the BHT from the open hole logs are fairly consistent with the gradient determined by Blackwell and others (1978), and thus will be considered the same as formation temperature throughout this study. BHT determined in the Clark and Wilson sand will be considered constant at any depth within the sand, although there may be a variation of several degrees due to convection.

Reservoir Fluids

Introduction . Water analyses are used in a variety of ways connected with the exploration and development of gas pools. Probably the most important of these uses is their application to the interpretation of electric well logs, where the electrical resistivity of the formation water is determined. Since formation water varies from zone to zone, water analysis may also be used to tell whether the water produced with the gas comes from the bottom of the well and is part of the formation water of the reservoir rock, or whether it is shallower formation water entering the well because of improper cementing of the casing or leaks due to breaks in the casing. In

addition, it is also necessary to know the effects of injected water, both on the minerals in the reservoir rock and on the equipment used in salt water disposal, where corrosion and scaling are potential problems.

Water analyses were conducted on the formation waters of four wells in the Mist Gas Field, by two separate organizations; the Oregon State Department of Environmental Quality (OSDEQ) and the MOGUL Corporation. The total dissolved solids (TDS) and ion concentrations determined in these analyses are listed in Table VI and VII, respectively. TDS averaged 26,444 mg/l and ranged from 24,582 to 27,598 mg/l. The analysis of CC#2 (non-productive) was performed by the OSDEQ to determine the potability of the formation water and the analysis of CC#6 R/D2 (Bruer pool), LVF#12-33 (Newton pool), and CC#13-1 (Diamond pool) were conducted by The MOGUL Corporation for Northwest Natural Gas Company.

The analyzed samples were collected by three different methods: drill stem test (DST), swabbing, and from the down stream separator (DSS). The sample from CC#2 was obtained from a DST. Sampling of this type is of good quality, although contamination by drilling fluids may occur during collection, it does not seem significant here.

The sample from CC#13-1 was obtained by swabbing. Swabbing is the mechanical removal of well fluids using a rubber cup attached to a wireline. The quality of this sample is considered questionable since the water in the well from which it was collected may not have been thoroughly flushed before collection. A reliable sample may be obtained once drilling has been completed, by swabbing the well for 8

TABLE VI
WATER ANALYSIS SPECIFICS

<u>WELL</u>	<u>POOL</u>	<u>ANALYSIS</u> <u>PERFORMED BY</u>	<u>SAMPLE</u> <u>SOURCE</u>	<u>TDS</u>
CC#6 R/D2	Bruer	MOGUL	DSS	26,228
CC#2	Non-prod.	OSDEQ	DST	27,370
LVF#12-33	Newton	MOGUL	DSS	24,582
CC#13-1	Diamond	MOGUL	Swab	<u>27,598</u>
Average				26,444

DSS= Downstream Separator

DST= Drill Stem Test

Swab= Swabbing

TDS= Total Dissolved Solids (mg/l)

OSDEQ= Oregon State Department of Environmental Quality

MOGUL= Mogul Corporation

TABLE VII
WATER ANALYSIS ION CONCENTRATIONS

<u>WELL</u>	<u>Na⁺</u>	<u>K⁺</u>	<u>Cl⁻</u>	<u>Mg⁺⁺</u>	<u>Ca⁺⁺</u>	<u>SO₄⁻</u>	<u>I⁻</u>
CC#6 R/D2	8500	40	15,500	87	1680	<1.0	ND
CC#2	7700	66	15,600	152	1130	33.5	39.0
LVF#12-33	6005	75	14,600	160	1074	2.0	ND
CC#13-1	8200	ND	14,800	270	1357	ND	ND
Sea Water	<u>Na⁺ + K⁺</u> 11,000		19,350	1300	420	2690	ND

ND = Not Determined

All measurements in mg/l.

hours or more.

Samples obtained from the downstream separator are considered to be the most reliable, since the water from these samples is derived entirely from the perforated zone and is not influenced by surrounding waters. CC#6 R/D2 and LVF#12-33 were the only samples taken from the downstream separator. Because of the high quality, and proximity of the CC#6 R/D2 well to the pools in this study, and since no analysis has been performed on the water of the Flora pool, values computed from the analysis of CC#6 R/D2 are considered to be most representative of the Bruer and Flora pools.

Origin of Formation Water . The Palmer system (Levorsen, 1967) was used in interpreting the history of the water analysis samples. Palmer groups together radicals that are either chemically similar or geologically associated, by the combination of four properties. They are:

- 1) Primary salinity, strong acids combined with primary bases.
- 2) Secondary salinity, strong acids combined with secondary bases, also known as permanent hardness.
- 3) Primary alkalinity, weak acids combined with the primary bases.
- 4) Secondary alkalinity, weak acids combined with secondary bases.

The character of the brine may then be described in terms of its reaction values by the equation;

$$\text{reaction value} = (\text{amount by weight (mg/l)}) * (\text{reaction coefficient}) \quad (1)$$

Reaction coefficients were taken from Levorsen (1967) (Table VIII).

Next, these reaction values were used to determine the relation between

TABLE VIII
REACTION COEFFICIENTS

<u>ION</u>	<u>COEFFICIENT</u>
Sodium, Na^+	0.0434
Potassium, K^+	0.0256
Calcium, Ca^{++}	0.0499
Magnesium, Mg^{++}	0.821
Sulfate, SO_4^-	0.0208
Chloride, Cl^-	0.0282

Mist Gas Field waters and other fields of varying ages, by plotting the composition of the dissolved salts in percentage reaction values of $\text{Na}^+ + \text{K}^+$, Ca^{++} , and Mg^{++} (Figure 13). Calculations for reaction values are shown in Appendix C. The normal evaporation direction of sea water, shown by the solid line on Figure 13, trends directly into the Tertiary water analyses, suggesting that these waters represent the early stages in the diagenesis of sea water. This early phase is marked by the precipitation of magnesium and calcium sulfate and carbonates, by a base exchange with clay sediments (de Sitter, 1947). The reaction values determined for the Mist Gas Field waters fall into this range, suggesting that the waters are in this early phase.

The concentration of several oil field brines compared with the Na^+ reaction values are shown in Figure 14 (de Sitter, 1947). The line extending downwards from the position of seawater represents dilution by meteoric water. The heavy line extending upwards from the position of sea water represents the theoretical change in the concentration of sea water, when all salts other than NaCl are extracted, again suggesting that these waters represent "fossil" sea water in an early stage of diagenesis.

Figure 13. Tertiary diagram of reaction value percentages. Dissolved salts include $\text{Na}^+ + \text{K}^+$, Ca^{++} , and Mg^{++} . Modified from de Sitter (1947).

Figure 14. The concentration of various oil field waters and Mist Gas Field waters, in relation to the Na^+ reaction values. Modified from de Sitter (1947).

Formation Water Resistivity . Formation water resistivity (R_w) is an important interpretation parameter necessary for the determination of water saturation (S_w) and porosity from electrical logs. R_w may be determined by four methods; water catalogs, direct measurement, chemical analysis, and from spontaneous potentials (SP). Since the Mist Gas Field is small and new, there are at present no water catalogs for the field. Also, no direct measurements of R_w have been recorded. Therefore, R_w was determined for CC#2, CC#6 R/D2, LVF#12-33, and CC#13-1 using chemical and SP analyses. Water resistivity was also determined for CC#10 using the SP method.

The most precise values of R_w were derived from the water chemical analysis. First, total NaCl equivalent concentrations were determined for each of the four samples. This was done by first multiplying the concentration of each ion by its weighting factor as determined from Schlumberger Chart GEN-8 (Schlumberger, 1979) to arrive at the equivalent NaCl concentration for each ion. Next, the individual ion equivalent NaCl concentrations were summed to arrive at the total equivalent NaCl concentration. Once the total equivalent NaCl concentration were determined, they were then plotted with formation temperature on Schlumberger chart GEN-9 (Schlumberger, 1979) to obtain R_w at formation temperature. Results and calculations are shown in Table IX and Appendix D, respectively.

The second method used to determine R_w , utilizes the SP curve to derive R_w at formation temperature. This procedure is more complicated and is outlined in Schlumberger (1972), utilizing Schlumberger charts GEN-9, SP-1, SP-2, SP-3 (Schlumberger, 1979). The results and

calculations are also shown in Table IX and Appendix D.

TABLE IX
WATER RESISTIVITY RESULTS

WELL	DEPTH meters/feet	BHT °C/°F	TOTAL NaCl EQUIVALENT mg/l	Rw (chemical) ohm-meter	Rw (SP) ohm-meter
CC#6 R/D2	798/2620	46/115	25,948	0.16	0.145
CC#2	846/2775	47/116	24,900	0.16	0.11
LVR#12-33	731/2399	41/106	22,125	0.205	0.037
CC#13-1	935/3069	43/110	<u>24,879</u>	<u>0.175</u>	<u>0.147</u>
Average			24,463	0.175	0.11

Rw obtained from the water analyses method averaged 0.175 ohm-meters and ranged from 0.16 to 0.205 ohm-meters. The resistivity for CC#6 R/D2 was 0.16 ohm-meters. Rw obtained from the SP method averaged 0.11 ohm-meters and ranged from .037 to 0.147 ohm-meters.

Water Saturation . In a formation containing gas, which is an electrical insulator, the resistivity is not only a function of the formation factor (F) and water resistivity (Rw), but also of the water saturation (Sw). Sw is the fraction of the pore volume occupied by formation water, and (1-Sw) is the fraction of pore volume occupied by hydrocarbons. Sw was calculated for the CC#10 well from Archie's saturation equation (Schlumberger, 1972);

$$S_w^n = (F)(R_w)/R_t \quad (2)$$

where n is the saturation exponent, equal to two and Rt is the true resistivity of the formation of interest. Rt is read directly from the deep induction curve of the log. The use of the Archie saturation

equation assumes that F is the same in the water-bearing zone as it is in the gas saturated interval. The equation is a good approximation in clean formations having a fairly regular distribution of porosity (i.e. no vugs or fractures), which is the case at Mist (see Chapter III, Reservoir Rock).

Using the empirical coefficient (a) and cementation factor (m), determined in the porosity analysis (see Chapter III, Reservoir Pore Space) of the Clark and Wilson sand, S_w averaged 47.5% and ranged from 26.4 to 80.0%, for the zone 814-836 meters (2670-2742 feet) in CC#10. Computed S_w values are listed in Appendix E and S_w plotted against depth is shown in Figure 15.

Gas . The natural gas found in the Bruer and Flora pools of the Mist Gas Field is non-associated (free gas) dry natural gas. The composition, specific gravity, and heating value of the gas varies, depending on the individual pool and well, and also as it is withdrawn from the reservoirs during production. The composition and specific gravities, with respect to time, are shown in Appendix F. The heating value of the Mist Gas Field gas varies from 27-29 KJ/m³ (890-960 Btu cu/ft), which is approximately 260 therms/m³ (9.2 therms/Mcf) (Oregon State Department of Geology and Mineral Industries, 1983).

The source rock for the in situ gas is still in debate. Armentrout and Suek (1985), suggest the gas has migrated into the field, since the gas is thermally mature and the surrounding shales of the Cowlitz Formation have relatively low vitrinite reflectance values. Suggestions of a possible source for the thermal gas are the Astoria Basin (Bruer, 1980) or the northern Willamette Basin (Armentrout and

Figure 15. Calculated water saturation versus depth for the CC#10 well.

Suek, 1985).

Petroleum source rock evaluations of outcrop rocks in Oregon, including the Mist area, contain < 1.0% organic carbon, which is predominantly of type III kerogen (Law and other, 1984). Thermal maturities with respect to hydrocarbon generation range from immature (young rock) to post mature (old rock), with most being immature to marginally mature. This indicates that these rocks were capable of generating gas and little or no oil.

Reservoir Pore Space

Introduction . Porosity and permeability may be determined directly from cores and indirectly from geophysical well logs. At Mist, two types of coring were performed from which porosity and permeability were determined; conventional and sidewall coring. Open hole logs from which a determination of porosity was attempted for the storage pools includes: neutron, density, sonic, and electric logs. In the producing zone of completed wells, porosities were determined by Cased Hole Reservoir Analysis (CHRA) using Thermal Decay Time Logs (TDT) (Schlumberger, 1980 and 1981). Analysis of the porosity and permeability of the Bruer and Flora pools began with the gathering, reviewing, and categorizing of core and geophysical log data. This organization permitted a preliminary determination of what data was available and most significant. This organizational summary is shown in Table X.

Core analysis . Conventional core measurements are considered the closest to actual reservoir porosities and permeabilities. Reese

TABLE X
POROSITY SOURCE SUMMARY

<u>WELL</u>	<u>ELECTRIC</u> <u>LOGS</u>	<u>OPEN HOLE</u> <u>RADIOACTIVE</u> <u>LOGS</u>	<u>VELOCITY</u> <u>LOGS</u>	<u>CASED HOLE</u> <u>RADIOACTIVE</u> <u>LOGS</u>	<u>CORES</u>
LVF#1	IES		CAV		
LVF#1 R/D1	DIL/SFL				
CC#1	IES		CAV		SIDEWALL
CC#1 R/D1	IES		CAV	TDT/CHRA	
CC#3	IES		CAV		
CC#3 R/D1	IES		CAV	TDT/CHRA	
CC#5	IES		CAV		CONVENTIONAL
CC#5 R/D1	IES				
CC#6	IES		CAV		CONVENTIONAL
CC#6 R/D1	IES		CAV		
CC#6 R/D2	IES		CAV	TDT/CHRA	
CC#32-10	IV/DIGL	GR	CAV		
CC#10	DIGL	GR NEUTRON DENSITY	CAV	TDT/CHRA	
CC#32-3	DIL/SFL		BHC		CONVENTIONAL
CC#33-3	DIL/SFL		BHC	TDT/CHRA	
CC#44-4	DIL/SFL		BHC		

IES = Induction Electric Survey

DIL/SFL = Dual Induction/Spherically Focussed Log

IV = Induction Velocity Log

DIGL = Dual Induction Guard Log

CAV = Compensated Accoustic Velocity Log

BHC = Borehole Compensated Sonic Log

TDT = Thermal Neutron Decay Time Log

CHRA = Cased Hole Reservoir Analysis

conventional coring was attempted on CC#6, CC#32-3, and CC#5 but was not successful (Oregon State Department of Geology and Mineral Industries, 1979 and 1980). The friable nature of the Clark and Wilson sand has precluded retrieval of typical subsurface samples in the underground storage area. Only a few abnormally indurated zones within the sand have been successfully cored. Analyses have not been performed on these atypical samples.

Although not located in the proposed storage reservoirs, nor in the Clark and Wilson sand, conventional core analyses were performed on the Clatskanie No. 1 and Clark and Wilson No. 6-1. The results for these wells are listed in Appendix G. The Clatskanie No.1 well did not locate the Clark and Wilson sand. However, the Clark and Wilson sand was identified in the C&W#6-1 well, and the retort method (The Texas Company, 1947) was used by the Texas Company laboratory to determine porosity and permeability from the cores. Three sections in the C&W#6-1 well were cored, providing 23 porosity and permeability values (Table XI). Porosity averaged 26.9% and ranged from 22.8 to 32.2%. Permeability averaged 0.36 um^2 (364.0 md) and ranged from 0.04 to 1.28 um^2 (45.2 to 1302.3 md).

Forty sidewall cores were recovered from CC#1. Porosity and permeability values for these cores were obtained from a laboratory analysis performed by Core Laboratories and are shown in Appendix H. One section in the CC#1 well was sidewall cored within the Clark and Wilson sand, providing nine porosity and permeability values (Table XII). The values of porosity averaged 32.1% and ranged from 22.2 to 33.7% (excluding the value of 22.2%, the range was 30.1 to 33.7%), and

TABLE XI

C&W#6-1 CONVENTIONAL CORE RESULTS

<u>DEPTH</u> (feet)	<u>AVERAGE</u> <u>POROSITY</u> percent	<u>POROSITY</u> <u>RANGE</u> percent	<u>AVERAGE</u> <u>PERMEABILITY</u> um ² /md	<u>PERMEABILITY</u> <u>RANGE</u> um ² /md
3082-3122	28.0	24.1-32.2	0.52/529.1	0.04-1.28/ 45.2-1302.3
3219-3239	26.0	23.1-29.4	0.20/201.1	0.06-0.39/ 56.4-398.5
3285-3304	26.2	22.8-29.0	0.27/279.0	0.07-0.49/ 73.9-499.0
AVERAGE	26.9		0.36/364.0	

NOTE: Values determined from a total of 23 plugs. The number of plugs for each section from uphole to downhole are 10, 7, 6, respectively.

TABLE XII

CC#1 SIDEWALL CORE RESULTS

<u>DEPTH</u> (feet)	<u>AVERAGE</u> <u>POROSITY</u> percent	<u>POROSITY</u> <u>RANGE</u> percent	<u>AVERAGE</u> <u>PERMEABILITY</u> um ² /md	<u>PERMEABILITY</u> <u>RANGE</u> um ² /md
2442-2450	32.1	30.1-33.7	0.16/158.6	0.01-0.32 / 14-326

NOTE: Values determined from 9 sidewall cores. Porosity average and range were determined excluding the value 22.2 %.

permeability averaged 0.16 um^2 (158.6 md) and ranged from 0.01 to 0.32 um^2 (14.0 to 326.0 md).

By plotting the average and range of the porosities (Figure 16) and permeabilities (Figure 17) obtained from the Clark and Wilson sand for both the conventional cores from the C&W#6-1 well and the sidewall cores from the CC#1 well, it is shown that sidewall porosities are approximately 5% higher than conventional core porosities, and that sidewall permeabilities are approximately 0.20 um^2 (200 md) lower than conventional core permeabilities. LeRoy and LeRoy (1977) state that sidewall porosities approach the values obtained from conventional analyses in formations having true porosities ranging from 32 to 34% (Figure 16), and that sidewall porosity values are normally higher than conventional values as porosity decreases. This is shown by the shaded region in Figure 16.

Percussion sidewall samples from friable and unconsolidated sand with permeabilities greater than 0.02 um^2 (20 md) (Keelan, 1977) usually yield measured permeabilities that are too low. This permeability reduction is attributed to partial blocking of pore flow paths by mud solids and to core compression by the bullet (Core Laboratories, 1980).

Geophysical Well Log Analyses . Porosity and permeability may also be determined from analysis of geophysical well logs. Reliable determination of log porosity may be obtained using neutron-density crossplots (Schlumberger, 1972) where the density-derived porosity is the abscissa and neutron-derived porosity is the ordinate (Figure 18).

Well CC#10 is the only well in which a neutron and density log

Figure 16. Sidewall versus conventional core porosity for the CC#1 and C&W#6-1 wells. The shaded region indicates actual sidewall porosity range for a given conventional porosity.

Figure 17. Sidewall versus conventional permeability for the CC#1 and C&W#6-1 wells.

Figure 18. Overall diagram of a neutron-density crossplot in the water zone. Modified from Hilchie (1983).

were run. Sonic (acoustic) and electric logs were run on most other wells, including CC#10. In order that porosity may be determined from all logs, the porosity determined from the neutron-density crossplots of CC#10 were correlated to that of the sonic and electric logs of CC#10. This was done by constructing neutron-density crossplots for CC#10 utilizing two different crossplots; one for the water zone (Figure 19) and one for the gas zone (Figure 20). Two crossplots were constructed because the density and neutron tools are affected by the presence of gas. Next, these neutron-density porosities were compared to the porosities determined from sonic and electric logs.

The first neutron-density crossplot (Figure 19) was constructed for the water zone below the gas zone. This crossplot, if used in a gas zone, gives low values of shale content and too high porosities due to the presence of gas. This crossplot was constructed so that shale content (V_{sh}) might also be determined. Figure 18 shows the total neutron-density crossplot. A complete crossplot is constructed from three basic points: a zero porosity-clean sand point, the 100% shale point, and the 100% porosity point. The constant percent of shale lines are parallel to the clean sand line, and the constant porosity lines are parallel to the zero porosity line joining the shale point of the matrix and the zero porosity clean sand point. The axes of the graph are: density sandstone porosity for the ordinate and neutron sandstone porosity for the abscissa. The clean sandstone line was constructed using the average density of 2.65 g/cm^3 , since the logs were originally run using sandstone density of 2.65 g/cm^3 . This is also the average density determined by a weighted density of outcrop

Figure 19. Neutron-density crossplot for the water zone in the CC#10 well.

Figure 20. Neutron-density crossplot for the gas zone in the CC#10 well.

samples from the upper Nehalem Basin (see Chapter III, Reservoir Rock). The clean sandstone line corresponds to and is constructed along the line where the density and neutron porosities are equal.

The shale point was obtained using the point on the neutron-density log that indicated the highest shale content. The shale point will change from well to well but the sandstone line will not. The line between the shale point and the matrix point was scaled from zero to 100% shale. The constant shale percentage lines were then constructed parallel to the clean sand line. The porosity lines were constructed parallel to the constructed zero porosity line between the matrix point and the shale point. Now every point plotted on the crossplot will show the shale corrected porosity and the volume of shale (V_{sh}) (Hilchie, 1983). Values for V_{sh} are listed in Appendix I.

A second neutron-density crossplot (Figure 20) was constructed for the gas zone. In the gas zone of shallow wells, the response of the density and neutron logs to gas is often approximated using a gas density and hydrogen index equal to zero (Schlumberger, 1979). If the formation consists of a single known lithology, both the porosity and an approximate value of the residual gas saturation (S_{gxo}) can be determined from neutron and density readings using Schlumberger Chart CP-5 (Schlumberger, 1979). This chart yields values of average water saturation in the flushed zone (S_{xo}) and porosity in sandstone for methane gas at conditions expected at shallow depths of about 300 to 1375 meters (1000 to 4500 feet), temperatures of approximately 49° C (120° F), and pressures of 13,790 kPa (2000 psi). Correction for excavation effect on the neutron reading is incorporated in this chart.

Excavation effect is caused by gas near the borehole. It is defined as the difference between original neutron values calculated when the tool was first introduced on the market and more recent calculations.

Initial calculations for the neutron tool were made as if the gas-filled portion of the porosity were replaced by rock matrix.

However, more recent calculations show that when this additional rock matrix is "excavated" and replaced with gas, the formations capability of lowering the neutrons speed is reduced. The consequence of ignoring the excavation effect in log interpretation is values too high for flushed-zone gas saturation and values too low for porosity.

By crossplotting neutron and density log values on Schlumberger Chart CP-5 (Figure 20) a low porosity section in CC#10 between 826-828 meters (2711-2717 feet) was revealed. The upper section 814-826 meters (2670-2711 feet) has an average porosity of 26.6% with a range of 21.5 to 32.5%. The lower section 828-835 meters (2717-2741 feet) has an average porosity of 28.7% and a range of 26.0 to 30.5%. Overall porosity, excluding the low porosity section, has an average of 27.4% with a range of 21.5 to 32.5%.

Another reliable source for porosity from a geophysical log may be obtained from the sonic log. Sonic logs were available for all wells in the study area with the exception of LVF#1 R/D1 and CC#5 R/D1. To arrive at a sonic porosity, Wylie's (Schlumberger, 1972) time average equation,

$$t_{\log} = \phi * t_{\text{fluid}} + (1 - \phi) * t_{\text{matrix}} \quad (3)$$

is normally used, where t is the reading on the sonic log in usec/ft, ϕ is the porosity, t_{matrix} is the transit time in the matrix material,

and t_{fluid} is about 0.30 usec/m (189 usec/ft) (corresponding to a fluid velocity of about 1615 m/sec (5,300 ft/sec)). However, when this equation is applied to the sonic logs of the Mist Gas Field, very high values of porosity (over 70%) are obtained (Industrial Gas Services, Inc., 1979). Several possible reasons for these high porosity values are:

1) The Cowlitz Formation is uncompacted due to its geologically "young" age and shallow depth. Uncompacted zones require the application of an empirically determined "compaction correction factor" (C_p) (Schlumberger, 1972), to Wylie's formula for porosity calculations. The degree of compaction may be determined from the following equation:

$$t_{\log} + [\phi * t_{\text{fluid}} + (1 - \phi) * t_{\text{matrix}}] C_p \quad (4)$$

Several approaches to determining C_p were utilized: density-sonic crossplot method, the neutron method, and the Ro method. Values of C_p determined by the density-sonic crossplot method, neutron method, and Ro method were 1.4, 1.6, and 1.9, respectively. The methods are outlined in Schlumberger (1972) and values of porosity calculated using the various C_p 's are listed in Appendix J. Figure 21 shows sonic porosity using the C_p determined by the three different methods and the neutron-density crossplot porosity. This plot suggests another correction factor must be applied to obtain correct formation porosity.

2) Residual gas saturation close to the wellbore causes an increase in travel time, thus resulting in porosities that are erroneously high.

3) Shale laminae in the sandstone will also cause sonic log

Figure 21. Sonic porosity versus depth, calculated using several compaction correction factors (C_p).

values to be too high. These high values are the results of cycle skipping. Cycle skipping occurs when the first arrival of compressional sound energy from the transmitter, although strong enough to trigger the receiver nearest the transmitter, may be too weak by the time it reaches the far receiver to trigger it (see Figure 22). Instead, the far receiver may be triggered by a different, later arrival in the sonic wave train, and the travel time measured on the pulse cycle will then be too large. When this occurs, the sonic curve shows a very abrupt and large excursion towards higher interval transit time values; this is known as "cycle skipping". Such skipping is more likely to occur when the signal is strongly attenuated by unconsolidated formations, formation fractures, gas saturation, aerated muds and rugose salt sections (Schlumberger, 1972).

All three of the above are probably affecting the sonic log reading in the wells. Therefore, the sonic logs cannot be used accurately to calculate porosity without applying unknown correction factors for compaction, gas effect, and shale effects.

Electric logs were run on all wells. The "Ro Method" (Schlumberger, 1972) of evaluation was used to calculate the formation factor (F) from Archies (Schlumberger, 1979) general equation

$$F = a/\phi^m \quad (5)$$

where $F = R_o/R_w$, (a) is an empirically derived constant, (m) is the cementation factor, and ϕ is porosity.

The "Ro Method" involves the use of the resistivity reading (R_o) in a "clean, water sand", 100% saturated with water of a known resistivity (R_w). Such sands are found at the base of the gas sand in

Figure 22. Location of transmitters and receivers on the sonic tool. Modified from Schlumberger (1972).

producing wells; and throughout the sand in holes with no gas. In the CC#10 well, R_o ranged from 2.0 to 5.0 ohm-meters in the water zone. A water resistivity of 0.16 ohm-meters at a reservoir temperature of 46°C (115°F), from the water analysis of CC#6 R/D2 well, was used in all calculations (see Chapter III, Reservoir Fluids). R_w was held constant throughout the computations.

Since a single porosity-single water interpretation method is used, the (a) coefficient will account for the conductivity occurring in sand. The conductivity is related to bound water in clays and surface conductance resulting from the cation exchange capacity (CEC), or semiconductors such as pyrite or glauconite. Secondary electrical conductivity from such sources results in an additional conductivity term in any total (or true) conductivity equation. A formation factor where the numerator has a value different from 1.0, compensates for that additional conductivity influence. The presence of clay usually decreases the value of resistivity within a reservoir bed. When this happens, (a) should be less than 1.0 as long as (m) does not change (Ransom, 1984).

Factors which influence (m) include; pore geometry, anisotropy, degree of electrical insulation by cementation, and the occurrence of an open fracture (Ransom, 1984). Pore geometry is the most important factor. Typical values of (m) are shown in Table XIII, in which $a = 1.0$ for all cases, except the Humble-Winsauer data, for which $a = 0.62$ (Ransom, 1984). Spherical grains have an (m) of about 1.3. As the grains become more flat or plate-like, (m) increases.

The Archie equation was then rearranged to;

TABLE XIII

TYPICAL VALUES OF m

<u>MATERIAL</u>	<u>m</u>	<u>REFERENCE</u>
Na, montmorillonite	3.28	Atkins and Smith
Ca, montmorillonite	2.70	Atkins and Smith
Muscovite	2.46	Atkins and Smith
Attapulgitic	2.46	Atkins and Smith
Mediterranean clays	2.20	
Sandstones	2.15	Humble relationship, Winsauer
Illite	2.11	Atkins and Smith
Carbonates	2.00	
Shell fragments	1.90	Jackson
Kaolinite	1.87	Atkins and Smith
Cemented sandstone	1.80	
Natural sands	1.60	Archie
Platy sands	1.52	Jackson
Rounded quartz sands	1.40	Jackson
Spheres	1.30	Wyllie and Gregory
Spheres	1.25	Jackson

m is the exponent in the Archie equation; $F = a/\phi^m$; and $a = 1.0$ for all data except the Humble-Winsauer data for which $a = 0.62$ (Ransom, 1984).

$$\phi = (a/F)^{1/m} \quad (6)$$

to determine porosity. Substituting in R_w/R_o for F gives;

$$\phi = (a/R_o/R_w)^{1/m} \quad (7).$$

Equation 7 was used to calculate porosity in the multiple regression computer program shown in Appendix L. The multiple regression program was taken from Davis (1973) and modified to compute porosity from induction log resistivities.

In this program equation 7 is put in the form;

$$Y = C_1 + (C_2)X \quad (8)$$

where $Y = \phi C_p$, $C_1 = \phi/m$, $C_2 = 1$, and $X = (a/F)^{1/m}$ (where $R_o/R_w = F$).

This allows C_1 and C_2 to vary so that the (a) coefficient may be determined independently from the cementation factor (m) , both of which vary linearly for the formation.

In the computer analysis, an overall (a) and (m) were first calculated for the zone between 836-893 meters (2742-2929 feet) in CC#10, shown in Figure 23. The (a) coefficient was determined to be 2.24 and (m) was equal to 1.37. These values were considered erroneous since the shape of the sand grains of the Cowlitz Formation are not spherical and (a) is much greater than 1.0.

Next, (a) and (m) were calculated for the sand zones. Sand zones were determined to be those zones with an SP greater than 65 (on a scale of 100 to zero), which corresponds to a V_{sh} of zero to 25 determined from the neutron-density crossplot. The (m) and (a) were determined for the sand zone to be 2.56 and 0.46 respectively. A maximum deviation of +5.7% and -5.3%, and an average deviation of +1.6% and +1.8% from neutron-density crossplot porosity was determined.

Figure 23. Neutron-density crossplot porosity and calculated computer porosity versus depth in the CC#10 well.

These are reasonable values as depicted in Table XIII. These values of (a) and (m) were also used to calculate water saturation from the Archie saturation equation (see Chapter III, Water Saturation).

Finally, using the average porosity determined above, a log permeability was determined. An empirical relation between permeability, porosity, and water saturation developed by Wyllie and Rose in 1950 (Schlumberger, 1979) is;

$$k^{1/2} = (c \phi / S_w) + c' \quad (9)$$

where ϕ is porosity, and S_w is water saturation. Field observations recorded by Schlumberger seemed to show that the constant c is itself a function of porosity. Thus Schlumberger (Schlumberger, 1979) developed the following equation for dry gas;

$$k^{1/2} = 79 \phi^3 / S_{wi} \quad (10)$$

where S_{wi} is irreducible water saturation. This expression is valid for estimating permeability in zones that are at irreducible water saturation. In examining the water saturations (see Chapter III, Reservoir Fluids) 26% is the lowest value for water saturation and, therefore, was considered to be irreducible. Using this value for irreducible water saturation and a porosity of 27% yields a permeability of 0.03 um^2 (36 md) (Figure 24). This very low value may be attributed to using an irreducible water saturation greater than the actual value. Since a reduction in irreducible water saturation would increase permeability.

Figure 24. Log permeability determined from porosity and water saturation. Modified from Schlumberger (1979).

CHAPTER IV

CONVERSION TO STORAGE

Introduction

Now that the geology and reservoir parameters of the Bruer and Flora pools have been determined, this information can be used in a preliminary analysis for the conversion of these pools to pipeline gas storage. A range of pressures used in storage operations is to be determined first. The upper pressure is based upon an assessment of the mechanical condition of all wells to be utilized in storage operations and delta pressures, defined as the maximum storage pressure minus discovery pressure. In selecting the lower pressure, the horsepower requirements for compressing the gas, market needs, production problems, and economics are considered. The scope of this study limits this discussion to the selection of the upper pressures.

Mechanical Conditions

The problems of converting a depleted gas field to storage starts with the mechanical refurbishing of wells and field lines to withstand storage pressures over a long period of time (Katz, 1968). It must be determined that all wells drilled to the producing horizon can be located, checked for leakage, and made mechanically sound. Even the wells classed as dry holes should be opened, recemented, or cased as observation wells.

Dehydrated natural gas with less than 1% CO₂, low concentrations

of H_2S and O_2 of the type encountered in pipelines, causes little or no significant corrosion inside steel pipelines (Katz, 1984b). Where liquid water accompanies natural gas, measurable but tolerable rates of corrosion may occur (Katz, 1984c). A survey conducted on 30 storage fields indicated that average corrosion rates for untreated pipe is 0.7 mils per year (mpy) while treated is 0.4 mpy (Bush, 1976). Since corrosion rates of 1 to 4 mpy are quoted as acceptable in normal design specifications, treatment to reduce corrosion is indicated for the more corrosive situations such as with the presence of H_2S (Katz, 1984c). The in situ gas in the Bruer and Flora pools is dehydrated and contains low concentrations of hydrogen sulfide, carbon dioxide, and oxygen (see Chapter III, Reservoir Fluids). Because of the short duration in which the Mist Gas Field equipment has been in use and very small quantities of corrosive agents in the original gas, well and line deterioration from corrosion should be minimal. Since the life expectancy of the storage field may be 30-50 years, and because gas foreign to the field will be injected, corrosion rates should be monitored using resistance probes, corrosion coupons, and/or hydrogen probes. If corrosion is found to be significant in any piece of equipment, it may be replaced or treated with a corrosion inhibitor.

Delta Pressures

Delta pressure is the maximum storage pressure above the discovery pressure. Natural gas reservoirs are generally found at discovery pressure gradients corresponding to a head of water or brine of from 4.5 to 11.8 kPa/m (0.20 to 0.52 psi/ft), while the pressure

gradient due to weight of overburden is about 22.6 kPa/m (1 psi/ft) (Katz, 1981). Experience shows that overpressure to 1.36 KPa/m (0.65 psi/ft) of depth is common and 17 kPa/m (0.75 psi/ft) has been used (Katz, 1981). Since the use of the field at the highest pressure level possible will normally give the maximum storage capacity and the wells will have the highest flow capacity, this maximum pressure is normally the goal of the design (Katz, 1968). However, for the Bruer and Flora pools the Oregon State Energy Facility Siting Council (1981) (EFSC) in the Site Certification Agreement, Rule 345-100-036, subpart 5 states:

Oregon Natural Gas Development Corporation (ONGDC) shall maintain average gas pressures in the underground storage reservoirs at levels equal to or below the natural gas pressures in the reservoirs, prior to production of natural gas which is 6980 KPa (1000 psi) in the Flora pool and 6477 KPa (940 psi) in the Bruer.

Provided, however, that ONGDC may maintain natural gas pressures at higher levels if ONGDC provides EFSC with results of a breakdown test of the caprock which shows to EFSC's satisfaction that higher level of pressure will not endanger the public health and safety. Such higher level in any event shall not exceed 8612 KPa (1250 psi).

The discovery pressures stated above are in error. Actual discovery pressures were 6649 KPa (965 psi) for the Bruer pool and 7386 KPa (1072 psi) for the Flora pool, as shown in Appendix G. This usage will be employed throughout this study. The discovery pressure gradient for the Mist Field was 0.930 KPa/m (0.443 psi/ft) (Stinson, personal communication, 1984). An increase to the common delta pressure gradient of 1.36 KPa/m (0.65 psi/ft) would be an increase of 0.435 KPa/m (0.207 psi/ft), which is equivalent to a discovery pressure of 9756 KPa (1416 psi) for the Bruer pool and 10,838 KPa (1573 psi) for the Flora pool. This represents an increase of 1144 KPa (166 psi) for

the Bruer pool and 2225 KPa (323 psi) for the Flora pool above the Site Certification Agreement higher level of 8612 KPa (1250 psi). If these levels are desired a caprock test of core from the caprock should be performed to determine if this higher pressure was feasible, also an amendment to the Site Certification Agreement would have to be obtained.

Storage Capacity

The original gas in place (OGIP) provides a close approximation of the storage capacity. The OGIP of the Bruer and Flora pools has been determined using the production-pressure-decline method (Stinson, 1979). This method utilizes semi-annual shut-in pressures collected in the spring and fall, recorded at regular depth intervals from each producing well. The procedure is as follows;

First, a gas compressibility factor (z) is determined at the recorded pressures, from an annual gas analysis of the pool. Next, the semi-annual shut-in pressures (P) are divided by z . Then, by plotting P/z versus cumulative production, OGIP may be determined by extending the curve to abandonment pressure. This procedure provides an accurate value of the OGIP with the assumption that the pool experiences volumetric depletion (i.e. little or no water drive). A plot of P/z versus gas withdrawn is a straight line at constant temperature. Water influx will cause an upward curvature of the P/z curve at reduced reservoir pressures. Wells in a common reservoir cannot be evaluated by individual well P/z curves because of gas movement within the reservoir (Katz, 1984a). Recorded P/z data for individual wells in

each pool are found in the primary production well summary (Appendix F), and P/z versus cumulative production curves are shown in Figures 25-27.

Figure 25 shows that the Flora pool has a straight line P/z curve, signifying volumetric depletion (i.e. little or no water drive). Extrapolation of the P/z curve reveals an OGIP of 0.25 Bcm (8.82 Bcf). Production to 11/19/84 was 0.240 Bcm (8.49 Bcf), leaving 0.009 Bcm (0.33 Bcf) in reserves. Abandonment pressure for the Flora pool is estimated to be 1206 KPa (175 psi) even though abandonment pressure for CC#10 was 2415 KPa (350 psi).

On the basis of individual well P/z data it appears that CC#1 R/D1 is isolated and should be evaluated separately while CC#3 R/D1 and CC#6 R/D2 appear to be in a common reservoir. The P/z curve for CC#3 R/D1 and CC#6 R/D2 wells (Figure 26) in the Bruer pool exhibit an unusual downward curvature, as if the reservoir volume were expanding. This behavior suggests that there may be yet another undiscovered gas-bearing reservoir nearby which could be connected to the Bruer pool. The drilling of additional storage wells may reveal such a reservoir. Extrapolation of the P/z curve reveals an OGIP of 7.98 Bcf. Production to 11/20/84 was 0.024 Bcm (7.653 Bcf), leaving 0.14 Mcm (0.321 Bcf) remaining at an abandonment pressure of 861 KPa (125 psi).

Using an individual P/z curve (Figure 27) for CC#1 R/D1 reveals an OGIP of 0.024 Bcm (0.853 Bcf) and indicates minor water influx since pressure rises as production declines to depletion (Katz, 1984a). Production to 11/20/84 was 0.024 Bcm (0.848 Bcf), leaving 0.14 Mcm (5.0 Mcf) remaining at an abandonment pressure of 2287 KPa (332 psi).

Figure 25. Production=pressure-decline curve for the Flora Pool. The straight line P/z curve suggests volumetric depletion.

Figure 26. Production-pressure-decline curve for the Bruer Pool, excluding the CC#1 well.

Figure 27. Production-pressure-decline curve for the CC#1 well, Bruer Pool.

One may determine how effective the barrier is between CC#1 R/D1, and CC#3 R/D1 and CC#6 R/D2 by injecting gas into CC#3 R/D1 and CC#6 R/D2 while monitoring pressure changes in CC#1 R/D1. The possibility exists that a spillpoint may be located between CC#1 R/D1 and CC#3 R/D1 and CC#6 R/D2. In this case, spillpoint monitor wells would aid in detecting gas movement.

Deliverability

Normally depleted gas wells have some record of productivity or back pressure performance. At the Mist Gas Field, as shown in Table XIV, both Drill Stem Tests (DST) and Back Pressure or Performance Tests (BPT) were conducted. DST provide an approximate value of open hole permeability and as a result can be used to give an approximate value of well performance. However, formation damage, which generally occurs during casing operations, will change open hole permeabilities, making DST invalid once the well has been completed. In contrast, BPT on gas wells are conducted once the well has been completed, thereby incorporating any formation damage into the final test results. Back pressure testing has become the conventional way to evaluate well deliverability, with isochronal flow testing the preferred method.

Isochronal back pressure test procedure consists of measuring the closed pressure and then, after opening the well to a fixed flow rate for a fixed period of time, measuring the flowing pressure. The well is then closed in long enough to allow the pressure to return to its original value before the second test at a higher flow rate is conducted. The second and all succeeding tests use the same length of

TABLE XIV
MIST GAS FIELD PRESSURE TESTING

<u>WELL</u>	<u>DST</u>	<u>BPT</u>	<u>SEMI-ANNUAL</u>
LVF#1	10-16-77		
LVF#1 R/D1			
CC#1			
CC#1 R/D1	4-24-79	9-11-79	YES
CC#3	5-27-79		
CC#3 R/D1		9-11-79	YES
CC#5			
CC#5 R/D1	7-6-79		
CC#6			
CC#6 R/D1			
CC#6 R/D2		9-10-79	YES
CC#32-10			
CC#10			YES
CC#32-3			
CC#33-3			YES
CC#44-4			

time as the first flow test, thirty minutes, and third and fourth flow points are usually taken. These points are then plotted on log paper as straight lines referred to as back pressure curves as shown on Figure 28.

By extrapolating the back pressure curve to atmospheric pressure the absolute open flow (AOF) may be determined. The AOF is the theoretical flow rate which would result from the reservoir flowing directly to atmospheric pressure through a frictionless pipe. This flow rate can never be achieved, however, it is a useful number when comparing several gas wells to get an estimation of their relative capacities.

Isochronal BP's were conducted on CC#1 R/D1, CC#3 R/D1, CC#6 R/D2, and CC#4 the week of September 10, 1979 by Diamond Shamrock Corporation (DSC). The results were analyzed by both ONGDC and DSC. ONGDC analyzed the data using wellhead recorded data while DSC used bottom hole recorded data. The AOF of both tests are shown in Table XV. In the case of CC#6 R/D2, there is a significant difference in the AOF calculated by DSC from downhole data and the AOF computed by ONGDC from wellhead data. This difference is due primarily to the tolerances of the pressure measurement devices. The downhole data revealed a pressure shut-in of only 48 KPa (7 psi) for the final flow rate whereas the wellhead pressures indicated a 69 KPa (10 psi) drawdown. This relatively minor difference at a flowing pressure of 6201 KPa (900 psi) becomes quite significant when the results are extrapolated to atmospheric pressure as shown in Table XV (Stinson, 1979).

Because downhole pressure measurements are considered more

Figure 28. Individual isochronal back pressure curves for four Mist Gas Field wells.

TABLE XV
ABSOLUTE OPEN FLOW POTENTIALS

<u>WELL</u>	<u>AOF (DSC)</u>	<u>AOF (ONGD)</u>
CC#1 R/D1	9.2 MMCFD	8.5 MMCFD
CC#3 R/D1	32	34
CC#6 R/D2	530	160
CC#4	1.6	1.8

TABLE XVI
WELL FLOW CHARACTERISTICS

<u>WELL</u>	<u>n (DSC)</u>	<u>n (ONGDC)</u>
CC#1 R/D1	0.839	0.854
CC#3 R/D1	0.781	0.810
CC#6 R/D2	1.000	0.884
CC#4	0.839	0.869

Note: n = 1.00 for perfect laminar flow;
n = 0.5 for total turbulent flow.

accurate than those recorded at the wellhead, downhole pressures will be utilized throughout this study. Figure 28 shows the back pressure curves for CC#1 R/D1, CC#3 R/D1, CC#6 R/D2, and CC#4 constructed using the flowing pressure points as determined by DSC. Although CC#4 is not in the Bruer or Flora pools it is included for the sake of completeness.

An equation for the back pressure curve expresses the relationship between the difference of squares of flowing pressures with the flow rate:

$$Q = C (p_1^2 - p_2^2) \quad (11)$$

where $Q = \text{MMcf/day}$ ($10^6 \text{ m}^3/\text{d}$); p_1 = initial pressure, psi (kPa); p_2 = final pressure, psi (kPa). From this data the reciprocal slope of the back pressure curve (n) may be determined by plotting the performance coefficient (C).

Under ideal conditions, the values of n and C remain constant for the life of the well with declining reservoir pressure. The value of n will remain constant in moderate or high permeability formations if there is no water encroachment or sand face contamination to create unsteady state conditions (Katz, 1984b).

The angle theta (θ), measured from the vertical as shown in Figure 28, is the key factor for determining the relative flow restriction due to turbulence. By defining $n = \tan \theta$, it has been determined that for perfect laminar flow $n = 1.00$ and for total turbulent flow $n = 0.5$. Table XVI compares the values for n determined by DSC with those determined by ONGDC. Both results show that the wells have excellent reservoir flow characteristics.

For high-permeability reservoirs the performance of a well over the life of the field can be predicted from a single back pressure curve. By using the difference in squares between the closed-in reservoir pressure and the flowing pressure, one can predict the flow rate for a given drawdown. Stinson (1979) calculated the expected production rates for each well using 4134, 4823, and 5512 KPa (600, 700, and 800 psi) flowing pressures. Using downhole pressure values, production rates were calculated. A comparison to ONGDC values are shown in Table XVII.

Katz (1968) states that a composite curve may be prepared for an entire field by adding the flow rates at same difference of squares and then drawing the field slope through the sum of the flow rates. Since BPT were conducted for only three Bruer pool wells and no tests were conducted on any Flora pool wells, the available Bruer pool curves were plotted on the same graph to find a common slope to be adopted for the Bruer pool. First, the flow rates were summed at a difference of squares of 1,278,000 KPa (200,000 psi) and was found to be 3.14 Bcm (112 MMcf/d). Then the n values were averaged, yielding a reciprocal slope of 0.873. This was then plotted as shown in Figure 29. The AOF for this curve is 1.4 Bcm/d (450 MMcf/d).

Backpressure curves are known to be influenced by well spacing, since the stabilized curve is dependant upon the radius of drainage. It should be noted that when converting a producing field to storage with the high rates of withdrawal encountered in storage facilities, that closer well spacing is likely to be indicated. This means that the stablization time for a gas well will be less, since gas comes a

TABLE XVII

PRODUCTION RATES

<u>WELL</u>	<u>FLOWING PRESSURE</u>					
	4134 KPa (600 psi)		4823 KPa (700 psi)		5512 KPa (800 psi)	
	<u>ONGDC</u>	<u>DSC</u>	<u>ONGDC</u>	<u>DSC</u>	<u>ONGDC</u>	<u>DSC</u>
CC#1 R/D1	2.0	2.2	3.1	3.2	4.0	4.2
CC#3 R/D1	4.2	8.2	6.0	11.5	7.3	15.0
CC#6 R/D2	7.5	80.0	11.5	135.0	14.5	190.0

Figure 29. Composite back pressure curve for the Bruer Pool.

shorter distance from the producing well (this is neglecting the travel time from the fringes of the reservoir). When old and new radii of drainage are known, it is possible to predict the change in C, the performance coefficient.

The following equation (Katz, 1968) was used to find the radius of drainage:

$$r_d = 0.0704 (k t p / \phi u) \quad (12)$$

where r_d is radius of drainage for flow time, t , in ft; t is flow time, in hours; k is formation permeability, in md; p is average flowing pressure in reservoir, in psi; ϕ is formation porosity, fractional; and u is gas viscosity, in centipoise. For the isochronal back pressure tests the flow time is 0.5 hours, average flowing pressure is 6548.2 KPa (950.4 psi, porosity is 27% (see Chapter III), gas viscosity is 0.0125 cp (determined from the Figure in Appendix K with a temperature of 15° C (60° F) and a specific gravity of 0.6) and average permeability (see Chapter III) is 0.36 μm^2 (364 md). Drainage radius were calculated for permeabilities of 0.36, 0.49, 0.99 μm^2 (364, 500, and 1000 md). Results are shown in Figure 30-32.

The radius of drainage equation can be simplified to predict the performance curve for the new radius of drainage. The equation for the new value of C is;

$$C_2 = C_1 [\ln (r_{d1}/r_w) / \ln (r_{d2}/r_w)] \quad (13)$$

where $C = Q / (p_f^2 - p_s^2)$; r_d is radius of drainage, in ft; Q is Flow rate, in Mcf/d; p_f is formation pressure, in psi; p_s is flowing sand face pressure, in psi; r_w is wellbore radius, in ft; n is reciprocal slope of back pressure curve; and subscripts 1 and 2 refer to flow

Figure 30. Back pressure curves for the Bruer Pool, calculated using a permeability of 0.36 um^2 (364 md).

Figure 31. Back pressure curves for the Bruer Pool, calculated using a permeability of 0.49 um^2 (500 md).

Figure 32. Back pressure curves for the Bruer Pool, calculated using a permeability of $0.99 \text{ } \mu\text{m}^2$ (1000 md).

times.

At a given difference in squares (psia²) the flow rate is decreased in the same proportion as C and the 183 meter (660 foot) curve may be drawn. Similar calculations for 101,225 meters² (25 acre) spacings were made and the calculated performance curves are shown in Figures 30-32.

The radius of drainage for 161, 960 and 101, 225 m² (25 and 40 acre) well spacing would be 183 meter (660 feet) and 159 meters (522 feet), respectively. For shifting the short term backpressure curve to the stabilized position, Katz (1968) used;

$$t_{stab} = 202 u \phi r_e / k p \quad (14)$$

where the exterior radius is defined as the exterior radius at which the flow rate (Mcf/d) is 0.01 times the flow rate at the well. The flow times for the 101,225 and 161,960 meters² (25 and 40 acre) spacing using the various permeabilities are shown in Table XVIII and plotted in Figures 30-32. It appears that an increase in permeability has little effect on the AOF, however, stabilization time is reduced and drainage radius increased.

Future Deliverability

An annual storage cycle of 200 days of injection at 1.4 Bcm (50 MMcf/d) and 100 days withdrawal at 2.8 Bcm (100 MMcf/d) is the storage cycle desired by Northwest Natural Gas Company (Stinson, personal communication, 1984). If the absolute open flow (AOF) from CC#1 R/D1 is disregarded since it has a low deliverability, and the AOF for CC#3 R/D1 and CC#6 R/D2 are averaged, an approximation of the deliverability

TABLE XVIII

STABILIZATION TIMES AND DRAINAGE RADIUS FOR VARIOUS PERMEABILITIES

PERMEABILITY	STABILIZATION TIME		DRAINAGE RADIUS
	25 acre spacing	40 acre spacing	
0.36 μm^2 (364 md)	0.54 hour	0.86 hour	154 meters (504 feet)
0.49 μm^2 (500 md)	0.39 hour	0.62 hour	180 meters (591 feet)
0.99 μm^2 (1000 md)	0.20 hour	0.31 hour	254 meters (835 feet)

to be expected from future production wells is between 0.9 and 14.8 Bcm/d (32 and 530 MMcf/d). This was calculated with the assumption of uniform porosity and permeability. Because this is a wide range, back pressure tests should be conducted on all future wells to determine the exact number of additional wells required to meet the desired flow rates.

Using the range of deliverability determined above it is estimated that the Bruer Pool will require 3-4 I/W wells. Two of these wells presently exist; CC#6 R/D2 and CC#32-10. The CC#32-10 well has never been back pressure tested, therefore, if CC#32-10 yeilds less than 15 Mcf/d, one additional well will be required.

No pressure testing has been conducted on any of the Flora Pool wells. However, the Bruer and Flora Pools have approximately the same gas content and reservoir characteristics, therefore, the two pools may have similar performance curves. The Flora Pool will require 3-4 I/W wells, in which the existing CC#33-3 and CC#10 wells can be utilized. The locations of the established and proposed I/W wells for the Bruer and Flora Pools is shown in Figure 33.

Once the character of the market is better known, a maximum sustained withdrawal can be calculated, and by adding the deliverabilities of the wells in the Bruer and Flora pools a common reservoir deliverability curve determined. If this curve falls short of required flow rates, the remedy is to drill more wells or increase the deliverability of the old wells. By examining a the structural map of the Mist Gas Field having known wells with their deliverabilities marked on it, well locations having higher deliverabilities may be

Figure 33. Location of existing and proposed injection/withdrawal wells.

found. By adding the estimated deliverabilities of these proposed wells to the total, the field needs may be achieved. When drilling future wells, flow tests should be conducted and a accumulated deliverability determined, to match the predicted deliverability curve.

CHAPTER V

PLANNED OBSERVATION

Introduction

In converting a gas field to storage, a long life is contemplated, such as 30-50 years. The possibility that gas might find a way to leave the reservoir especially through mechanical imperfections should be considered carefully (Katz, 1968). The way to detect and prevent loss or migration of storage gas is through monitoring. Monitoring includes: understanding the complete system, data acquisition and analysis, and the concept of expected behavior and noted deviations (Katz, 1984b). The system under consideration includes: surface piping (see Chapter IV, Mechanical Conditions), well bores, and rock layers above and below the storage horizon to distances of 1.6 to 4.8 km (1 to 3 miles) or more surrounding the storage area. Monitoring data may be collected utilizing various types of observation wells. The following is a discussion on the various types of observation wells and their utilization at the Mist Underground Storage Projects.

Observation Wells

Observation wells are required for the monitoring of gas flow to or from the reservoir for inventory, and operating purposes. In addition, monitoring of water pressures and presence of gas in the gas storage aquifer and any permeable zone between the storage zone caprock and the ground surface (intermediate zones) should be performed. Gas movement monitor wells, which could signal unwanted gas loss or

movement to a structural saddle (spill point), are also a part of monitoring (Katz, 1977).

Katz (1977) developed a classification scheme for the various types of observation wells used in gas storage monitoring. The six types of observation wells are indicated on an aerial plan for a typical storage field in Figure 34, and in cross section for a typical storage field showing well completions in Figure 35.

Injection/withdrawal (I/W) wells (class 1) are utilized in gas storage operations. They are attached to the gas pipeline system for carrying storage gas to and from the compressor plant, such as Miller Station at the Mist Gas Field. Normally a low deliverability I/W well in the center of each pool is closed-in and used for measuring gas reservoir pressures in static condition year round (Katz, 1968). This particular well is referred to as a key well. The second group of well (class 2) are water wells. These wells were initially drilled to determine geologic structure and subsequently are used to measure water level and pressure in the storage zone beyond the gas reservoir. A spill point well (class 3) is especially identified since it "watches the back door" so to speak-to see if there is any gas reaching a structural saddle (Katz, 1968). Class 4 and 5 well are used to monitor the water level in intermediate permeable layers for pressure level changes caused by mechanical leaks from the casing or cement in the well bore. a well used to follow the downward movement of gas prior to a spill point is identified as a class 6 well.

The following suggestions are made for the types and locations of observation wells for the Mist Underground Storage Project reservoirs.

Figure 34. Typical location of observation wells related to structure of storage reservoir. Modified from Katz (1977).

Figure 35. Typical section of storage field with location of observation wells. Modified from Katz (1977).

Utilizing Katz's (1977) classification, the type and location of each observation well is indicated on an aerial plan of the Bruer and Flora Pools (Figure 36). The location and number of I/W (class 1) wells is discussed in Chapter IV, Future Deliverability. Normally a low deliverability I/W well near the center of each pool is utilized as a key well. In the Bruer Pool, well CC#3 R/D1 may be used as a key well, depending on the deliverability of the proposed wells. The Flora Pool presently has no wells which may serve as a key well, hence one will have to be installed.

There are presently a number of wells which may serve as water (class 2) wells near both Pools. Wells CC#5 R/D1 and LVF#1 R/D1 may be utilized near the Bruer Pool and CC#14-2, CC#13-2, and CC#32-3 for the Flora Pool.

A spill point (class 3) well may be required between CC#6 R/D2 and CC#1 R/D1 in the Bruer Pool. To determine if there is communication, pressures should be monitored closely to see if there is a rise in pressure in CC#1 R/D1, while injecting pipeline gas into the Bruer Pool. No class 3 wells will be required for the Flora Pool.

Well logs from both pools and the surrounding area indicate little or no zones having permeable layers between the storage reservoir and the ground surface, except for a fractured shale near the ground surface. Water produced from the fractured shale is utilized as drinking water at the Miller Station. A class 5 water well should be installed in this shale. The location of possible class 4 wells may be found by conventional coring and testing suspect zones. Gas and water analysis should be conducted on any natural gas and water found in

Figure 36. Location of observation wells related to structure of the Bruer and Flora Pools.

these suspect (intermediate) zones in the vicinity of the Mist Underground Storage Project. Such analysis may aid in identifying any escaped pipeline gas. No class 6 well will be required for either Pool.

CHAPTER VI

SUMMARY

The trapping mechanism for the Bruer and Flora pools is closure against down-to-the-south and down-to-the-northwest faults. The overlying shales of the upper Cowlitz Formation and Keasey Formation create a local seal for the gas reservoirs. X-ray diffraction and density log readings indicate the clay in these shales is smectite. Smectite clays provide an excellent caprock seal.

The reservoir rock of the Bruer and Flora pools is the Clark and Wilson sand of the middle to late Eocene Cowlitz Formation. In outcrop, the sand is a well sorted fine to medium grained friable arkosic sand with some cross-stratification and lignitic clasts. The framework grains can be divided into; quartz, feldspars, rock fragments, glass and micas. The average weighted grain density of the sand grains using this classification is 2.65 g/cm³.

Due to the abundance of potassium feldspar, hence K²⁰, the unstable isotope K⁴⁰ is present in large quantities. Because this isotope naturally emits gamma rays, the total background radiation of the sand is roughly equal to that of the shale. This makes the sand virtually indistinguishable from shale on the gamma ray log.

Bottom Hole temperatures (BHT) were available for all wells. A plot of BHT versus depth for the Bruer and Flora pools indicate that the Bruer pool is approximately 7°C (20°F) warmer than the Flora pool, even though the Flora pool is deeper. Since Schlumberger logged all Flora pool wells and Welex logged all Bruer pool wells, a calibrated temperature survey would reveal if this difference is a result of

equipment difference or if it is an actual anomaly.

A comparison of thermal gradients determined by a previous study for the Oregon Coast Range and gradient determined using BHT, suggest that BHT from open hole logs provide a reasonably accurate value of formation temperature. BHT determined in the Clark and Wilson sand was considered constant at any depth within the sand throughout this study.

Four water analyses were provided from which total dissolved solids (TDS) and ion concentrations had been determined. The average TDS from these analysis was 26,444 mg/l. Of the four water analysis, CC#6 R/D2 is considered to be the most representative of the Bruer and Flora pools.

The origin of the formation waters was interpreted using the Palmer system. This system requires the determination of reaction values. A plot of the reaction value percentages of $\text{Na}^+ + \text{K}^+$, Ca^{++} and Mg^{++} suggest that the Clark and Wilson formation waters are in the early stages of sea water diagenesis. A plot of concentration versus Na^+ reaction values also support this.

Formation water resistivity (R_w) was determined using a chemical and spontaneous potential (SP) analysis. The most precise value of R_w , was derived from the chemical analysis, which averaged 0.175 ohm-meters. The R_w for CC#6 R/D2 was 0.16 ohm-meters. R_w using the SP analysis averaged 0.11 ohm-meters with CC#6 R/D2 equal to 0.145 ohm-meters.

Water saturation (S_w) was determined from the Archie saturation equation, using the cementation factor (m) and empirical coefficient (a) determined in the porosity analysis. S_w averaged 47.5% and ranged

from 26.4 to 80.0% for the zone 814-836 meters (2670-2742 feet) in CC#10.

Core and geophysical log data from the field are sparse. Porosity and permeability have been previously determined by conventional core analysis in the Clark and Wilson sand from the Clark and Wilson No. 6-1 well, 5 Km (3 miles) southeast of present production. Porosity and permeability in this well averaged 26.9% and 0.36 um^2 (364 md), respectively. Porosities and permeabilities obtained by sidewall core analysis from the CC#1 well in the Bruer Pool averaged 32.1% and 0.16 um^2 (158.6 md), respectively. These values were considered erroneous, therefore, porosity and permeability were derived from analysis of geophysical logs.

An attempt was made to determine porosities from acoustic logs. Acoustic logs require compaction, residual gas, and shale correction factors, which could not be determined due to cycle skipping. However, by constructing neutron-density crossplots, reasonable porosity values were obtained. Average crossplot porosity equaled 27.4% in the gas zone of CC#10 between 814-836 meters (2670 to 2741 feet), and 23.4% in the water zone between 836-893 meters (2742 to 2930 feet). A low porosity section was found in CC#10 between 826 to 828 meters (2711 to 2717 feet).

To determine porosity from any well within the storage reservoirs a multiple regression analysis, using the porosity determined from the neutron-density crossplots and data from induction logs was performed. From this analysis the cementation factor (m) and empirical coefficient (a) in the Archie equation were determined to be 2.56 and 0.46,

respectively. Overall porosity averaged 23.4% in the water zone between 836-893 meters (2742 to 2930 feet), while porosity in the sand (determined by an SP > 65 mv) averaged 26.1%. A maximum deviation of +5.7% and -5.3% and an average deviation of +1.6% and -1.8% from neutron-density crossplot porosities was determined. TABLE XIX summarizes the porosity and permeability results.

Permeability, determined using an empirical relationship between permeability, porosity and water saturation, was calculated to be 0.03 μm^2 (36 md). This is considered to be erroneously low.

TABLE XIX

POROSITY AND PERMEABILITY SUMMARY

SOURCE	POROSITY		PERMEABILITY	
	AVERAGE	RANGE	AVERAGE	RANGE
	(percent)		($\mu\text{m}^2/\text{md}$) 0.04-1.28/	
C&W#6-1	26.9	22.8-32.2	0.36/364	45.2-1302.3
(conventional core)				
			0.01-0.32	
CC#1	32.1	30.1-33.7	0.16/159	14-326
(sidewall core)				
CC#10	27.4	21.5-32.5	0.03/36 *	ND
(neutron-density cross plot)				

* Calculated using porosity = 27% and water saturation = 26%.

ND = Not determined.

A range of upper pressures to be used in storage operations were determined based on an assessment of the mechanical conditions of all wells to be utilized in storage operations and delta pressures. All wells drilled to the producing horizon should be checked for leakage and made mechanically sound, including dry holes. Corrosion monitoring should also be implemented.

The discovery pressures stated in the site certification agreement are in error. Actual discovery pressures are 6649 KPa (965 psi) for the Bruer pool and 7386 KPa (1072 psi) for the Flora pool. The discovery pressure gradient is 0.930 KPa/m (0.443 psi/ft). An increase to the common delta pressure gradient of 1.36 KPa/m (0.65 psi/ft) is equivalent to a discovery pressure of 9756 KPa (1416 psi) for the Bruer pool and 10,838 KPa (1573 psi) for the Flora pool. This represents an increase of 1144 KPa (166 psi) for the Bruer pool and 2225 KPa (323 psi) for the Flora pool above the site certification agreement higher level of 8612 KPa (1250 psi).

OGIP had previously been determined for the Bruer and Flora pools using the production-pressure-decline method. The Flora pool has little or no water drive and an OGIP of 0.25 Bcm (8.82 Bcf). Individual well P/z data indicates that CC#1 R/D1 is isolated and should be evaluated separately while CC#3 R/D1 and CC#6 R/D2 appear to be in a common reservoir. OGIP for CC#1 R/D1 was determined to be 0.024 Bcm (0.853 Bcf) and minor water influx is indicated. The OGIP for the Bruer Pool excluding CC#1 R/D1 is 0.22 Bcm (7.98 Bcf). An unusual downward curvature of the P/z curve may indicate that there is

yet another undiscovered gas-bearing reservoir nearby. Back pressure tests (BPT) were conducted on three wells in the Bruer pool and one south of the pool. Using these down hole pressure measurements the absolute open flow (AOF) and flow characteristics (n) for each well was determined. The three Bruer pool BPT were combined to find the common AOF for the pool to be 1.4 Bcm/d (450 MMcf/d). Using a well spacing of 161,960 and 101,225 meters² (25 and 40 acres) the stabilization time were determined to be with a permeability of 0.36, 0.49, 0.99 μm^2 (364, 500 and 1000 md).

Using an annual storage cycle of 200 day injection at 1.4 Bcm (50 MMcf/d) and 100 day withdrawal at 2.8 Bcm (100 MMcf/d), an approximation of deliverabilities was determined to be between 0.9 and 14.8 Bcm/d (32 and 530 MMcf/d). This was calculated with the assumption of uniform porosity and permeability.

Using the average porosity for the reservoir and back pressure tests, a deliverability analysis was performed to determine the drainage radius and stabilization times. This analysis indicates that one, possibly two, wells are required for the Bruer Pool and two additional wells will be required for the Flora Pool to meet the deliverability required by Northwest Natural Gas Company. By plotting the values for deliverability on a structural map, the location of future wells may be determined.

In general, it appears that field parameters of individual wells varies greatly, and that parameter ranges are important. It is also clear that additional field information should be acquired. This information can be collected during the drilling of wells to be used in

the Mist Underground Storage Project.

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APPENDIX

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SELECTED WELL LOGS FROM THE MIST GAS FIELD

Electric log of the C&W#6-1 well, sec. 19, T. 6N., R. 4W.

Electric log of the CC#1 well, sec. 11,
T. 6N., R. 5W.

Electric log of the CC#10 well, sec. 3,
T. 6N., R. 5W.

Sonic log of the CC#10 well, sec. 3,
T. 6N., R. 5W.

Neutron-density log of the CC#10 well,
sec. 3, T. 6N., R. 5W.

APPENDIX B

COWLITZ FORMATION WEIGHTED GRAIN DENSITY CALCULATIONS *

<u>COMPONENT</u>	<u>PERCENT COMPOSITION</u>	<u>AVERAGE DENSITY</u>	<u>WEIGHTED DENSITY</u>
Rock fragments	0.11 / 1.09	X 2.65	= 0.27
Quartz	0.46 / 1.09	X 2.65	= 1.12
Potassium Feldspar	0.21 / 1.09	X 2.56	= 0.49
Plagioclase Feldspar	0.22 / 1.09	X 2.69	= 0.54
Mica	<u>0.09</u> / 1.09	X <u>2.80</u>	= <u>0.23</u>
TOTAL	1.09	13.35	2.65
AVERAGE			2.67

* Densities given in g/cm³.

APPENDIX C

CALCULATED S_w VERSUS DEPTH FOR WELL CC#10

CC#6 R/D2

ION	CONCENTRATION BY WEIGHT (ppm)	REACTION COEFFICIENT	REACTION VALUE	REACTION VALUE PERCENTAGE
Na^+	8500	x	$= 368.90$	38.33
K^+	40	x	$= 1.02$	0.11
Ca^{++}	1680	x	$= 83.83$	8.71
Mg^{++}	87	x	$= 71.43$	7.42
SO_4^-	<1.0	x	$= <0.02$	<0.002
Cl^-	15000	x	$= 437.10$	45.42
TOTAL			962.30	

CC#2

ION	CONCENTRATION BY WEIGHT (ppm)	REACTION COEFFICIENT	REACTION VALUE	REACTION VALUE PERCENTAGE
Na ⁺	7700	x	334.18	Na ⁺ + K ⁺ 40.76
K ⁺	66	x	54.19	388.37 47.37
Ca ⁺⁺	1130	x	23.50	Ca ⁺⁺ + Mg ⁺⁺ 2.87
Mg ⁺⁺	152	x	7.58	31.08 3.79
SO ₄ ⁻	34	x	0.95	0.12
Cl ⁻	15600	x	399.36	48.71
TOTAL			819.80	

LVF# 12-33

ION	CONCENTRATION BY WEIGHT (ppm)	REACTION COEFFICIENT	REACTION VALUE	REACTION VALUE PERCENTAGE
Na ⁺	6005	x	=	
		0.0434	260.62	35.88
K ⁺	75	x	=	
		0.0256	61.58	8.48
Ca ⁺⁺	1074	x	=	
		0.0499	22.34	3.08
Mg ⁺⁺	160	x	=	
		0.8210	7.98	1.10
SO ₄ ⁻	2	x	=	
		0.0208	0.06	0.01
Cl ⁻	14600	x	=	
		0.0282	373.76	51.46
TOTAL			726.30	

Na⁺ + K⁺ Na⁺ + K⁺

322.20 44.36

Ca⁺⁺ + Mg⁺⁺ Ca⁺⁺ + Mg⁺⁺

30.32 4.18

CC# 13-1

ION	CONCENTRATION BY WEIGHT (ppm)	REACTION COEFFICIENT	REACTION VALUE	REACTION VALUE PERCENTAGE
Na ⁺	8200	x 0.0434	= 355.88	45.83
K ⁺	ND	x 0.0256	= ND	ND
Ca ⁺⁺	1357	x 0.0499	= 67.71	8.72
Mg ⁺⁺	270	x 0.8210	= 13.47	1.73
SO ₄ ⁻	ND	x 0.0208	= ND	ND
Cl ⁻	14800	x 0.0282	= 378.88	48.80
TOTAL			776.46	

ND = NOT DETERMINED

NOTE: SAMPLE COLLECTED USING A 0.45 um FILTER.

APPENDIX D.

WATER RESISTIVITY (Rw) CALCULATIONS

Rw FROM WATER ANALYSIS - CC#6 R/D2 (BRUER POOL)

ION	CONCENTRATION (ppm)		WEIGHTING FACTOR		NaCl CONCENTRATION (ppm)
Na ⁺	8500	}	x	1.00	= 24000
Cl ⁻	15000				
Ca ⁺⁺	1680	x	1.04	=	1747
Mg ⁺⁺	87	x	1.90	=	165
SO ₄ ⁻	<1.0	x	---	=	---
K ⁺	40	x	0.90	=	<u>36</u>
TOTAL EQUIVALENT NaCl CONCENTRATION					= 25948

FROM SCHLUMBERGER CHART GEN-9, THE WATER RESISTIVITY, Rw,
AT A FORMATION TEMPERATURE OF 115 °F:

$$R_w @ 115^{\circ} F = 0.16 \text{ ohm-meters.}$$

TOTAL DISSOLVED SOLIDS = 26,228 mg/l.

WEIGHTING FACTORS FROM SCHLUMBERGER CHART GEN-8.

Rw FROM SP ANALYSIS - CC#6 R/D2

$$SSP = -74 \text{ mv}$$

$$R_{mf} = 1.66 @ 82^{\circ} F$$

SINCE $R_{mf} > 0.1 \text{ m}$, CONVERT R_{mf} TO FORMATION
TEMPERATURE WITH GEN-9.

$$R_{mf} @ 115^{\circ} F = 1.66 (82 + 6.77/115 + 6.77) = 1.210$$

$$\begin{aligned} R_{mfeq} &= 0.85(R_{mf}) \\ &= 0.85(1.210) = 1.0285 @ 115^{\circ} F \end{aligned}$$

$$R_{weq} = 0.12 @ 115^{\circ} F \text{ FROM SCHLUMBERGER CHART SP-1}$$

$$R_w = 0.145 \text{ FROM SP-2}$$

Rw FROM WATER ANALYSIS - CC#2 (DRY HOLE)

ION	CONCENTRATION (ppm)		WEIGHTING FACTOR		NaCl CONCENTRATION (ppm)
Na ⁺	7700	}	x	1.00	= 23300
Cl ⁻	15600				
Ca ⁺⁺	1130	x	1.09	=	1232
Mg ⁺⁺	152	x	1.85	=	281
SO ₄ ⁻	34	x	0.77	=	26
K ⁺	66	x	0.92	=	<u>61</u>
TOTAL EQUIVALENT NaCl CONCENTRATION					= 24900

FROM SCHLUMBERGER CHART GEN-9, THE WATER RESISTIVITY, R_w ,
AT A FORMATION TEMPERATURE OF 116 °F:

$$R_w @ 116 \text{ } ^\circ\text{F} = 0.16 \text{ ohm-meters.}$$

TOTAL DISSOLVED SOLIDS = 27,370 mg/l.

WEIGHTING FACTORS FROM SCHLUMBERGER CHART GEN-8.

Rw FROM SP ANALYSIS - CC#2

$$SSP = -60 \text{ mv}$$

$$R_{mf} = 2.85 @ 60 \text{ } ^\circ\text{F}$$

SINCE $R_{mf} > 0.1 \text{ m}$, CONVERT R_{mf} TO FORMATION
TEMPERATURE WITH GEN-9.

$$R_{mf} @ 60 \text{ } ^\circ\text{F} = 2.85(60 + 6.77/116 + 6.77) = 1.55$$

$$\begin{aligned} R_{mfeq} &= 0.85(R_{mf}) \\ &= 0.85(1.55) = 1.32 @ 116 \text{ } ^\circ\text{F} \end{aligned}$$

$$R_{weq} = 0.092 @ 116 \text{ } ^\circ\text{F FROM SCHLUMBERGER CHART SP-1}$$

$$R_w = 0.11 \text{ FROM SP-2}$$

Rw FROM WATER ANALYSIS - LVF#12-33 (NEWTON POOL)

ION	CONCENTRATION (ppm)		WEIGHTING FACTOR		NaCl CONCENTRATION (ppm)
Na ⁺	6005	}	x	1.00	= 20605
Cl ⁻	14600				
Ca ⁺⁺	1074	x	1.09	=	1171
Mg ⁺⁺	160	x	1.83	=	293
SO ₄ ⁻	2	x	---	=	---
K ⁺	75	x	0.75	=	<u>56</u>
TOTAL EQUIVALENT NaCl CONCENTRATION					= 22125

FROM SCHLUMBERGER CHART GEN-9, THE WATER RESISTIVITY, R_w ,
AT A FORMATION TEMPERATURE OF 106 °F:

$$R_w @ 106 \text{ °F} = 0.205 \text{ ohm-meters.}$$

TOTAL DISSOLVED SOLIDS = 24,582 mg/l.

WEIGHTING FACTORS FROM SCHLUMBERGER CHART GEN-8.

Rw FROM SP ANALYSIS - LVF#12-33

$$SSP = -57 \text{ mv}$$

$$R_{mf} = 1.61 @ 80 \text{ °F}$$

SINCE $R_{mf} > 0.1 \text{ m}$, CONVERT R_{mf} TO FORMATION
TEMPERATURE WITH GEN-9.

$$R_{mf} @ 80 \text{ °F} = 1.16 (80 + 6.77/106 + 6.77) = 0.893$$

$$\begin{aligned} R_{mfeq} &= 0.85(R_{mf}) \\ &= 0.85(0.893) = 0.076 @ 106 \text{ °F} \end{aligned}$$

$$R_{weq} = 0.017 @ 106 \text{ °F FROM SCHLUMBERGER CHART SP-1}$$

$$R_w = 0.037 \text{ FROM SP-2}$$

Rw FROM WATER ANALYSIS - CC#13-1 (DIAMOND POOL)

ION	CONCENTRATION (ppm)		WEIGHTING FACTOR		NaCl CONCENTRATION (ppm)
Na ⁺	8200	}	x	1.00	= 23000
Cl ⁻	14800				
Ca ⁺⁺	1357	x	1.03	=	1398
Mg ⁺⁺	270	x	1.78	=	481
SO ₄ ⁻	---	x	---	=	---
K ⁺	---	x	---	=	---
TOTAL EQUIVALENT NaCl CONCENTRATION					= 24879

FROM SCHLUMBERGER CHART GEN-9, THE WATER RESISTIVITY, R_w ,
AT A FORMATION TEMPERATURE OF 110 °F:

$$R_w @ 110 \text{ °F} = 0.175 \text{ ohm-meters.}$$

TOTAL DISSOLVED SOLIDS = 27,598 mg/l.

WEIGHTING FACTORS FROM SCHLUMBERGER CHART GEN-8.

Rw FROM SP ANALYSIS - CC#13-1 R/D1

$$SSP = -88 \text{ mv}$$

$$R_{mf} = 5.21 @ 50 \text{ °F}$$

SINCE $R_{mf} > 0.1 \text{ m}$, CONVERT R_{mf} TO FORMATION
TEMPERATURE WITH GEN-9.

$$R_{mf} @ 50 \text{ °F} = 5.21(50 + 6.77/110 + 6.77) = 2.533$$

$$\begin{aligned} R_{mfeq} &= 0.85(R_{mf}) \\ &= 0.855(2.533) = 2.153 @ 110 \text{ °F} \end{aligned}$$

$$R_{weq} = 0.145 @ 110 \text{ °F FROM SCHLUMBERGER CHART SP-1}$$

$$R_w = 0.17 \text{ FROM SP-2}$$

Rw FROM SP ANALYSIS - CC#10

SSP = -78 mv

Rmf = 3.57 @ 60 °F

SINCE Rmf > 0.1 m, CONVERT Rmf TO FORMATION
TEMPERATURE WITH GEN-9.

$Rmf @ 60\text{ }^{\circ}\text{F} = 3.57(60 + 6.77/109 + 6.77) = 2.059$

$Rmfeq = 0.85(Rmf)$
 $= 0.85(2.059) = 1.7502 @ 109\text{ }^{\circ}\text{F}$

$Rweq = 0.19 @ 109\text{ }^{\circ}\text{F}$ FROM SCHLUMBERGER CHART SP-1

$Rw = 0.225$ FROM SP-2

APPENDIX E

CALCULATED Sw VERSUS DEPTH FOR WELL CC#10

DEPTH		Sw	DEPTH		Sw
(meters)	(feet)	(percent)	(meters)	(feet)	(percent)
813.8	2670	50.7	820.2	2691	30.9
814.1	2671	48.6	820.5	2692	29.5
814.4	2672	48.5	820.8	2693	27.7
814.7	2673	44.4	821.1	2694	28.3
815.0	2674	37.1	821.4	2695	27.7
815.3	2675	39.3	821.7	2696	27.7
815.6	2676	36.6	822.0	2697	28.3
815.9	2677	32.7	822.3	2698	28.9
816.2	2678	31.6	822.6	2699	29.5
816.5	2679	32.4	822.9	2700	28.8
816.8	2680	40.3	823.2	2701	29.5
817.1	2681	43.9	823.5	2702	30.2
817.4	2682	41.7	823.8	2703	34.1
817.7	2683	38.3	824.1	2704	34.1
818.0	2683	34.4	824.4	2705	30.2
818.3	2685	32.4	824.7	2706	35.4
818.6	2686	31.6	825.0	2707	37.0
819.0	2687	28.3	825.4	2708	38.4
819.3	2688	27.7	825.7	2709	40.8
819.6	2689	28.9	826.0	2710	37.5
819.9	2690	30.0	826.3	2711	38.2

DEPTH		Sw	DEPTH		Sw
(meters)	(feet)	(percent)	(meters)	(feet)	(percent)
826.6	2712	50.0	833.0	2733	46.2
826.9	2713	45.9	833.3	2734	47.8
827.2	2714	53.0	833.6	2735	55.1
827.5	2715	55.6	833.9	2736	54.4
827.8	2716	51.8	834.2	2737	59.1
828.1	2717	57.6	834.5	2738	69.3
828.4	2718	48.3	834.8	2739	64.9
828.7	2719	35.8	835.1	2740	66.2
829.0	2720	29.0	835.4	2741	73.0
829.3	2721	26.4	835.7	2742	80.0
829.6	2722	27.5			
829.9	2723	28.9			
830.2	2724	30.2			
830.5	2725	30.9			
830.8	2726	31.6			
831.1	2727	32.7			
831.4	2728	33.0			
831.8	2729	36.6			
832.1	2730	38.1			
832.4	2731	41.0			
832.7	2732	43.2			

APPENDIX F

RESERVOIR SUMMARIES FOR THE BRUER AND FLORA POOLS

COLUMBIA COUNTY #1 RD
MIST GAS FIELD
BRUER RESERVOIR

WELL DATA

=====

Surface Elevation:	1033
Drilled Depth:	3105
Perforated Zone:	2448-2460
Net Perforations:	12
Date Completed:	5/1/79

CASING DATA

=====

Surface:	359', 7"
Product:	2598', 4 1/2"
Tubing:	2376', 2 3/8"
Plugs:	None

RESERVOIR DATA	9/10/79	3/19/80	9/1/80	3/26/81	6/8/82	2/22/83	10/24/83	4/17/84	10/23/84	11/20/84
=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
Pressure (PSIA)	971.3	940.2	827.2	625.2	330.4	357.5	332.7	331.6	348.4	351.7
Temperature (F)	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Composition:										
% C44	92.5x	92.2x	90.4x	90.4x	90.7x	90.7x	90.7x	90.7x	90.7x	90.7x
% N2	7.5x	7.8x	9.5x	9.5x	9.3x	9.3x	9.3x	9.3x	9.3x	9.3x
Other			0.1x	0.1x						
BTU/Cf	938.0	935.3	915.6	915.6	918.0	918.0	918.0	918.0	918.0	918.0
Specific Gravity	0.586	0.587	0.595	0.595	0.593	0.593	0.593	0.593	0.593	0.593
I	0.913	0.915	0.924	0.941	0.967	0.965	0.967	0.967	0.966	0.965
GAS-IN-PLACE DATA										
=====										
Production to Date (MMCF)	0.0	22.7	137.1	295.2	555.5	571.1	571.1	571.1	571.1	571.1
P/Z (PSIA)	1064	1027	895	665	342	371	344	343	361	364
Orig. Gas-in-Place (MMCF)		659.58	880.79	797.50	814.50	843.72	844.61	844.72	849.15	852.91
RESERVES DATA										
=====										
Abandonment Pres. (PSIA)		125	125	125	150	150	300	332	332	332
Original Reserves (MMCF)		581.89	775.54	702.73	697.69	722.22	597.66	570.53	573.36	575.75
Remaining Reserves (MMCF)		558.39	638.44	407.53	142.19	151.12	26.56	0.00	2.26	4.65

NOTES

=====

BRUER RESERVOIR
(Excluding CC #1)

MIST GAS FIELD

WELLS IN BRUER RESERVOIR

Columbia County #1 RD
Columbia County #3 RD
Columbia County #6 RD

RESERVOIR DATA

Date Discovered: 5/1/79
Date First Produced: 12/30/79
Reservoir Temp (Deg F) 110

[illegible]

FLORA RESERVOIR

MIST GAS FIELD

WELLS IN FLORA RESERVOIR

Columbia County #10
Columbia County #33-3

RESERVOIR DATA

Date Discovered: 10/8/79
Date First Produced: 4/26/80
Reservoir Temp (Deg F) 110

	3/20/80	11/13/80	3/26/81	6/9/82	2/22/82	10/24/83	4/18/84	10/24/84	11/19/84
PRESSURE DATA .									
CC #10 Pressure (PSIA)	1072.2	913.2	715.2	427.5	358.5	309.2	289.9	240.8	235.4
CC #33-3 Press. (PSIA)	---	869.2	713.2	425.4	342.3	272.9	229.4	198.7	205.1
Weighted Ave (PSIA)	1072.2	897.0	714.3	426.5	349.7	288.3	254.0	215.2	217.0

PRODUCTION DATA

	3/20/80	11/13/80	3/26/81	6/9/82	2/22/82	10/24/83	4/18/84	10/24/84	11/19/84
CC #10 (MMCF)	0.0	989.7	1742.6	2776.4	2810.3	2810.3	2810.3	2810.3	2810.3
CC #33-3 (MMCF)	0.0	576.3	1366.3	2702.6	3353.2	3826.8	4106.1	4345.8	4355.2
TOTAL (MMCF)	0.0	1566.0	3108.9	5479.0	6163.5	6637.1	6916.4	7156.1	7165.5

GAS COMPOSITION

	3/20/80	11/13/80	3/26/81	6/9/82	2/22/82	10/24/83	4/18/84	10/24/84	11/19/84
% CH ₄	95.0%	95.9%	95.9%	96.4%	96.4%	97.9%	94.6%	94.6%	94.6%
% N ₂	4.9%	4.1%	4.1%	3.6%	3.6%	2.1%	5.3%	5.3%	5.3%
Other	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
BTU/CF	965.5	955.0	955.0	975.0	975.0	990.8	958.6	958.6	958.6
Specific Gravity	0.576	0.572	0.572	0.569	0.569	0.563	0.577	0.577	0.577
Z	0.902	0.915	0.931	0.957	0.965	0.971	0.974	0.978	0.978

GAS-IN-PLACE DATA

	3/20/80	11/13/80	3/26/81	6/9/82	2/22/82	10/24/83	4/18/84	10/24/84	11/19/84
P/Z (PSIA)	1189	980	767	446	363	297	261	220	222
Orig. Gas-in-Place (MMCF)		8900.43	8775.41	8759.95	8816.80	8829.16	8839.29	8824.21	8821.23

RESERVES DATA

	3/20/80	11/13/80	3/26/81	6/9/82	2/22/82	10/24/83	4/18/84	10/24/84	11/19/84
Abandonment Pres. (PSIA)		125	125	125	150	175	175	175	175
Original Reserves (MMCF)		7952.52	7841.64	7828.09	7687.00	7505.46	7513.45	7501.32	7498.92
Remaining Reserves (MMCF)		6386.52	4732.74	2349.09	1523.50	868.37	597.05	345.23	333.42

NOTES

Field shut in on 11/1/1984

POROSITY AND PERMEABILITY OF COWLITZ FORMATION CORES*

TEXACO "CLATSKANIE NO. 1"

DEPTH (FEET)	PERMEABILITY (MILLIDARCIES)	POROSITY (PERCENT)	OIL SAT. (PERCENT)	WATER SAT. (PERCENT)	ROCK CLASSIFICATION
2124	82.0	24.5	0	91	Sandstone, arkosic
2132	8.0	20.3	0	91	Siltstone
2623	30.7	25.3	-	-	Sandstone, arkosic
2626	39.0	22.9	-	-	Sandstone, arkosic
2629	106.0	27.2	-	-	Sandstone, arkosic
2632	22.0	24.5	-	-	Sandstone, arkosic
2636	0.0	8.3	-	-	Siltstone
2638	29.0	21.5	-	-	Sandstone, arkosic
2642	9.0	21.1	-	-	Siltstone
2645	10.5	21.0	-	-	Siltstone
2648	8500.0	25.7	-	-	Sandstone, arkosic
2653	722.0	25.1	-	-	Sandstone, arkosic
2690	0.0	10.4	-	-	Siltstone
2694	1.2	19.5	-	-	Siltstone
2697	4.5	20.0	-	-	Siltstone
2699	17.0	27.9	-	-	Sandstone, arkosic
2702	1.4	22.4	-	-	Siltstone
2705	1.9	21.3	-	-	Siltstone
2708	1.7	15.8	-	-	Siltstone
2815	440.0	21.5	-	-	Sandstone, arkosic
2820	0.90	25.0	-	-	Siltstone
2835	0.87	20.3	-	-	Siltstone
5120	0.58	13.7	0	57	Sandstone, silty
5132	0.0	12.5	0	99	Siltstone, sandy
5442	0.0	7.1	0	100	Sandstone, silty
5455	0.0	8.5	0	100	Sandstone, silty

*Samples run in Texaco's Technical Service and Research Laboratory, 1947.

POROSITY AND PERMEABILITY OF COWLITZ FORMATION CORES*

TEXACO "CLARK & WILSON NO. 1"

DEPTH (FEET)	PERMEABILITY (MILLIDARCIES)	POROSITY (PERCENT)	OIL SAT. (PERCENT)	WATER SAT. (PERCENT)	ROCK CLASSIFICATION
1810.0	3.0	37.8	-	-	Sandstone, arkosic, micaceous
2015.6	81.1	29.0	0	125.0	Sandstone, arkosic, micaceous
2019.0	53.0	39.8	0	102.0	Sandstone, arkosic, micaceous
2020.0	28.5	36.7	0	87.0	Sandstone, arkosic, micaceous
2023.0	26.5	39.0	0	78.0	Sandstone, arkosic, micaceous
2028.6	10.2	29.7	0	94.0	Sandstone, arkosic, micaceous
2033+	59.7	30.8	-	-	Sandstone, arkosic, micaceous
2037.0	-	too friable	0	11.1	Sandstone, arkosic, micaceous
2039.0	-	too friable	0	18.6	Sandstone, arkosic, micaceous
2046.0	0	10.0	0	87.5	Sandstone, clayey
2050.0	19.4	30.2	0	100.1	Sandstone, arkosic, clayey
2054.0	6.4	29.2	0	92.9	Sandstone, arkosic, clayey
2058.0	3.6	27.9	0	99.0	Sandstone, arkosic, clayey
2060.0	3.5	29.4	0	97.0	Sandstone, arkosic, clayey
2063-4	6.5	29.0	0	109.1	Sandstone, arkosic, clayey
2066-7	6.0	26.7	0	106.1	Sandstone, arkosic, clayey
2070.6	5.1	25.5	0	120.0	Sandstone, arkosic, clayey
3066.0	23.2	23.0	0	118.6	Sandstone, arkosic, micaceous
3068.0	18.0	22.2	0	102.0	Sandstone, arkosic, micaceous
3070.0	46.2	21.7	0	112.5	Sandstone, arkosic, micaceous
3073.0	65.0	23.1	0	96.5	Sandstone, arkosic, micaceous
3075.0	18.1	19.2	0	108.0	Sandstone, arkosic, micaceous
3077.0	84.6	23.9	0	89.8	Sandstone, arkosic, micaceous
3081.0	22.0	27.4	0	99.5	Sandstone, arkosic, micaceous
3082.0	521.6	29.5	0	99.6	Sandstone, arkosic, micaceous
3085.0	806.1	27.9	0	89.0	Sandstone, arkosic, micaceous
3088.0	348.4	25.9	0	91.1	Sandstone, arkosic, micaceous
3090.0	379.4	29.4	0	82.3	Sandstone, arkosic, micaceous
3093.0	49.6	24.1	0	117.9	Sandstone, arkosic, micaceous
3099.0	45.2	28.1	0	93.5	Sandstone, arkosic, micaceous
3103.0	553.8	32.2	0	72.2	Sandstone, arkosic, micaceous
3105.0	1,302.3	26.2	0	95.5	Sandstone, arkosic, micaceous
3112.0	566.7	29.4	0	93.1	Sandstone, arkosic, micaceous
3122.0	717.6	26.9	0	84.5	Sandstone, arkosic, micaceous
3212.0	-	too friable	0	8.4	Sandstone, arkosic, micaceous

TEXACO "CLARK & WILSON NO. 1" Continued

DEPTH (FEET)	PERMEABILITY (MILLIDARCIES)	POROSITY (PERCENT)	OIL SAT. (PERCENT)	WATER SAT. (PERCENT)	ROCK CLASSIFICATION
3214.0	-	too friable	0	11.2	Sandstone, arkosic, micaceous
3219.0	56.4	26.3	0	118.3	Sandstone, arkosic, micaceous
3224.0	251.1	27.5	0	86.4	Sandstone, arkosic, micaceous
3226.0	163.9	25.5	0	93.2	Sandstone, arkosic, micaceous
3229.0	151.5	26.4	0	118.8	Sandstone, arkosic, micaceous
3232.0	-	too friable	0	16.7	Sandstone, arkosic, micaceous
3234.0	290.8	23.1	0	135.7	Sandstone, arkosic, micaceous
3236.0	95.2	24.0	0	135.0	Sandstone, arkosic, micaceous
3239.0	398.5	29.4	0	91.6	Sandstone, arkosic, micaceous
3285.0	73.9	22.8	0	102.6	Sandstone, arkosic, micaceous
3287.0	276.7	26.5	0	87.2	Sandstone, arkosic, micaceous
3290.0	192.0	25.3	0	87.2	Sandstone, arkosic, micaceous
3296.0	144.0	26.2	0	82.4	Sandstone, arkosic, micaceous
3300.0	488.4	29.0	0	74.1	Sandstone, arkosic, micaceous
3304.0	499.0	27.1	0	85.4	Sandstone, arkosic, micaceous
3310.0	134.9	25.5	0	77.4	Sandstone, arkosic, micaceous
4830.0	-	too friable	-	-	Sandstone, silty, tuffaceous
5935.0	-	too friable	-	-	Sandstone, silty, tuffaceous
7378.0	-	too friable	-	-	Sandstone (?), hard, silty
7726.0	0	2.6	-	-	Siltstone, sandy
7832.0	0	0.8	-	-	Siltstone, sandy
7865.0	0	12.8	-	-	Siltstone, sandy
7895.0	-	too friable	-	-	Sandstone (?)
7900.0	0	15.8	-	-	Siltstone, sandy
7905.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7930.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7931.0	0	4.6	-	-	Siltstone, sandy
7935.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7938.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7940.0	0	4.7	-	-	Siltstone, sandy
7948.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7972.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7975.0	-	too friable	-	-	Sandstone, arkosic, micaceous
7985.0	-	too friable	-	-	Sandstone, arkosic, micaceous
8005.0	0	2.4	-	-	Siltstone, sandy
8023.0	0	4.0	-	-	Sandstone, arkosic, hard, tight
8060.0	0	3.0	-	-	Sandstone, arkosic, hard, tight
8163.0	0	10.9	0	145.5	Sandstone, arkosic, hard, tight

TEXACO "CLARK & WILSON NO. 1" Continued

DEPTH (FEET)	PERMEABILITY (MILLIDARCIES)	POROSITY (PERCENT)	OIL SAT. (PERCENT)	WATER SAT. (PERCENT)	ROCK CLASSIFICATION
8166.0	0	4.2	0	94.7	Sandstone, arkosic, hard, tight
8170.0	0.94	13.5	0	69.0	Sandstone, arkosic, hard, tight
8174.0	0	7.5	0	206.5	Sandstone, arkosic, hard, tight
8177.0	0	8.6	0	99.5	Sandstone, arkosic, hard, tight
8182.0	0	10.3	-	-	Sandstone, arkosic, hard, tight
8189.0	0	5.3	-	-	Sandstone, arkosic, hard, tight
8191.0	0	8.8	-	-	Sandstone, arkosic, hard, tight
8193.0	0	11.4	-	-	Sandstone, arkosic, hard, tight
8195.0	0	11.3	-	-	Sandstone, arkosic, hard, tight
8198.0	0	8.8	-	-	Sandstone, arkosic, hard, tight
8201.0	0	11.0	-	-	Sandstone, arkosic, hard, tight
8204.0	0	1.7	-	-	Sandstone, arkosic, hard, tight
8225.0	0	0.4	-	-	Siltstone

* Samples run in Texaco's Technical Service and Research Laboratory, 1947.

CC#1 SIDEWALL CORE RESULTS

DEPTH, FEET	PERM. MD.	POR. %	% POR. SAT.		O/W	smpl. wt.	API	DESCRIPTION
			OIL	TOTAL WATER				
2301	197	28.1	0.0	65.1	---	11		sd; gy, vfgr, calc, no stn, no flu
2306	19	29.5	0.0	76.4	---	11		sd; gy, vfgr, vshy, no stn, no flu
8	12	27.9	0.0	89.9	---	10		sh; gy, f gy sd incls, no stn, no flu
2439	18	25.4	0.0	84.0	---	9		same
2440	97	29.5	0.0	60.8	---	12		sd; gy, fgr, slty/clt lom, calc, no stn, no flu
2441	179	31.6	0.0	57.3	---	8		same
2442	221	32.0	0.0	57.1	---	11		some
2443	212	22.2	0.0	75.5	---	13		sd; gy, fgr, slty, calc/carb lom, no stn, no flu
2444	148	33.7	0.0	60.4	---	11		sd; gy, fgr, slty, clt incls, calc, no stn, no flu
2445	64	30.1	0.0	79.1	---	12		sd; gy, fgr, slty, hvy carb loms, no stn, no flu
2446	287	32.5	0.0	66.8	---	13		sd; gy, fgr, slty, calc, no stn, no flu
2447	14	30.1	0.0	74.6	---	15		sd; gy, fgr, slty, shly, no stn, no flu
2448	103	31.8	0.0	72.3	---	18		sd; gy, fgr, slty, carb loms, no stn, no flu
2449	52	33.3	0.0	64.7	---	10		sd; lt ton, fgr, slty/hvy incls, no stn, no flu
2450	326	33.1	0.0	63.0	---	8		sd; gy, fgr, slty, no stn, no flu
2456	445	33.4	0.0	73.7	---	13		same
2459	363	34.2	0.0	83.0	---	12		some
2508	41	28.4	0.0	74.7	---	12		sh; gy/qv sd loms, no stn, no flu
2511	84	32.5	0.0	77.1	---	11		sd; lt ton, fgr, slty, muddy, no stn, no flu
2520	683	33.2	0.0	81.1	---	13		sd; gy, f-mgr, slty, no stn, no flu
2531	78	30.1	0.0	73.2	---	11		sd' gy, fgr, slty/abnt carb loms, no stn, no flu
2563	141	30.5	0.0	74.5	---	13		sd; lt ton, fgr, slty, hi calc, no stn, no flu
3	316	34.6	0.0	81.4	---	10		sd; gy, fgr, slty, no stn, no flu
2599	62	32.6	0.0	80.0	---	9		same/carb loms, calc, no stn, no flu
2602	417	29.5	0.0	82.4	---	12		sd; gy, fgr, slty, no stn, no flu
2609	122	33.7	0.0	74.7	---	14		sd; gy, fgr, slty, calc/carb loms, no stn, no flu
2643	100	32.2	0.0	92.7	---	15		sd; gy, fgr, slty, clt, no stn, no flu
2643	70	32.5	0.0	70.6	---	10		sd; gy, vf-fgr, vcarb loms, clt, no stn, no flu
2688	94	32.8	0.0	73.5	----	15		same
2759	346	31.5	0.0	84.9	----	13		sd; lt gy, f-mgr, slty, no stn, no flu
2794	109	33.3	0.0	79.9	----	13		sd; gy, vfgr, clt, no stn, no flu
2802	88	24.8	0.0	81.5	----	10		sd; gy, fgr, slty, clt, no stn, no flu
2853	26	37.7	0.0	90.2	----	9		sd; gy, vfgr, vclt, no stn, no flu
2899	192	31.3	0.0	82.4	----	11		sd; gy, fgr, slty, no stn, no flu
2914	41	34.0	5.6	69.8	.08	13		sd; gy, vfgr, abnt carb loms, no stn, no flu
2943	175	30.2	0.0	90.4	----	11		sd; gy, fgr, slty, clt, no stn, no flu
2975	54	24.1	0.0	92.1	----	6		sd; gy, fgr, slty/carb incls, no stn, no flu
2989	431	31.3	0.0	90.9	----	9		sd; gy, fgr, slty, no stn, no flu
3011	162	29.2	0.0	72.3	----	5		some/clt

APPENDIX I

CALCULATED SHALE VOLUMES FOR WELL CC#10

DEPTH		Vsh (percent)	DEPTH		Vsh (percent)
(meters)	(feet)		(meters)	(feet)	
792.4	2600	98	798.8	2621	82
792.7	2601	96	799.1	2622	81
793.0	2602	100	799.4	2623	80
793.4	2603	97	799.8	2624	83
793.7	2604	90	800.1	2625	85
794.0	2605	86	800.4	2626	88
794.3	2606	89	800.7	2627	87
794.6	2607	92	801.0	2628	89
794.9	2608	99	801.3	2629	89
795.2	2609	97	801.6	2630	88
795.5	2610	91	801.9	2631	83
795.8	2611	88	802.2	2632	80
796.1	2612	90	802.5	2633	78
796.4	2613	89	802.8	2634	81
796.7	2614	89	803.1	2635	80
797.0	2615	90	803.4	2636	80
797.3	2616	94	803.7	2637	83
797.6	2617	92	804.0	2638	87
797.9	2618	90	804.3	2639	87
798.2	2619	88	804.6	2640	89
798.5	2620	83	804.9	2641	95

DEPTH		Vsh (percent)	DEPTH		Vsh (percent)
(meters)	(feet)		(meters)	(feet)	
805.2	2642	100	837.5	2748	21
805.5	2643	95	837.8	2749	21
805.8	2644	92	838.2	2750	21
806.2	2645	91	838.5	2751	16
806.5	2646	89	838.8	2752	15
806.8	2647	86	839.1	2753	17
807.1	2648	83	839.4	2754	17
807.4	2649	84	839.7	2755	18
807.7	2650	83	840.0	2756	14
808.0	2651	82	840.3	2757	13
808.3	2652	80	840.6	2758	13
808.6	2653	73	840.9	2759	13
809.0	2654	69	841.2	2760	13
809.2	2655	66	841.5	2761	14
809.5	2656	66	841.8	2762	14
809.8	2657	70	842.1	2763	14
810.1	2658	75	842.4	2764	34
810.4	2659	75	842.7	2765	31
810.7	2660	78	843.0	2766	34
GAS ZONE			843.3	2767	34
			843.6	2768	34

DEPTH		Vsh (percent)	DEPTH		Vsh (percent)
(meters)	(feet)		(meters)	(feet)	
844.0	2769	34	850.4	2790	14
844.2	2770	35	850.6	2791	14
844.6	2771	30	851.0	2792	14
844.9	2772	22	851.3	2793	11
845.2	2773	17	851.6	2794	14
845.5	2774	4	851.9	2795	16
845.8	2775	0	852.2	2796	11
846.1	2776	0	852.5	2797	2
846.4	2777	0	852.8	2798	2
846.7	2778	0	853.1	2799	8
847.0	2779	0	853.4	2800	7
847.3	2780	5	853.7	2801	11
847.6	2781	6	854.0	2802	8
847.9	2782	8	854.3	2803	10
848.2	2783	8	854.6	2804	19
848.5	2784	7	854.9	2805	30
848.8	2785	5	855.2	2806	27
849.1	2786	10	855.5	2807	21
849.4	2787	18	855.8	2808	11
849.7	2788	14	856.1	2809	10
850.0	2789	14	856.4	2810	15

DEPTH		Vsh (percent)	DEPTH		Vsh (percent)
(meters)	(feet)		(meters)	(feet)	
856.8	2811	14	863.2	2832	22
857.0	2812	10	863.4	2833	27
857.4	2813	10	863.8	2834	27
857.7	2814	10	864.1	2835	20
858.0	2815	11	864.4	2836	20
858.3	2816	20	864.7	2837	17
858.6	2817	17	865.0	2838	10
858.9	2818	20	865.3	2839	5
859.2	2819	20	865.6	2840	1
859.5	2820	14	865.9	2841	5
859.8	2821	13	866.2	2842	3
860.1	2822	16	866.5	2843	3
860.4	2823	27	866.8	2844	3
860.7	2824	27	867.1	2845	10
861.0	2825	27	867.4	2846	12
861.3	2826	31	867.7	2847	12
861.6	2827	38	868.2	2848	9
861.9	2828	36	868.3	2849	5
862.2	2829	31	868.6	2850	3
862.5	2830	25	868.9	2851	5
862.8	2831	24	869.2	2852	7

DEPTH		Vsh (percent)	DEPTH		Vsh (percent)
(meters)	(feet)		(meters)	(feet)	
869.6	2853	5	876.0	2874	14
869.8	2854	5	876.2	2875	16
870.2	2855	12	876.6	2876	17
870.5	2856	15	876.9	2877	15
870.8	2857	13	877.2	2878	7
871.1	2858	10	877.5	2879	5
871.4	2859	8	877.8	2880	3
871.7	2860	5	878.1	2881	3
872.0	2861	5	878.4	2882	5
872.3	2862	5	878.7	2883	3
872.6	2863	3	879.0	2884	1
872.9	2864	5	879.3	2885	0
873.2	2865	15	879.6	2886	1
873.5	2866	21	879.9	2887	3
873.8	2867	20	880.2	2888	3
874.1	2868	20	880.5	2889	5
874.4	2869	23	880.8	2890	10
874.7	2870	24	881.1	2891	16
875.0	2871	20	881.4	2892	20
875.3	2872	14	881.7	2893	26
875.6	2873	17	882.0	2894	34

DEPTH		Vsh (percent)	DEPTH		Vsh (percent)
(meters)	(feet)		(meters)	(feet)	
882.4	2895	39	888.8	2916	17
882.6	2896	42	889.0	2917	13
883.0	2897	44	889.4	2918	18
883.3	2898	36	889.7	1919	3
883.6	2899	12	890.0	1920	0
883.9	2900	9	890.3	2921	0
884.2	2901	18	890.6	2922	2
884.5	2902	10	890.9	2923	4
884.8	2903	10	891.2	2924	6
885.1	2904	7	891.5	2925	16
885.4	2905	7	891.8	2926	5
885.7	2906	18	892.1	2927	5
886.0	2907	29	892.4	2928	7
886.3	2908	40	892.7	2929	5
886.6	2909	42	893.0	2930	0
886.9	2910	41			
887.2	2911	33			
887.5	2912	40			
887.8	2913	40			
888.1	2914	34			
888.4	2915	26			

APPENDIX J

SONIC POROSITY CALCULATED USING SEVERAL SONIC
CORRECTION FACTORS FOR WELL CC#10

DEPTH		SONIC POROSITY (%)		
meters	feet	density-sonic Cp = 1.4	neutron Cp = 1.6	Ro Cp = 1.9
847.3	2780	31.9	27.9	23.5
847.9	2782	36.1	31.6	26.6
848.5	2784	35.6	31.1	26.2
849.1	2786	34.5	30.2	25.4
849.7	2788	37.2	32.6	27.4
850.4	2790	39.9	34.9	29.4
851.0	2792	36.1	31.6	26.6
851.6	2794	37.2	32.6	27.4
852.2	2796	45.2	39.6	33.3
852.8	2798	42.6	37.2	31.4
853.4	2800	43.5	30.2	25.4
854.0	2802	29.1	25.0	21.5
854.6	2804	25.4	22.2	18.7
855.2	2806	42.6	37.2	31.4
855.8	2808	45.2	39.6	33.3
856.4	2810	44.7	39.1	32.9
857.0	2812	35.6	31.1	26.2
857.7	2814	32.4	28.3	23.8
858.3	2816	31.9	27.9	23.5
858.9	2818	32.4	28.3	23.8
859.5	2820	31.3	27.4	23.0

VISCOSITY OF 0.6 GRAVITY GAS VERSUS TEMPERATURE