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WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 4, 2007

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Gentlemen:

In accordance with your request, we have estimated the gross (100 percent) proved and probable gas reserves, as of December 31, 2005, for certain oil and gas properties located in the Cook Inlet Region of Alaska. It is our understanding that this report will be used as part of the Application to Amend Authorization to Export Liquefied Natural Gas to be filed with the United States Department of Energy. The information used in preparing this report was limited to data solely available in the public domain.

We estimate the gross (100 percent) gas reserves for the Cook Inlet Region of Alaska, as of December 31, 2005, to be:

Category	Gross (100 Percent) Gas Reserves (BCF)
Total Proved (1P)	1,211.8
Probable	514.6
Proved + Probable (2P)	1,726.4

Gas volumes are expressed in billions of cubic feet (BCF), determined using 60 degrees Fahrenheit and 14.65 pounds per square inch absolute.

The estimates shown in this report are for proved and probable reserves. No study was made to determine whether possible reserves might be established for these properties. For the purposes of this report, we refer to the proved reserves as "1P" reserves and the proved plus probable reserves as "2P" reserves. Reserve categorization conveys the relative degree of certainty; the estimates of reserves included herein have not been adjusted for risk. Definitions of reserve categories are presented immediately following this letter. As shown in the Table of Contents, this report includes a technical discussion along with pertinent figures.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and their related facilities. We have not investigated possible environmental liability related to the properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. They may or may not be recovered, and, because of governmental policies and uncertainties of supply and demand, the actual production rates may vary from assumptions made while preparing this report. Also, estimates of reserves may increase or decrease as a result of future operations.

In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geologic. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geologic data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from the nonconfidential files of the Alaska Oil and Gas Conservation Commission, the Alaska Department of Natural Resources, and IHS Energy using PI/Dwights Plus® on CD 1.6 and were accepted as accurate. Supporting geologic, field performance, and work data are on file in our office. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties and are not employed on a contingent basis.

Very truly yours,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Frederic D. Sewell, P.E.
Frederic D. Sewell, P.E.
Chairman and Chief Executive Officer

By: /s/ Danny D. Simmons, P.E.
Danny D. Simmons, P.E.
Executive Vice President

Date Signed: January 4, 2007

By: /s/ David E. Nice, P.G.
David E. Nice, P.G.
Vice President and Technical Advisor

Date Signed: January 4, 2007

RBT:LPV

NETHERLAND, SEWELL
& ASSOCIATES, INC.

PETROLEUM RESERVES DEFINITIONS

Approved by the Society of Petroleum Engineers and World Petroleum Council, March 1997

Reserves derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of development, degree of depletion of the reservoirs, and amount of available data. Use of these definitions should sharpen the distinction between the various classifications and provide more consistent reserves reporting.

DEFINITIONS

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the Society of Petroleum Engineers (SPE) and World Petroleum Council (WPC, formerly World Petroleum Congresses) in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

PROVED RESERVES

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

PETROLEUM RESERVES DEFINITIONS

Approved by the Society of Petroleum Engineers and World Petroleum Council, March 1997

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

Possible Reserves
Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

RESERVE STATUS CATEGORIES
Reserve status categories define the development and producing status of wells and reservoirs.

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing: Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-producing: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves: Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE) Inc., and the Executive Board, World Petroleum Council (WPC), March 1997. (Reprinted with permission.)

NETHERLAND, SEWELL & ASSOCIATES, INC.

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THE COOK INLET REGION OF ALASKA

1.0 OVERVIEW

Netherland, Sewell & Associates, Inc. (NSAI) has been engaged by ConocoPhillips Alaska Natural Gas Corporation (ConocoPhillips) and Marathon Oil Company (Marathon) to estimate the gross (100 percent) proved and probable gas reserves, as of December 31, 2005, for the Cook Inlet Region of Alaska. It is our understanding that this report will be used as part of the Application to Amend Authorization to Export Liquefied Natural Gas to be filed with the United States Department of Energy.

The information used in preparing this report was limited to data solely available in the public domain. These data were obtained from the nonconfidential files of the Alaska Oil and Gas Conservation Commission (AOGCC), the Alaska Department of Natural Resources, and IHS Energy using PI/Dwights Plus® on CD 1.6. Data from the AOGCC was made available at their offices in Anchorage, Alaska, or via their website at http://www.state.ak.us/local/akpages/ADMIN/ogc/homeogc.htm. PI/Dwights is a database of well and production data built from publicly available information.

The following table sets forth our estimates of the gross (100 percent) gas reserves for the Cook Inlet Region of Alaska, as of December 31, 2005:

Category	Gross (100 Percent) Gas Reserves (BCF)
Total Proved (1P)	1,211.8
Probable	514.6
Proved + Probable (2P)	1,726.4

Gas volumes are expressed in billions of standard cubic feet (BCF), determined using 60 degrees Fahrenheit and 14.65 psia. For the purposes of this report, we refer to the proved reserves as "1P" reserves and the proved plus probable reserves as "2P" reserves. Reserve categorization conveys the relative degree of certainty; the estimates of reserves included herein have not been adjusted for risk.

1.1 PROPERTY DESCRIPTION

1.1.1 General

The properties included in this report consist of 22 active field areas located in the Cook Inlet Basin. For the purposes of this report, we have subdivided the properties into eight field areas: (1) Beaver Creek, (2) Beluga River, (3) Cannery Loop Unit, (4) Kenai, (5) McArthur River, (6) Ninilchik, (7) North Cook Inlet, and (8) Other. The Other field area is comprised of 15 fields and is discussed in Section 10.0 of this report.

The following table sets forth the gross (100 percent) gas reserves by field area, as of December 31, 2005:

Field Area	Gross (100 Percent) Gas Reserves (BCF) 1P	2P
Beaver Creek	39.6	41.1
Beluga River	473.3	509.4
Cannery Loop Unit	44.2	44.2
Kenai	98.0	173.2
McArthur River	89.4	174.9
Ninilchik	56.4	82.5
North Cook Inlet	350.3	610.2
Other	60.6	90.9
Total	1,211.8	1,726.4

1.1.2 Geologic Setting

The Cook Inlet Region is located in southern Alaska, as shown on the regional location map in Figure 1.3.1. It is bordered by the granitic batholiths of the Aleutian Range and the Talkeetna Mountains on the northwest and by the Border Ranges of the Kenai Peninsula on the southeast. The area has been part of a convergent margin since the Jurassic Period. The sediments deposited between these mountain ranges consist of Jurassic and Lower Cretaceous rocks of peninsular terrain and Upper Cretaceous and Cenozoic rocks of the Postamalgum sequence.

1.1.3 Stratigraphy

The Cook Inlet was a back-arc basin for most of the Jurassic Period. The Lower Jurassic Talkeetna Formation consists of poorly-bedded volcanics and tuffs interbedded with marine sandstone, shale, and limestone to the southwest. This formation lies unconformably on Triassic metamorphics.

As shown in Figure 1.3.2, Middle and Upper Jurassic marine sedimentary rocks overlie the Talkeetna Formation. This upwardly shallowing succession of rocks is subdivided into the Tuxedni Group, the Chinitna Formation, and the Naknek Formation. The shale-prone Tuxedni Group is thought to be the primary source of oil in the Cook Inlet.

The Cretaceous/Paleocene boundary is marked by an unconformity and a change from marine deposition to non-marine deposition. This change in sedimentation also marks the change from a back-arc basin to a fore-arc basin. The West Foreland Formation of Paleocene and Eocene age is predominantly composed of feldspathic sandstone, coal, and minor conglomerates.

Unconformably overlying the West Foreland Formation is the Oligocene Hemlock Formation. The Hemlock is predominantly a conglomerate and is the most prolific oil producer in the basin. The Hemlock grades upward into the sands, siltstones, shales, and coals of the Tyonek Formation.

The Tyonek Formation is Oligocene to Lower Miocene in age and produces some oil in the lower part of the formation. The upper section of the Tyonek primarily produces non-associated gas of probable biogenic origin. The Tyonek sands are riverine and point bar deposits and therefore may be more limited in extent and typically exhibit depletion-drive reservoir energy.

Unconformably overlying the Tyonek is the Beluga Formation. The Beluga is of Upper Miocene age and is composed of sandstone, siltstone, shale, and coal similar to the Tyonek, but the sand bodies have less areal extent and are less correlatable than the Tyonek. Reservoirs in the Beluga typically contain non-associated gas of biogenic origin.

The sand-rich Sterling Formation overlies the Beluga. Individual sands can reach a thickness of greater than 200 feet and are very correlatable. These sands were deposited in an anastomosing, or braided, river valley. Reservoir top seal and fault juxtaposition are significant risks in these sands. Non-associated gas sands that exhibit a combination of pressure depletion and water-drive are predominant in the Sterling Formation.

1.1.4 Structure and Hydrocarbon Migration

The Cook Inlet has experienced compressional forces since the late Mesozoic age. Mild compressional forces folded the sediments into broad folds on the edges of the basin during the Upper Miocene. Oil migrated from the center of the basin into reservoir rocks at this time. Increased compression during Pliocene and Pleistocene time caused intense folding and high-angle reverse faulting. Secondary oil migration into these new structures occurred at this time.

The non-associated dry gas found in the Tyonek, Beluga, and Sterling Formations is probably indigenously sourced from the coals that are deposited with the sands and from marsh gas of biologic origin that has been buried with the sediments.

1.2 PETROPHYSICAL ANALYSIS

The digital well log data used in this study are publicly available through the AOGCC. All wells with sufficient log curves for log analysis were retrieved for the Kenai and Ninilchik field areas.

Baselines developed for the spontaneous potential data and environmental corrections were performed for the bulk density measurements. Corrections conducted for a sample of the resistivity measurements indicated that standard corrections procedures had a negligible impact on the deep resistivity readings. Since sufficient data to perform environmental correction calculations did not exist for most wells and preliminary calculations showed little impact, no corrections were performed for the resistivity data.

Coals and tight intervals were identified using the resistivity, bulk density, and sonic log measurements. These intervals were eliminated from subsequent petrophysical analysis.

Shale volume was predicted using the spontaneous potential, resistivity, and neutron and bulk density log measurements. Multiple shale volume indicators were employed, and the lowest predicted shale volume was carried forward for subsequent petrophysical modeling.

Total porosity was generally calculated from either the bulk density or sonic log measurements. In situations where both measurements were available, the porosity values calculated from the bulk density measurements were considered more reliable. When sonic log measurements were only available, corrections were applied to account for compaction effects observed in the raw measurements. These corrections were based on analysis of wells that had both sonic and bulk density measurements over the same intervals. Porosities were calculated using standard density-neutron techniques for a few wells logged with modern equipment.

Water saturation calculations were performed using three models: the standard Archie model, a laminated sand-shale model, and the Dual Water model for dispersed clays. These models represent the effects of uncertainties in clay and shale volume and distribution on the prediction of water saturation. Calculations were conducted for three formation water resistivity conditions (0.25, 1.0, and 2.5 ohm-meters at 77 degrees Fahrenheit). These resistivities reasonably reflect the range of formation water resistivity values found in the field areas. Petrophysical calculations were carried out for approximately 9 wells.

Core data were not publicly available to compare measured values of porosity and water saturation against log-derived values. However, the results of the porosity and water saturation calculations with respect to well performance indicate that there is no one best interpretation model. The well performance indicates that results somewhere between those predicted with the laminated sand-shale model and the Dual Water model are the most reasonable. A wide range of possible outcomes is predicted with these two models. It is not possible to accurately define clay and shale distribution or formation water resistivity with log data alone, and sufficient core data to accurately model clay composition and distribution over large areas were not available. Thus, sufficient certainty does not exist to use the log interpretation results alone to predict the performance of potential behind pipe reserves. However, when used in conjunction with production and test data, log interpretation results can be helpful in identifying behind pipe potential.

FIGURES

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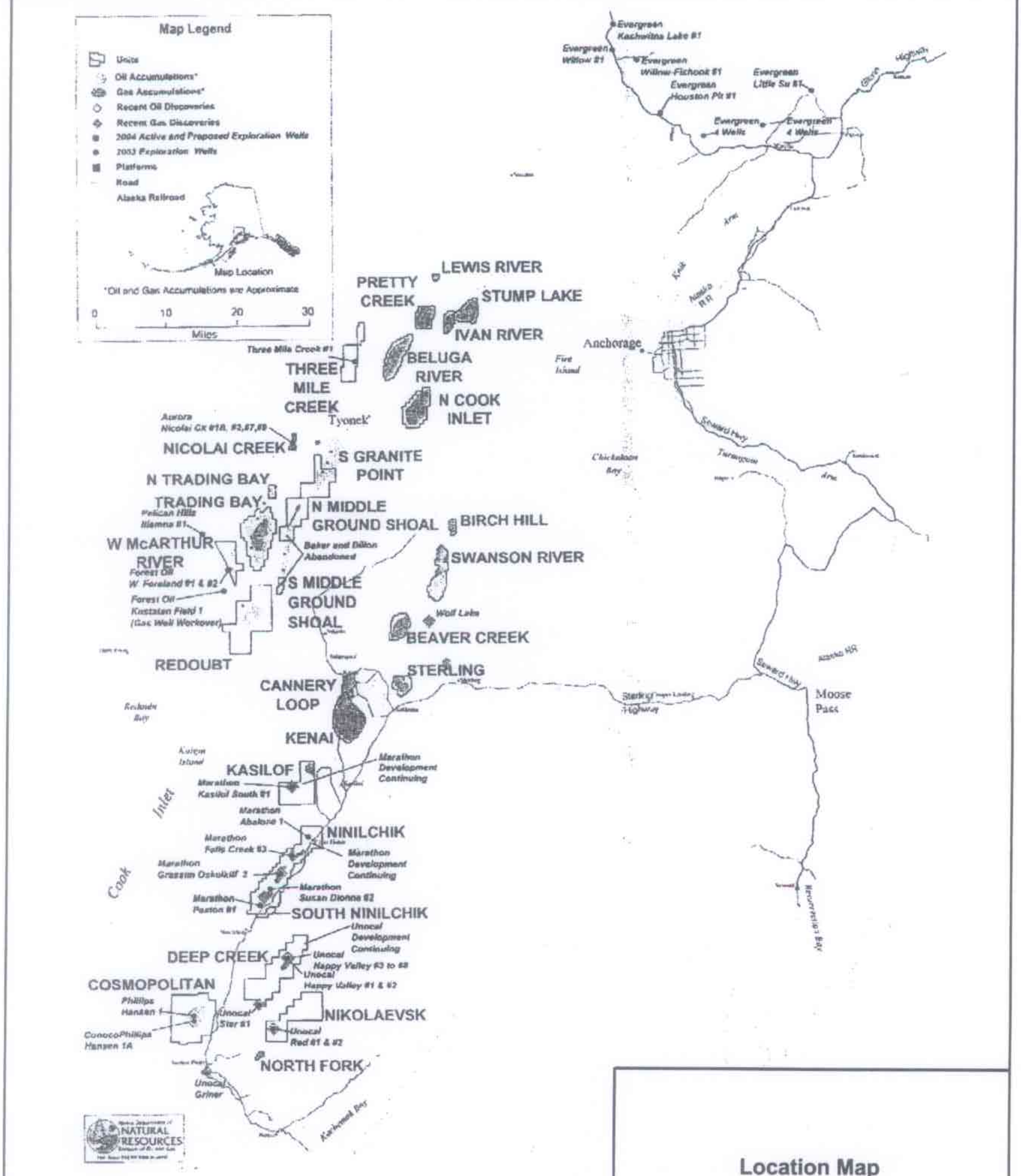

Important Note:

The presented material was assembled and revised by Netherland, Sewell & Associates, Inc. ("NSAI") from data and interpretations provided by public domain sources including the Alaska Oil and Gas Conservation Commission. This exhibit is for illustrative purposes only and we have not verified the content thereon.

Location Map

Cook Inlet Region, Alaska

Figure 1.3.1

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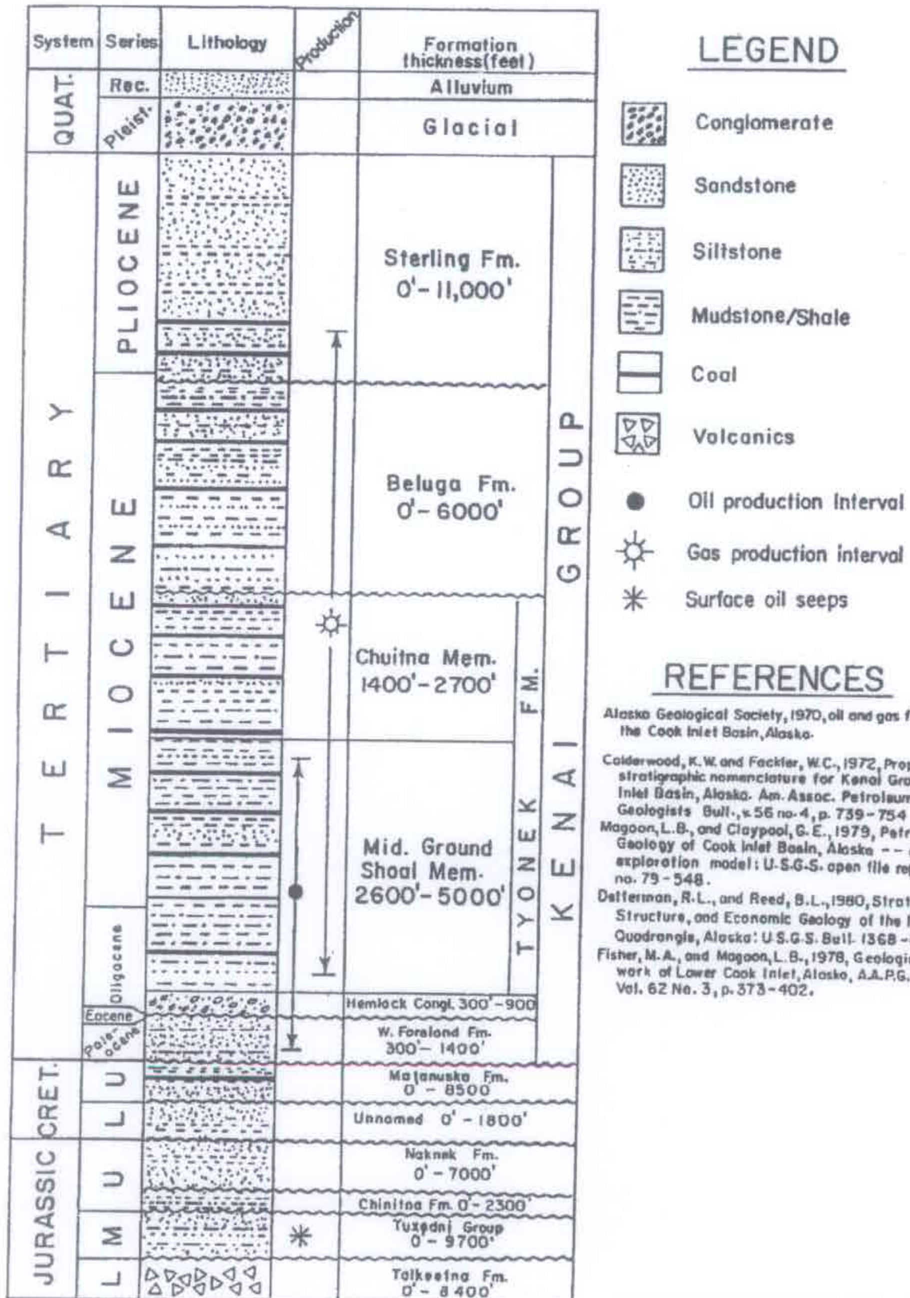

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Important Note:

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Generalized Stratigraphic Column

Cook Inlet Region, Alaska

Figure 1.3.2

2.0 RESERVES METHODOLOGY

For the purposes of this report, three generally practiced techniques for the estimation of reserves were used. They include decline curve analysis, material balance, and volumetric analysis.

2.1 DECLINE CURVE ANALYSIS

Decline curve analysis is a method of forecasting the rate, and hence remaining reserves, by fitting a curve to historical production data and extrapolating that curve into the future. Various methods of decline curve analysis are utilized based on the type and manner of the production decline rate versus time (Slider, 1983). Exponential decline appears linear on a plot of production versus time on a semi-logarithmic scale. The rate of decline, shown with a negative assuming the rate is dropping with time, can be expressed as:

$$-a = \frac{1}{q}\frac{\Delta q}{\Delta t}$$

where: a = decline factor, 1/month
q = rate of production, MCF/month
$\Delta q/\Delta t$ = rate of decline, (MCF/month)/month

To determine the rate at a given time, the integral of the equation above is taken from time 0 to time t and the initial rate of q_i to some rate q in time. The results are:

$$q = q_i e^{-at}$$

where: q = producing rate at time t, MCF/month
q_i = producing rate at time zero, MCF/month
t = producing time, month

At a given time, t, in the production of a well the cumulative gas produced, G_p, can be determined by integration of this form with respect to time. The results are:

$$G_p = \int_0^t q_i e^{-at}\,dt$$

The estimated ultimate gas recovery, G, of a producing gas well with sufficient data on an established exponential decline can be expressed as:

$$G = \frac{q_i - q}{a}$$

This particular equation requires an estimation of the final or abandonment rate for the well in order to determine the ultimate gas recovery for the well. For gas producing wells where the primary drive mechanism in the reservoir is depletion and the water-to-gas ratio remains relatively low, this final rate is often dependent on the lease operating costs used to determine the economic limit for the property. For gas producing wells where the primary drive mechanism is water drive, the final rate will be dominated by the wellbore configuration and liquid load-up late in life. In most cases, where decline curve analysis was used as the method for determining remaining reserves, an abandonment rate of 500 MCF per day per well was used for this evaluation.

The reliability of this method generally increases with more available historical data. In fitting the historical trend to a curve, only those periods of time in which the well was not held under operational constraints should be considered in performing this type of analysis.

Some production from field areas in the Cook Inlet Basin show the effect of seasonal swings in gas demand from local markets. This causes erratic production trends and may increase the difficulty of employing decline curve analysis. However, because of insufficient subsurface data, this is often the only method available for estimating remaining reserves in certain field areas. Often decline curve analysis of historical gas production data is used as a means to validate a more rigorous volumetric or material balance study on a well or field area.

2.2 MATERIAL BALANCE

For a gas reservoir that experiences minimal water production or aquifer encroachment, the reservoir drive is primarily through expansion of the remaining gas in the reservoir and the reservoir drive is referred to as volumetric or depletion (Craft et al, 1991). This type of system is essentially closed, although examples to the contrary exist. For the most part, the Tyonek, Beluga, and Sterling Reservoirs exhibit depletion-drive type behavior. The material balance equation in a form to represent this system is:

$$G(B_g - B_{gi}) = G_p B_g$$

where: B_g = gas formation volume factor, RB/SCF
B_{gi} = initial gas formation volume factor, RB/SCF

By use of the ideal gas law, this form of the equation can be modified using the relationship:

$$B_g = 0.00504 \frac{ZT}{P}$$

where: Z = gas deviation factor, decimal
T = reservoir temperature, °R
P = reservoir pressure, psia

The material balance equation can then be reduced to:

$$\frac{P}{Z} = \frac{P_i}{Z_i} - \frac{G_p P_i}{G Z_i}$$

This form of the material balance equation shows a linear relationship between the produced gas volumes and the value of P/Z. An estimate of original gas-in-place (OGIP) can be made by extrapolation of the straight line running through plotted P/Z versus G_p values for a depletion drive reservoir to a P/Z value of zero. The estimated ultimate recovery for the reservoir may be determined by extending the line to an expected abandonment pressure (P_a/Z_a).

This form of the material balance equation is not applicable to gas reservoirs experiencing water influx (Dake, 1978). Traditionally, water influx has been identified on a P/Z versus G_p plot by the concave upward inflection of the curve, as shown in Figure 2.1.1. Water influx can also present on a P/Z plot as a concave downward inflection when total production is increasing and the aquifer source is not infinite acting (GRI, 1993). Reliable extrapolation of a P/Z versus G_p plot usually requires multiple years of stable production and pressure data. For this evaluation at least ten years of production and pressure data were available for most field areas where this method for estimating remaining gas reserves was employed. Material balance calculations were performed to determine the recoverable reserves for applicable field areas with established linear P/Z trends or established trends that indicate water influx is reasonably certain not to exist based on available data.

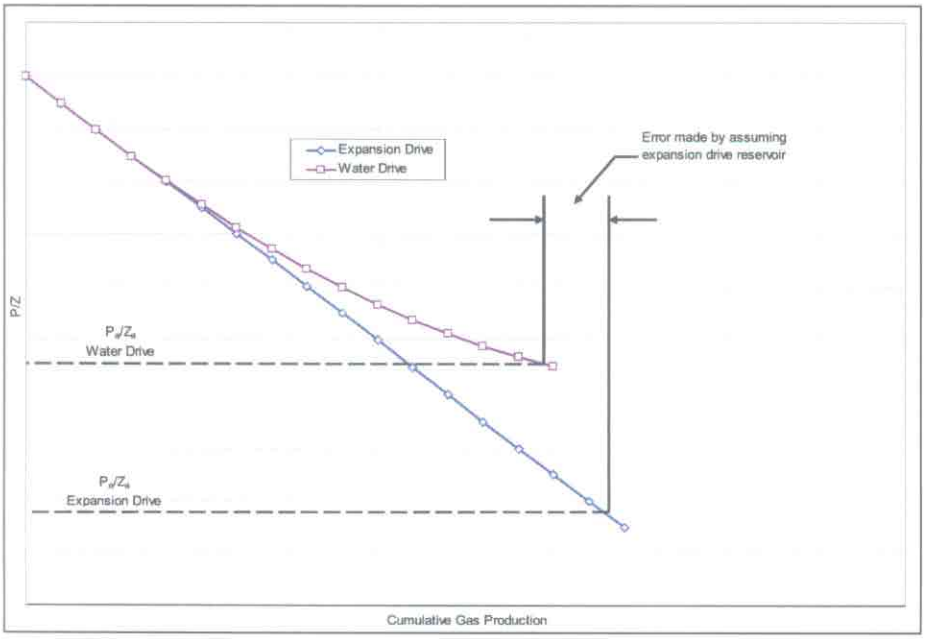

Figure 2.1.1 *Material balance graph for volumetric-versus-water drive reservoir where aquifer is infinite-acting.*

2.3 VOLUMETRIC ANALYSIS

If the geologic size, petrophysical attributes, and reservoir fluid properties are known, the amount of OGIP in a reservoir may be calculated using the following:

$$G = \frac{7758 A h \phi (1 - S_w)}{B_g}$$

where: A = area, acres
h = net pay, feet
ϕ = porosity, fraction
S_w = water saturation, fraction

One step in performing a volumetric analysis is to estimate petrophysics for a reservoir. Log analysis was performed for several key wells in each field area where volumetric analysis was utilized.

Log analysis is a process that requires reading open-hole log output. The output is then used to convert the data into in-situ values of certain reservoir parameters. Commonly run open-hole logging tools include resistivity and porosity tools. Water saturation and formation porosity estimates may be determined from this analysis.

Porosity is the percentage of the void space in a given rock, or:

$$\phi = \frac{V_p}{V_b} = \frac{V_b - V_g}{V_b}$$

where: V_p = pore volume
V_b = bulk volume
V_g = grain volume

In this study, the porosities were derived from density and neutron logs.

Water saturation is the percentage of the pore volume of the reservoir rock containing water. The pore volume that is not filled with water is assumed to be filled with hydrocarbons.

One method used for estimating water saturation from resistivity logs in clean formations with homogenous intergranular porosity is Archie's water saturation equation. The equation is:

$$S_w{}^n = \frac{FR_w}{R_t}$$

where: n = saturation exponent (generally 2)
F = formation resistivity factor, dimensionless
R_w = formation resistivity, ohm-meters
R_t = true formation resistivity, ohm-meters

F is usually obtained from the measured porosity of the formation through the relationship:

$$F = \frac{a}{\phi^m}$$

where: a = 1
m = 2

The water saturation estimates from the Archie equation depend on the accuracy of the input parameters R_w, F, and R_t.

Contour maps of geologic structure and net formation thickness (isopach) are used to estimate the bulk productive volume of the reservoir. A structural contour map is used to represent oil-water, gas-water, or gas-oil contacts, which is then used to create isopach maps. The bulk productive volume of the reservoir is estimated by planimetering these isopach maps.

The data used for volumetric calculations in this study were available through the AOGCC. In computing the reservoir volume, the lowest known gas or gas-water contact and faults were utilized in defining the reservoir limits. Net pay values were derived from interpretation of the petrophysical data.

3.0 BEAVER CREEK FIELD

3.1 OVERVIEW

Positioned in the eastern portion of the Cook Inlet Basin and operated by Marathon, Beaver Creek Field has produced, through December 2005, 185.9 BCF of gas since its discovery in 1972. Gas production has been from the Beluga, Sterling, and Tyonek Formations. The monthly historical gas production and average well count by year are shown in Figure 3.1.1. A representative structure map is shown in Figure 3.3.1.

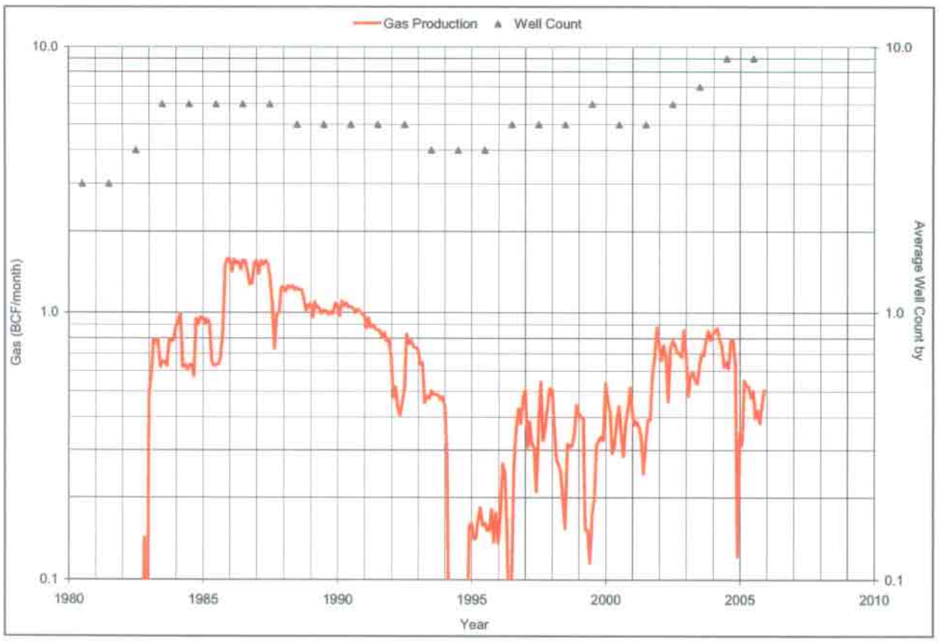

Figure 3.1.1 *Monthly historical gas production and average well count by year for Beaver Creek Field.*

3.2 RESERVES SUMMARY

We estimate the gross (100 percent) gas reserves for Beaver Creek Field, as of December 31, 2005, to be:

Formation	Gross (100 Percent) Gas Reserves (BCF) 1P	2P
Beluga	36.9	38.3
Sterling	0.0	0.0
Tyonek	2.8	2.9
Total	39.6	41.1

Totals may not add because of rounding.

3.2.1 Beluga Formation

Production from the Beluga Formation began in January 1989 with the drilling of the BC-1A well. Multiple wells have produced from this horizon with cumulative gas production, through December 2005, of 52.5 BCF. As of December 2005 there are eight active completions in the Beluga Formation. The monthly historical gas production and average well count by year are shown in Figure 3.2.1.

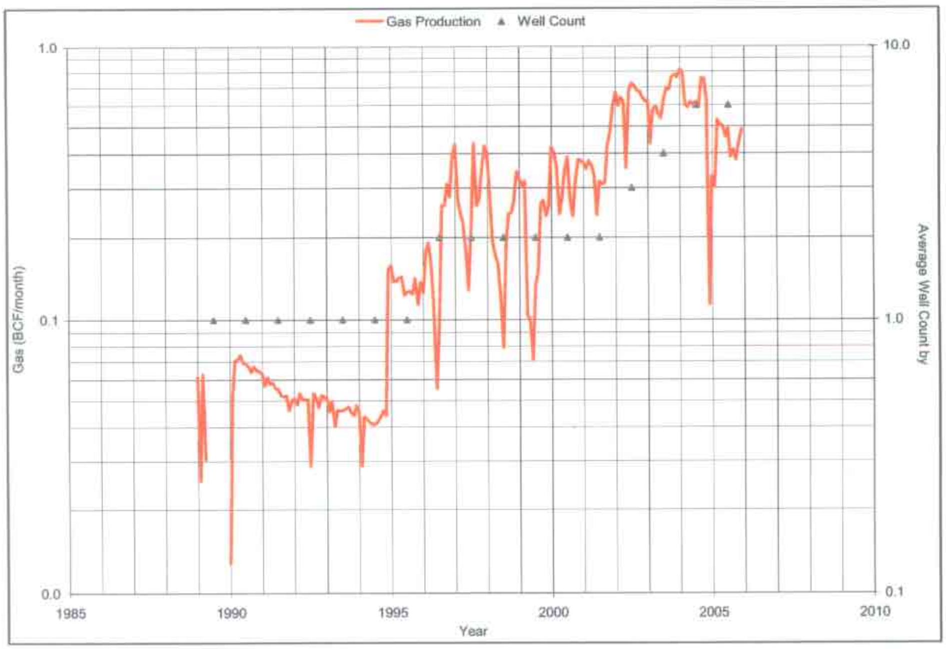

Figure 3.2.1 *Monthly historical gas production and average well count by year for the Beaver Creek Beluga Formation.*

Reserves have been estimated using material balance methods from the available data for this reservoir. The estimated OGIP is 96.1 BCF, as shown on the P/Z versus G_p graph in Figure 3.2.2. Based on an abandonment pressure of 250 psi, the 1P estimated ultimate recovery (EUR) for these wells is 89.4 BCF of gas, resulting in a recovery efficiency of approximately 93 percent. Lowering the abandonment pressure to 200 psi results in a 2P EUR of 90.8 BCF of gas and a recovery efficiency of approximately 94 percent.

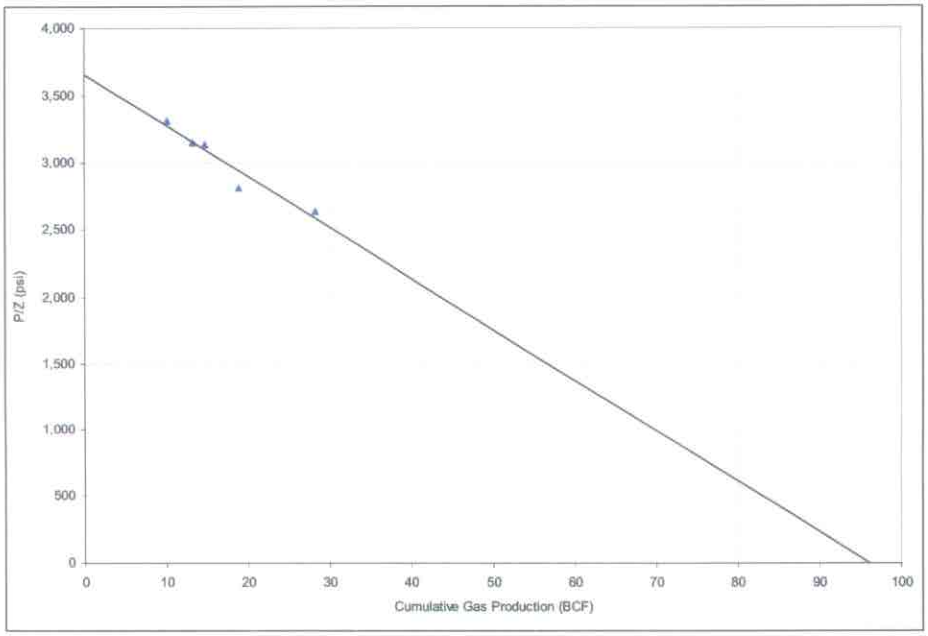

Figure 3.2.2 *Material balance graph for the Beaver Creek Beluga Formation.*

The following table summarizes the material balance parameter/result for the Beaver Creek Beluga Formation:

Parameter/Result	Gas (BCF) 1P	Gas (BCF) 2P
Original Gas-in-Place	96.1	96.1
Cumulative Production through 12-31-2005	52.5	52.5
Estimated Ultimate Recovery	89.4	90.8
Gross (100 Percent) Reserves, as of 12-31-2005	36.9	38.3

3.2.2 Tyonek Formation

The Tyonek Formation began gas production at Beaver Creek Field in March 1996 with the drilling of the BC-6 well. Cumulative gas production from the Tyonek Formation, through December 2005, is 5.4 BCF from three wells, the BC-4, BC-5, and BC-6. The BC-4 and BC-5 wells produce primarily oil; the BC-6 well is a dry gas well. The monthly historical gas production and average well count by year are shown in Figure 3.2.3.

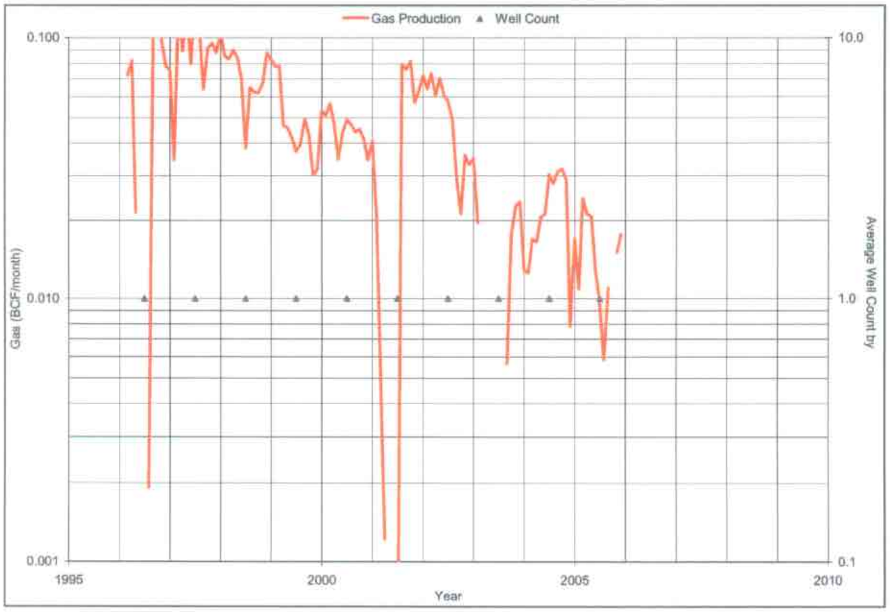

Figure 3.2.3 *Monthly historical gas production and average well count by year for the Beaver Creek Tyonek Formation.*

Reserves have been estimated using material balance methods from the available data for this reservoir. The estimated OGIP is 8.6 BCF, as shown on the P/Z versus G_p plot in Figure 3.2.4. Using an abandonment pressure of 250 psi, the 1P EUR is 8.15 BCF of gas, resulting in a recovery efficiency of approximately 95 percent. Lowering the abandonment pressure to 200 psi results in a 2P EUR of 8.24 BCF of gas and a recovery efficiency of approximately 96 percent.

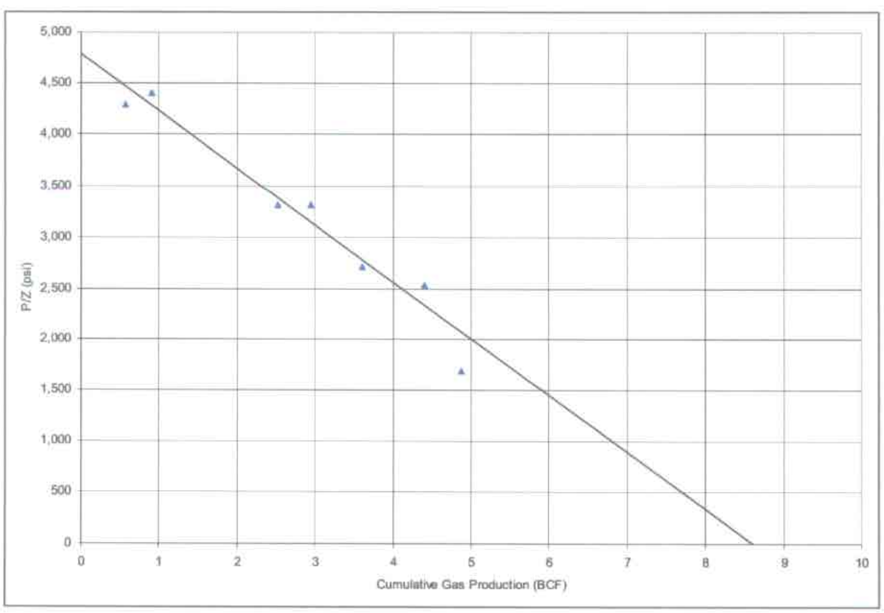

Figure 3.2.4 *Material balance graph for the Beaver Creek Tyonek Formation.*

The following table summarizes the material balance parameter/result for the Beaver Creek Tyonek Formation:

Parameter/Result	Gas (BCF) 1P	Gas (BCF) 2P
Original Gas-in-Place	8.6	8.6
Cumulative Production through 12-31-2005	5.4	5.4
Estimated Ultimate Recovery	8.2	8.2
Gross (100 Percent) Reserves, as of 12-31-2005	2.8	2.9

Totals may not add because of rounding.

FIGURES

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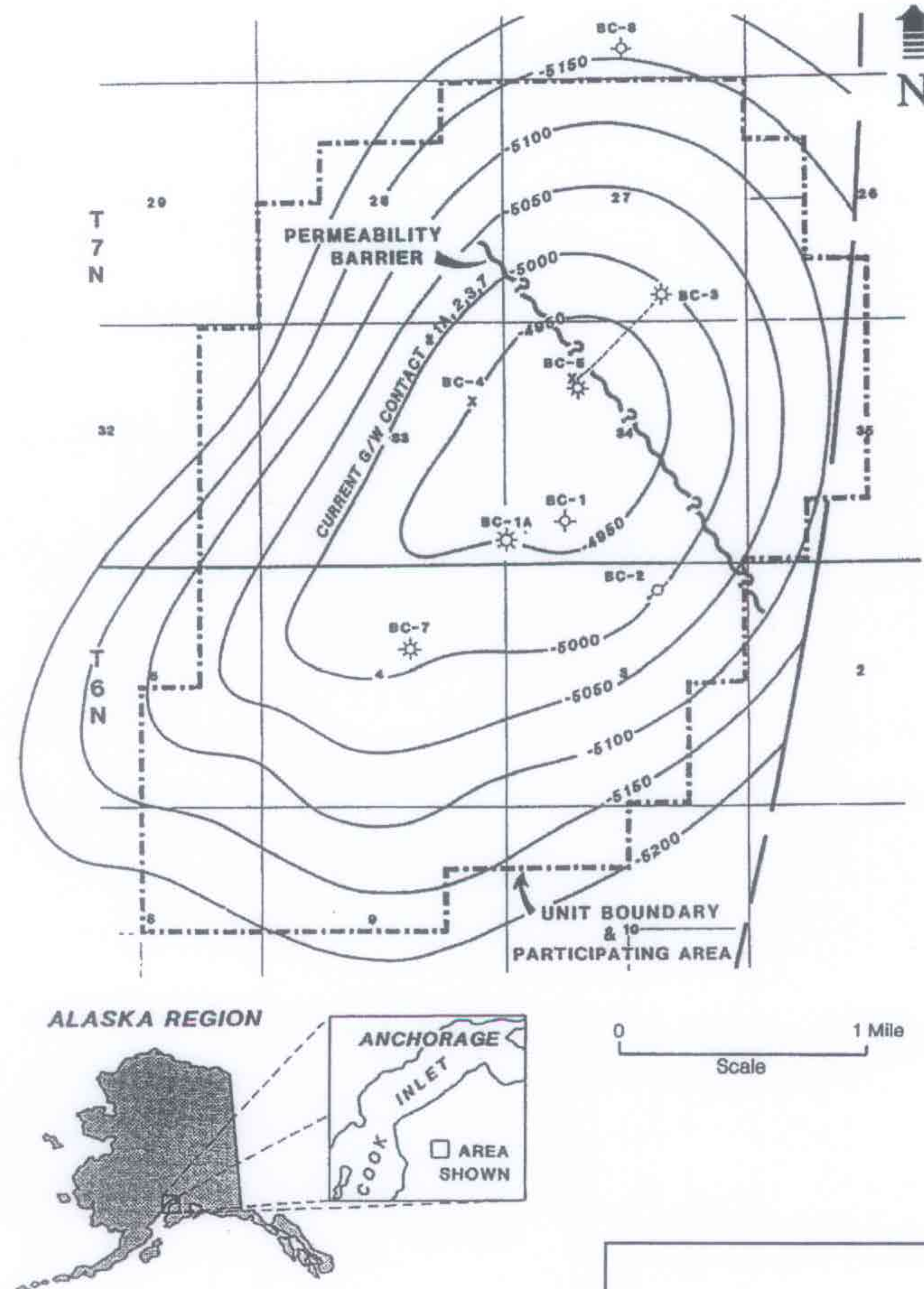

Structure Map
Top Sterling B-3 Sand

Beaver Creek Field
Cook Inlet Region, Alaska

Important Note:

The presented material was assembled and revised by Netherland, Sewell & Associates, Inc. ("NSAI") from data and interpretations provided by public domain sources including the Alaska Oil and Gas Conservation Commission. This exhibit is for illustrative purposes only and we have not verified the content thereon.

Figure 3.3.1

4.0 BELUGA RIVER FIELD

4.1 OVERVIEW

Positioned in the western portion of the Cook Inlet Basin and operated by ConocoPhillips, Beluga River Field has produced, through December 2005, 960.6 BCF of gas from 17 wellbores since production began in 1963. Gas production has been from the Beluga and Sterling Formations. The monthly historical gas production and average well count by year are shown in Figure 4.1.1. A representative structure map is shown in Figure 4.3.1.

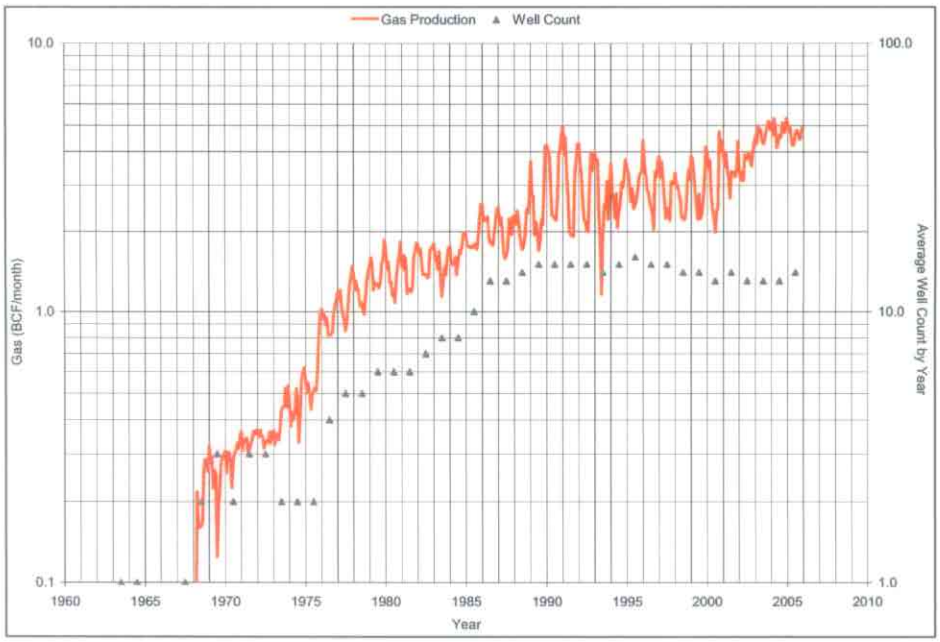

Figure 4.1.1 *Monthly historical gas production and average well count by year for Beluga River Field.*

4.2 RESERVES SUMMARY

We estimate the gross (100 percent) gas reserves for Beluga River Field, as of December 31, 2005, to be:

Formation	Gross (100 Percent) Gas Reserves (BCF) 1P	2P
Beluga and Sterling	473.3	509.4

4.2.1 Beluga and Sterling Formations

As shown in Figure 4.2.1, the reservoir pressure data represent two separate reservoirs, the Sterling and Beluga. The datum for the Sterling and Beluga are approximately 3,300 and 4,500 feet deep subsea, respectively. The early time pressure data shown in Figure 4.2.1 were gathered from AOGCC annual reports; separate pressures were not given for each reservoir. It is unknown whether these data represent individual bottomhole pressures or average pressures for the field. Although there is no data to confirm the source of the early time annual pressure data, we believe that it represents pressures in the higher-pressured Beluga tank and that the steep initial decline in bottomhole pressure data indicates that the reservoirs were not fully completed in all members of each reservoir. The pressure data between approximately 500 BCF and 900 BCF of cumulative gas production shown in Figure 4.2.1 represent individual bottomhole pressure surveys taken since 2000. Upon inspection, two pressure trends can be seen, the higher trend represents the higher-pressured Beluga Reservoir and the lower represents the Sterling Reservoir. However, the public data available does not lend itself to a reasonable method to allocate production from each reservoir; therefore, average monthly P/Z points from the pressure data since 2000 have been used in conjunction with the total field production by month for reserve estimation, as shown in Figure 4.2.2.

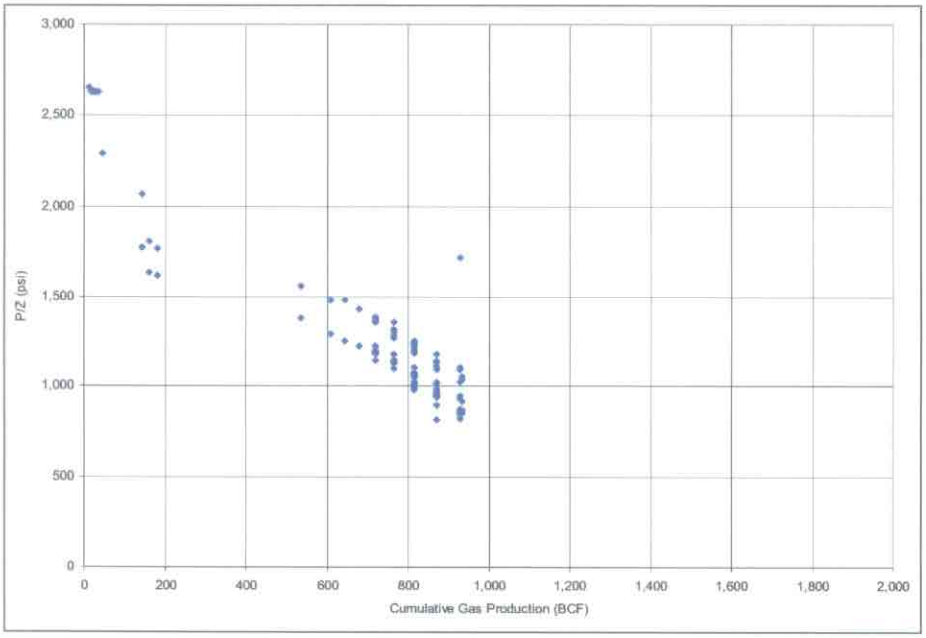

Figure 4.2.1 *Original material balance graph for Beluga River Field.*

Reserves have been estimated using material balance methods from the available data for these reservoirs. As shown in Figure 4.2.2, the estimated OGIP is 1,614.2 BCF. Based on an abandonment pressure of 250 psi, the 1P EUR is 1,433.9 BCF of gas, with a recovery efficiency of approximately 89 percent. Lowering the abandonment pressure to 200 psi results in a 2P EUR of 1,470.0 BCF of gas and a recovery efficiency of approximately 91 percent.

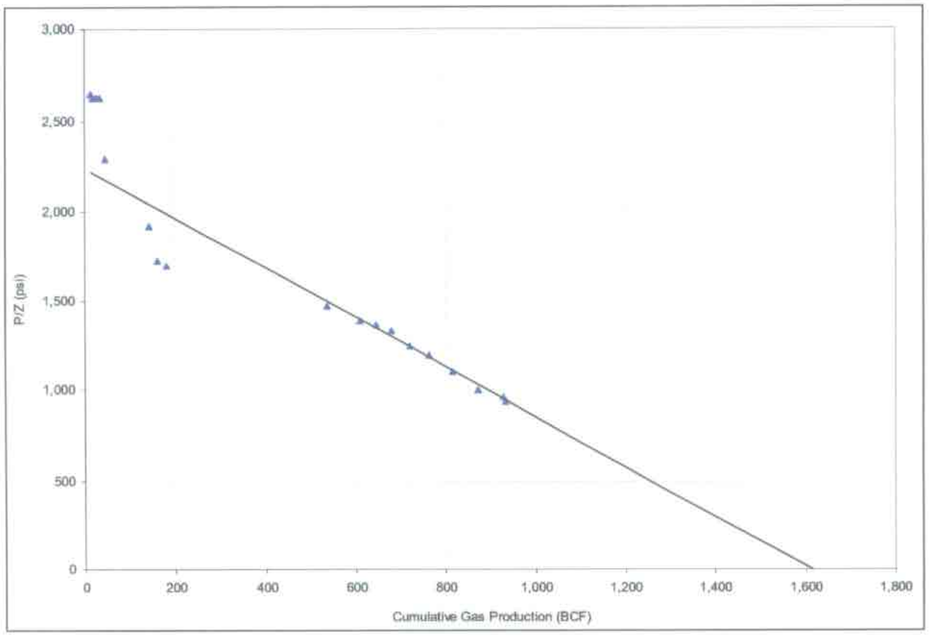

Figure 4.2.2 *Material balance graph for the Beluga River Beluga and Sterling Formations.*

The following table summarizes the material balance parameter/result for the Beluga River Beluga and Sterling Formations:

Parameter/Result	Gas (BCF) 1P	Gas (BCF) 2P
Original Gas-in-Place	1,614.2	1,614.2
Cumulative Production through 12-31-2005	960.6	960.6
Estimated Ultimate Recovery	1,433.9	1,470.0
Gross (100 Percent) Reserves, as of 12-31-2005	473.3	509.4

FIGURES

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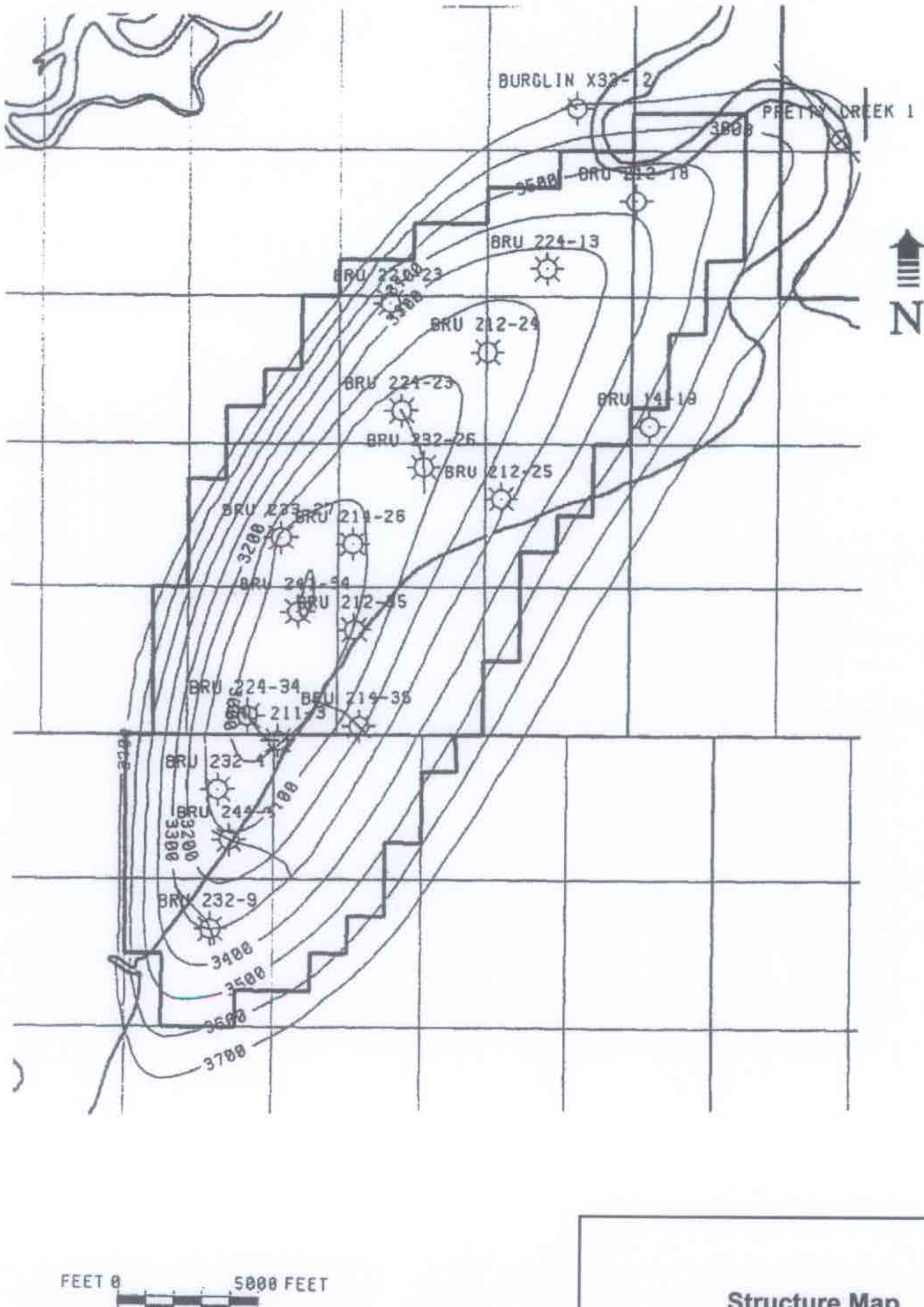

Structure Map
Top A Zone

Beluga River Field
Cook Inlet Region, Alaska

Important Note:

The presented material was assembled and revised by Netherland, Sewell & Associates, Inc. ("NSAI") from data and interpretations provided by public domain sources including the Alaska Oil and Gas Conservation Commission. This exhibit is for illustrative purposes only and we have not verified the content thereon.

Figure 4.3.1