State of Alaska
Department of Natural Resources
Division of Oil and Gas

Bill Walker, *Governor*
Mark Myers, *Commissioner*
Corri Feige, *Director*

Updated Engineering Evaluation of Remaining Cook Inlet Gas Reserves

By

Islin Munisteri, *Petroleum Reservoir Engineer*

John D. Burdick, *Petroleum Reservoir Engineer*

Jack D. Hartz P.E., *Contracting Petroleum Reservoir Engineer*

Edited by

Paul L. Decker, *Resource Evaluation Section Manager*

September 2015

Alaska Division of Oil and Gas, 550 W. 7th Ave, Suite 1100
Anchorage, Alaska 99501-3560

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Abbreviations and Definitions

AOGCC	Alaska Oil and Gas Conservation Commission
BCF	Billion Cubic Feet of Gas at standard conditions
BOPD	Barrels of Oil per Day
Bbbl	Billion Barrels of Oil
Lighthouse mode	Wells shut in, production facilities cleaned, platforms decommissioned, but navigational aids remain
DCA	Decline Curve Analysis
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery, expressed in BCF; the sum of the cumulative produced gas and remaining reserves
MCFD	Thousands of Cubic Feet of Gas per Day at standard conditions
OGIP	Original Gas-In-Place, in BCF, is the original gas in the reservoir before production or injection begins
P/z	Reservoir pressure divided by z-factor of gas
Pool	'"Pool" means an underground reservoir containing, or appearing to contain, a common accumulation of oil or gas; each zone of a general structure which is completely separated from any other zone in the structure is covered by the term "pool"' AS 31.05.170
PSIA	Pounds per square inch absolute, is a unit of pressure and used to make it clear that the pressure is relative in a vacuum rather ambient atmospheric pressure
PVT	Pressure-Volume-Temperature means an oilfield fluid study for oil, gas, or water conducted in a laboratory
TCF	Trillion Cubic Feet of Gas at standard conditions
z-factor	A gas compressibility factor used to correct the Ideal Gas Law to standard conditions (McCain, 1990)

Executive Summary

The Cook Inlet basin has produced 8,308 BCF of gas and 1.350 Bbbls of oil as of December 31, 2014, with approximately 1,183 BCF of proved and probable remaining gas reserves. These volumes are quantified from production and surveillance data available from existing and previously producing wellbores as of that date.

There has been continued concern over whether the existing system of natural gas production and delivery in the Cook Inlet basin can continue to meet the energy demands of south-central Alaska. This report addresses the remaining gas reserves in the Cook Inlet basin from a reservoir engineering perspective. The economics of drilling additional wells, optimizing pipeline pressures, gas consumption predictions, and other sources of gas consumption are not included within the scope of this report.

Reservoir engineering principles were used to evaluate the volumes of gas remaining in existing fields within the Cook Inlet basin. The analyses contained within this report represent current estimates by Division of Oil and Gas staff, not the operators. Like the 2009 Division of Oil and Gas study "Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves", estimates are based on public data reported by the operators to the Alaska Oil and Gas Conservation Commission (AOGGC). AOGCC defines reservoirs as pools, and the same nomenclature has been applied throughout this study. All 34 currently or historically producing Cook Inlet gas fields, many of which contain multiple pools, were evaluated by applying both decline curve analysis and material balance engineering methods to the publicly available production and pressure data. Based on extrapolations of production trends, these engineering techniques were used to derive estimates of remaining reserves in two tranches, which are considered approximately equivalent to the proved and probable reserves categories.

The petroleum engineering analysis pursued in this study allows the evaluation of remaining gas volumes at varying levels of production certainty and readiness. The total 1P (proved) reserves remaining to be produced from all existing fields in the Cook Inlet basin is estimated at approximately 711 BCF, including associated gas from oil production. This volume was identified by the base case decline curve analyses and assumes sufficient investment to maintain existing wells and their established production trends.

Additional probable reserves that would be recoverable by mitigating well problems and increasing investment in existing fields are estimated at approximately 472 BCF, with a total of 1,183 BCF 2P (proved + probable) reserves remaining in existing fields basin-wide. This volume is identified as a pool-by-pool difference in the results of both material balance calculations versus base case and upside decline curve analyses, and the addition of recompletions in previously producing wells using the upside decline curve analysis, as seen in **Figure ES-1.**

This study does not address prospective (undiscovered) or contingent (discovered, non-producing) resources, nor do these engineering methods quantify 3P (proved + probable + possible) reserves. The division's estimates may be updated as additional production and reservoir pressure data become available and as recent discoveries are developed and brought into production.

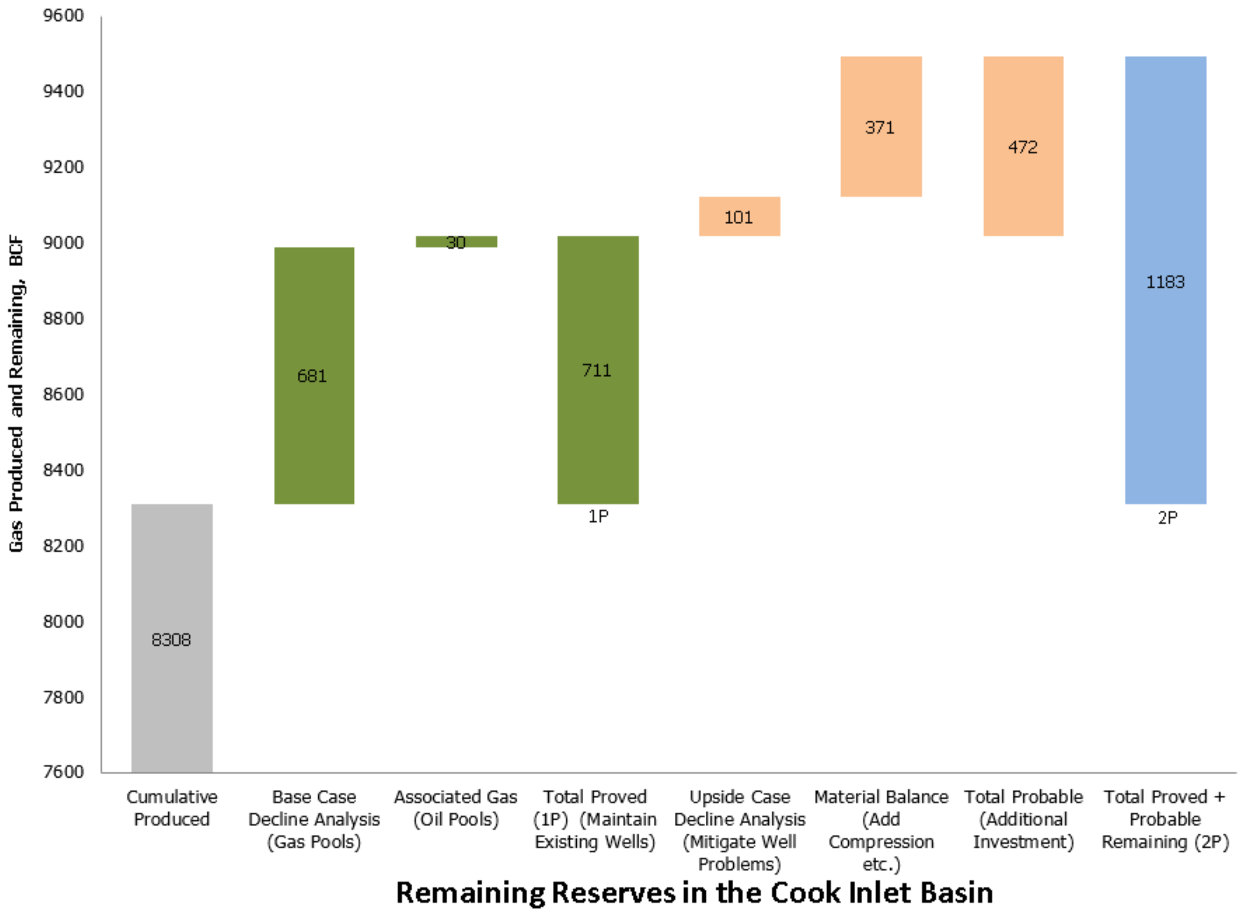

Figure ES-1. Cumulative gas produced as of December 31, 2014, and remaining reserves, categorized by production certainty and by whether additional investment is necessary. The chart reads left to right as follows. Past production totals 8,308 BCF. Proved reserves remaining estimated from decline analysis include 681 BCF from non-associated dry gas pools and 30 BCF associated gas from oil pools, totaling to 711 BCF 1P reserves expected to be recovered through maintenance of existing well stock. Probable reserves include 101 BCF identified in an upside-case decline analysis, expected to be recoverable by mitigating problem wells, plus 371 BCF identified by material balance analysis, expected to be recoverable by adding compression and/or managing pipeline system pressures. Total probable reserves are thus 472 BCF. Summing total proved (1P) and total probable yields the 2P estimate of 1,183 BCF remaining in existing fields. Note that this approach does not address possible reserves, nor contingent resources (discovered undeveloped fields such as Kitchen Lights and Cosmopolitan).

1. Introduction

1.1. *Historical Analysis and Trends of Cook Inlet*

Oil and gas production started in the Cook Inlet basin after the discovery of the Swanson River field in 1958. As of December 31, 2014, the Cook Inlet basin has produced approximately 8.308 TCF of gas and 1.350 Bbbls of oil. Historically, there has been gas cycling for EOR purposes within the Cook Inlet basin, particularly within the Swanson River field. Hence, a net balance of both produced and injected gas has been considered in order to calculate the cumulative produced gas within the entire Cook Inlet basin. **Figure 1-1** shows a summary of the Cook Inlet basin by means of production data, number of active wells, and cumulative production.

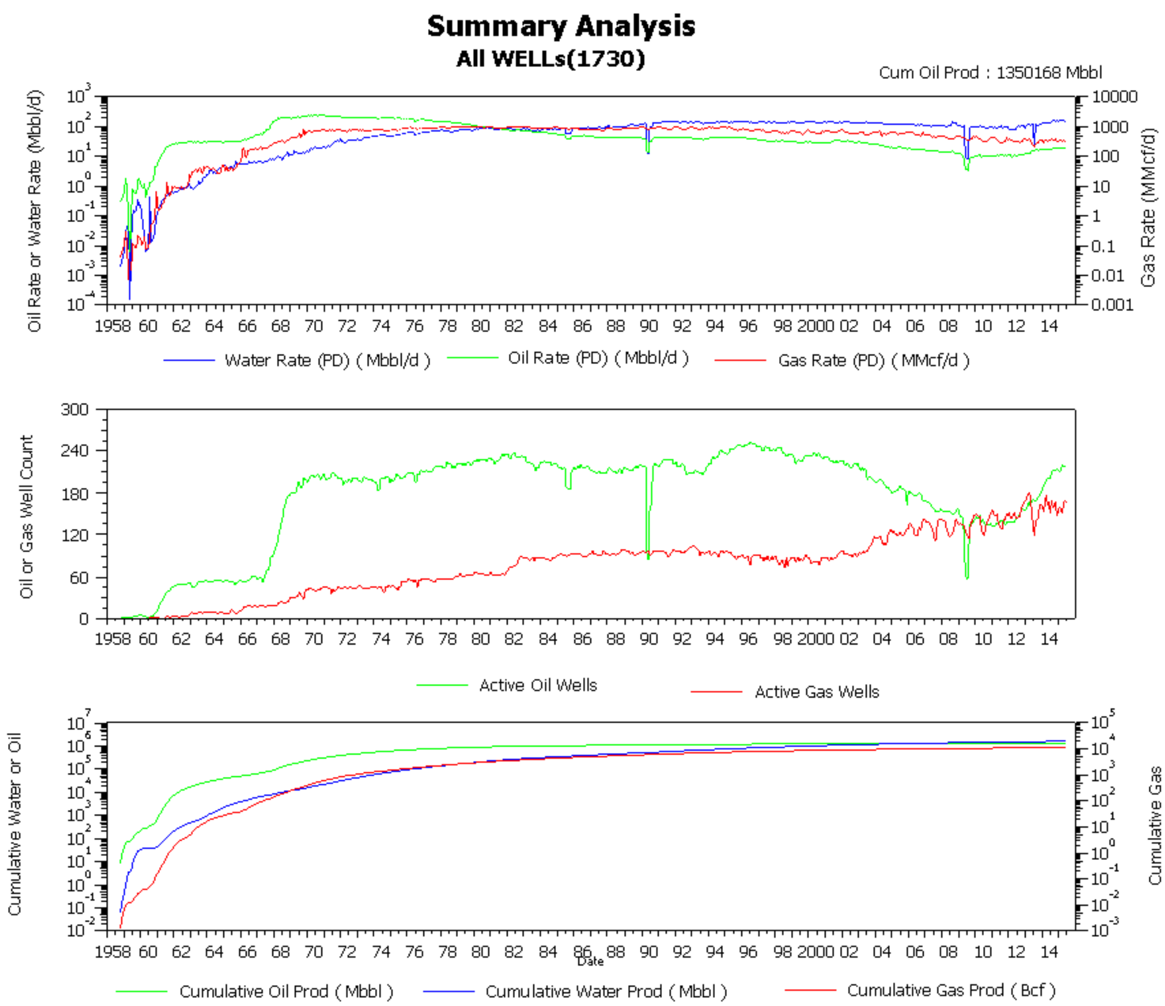

Figure 1-1. Summary of Cook Inlet production.

The number of new field startups in Cook Inlet has varied by decade (**Figure 1-2**). Before the discovery of the Prudhoe Bay field on the North Slope in 1968, a surge in Cook Inlet exploration and development had taken place in the late 1950s and 1960s. Early exploration succeeded at finding gas, to the extent that a large surplus developed relative to the local market. Exports of LNG and urea-based fertilizer provided an outlet for otherwise stranded gas for more than four decades beginning in the late 1960s, but limited demand led to less exploration and development activity from 1970 to 2000. A number of smaller-sized fields came on production during the 2000s. Activity during 2000-2015 was spurred by a shrinking reserves surplus and anticipated needs of the Southcentral gas market.

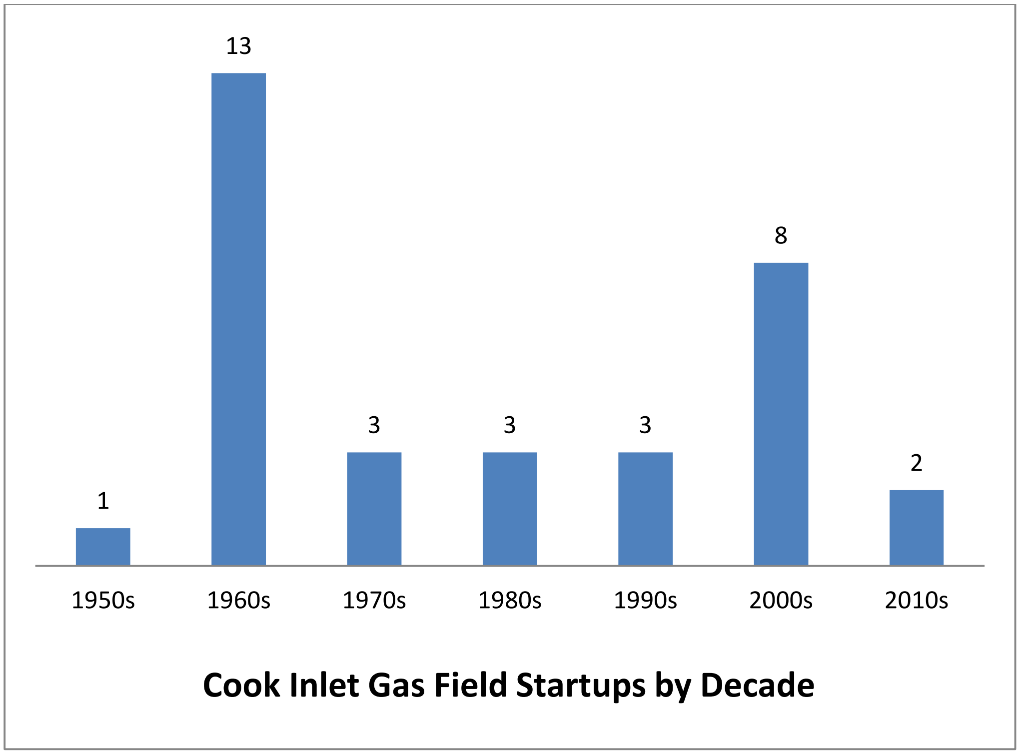

Figure 1-2. Number of gas field startups by decade in the Cook Inlet.

The Cook Inlet basin has been on production for 56 years, starting with the Swanson River field, followed by the Kenai, Sterling, and Beluga River fields, respectively. The two most recent gas fields, Kenai Loop and Nikolaevsk, began sustained production in 2012. Though Nikolaevsk was discovered in 2004, gas production was delayed because of its distance from the pipeline grid at Happy Valley (Lidji, 2013). **Figure 1-3** shows the age for all Cook Inlet oil and gas fields with historical production as of December 31, 2014. The average age of all Cook Inlet fields is approximately 30 years.

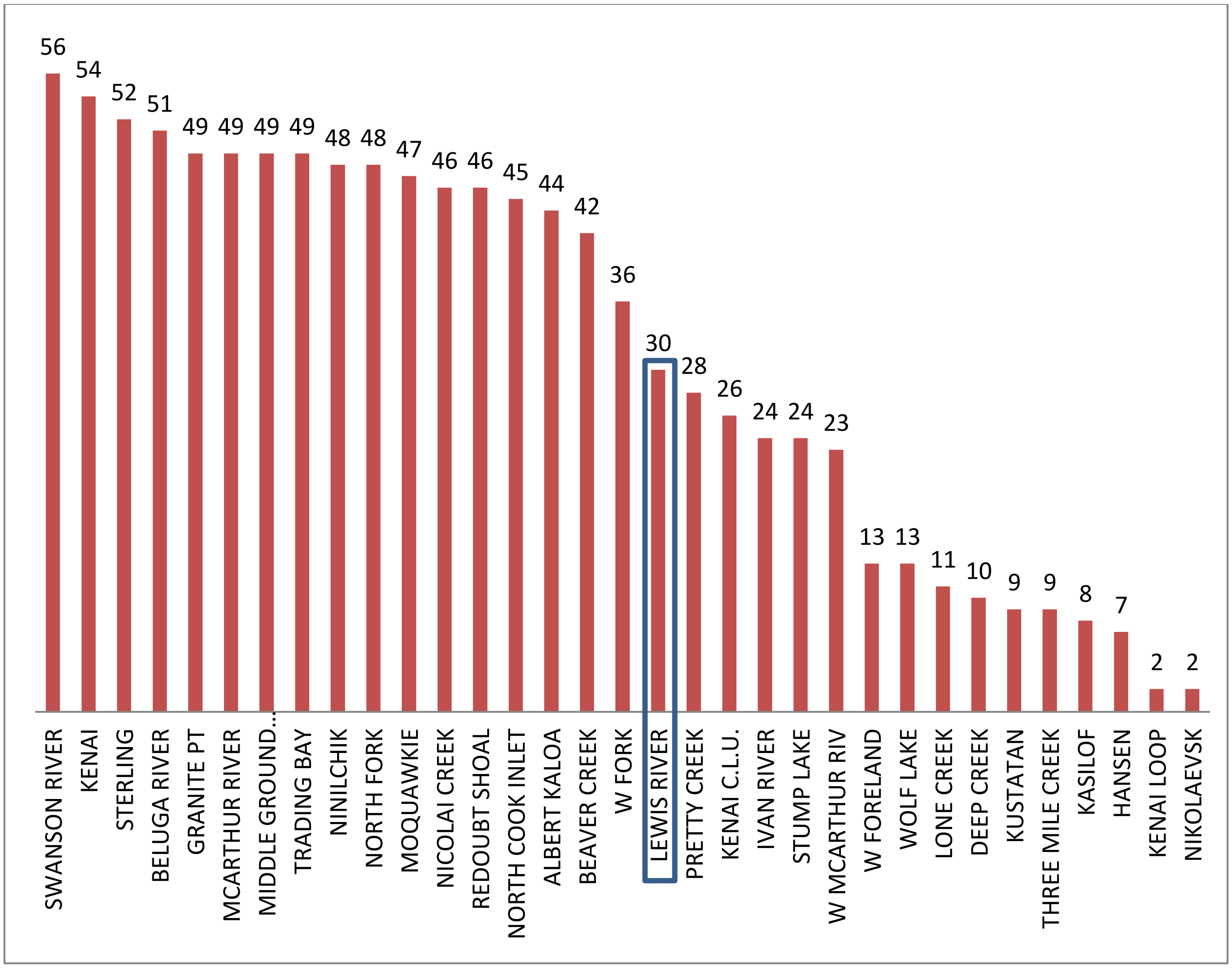

Figure 1-3. Age of Cook Inlet oil and gas fields; 30 years is the average field age, as of December 31, 2014.

1.2. Recent Trends in Cook Inlet Since the 2009 Study

A total of 43 new gas wells were drilled and completed from 2010 through 2014, a 22 percent decrease from the 55 during the period from 2005 to 2009, according to analysis conducted using the public AOGCC database.

Hilcorp's entry in the Cook Inlet basin through the acquisition of Chevron/Union assets in 2011, followed by purchase of Marathon's assets in 2013 (Lidji, 2013), has dramatically transformed the basin's commercial landscape. The majority of existing fields have been consolidated into a single operator's portfolio, with a sharp focus on increasing lowest-cost production by remediating problem wells, finding bypassed reserves, developing newer evaluation techniques, and expanding the areal extent and stratigraphic interval of production in existing fields. This level of activity is in stark contrast to that of previous operators, for whom Cook Inlet was no longer a core focus area. Both oil and gas production rates have increased markedly, and utilities have secured multi-year contracts for gas deliveries, significantly easing the near-term gas availability concerns of consumers throughout the region.

This study is motivated in part by questions over whether Cook Inlet gas supplies are now sufficiently abundant to also satisfy new long-term, non-local nodes of demand in addition to Southcentral's status-quo utility demand (approximately 90 BCF/yr). Proposed projects include restarting the ConocoPhillips LNG export facility (up to 88 BCF/yr) and Agrium fertilizer plant (up to 55 BCF/yr), new exports to Japan by Resources Energy, Inc. (49 BCF/yr), a gas pipeline from Cook Inlet to the Donlin Gold project near McGrath (13 BCF/yr), and delivering LNG by rail to the greater Fairbanks area (approximately 5 to 10 BCF/yr). Which of these projects would be appropriately supplied from Cook Inlet fields, and for how long? Which are better suited for supply from the North Slope through the Alaska Liquefied Natural Gas (AKLNG) project? These are important questions that this study may help address, but their answers are clearly beyond the scope of this report.

1.3. Cook Inlet Geological Setting

The Cook Inlet basin is a northeast-southwest trending, fault bounded forearc basin that extends from the Matanuska Valley southward between the mountainous uplands of the Kenai Peninsula and the Alaska Peninsula. Numerous northeast-southwest trending anticlinal folds exist within the basin due to extensive right lateral strike-slip and dip-slip motion along the northern and northwestern basin-bounding faults.

Mesozoic and Tertiary sedimentary strata make up the basin fill. Most of the producing reservoirs in Cook Inlet basin are found in the non-marine Tertiary section **(Figure 1-4).** Along the basin margins, the Tertiary reservoirs consist largely of gravelly alluvial fans and sandy braided channels. Toward the basin axis, the reservoirs consist largely of fluvial channels interlayered with overbank silts, clays, and coals.

There are two distinct petroleum systems in the Cook Inlet basin: a thermogenic system, consisting of oil and associated gas derived from deep burial of Mesozoic source rocks, and a biogenic system comprising dry (non-associated) methane generated in the shallow subsurface as a byproduct of bacteria feeding on Tertiary coals. Approximately 94 percent of the gas recovered from legacy fields is estimated to be of biogenic origin (Claypool, Threlkeld, & Magoon, 1980). Reservoirs in the Sterling and Beluga formations are primarily dry gas. Reservoirs in the West Foreland and Hemlock formation are primarily oil. The Tyonek formation contains both dry gas and oil reservoirs. A base map showing current oil and gas fields are shown in **Figure 1-5. Figure 1-6** illustrates existing pipeline infrastructure within the Cook Inlet.

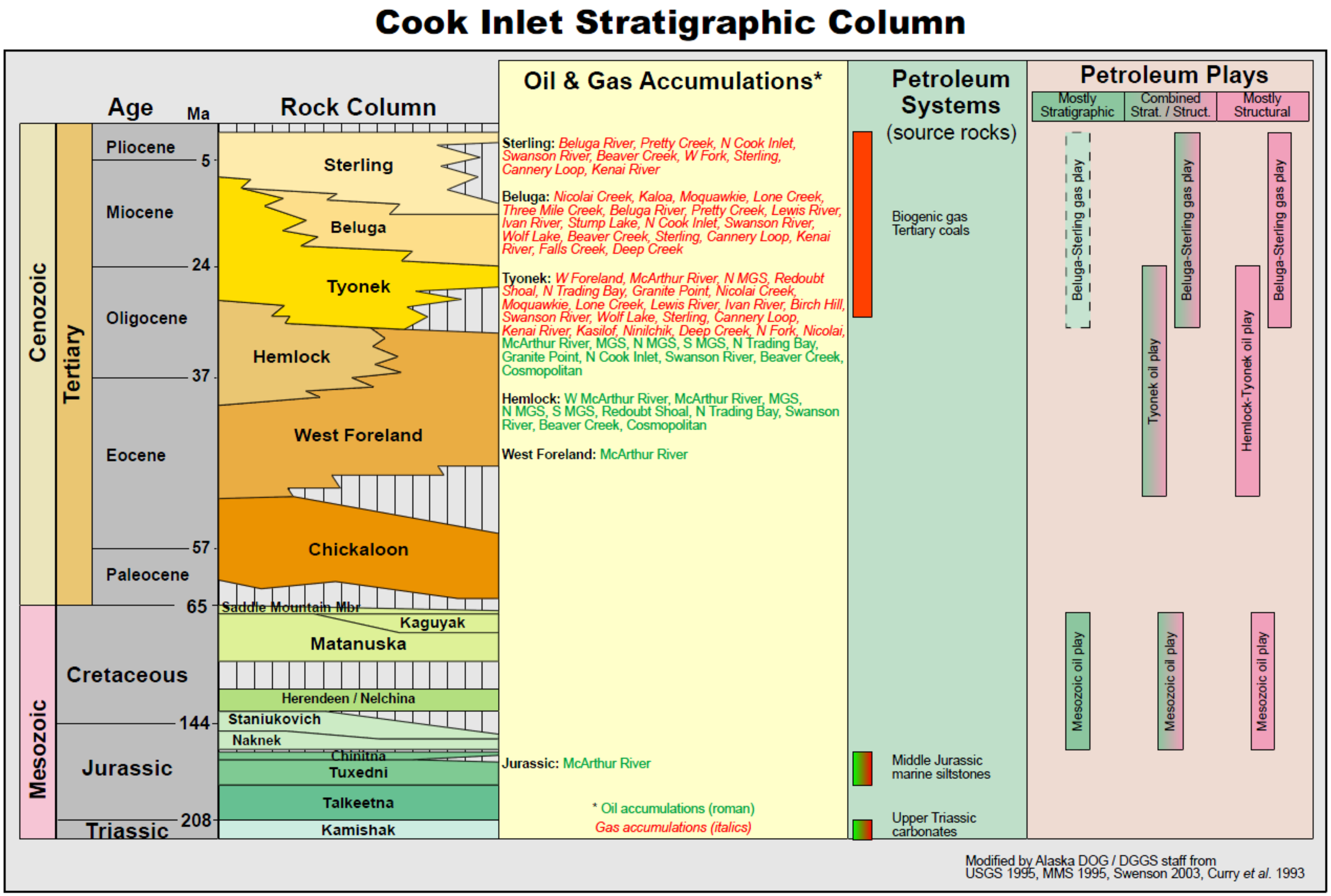

Figure 1-4. Cook Inlet stratigraphic column, with petroleum plays and oil and gas accumulations.

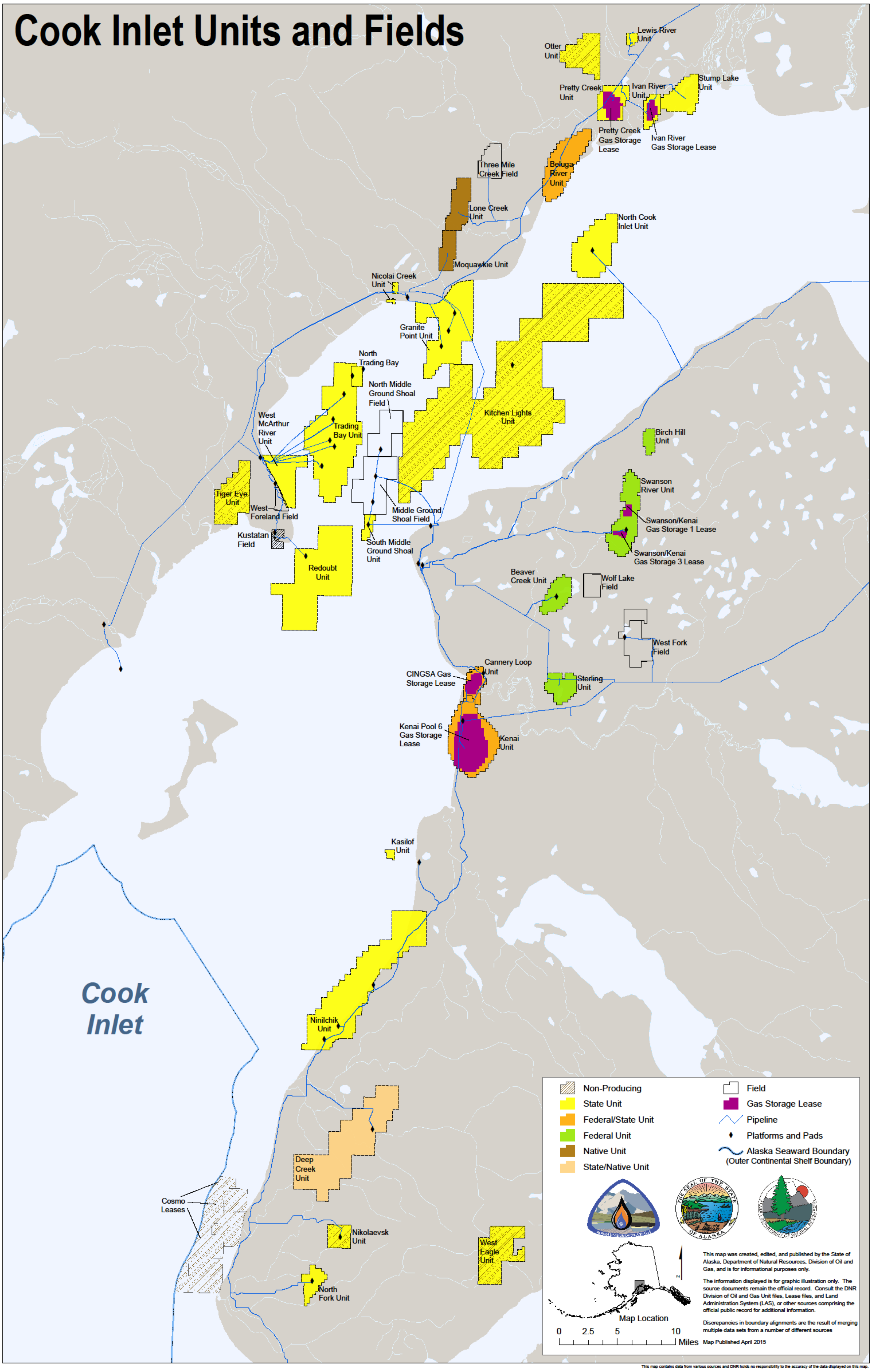

Figure 1-5. Base map of Cook Inlet fields and units, as of June 2015.

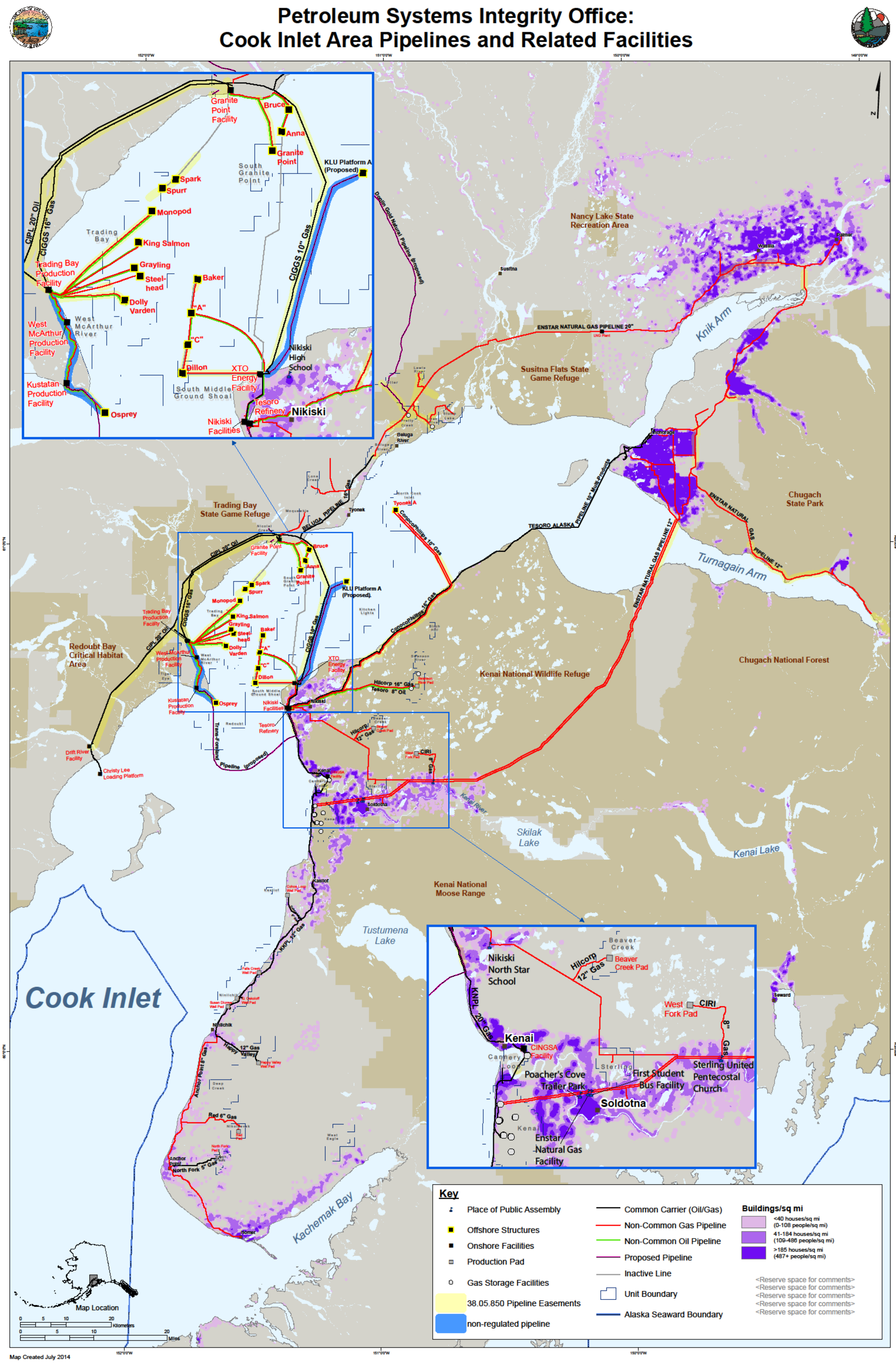

Figure 1-6. Base map of Cook Inlet pipelines, as of June 2014.

2. Assumptions

Below are assumptions that were employed during the study.

2.1. Reserves Briefly Defined

The Petroleum Resources Management System (PRMS) is a system sponsored by various societies worldwide to categorize and classify all petroleum reserves and resources (Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, 2011). The PRMS divides total in-place oil and gas into three major categories: undiscovered, discovered sub-commercial, and discovered commercial resources (**Figure 2-1**). Undiscovered volumes, also known as "prospective resource", are estimated to exist in accumulations not yet found by drilling. Discovered, sub-commercial volumes are often referred to as "contingent resource"; although confirmed by drilling, resources are not yet ready for production, or have not yet been demonstrated to be commercially viable to produce. Discovered, commercial oil and gas make up the "reserves" category. Reserves volumes are further subcategorized by certainty of production into 1P (proved, or 90 percent certainty), 2P (proved and probable, or 50 percent certainty), and 3P (proved, probable, and possible, or 10 percent certainty).

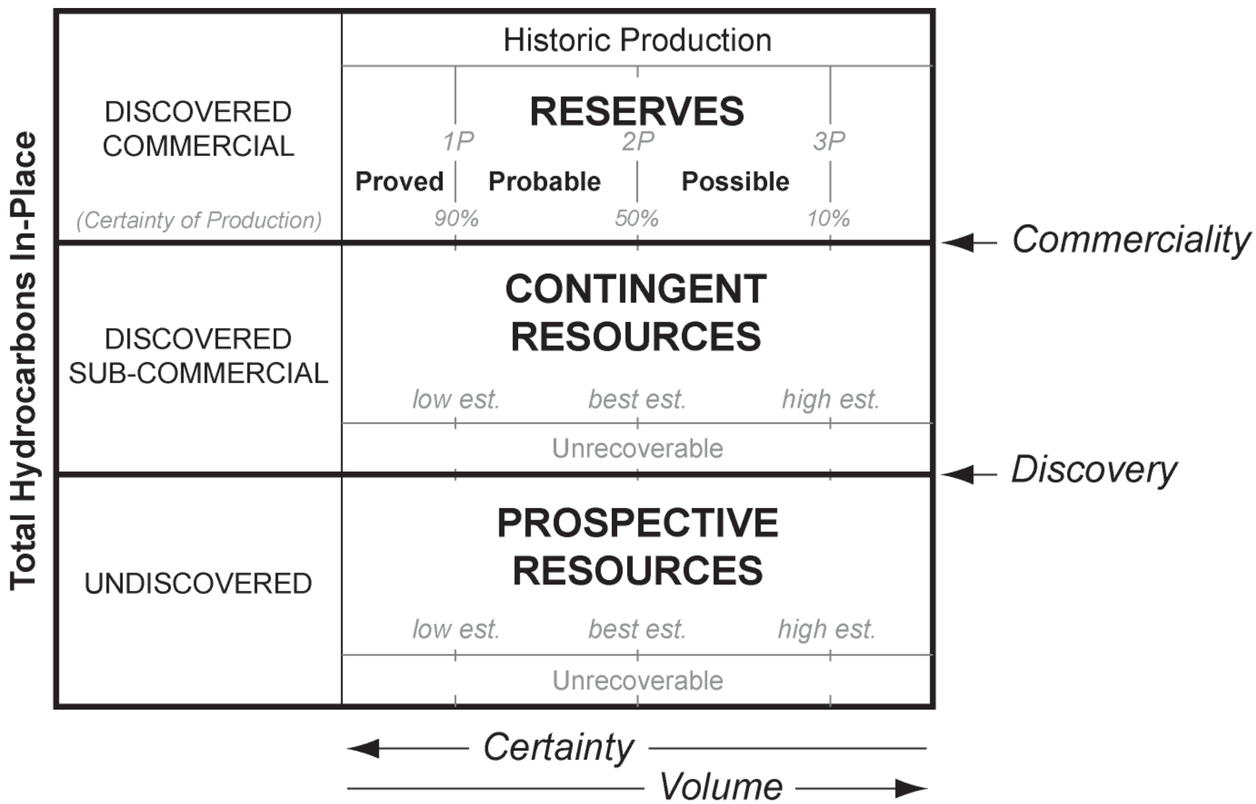

Figure 2-1. PRMS resource classifications, as adapted from SPE et al., 2011.

For the purpose of this study, reserves are determined by using decline curve analysis (DCA) and material balance engineering methods that are deemed as acceptable approaches to approximate the levels of production certainty associated with 1P and 2P reserves estimates. Reserves determined through DCA applied to currently producing wells are appropriately identified as the proved category, or 1P, and represent future production from productive wells as of December 31, 2014. The underlying premise of DCA is that a trend from historical production (dependent on drilling, maintenance, and remediation) will behave as such into the future. The results of DCA represent a snapshot of the past performance characteristics of a given reservoir and the resultant trend that determines future recovery.

The reserves calculated through material balance or restoring production from problem wells are roughly equivalent to probable reserves, and can be recovered through additional capital investment, such as the installation of downhole pumps and compression, and operation expenses such as water production mitigation and stimulation. The 50 percent likelihood that probable reserves will be recovered depends in large part on future economic conditions such as gas price and operation and maintenance expenses.

2.2. Constraints in the System

The gas market in south-central Alaska is considered to be a nearly closed market with little connection to alternative points of sale. Previously continuous sales of liquefied natural gas and fertilizer provided access to external markets for Cook Inlet gas. Gas supply is also constrained by utility demand in south-central Alaska, which currently reflects the gas production that is sold directly to market.

The production trends observed through DCA and material balance calculations are not necessarily indicative of actual reservoir potential. Rather, production trends may reflect artificial constraints, such as limited overall demand, seasonal demand fluctuations, high pipeline system pressure, lack of compression, limited water handling, or limited pump capacity. Additional geological considerations, such as potential reserves in bypassed reservoirs, discoveries not yet on production, and nonproducing intervals in existing wells and fields are outside the scope of this engineering-based study and have not been considered.

2.3. Life of Field Assumptions for Decline Curve Analysis

Proved reserves were estimated using DCA to forecast production and applying end of life constraints to truncate the forecast as appropriate. Completions that had production through December 2014 in the public AOGCC database were forecasted, excluding gas storage wells. When injected, storage gas is added to the inventory of remaining gas reserves, which is ultimately produced from the storage reservoir for sales.

Wells producing dry gas are forecasted on a completion-by-completion basis, using rates calculated from “days on production”, since gas is reported to the AOGCC on a monthly basis. The end of life constraint for each completion was determined by flow rate that either reaches a 50 MCFD abandonment rate, or a 30-year time span from the initial forecast date, whichever condition is met first. A modified hyperbolic to exponential decline is applied when the annual effective decline rate has reached either 5% or 10% (Ryder Scott Reservoir Solutions, 2011), depending on existing production data.

For wells producing black oil with associated gas, as seen on most Cook Inlet platforms, the forecast period ends at a platform-basis abandonment rate limit of 300 BOPD (except for the 350 BOPD at the Monopod platform). Analogue data from platform shutdowns or that were put into “lighthouse mode” are useful in estimating platform abandonment rate limits. The Baker platform, formerly operated by Unocal and currently operated by Hilcorp, was put into “lighthouse mode” when oil production from the platform declined to approximately 515 BOPD in 2003 (Petroleum News, 2010), and production was halted. The Spark and Spurr platforms averaged approximately 360 and 270 BOPD, respectively, during their last year of production before being placed in “lighthouse mode”. Additionally, the Osprey platform operated at a low rate of approximately 226 BOPD in 2013 (Bradner, 2014). The average of the abandonment rates quoted above is approximately 340 BOPD.

For wells producing oil and associated gas to onshore facilities such as Swanson River, West McArthur River, and Beaver Creek, the forecast period ends at an abandonment rate of 50 BOPD per well, or at 30 years from the initial forecasted date, depending on the constraint that occurs first during forecasting. **Table 2-1, Table 2-2,** and **Table 2-3** show abandonment rate assumptions at a facility and pool level.

Platform	Oil Pool(s) (AOGCC)	Abandonment Rate (BOPD), Platform Basis Actual	Assumption
Granite Point Field			
Anna	Hemlock Middle Kenai	300	300
Bruce	Hemlock Middle Kenai	300	300
Granite Point	Hemlock Middle Kenai	300	300
Middle Ground Shoal Field			
"A"	E Oil F Oil G Oil	300	300
"C"	E Oil F Oil G Oil	383*	300
Redoubt Shoal Field			
Osprey	Undefined Oil	300	300
Trading Bay Field			
Monopod	Hemlock	107*	50
Monopod	Mid Kenai B	50	50
Monopod	Mid Kenai C	71*	50
Monopod	Mid Kenai D	74*	50
Monopod	Mid Kenai	50	50
Monopod	Mid Kenai E	50	50
Monopod	Mid Kenai G – NE Hemlock-NE Oil	50	50
McArthur River Field			
Dolly Varden	Hemlock	150	150
Dolly Varden	Middle Kenai G	150	150
Grayling	Hemlock	162*	100
Grayling	Middle Kenai G	100	100
Grayling	West Foreland	150*	100
Steelhead	Hemlock	150	150
Steelhead	Middle Kenai G	150	150
King Salmon	Hemlock	150	150
King Salmon	Middle Kenai G	150	150
*Reached field abandonment time limit first			

Table 2-1. Abandonment rate assumptions for oil pools producing to an offshore platform, forecasted on a facility level.

Field	Oil Pool (AOGCC)	Abandonment Rate (BOPD), Well Basis
Beaver Creek	Beaver Creek Oil	50
West McArthur River	W McAr Riv Oil	50
West McArthur River	Hemlock Oil	50
Swanson River	Hemlock	50

Table 2-2. Abandonment rate assumptions for oil pools producing to an onshore facility.

Platform	Gas Pool (AOGCC)	Abandonment Rate (MCFD), Pool Basis
Steelhead	Mid Kenai Gas	1200

Table 2-3. Abandonment rate assumptions for a non-associated gas pool in the McArthur River field producing to an offshore facility, forecasted on a pool level. The abandonment rate for the pool was calculated using 50 MCFD per well multiplied by 24 wells; hence the abandonment rate was 1,200 MCFD.

A sensitivity analysis examined the EUR differences resulting from a 225 BOPD versus a 300 BOPD economic limit using data from the Middle Kenai Oil pool producing from the Anna platform within the Granite Point field. Ultimately, the changes between the two rate limits resulted in an EUR difference of just 1.01%. The higher rate limit was chosen for consistency with conservative production assumptions.

2.4. Base Case vs. Upside Case Decline Curve Analysis

DCA for the base case assumed no additional investment in production wells. Historical production performance predicts future production performance in this case, and the reserves identified belong in the proved (1P) category. In contrast, production wells requiring additional investment were also forecasted, but with different assumptions applied. Reserves in these wells are assigned to the probable category.

For wells that require additional investment, renewed production was assumed to begin January 1, 2018. This assumes that if field studies justified investment targeting well interventions (such as water shut-off, repair damaged completions, remove skin damage, etc.), then additional upside reserves would be captured in those wells. Wells forecasted in the upside cases were not included in the base cases.

2.5. Assumptions for Material Balance

Material balance is an engineering method where cumulative gas production data is plotted against reservoir pressure and gas PVT relationships (P/z) to calculate the volumetric accumulation of gas originally in place (Hartz, et al., 2009). The same technique was used in the 2009 study by the Division of Oil and Gas.

Original gas-in-place (OGIP) and Estimated Ultimate Recovery (EUR) volumes are determined by using the Abnormally-Pressured Gas Material Balance Program developed by Ryder Scott Reservoir Solutions (Version 6, July 2011). The program uses a modified Ramagost P/z versus Cumulative Gas Production analysis technique. The method incorporates a least squares mean fit (LSMF) of early time data to determine the apparent OGIP (Ryder Scott Software Solutions, 2011). With the inclusion of both production and pressure data later in time, a possible lower EUR may be observed, which may imply aquifer influx. The final point plotted on the x-axis (P/z = 0) seen in some material balance plots as shown in **Appendix A** represents the OGIP.

Once OGIP is determined, the EUR volume is estimated assuming an abandonment pressure of 50 psia. A sensitivity analysis examined the EUR differences resulting from a 50 psia abandonment pressure limit versus a 100 psia abandonment pressure limit. The changes between the two resulted in an average EUR difference of 2.71%. The lower abandonment pressure limit is chosen based on current operating capabilities in the Cook Inlet basin.

In many cases, material balance indicates the presence of additional recoverable gas beyond the reserves determined by DCA alone. Recovery of these additional reserves involves depleting the reservoir to a lower pressure, which in turn, requires additional compression to pressurize produced gas to the pipeline system entry pressure. Alternatively, overall system pressure can be lowered, though there are practical rate limits to any such decreases.

Material balance analyses may indicate a change in the P/z trend with additional production and pressure data from a new completion. Additional perforations in a new zone, interval, or reservoir will increase the calculated values of both the estimated OGIP and EUR.

2.6. Limitations of Decline and Material Balance Analyses

DCA is a standard engineering technique where past production trends, such as rate-time, are extrapolated on a semi-log scale (Arps, 1945). DCA assumes that past trends will remain the same, including lease operating expenses and wellhead pressures. The integration of the area under extrapolated production forecast curve yields remaining reserves that are recoverable in existing wellbores. Using DCA to evaluate remaining oil and gas reserves has historically been used since 1945 (Arps, 1945); however, it only represents a single snapshot in time. The future performance of gas completions is predicted based on historical production trends. Increased investment (such as new wells, recompletions, added compression, etc.) often increases the ultimate recovery. Ultimately, all DCA-based reserves estimates are dependent on the economic limit assumptions used to truncate future production.

Material balance calculations also have limitations, including the quality of both original and historical static pressure data within the public domain (Dake, 2001). Although material balance calculations show additional remaining EUR for the Sterling field in the Beluga and Tyonek gas pools, as well as Beaver Creek field in the Beluga and Sterling gas pools, and Beluga River field Undefined gas pool, water breakthrough at the well level, with approximately 20 barrels of water per million standard cubic feet of gas caused the wells to be shut in. The decline in gas rate, increasing water encroachment, and the inability to lift the water out of the wellbore were all pertinent factors that caused wells to be plugged and abandoned or temporarily shut in. Abandonment pressures for these particular cases were 1000 psia or higher.

2.7. Assumptions for Oil Pools

Solution gas associated with the fields producing oil must also be considered as part of the gas reserves inventory. The solution gas-oil-ratio (GOR) may vary between reservoirs (pools) within a given field. **Table 2-4** shows the solution GORs for oil pools within the Cook Inlet basin. GOR values were obtained from the AOGCC Statistical Pool Reports database (Alaska Oil and Gas Conservation Commission, 2004).

Field	Oil Pool (AOGCC)	Solution GOR (SCF/STB)
Beaver Creek	Beaver Creek Oil	235
Granite Point*	Hemlock Undefined Oil	800
Granite Point*	Middle Kenai Oil	1110
McArthur River	Hemlock Oil	404
McArthur River	MidKenai G Oil	422
McArthur River	W Foreland Oil	271
Middle Ground Shoal	A Oil	1000
Middle Ground Shoal	B, C, D Oil	650
Middle Ground Shoal	E, F, G Oil	381
Redoubt Shoal	Undefined Oil	265
Swanson River	Hemlock Oil	175
Swanson River	Undefined Oil	175 (assumed from Hemlock Oil Pool)
Trading Bay	Mid Kenai G – NE Hemlock-NE Oil	275
Trading Bay	Hemlock Oil	318
Trading Bay	Mid Kenai B Oil	188
Trading Bay	Mid Kenai C Oil	370
Trading Bay	Mid Kenai D Oil	440
Trading Bay	Mid Kenai E Oil	563
Trading Bay	Undefined Oil	266
Trading Bay	W Foreland Oil	314
West McArthur River	Hemlock Undefined Oil	260
West McArthur River	W McArthur River Oil	235

Table 2-4. Assumptions for solution GOR used in the Cook Inlet basin, grouped by pool and field.

*At Granite Point, a weighted average of the GORs based on the cumulative oil production between the Middle Kenai and Hemlock was used to calculate the remaining associated gas.

3. Results and Discussion

The Cook Inlet basin is at a fairly mature stage in terms of exploring for and producing conventional oil and gas in structural traps. However, as of 2011, the USGS estimated mean technically recoverable resources of 599 MMBO and 19 TCF of gas still awaiting discovery in the basin, the majority of which is assessed in the Tertiary formations that have already produced 8.3 TCF of gas through 2014. This study does not address undiscovered resource potential; the focus here is on applying petroleum engineering methods to production data to estimate the gas reserves remaining in existing fields. **Table 3-1** is a summary by field of cumulative gas produced through 2014, remaining reserves presented in columns according to the methods and data used in this study to identify the various categories, and EUR.

Field	Cumulative Gas Produced, as of 12/31/2014, BCF	Base Case Decline Analysis (Gas Pools), BCF	Associated Gas (Oil Pools), BCF	Total Proved 1P Reserves, BCF	Upside Case Decline Analysis, BCF	Material Balance, BCF	Total Probable, BCF	Total Proved + Probable Remaining, 2P Reserves, BCF	Estimated Ultimate Recovery, BCF
Albert Kaloa	4	0	0	0	0	0	0	0	4
Beaver Creek	221	12	0	12	8	2	10	23	244
Beluga River	1298	170	0	170	34	0	34	204	1502
Birch Hill	0	0	0	0	0	0	0	0	0
Deep Creek	28	7	0	7	0	0	0	7	35
Granite Point	135	0	16	16	0	2	2	18	153
Hansen	0	0	0	0	0	0	0	0	0
Ivan River	85	2	0	2	0	7	7	9	94
Kasilof	4	0	0	0	2	0	2	2	7
Kenai	2435	112	0	112	11	66	77	189	2624
Kenai C.L.U.	191	20	0	20	0	12	12	32	224
Kenai Loop	8	26	0	26	0	0	0	26	34
Kustatan	0	0	0	0	0	0	0	0	1
Lewis River	15	3	0	3	0	8	8	11	26
Lone Creek	11	2	0	2	0	8	8	10	21
McArthur River	1476	30	7	38	0	35	35	73	1549
Middle Ground Shoal	111	0	5	5	0	17	17	22	133
Moquawkie	5	0	0	0	0	6	6	6	11
Nicolai Creek	9	2	0	2	3	0	4	5	14
Nikolaevsk	1	0	0	0	0	1	1	1	2
Ninilchik	164	100	0	100	8	0	8	108	271
North Cook Inlet	1889	130	0	130	31	164	195	325	2214
North Fork	9	17	0	17	0	16	16	32	42
Pretty Creek	10	0	0	0	0	8	8	8	17
Redoubt Shoal	2	0	1	1	0	1	1	2	4
Sterling	14	0	0	0	1	3	4	4	18
Stump Lake	7	0	0	0	1	7	8	8	14
Swanson River	70	18	1	18	0	0	0	18	89
Three Mile Creek	2	1	0	1	0	1	1	1	4
Trading Bay	82	30	0	30	0	3	3	33	115
West Foreland	11	0	0	0	0	2	2	2	13
West Fork	6	0	0	0	1	1	2	2	8
West McArthur River	3	0	1	1	0	0	0	1	4
Wolf Lake	1	0	0	0	1	1	2	2	2
Total	**8308**	**681**	**30**	**711**	**101**	**371**	**472**	**1183**	**9491**

Table 3-1. Summary, by field, of cumulative gas production, estimated remaining reserves, and EUR. Summed values may disagree slightly with component values due to rounding.

Table 3-2 presents similar information broken down to the pool level. The Cook Inlet basin currently has 55 onshore gas pools, six offshore gas pools, five gas storage pools, 18 offshore oil pools, and seven onshore oil pools. Since the 2009 DOG study, three new gas fields achieved first production: Nikolaevsk, North Fork, and Kenai Loop.

Field	Pool	Cumulative Gas Produced, as of 12/31/2014, BCF	Base Case Decline Analysis (Gas Pools), BCF	Associated Gas (Oil Pools), BCF	Total Proved 1P Reserves, BCF	Upside Case Decline Analysis, BCF	Material Balance, BCF	Total Probable, BCF	Total Proved + Probable Remaining, 2P Reserves, BCF	Estimated Ultimate Recovery, BCF
Albert Kaloa	Undefined Gas	3.6	0.0	0.0	0.0	0.1	0.0	0.1	0.1	3.7
Beaver Creek	Beaver Creek Oil	2.5	0.0	0.1	0.1	0.0	0.0	0.0	0.1	2.7
Beaver Creek	Beluga Gas	86.6	12.1	0.0	12.1	8.4	0.0	8.4	20.5	107.1
Beaver Creek	Sterling Gas	126.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.7
Beaver Creek	Tyonek Undef Gas	5.5	0.0	0.0	0.0	0.0	2.1	2.1	2.1	7.6
Beluga River	Undefined Gas	1298.0	170.2	0.0	170.2	33.7	0.0	33.7	203.8	1501.8
Birch Hill	Undefined Gas	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Deep Creek	Hv Beluga/Tyonek	23.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.8
Deep Creek	Tyonek Undef Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deep Creek	Undefined Gas	4.0	6.9	0.0	6.9	0.0	0.0	0.0	6.9	10.8
Granite Point	Hemlock Undef Oil	2.3	0.0	0.1	0.1	0.0	0.0	0.0	0.1	2.4
Granite Point	Middle Kenai Oil	131.6	0.0	15.8	15.8	0.0	0.0	0.0	15.8	147.4
Granite Point	Undefined Gas	0.9	0.0	0.0	0.0	0.0	1.9	1.9	1.9	2.8
Hansen	Hansen Undef Oil	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Ivan River	Undefined Gas	85.0	1.8	0.0	1.8	0.0	7.1	7.1	8.8	93.9
Kasilof	Tyonek Undef Gas	4.3	0.0	0.0	0.0	2.2	0.0	2.2	2.2	6.6
Kenai C.L.U.	Beluga Gas	92.6	19.4	0.0	19.4	0.0	0.0	0.0	19.4	112.0
Kenai C.L.U.	Sterling Und Gas	23.0	0.0	0.0	0.0	0.0	4.0	4.0	4.0	27.0
Kenai C.L.U.	Tyonek D Gas	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4
Kenai C.L.U.	Upper Tyonek Gas	74.5	0.7	0.0	0.7	0.0	8.0	8.0	8.7	83.2
Kenai Loop	Undefined Gas	8.2	25.7	0.0	25.7	0.0	0.0	0.0	25.7	33.9
Kenai	Beluga - Up Tyonek Gas	372.8	78.3	0.0	78.3	11.5	0.0	11.5	89.7	462.5
Kenai	Beluga Undefined Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kenai	Sterling 3 Gas	333.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	333.4
Kenai	Sterling 4 Gas	452.3	0.0	0.0	0.0	0.0	0.4	0.4	0.4	452.7
Kenai	Sterling 5.1 Gas	484.6	0.0	0.0	0.0	0.0	40.8	40.8	40.8	525.4
Kenai	Sterling 5.2 Gas	44.6	0.0	0.0	0.0	0.0	24.4	24.4	24.4	69.0
Kenai	Sterling 6 Gas	545.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	545.2
Kenai	Sterling Upper Undf Gas	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Kenai	Tyonek Gas	202.4	33.7	0.0	33.7	0.0	0.0	0.0	33.7	236.1
Kustatan	Kustatan Field 1 Gas	0.3	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.6
Lewis River	Undefined Gas	14.8	2.9	0.0	2.9	0.0	7.8	7.8	10.7	25.5
Lone Creek	Undefined Gas	10.6	2.4	0.0	2.4	0.0	7.7	7.7	10.1	20.7
McArthur River	Hemlock Oil	220.7	0.0	5.3	5.3	0.0	0.0	0.0	5.3	226.0
McArthur River	Midkenai G Oil	36.8	0.0	1.5	1.5	0.0	0.0	0.0	1.5	38.3
McArthur River	Midkenai Gas	1209.9	30.4	0.0	30.4	0.0	35.1	35.1	65.5	1275.4
McArthur River	Undefined Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
McArthur River	W Foreland Oil	8.7	0.0	0.4	0.4	0.0	0.0	0.0	0.4	9.1
Middle Ground Shoal	A Oil	5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3
Middle Ground Shoal	BCD Oil	8.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.8
Middle Ground Shoal	EFG Oil	80.4	0.0	4.6	4.6	0.0	0.0	0.0	4.6	85.0
Middle Ground Shoal	Undef Gas	16.8	0.0	0.0	0.0	0.0	17.1	17.1	17.1	33.9

Table 3-2. Summary, by pool, of cumulative gas production, estimated remaining reserves, and EUR. Note that the decline analyses were completed well-by-well, then rolled up on a pool level. Summed values may disagree slightly with component values due to rounding.

Field	Pool	Cumulative Gas Produced, as of 12/31/2014, BCF	Base Case Decline Analysis (Gas Pools), BCF	Associated Gas (Oil Pools), BCF	Total Proved 1P Reserves, BCF	Upside Case Decline Analysis, BCF	Material Balance, BCF	Total Probable, BCF	Total Proved + Probable Remaining, 2P Reserves, BCF	Estimated Ultimate Recovery, BCF
Moquawkie	Undefined Gas	5.0	0.1	0.0	0.1	0.0	6.0	6.0	6.1	11.1
Nicolai Creek	Beluga Und Gas	3.4	0.1	0.0	0.1	0.1	0.3	0.4	0.5	3.9
Nicolai Creek	N Und U Ty Gas	3.6	0.5	0.0	0.5	3.2	0.0	3.2	3.7	7.3
Nicolai Creek	S Und U Ty Gas	1.6	1.1	0.0	1.1	0.0	0.0	0.0	1.1	2.7
Nikolaevsk	Tyonek Undef Gas	0.7	0.0	0.0	0.0	0.3	1.1	1.4	1.4	2.0
Ninilchik	Beluga-Tyonek Gas	163.6	99.7	0.0	99.7	8.0	0.0	8.0	107.7	271.2
North Cook Inlet	Tertiary Gas	1888.7	129.9	0.0	129.9	31.3	163.9	195.2	325.1	2213.8
North Fork	Undefined Gas	9.5	16.5	0.0	16.5	0.0	15.8	15.8	32.3	41.8
Pioneer	Tyonek Undefined Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pretty Creek	Undefined Gas	9.5	0.0	0.0	0.0	0.0	7.8	7.8	7.8	17.3
Redoubt Shoal	Undef G-O Gas	0.5	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.9
Redoubt Shoal	Undefined Oil	0.8	0.0	0.7	0.7	0.0	0.0	0.0	0.7	1.5
Redoubt Shoal	Undf Tyonek Gas	0.9	0.0	0.0	0.0	0.0	0.9	0.9	0.9	1.8
Sterling	Lw Bel/Tyonek Und Gs	1.0	0.0	0.0	0.0	0.0	2.9	2.9	2.9	3.9
Sterling	Sterling Undef Gas	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
Sterling	Up Beluga Undef Gas	9.1	0.0	0.0	0.0	0.6	0.5	1.1	1.1	10.2
Sterling	Beluga Undefined Gas	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Sterling	Tyonek Undefined Gas	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Stump Lake	Undefined Gas	6.7	0.0	0.0	0.0	0.6	7.1	7.8	7.8	14.4
Swanson River	Beluga Gas	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5
Swanson River	Hemlock Oil	14.2	0.0	0.5	0.5	0.0	0.0	0.0	0.5	14.7
Swanson River	Hm-Strl Und Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Swanson River	Strlg/U Blug Gs	33.0	17.5	0.0	17.5	0.0	0.0	0.0	17.5	50.5
Swanson River	Tyonek Gas	19.2	0.3	0.0	0.3	0.0	0.0	0.0	0.3	19.6
Swanson River	Undefined Oil	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Three Mile Creek	Beluga Gas	2.5	0.5	0.0	0.5	0.1	0.8	0.9	1.5	3.9
Trading Bay	G-Ne/Hemlk-Ne Oil	6.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.5
Trading Bay	Hemlock Oil	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4
Trading Bay	M.Kenai Unallocat	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
Trading Bay	Mid Kenai B Oil	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.3
Trading Bay	Mid Kenai C Oil	15.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.1
Trading Bay	Mid Kenai D Oil	24.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.5
Trading Bay	Mid Kenai E Oil	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0
Trading Bay	Undefined Gas	5.7	30.4	0.0	30.4	0.0	3.0	3.0	33.4	39.1
Trading Bay	Undefined Oil	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1
Trading Bay	W Foreland Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Foreland	Tyonek Und 4.0 Gas	8.0	0.2	0.0	0.2	0.0	0.5	0.5	0.6	8.7
West Foreland	Tyonek Und 4.2 Gas	3.2	0.0	0.0	0.0	0.0	1.1	1.1	1.1	4.3
West Fork	Sterling A Gas	1.2	0.0	0.0	0.0	0.0	1.0	1.0	1.0	2.2
West Fork	Sterling B Gas	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4
West Fork	Undefined Gas	3.3	0.0	0.0	0.0	0.8	0.0	0.8	0.8	4.1
West McArthur River	Hemlock Und Oil	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.1	0.2
West McArthur River	W Mcar Riv Oil	3.4	0.0	0.6	0.6	0.0	0.0	0.0	0.6	4.0
Wolf Lake	Bel-Tyon Undef Gas	0.8	0.0	0.0	0.0	0.6	1.0	1.6	1.6	2.4

Table 3-2, continued.

Decline curve analyses from the base case indicate there is approximately 711 BCF of remaining 1P (proved) reserves, including dry gas and associated gas that can be recovered from currently existing producing wells.

A more optimistic DCA case, assuming investment in remediation of well problems can be justified, may recover an additional 101 BCF gas; this is assigned to the probable reserves category. Material balance analyses indicate that an additional 371 BCF of probable reserves may be recovered by investment to reduce well back pressure in fields where the EUR from P/z analysis exceeds EUR from DCA alone. The two tranches of probable reserves from upside DCA and material balance analyses yield total probable reserves of 472 BCF. Hence, the total proved plus probable (2P) reserves in producing fields basin-wide are estimated at 1,183 BCF. This study does not attempt to estimate 3P reserves, which would include more speculative volumes that stand less than 10 percent chance of being produced.

These results do not include the gas discovered at Kitchen Lights and Cosmopolitan, where promising gas test rates bode well for future additions to the Cook Inlet gas reserves base. The operators maintain proprietary early-stage volumetric estimates for these projects that will continue to be refined as development proceeds, but at this point, there is no production history for quantifying gas reserves through decline or material balance analysis.

Since 1996, a number of studies have predicted shortfalls in gas supply to the constrained market in both south-central Alaska and LNG markets. **Figure 3-1** illustrates Cook Inlet reserves and EUR as determined in seven studies since 1996. Reserves were calculated in different ways and assigned to different categories in the various studies. For the purpose of comparison, estimated reserves are shown as a single figure for each study.

The first report estimated total gas reserves of 3,787 BCF (GeoQuest Reservoir Technologies, 1996). A 1997 rebuttal stated that the total reserves within the Cook Inlet basin were approximately 2,436 BCF (Malkwicz, Hueni, and Associates., 1997). In 2004 a study backed by the Department of Energy (Thomas, Doughty, Faulder, & Hite, 2004) estimated Cook Inlet reserves at 1,714 BCF. ConocoPhllips' renewal of the LNG export license spurred another update, which estimated total reserves of 1,727 BCF in 2007 (Netherland, Sewell and Associates, Inc., 2007). DNR's previous study (Hartz and others, 2009) recognized 1,142 BCF in reserves through the same combination of decline analysis and material balance techniques used in the current study; that study also documented additional tranches of geologically-identified resources not included in this reserves comparison. This was followed by a report issued by Petrotechnical Resources of Alaska under contract to utilities ENSTAR, Chugach Electric, and Municipal Light and Power, which used decline analysis alone to conclude that reserves of 729 BCF could be recovered from existing wells within the Cook Inlet basin (Stokes, Grether, & Walsh, 2010).

Figure 3-1 shows that there is an overall upward trend to the EUR from existing fields over the last 20 years, although EUR has not always increased from one study to the next. This is an example of reserves growth, a common phenomenon in producing basins as they mature, in which continuing investment in producing fields yields more production than could be forecasted earlier in field life.

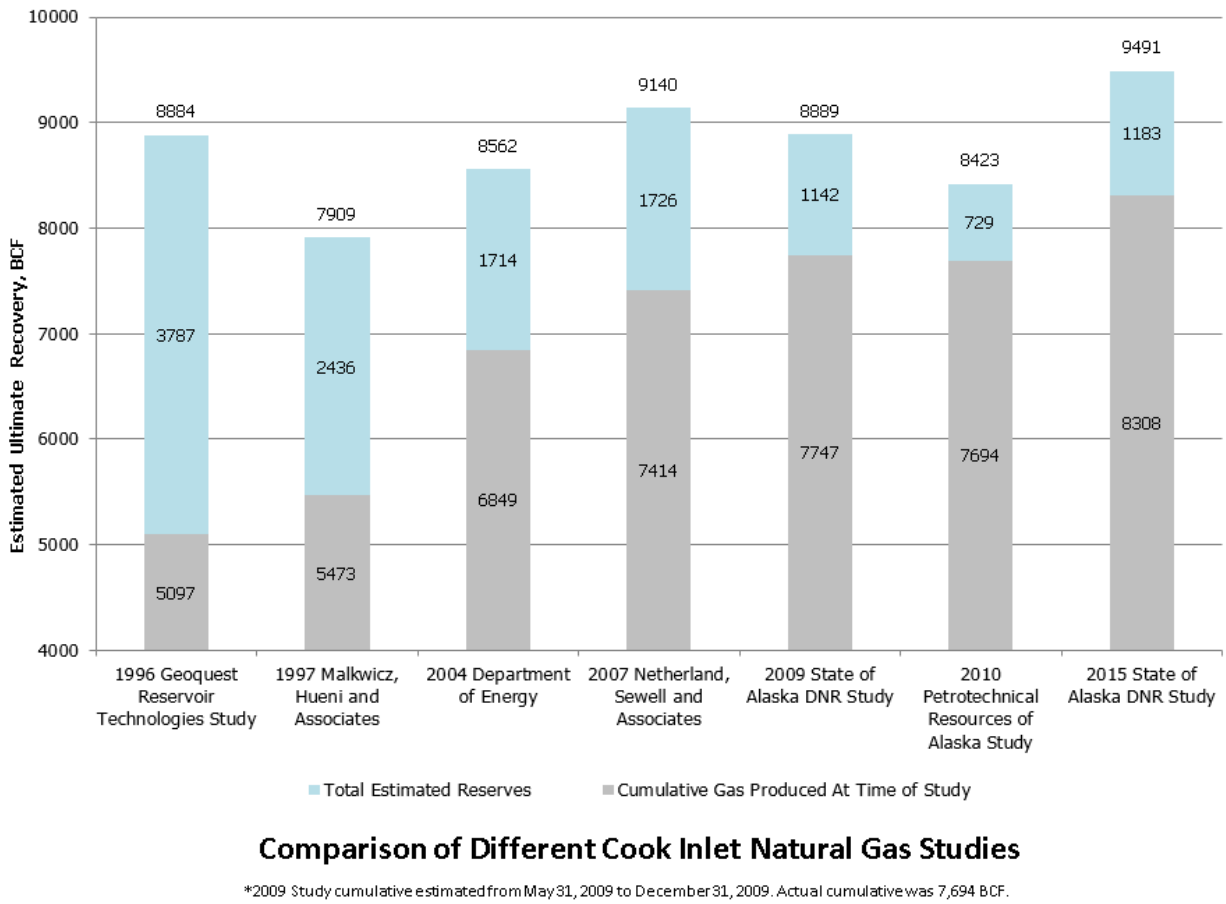

Figure 3-1. Comparison of Cook Inlet gas reserve estimates over time. Numbers above the bars show Estimated Ultimate Recovery by study. Summed values may disagree slightly with component values due to rounding.

This study does not include detailed analysis of gas storage reservoirs, nor the possible reserves growth in depleted reservoirs now used for storage. **Table 3-3** shows the cumulative balance of gas storage reservoirs, through 2014. The balance is determined by the difference of the cumulative gas injected and cumulative gas withdrawn. The table below shows that more gas has been injected than withdrawn, and a total of approximately 35 BCF were contained in storage as of year-end 2014. This volume is not included in the reserves calculated in this study.

Gas Storage Pool (AOGCC)	Cumulative Storage Gas Injection, BCF	Cumulative Storage Gas Withdrawn, BCF	Gas Remaining in Storage, BCF
Kenai Cannery Loop Unit, Sterling C (CINGSA)	17.5	7.20	10.3
Kenai, Sterling 6 Gas Stor	32.0	12.2	19.8
Pretty Creek, Beluga	5.45	4.04	1.41
Swanson River 64-5 Tyonek	11.5	10.1	1.40
Swanson River 77-3 Tyonek	11.7	9.92	1.78

Table 3-3. Cumulative injection, withdrawal, and approximately 35 BCF storage balance for Cook Inlet gas storage reservoirs as of December 31, 2014.

4. Conclusions

This report summarizes an integrative effort to quantify remaining gas reserves in Cook Inlet fields, and categorizes them relative to whether current or future investments are necessary to keep gas producing. Whereas most of the reserves in Cook Inlet's legacy fields have been recovered, as seen in **Figure 4-1**, significant remaining volumes are identified, especially in some of the basin's largest fields.

Gas fields with the largest proved and probable (2P) estimated remaining reserves base, in descending order, are North Cook Inlet, Beluga River, Kenai, and Ninilchik (**Figure 4-2**); each has more than 100 BCF in estimated 2P reserves, and collectively they constitute approximately 826 BCF of proved and probable (2P) gas reserves. These four fields account for about 70 percent of the remaining reserves. Smaller gas fields, each containing 0.2 to 73 BCF, account for approximately 357 BCF of additional 2P reserves (**Figure 4-3**), about 30 percent of 2P reserves basin-wide.

The four largest gas fields in the basin in terms of EUR, in descending order, are Kenai, North Cook Inlet, McArthur River, and Beluga River. These four fields combined account for approximately 83 percent of total EUR. Based on the petroleum engineering methods employed, the assumptions used, and the historical production and reservoir pressure data available, a total of approximately 1,183 BCF of proved and probable (2P) remaining reserves are calculated in currently producing fields basin-wide. Additional gas from the Kitchen Lights and Cosmopolitan discoveries is expected to move into the reserves category as those fields are developed.

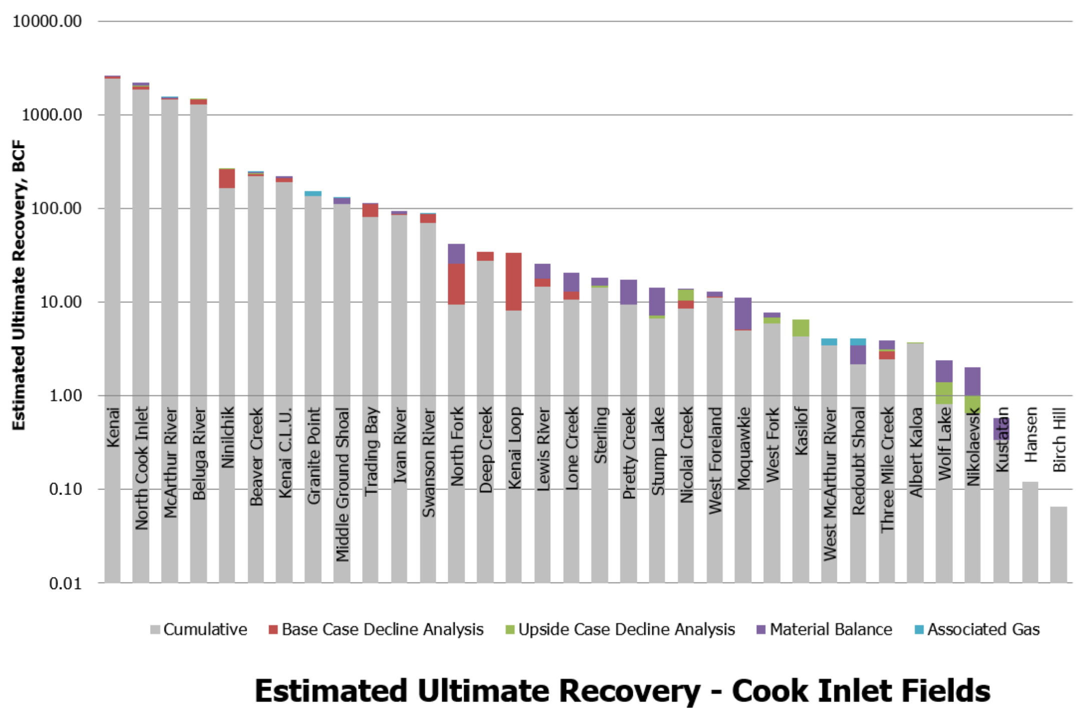

Figure 4-1. Estimated Ultimate Recovery of Cook Inlet, based on analysis conducted in this study. Note that the y-axis scale is logarithmic.

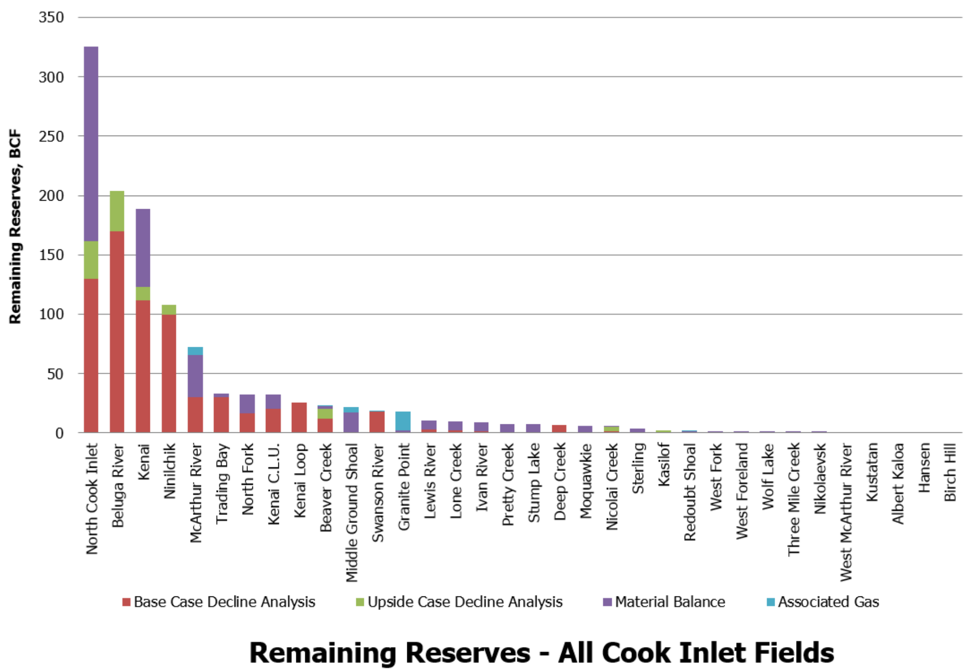

Figure 4-2. Remaining reserves of the Cook Inlet basin, including fields where remaining reserves are greater than 100 BCF (North Cook Inlet, Beluga River, Kenai, and Ninilchik).

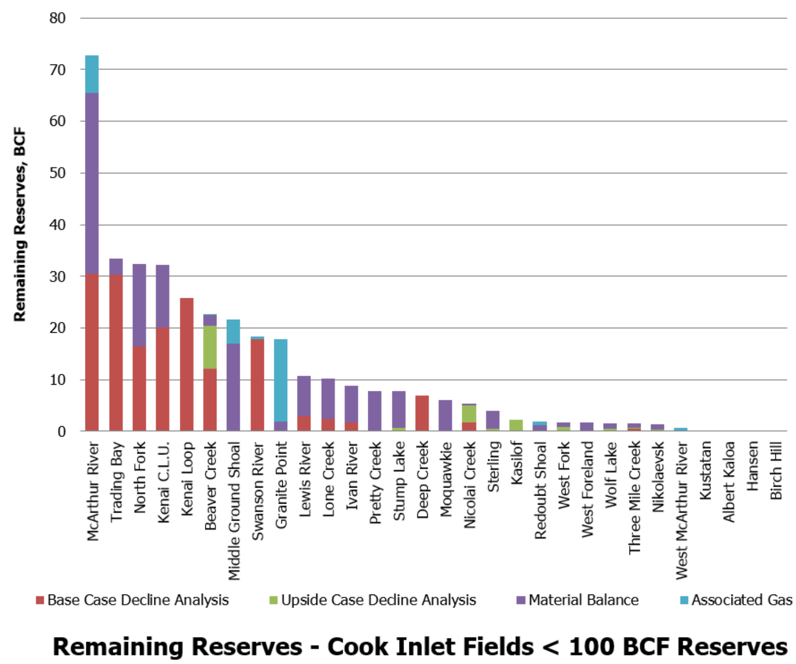

Figure 4-3. Remaining reserves of the Cook Inlet basin, depicting only the fields where remaining reserves are less than 100 BCF.

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Appendix A. Summaries of EUR for Gas by Pool

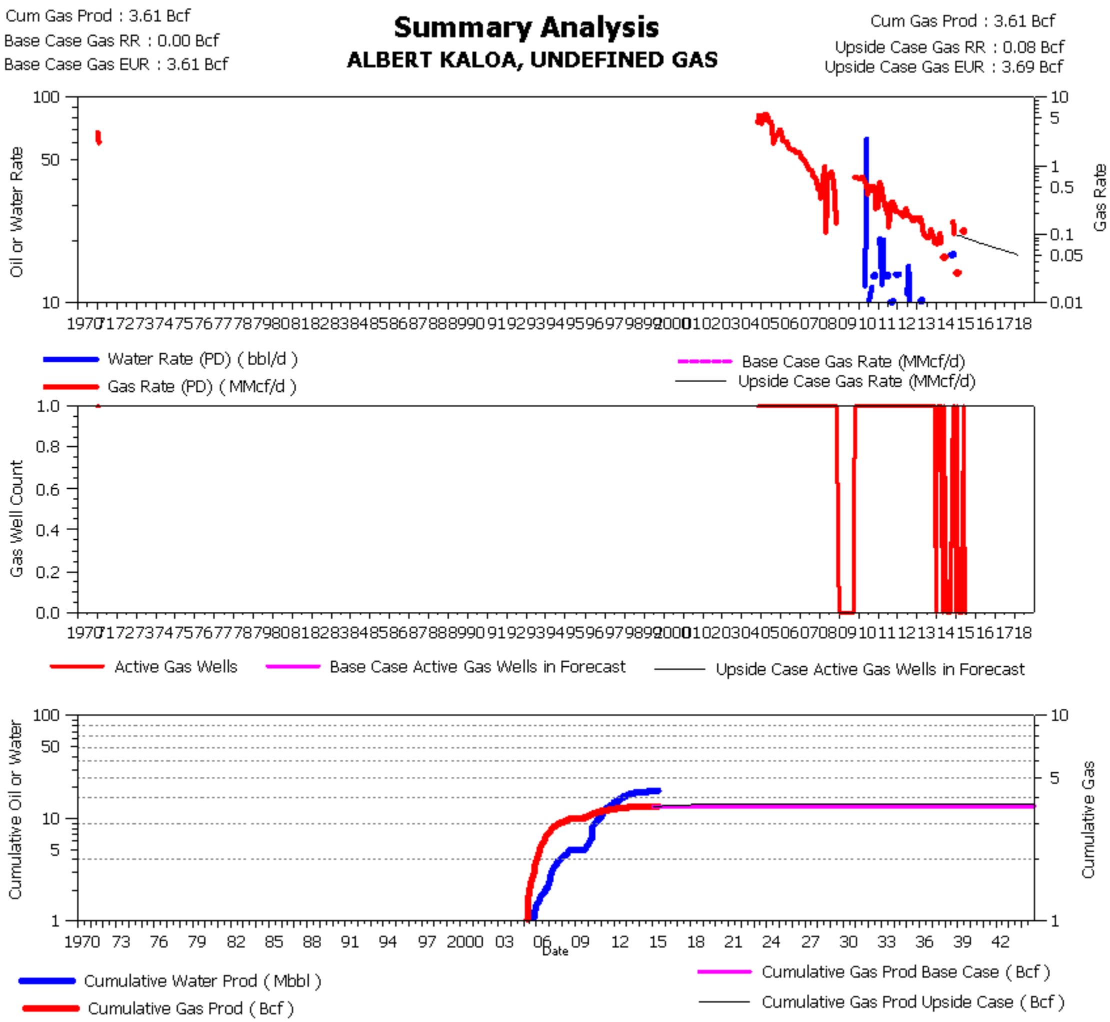

Figure A-1. Albert Kaloa field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

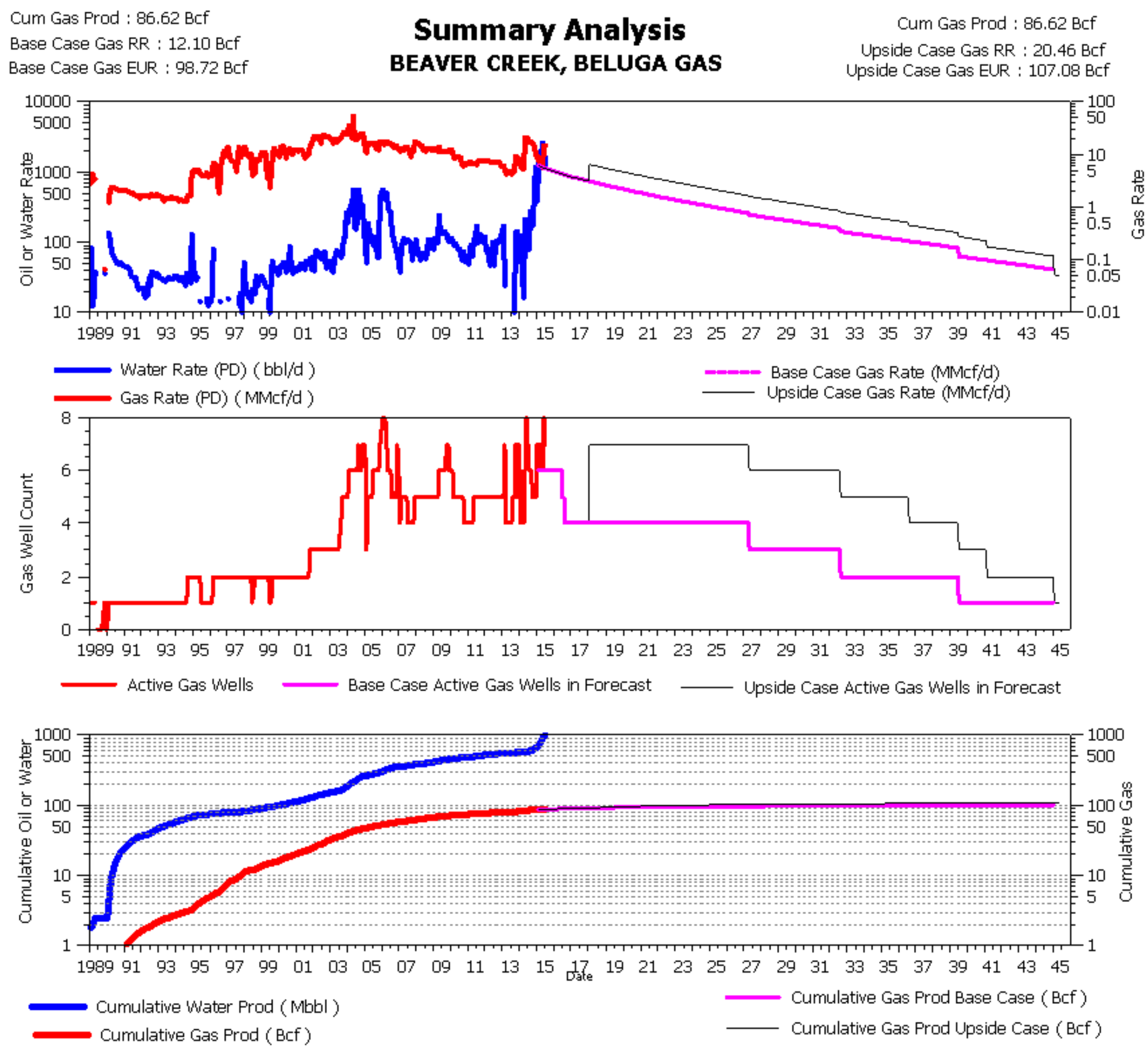

Figure A-2. Beaver Creek field. Beluga gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

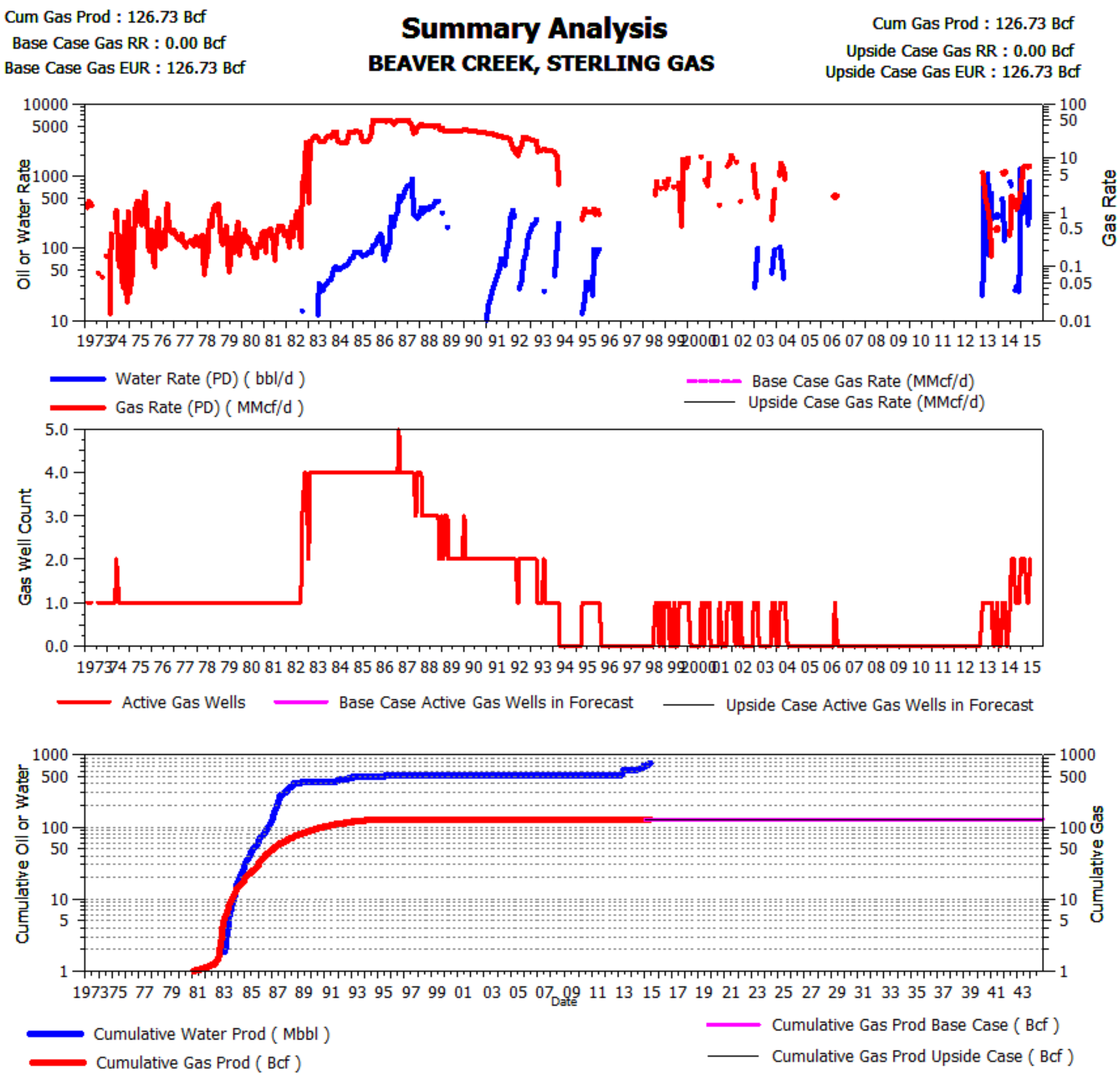

Figure A-3. Beaver Creek field. Sterling gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

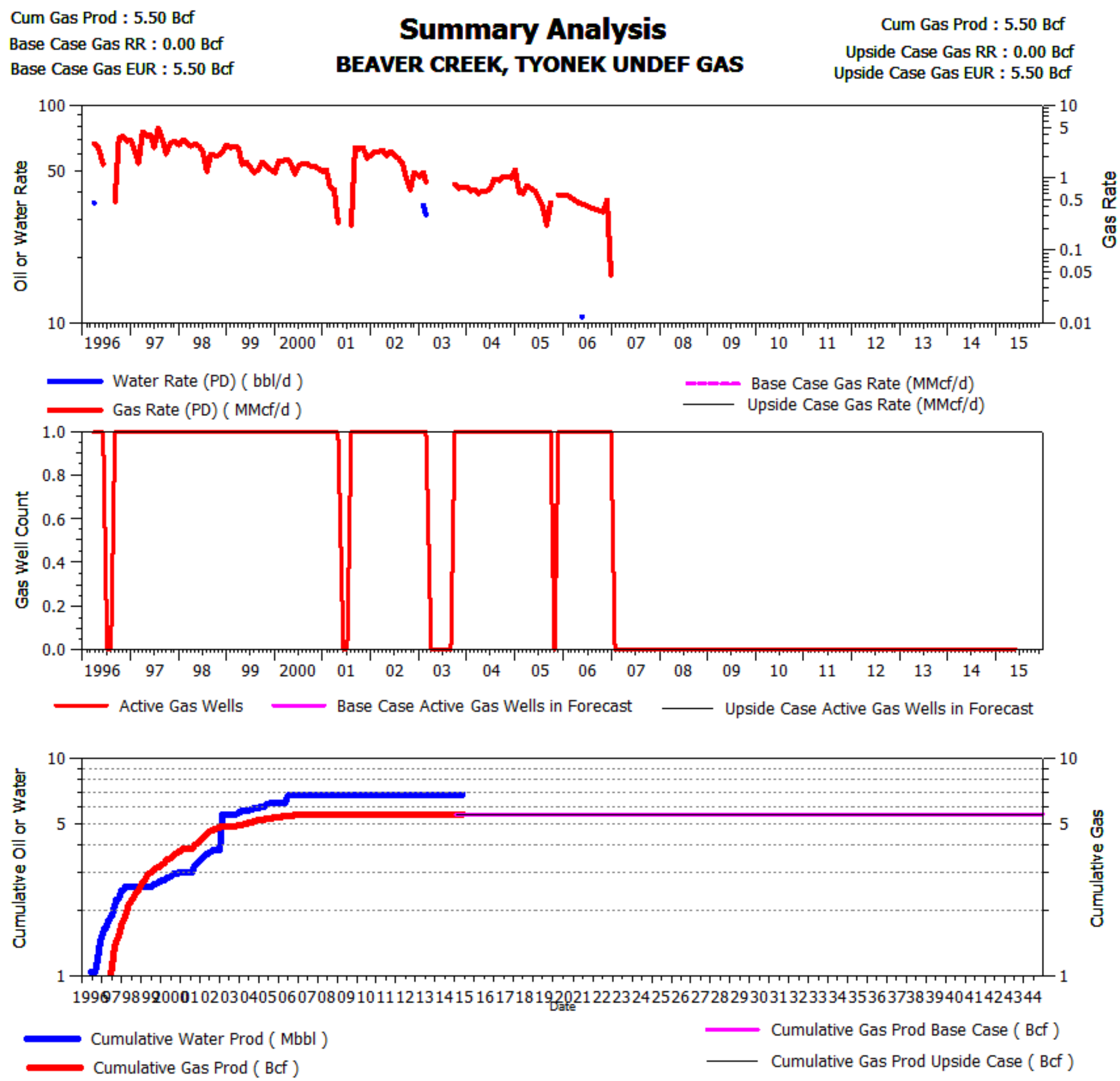

Figure A-4. Beaver Creek field. Tyonek Undefiined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

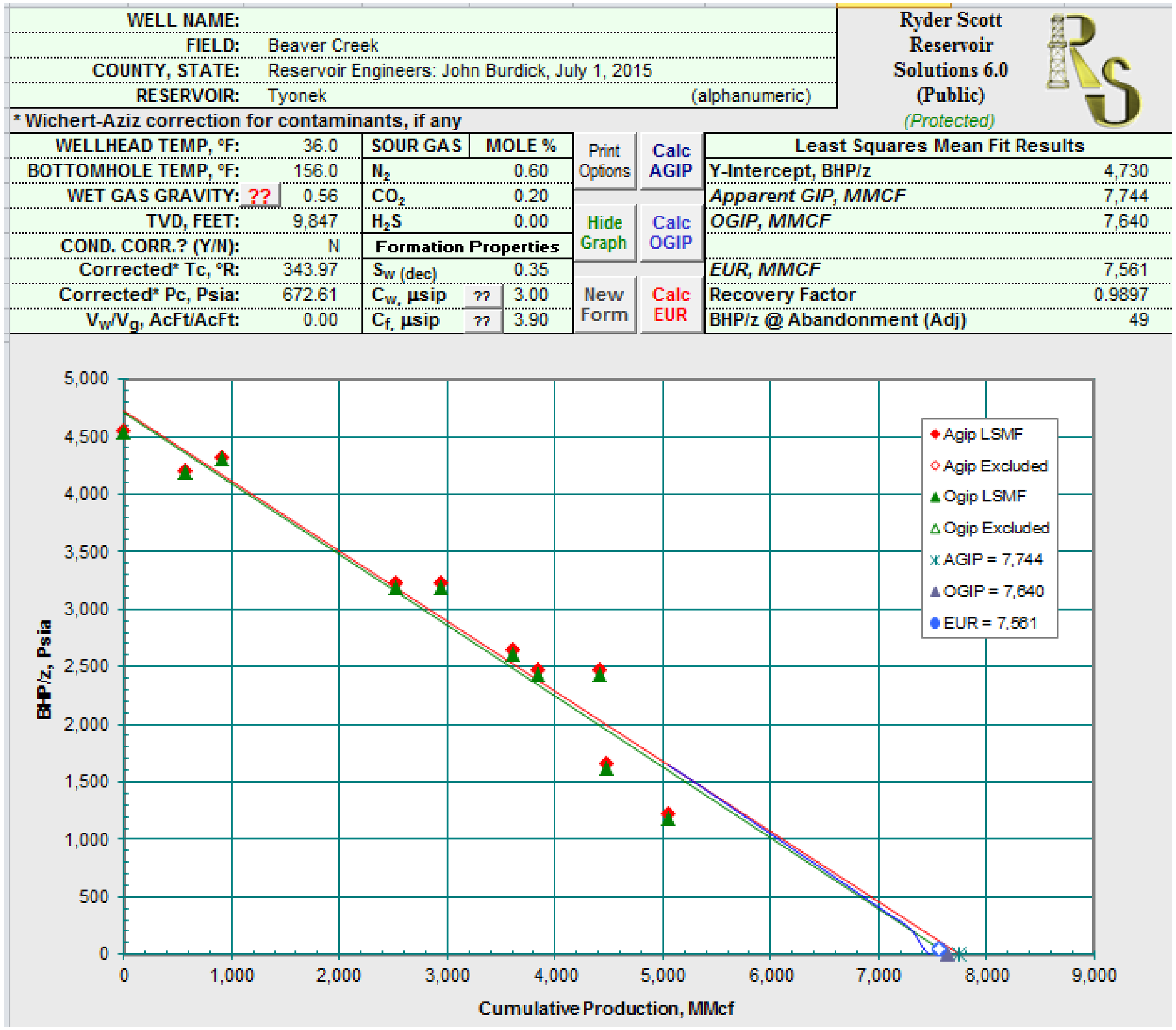

Figure A-5. Material balance and assumptions for Beaver Creek field, Sterling gas pool.

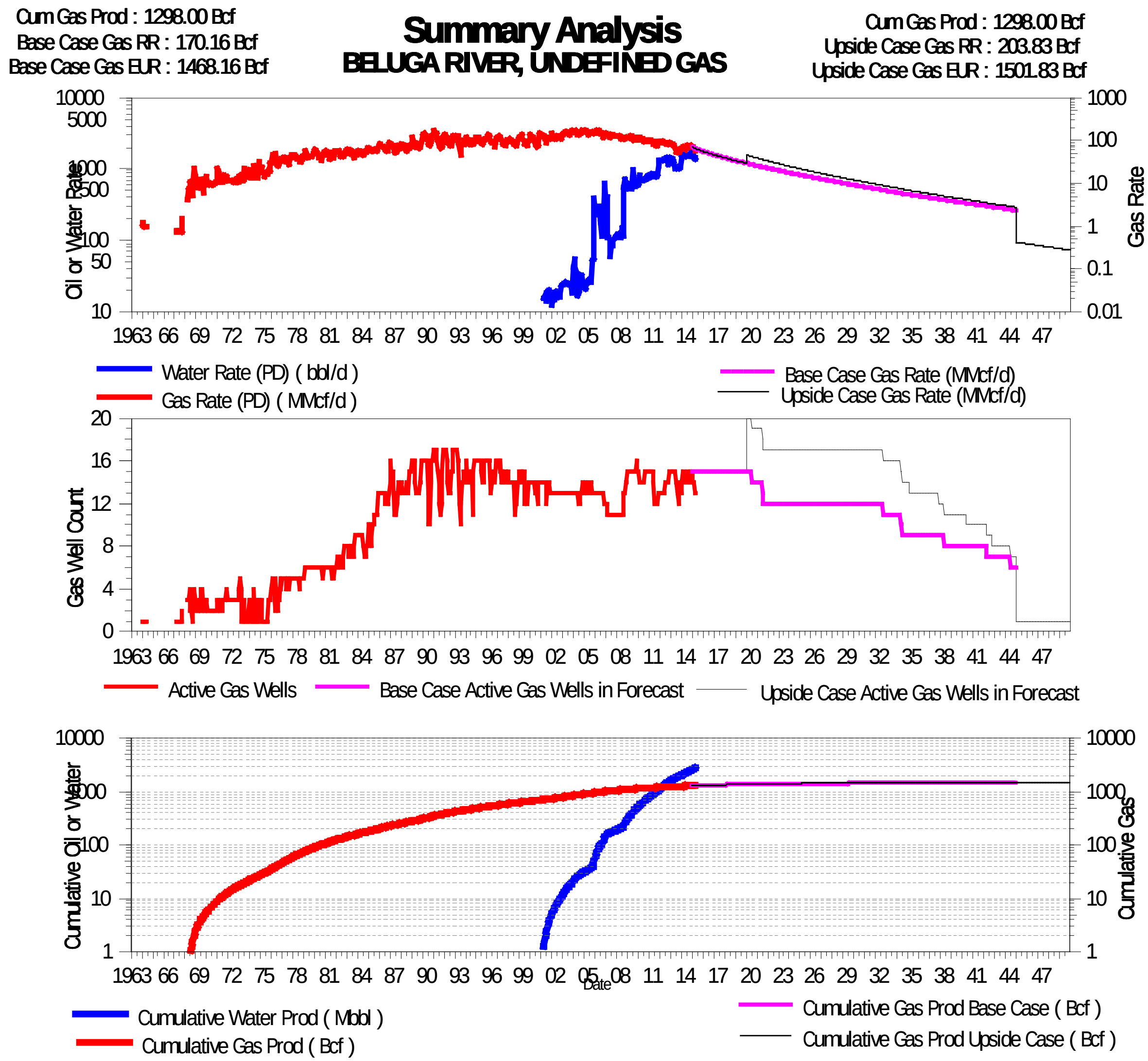

Figure A-6. Beluga River field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

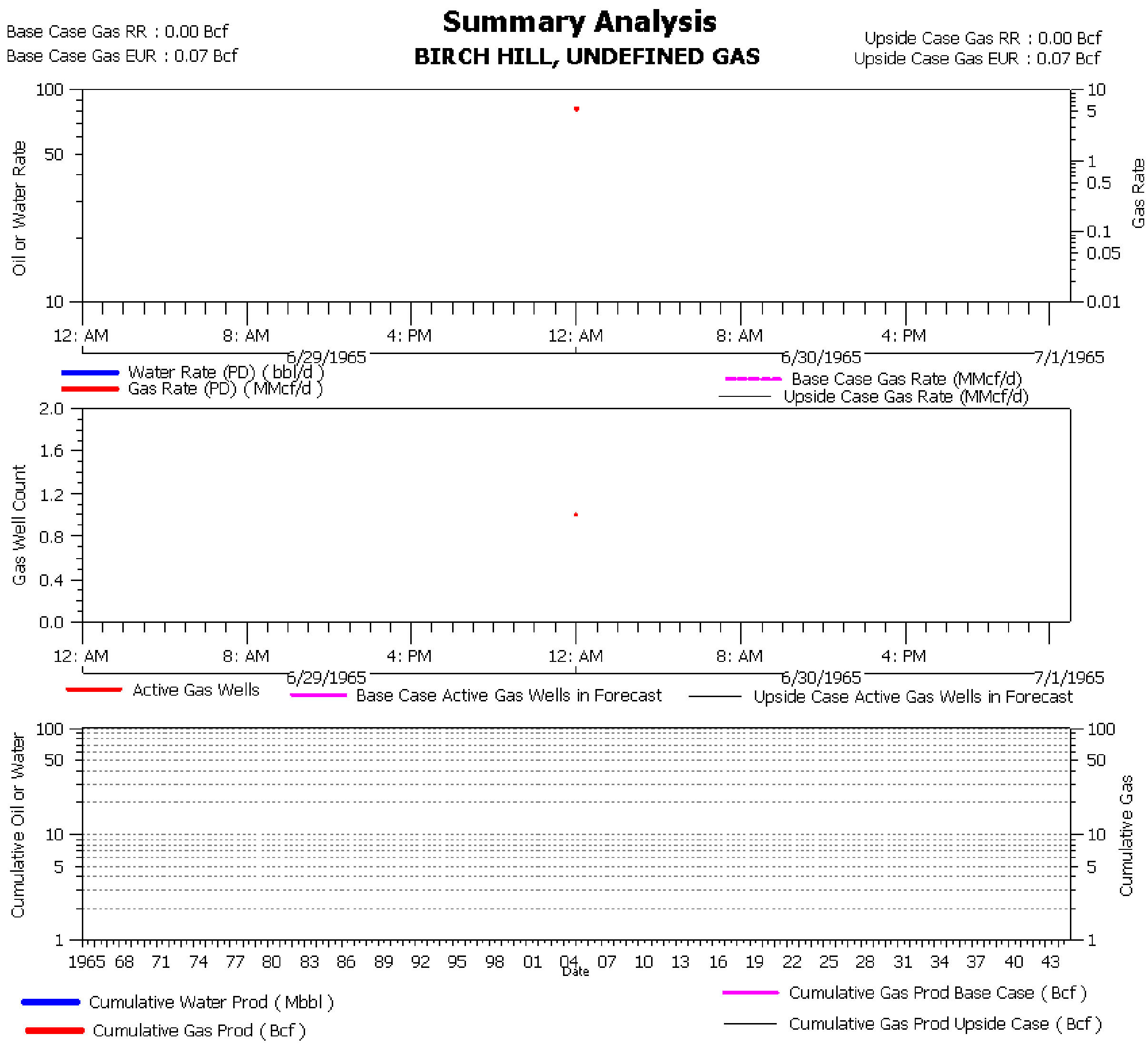

Figure A-7. Birch Hill field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

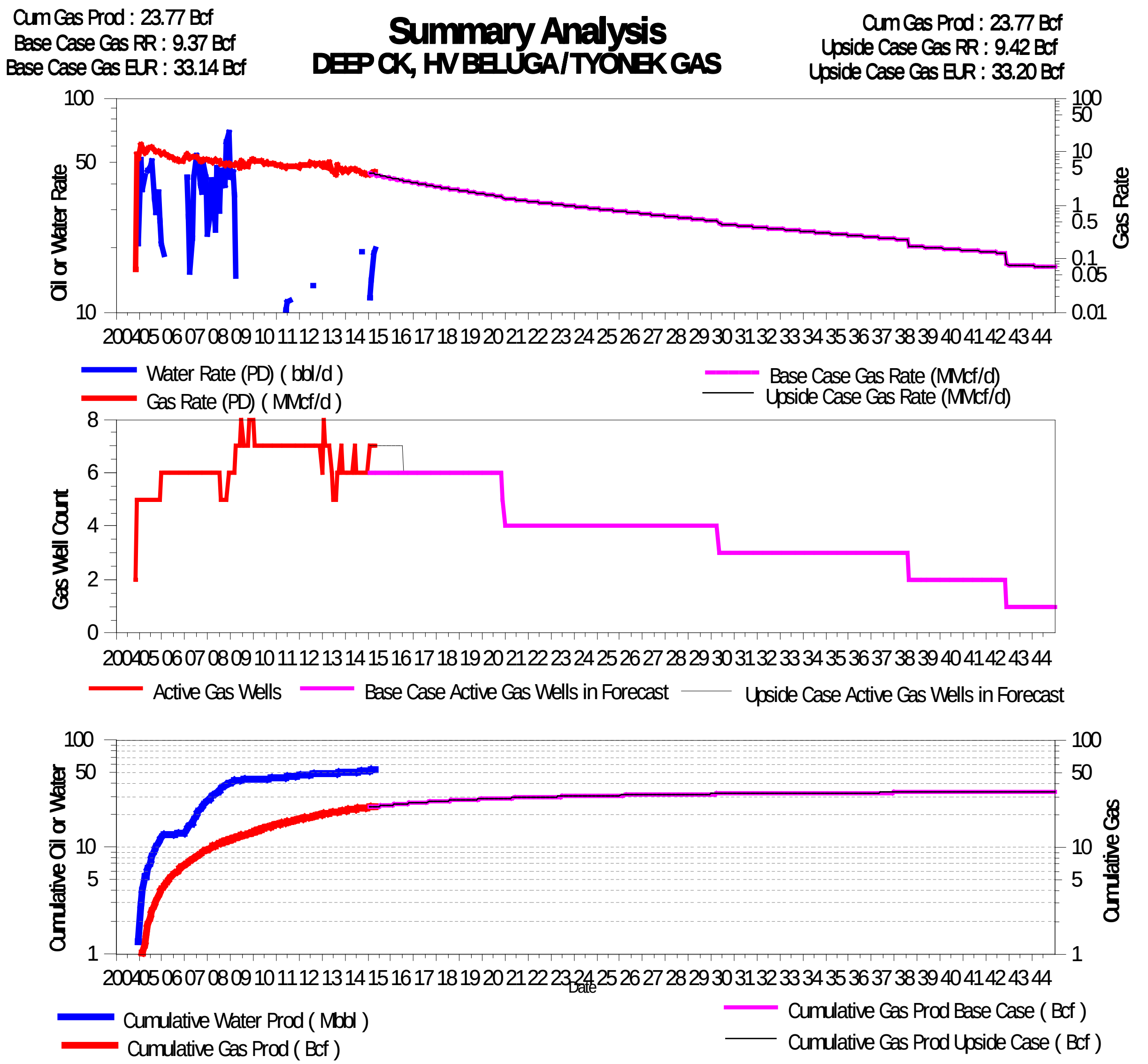

Figure A-8. Deep Creek field. Happy Valley Beluga and Tyonek gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

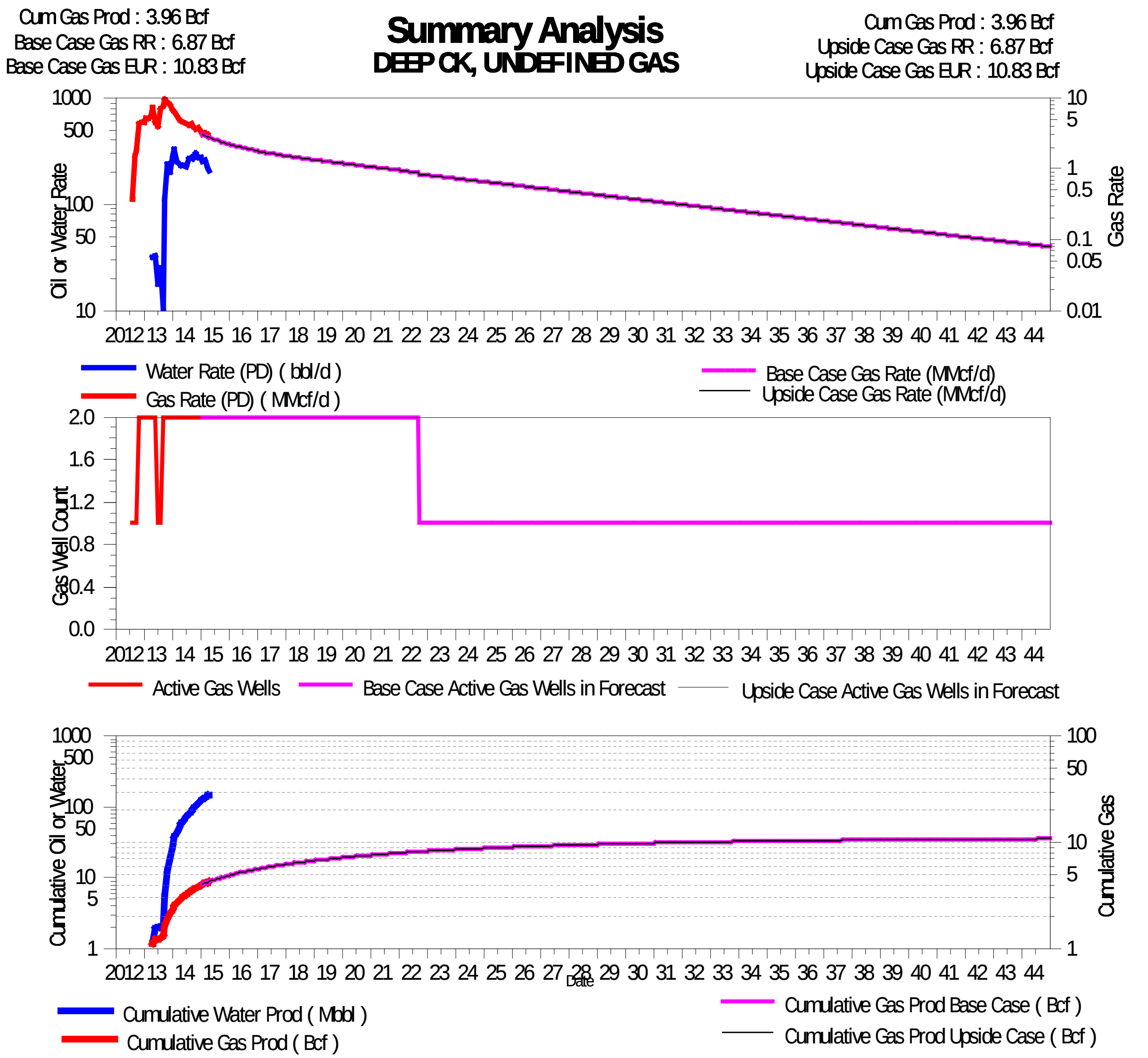

Figure A-9. Deep Creek field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

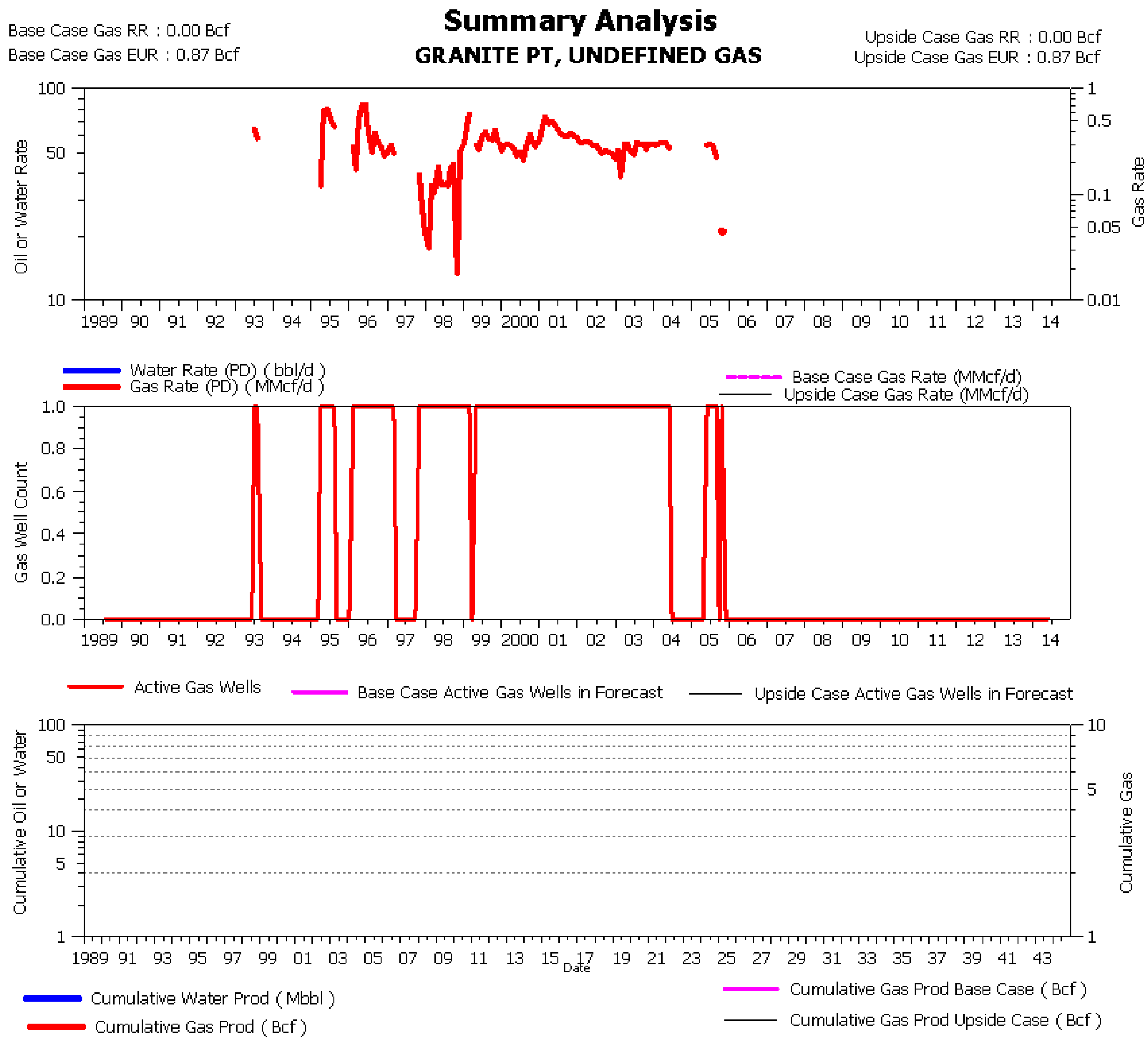

Figure A-10. Granite Point field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:			Ryder Scott Reservoir Solutions 6.0 (Public) *(Protected)*
FIELD:	Granite Point		
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, June 2, 2015		
RESERVOIR:	Undefined Gas Pool	(alphanumeric)	

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	100.0	N_2	0.00			Y-Intercept, BHP/z	2,323
WET GAS GRAVITY: ??	0.56	CO_2	0.00			*Apparent GIP, MMCF*	2,896
TVD, FEET:	4,088	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	2,858
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	346.08	S_w (dec)	0.53			*EUR, MMCF*	2,797
Corrected* Pc, Psia:	673.64	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9788
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.51			BHP/z @ Abandonment (Adj)	50

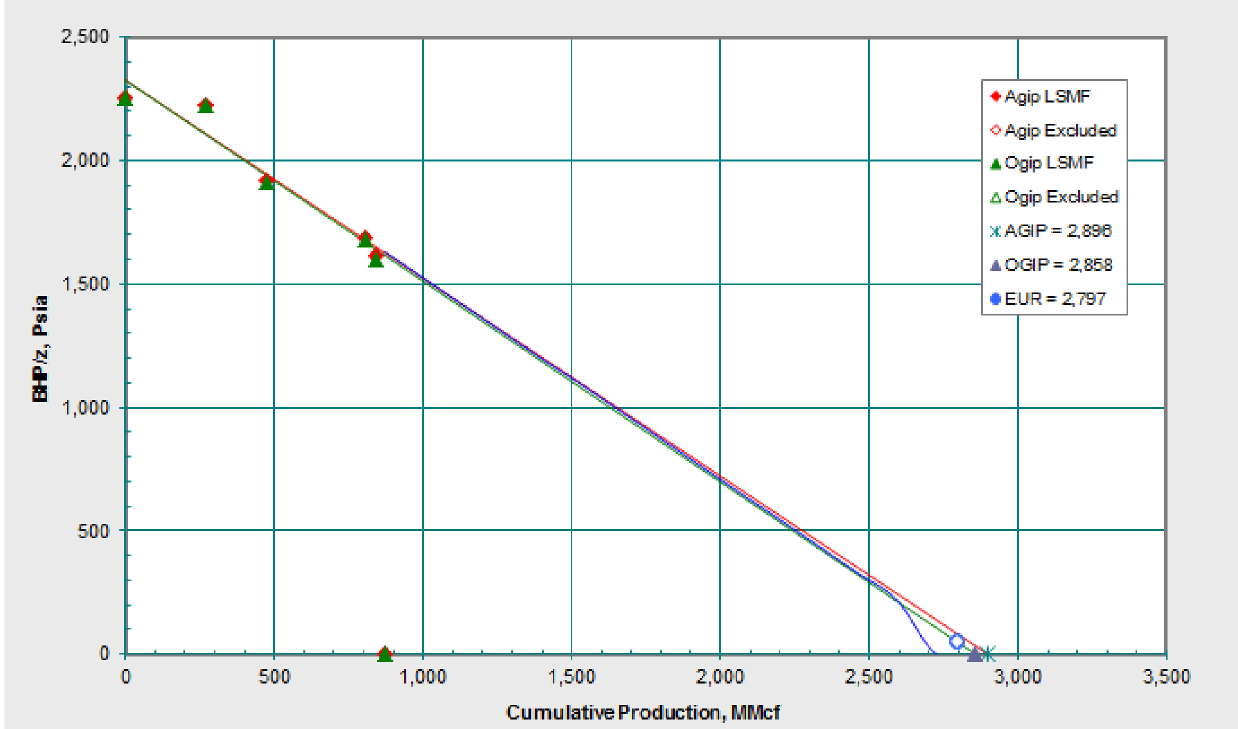

Figure A-11. Material balance and assumptions for Granite Point field, Undefined gas pool.

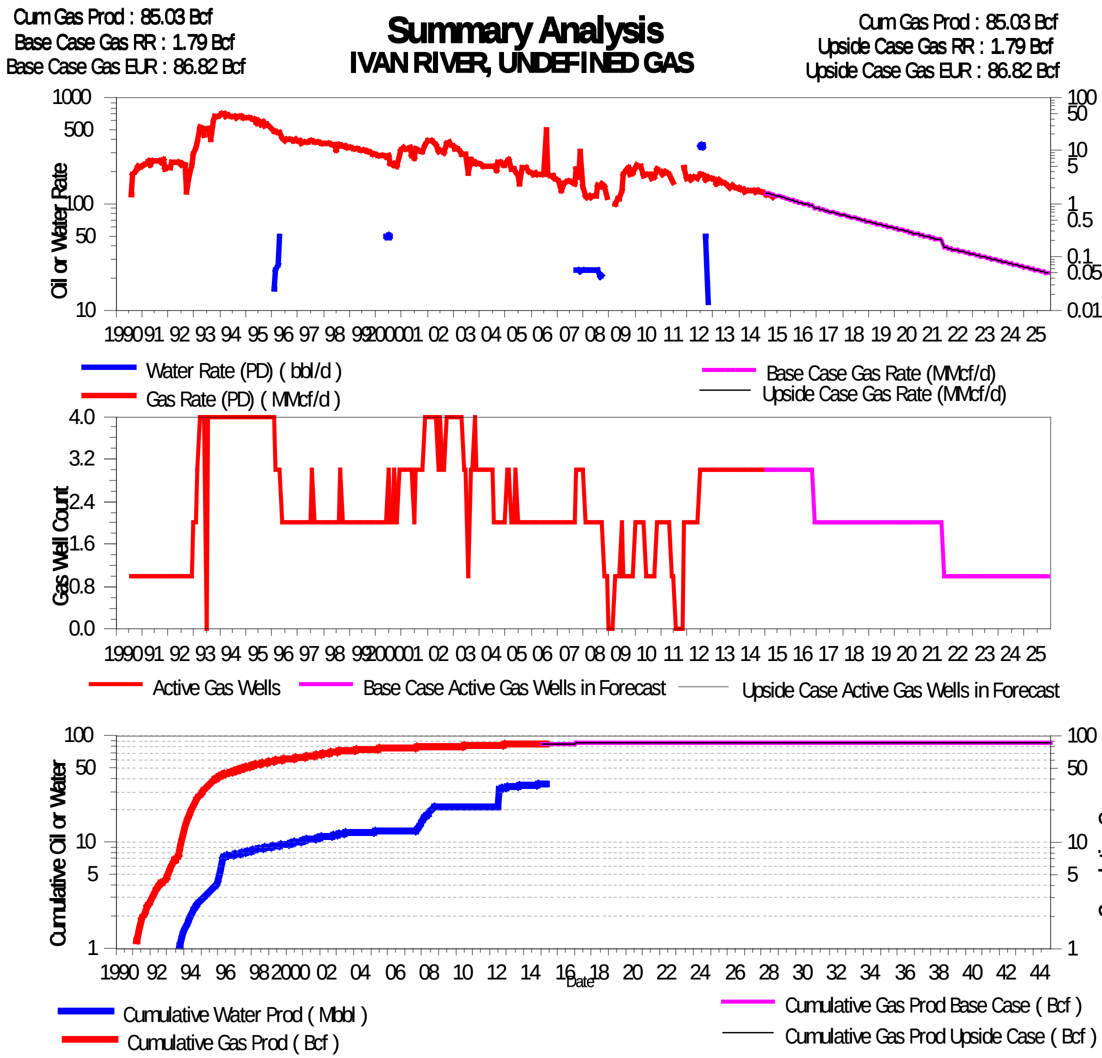

Figure A-12. Ivan River field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	Ivan River
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, June 2, 2015
RESERVOIR:	Sterling-Beluga and Tyonek (alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)

(Protected)

* Wichert-Aziz correction for contaminants, if any

		SOUR GAS	MOLE %
WELLHEAD TEMP, °F:	36.0	N_2	0.80
BOTTOMHOLE TEMP, °F:	128.0	CO_2	0.10
WET GAS GRAVITY: ??	0.56	H_2S	0.00
TVD, FEET:	7,800		
COND. CORR.? (Y/N):	N	**Formation Properties**	
Corrected* Tc, °R:	343.78	S_w (dec)	0.45
Corrected* Pc, Psia:	672.24	C_w, µsip ??	3.00
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.65

Print Options | Calc AGIP | Hide Graph | Calc OGIP | New Form | Calc EUR

Least Squares Mean Fit Results	
Y-Intercept, BHP/z	5,090
Apparent GIP, MMCF	94,198
OGIP, MMCF	93,576
EUR, MMCF	92,686
Recovery Factor	0.9905
BHP/z @ Abandonment (Adj)	48

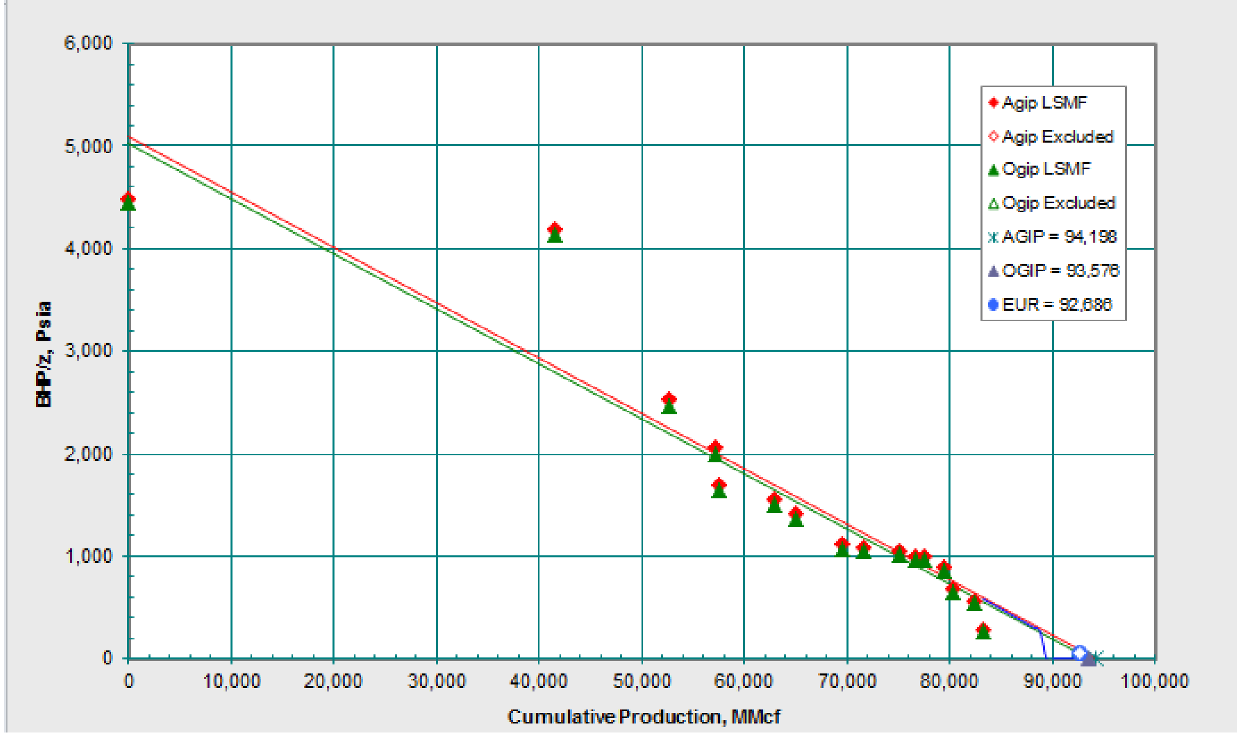

Figure A-13. Material balance and assumptions for Ivan River field, Undefined gas pool.

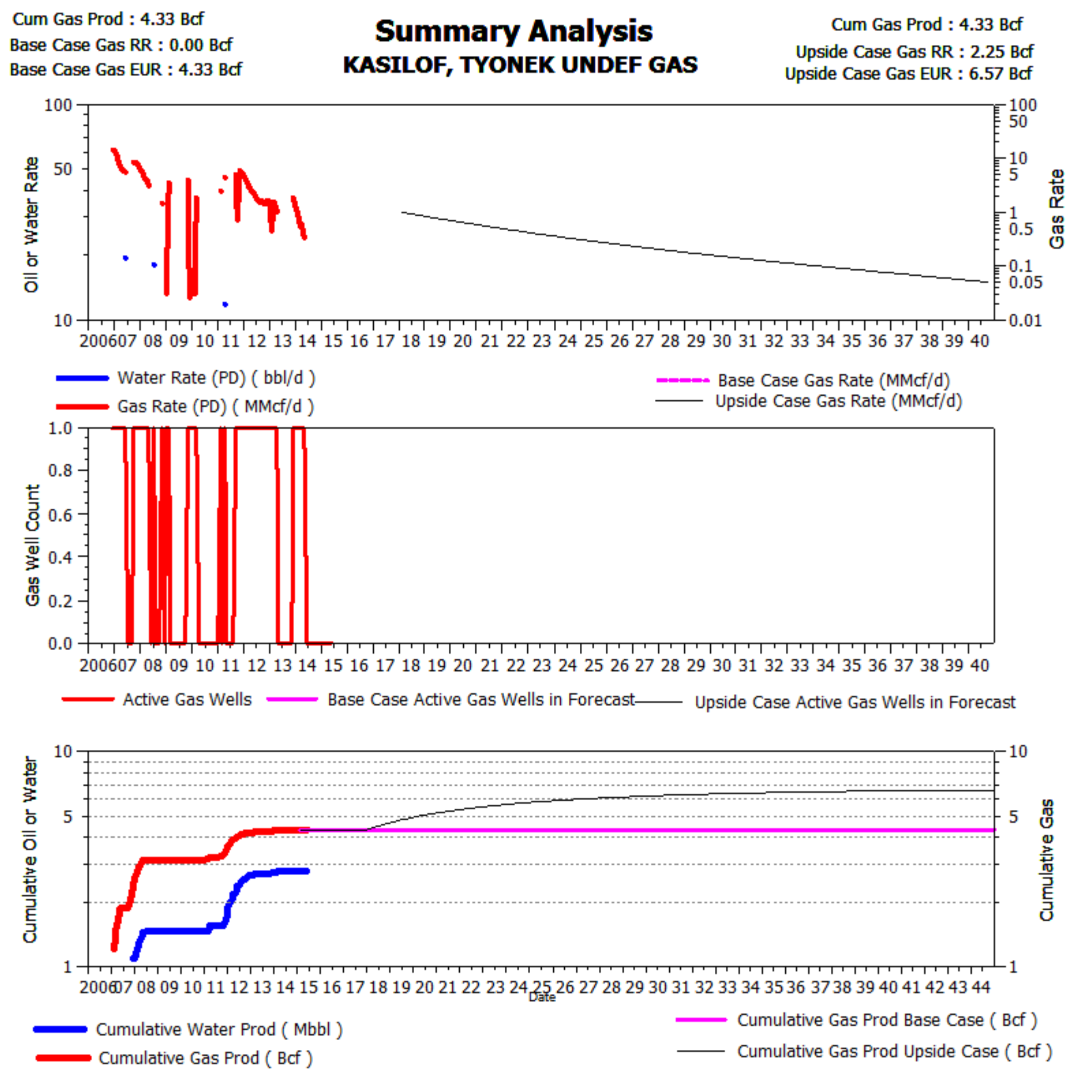

Figure A-14. Kasilof field. Tyonek Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

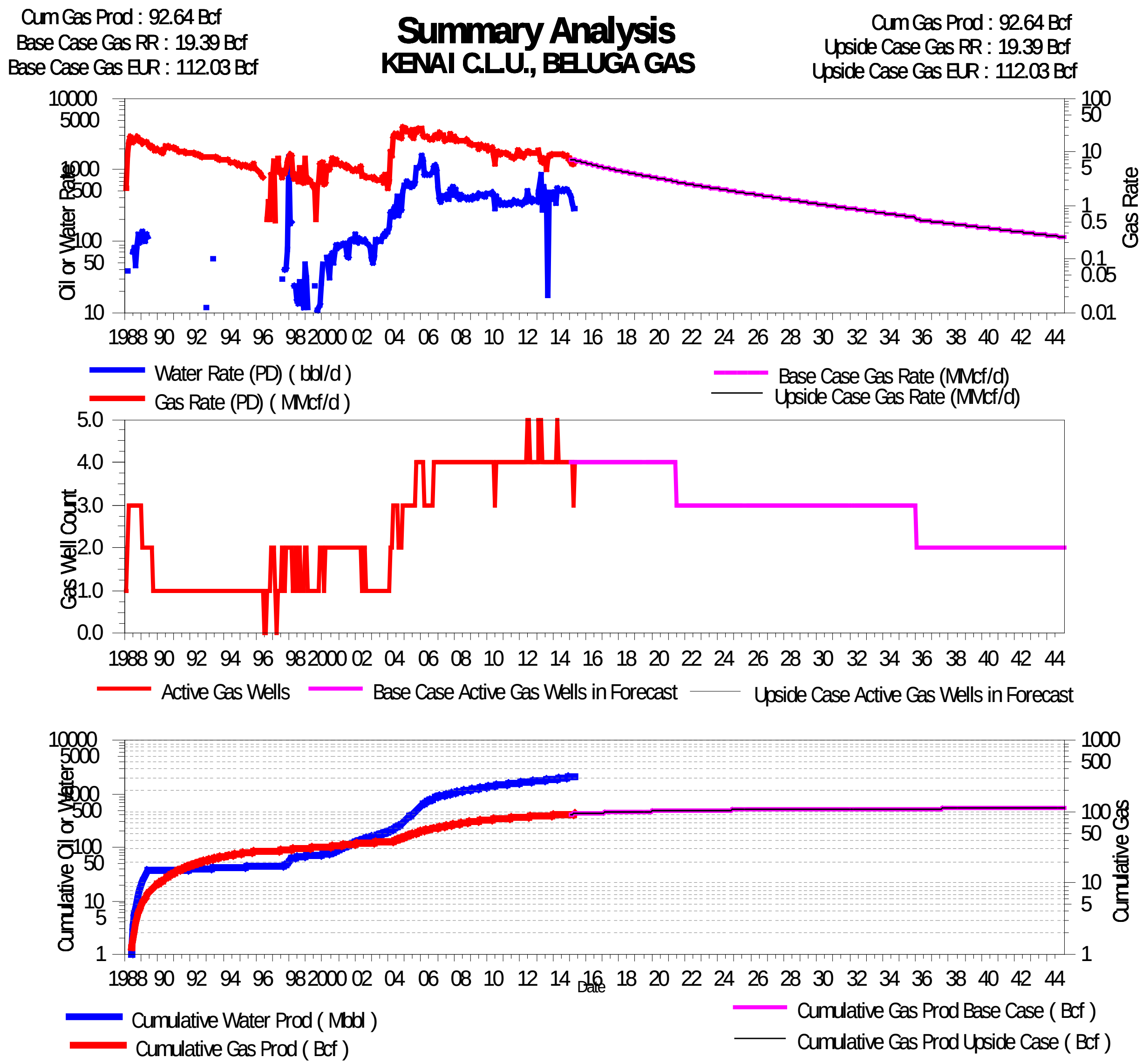

Figure A-15. Kenai C.L.U. field. Beluga gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

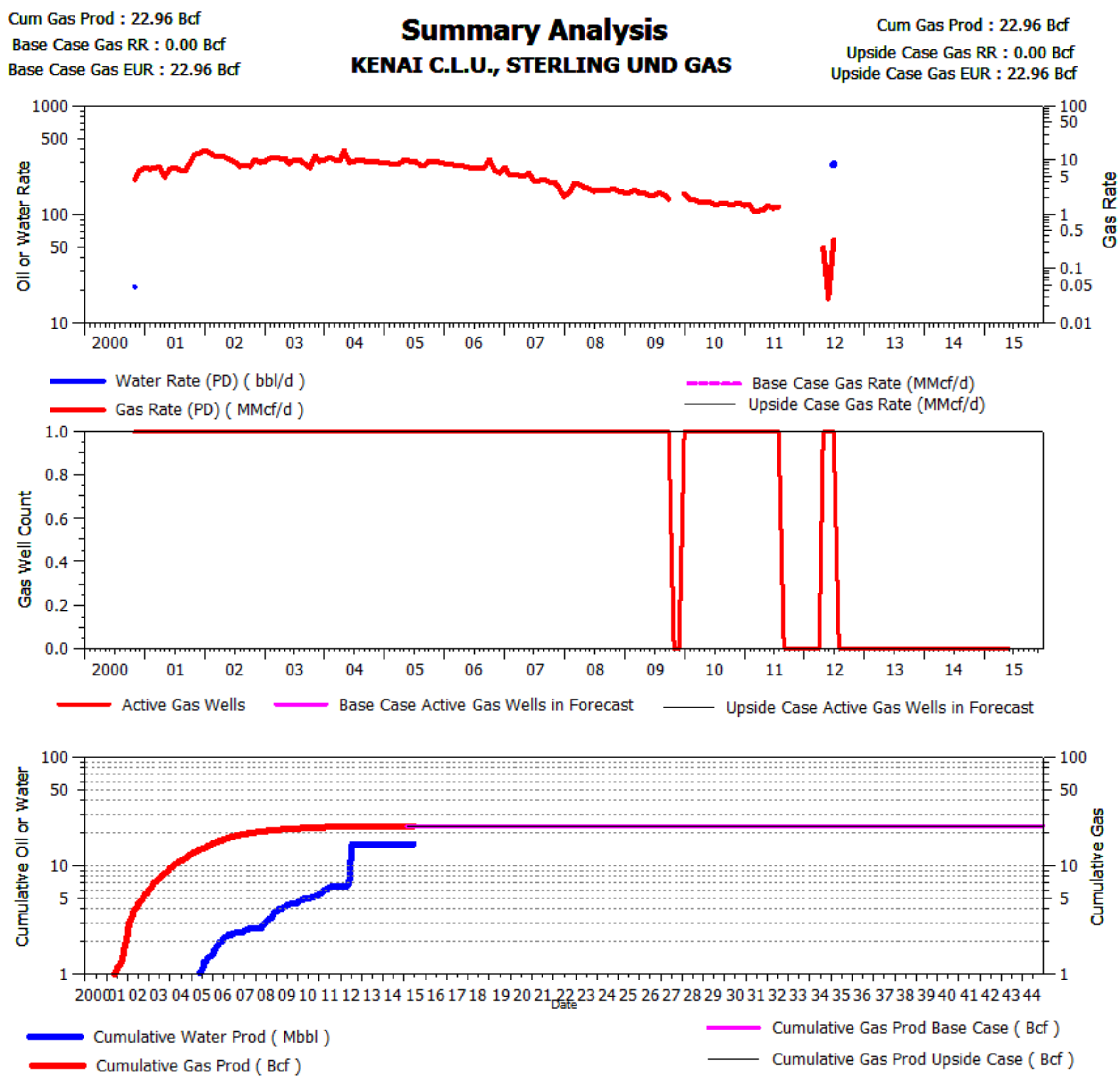

Figure A-16. Kenai C.L.U. field. Sterling undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

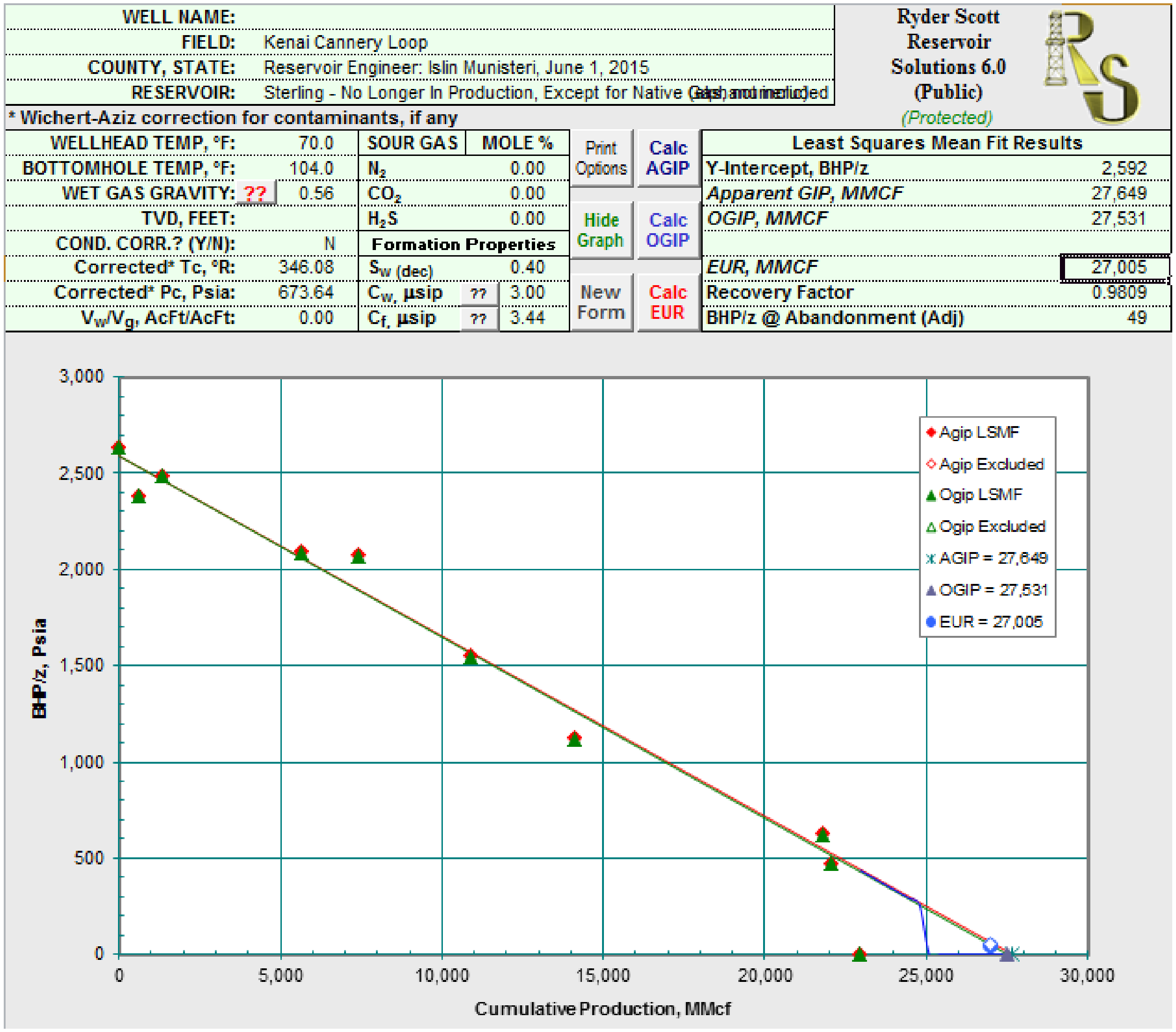

Figure A-17. Material balance and assumptions for Kenai Cannery Loop Unit field, Sterling Undefined gas pool.

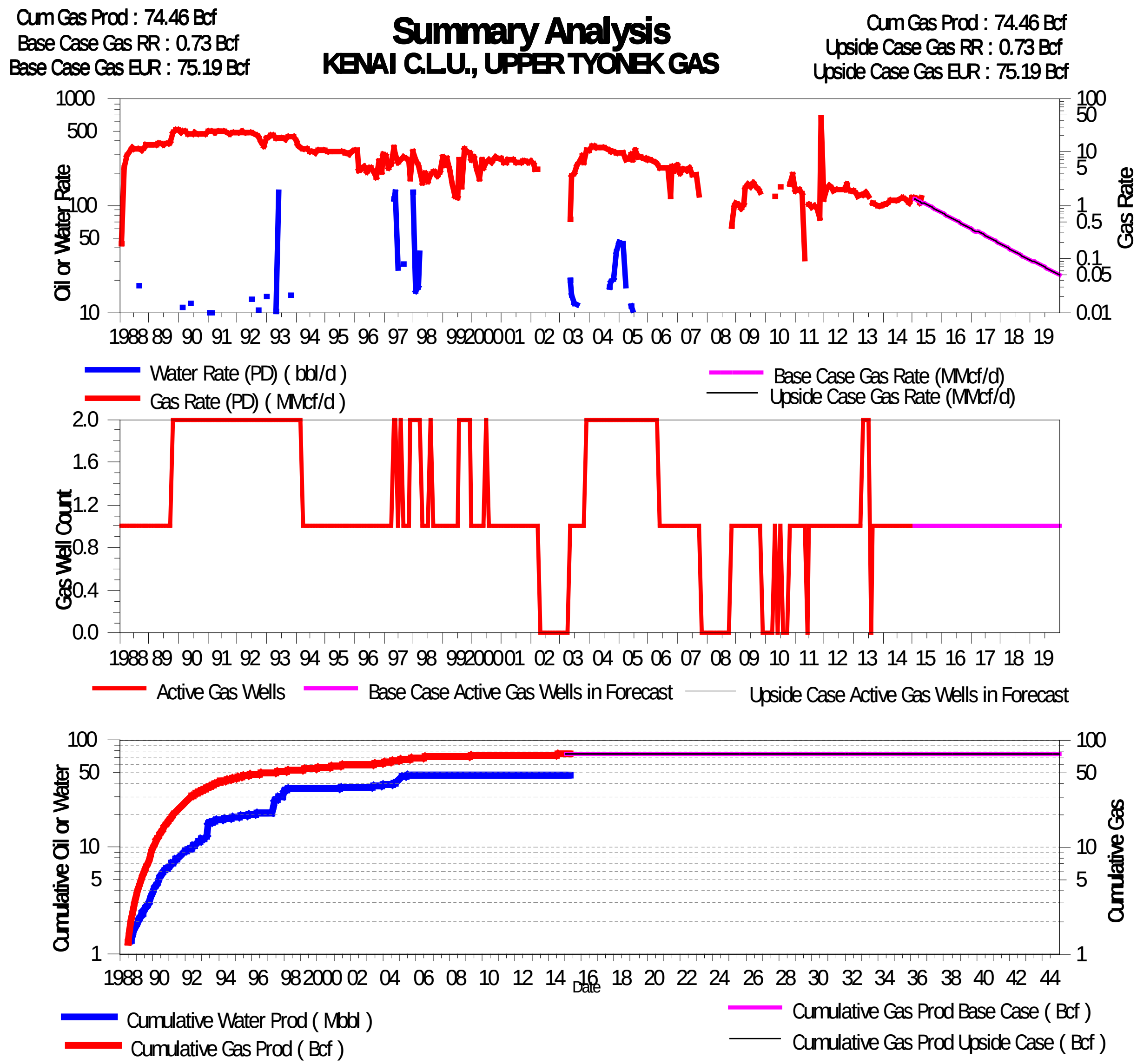

Figure A-18. Kenai Cannery Loop Unit field. Upper Tyonek gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:			Ryder Scott Reservoir Solutions 6.0 (Public)
FIELD:	Cannery Loop		
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, June 1, 2015		
RESERVOIR:	Upper Tyonek	(alphanumeric)	*(Protected)*

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	**Least Squares Mean Fit Results**	
BOTTOMHOLE TEMP, °F:	144.0	N_2	0.00			Y-Intercept, BHP/z	5,125
WET GAS GRAVITY: ??	0.56	CO_2	0.00			*Apparent GIP, MMCF*	85,011
TVD, FEET:	8,700	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	83,986
COND. CORR.? (Y/N):	N	**Formation Properties**					
Corrected* Tc, °R:	346.08	S_w (dec)	0.45			*EUR, MMCF*	83,196
Corrected* Pc, Psia:	673.64	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9906
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.44			BHP/z @ Abandonment (Adj)	48

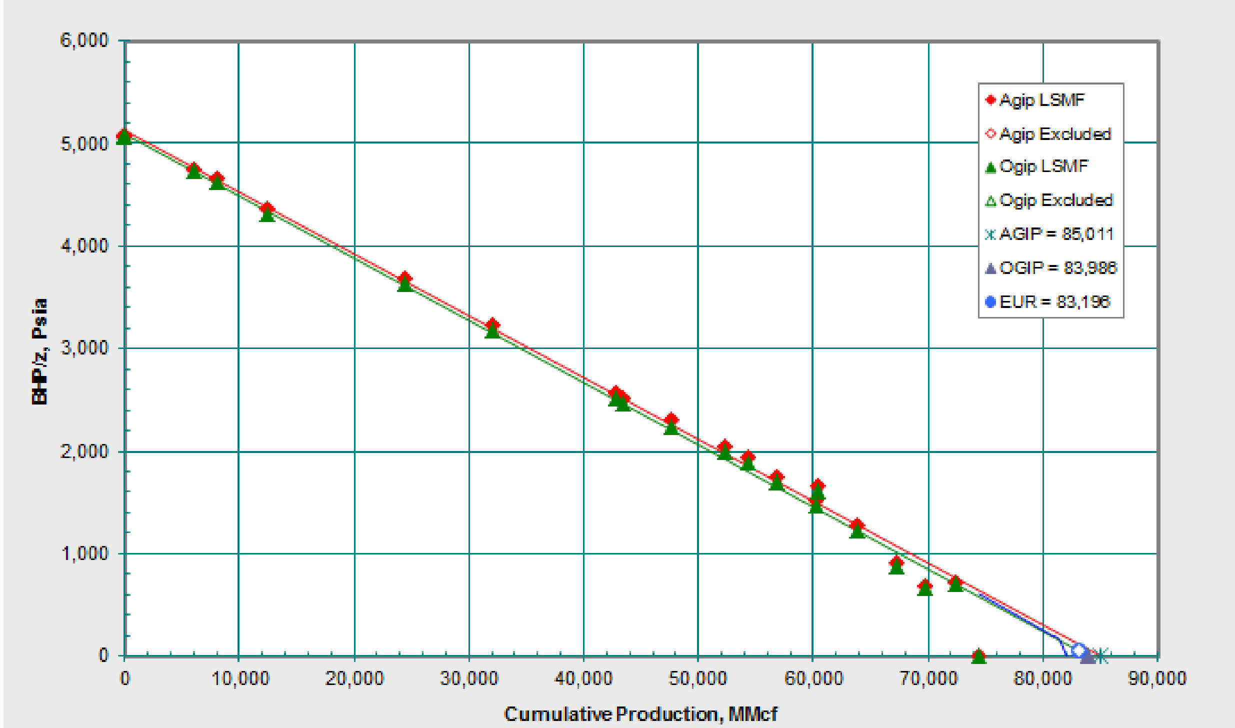

Figure A-19. Material balance and assumptions for Kenai Cannery Loop Unit field, Upper Tyonek gas pool.

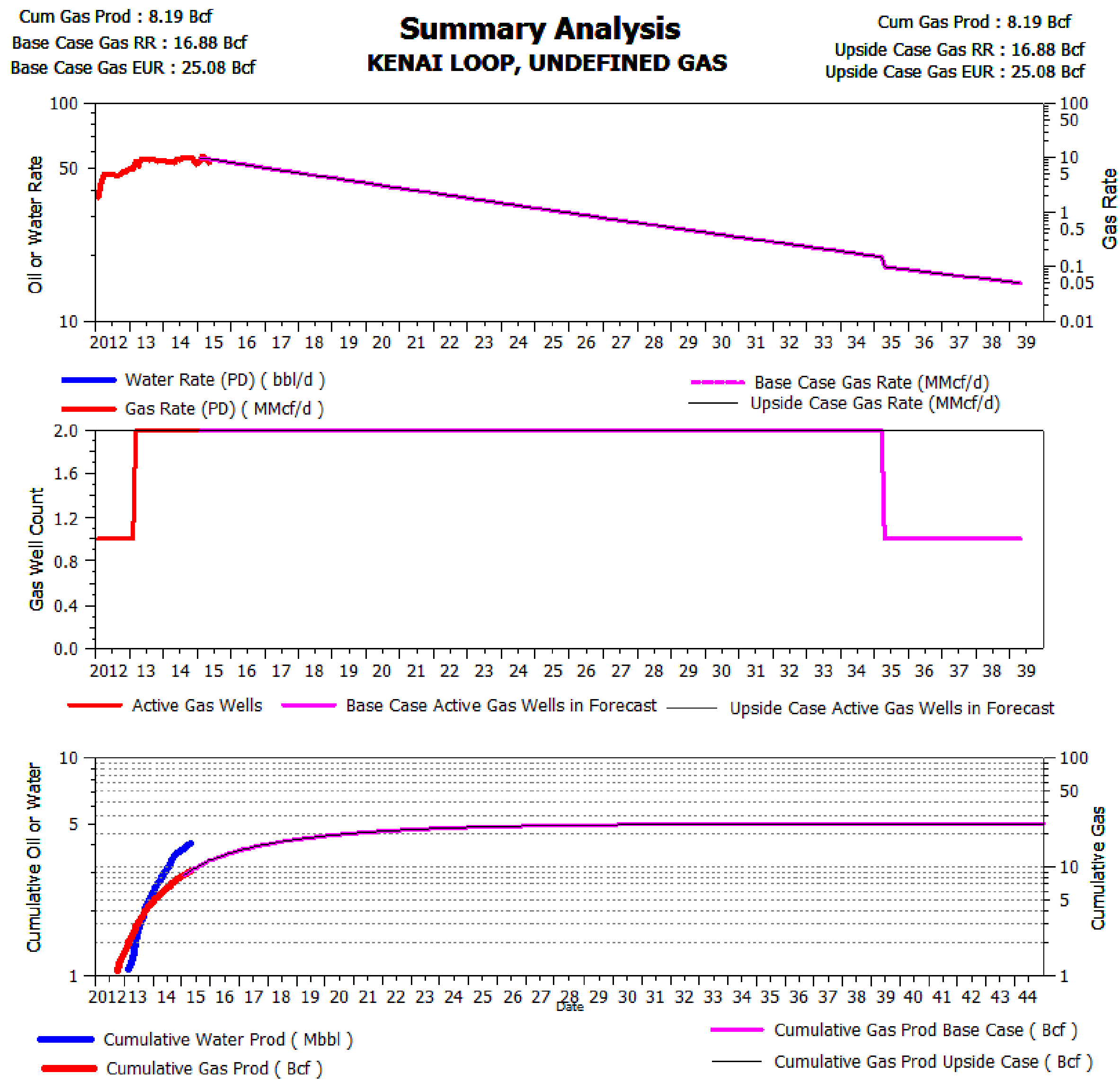

Figure A-20. Kenai Loop field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

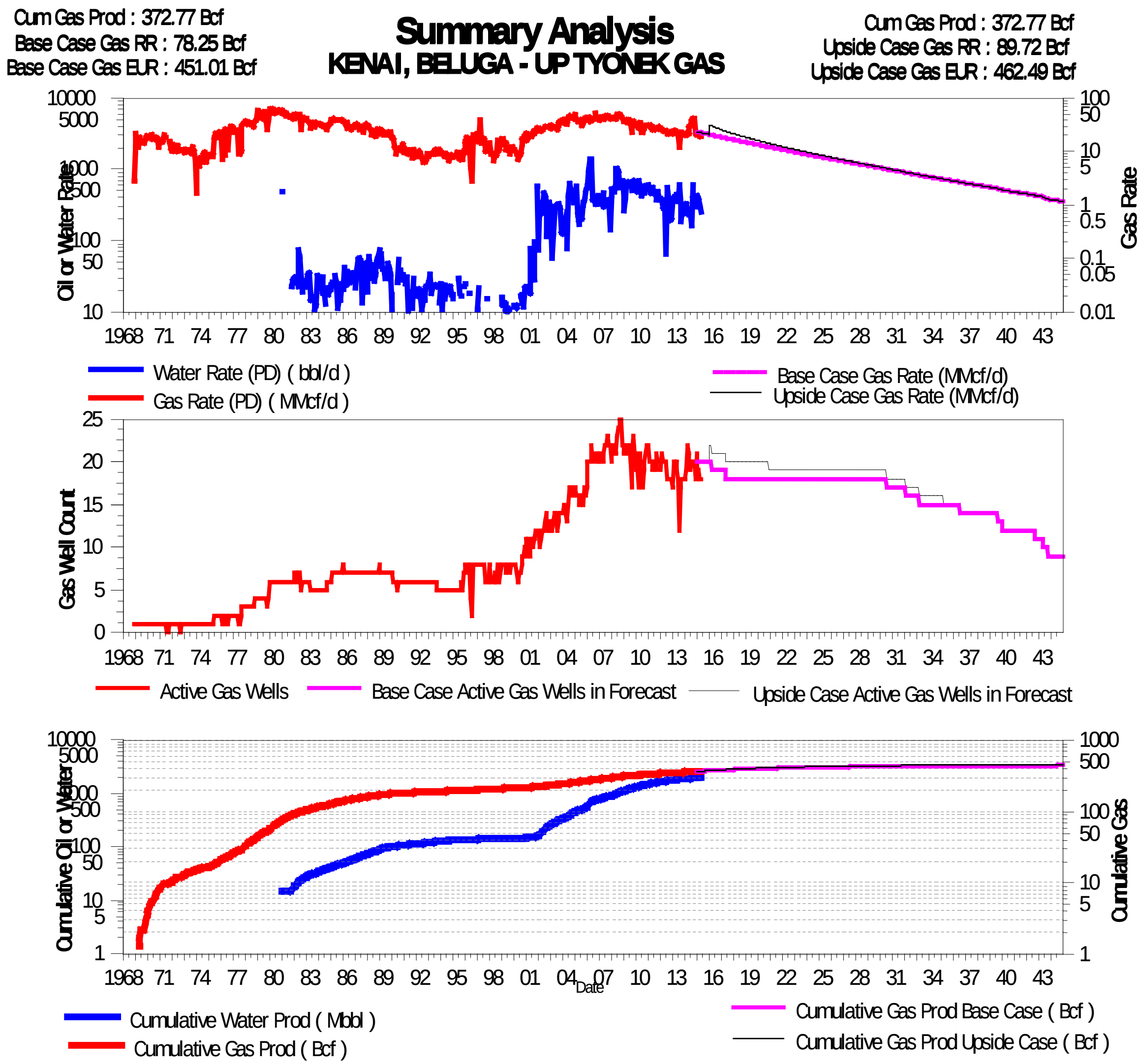

Figure A-21. Kenai field. Beluga-Upper Tyonek gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

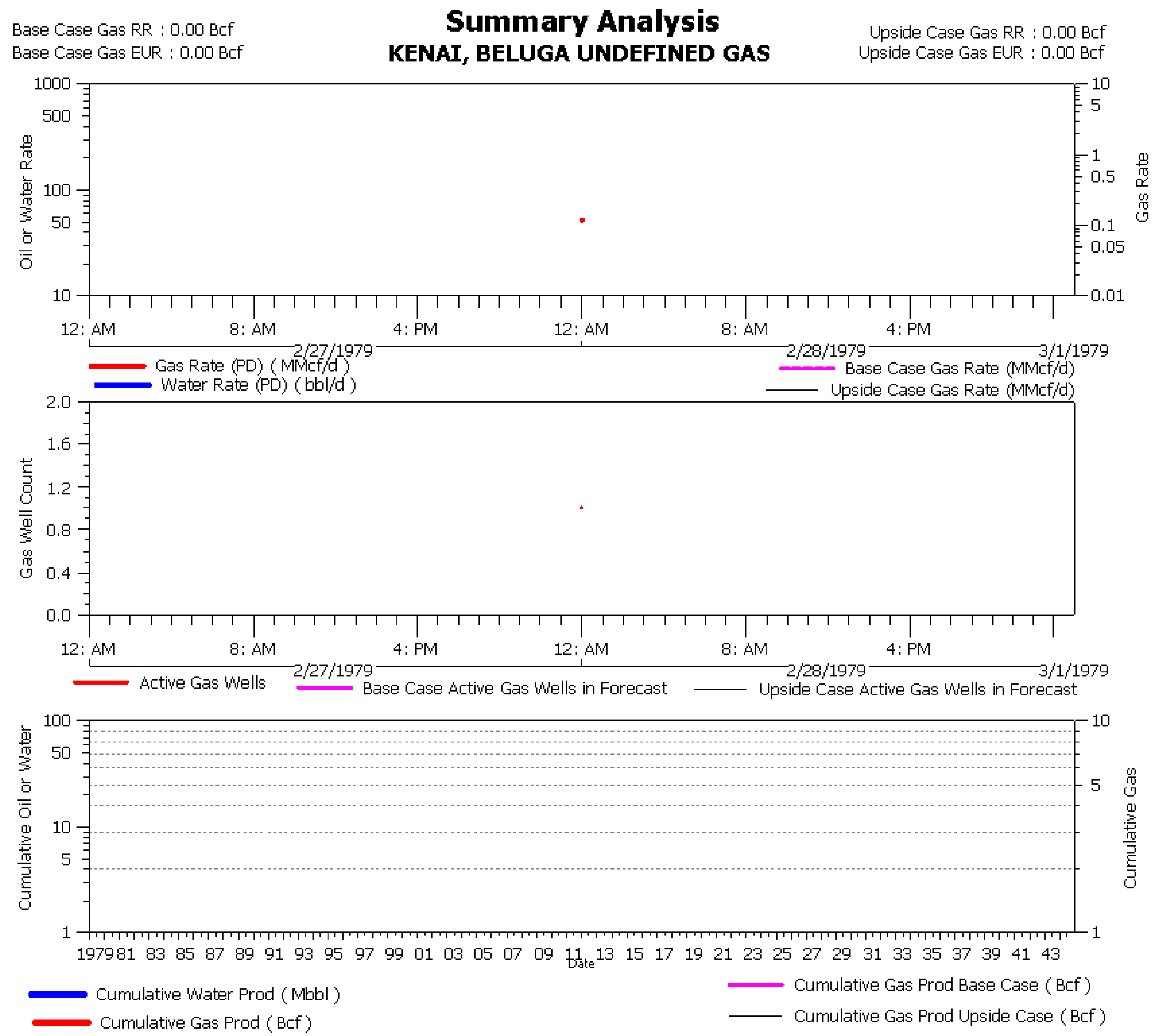

Figure A-22. Kenai field. Beluga undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

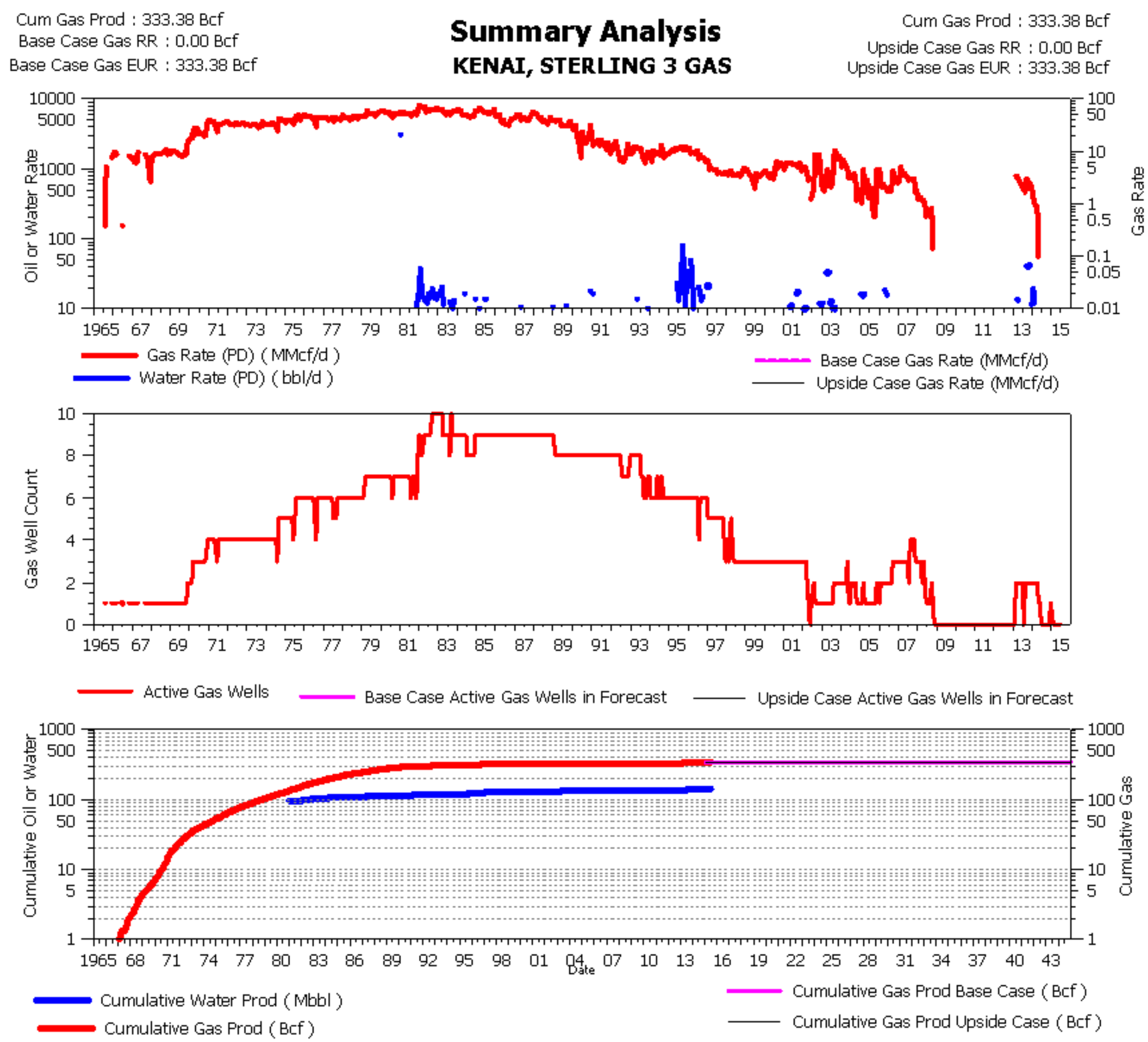

Figure A-23. Kenai field. Sterling 4 gas pool.

Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

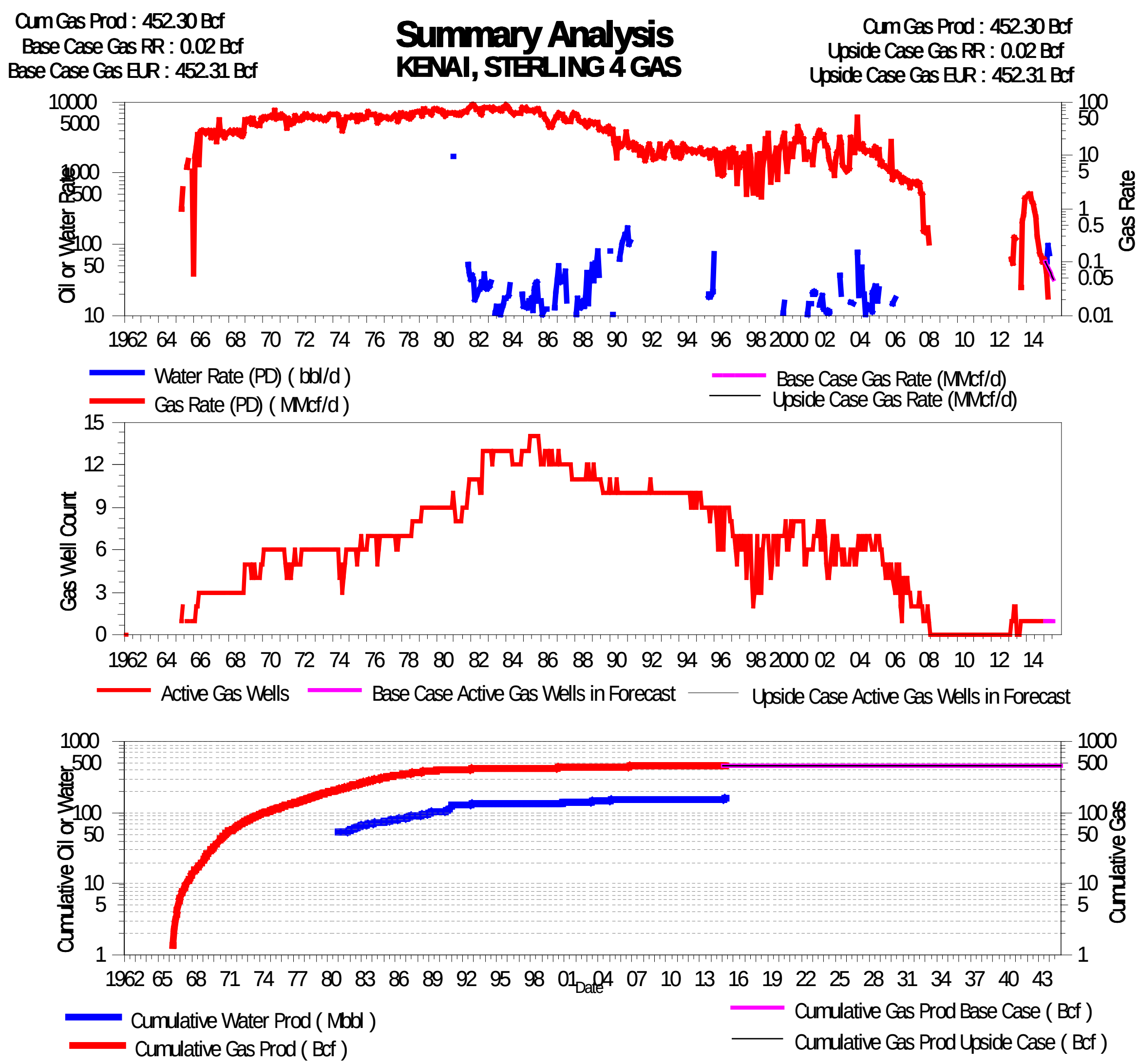

Figure A-24. Kenai field. Sterling 4 gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	Kenai
COUNTY, STATE:	Reservoir Enigneer: Islin Munisteri, June 5, 2015
RESERVOIR:	Sterling 4 (Comps from KU 22-6x Sterling 6) (alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)
(Protected)

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	**Least Squares Mean Fit Results**	
BOTTOMHOLE TEMP, °F:	93.0	N_2	0.34			Y-Intercept, BHP/z	2,327
WET GAS GRAVITY: ??	0.56	CO_2	0.24			*Apparent GIP, MMCF*	495,542
TVD, FEET:	3,690	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	456,962
COND. CORR.? (Y/N):	N	**Formation Properties**					
Corrected* Tc, °R:	344.50	S_w (dec)	0.35			*EUR, MMCF*	452,671
Corrected* Pc, Psia:	673.07	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9906
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.44			BHP/z @ Abandonment (Adj)	48

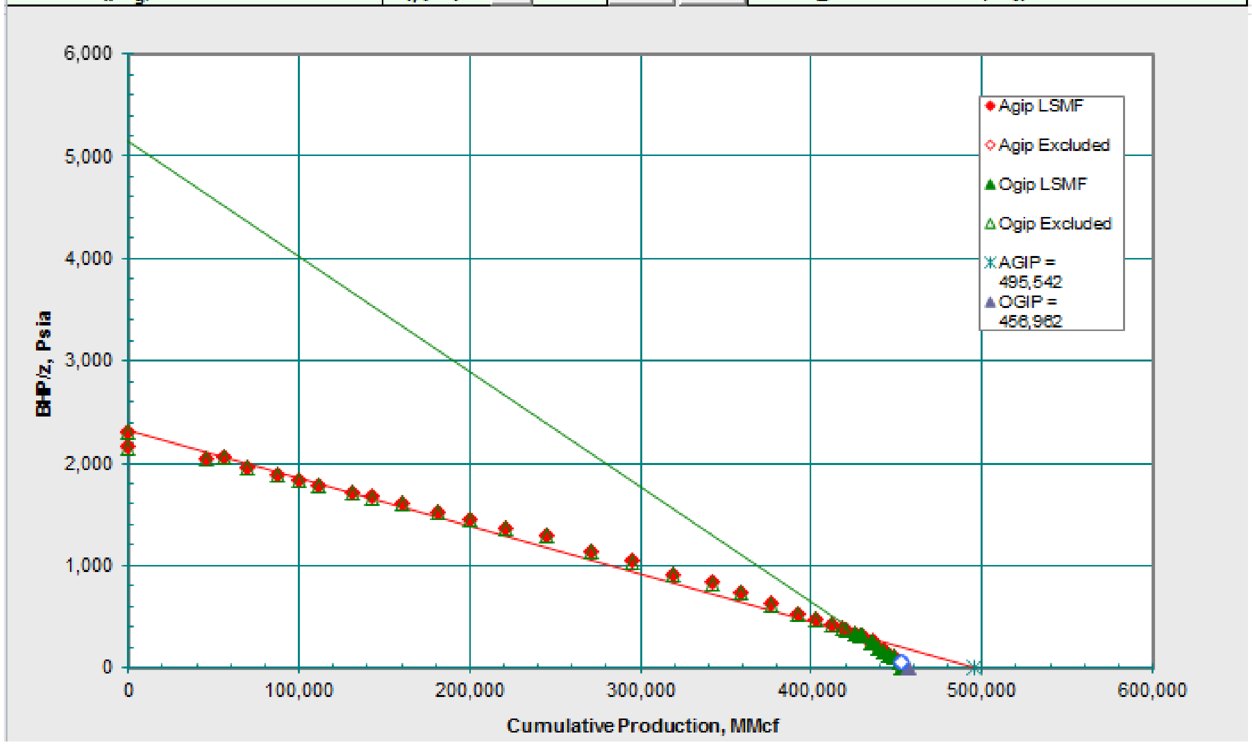

Figure A-25. Material balance and assumptions for Kenai field, Sterling 4 gas pool.

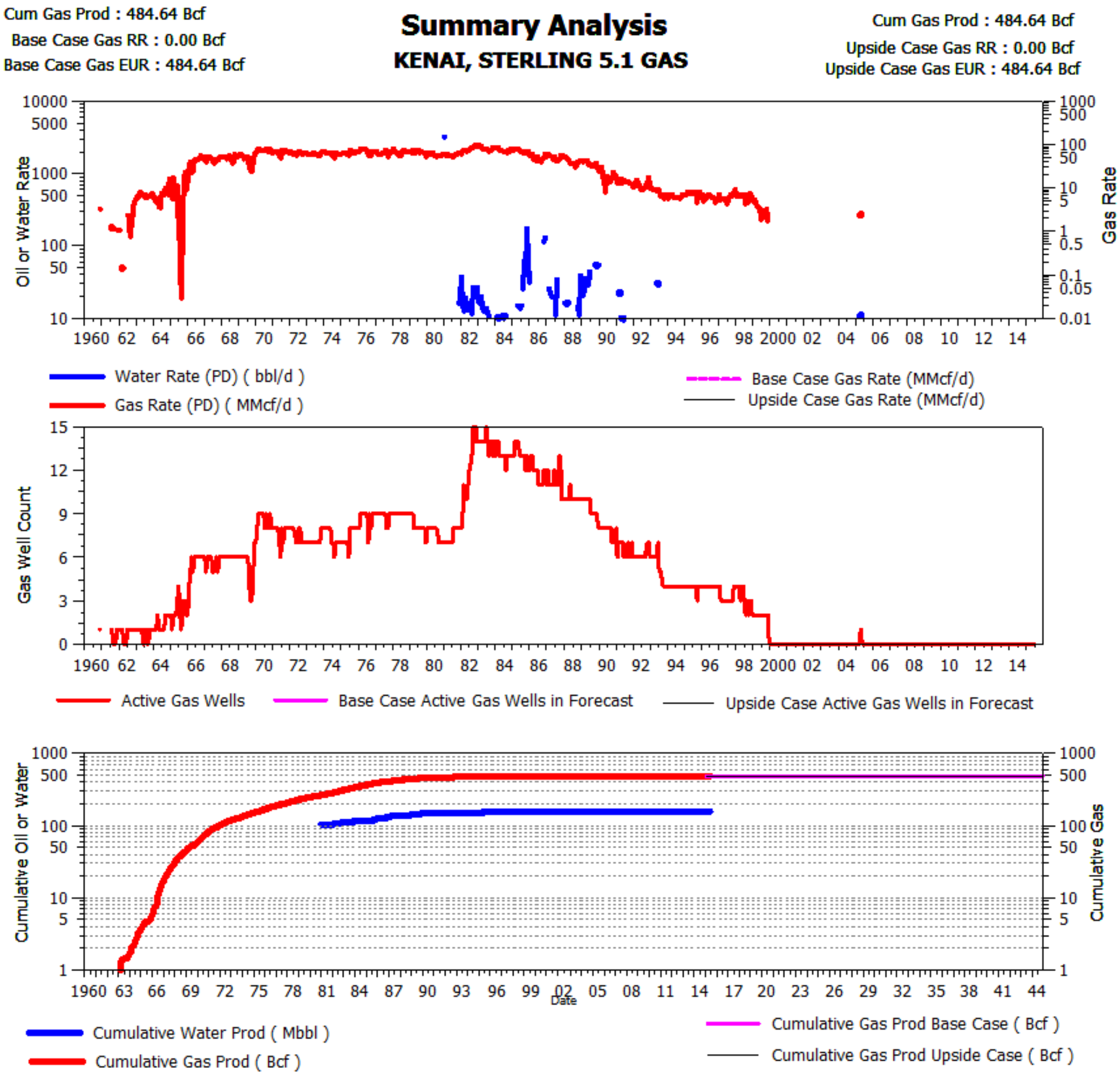

Figure A-26. Kenai field. Sterling 5.1 gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:						Ryder Scott Reservoir Solutions 6.0 (Public)	
FIELD:	Kenai						
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, June 5, 2015						
RESERVOIR:	Sterling 5.1 (Comp from KU 22-6x Sterling 6) (alphanumeric)					*(Protected)*	
* Wichert-Aziz correction for contaminants, if any							
WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	97.0	N_2	0.34			Y-Intercept, BHP/z	2,477
WET GAS GRAVITY: ??	0.58	CO_2	0.24			*Apparent GIP, MMCF*	582,636
TVD, FEET:	4,025	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	533,123
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	350.72	S_W (dec)	0.45			*EUR, MMCF*	525,425
Corrected* Pc, Psia:	672.54	C_W, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9856
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	4.32			BHP/z @ Abandonment (Adj)	49

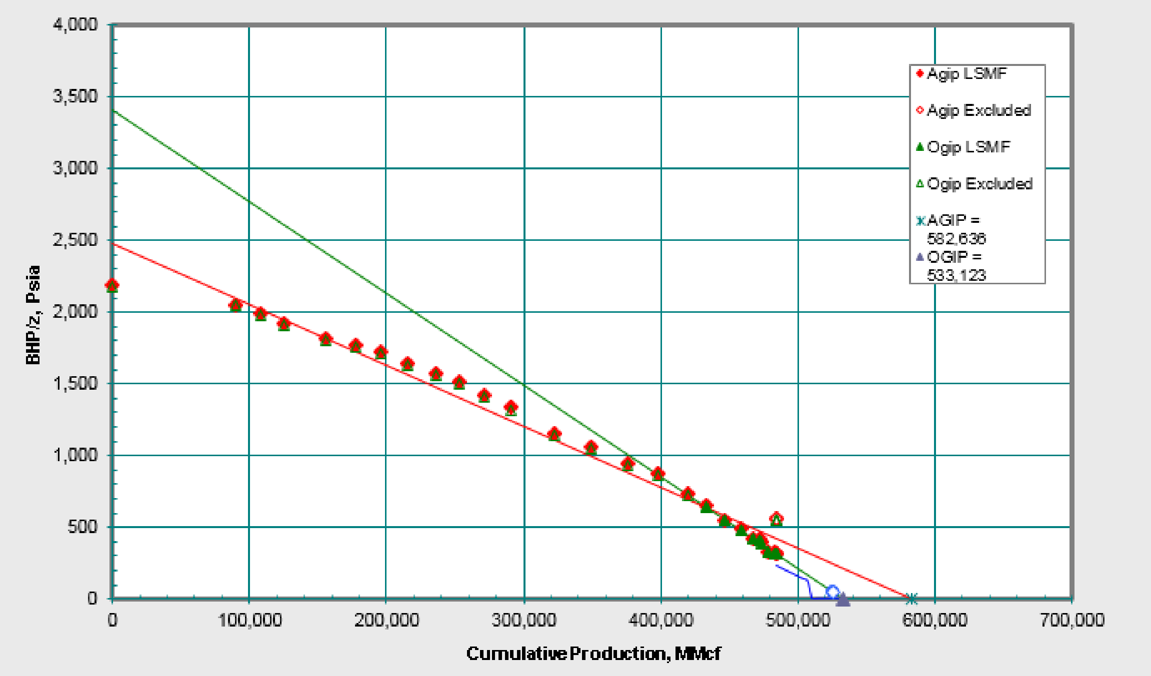

Figure A-27. Material balance and assumptions for Kenai field, Sterling 5.1 gas pool.

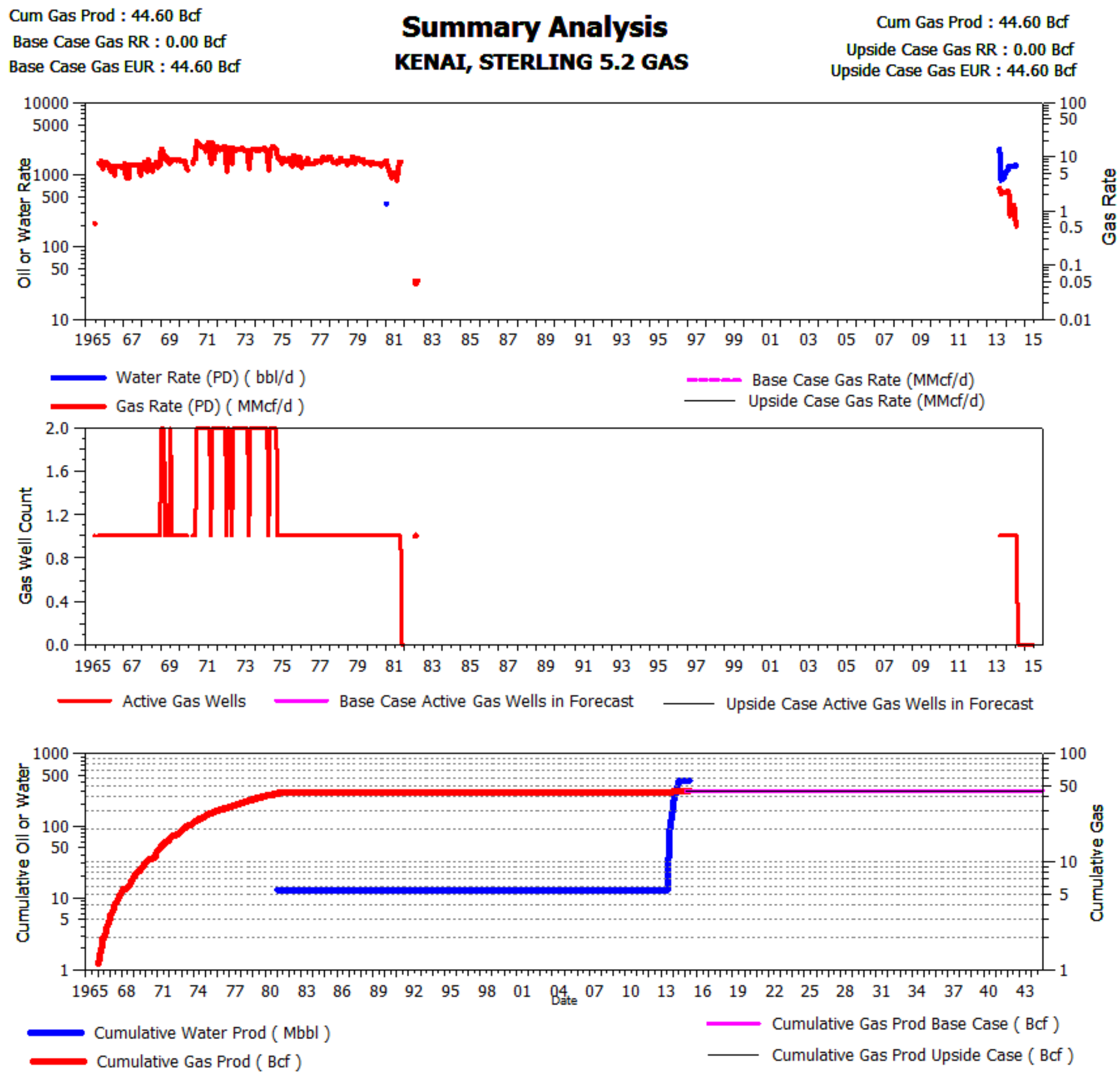

Figure A-28. Kenai field. Sterling 5.2 gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

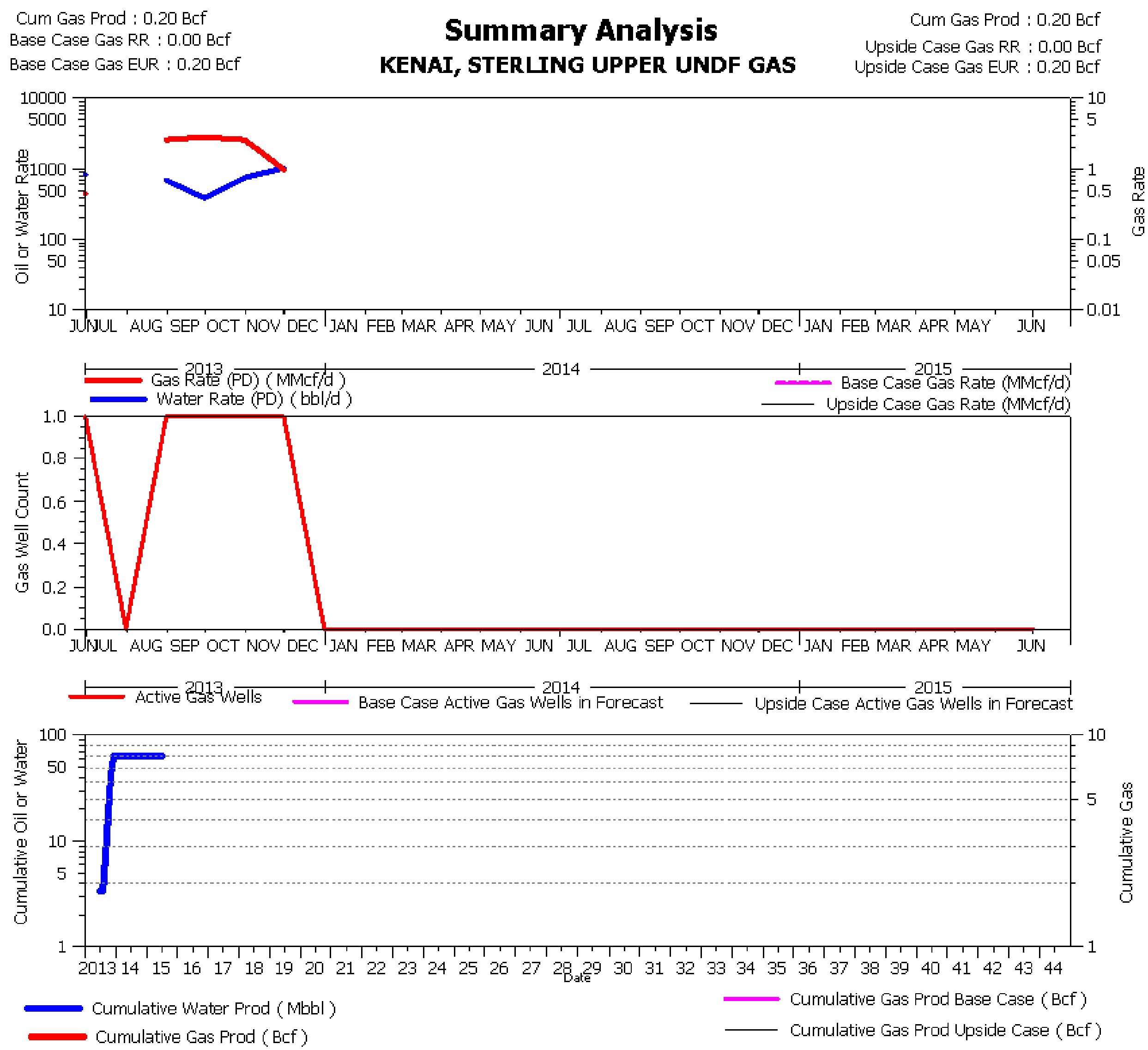

Figure A-29. Kenai field. Sterling Upper undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

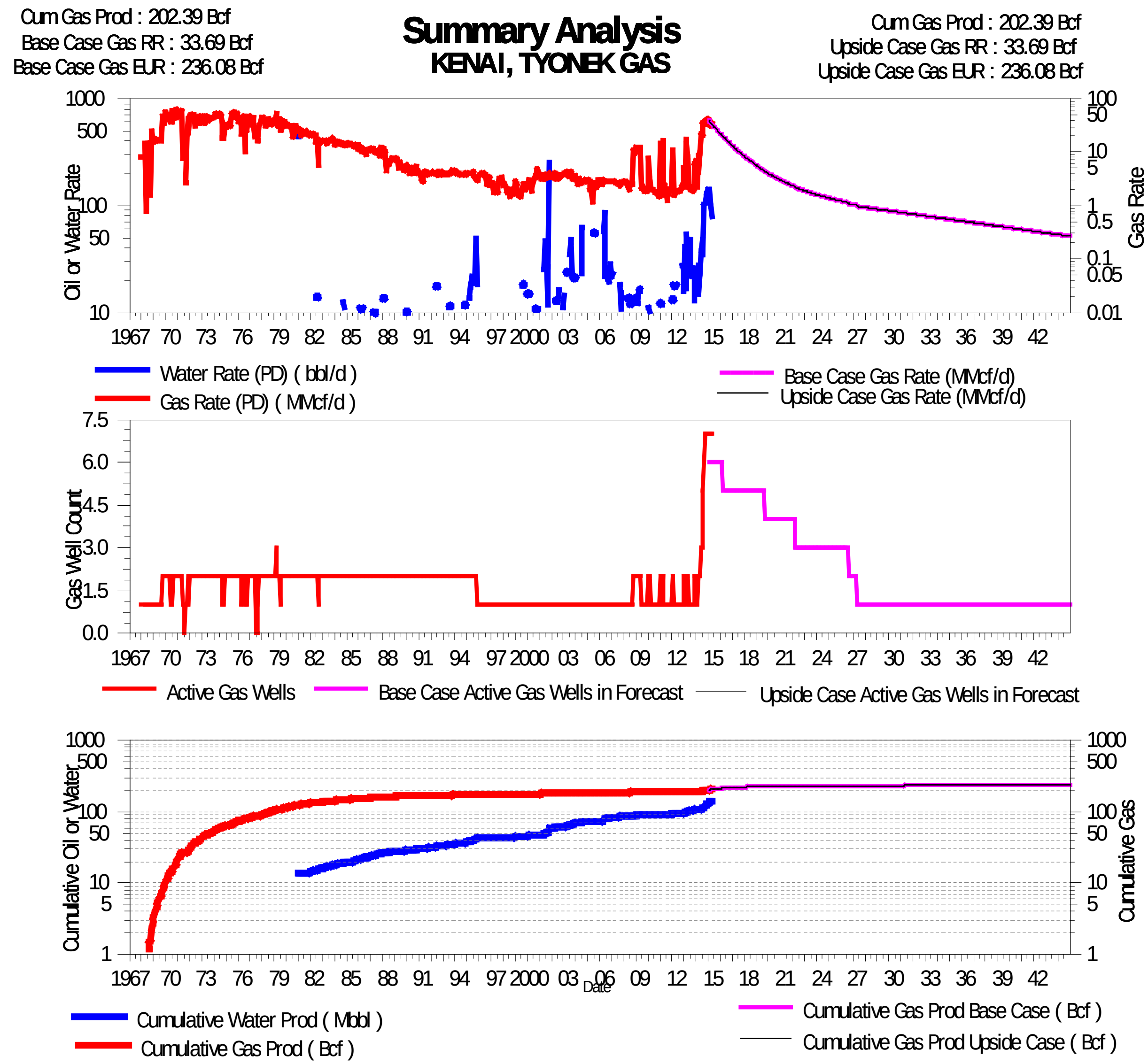

Figure A-30. Kenai field. Tyonek gas pool.

Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

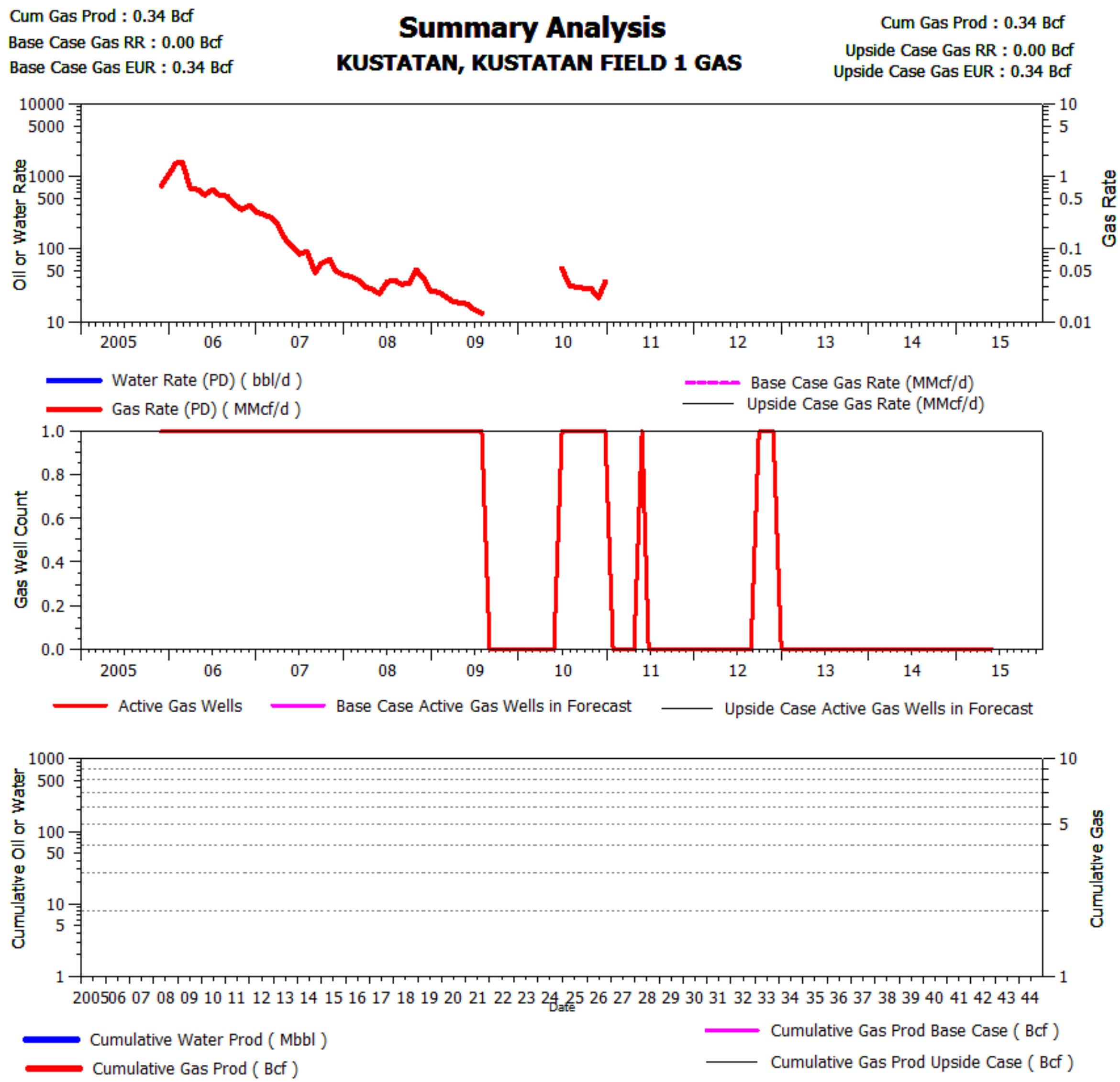

Figure A-31. Kustatan field, Kustatan Field 1 Gas pool (producing from Tyonek).s
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:						Ryder Scott Reservoir Solutions 6.0 (Public)	
FIELD:	Kustatan						
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, June 1, 2015						
RESERVOIR:	Tyonek	(alphanumeric)					
* Wichert-Aziz correction for contaminants, if any						(Protected)	
WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	103.0	N_2	0.00			Y-Intercept, BHP/z	2,820
WET GAS GRAVITY: ??	0.586	CO_2	0.00			*Apparent GIP, MMCF*	589
TVD, FEET:	5,353	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	584
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	354.16	S_w (dec)	0.45			*EUR, MMCF*	574
Corrected* Pc, Psia:	672.91	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9825
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.65			BHP/z @ Abandonment (Adj)	48

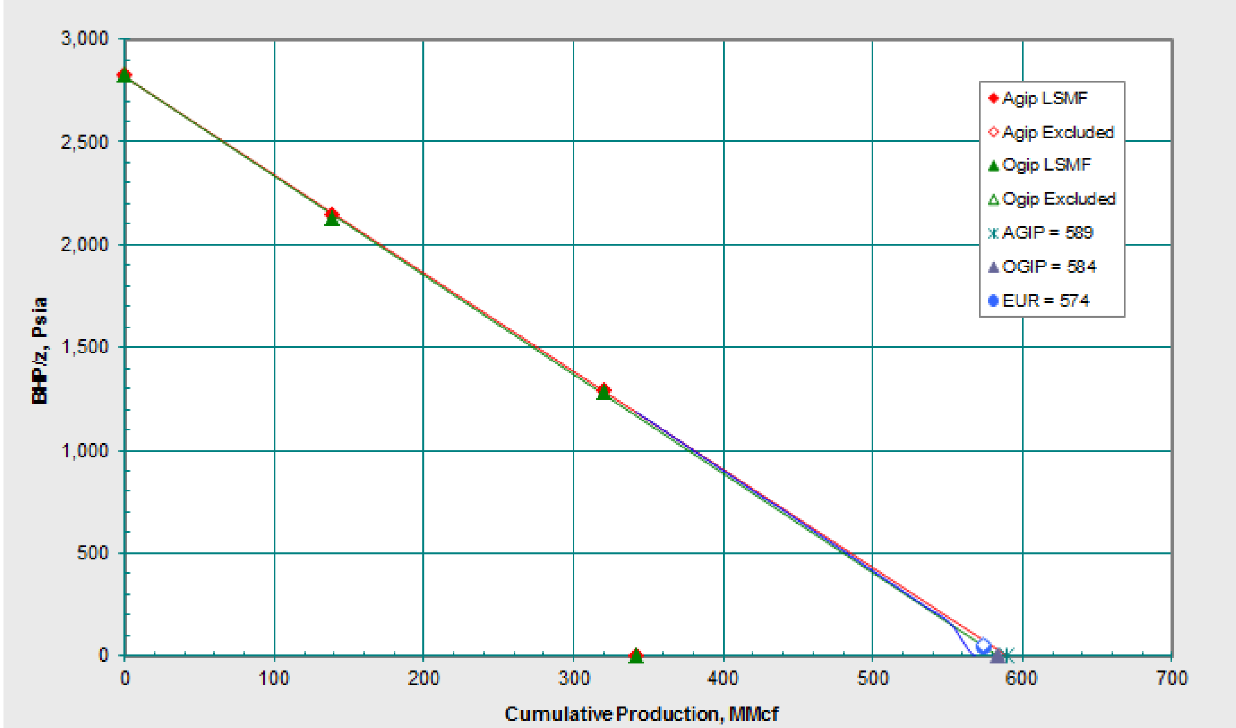

Figure A-32. Material balance and assumptions for Kustatan field, Kustatan Field 1 gas pool (producing from Tyonek).

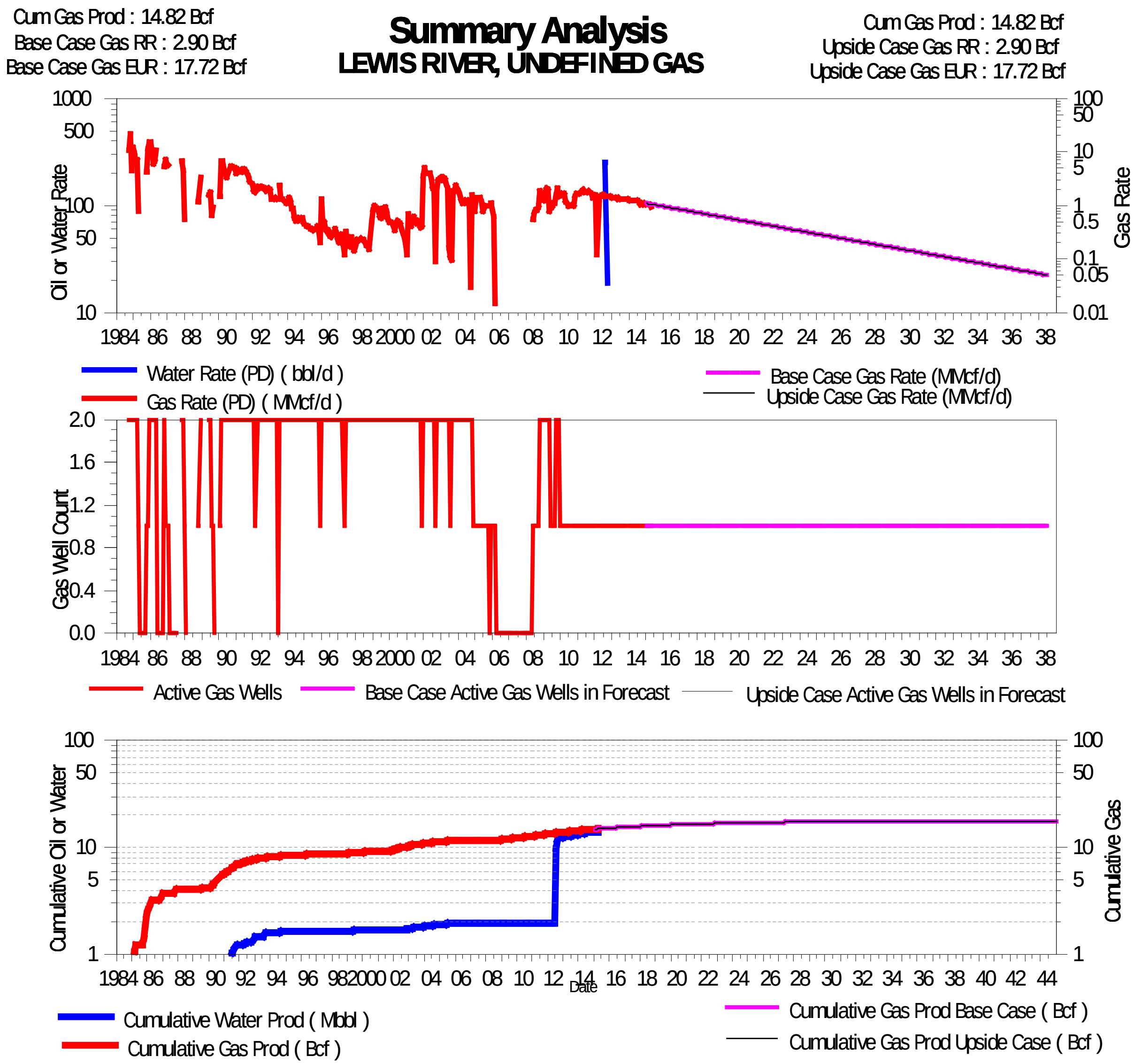

Figure A-33. Lewis River Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

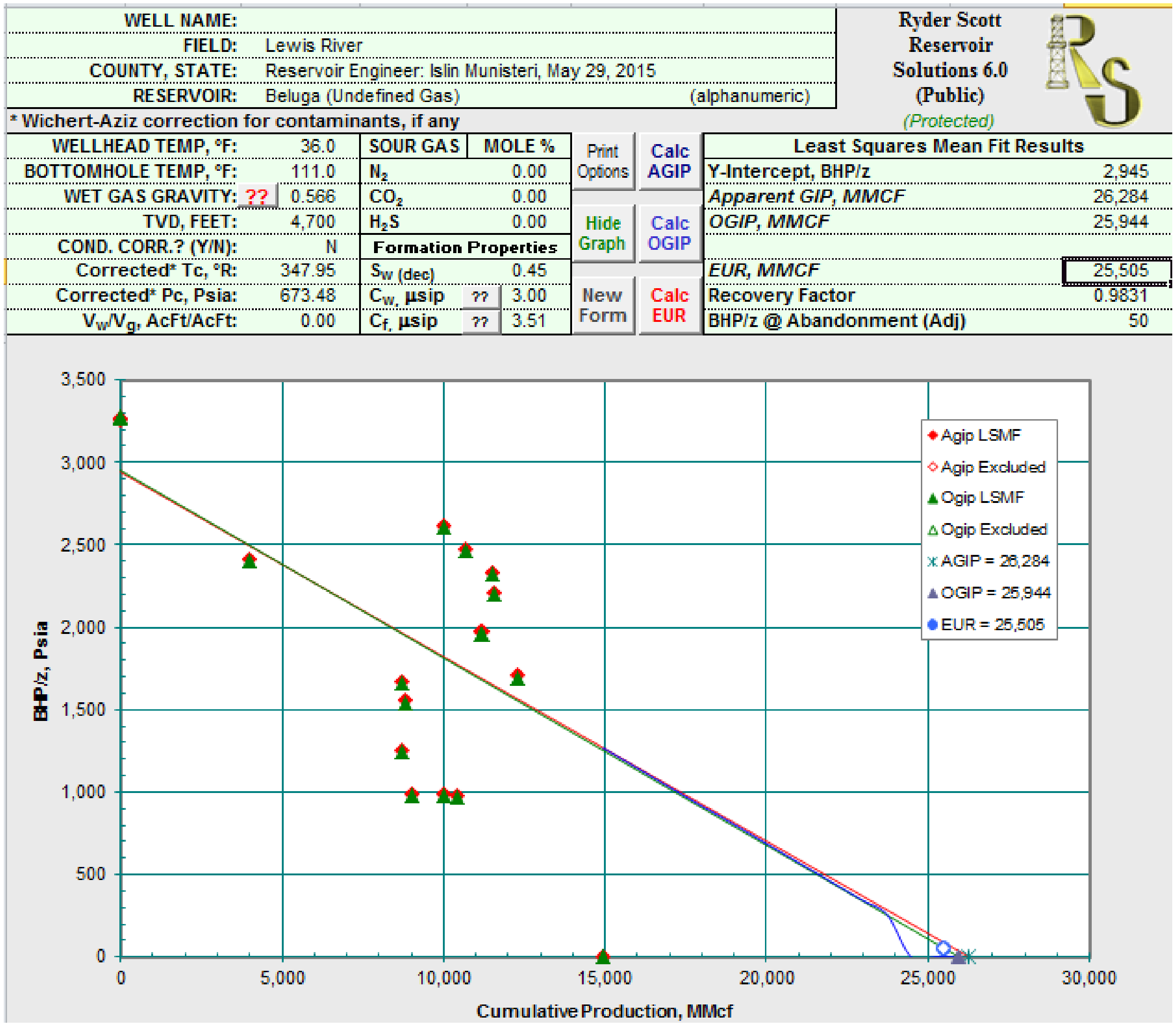

Figure A-34. Material balance and assumptions for Lewis River field, Undefined gas pool (producing from Beluga).

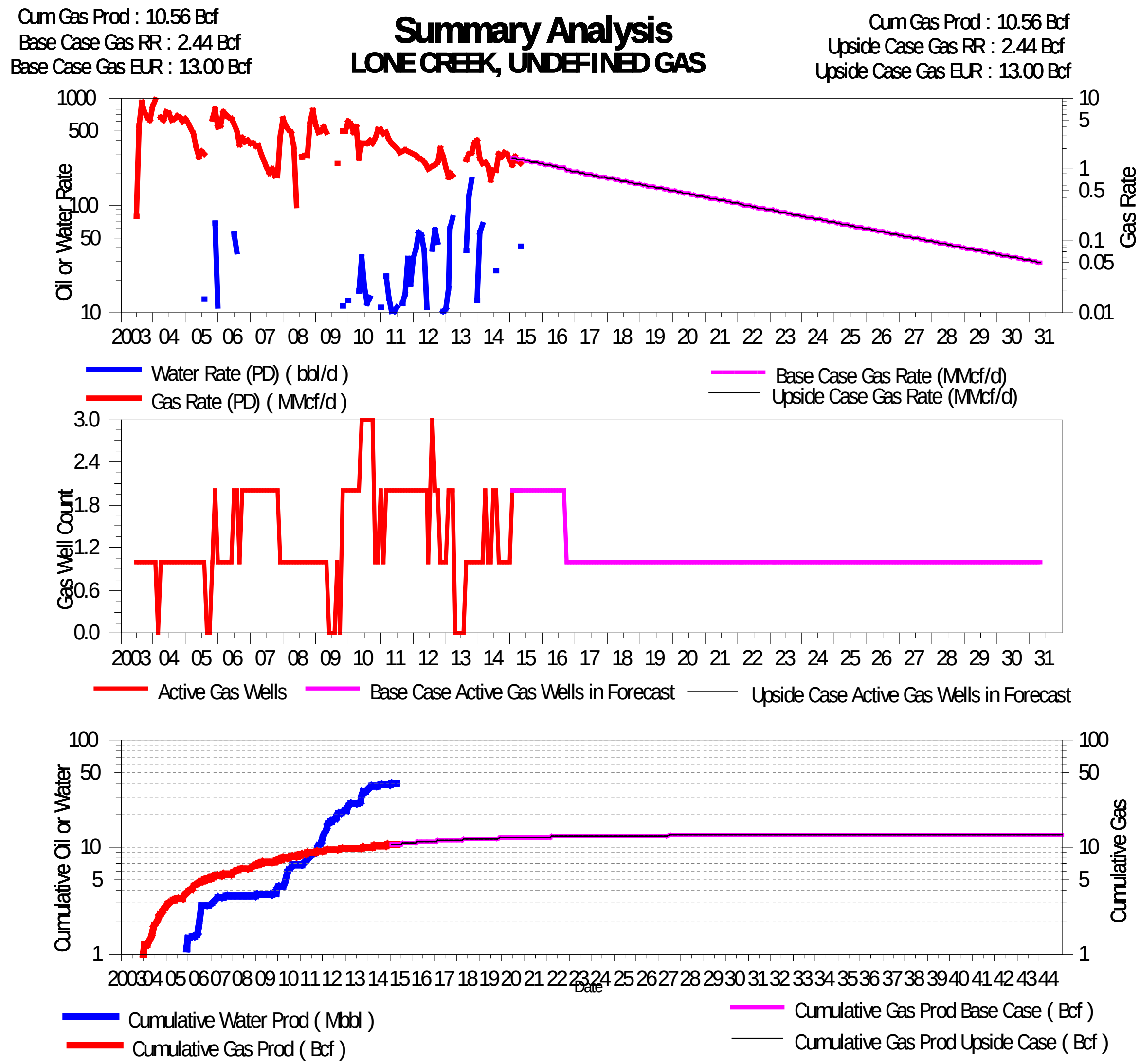

Figure A-35. Lone Creek field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:		Ryder Scott Reservoir Solutions 6.0 (Public)	
FIELD:	Lone Creek	*(Protected)*	
COUNTY, STATE:	Reservoir Engineer: Isln Munisteri, May 29, 2015		
RESERVOIR:	Tyonek (Undefined Gas)	(alphanumeric)	

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP
BOTTOMHOLE TEMP, °F:	78.9	N_2	0.03		
WET GAS GRAVITY: ??	0.562	CO_2	1.15	Hide Graph	Calc OGIP
TVD, FEET:	1,958	H_2S	0.00		
COND. CORR.? (Y/N):	N	Formation Properties			
Corrected* Tc, °R:	343.46	S_w (dec)	0.30	New Form	Calc EUR
Corrected* Pc, Psia:	674.36	C_w, µsip ??	3.00		
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.73		

Least Squares Mean Fit Results	
Y-Intercept, BHP/z	1,153
Apparent GIP, MMCF	21,678
OGIP, MMCF	21,631
EUR, MMCF	20,693
Recovery Factor	0.9566
BHP/z @ Abandonment (Adj)	50

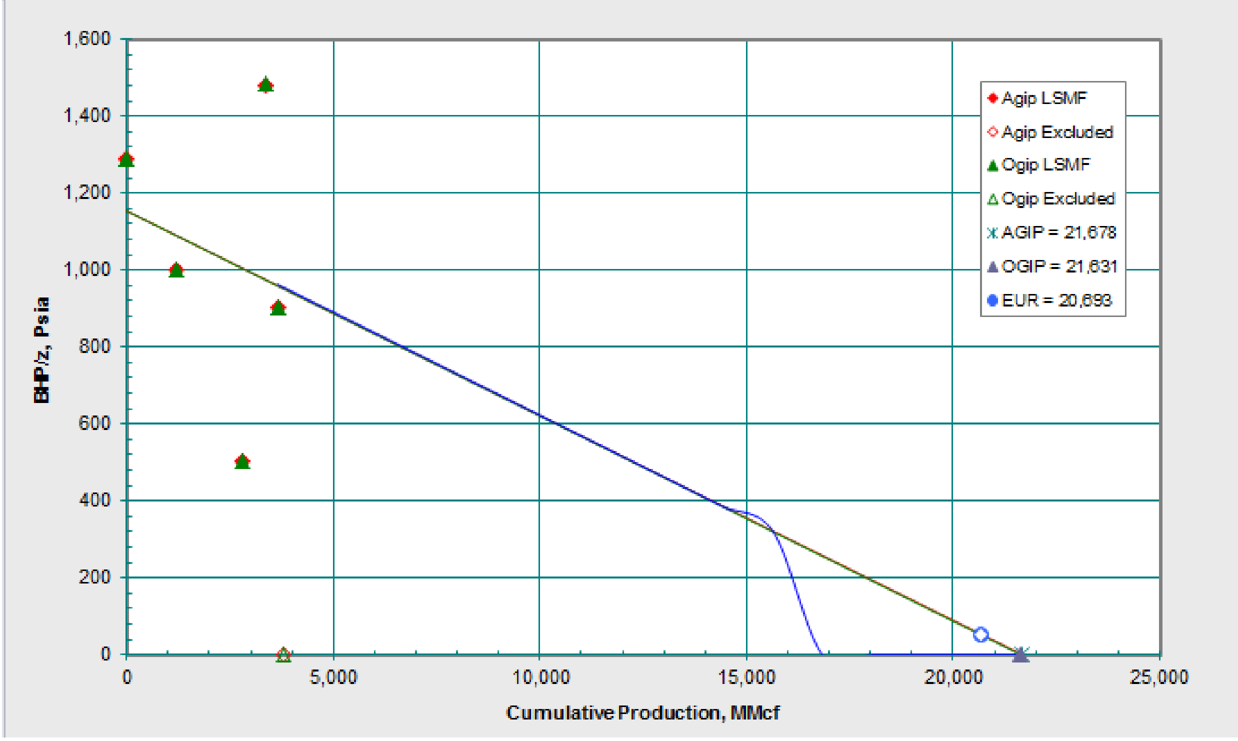

Figure A-36. Material balance and assumptions for Lone Creek field, Undefined gas pool (producing from Tyonek).

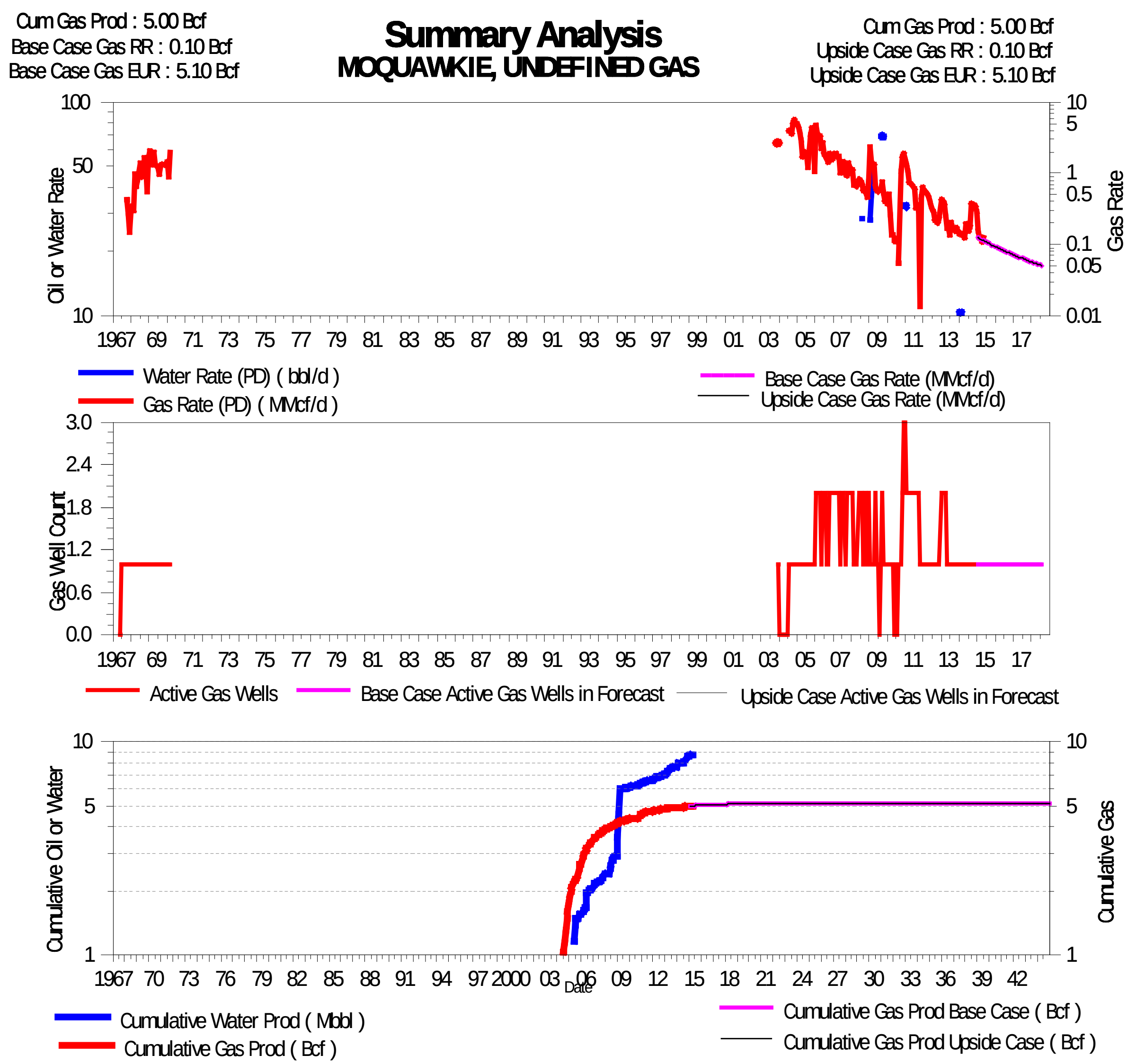

Figure A-37. Moquawkie field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:						Ryder Scott Reservoir Solutions 6.0 (Public)	
FIELD:	Moquawkie						
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 29, 2015						
RESERVOIR:	Tyonek (Undefined Gas) (alphanumeric)						
* Wichert-Aziz correction for contaminants, if any						*(Protected)*	
WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	85.0	N_2	1.36			Y-Intercept, BHP/z	1,534
WET GAS GRAVITY: ??	0.56	CO_2	0.00			*Apparent GIP, MMCF*	11,541
TVD, FEET:	2,250	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	11,486
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	342.74	S_W (dec)	0.38			*EUR, MMCF*	11,113
Corrected* Pc, Psia:	671.33	C_W, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9675
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.51			BHP/z @ Abandonment (Adj)	50

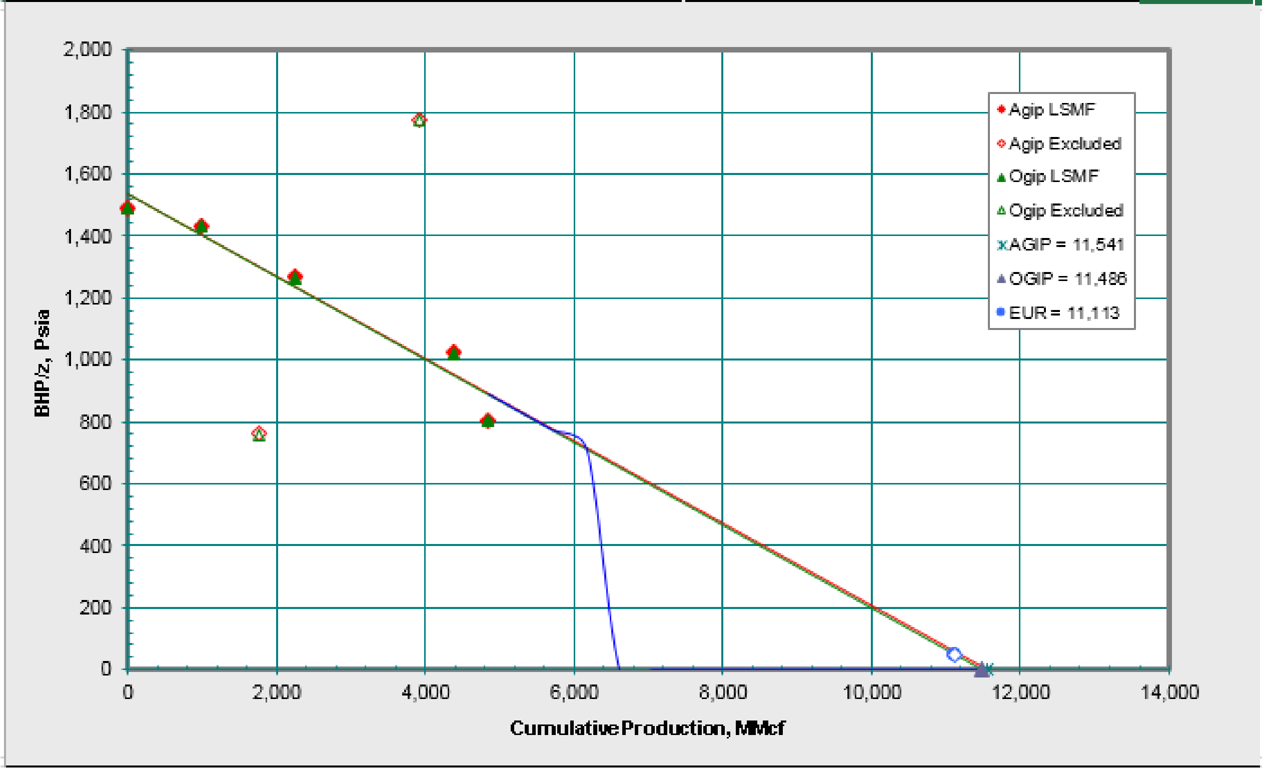

Figure A-38. Material balance and assumptions for Moquawkie field, Undefined gas pool (producing from the Tyonek).

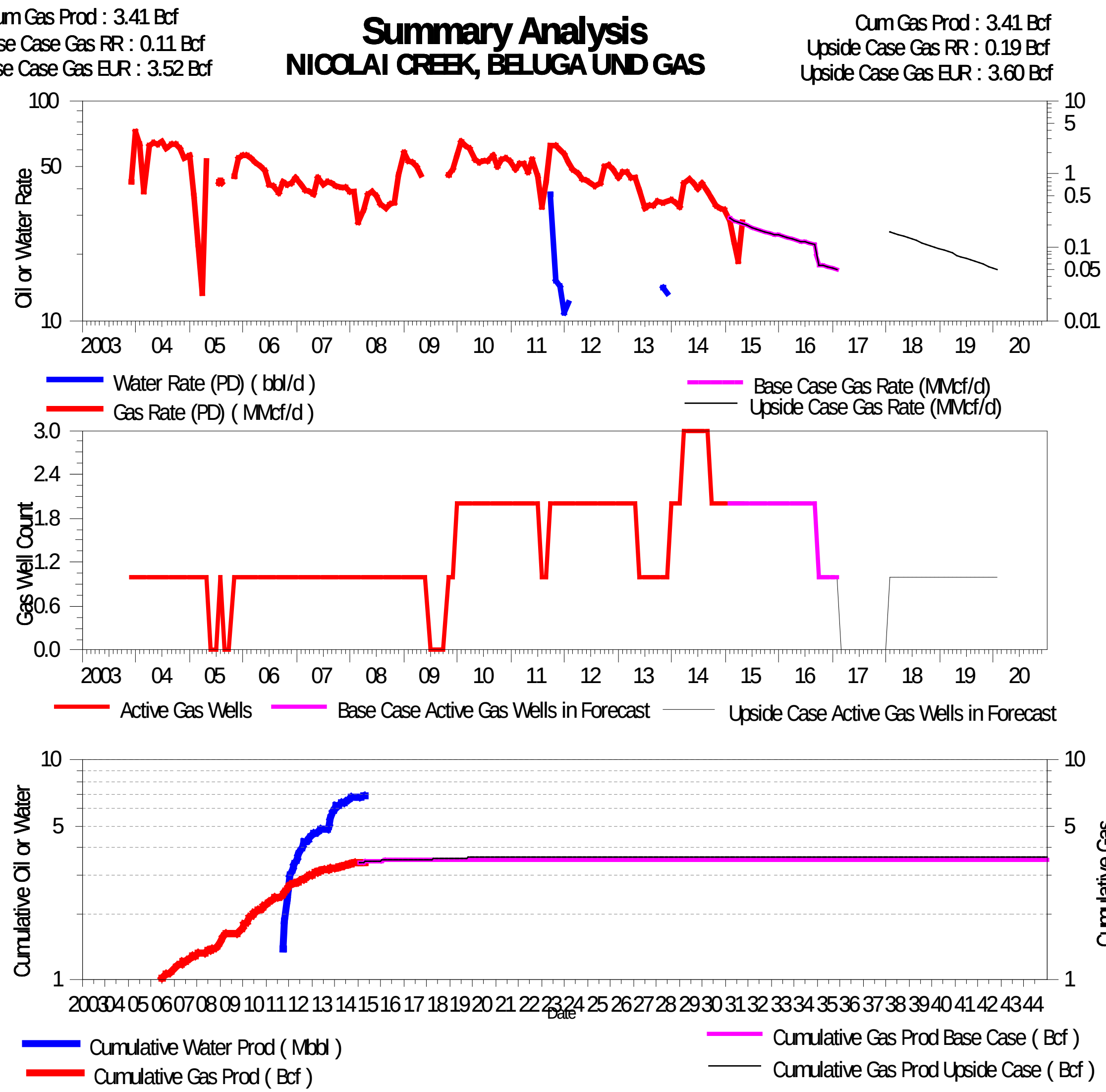

Figure A-39. Nicolai Creek. Beluga and undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:						Ryder Scott Reservoir Solutions 6.0 (Public) (Protected)	
FIELD:	Nicolai Creek						
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 29, 2015						
RESERVOIR:	Beluga 1552-1904 ft (Lower Completion NCU-9) (alphanumeric)						
* Wichert-Aziz correction for contaminants, if any							
WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	74.0	N_2	0.87			Y-Intercept, BHP/z	656
WET GAS GRAVITY: ??	0.562	CO_2	0.33			*Apparent GIP, MMCF*	683
TVD, FEET:	1,728	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	682
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	343.56	$S_{W\ (dec)}$	0.00			*EUR, MMCF*	630
Corrected* Pc, Psia:	672.16	C_W, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9235
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	4.86			BHP/z @ Abandonment (Adj)	50

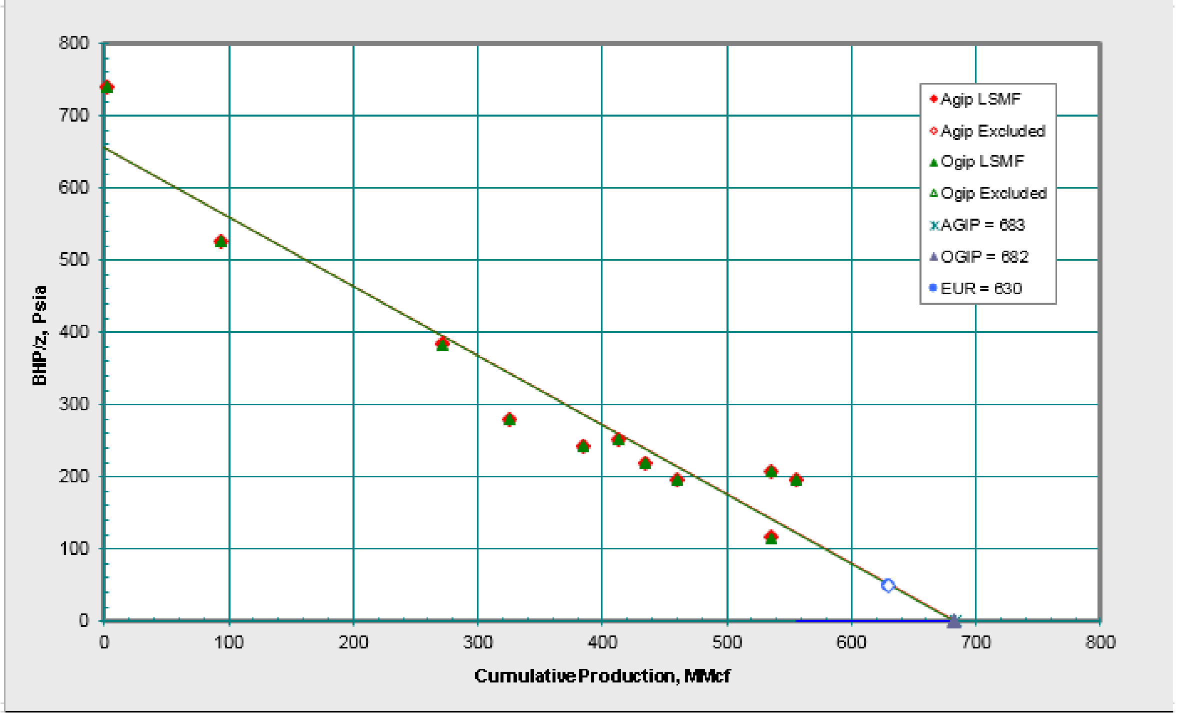

Figure A-40. Material balance and assumptions for Nicolai Creek field, Beluga and undefined pool.

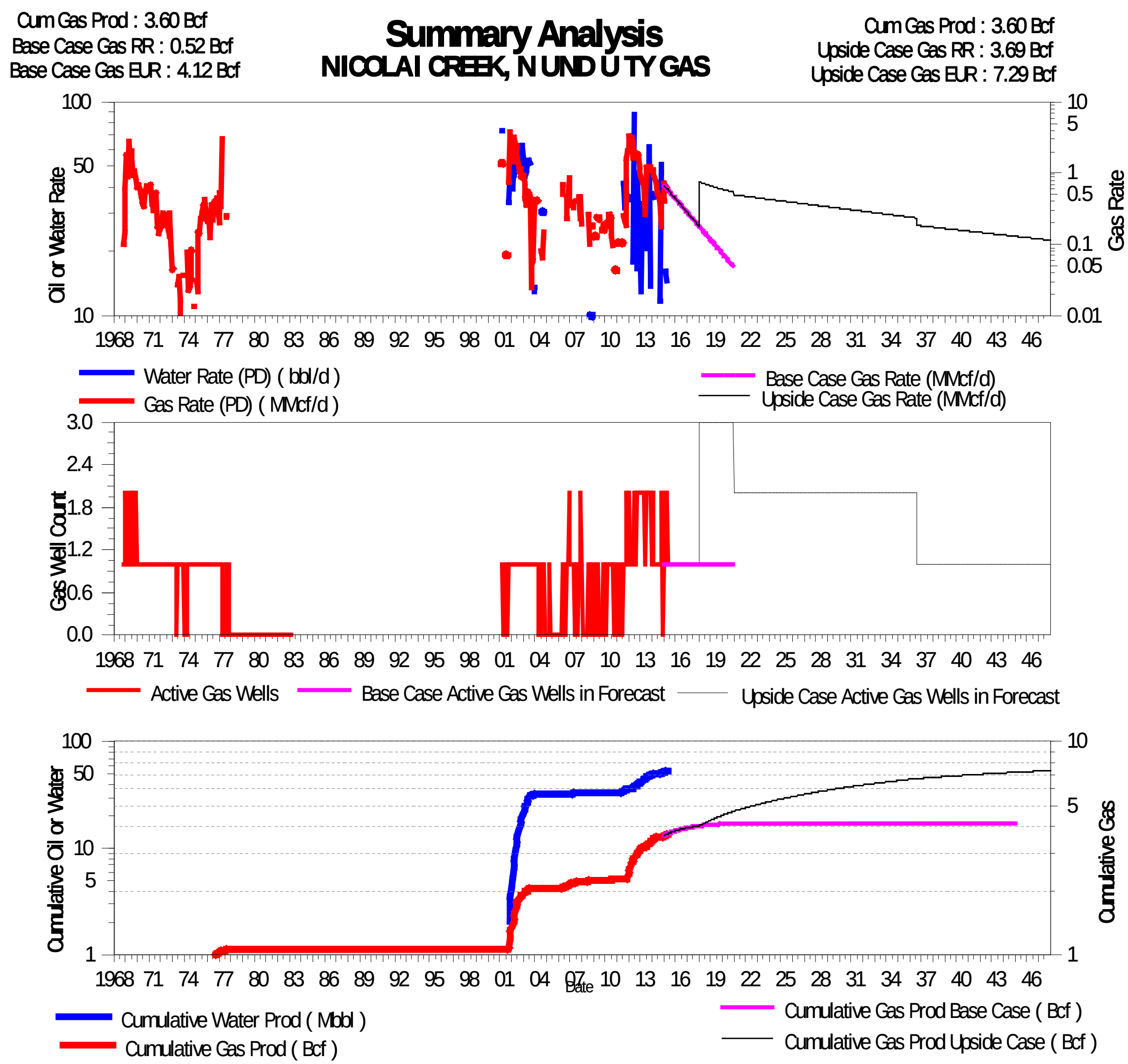

Figure A-41. Nicolai Creek field. Undefined and Upper Tyonek Gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

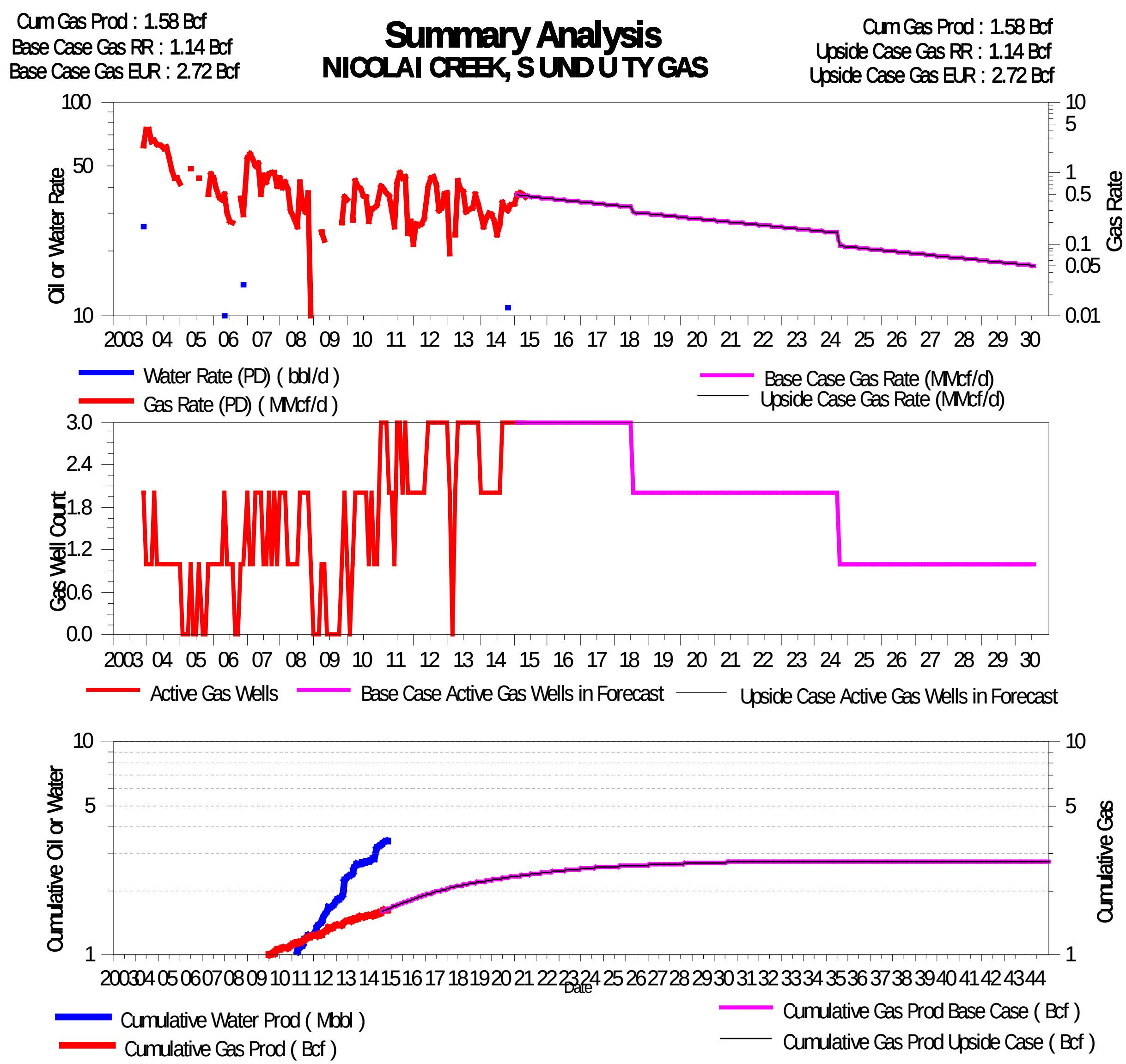

Figure A-42. Nicolai Creek field. South undefined and Upper Tyonek gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

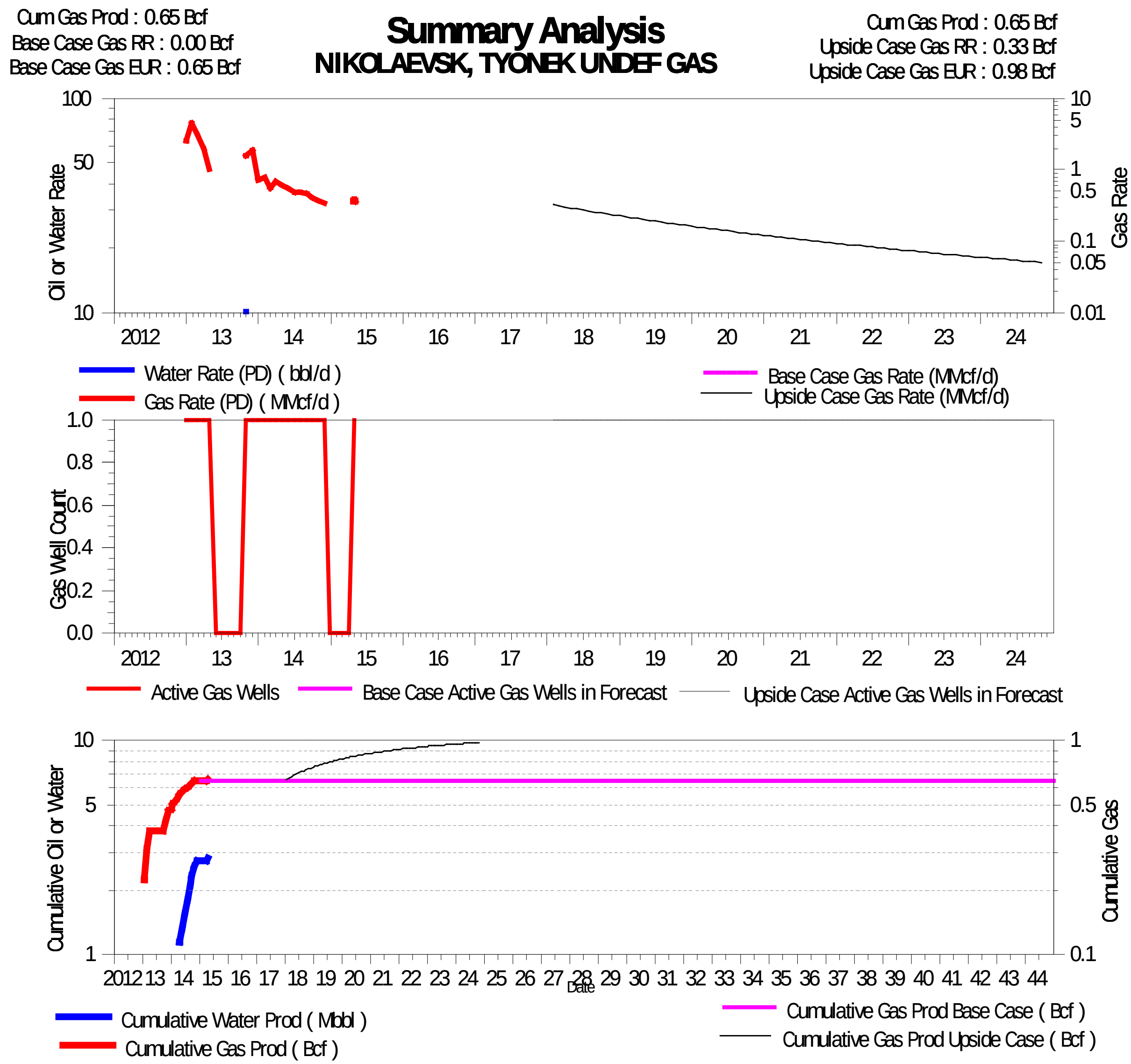

Figure A-43. Nikolaevsk field. Tyonek undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

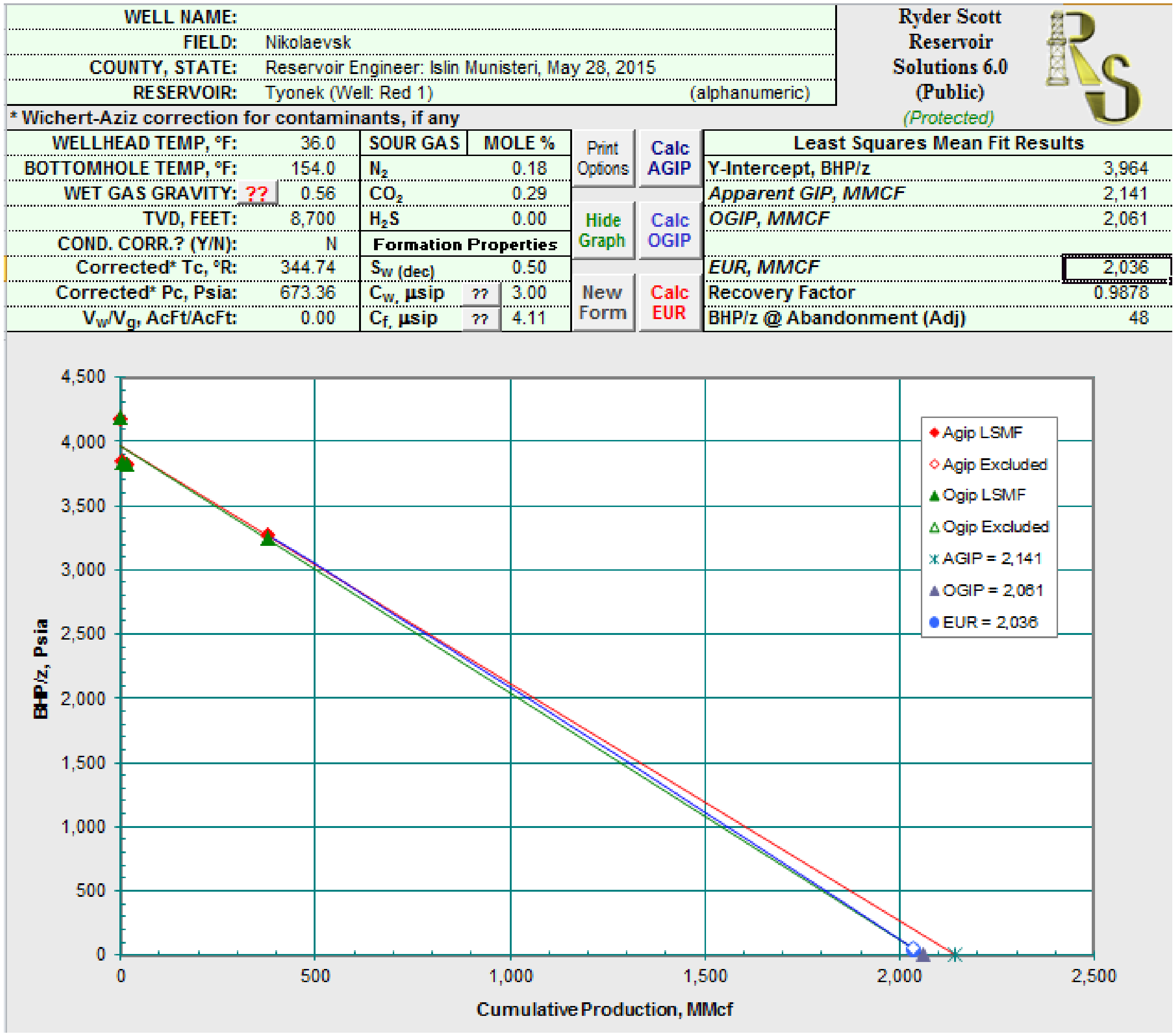

Figure A-44. Material balance and assumptions for Nikolaevsk field, Tyonek Uudefined gas pool.

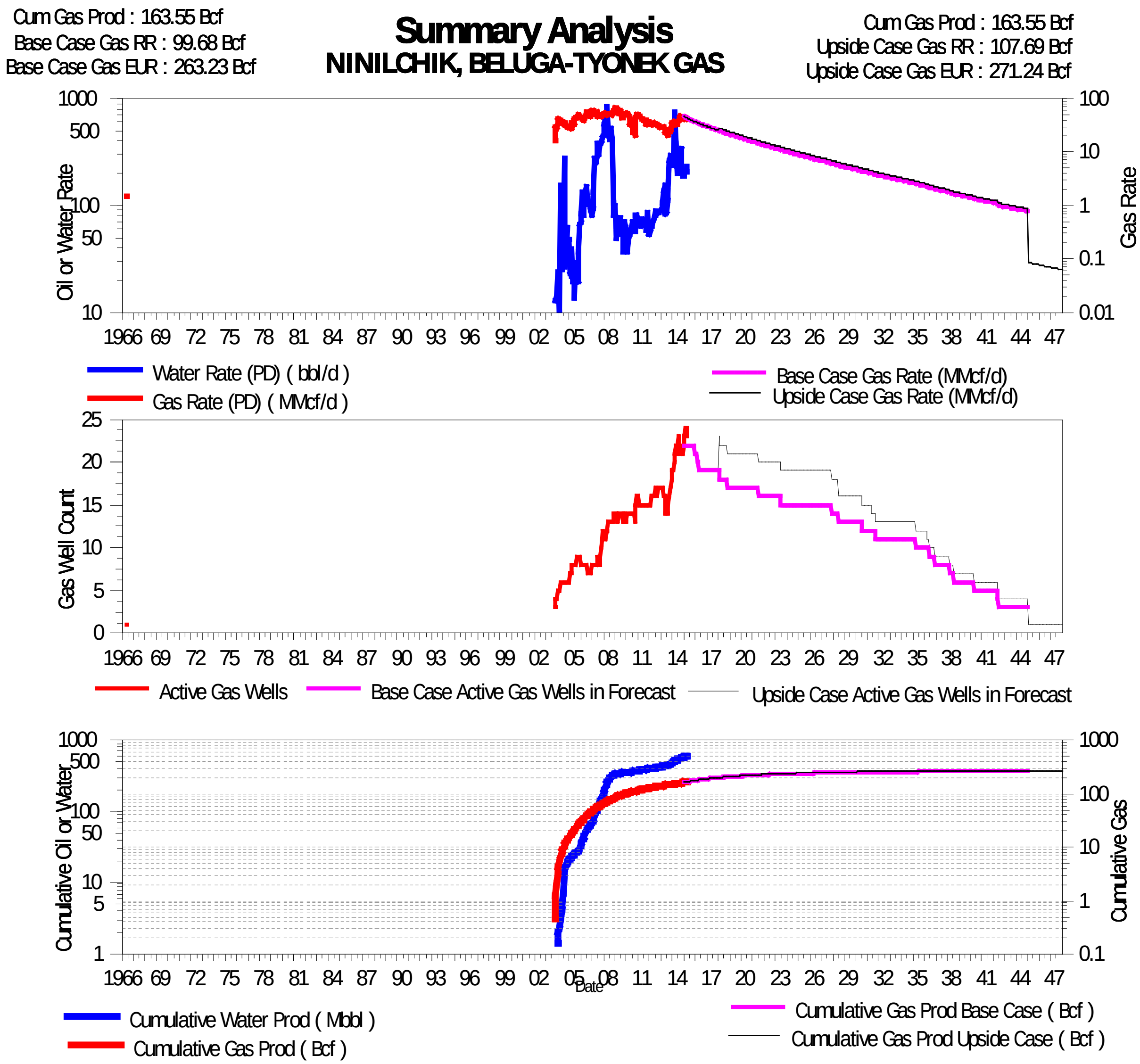

Figure A-45. Ninilchik field. Beluga-Tyonek gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

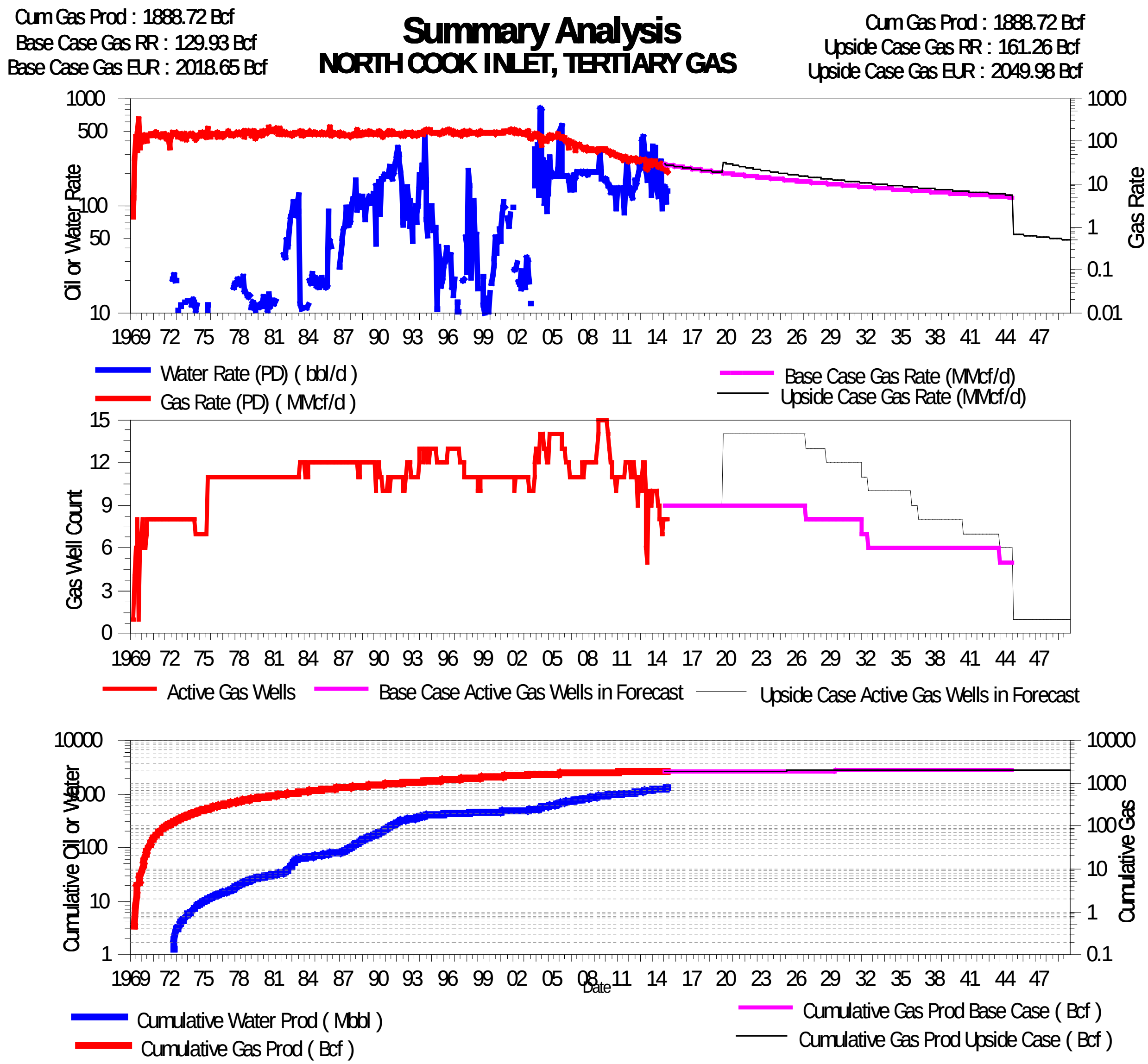

Figure A-46. North Cook Inlet field. Tertiary gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	North Cook Inlet
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 27, 2015
RESERVOIR:	Tyonek (Tertiary Gas pool) (Comp from NCIU A-15) (alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)

(Protected)

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	109.0	N_2	0.25			Y-Intercept, BHP/z	2,551
WET GAS GRAVITY: ??	0.565	CO_2	0.25			*Apparent GIP, MMCF*	2,229,881
TVD, FEET:	4,200	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	2,256,143
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	346.24	S_w (dec)	0.40			*EUR, MMCF*	2,213,844
Corrected* Pc, Psia:	673.09	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9813
V_w/V_g, AcFt/AcFt:	5.00	C_f, µsip ??	3.17			BHP/z @ Abandonment (Adj)	44

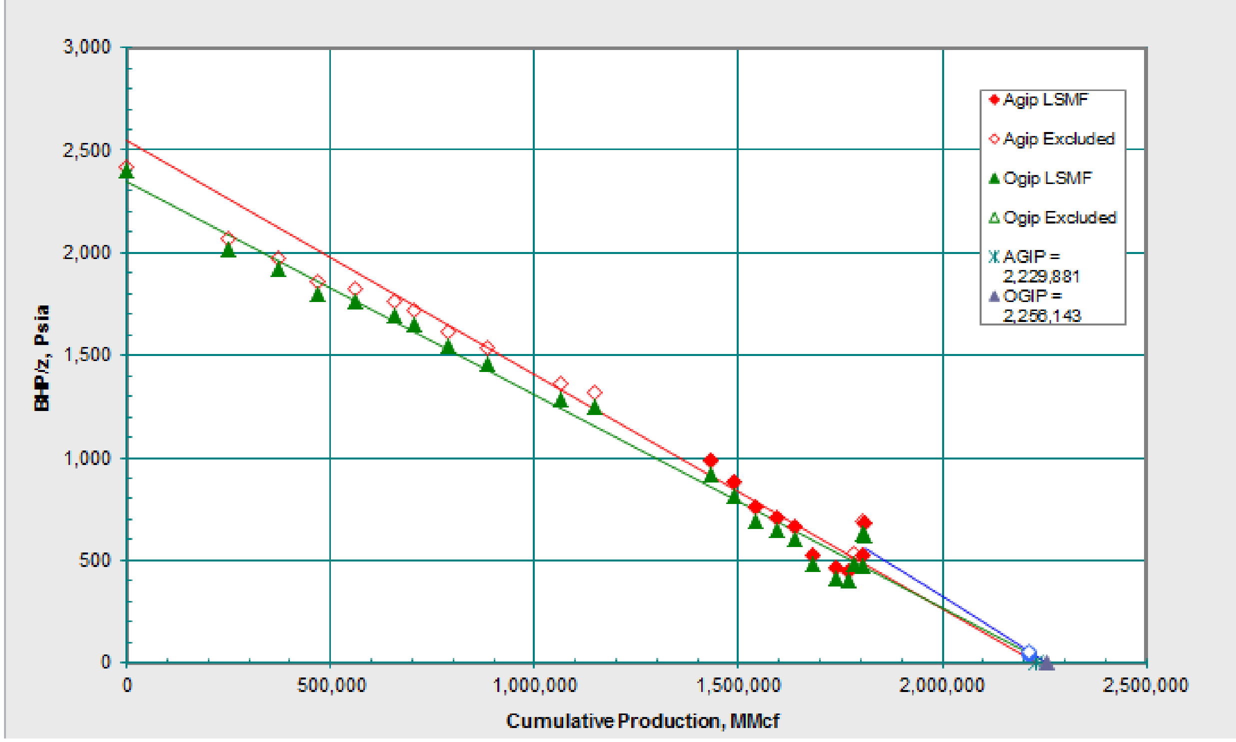

Figure A-47. Material balance and assumptions for Kenai field, Sterling 4 gas pool.

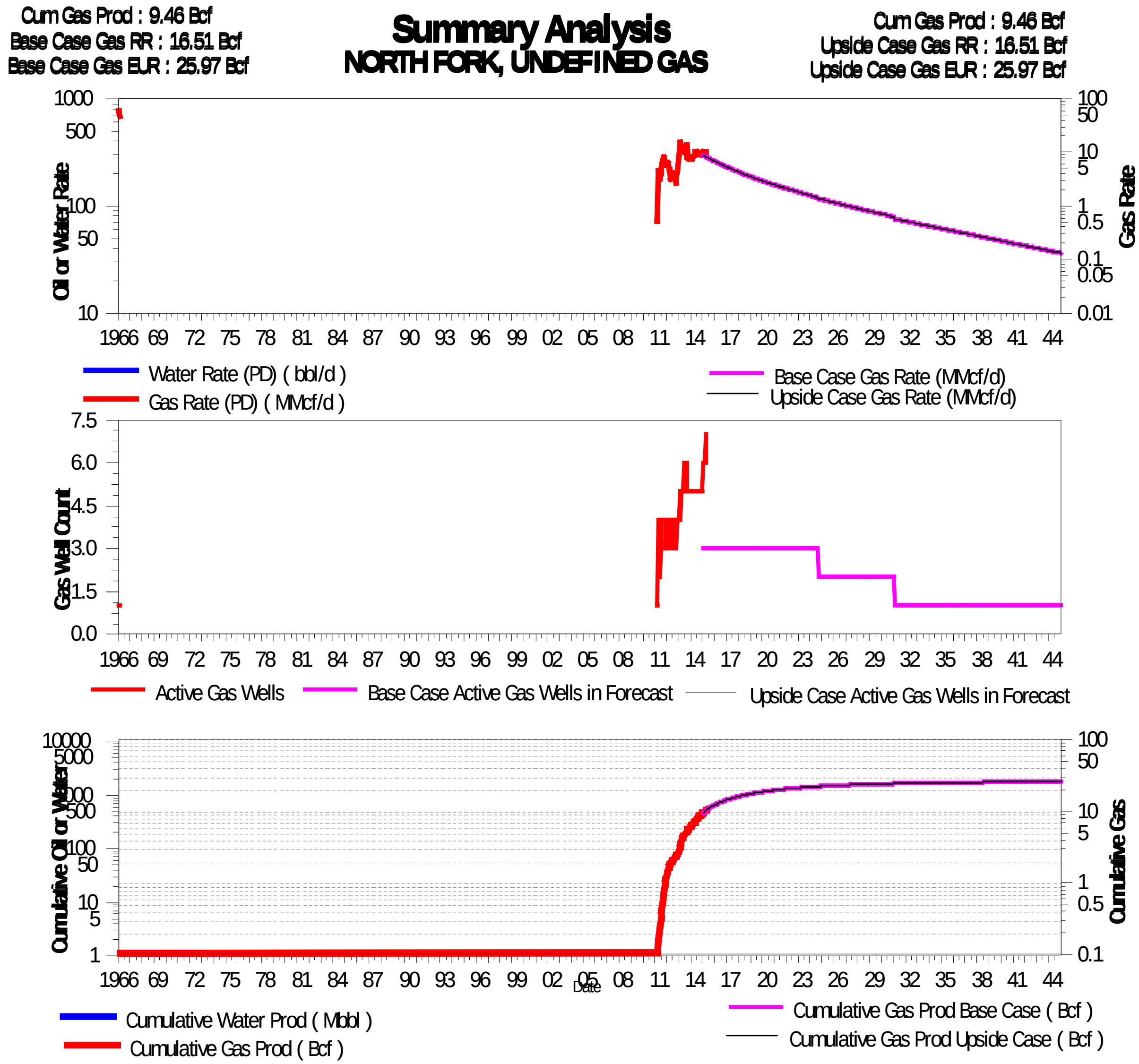

Figure A-48. North Fork field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	North Fork
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 27, 2015
RESERVOIR:	Tyonek (Undefined Gas) (alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)

(Protected)

* Wichert-Aziz correction for contaminants, if any

		SOUR GAS	MOLE %			Least Squares Mean Fit Results	
WELLHEAD TEMP, °F:	36.0			Print Options	Calc AGIP		
BOTTOMHOLE TEMP, °F:	140.0	N_2	1.03			Y-Intercept, BHP/z	3,469
WET GAS GRAVITY: ??	0.565	CO_2	0.34			*Apparent GIP, MMCF*	43,502
TVD, FEET:	7,200	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	42,372
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	344.08	S_w (dec)	0.50	New Form	Calc EUR	*EUR, MMCF*	41,778
Corrected* Pc, Psia:	671.82	C_w, µsip ??	3.00			Recovery Factor	0.9860
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.81			BHP/z @ Abandonment (Adj)	49

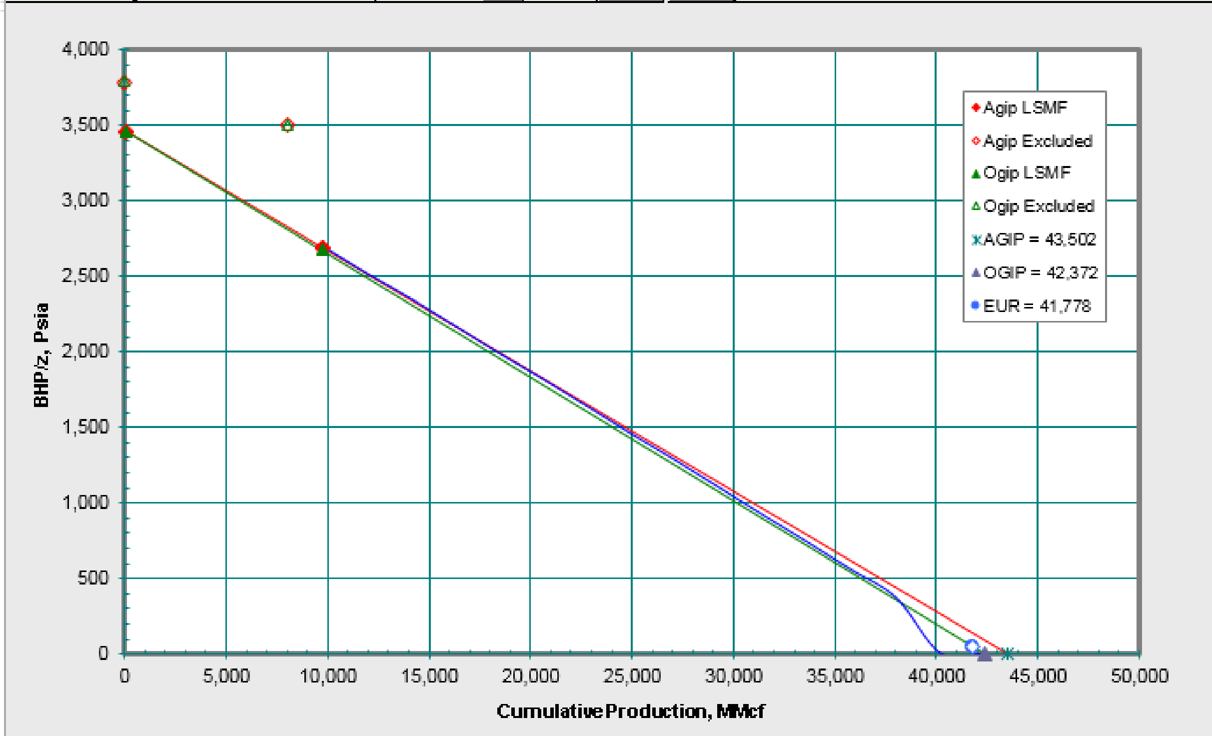

Figure A-49. Material balance and assumptions for North Fork field, Undefined gas pool (producing from the Tyonek).

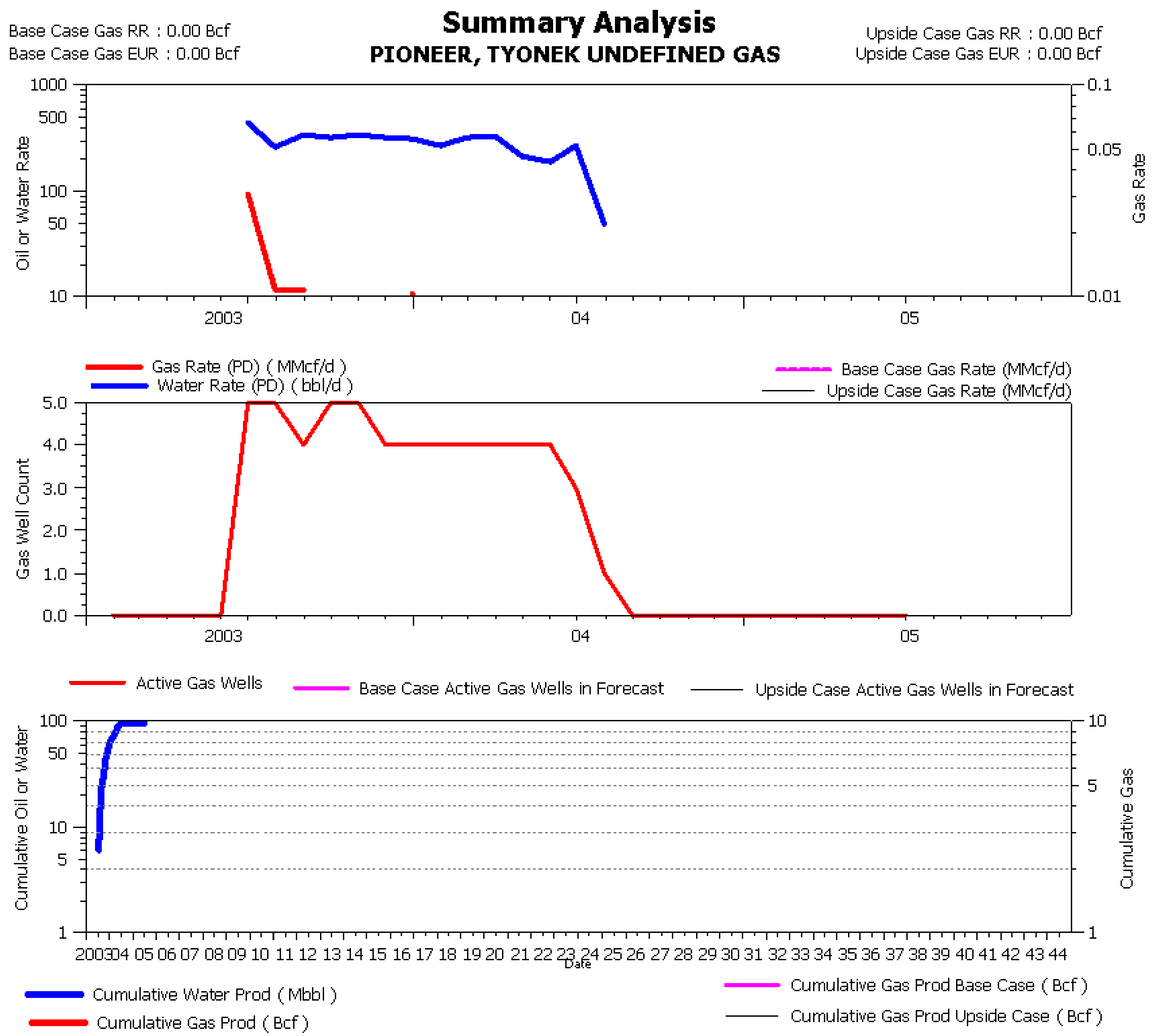

Figure A-50. Pioneer field. Tyonek undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

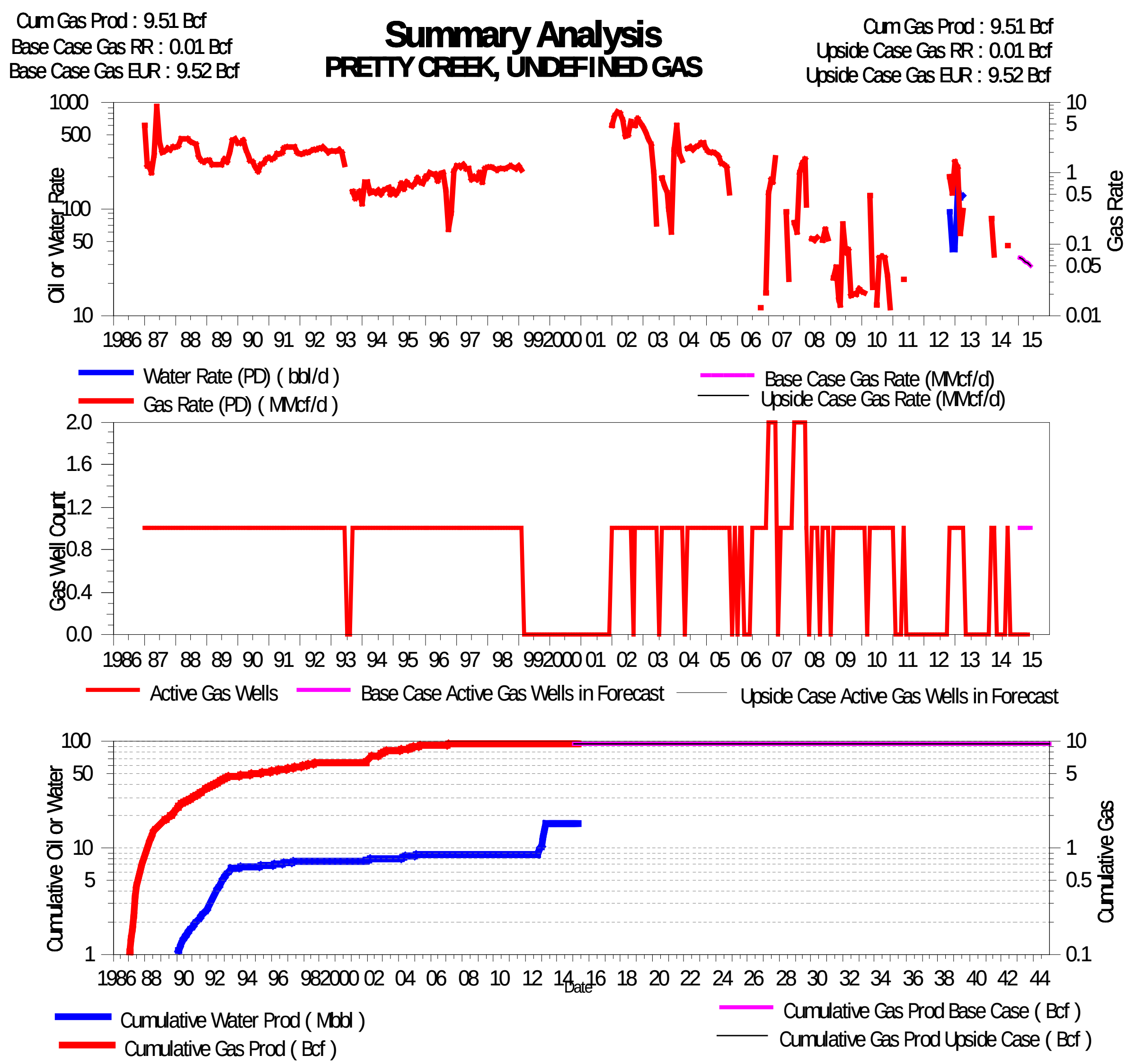

Figure A-51. Pretty Creek field. Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	Pretty Creek Unit
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 27, 2015
RESERVOIR:	Beluga (alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)

(Protected)

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS		MOLE %
BOTTOMHOLE TEMP, °F:	90.0	N_2		0.00
WET GAS GRAVITY: ??	0.56	CO_2		0.00
TVD, FEET:	3,364	H_2S		0.00
COND. CORR.? (Y/N):	N	Formation Properties		
Corrected* Tc, °R:	346.08	S_W (dec)		0.45
Corrected* Pc, Psia:	673.64	C_W, µsip	??	3.00
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip	??	3.51

Print Options | Calc AGIP | Hide Graph | Calc OGIP | New Form | Calc EUR

Least Squares Mean Fit Results	
Y-Intercept, BHP/z	2,238
Apparent GIP, MMCF	17,866
OGIP, MMCF	17,721
EUR, MMCF	17,317
Recovery Factor	0.9772
BHP/z @ Abandonment (Adj)	51

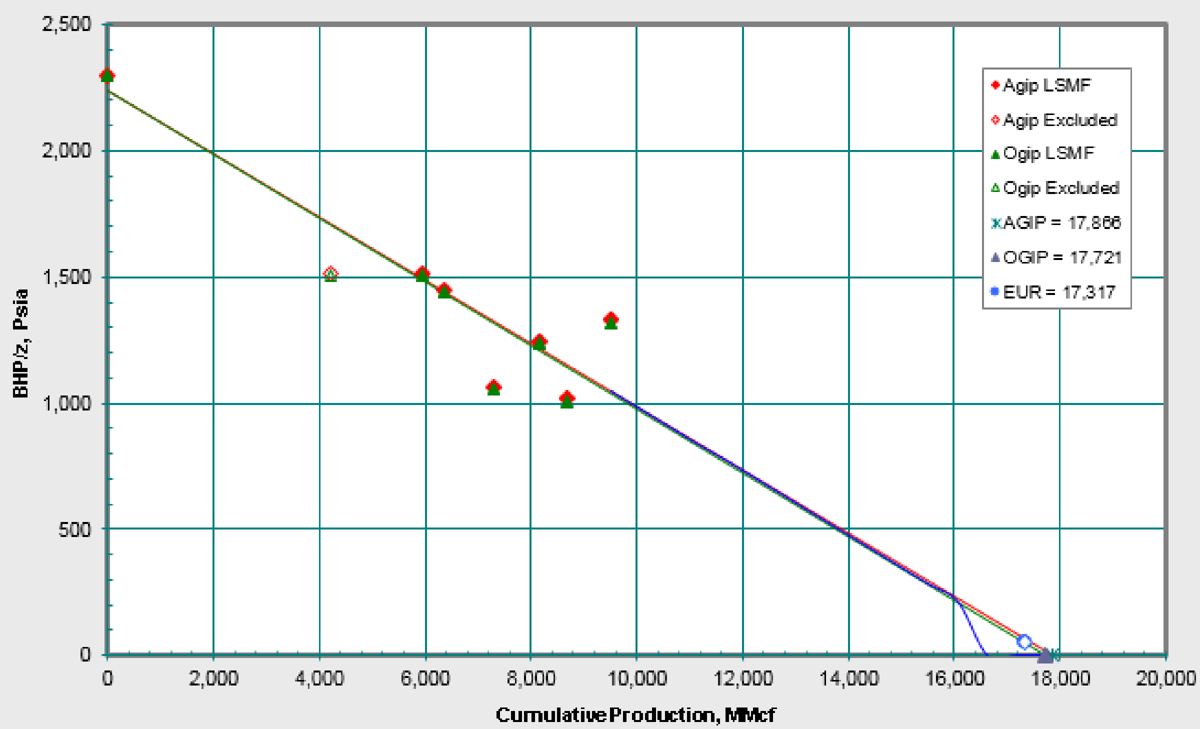

Figure A-52. Material balance and assumptions for Pretty Creek field, Undefined gas pool (producing from the Beluga).

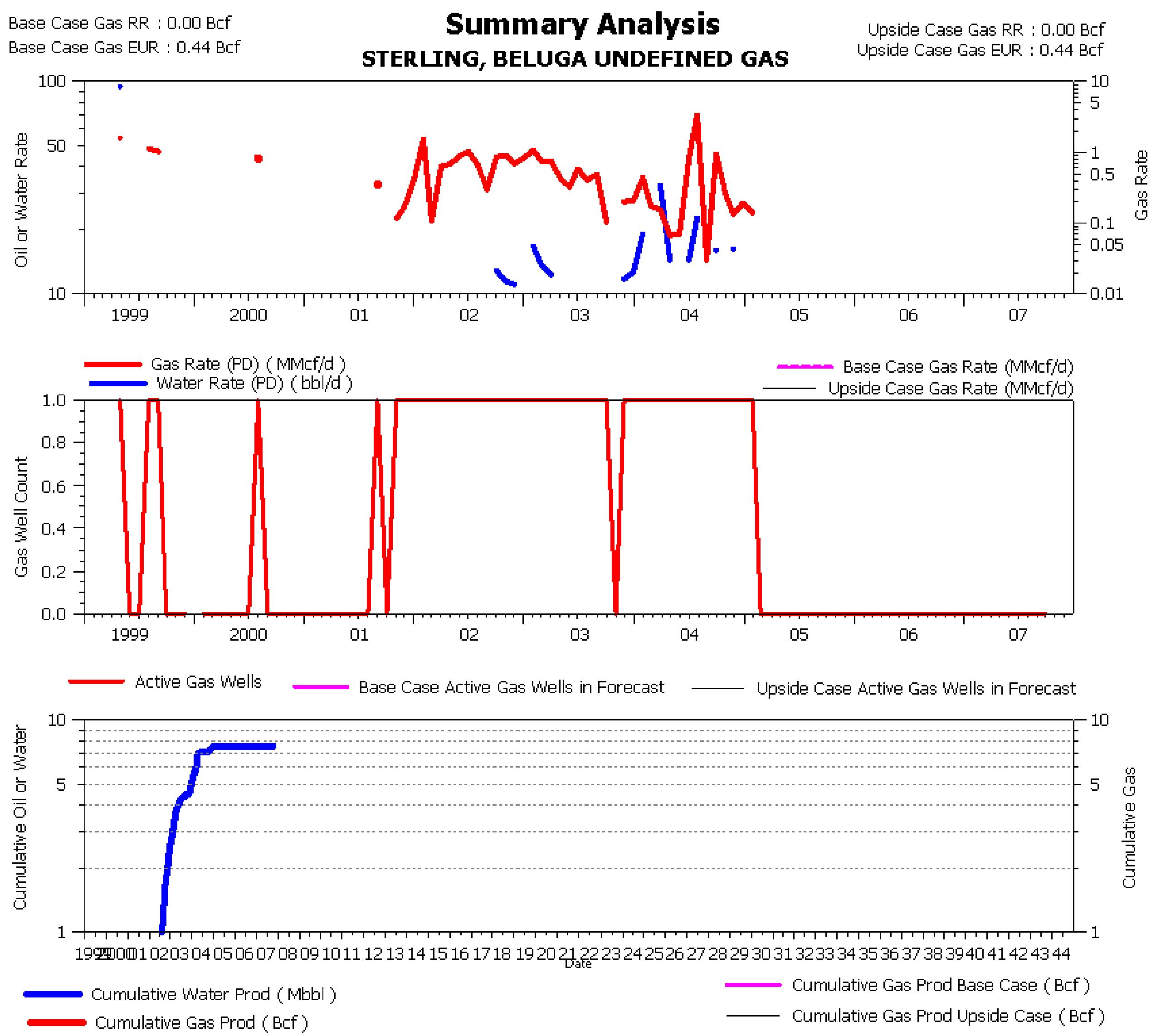

Figure A-53. Sterling field. Beluga undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

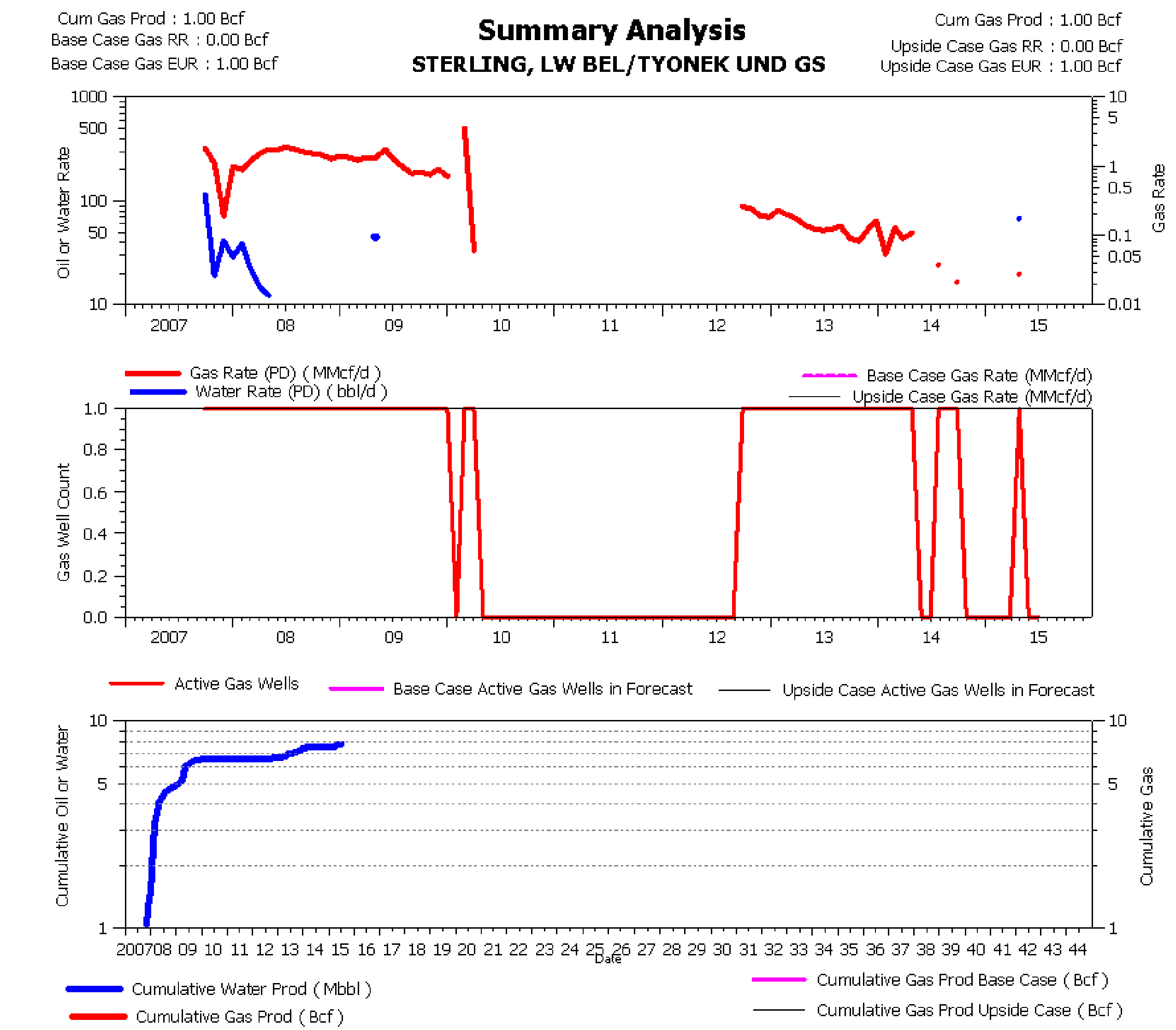

Figure A-54. Sterling field. Lower Beluga and Tyonek undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	Sterling
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 27, 2015
RESERVOIR:	Lwr Beluga/Tyonek (Only well prod: Sterling Unit 41-15) (alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)

(Protected)

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options / Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	131.0	N_2	0.35		Y-Intercept, BHP/z	3,851
WET GAS GRAVITY: ??	0.56	CO_2	0.33		*Apparent GIP, MMCF*	5,075
TVD, FEET:	8,104	H_2S	0.00	Hide Graph / Calc OGIP	*OGIP, MMCF*	3,982
COND. CORR.? (Y/N):	N	Formation Properties				
Corrected* Tc, °R:	344.23	$S_{W\ (dec)}$	0.50		*EUR, MMCF*	3,946
Corrected* Pc, Psia:	673.10	C_W, μsip ??	3.00	New Form / Calc EUR	Recovery Factor	0.9910
V_w/V_g, AcFt/AcFt:	5.00	C_f, μsip ??	4.86		BHP/z @ Abandonment (Adj)	35

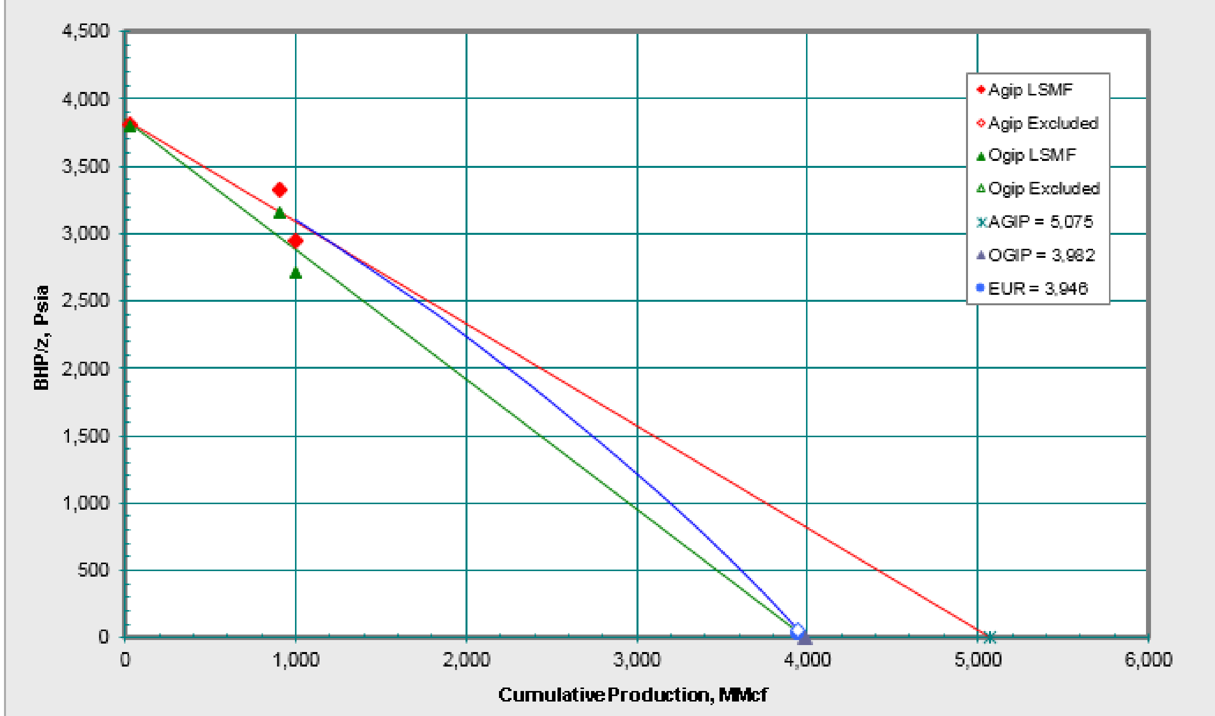

Figure A-55. Material balance and assumptions for Sterling field, Lower Beluga and Tyonek undefined gas pool.

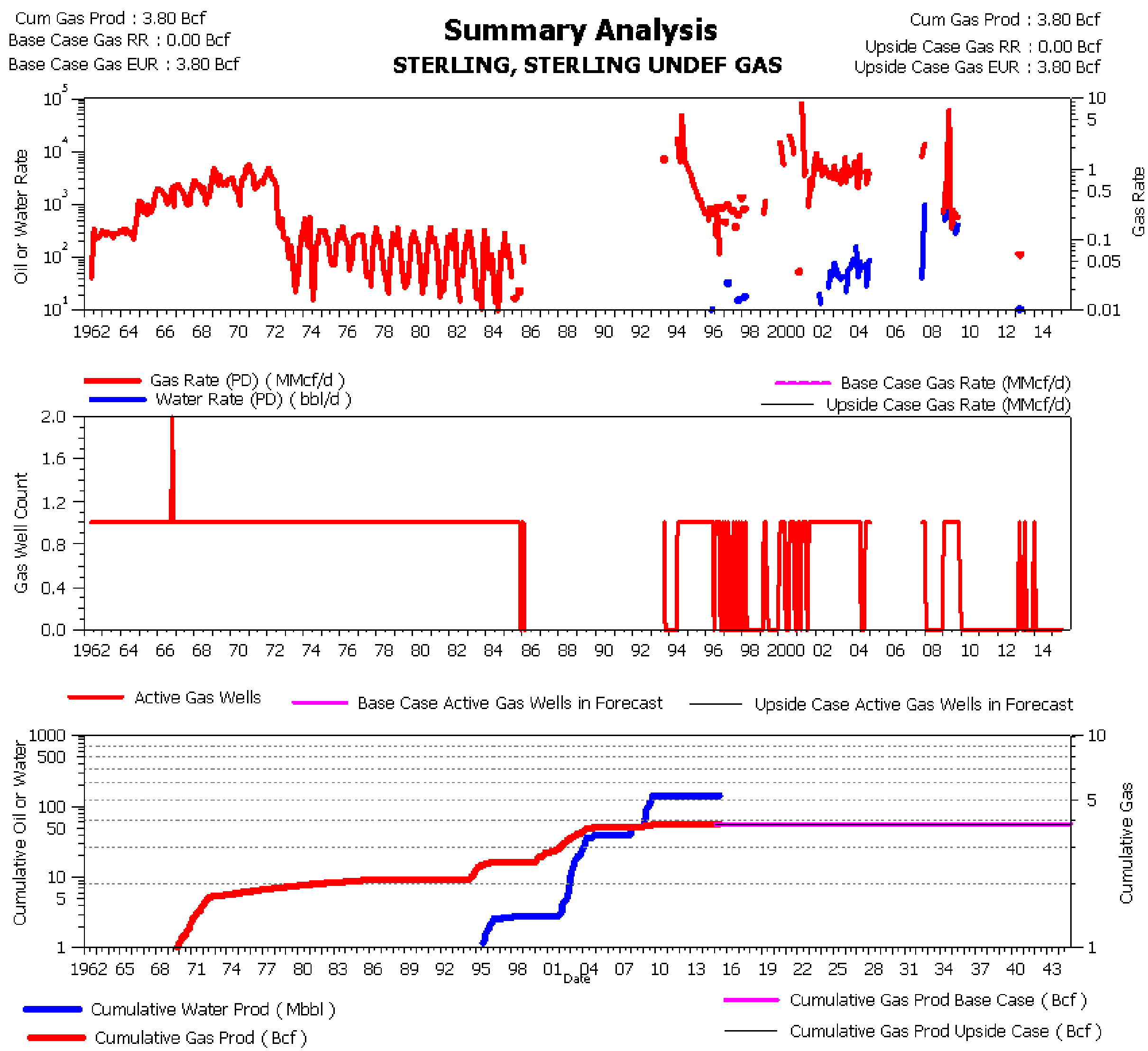

Figure A-56. Sterling field. Sterling undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

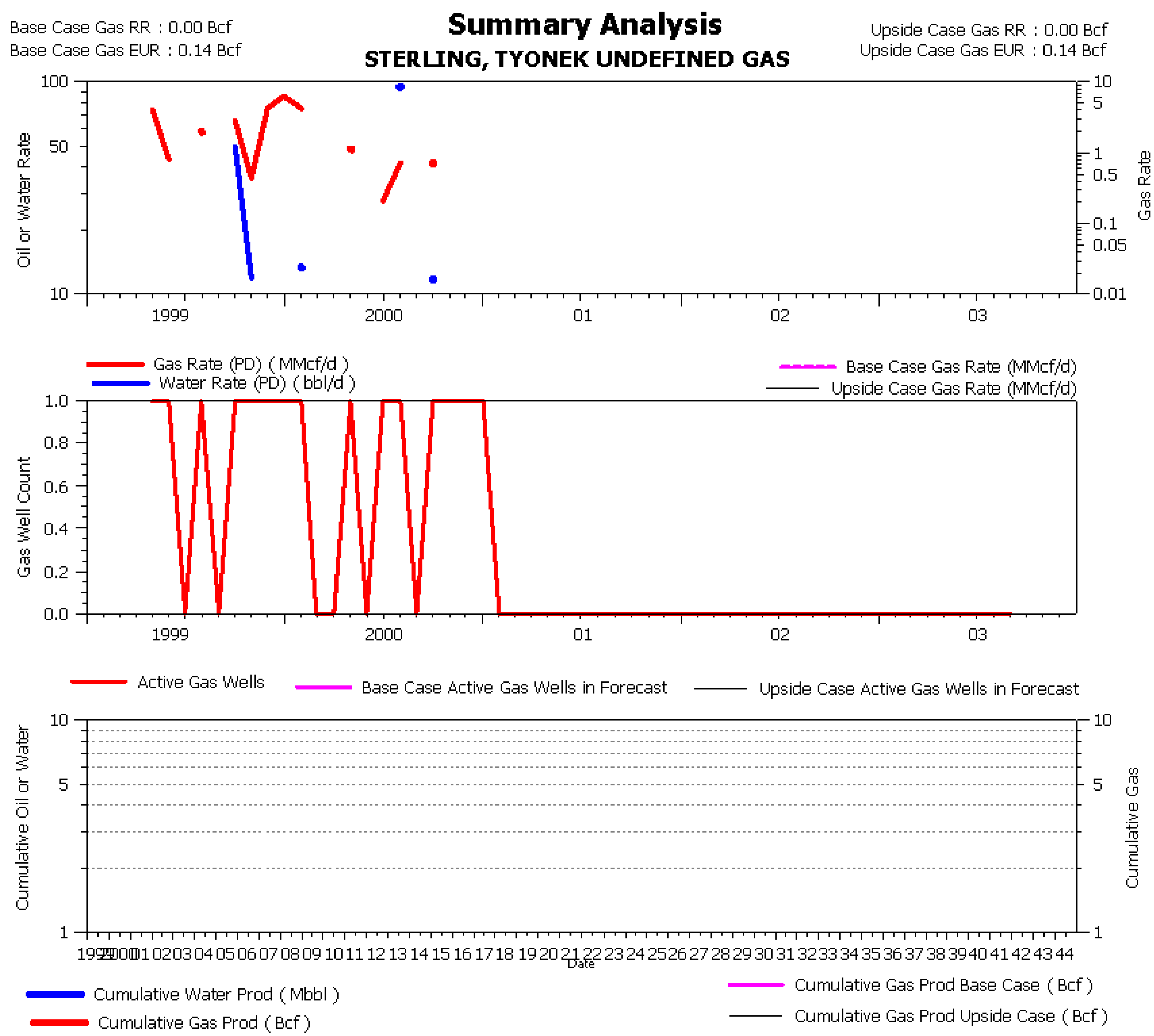

Figure A-57. Sterling field. Tyonek undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

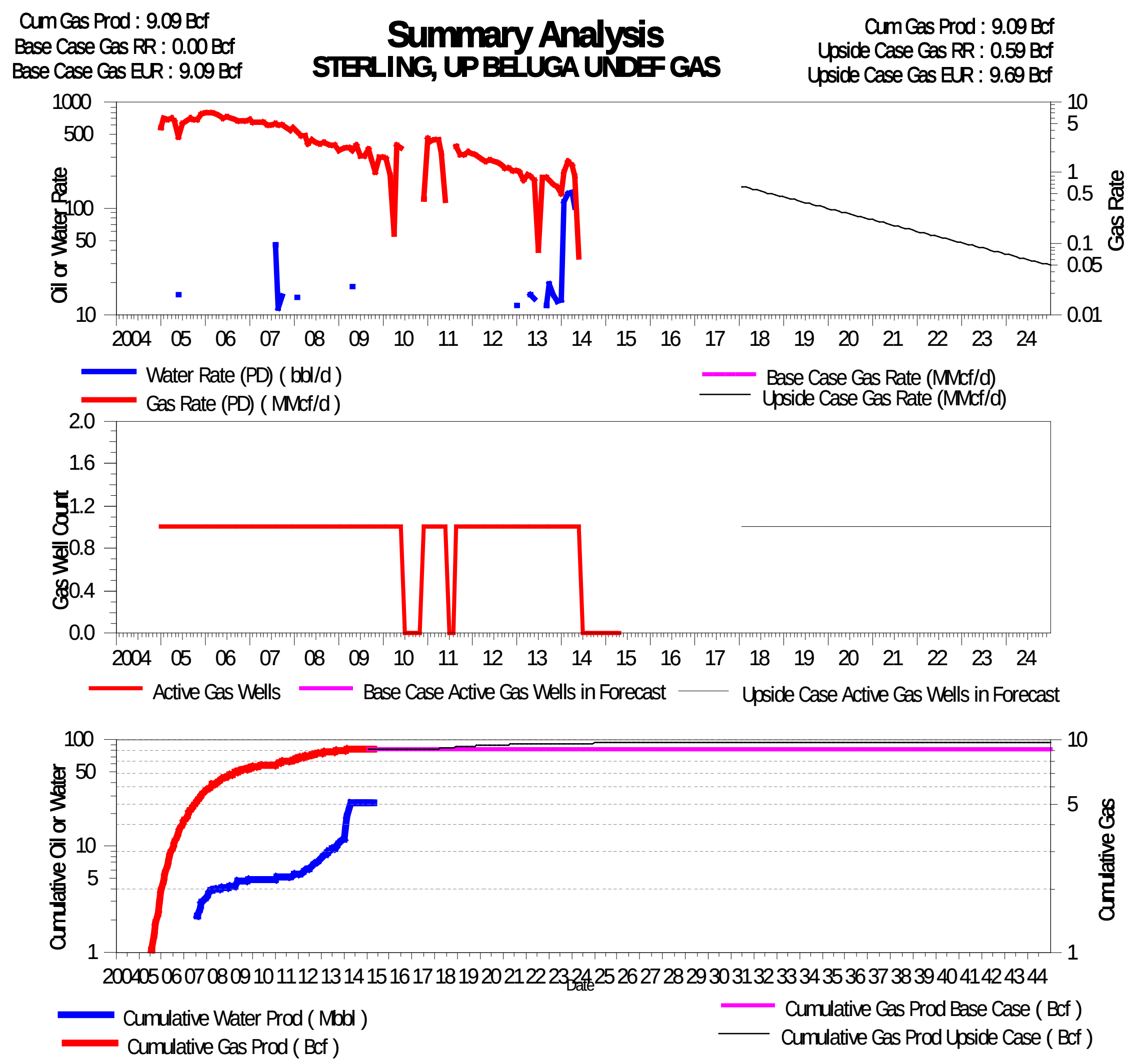

Figure A-58. Sterling field. Upper Beluga and undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

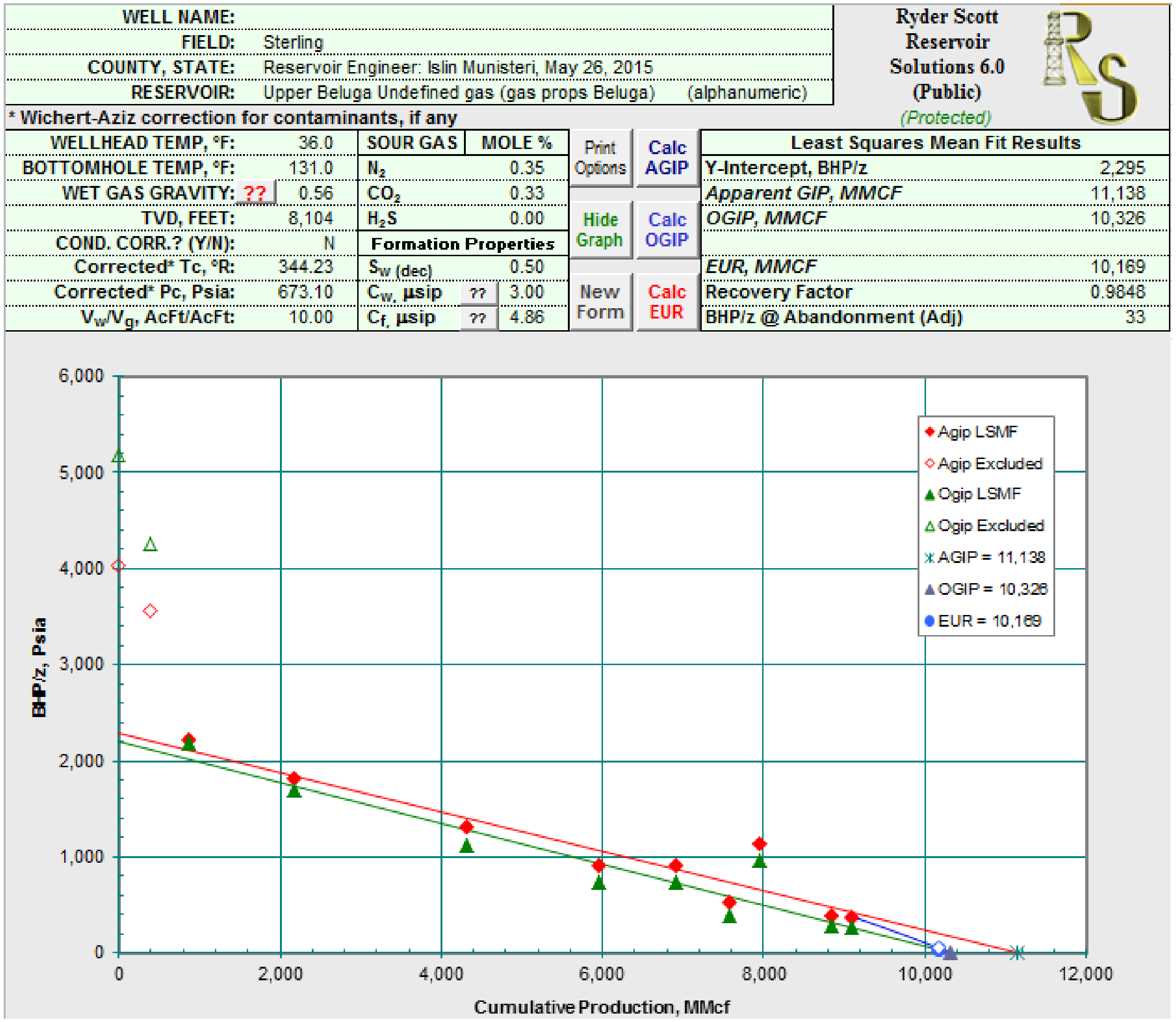

Figure A-59. Material balance and assumptions for Sterling field, Upper Beluga Undefined gas pool.

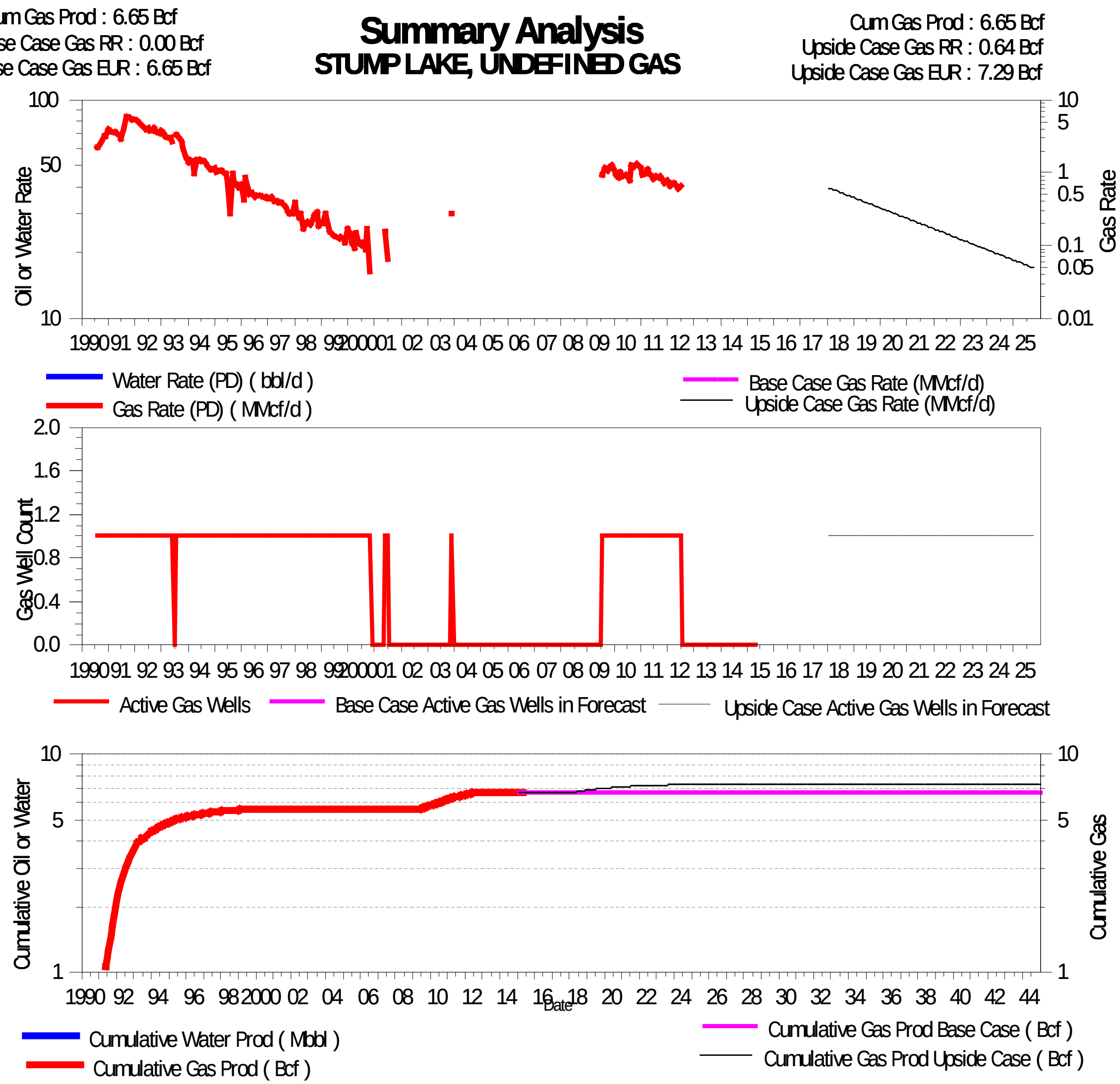

Figure A-60. Stump Lake field. Undefined gas pool.

Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

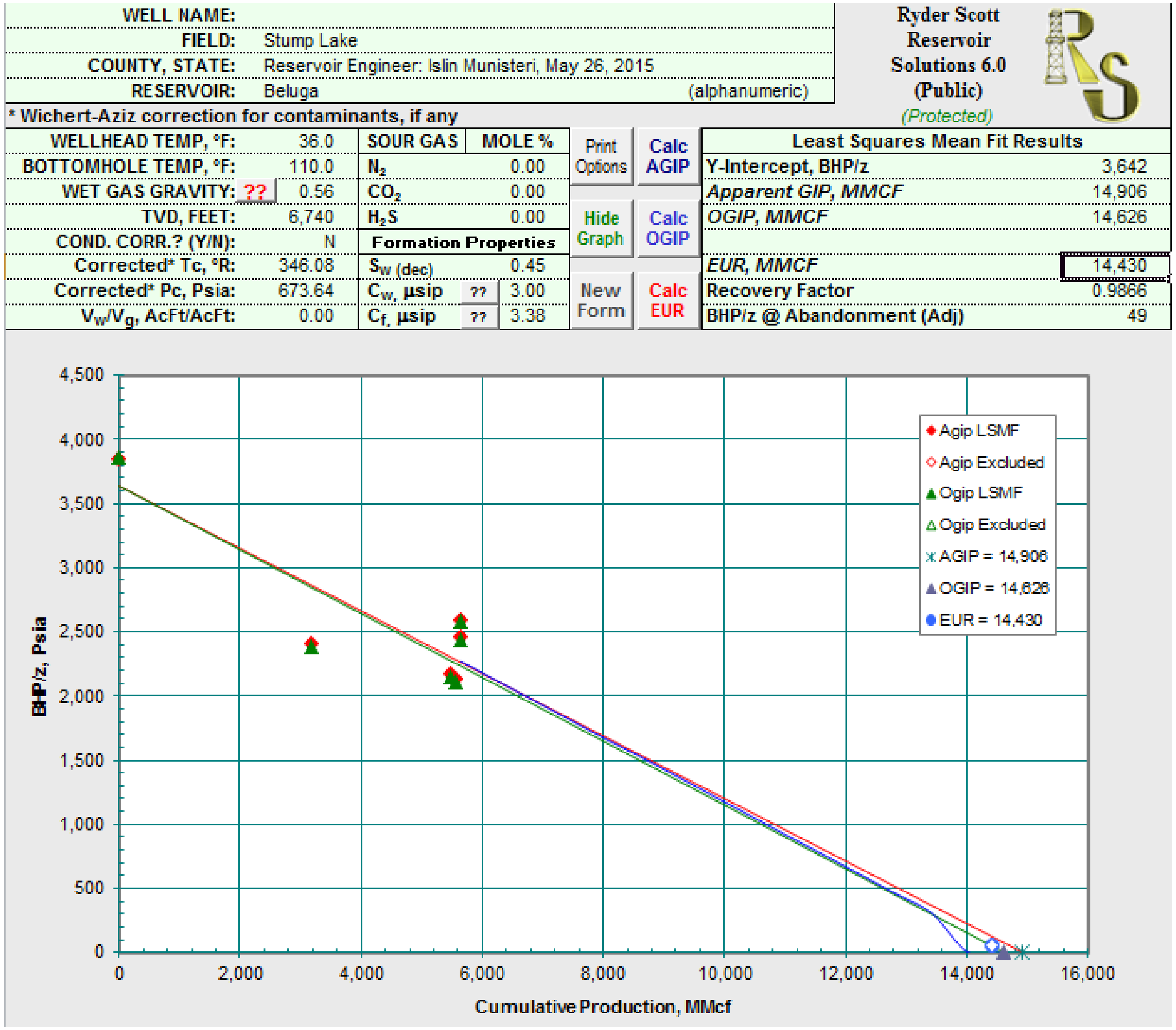

Figure A-61. Material balance and assumptions for Stump Lake field, Undefined gas pool (producing from the Beluga).

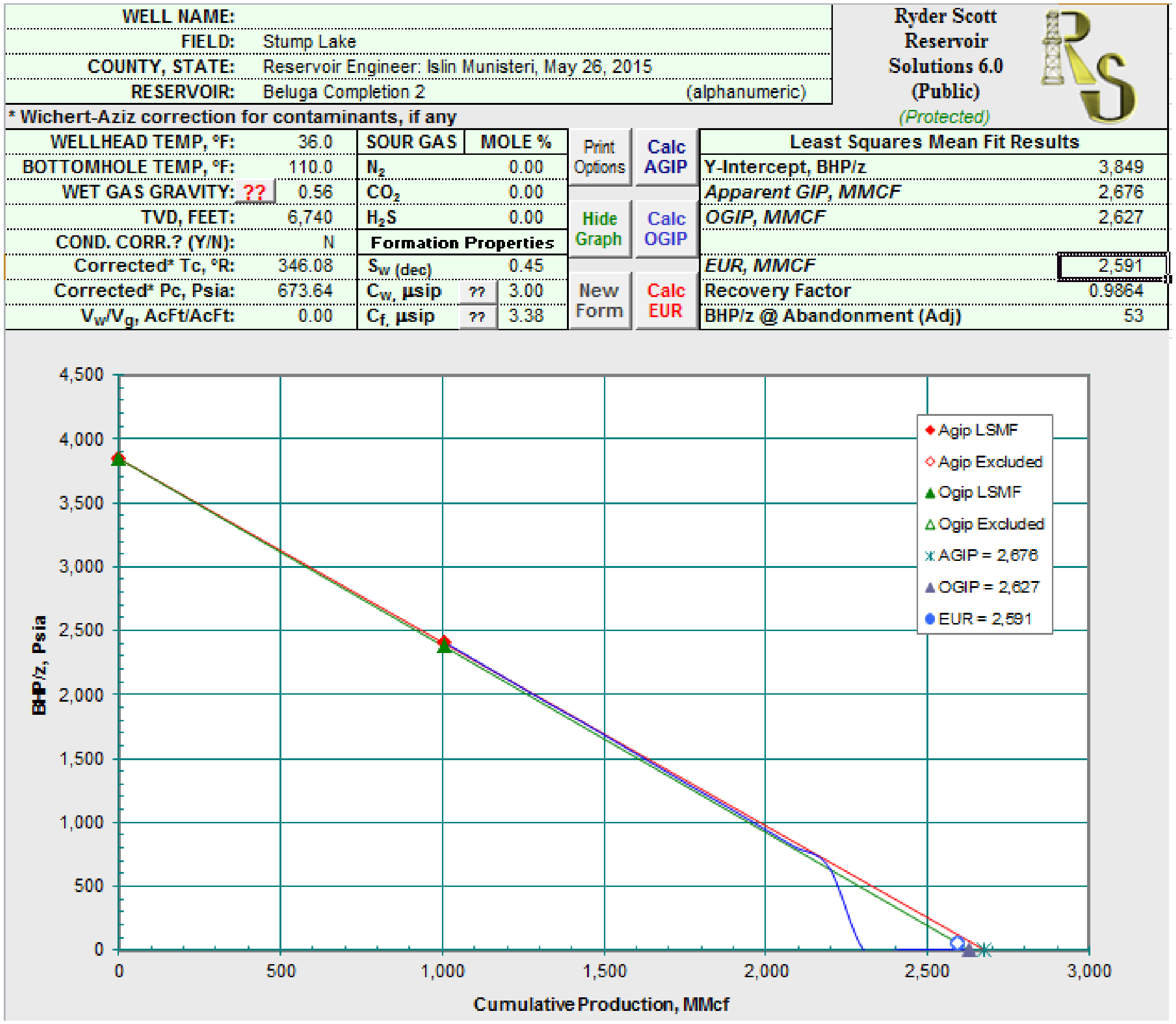

Figure A-62. Material balance and assumptions for Stump Lake field, Undefined gas pool (producing from the Beluga). More recent data suggests that there are additional sands perforated at Stump Lake. Their higher pressures are shown here.

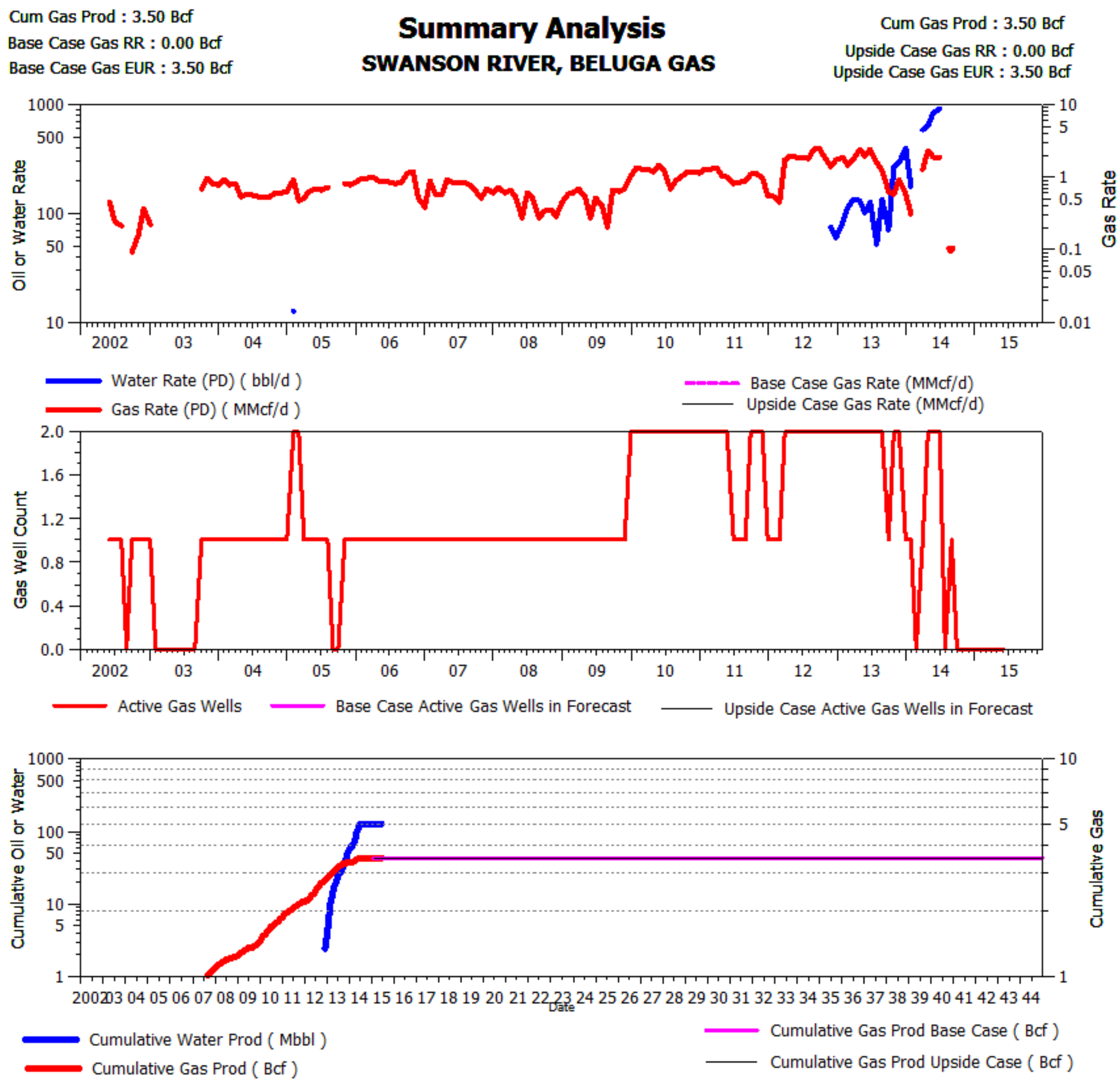

Figure A-63. Swanson River field. Beluga gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

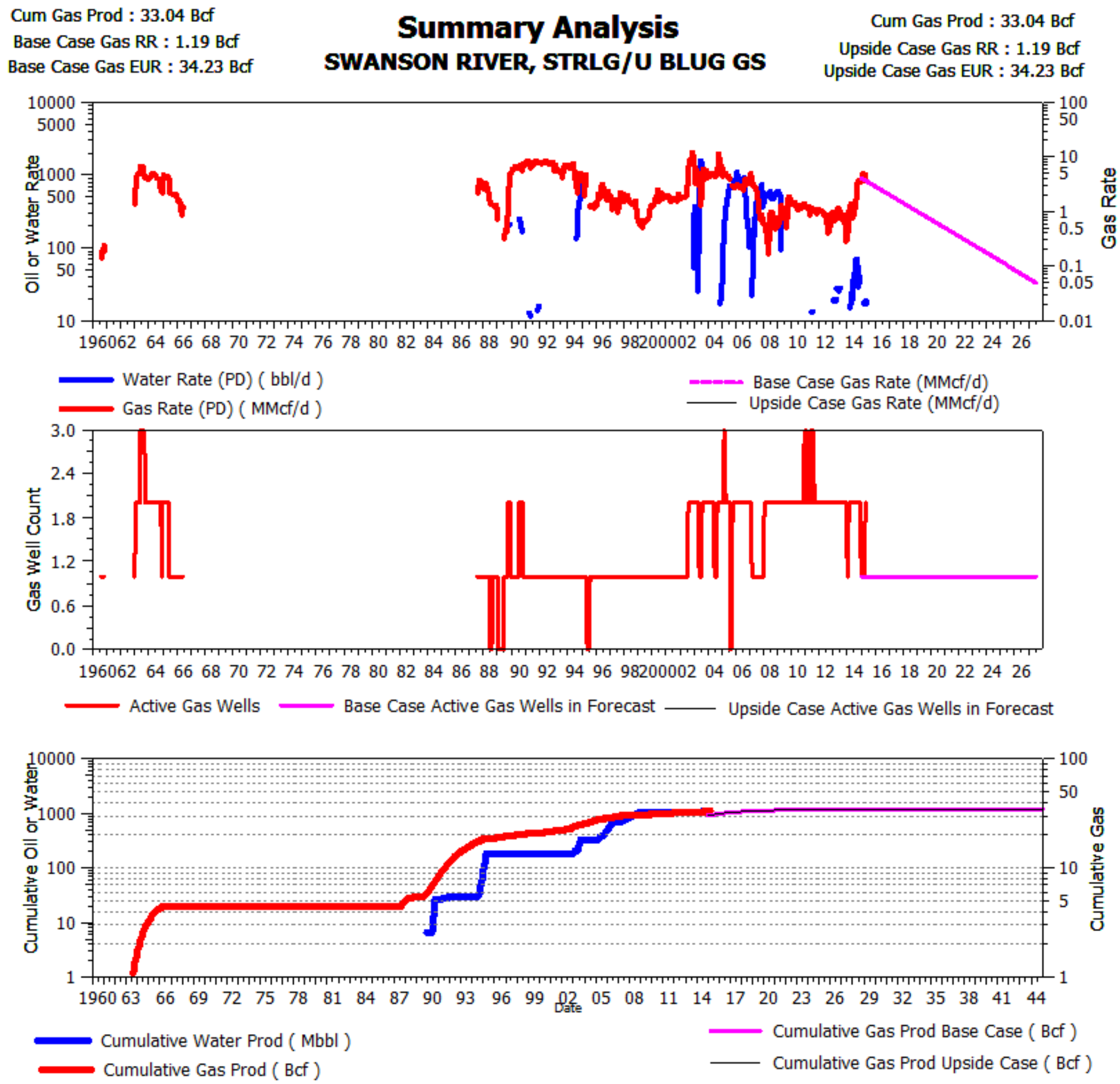

Figure A-64. Swanson River field. Sterling and Upper Beluga gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

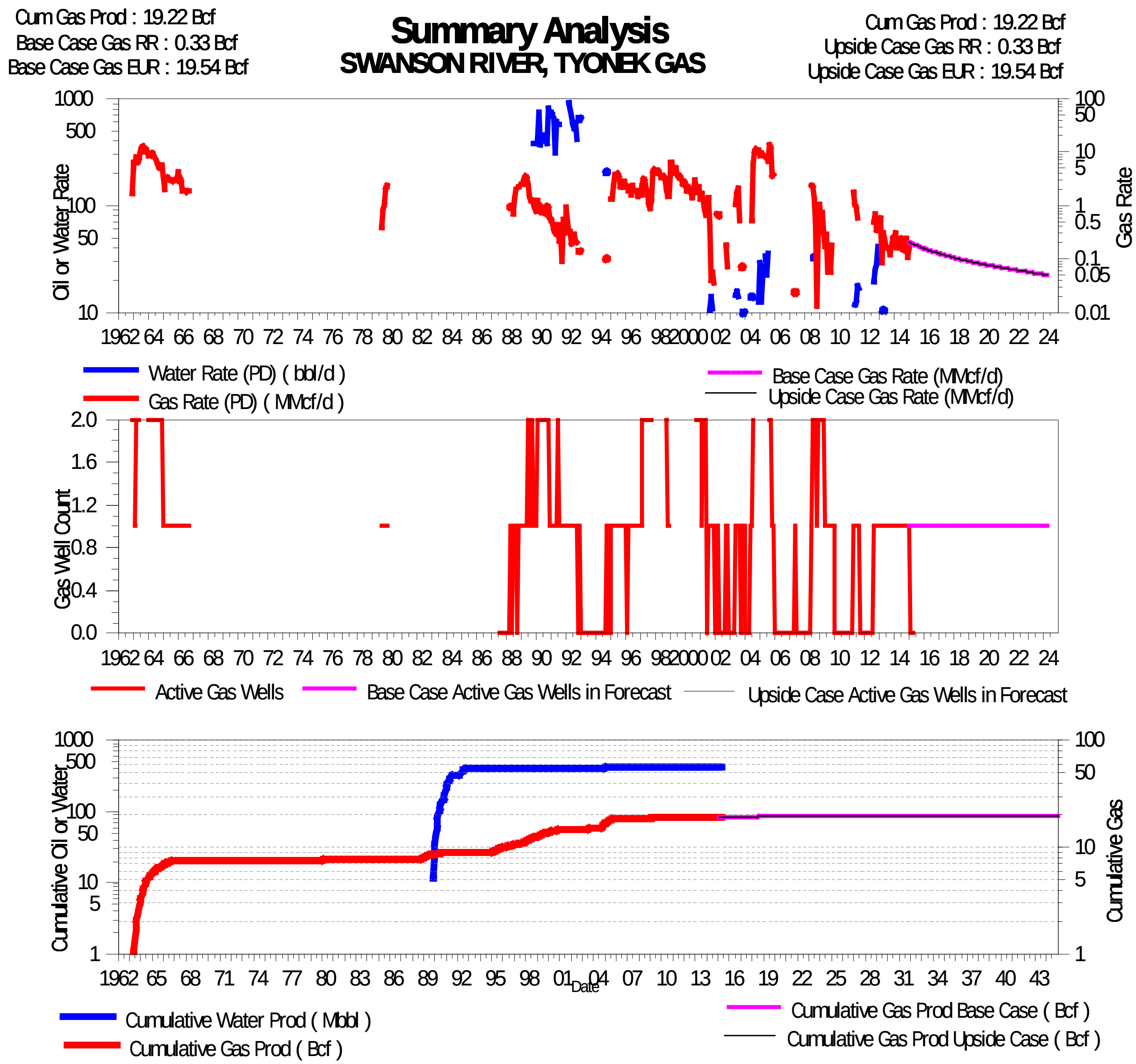

Figure A-65. Swanson River field. Tyonek gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

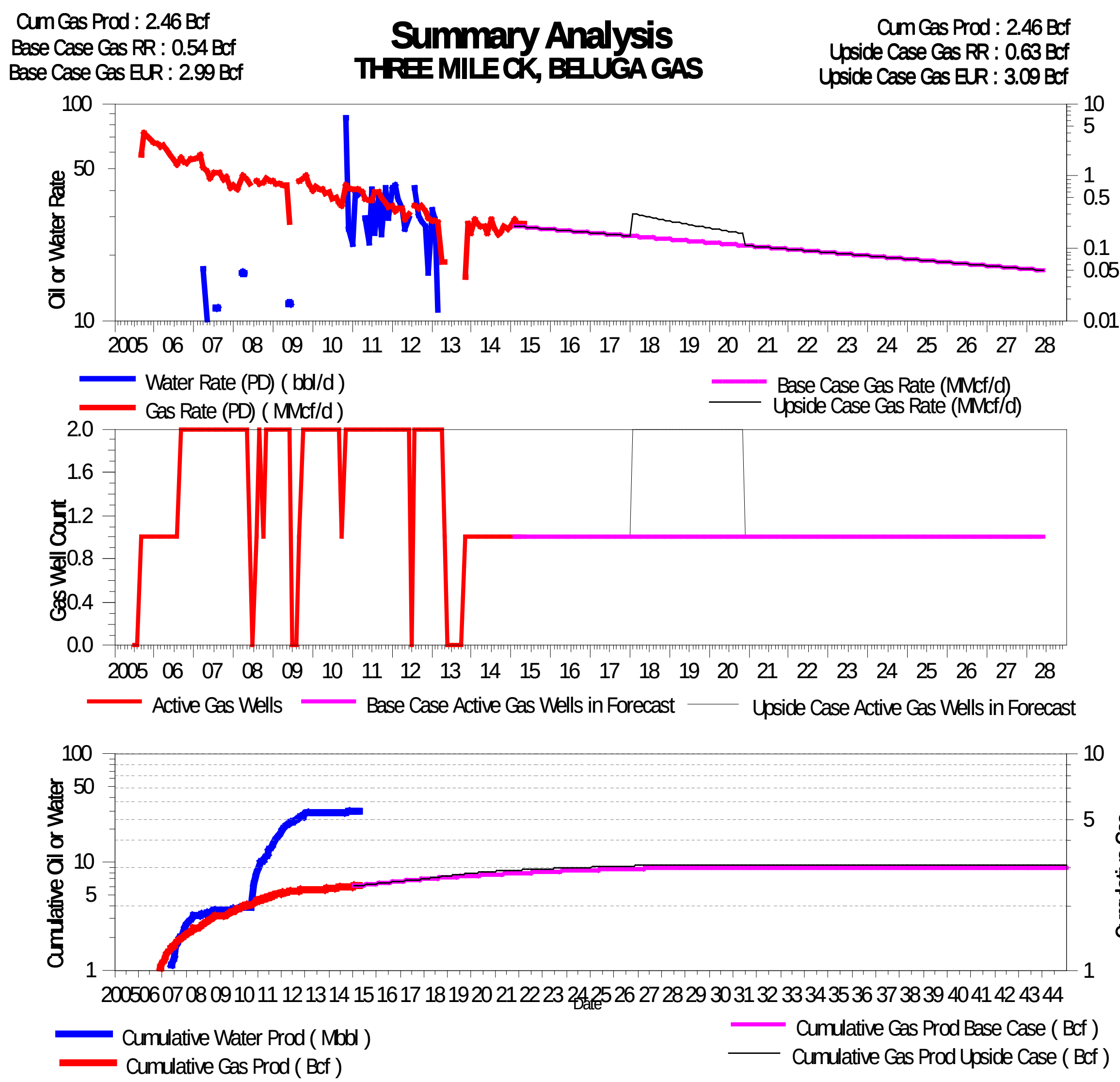

Figure A-66. Three Mile Creek field. Beluga gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

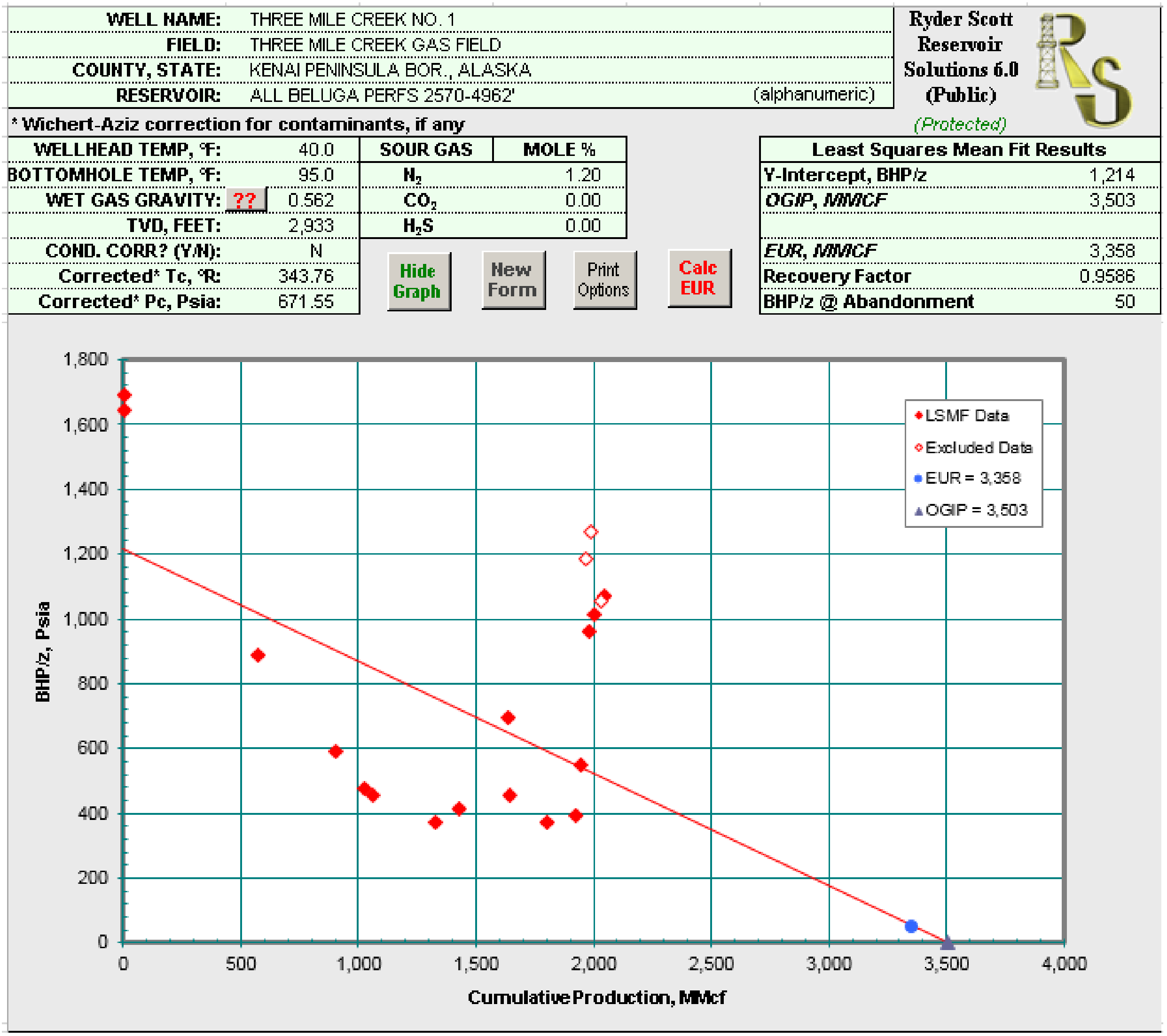

Figure A-67. Material balance and assumptions for Three Mile Creek field, Beluga gas pool, Three Mile Creek No. 1 well. Material balance provided courtesy of Ed Jones using the Normally Pressured Ryder Scott material balance software **(Aurora Gas, LLC, 2015)**.

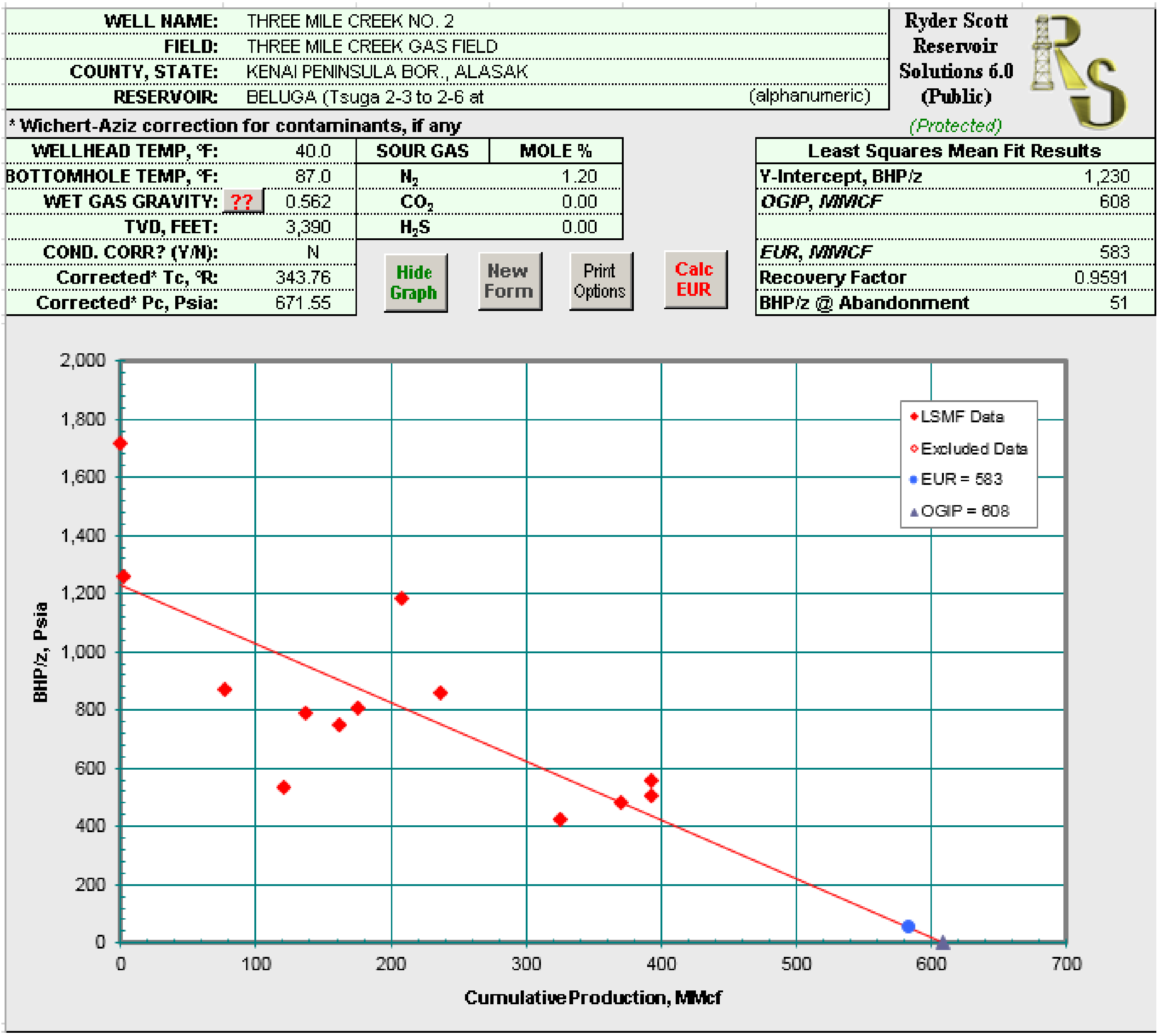

Figure A-68. Material balance and assumptions for Three Mile Creek field, Beluga gas pool, Three Mile Creek No. 2 well. Material balance provided courtesy of Ed Jones using the Normally Pressured Ryder Scott material balance software **(Aurora Gas, LLC, 2015)**.

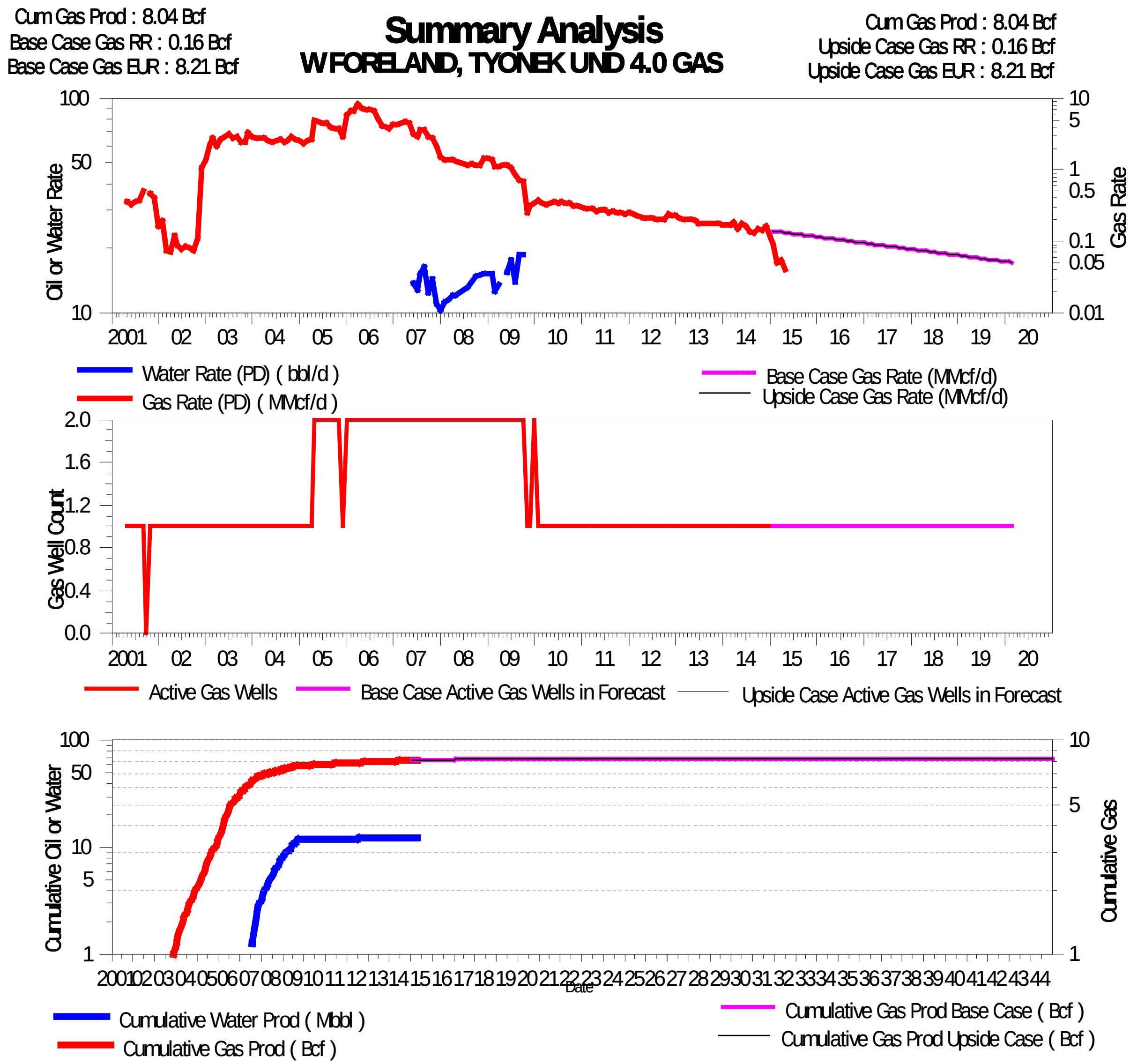

Figure A-69. West Foreland field. Tyonek Undefined 4.0 gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:			
FIELD:	West Foreland		
COUNTY, STATE:	Reservoir Engineer, Islin Munisteri, 5/26/2015		
RESERVOIR:	T 4-0. 9200 ft sand	(alphanumeric)	

Ryder Scott Reservoir Solutions 6.0 (Public) *(Protected)*

* Wichert-Aziz correction for contaminants, if any

		SOUR GAS	MOLE %			Least Squares Mean Fit Results	
WELLHEAD TEMP, °F:	70.0			Print Options	Calc AGIP		
BOTTOMHOLE TEMP, °F:	175.0	N_2	5.40			Y-Intercept, BHP/z	4,402
WET GAS GRAVITY: ??	0.586	CO_2	0.01			*Apparent GIP, MMCF*	8,795
TVD, FEET:	9,200	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	8,767
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	340.90	S_w (dec)	0.25			*EUR, MMCF*	8,669
Corrected* Pc, Psia:	663.77	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9888
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.32			BHP/z @ Abandonment (Adj)	49

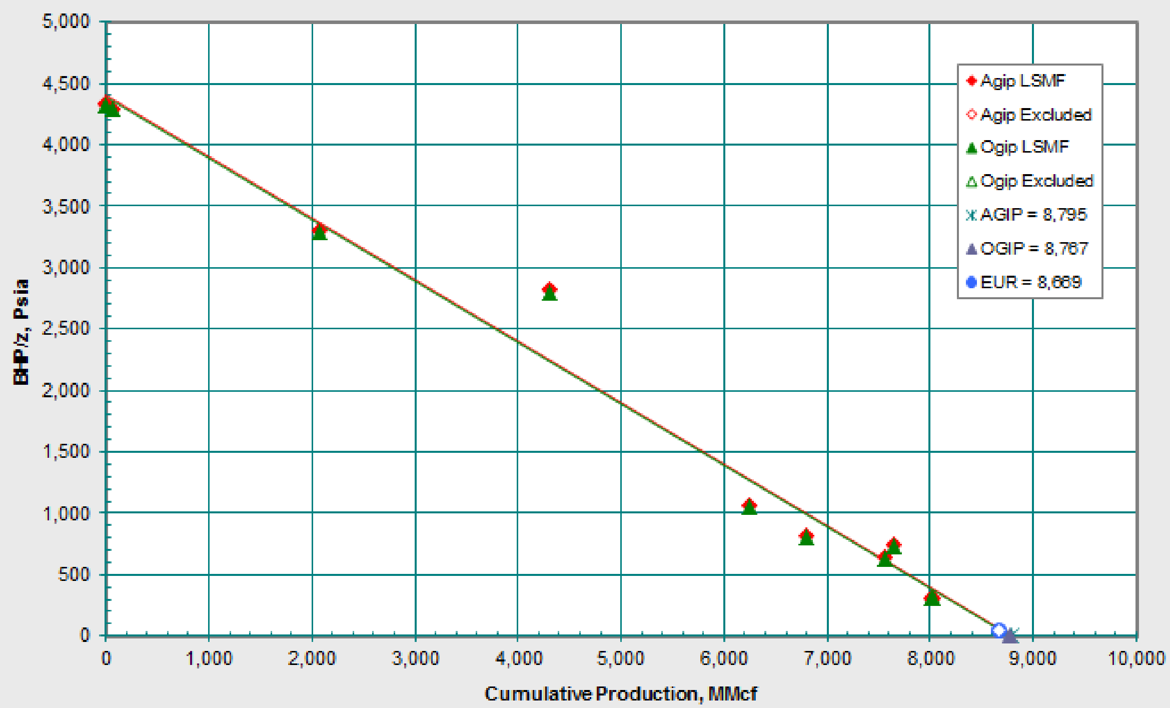

Figure A-70. Material balance and assumptions for West Foreland field, Tyonek Undefined 4.0 gas pool.

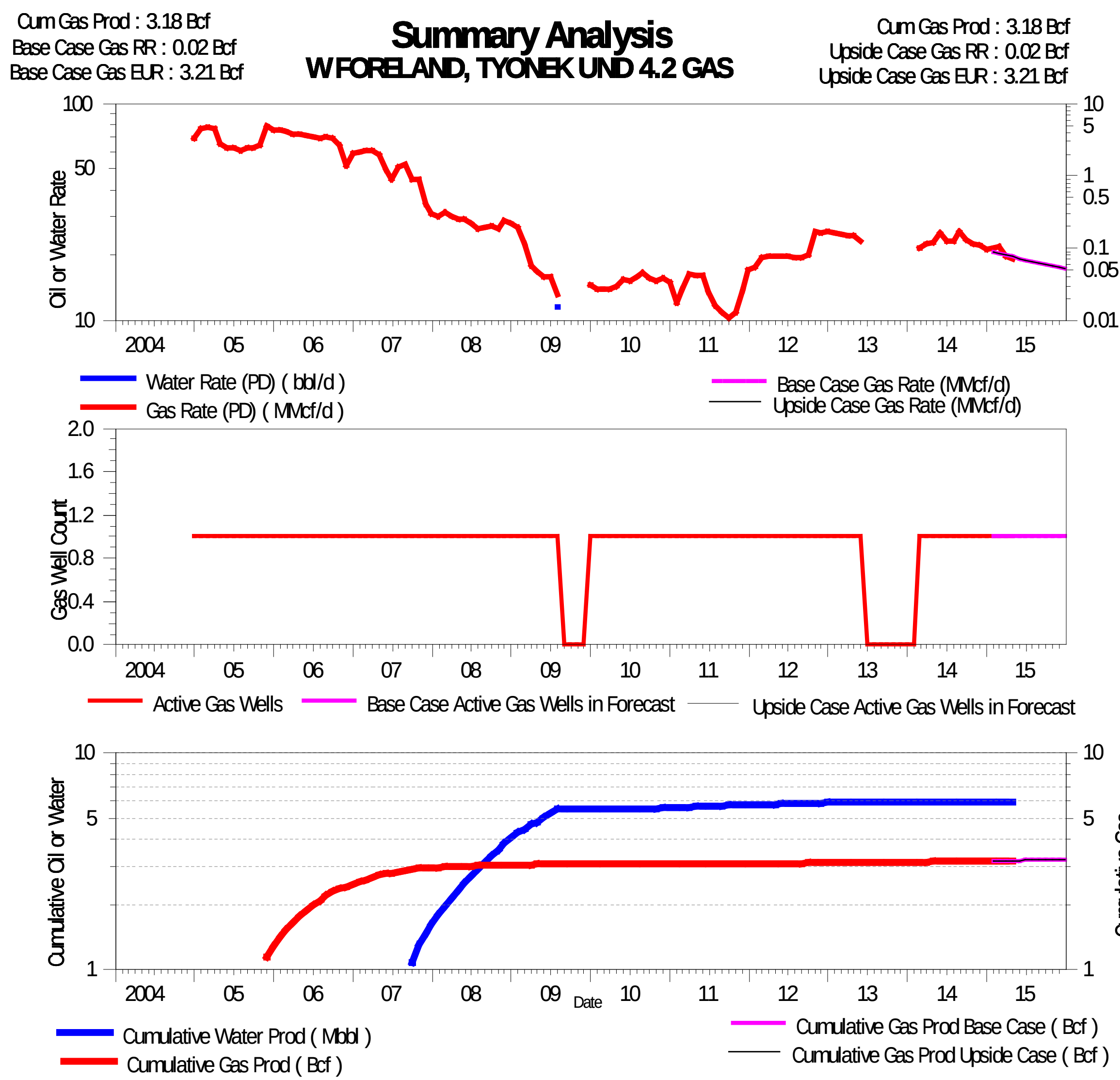

Figure A-71. West Foreland field. Tyonek Undefined 4.2 gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:	
FIELD:	West Foreland
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, 5/26/2015
RESERVOIR:	Tyonek 4-2, 8500 ft reservoir (Comps from Tyonek 4-1)(alphanumeric)

Ryder Scott Reservoir Solutions 6.0 (Public)

(Protected)

* Wichert-Aziz correction for contaminants, if any

		SOUR GAS	MOLE %			Least Squares Mean Fit Results	
WELLHEAD TEMP, °F:	70.0	N_2	5.40	Print Options	Calc AGIP	Y-Intercept, BHP/z	3,817
BOTTOMHOLE TEMP, °F:	162.0	CO_2	0.01			*Apparent GIP, MMCF*	4,361
WET GAS GRAVITY: ??	0.5841	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	4,337
TVD, FEET:	7,985	**Formation Properties**					
COND. CORR.? (Y/N):	N	S_w (dec)	0.25			*EUR, MMCF*	4,281
Corrected* Tc, °R:	340.28	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9871
Corrected* Pc, Psia:	663.81	C_f, µsip ??	3.38			BHP/z @ Abandonment (Adj)	49
V_w/V_g, AcFt/AcFt:	0.00						

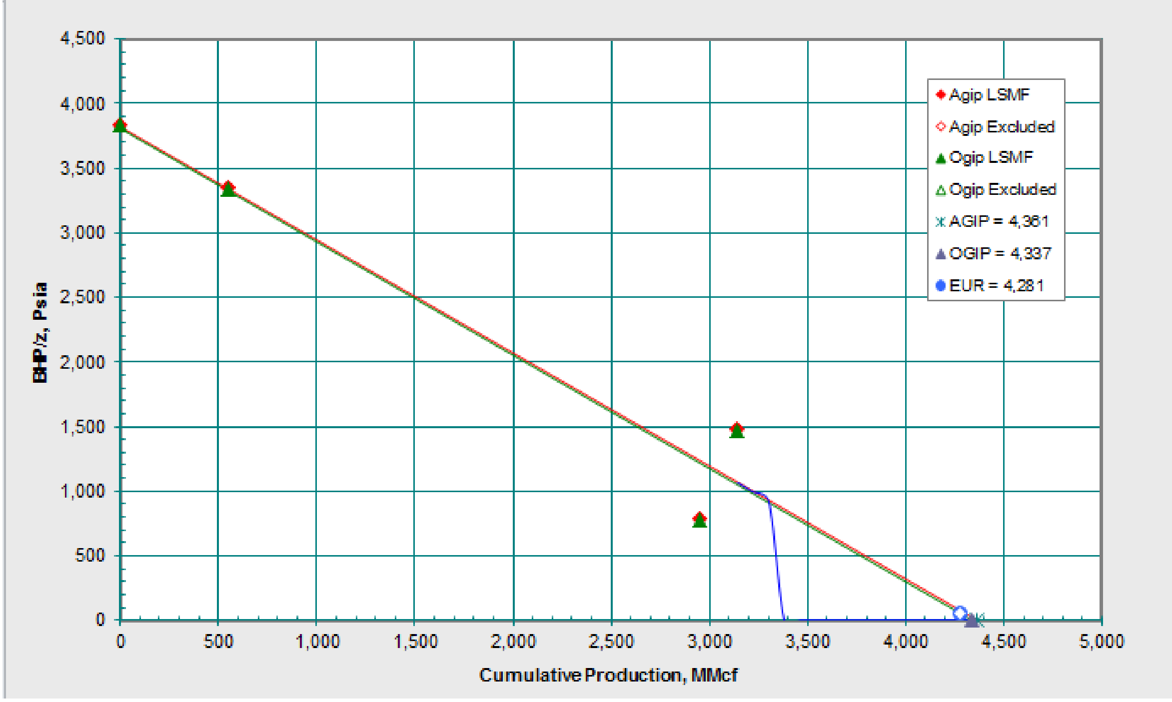

Figure A-72. Material balance and assumptions for West Foreland field, Tyonek Undefined 4.2 gas pool.

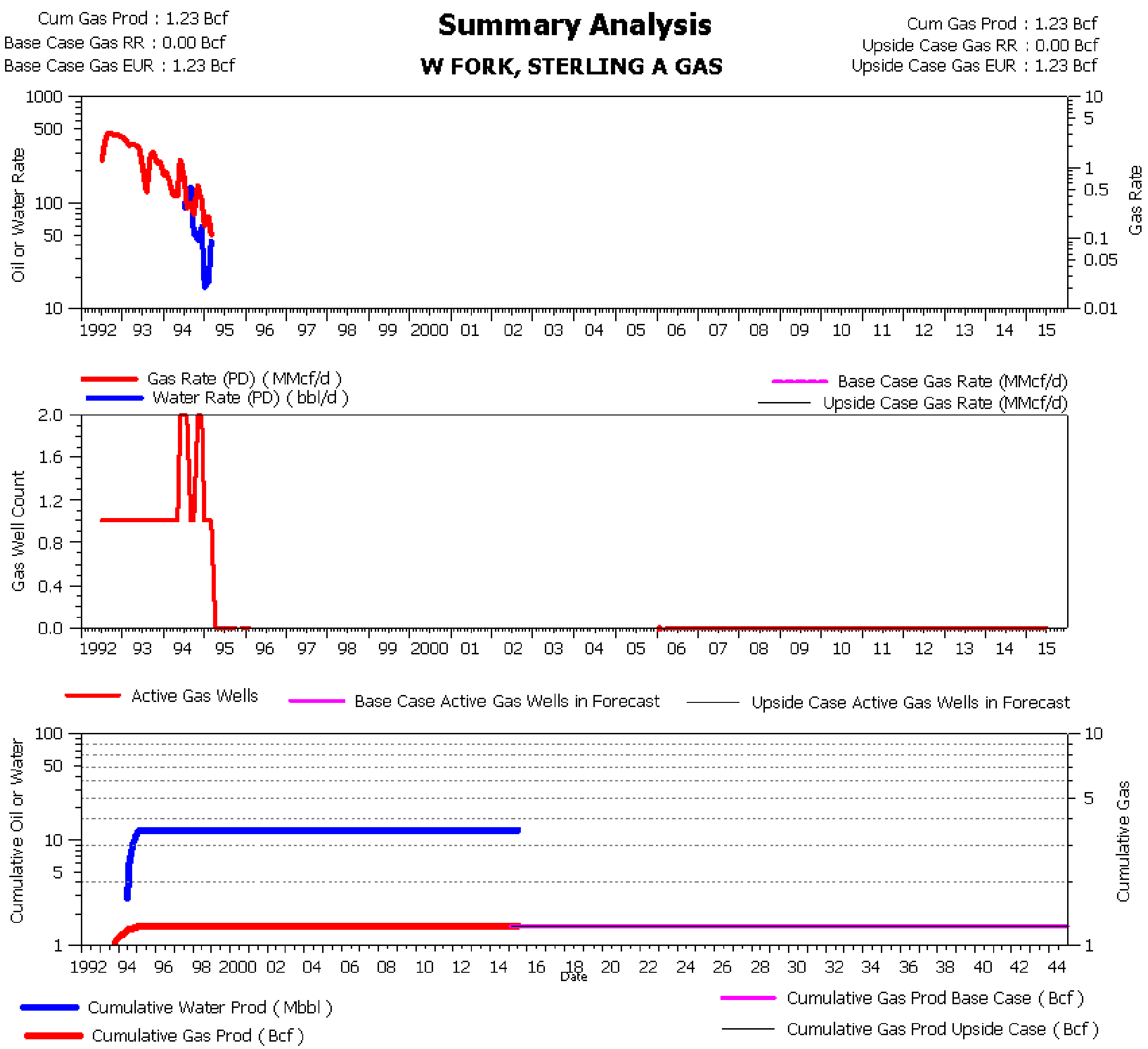

Figure A-73. West Fork field, Sterling A gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

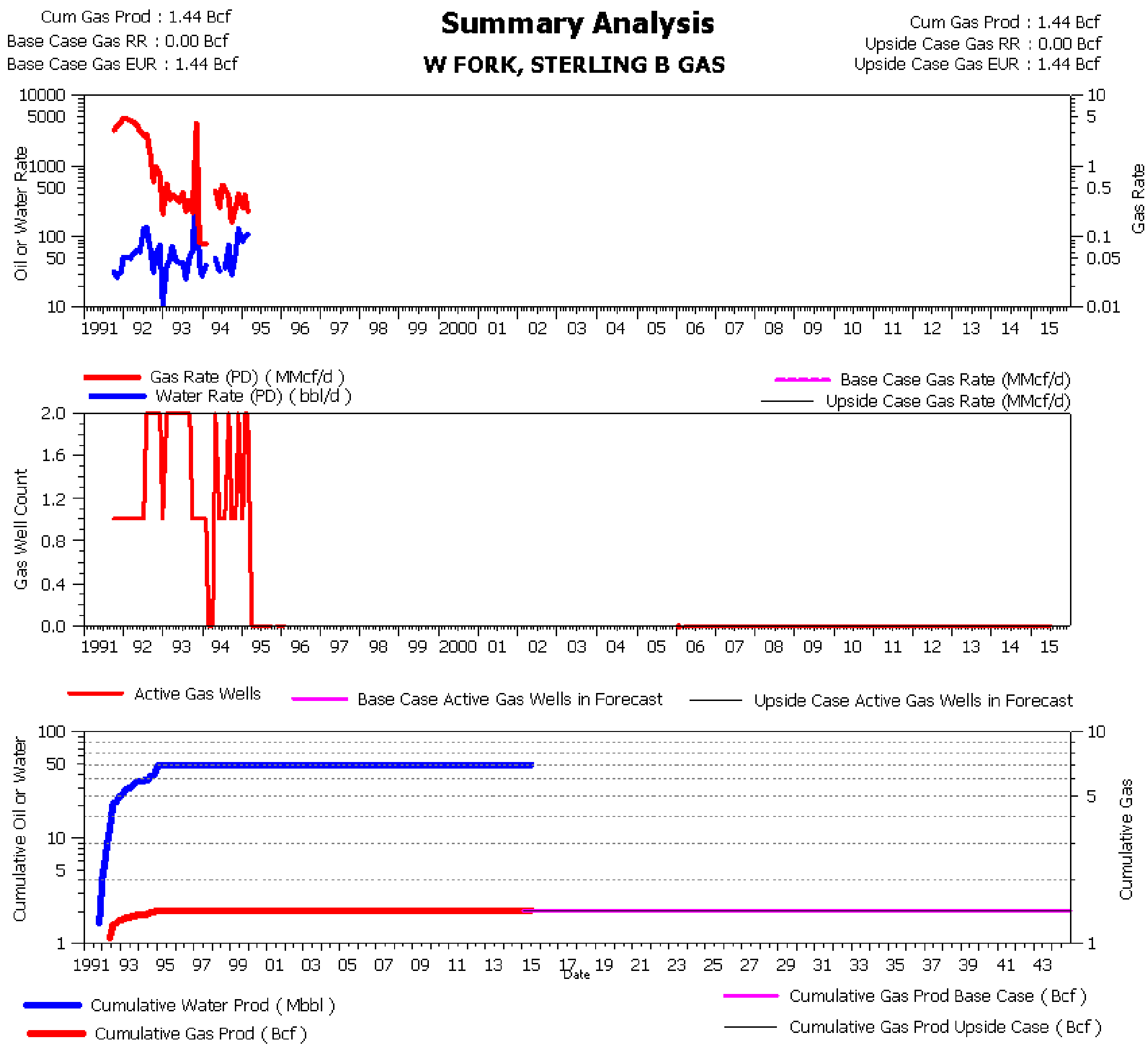

Figure A-74. West Fork field, Sterling B gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

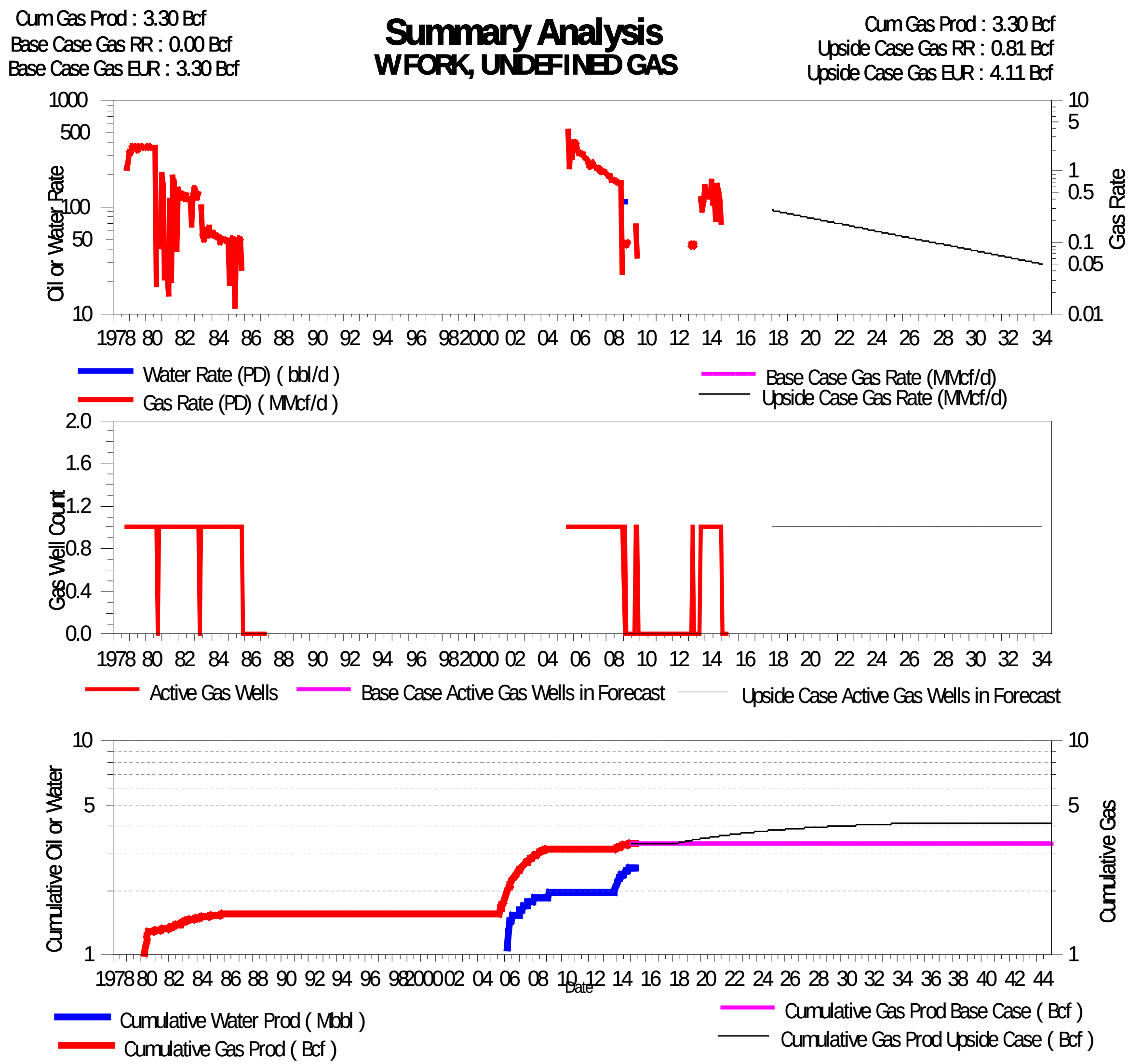

Figure A-75. West Fork field, Undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:			Ryder Scott Reservoir Solutions 6.0 (Public)
FIELD:	West Fork		
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, 5/22/2015		
RESERVOIR:	Undefined	(alphanumeric)	*(Protected)*

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	35.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	**Least Squares Mean Fit Results**	
BOTTOMHOLE TEMP, °F:	132.0	N_2	1.39			Y-Intercept, BHP/z	7,002
WET GAS GRAVITY: ??	0.6	CO_2	0.03			*Apparent GIP, MMCF*	4,047
TVD, FEET:	7,148	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	4,012
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	354.98	S_W (dec)	0.50			*EUR, MMCF*	3,985
Corrected* Pc, Psia:	670.13	C_W, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9932
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.08			BHP/z @ Abandonment (Adj)	45

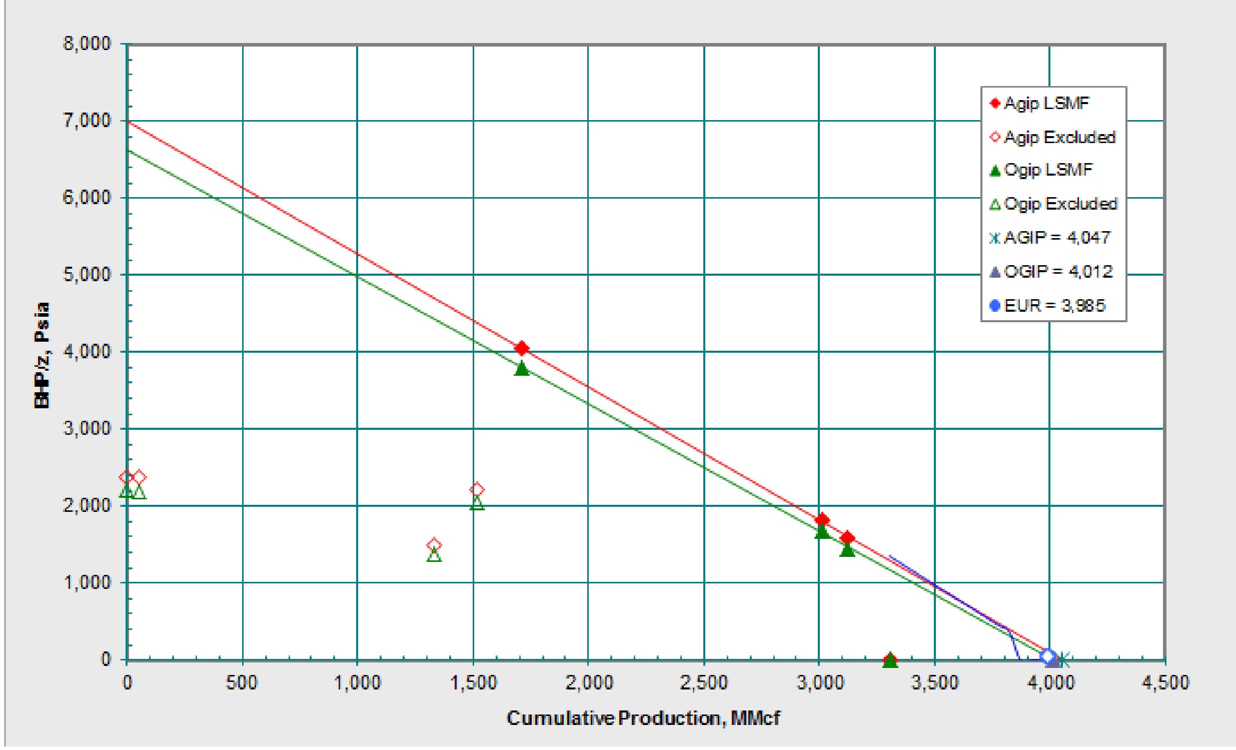

Figure A-76. Material balance and assumptions for West Fork field, Undefined gas pool (producing from the Sterling).

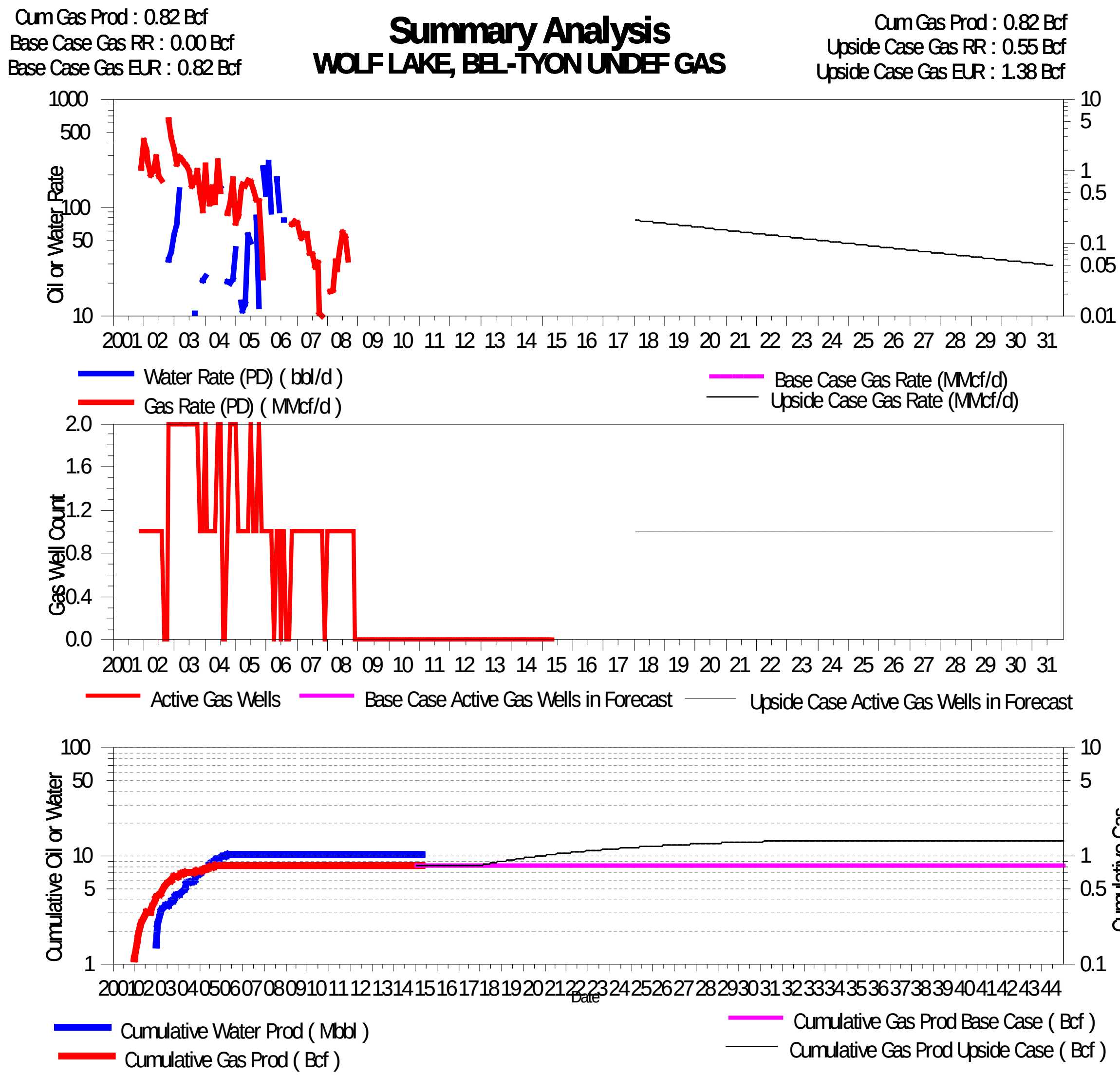

Figure A-77. Wolf Lake field. Beluga-Tyonek undefined gas pool.
Note that upside case remaining reserves include base case remaining reserves. Total upside gas reserves would be the difference of upside case and base case.

WELL NAME:		Ryder Scott Reservoir Solutions 6.0 (Public)
FIELD:	Wolf Lake	
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, June 8, 2015	
RESERVOIR:	Beluga and Tyonek (alphanumeric)	(Protected)

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	125.0	N_2	0.00			Y-Intercept, BHP/z	3,908
WET GAS GRAVITY: ??	0.56	CO_2	0.00	Hide Graph	Calc OGIP	*Apparent GIP, MMCF*	2,461
TVD, FEET:	6,749	H_2S	0.00			*OGIP, MMCF*	2,431
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	346.08	S_w (dec)	0.35	New Form	Calc EUR	*EUR, MMCF*	2,400
Corrected* Pc, Psia:	673.64	C_w, µsip ??	3.00			Recovery Factor	0.9874
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.32			BHP/z @ Abandonment (Adj)	50

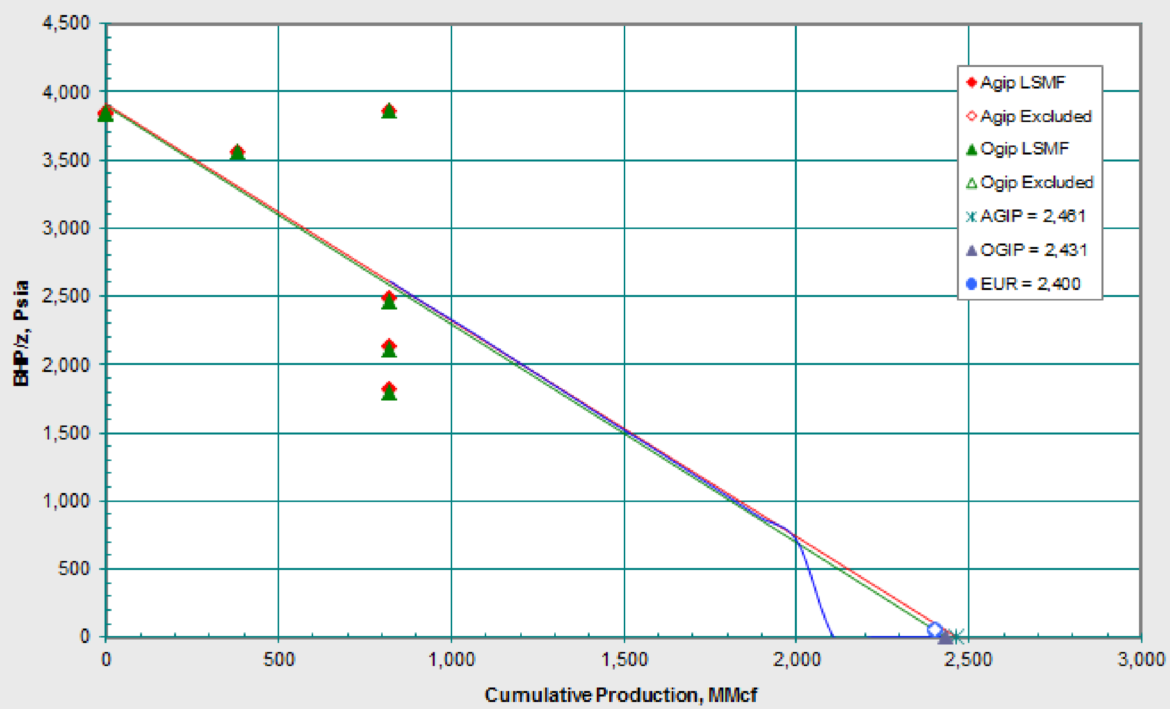

Figure A-78. Material balance and assumptions for Wolf Lake field, Beluga-Tyonek Undefined gas pool.

Appendix B. Summaries of EUR for Gas Pools, with Decline Analysis Conducted on a Pool Basis Due to Platform Abandonment Rates

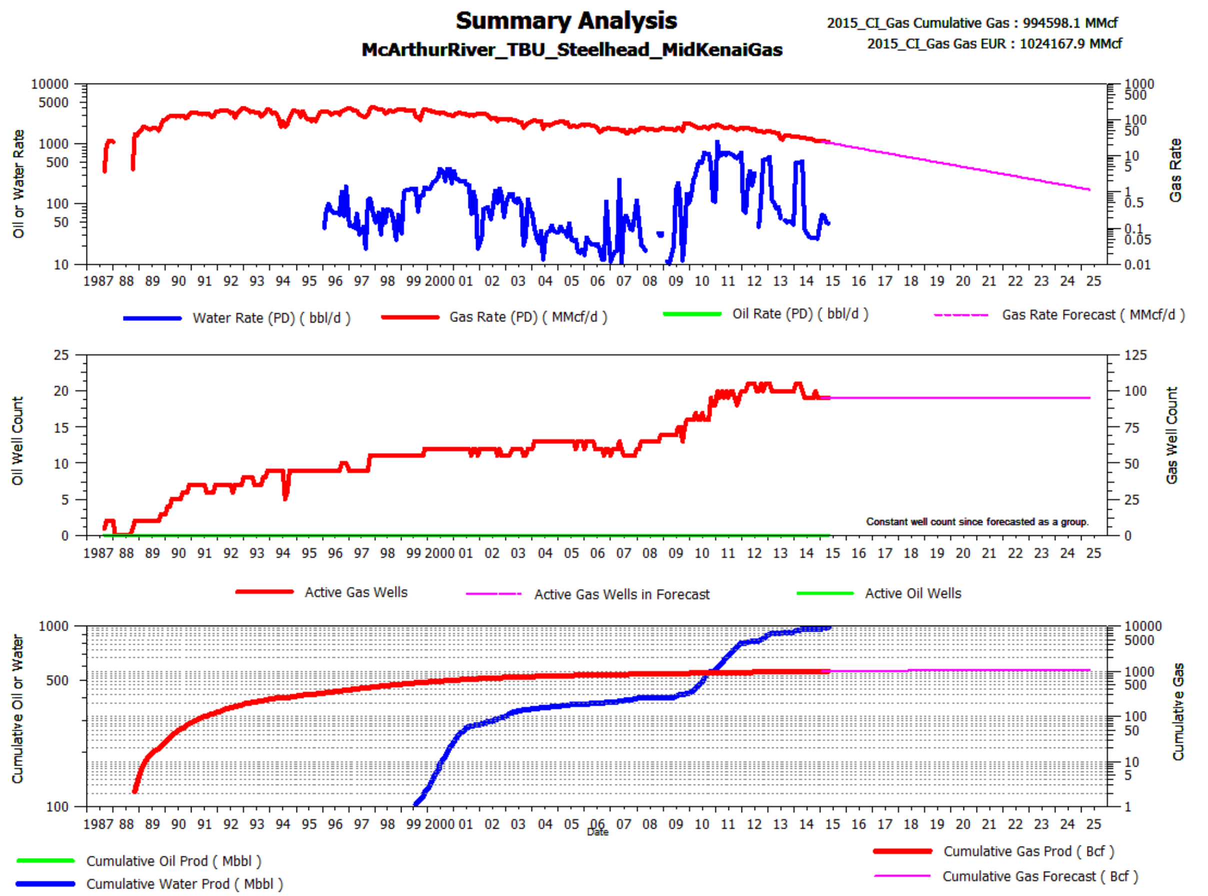

Figure B-1. McArthur River Field, Mid Kenai Gas pool, producing to the Steelhead platform.

WELL NAME:			Ryder Scott Reservoir Solutions 6.0 (Public)
FIELD:	McArthur River		*(Protected)*
COUNTY, STATE:	Reservoir Engineer: Islin Munisteri, May 29, 2015		
RESERVOIR:	Grayling Gas Sands (Tyonek Mid Kenai Gas)	(alphanumeric)	

* Wichert-Aziz correction for contaminants, if any

WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	**Least Squares Mean Fit Results**	
BOTTOMHOLE TEMP, °F:	120.0	N_2	0.00			Y-Intercept, BHP/z	2,268
WET GAS GRAVITY: ??	0.564	CO_2	0.00			*Apparent GIP, MMCF*	1,310,799
TVD, FEET:	4,500	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	1,305,958
COND. CORR.? (Y/N):	N	**Formation Properties**					
Corrected* Tc, °R:	347.32	S_w (dec)	0.36			*EUR, MMCF*	1,275,438
Corrected* Pc, Psia:	673.53	C_w, µsip ??	3.00	New Form	Calc EUR	Recovery Factor	0.9766
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	3.51			BHP/z @ Abandonment (Adj)	53

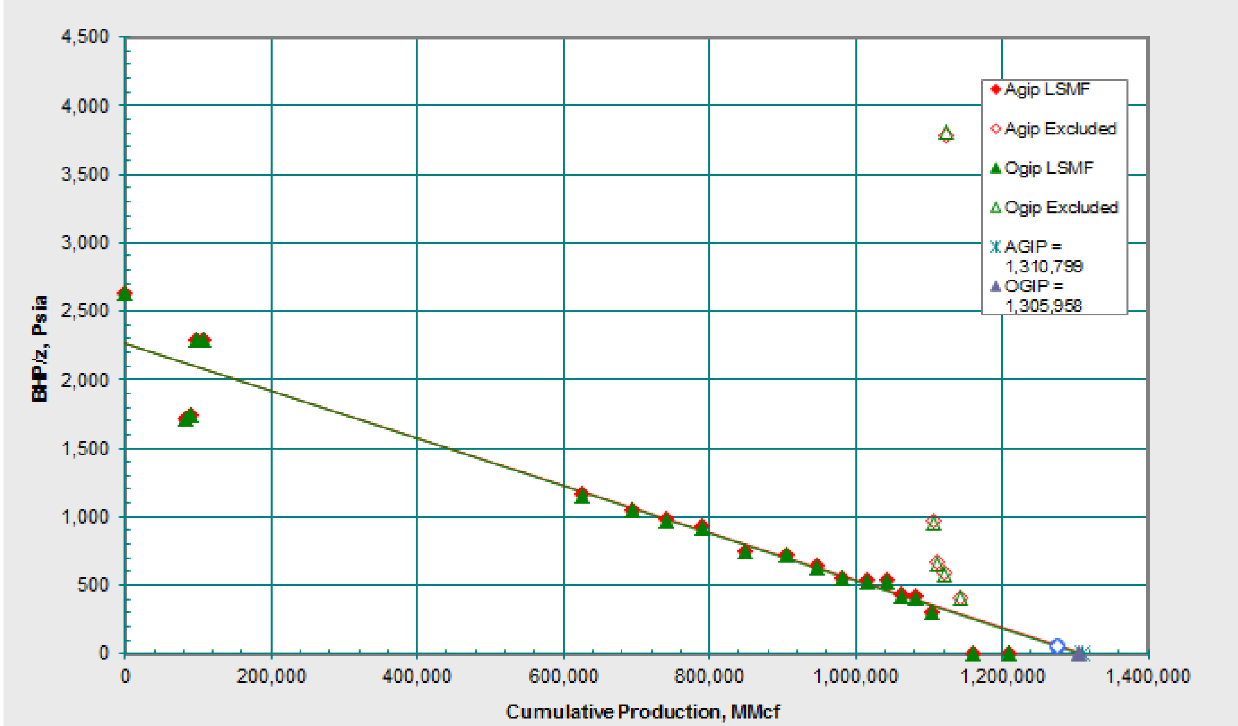

Figure B-2. Material balance and assumptions for McArthur River field Mid Kenai gas pool (producing from the Tyonek).

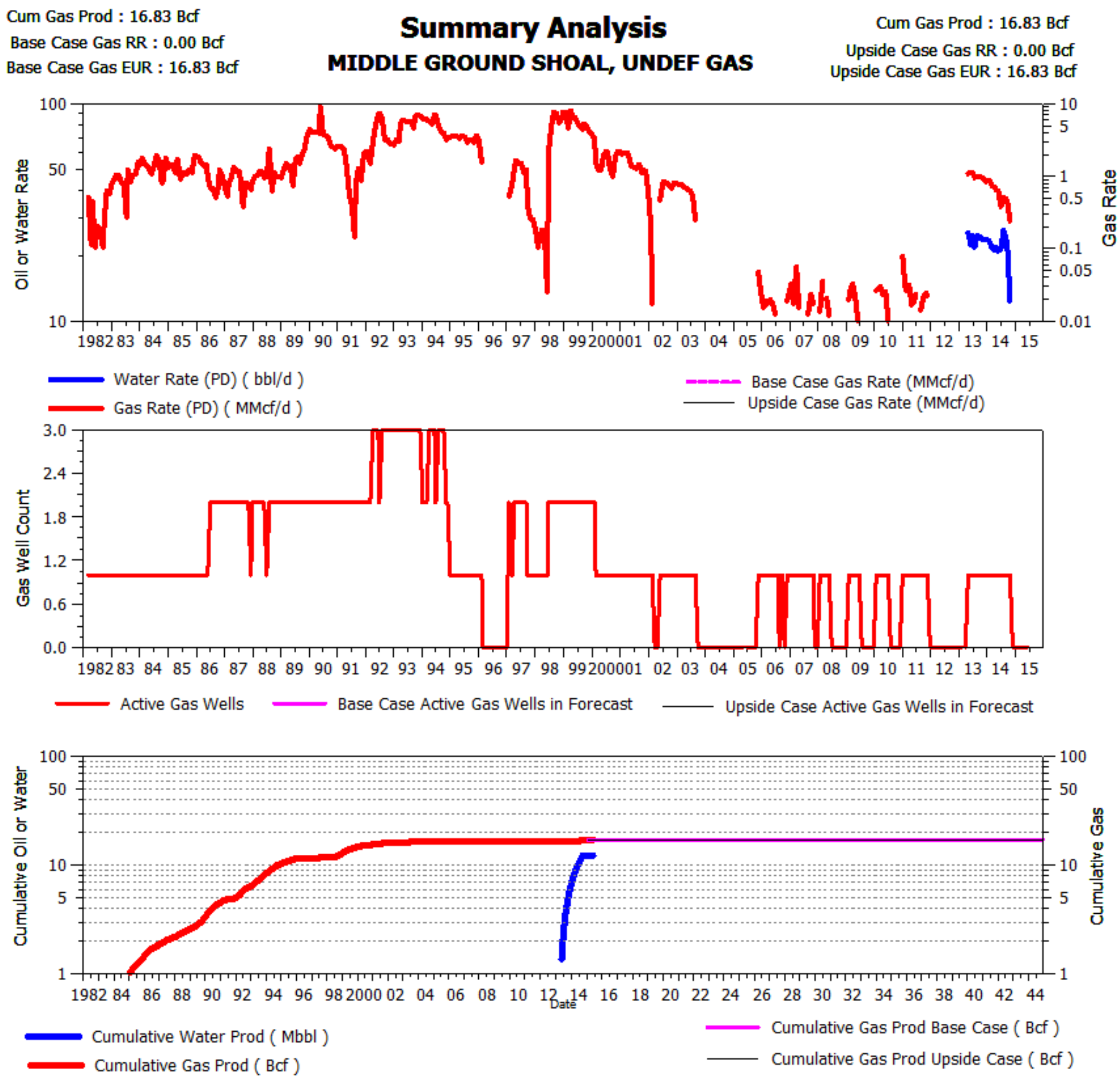

Figure B-3. Middle Ground Shoal field, Undefined gas pool, producing to the Steelhead platform.

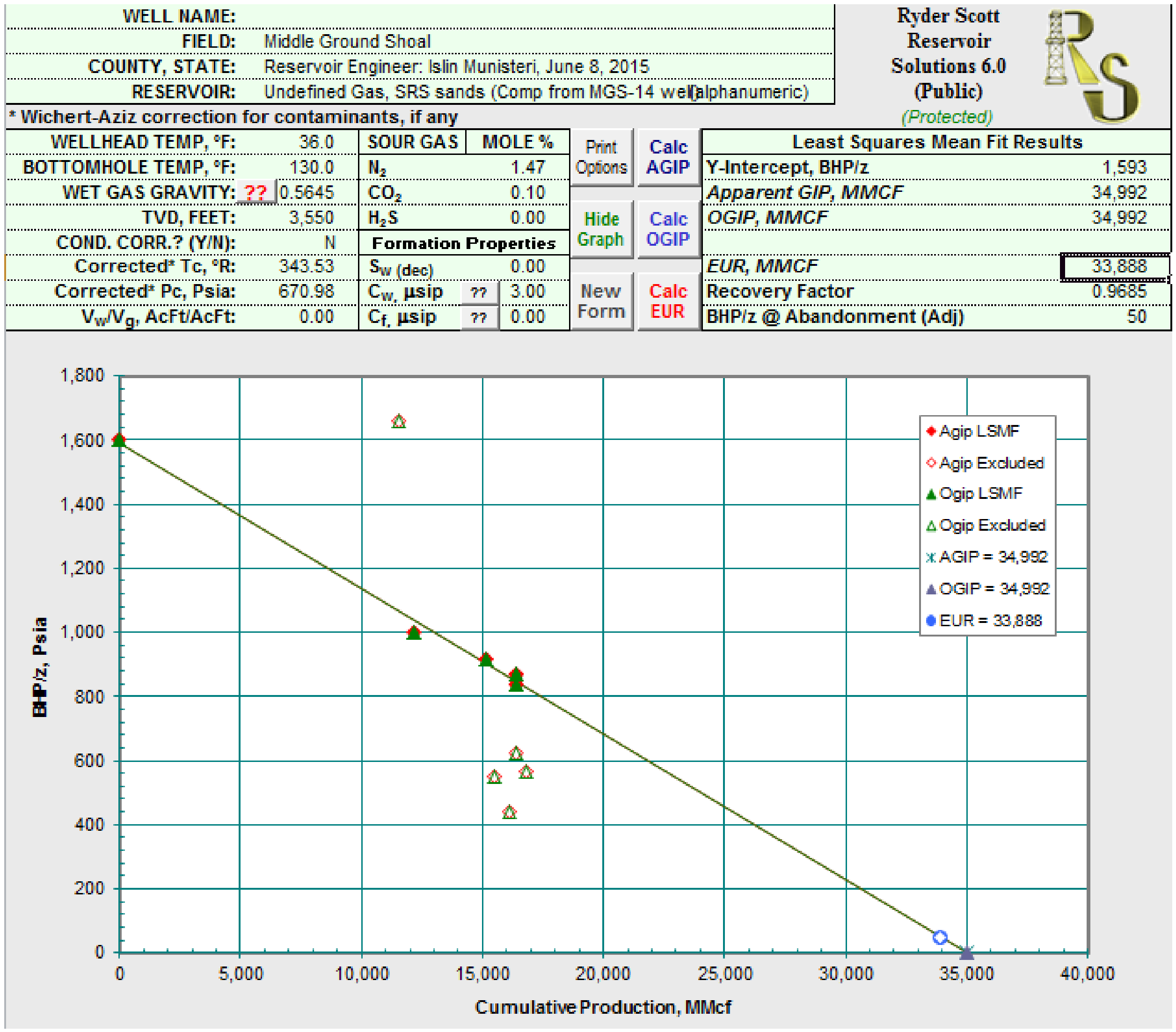

Figure B-4. Material balance and assumptions for Middle Ground Shoal field, Undefined gas pool.

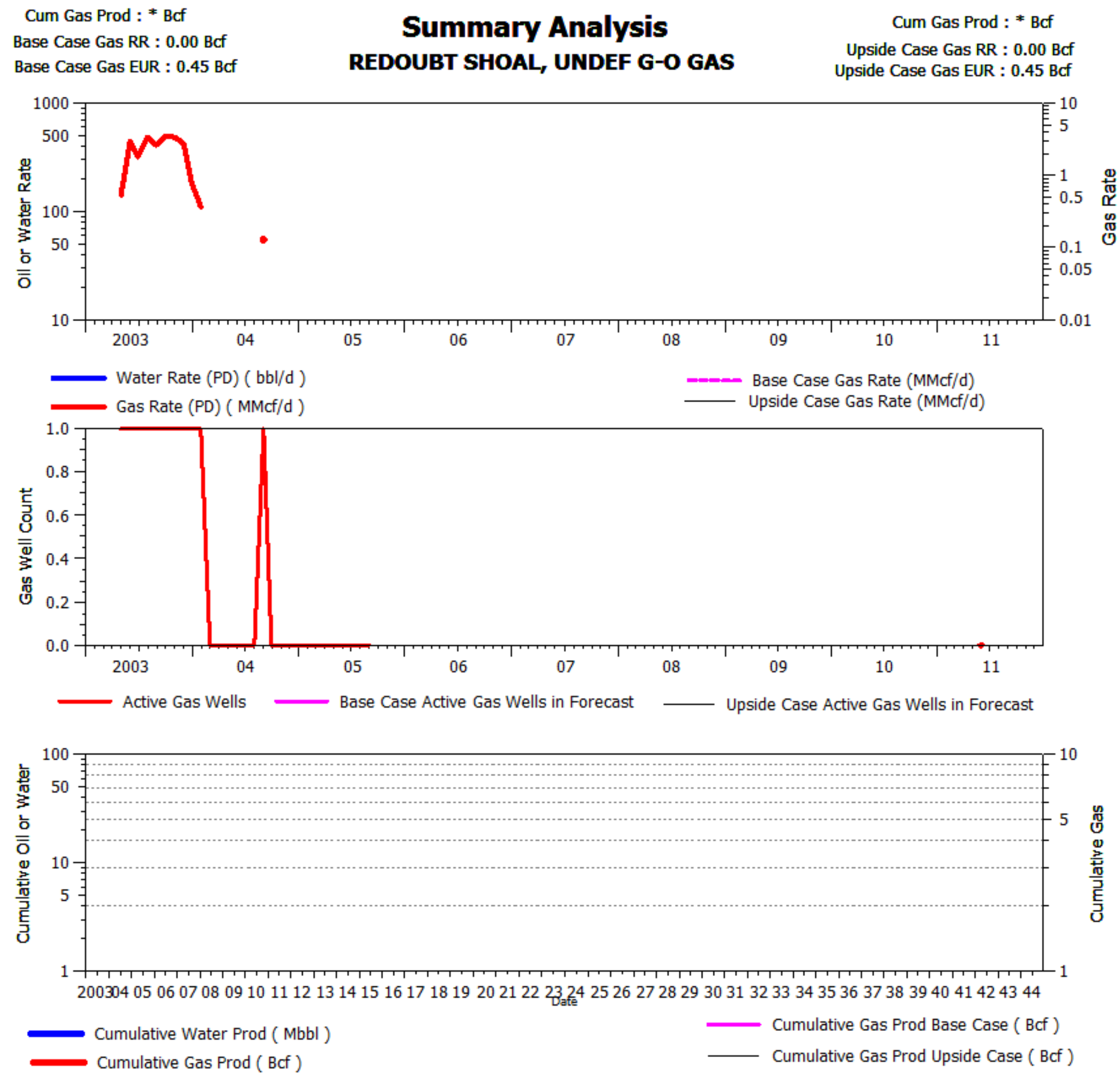

Figure B-5. Middle Ground Shoal field, Undefined G-O gas pool (produces from the Beluga).

WELL NAME:						Ryder Scott Reservoir Solutions 6.0 (Public) (Protected)	
FIELD:	Redoubt						
COUNTY, STATE:	July 8, 2015, Reservoir Engineer: Islin Munisteri						
RESERVOIR:	Undefined G-O Gas (RU-3 only) (alphanumeric)						
* Wichert-Aziz correction for contaminants, if any							
WELLHEAD TEMP, °F:	36.0	SOUR GAS	MOLE %	Print Options	Calc AGIP	Least Squares Mean Fit Results	
BOTTOMHOLE TEMP, °F:	190.0	N_2	0.00			Y-Intercept, BHP/z	5,145
WET GAS GRAVITY: ??	0.6	CO_2	0.00			*Apparent GIP, MMCF*	889
TVD, FEET:	11,320	H_2S	0.00	Hide Graph	Calc OGIP	*OGIP, MMCF*	870
COND. CORR.? (Y/N):	N	Formation Properties					
Corrected* Tc, °R:	358.50	S_w (dec)	0.38	New Form	Calc EUR	*EUR, MMCF*	862
Corrected* Pc, Psia:	672.50	C_w, µsip ??	3.00			Recovery Factor	0.9907
V_w/V_g, AcFt/AcFt:	0.00	C_f, µsip ??	4.11			BHP/z @ Abandonment (Adj)	47

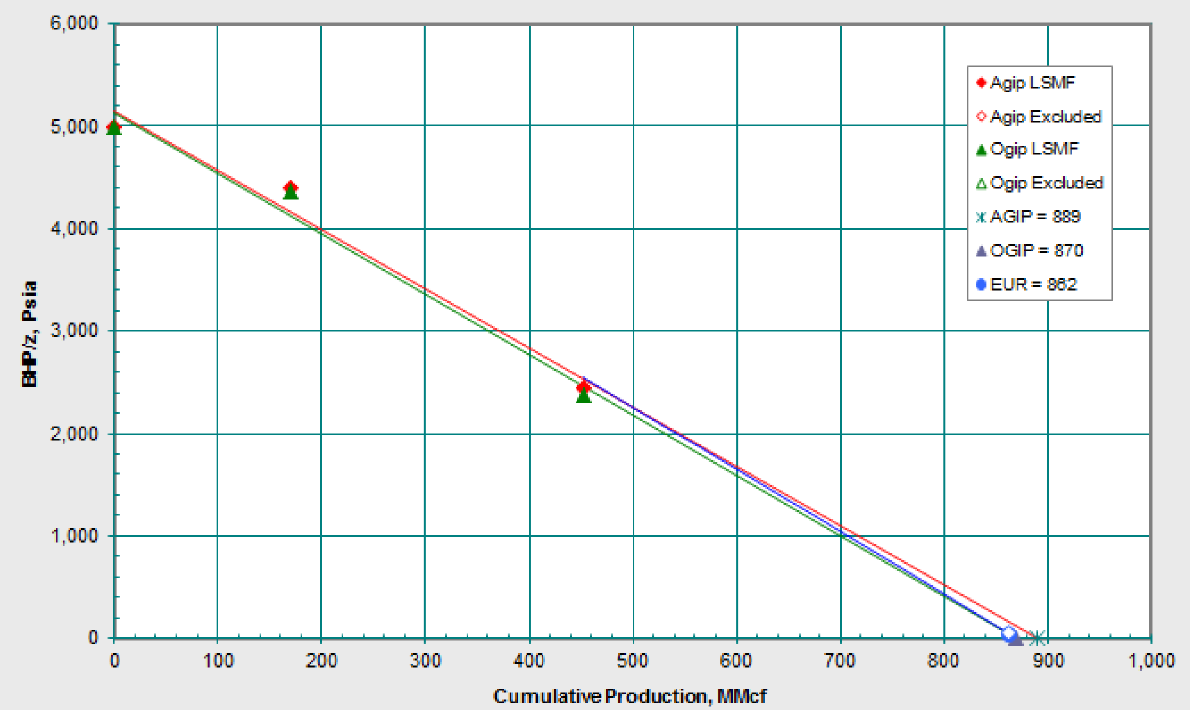

Figure B-6. Material balance and assumptions for Redoubt Shoal field, Undefined G-O gas pool.

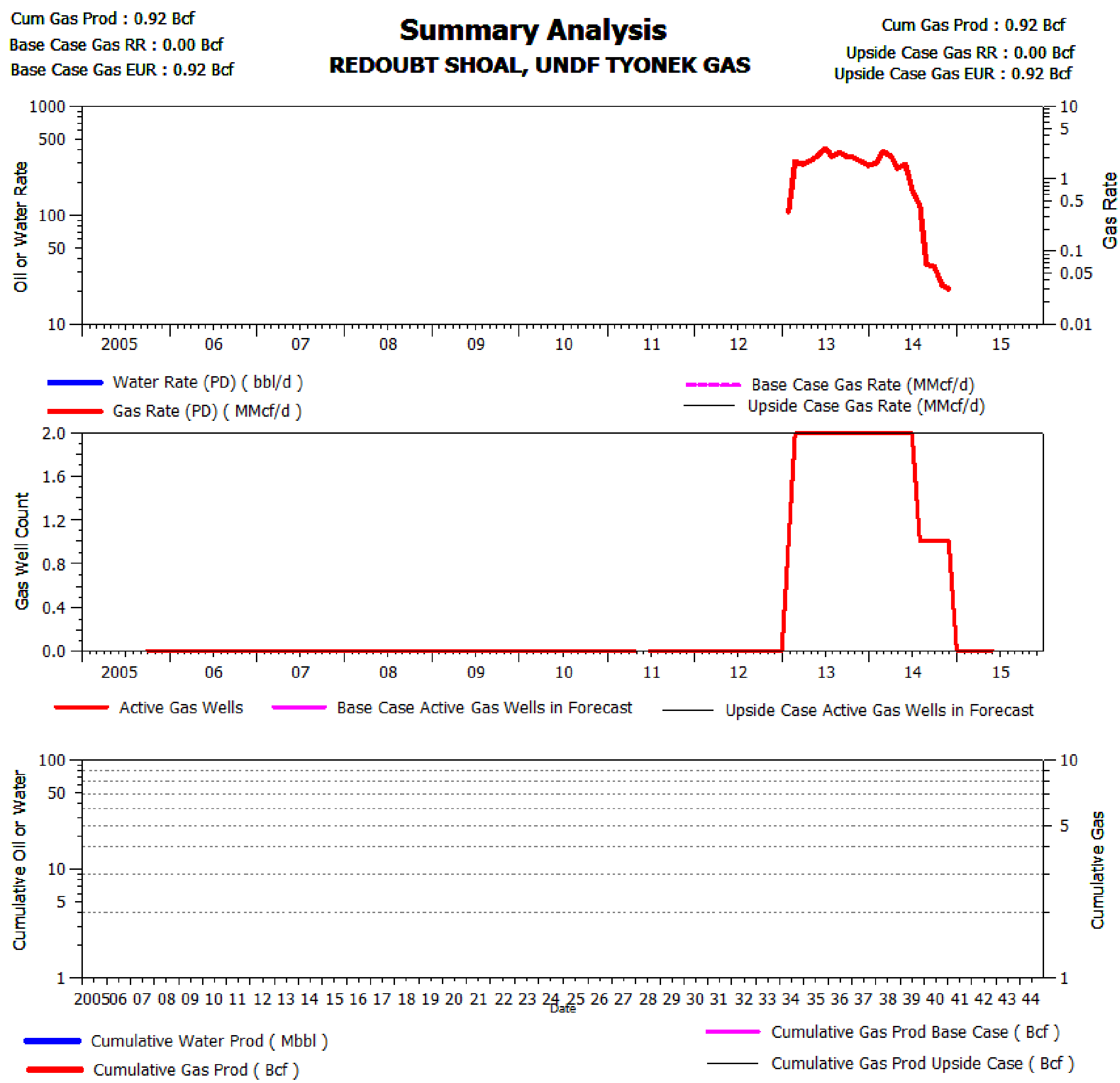

Figure B-7. Middle Ground Shoal field, Undefined Tyonek gas pool.

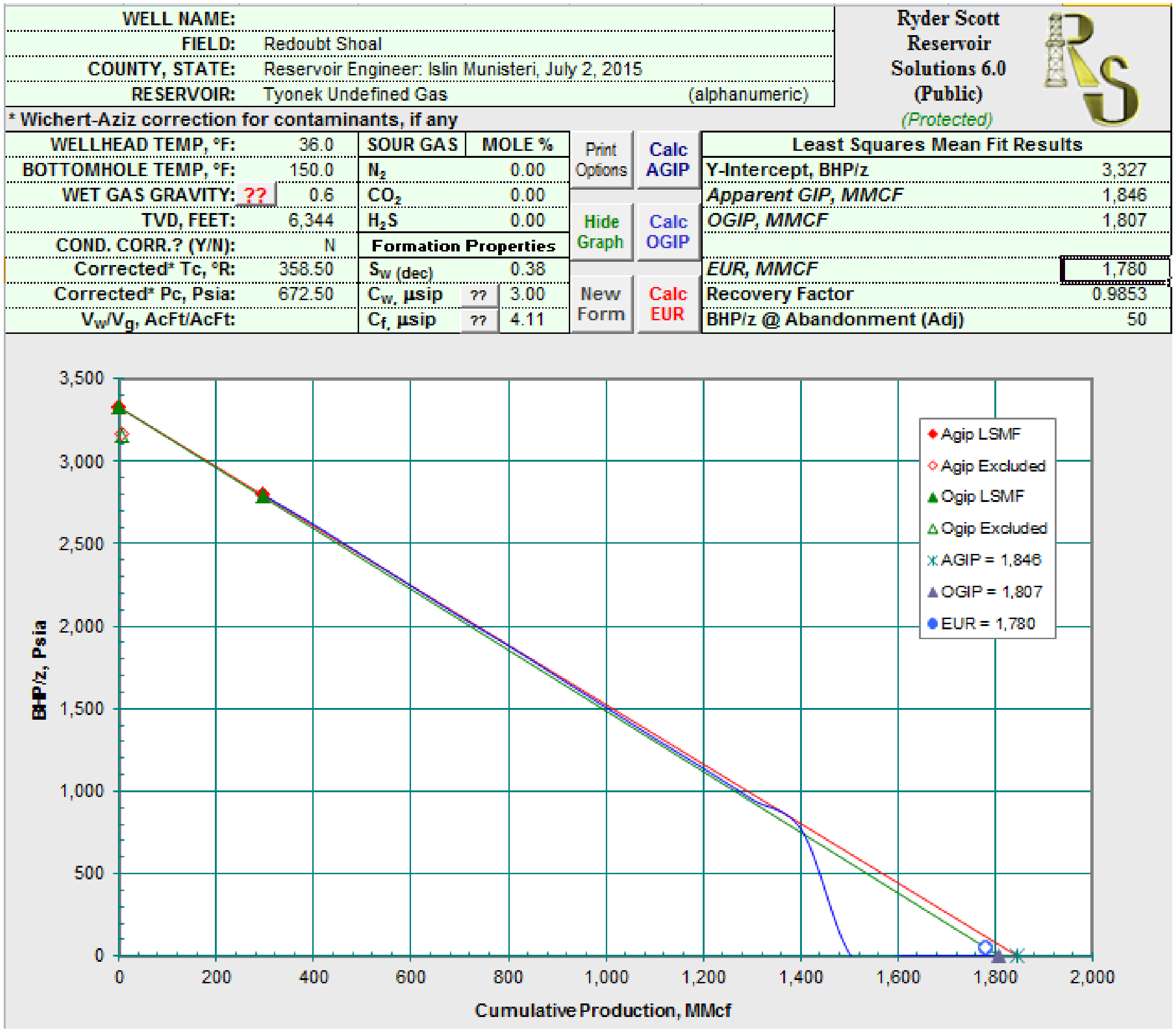

Figure B-8. Material balance and assumptions for Redoubt Shoal field, Tyonek Undefined gas pool.

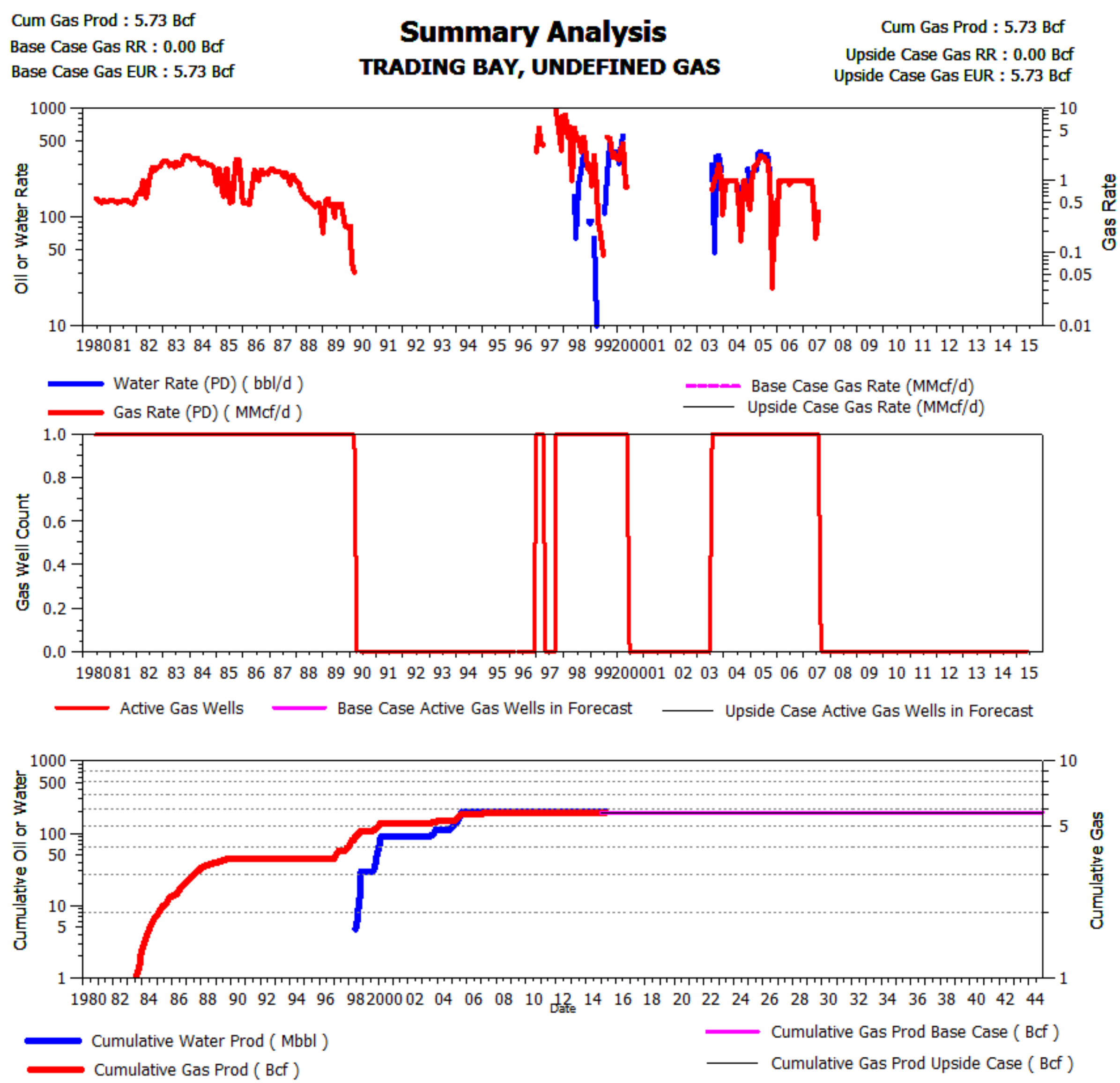

Figure B-9. Middle Ground Shoal field, Undefined gas pool (producing from the Tyonek).

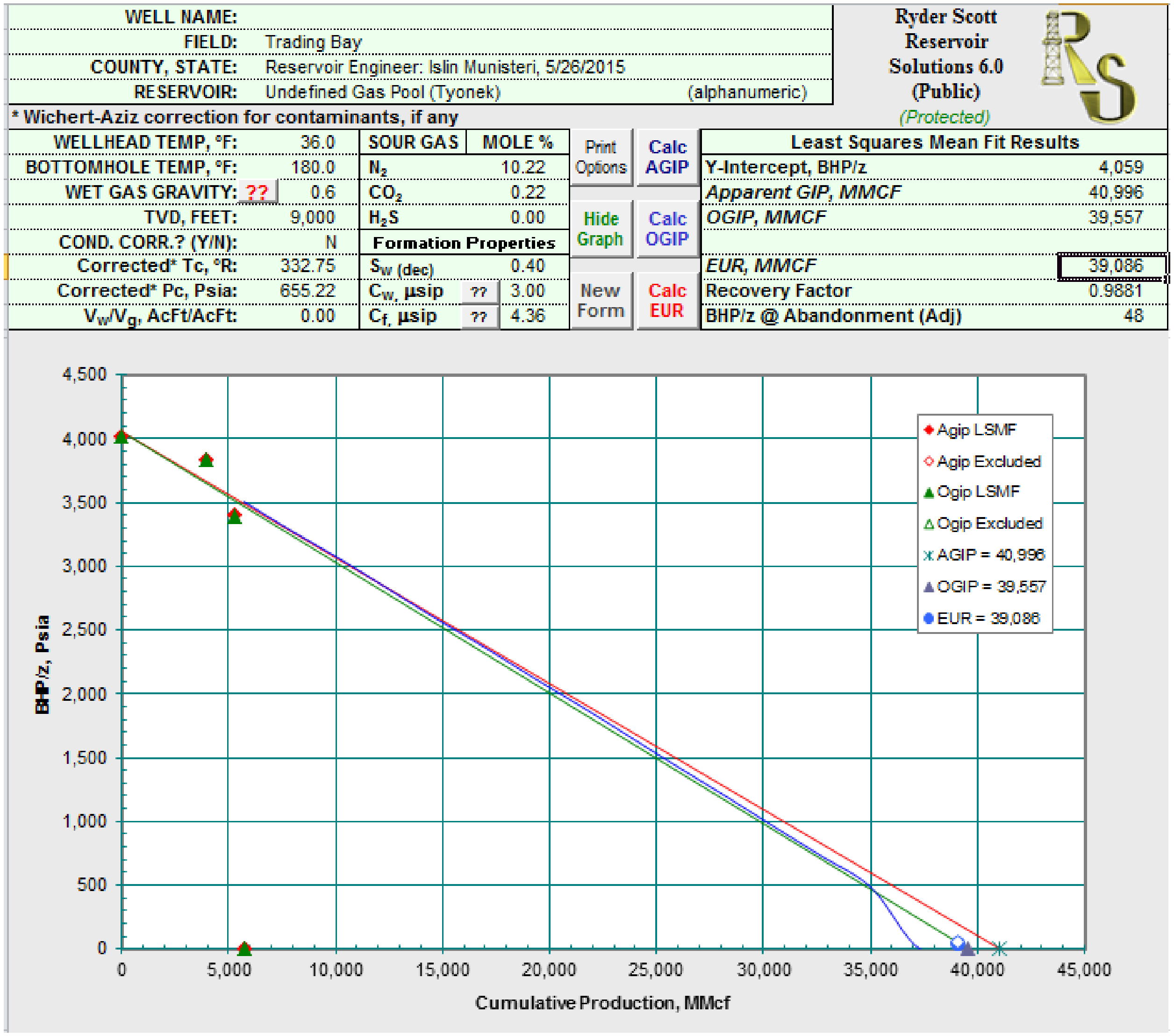

Figure B-10. Material balance and assumptions for Trading Bay field, Undefined gas pool (producing from Tyonek).

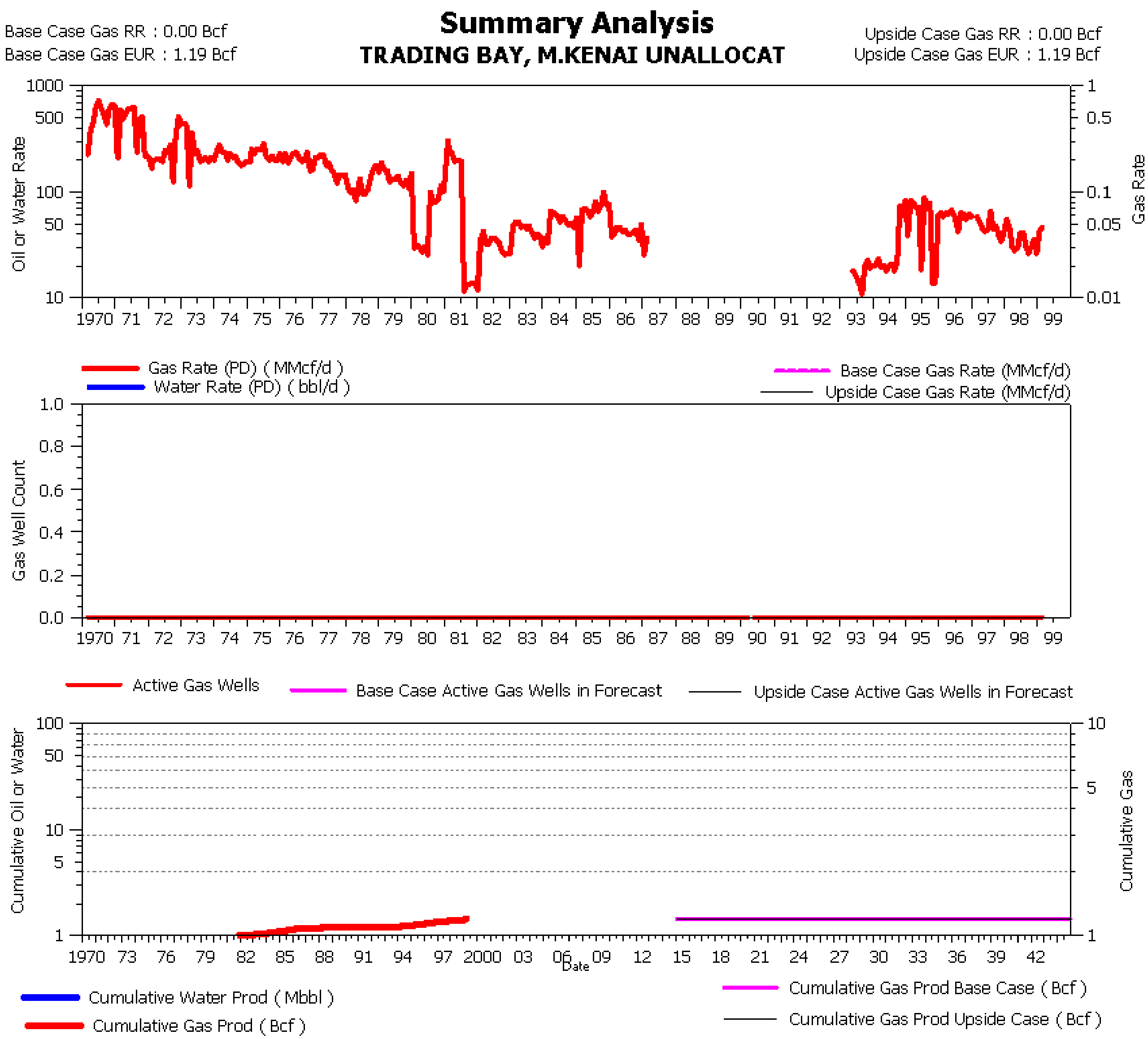

Figure B-11. Trading Bay Field, with Mid Kenai Unallocated gas pool. Included for completeness.

Appendix C. Summaries of EUR for Oil Pools Producing to Offshore Facilities in the Cook Inlet

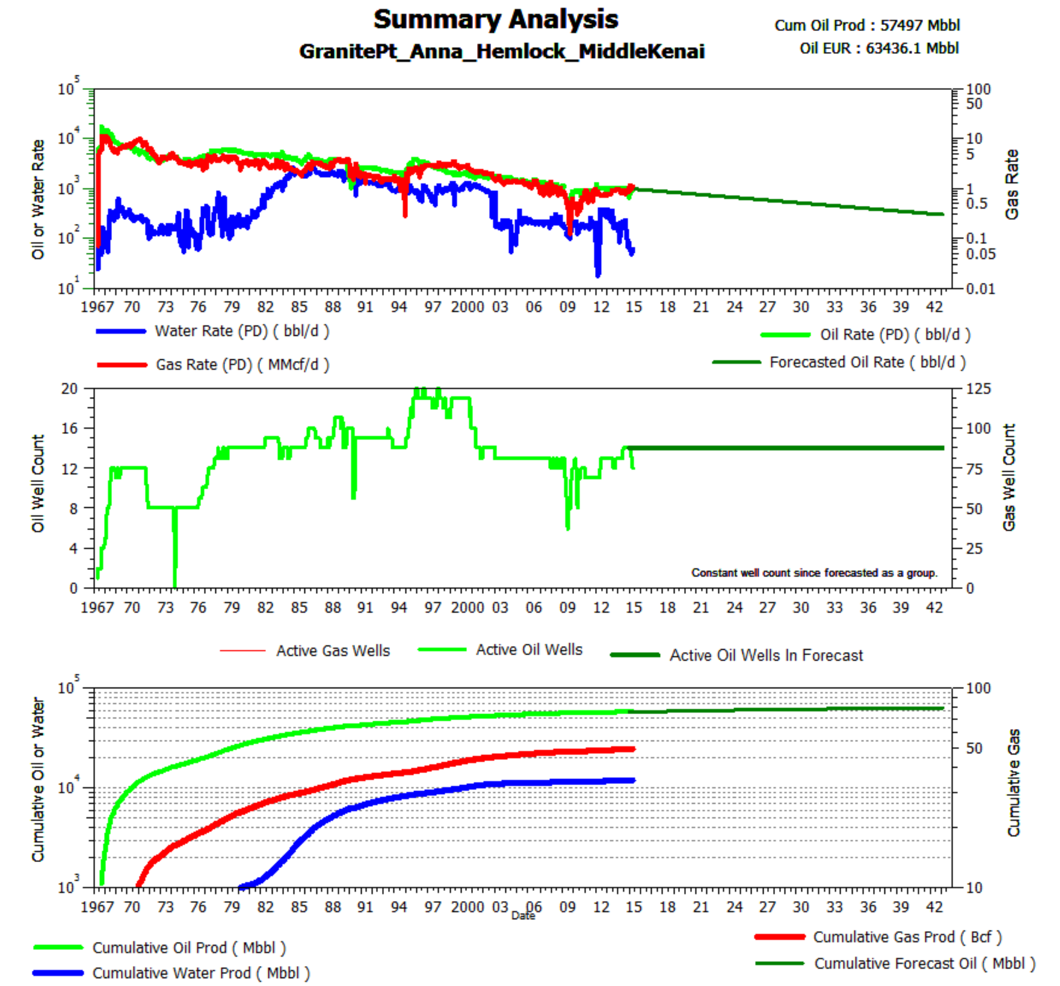

Figure C-1. Granite Point Field, with combined Hemlock and Middle Kenai oil pools, producing to the Anna platform.

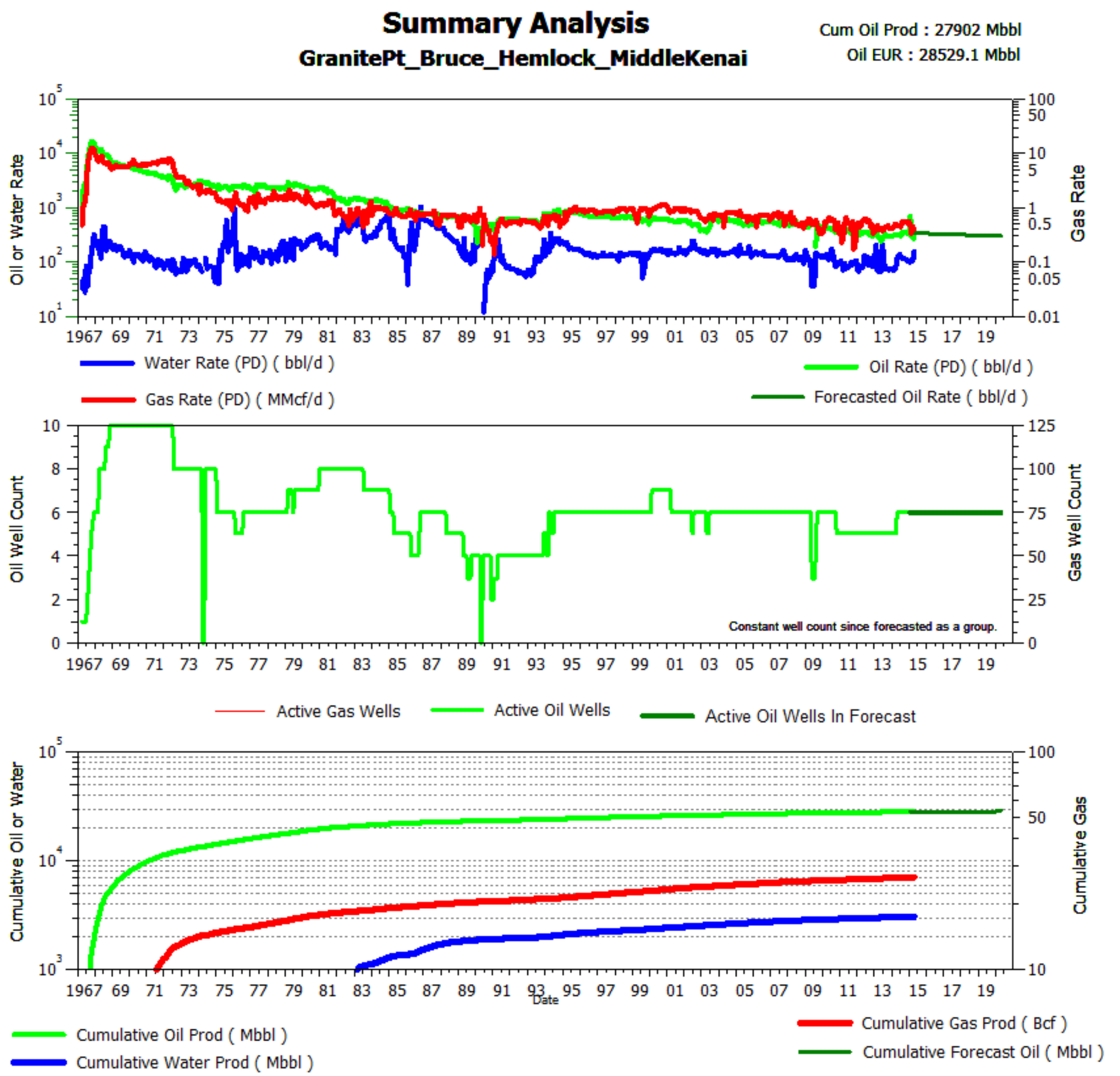

Figure C-2. Granite Point Field, with combined Hemlock and Middle Kenai oil pools, producing to the Bruce platform.

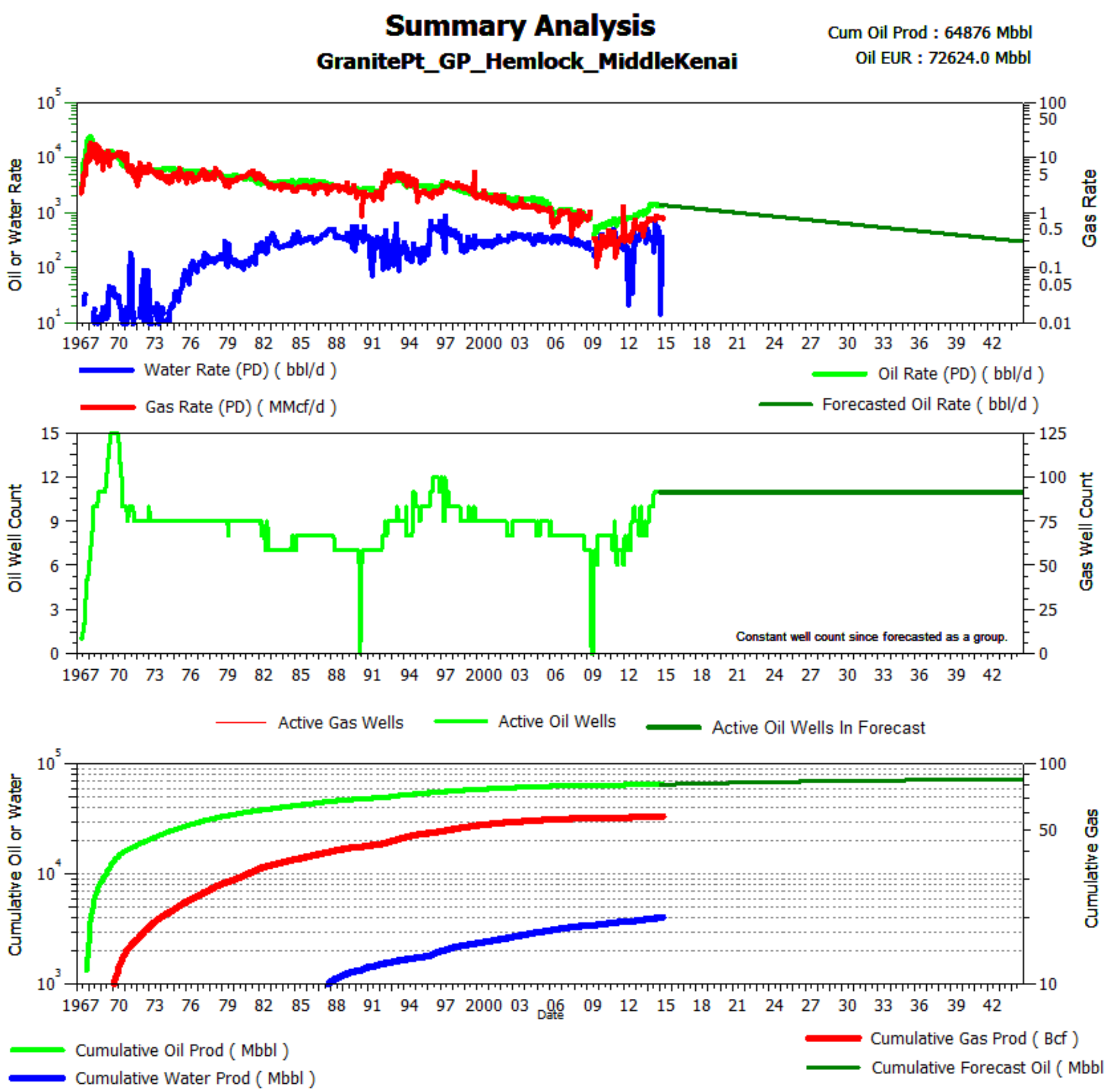

Figure C-3. Granite Point Field, with combined Hemlock and Middle Kenai oil pools, producing to the Granite Point platform.

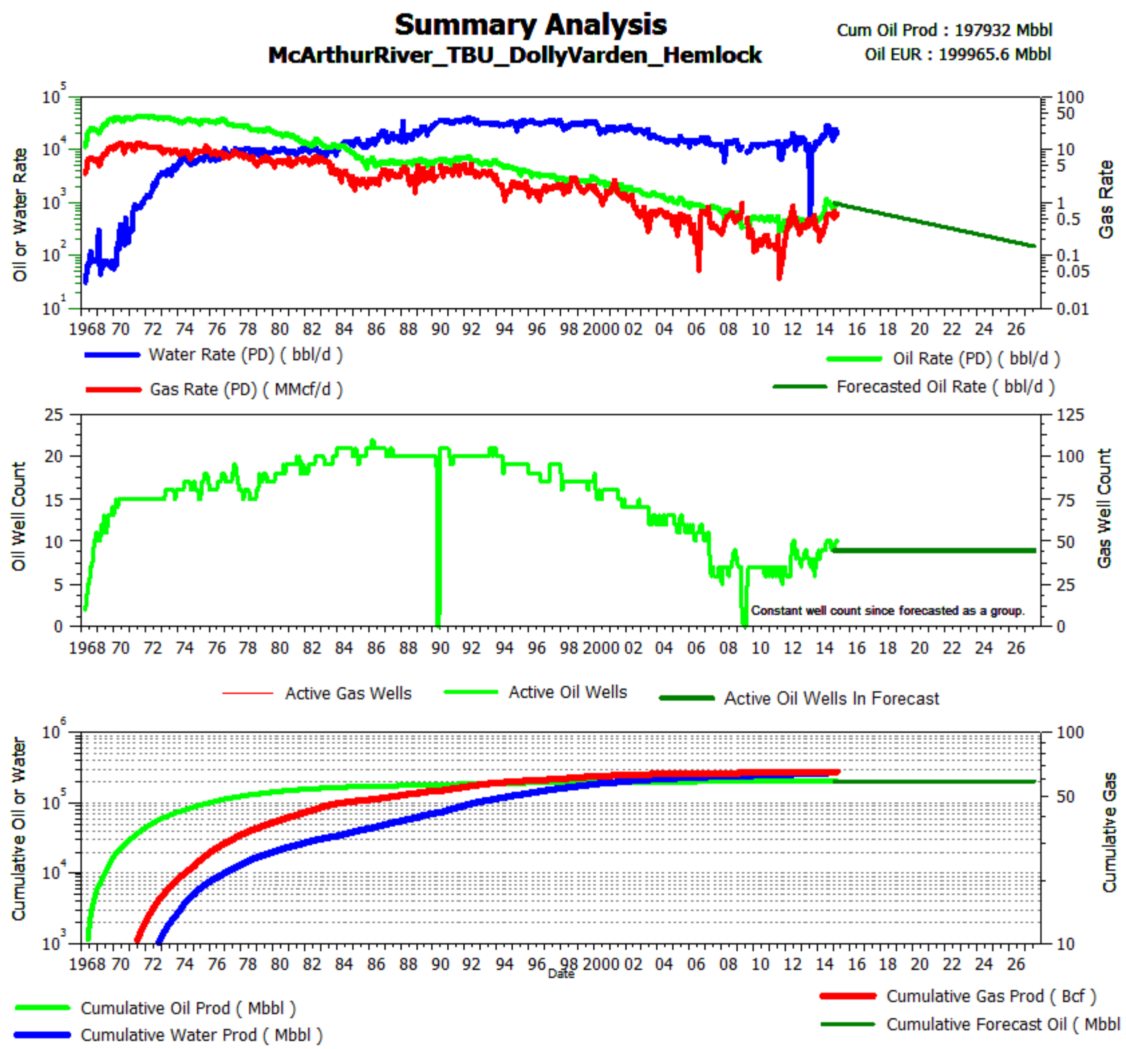

Figure C-4. McArthur River Field, with the Hemlock oil pool, producing to the Dolly Varden platform.

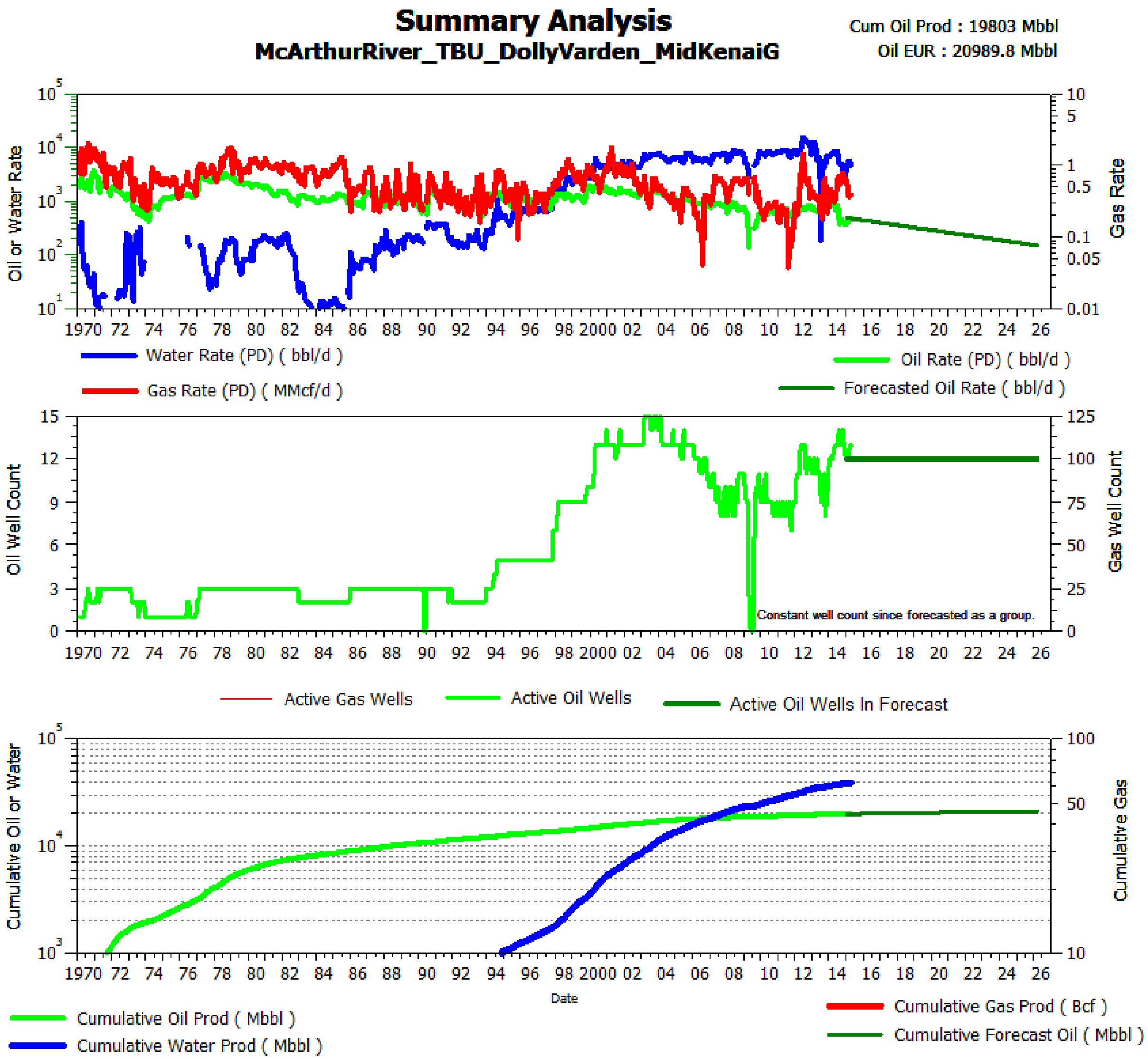

Figure C-5. McArthur River Field, with the Mid Kenai G oil pool, producing to the Dolly Varden platform.

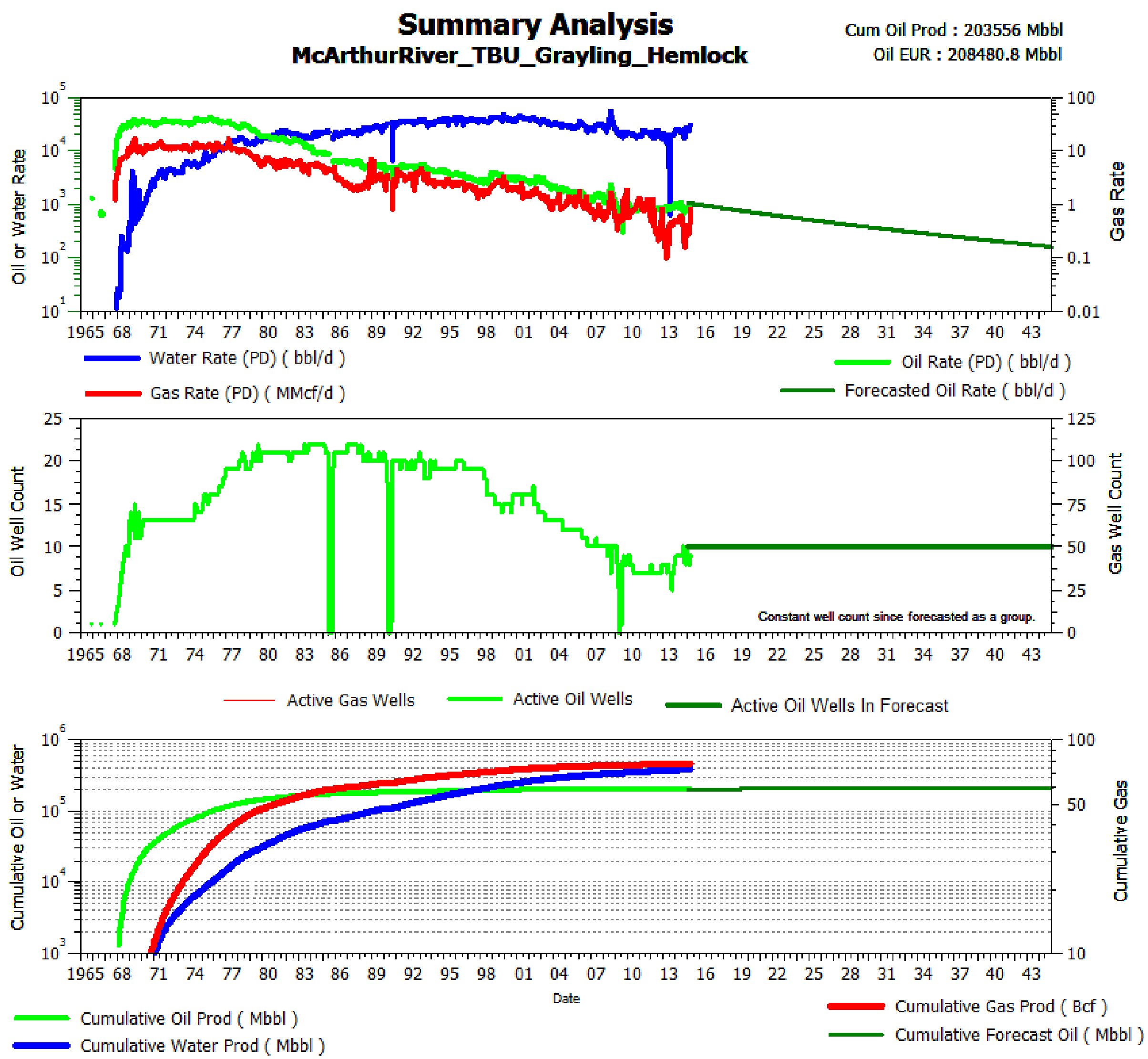

Figure C-6. McArthur River Field, with the Hemlock oil pool, producing to the Grayling platform.

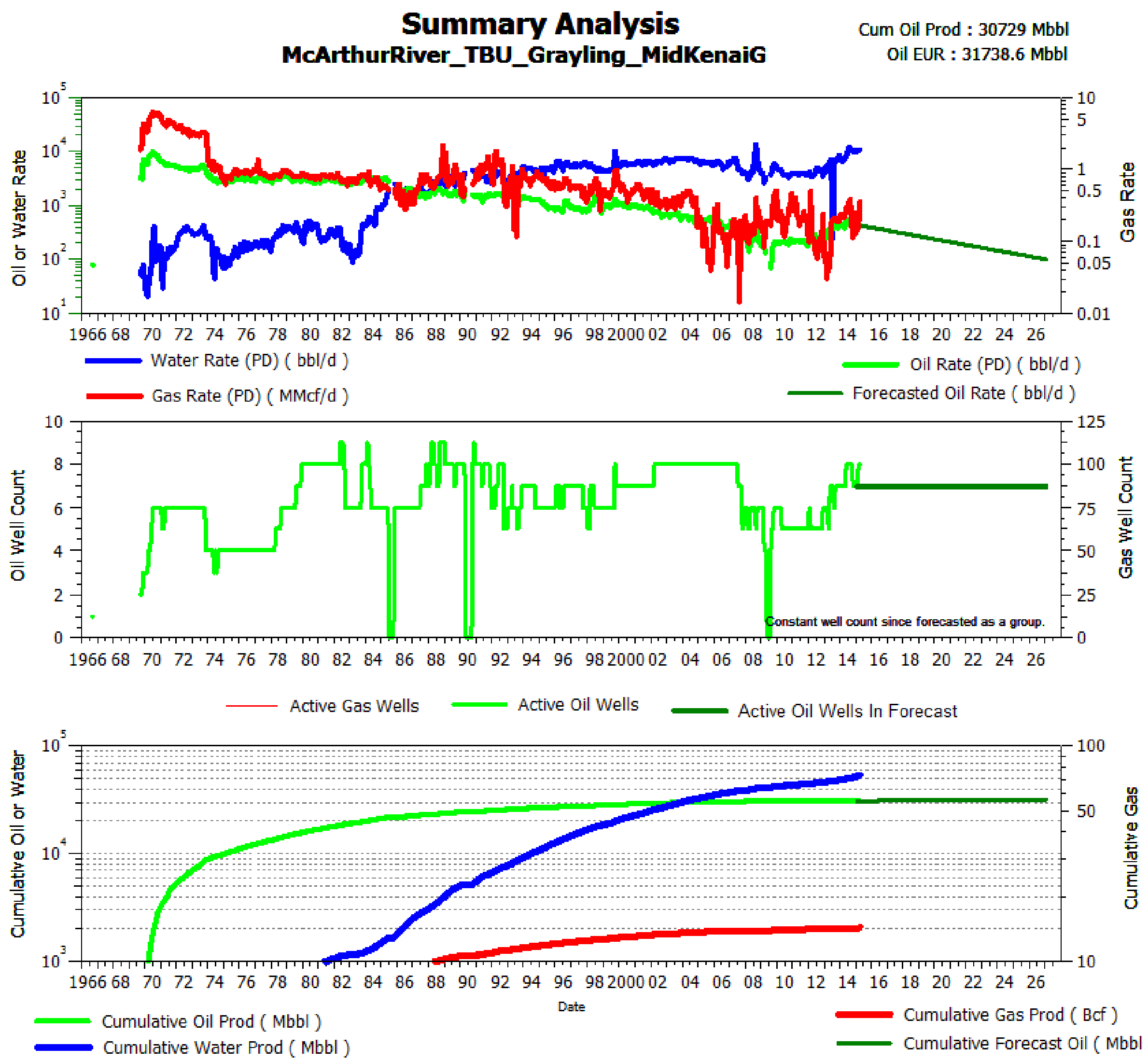

Figure C-7. McArthur River Field, with the Mid Kenai G oil pool, producing to the Grayling platform.

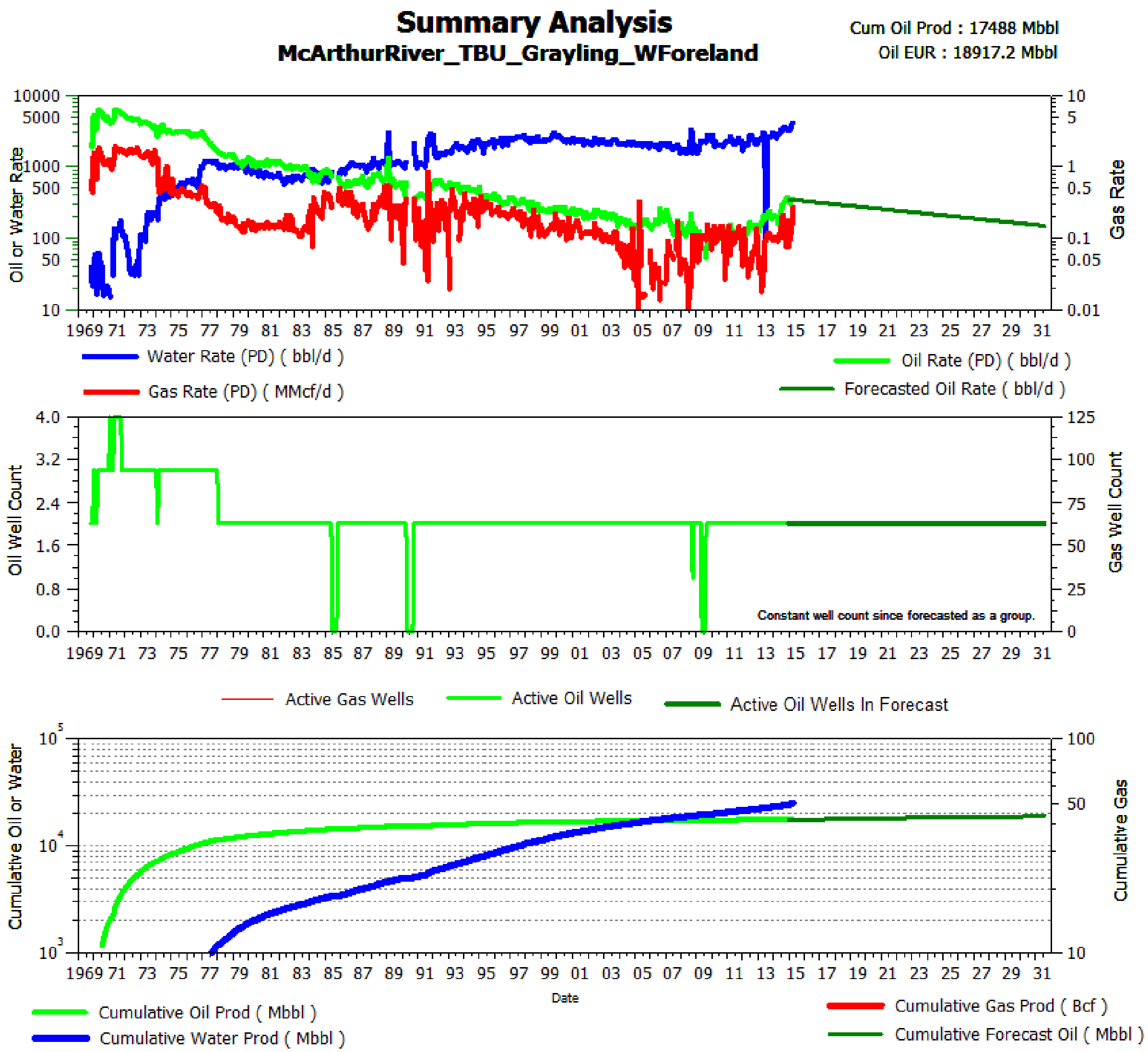

Figure C-8. McArthur River Field, with the West Foreland G oil pool, producing to the Grayling platform.

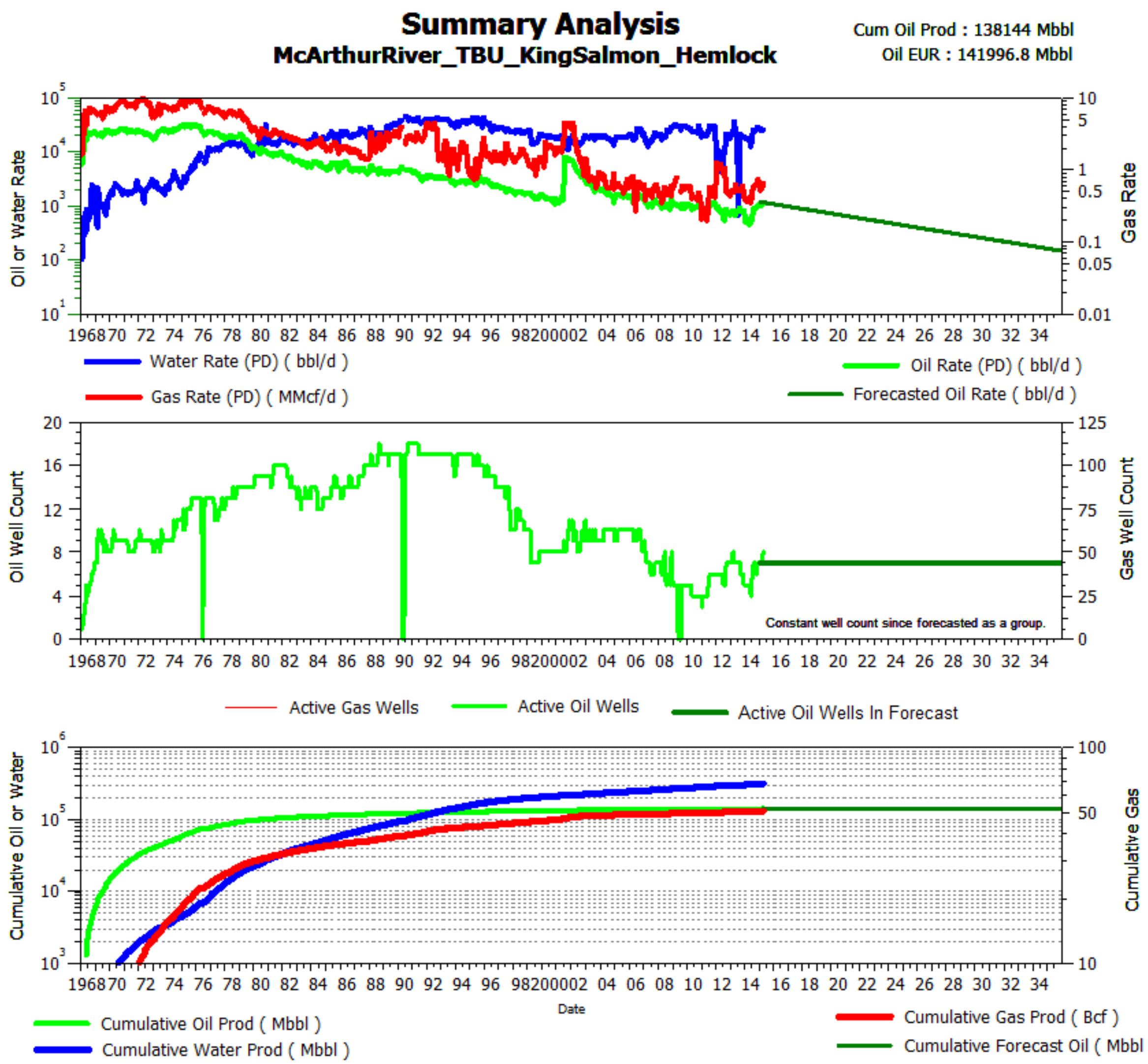

Figure C-9. McArthur River Field, with the Hemlock oil pool, producing to the King Salmon platform.

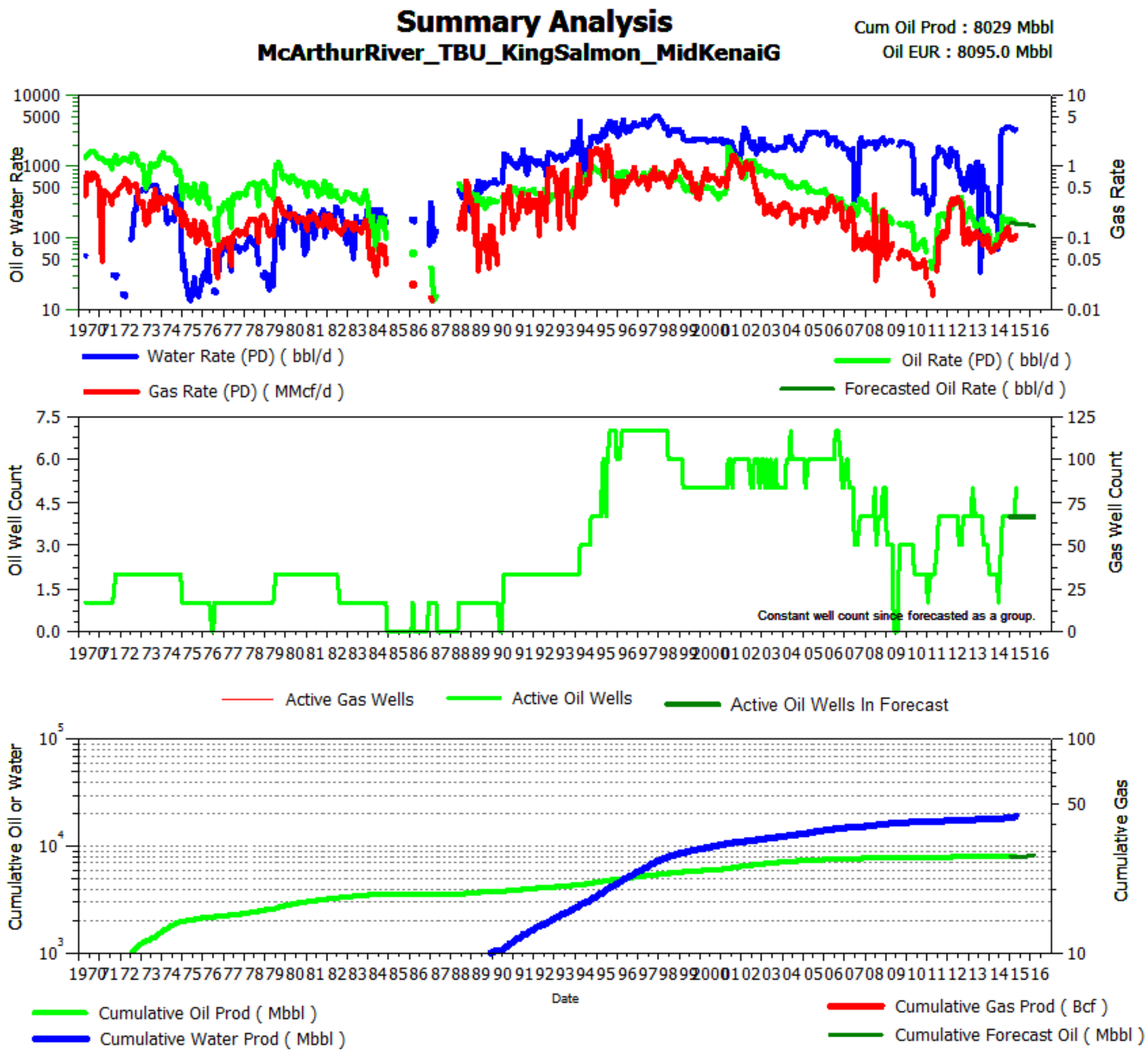

Figure C-10. McArthur River Field, with the Mid Kenai G oil pool, producing to the King Salmon platform.

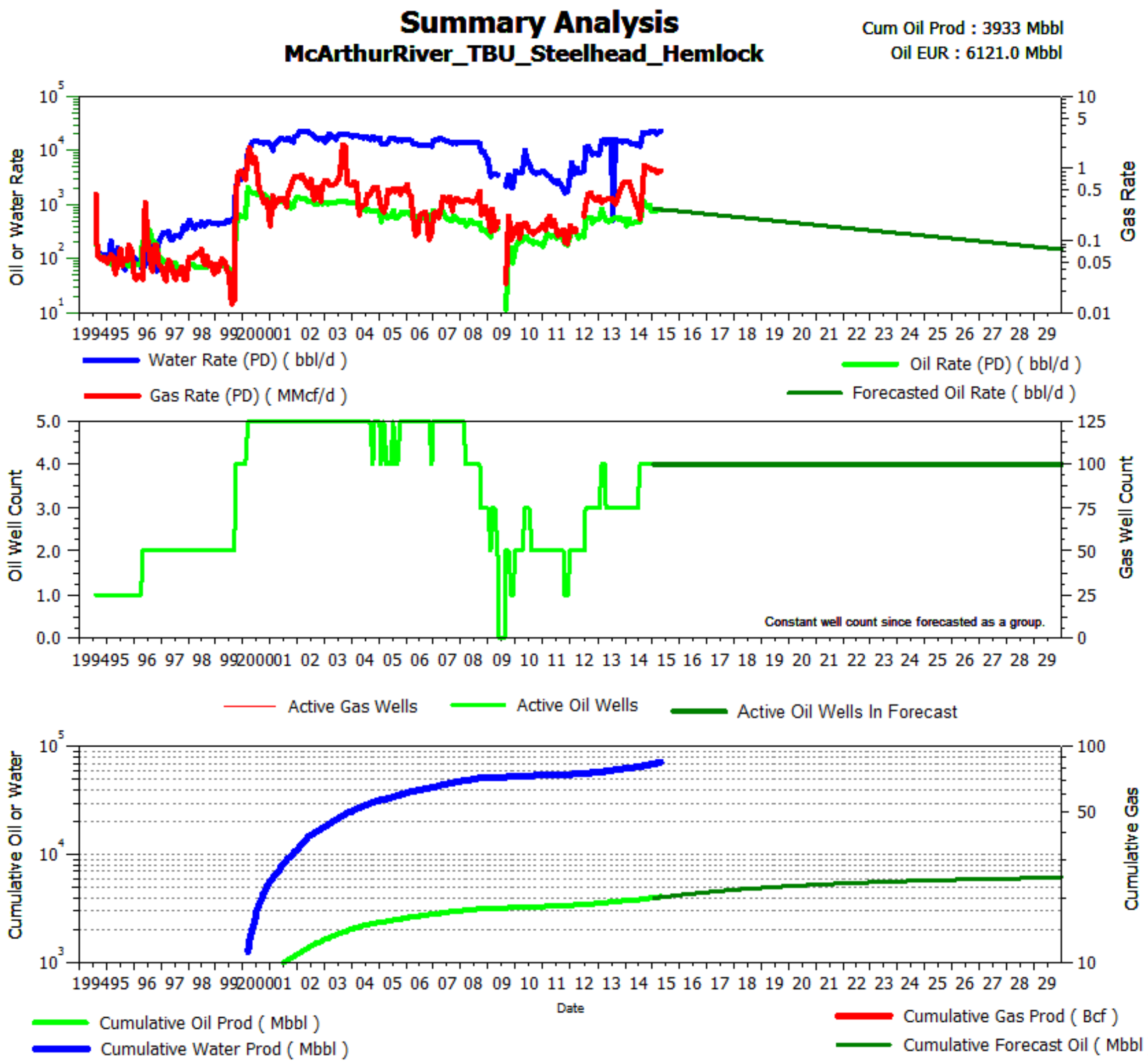

Figure C-11. McArthur River Field, with the Hemlock oil pool, producing to the Steelhead platform.

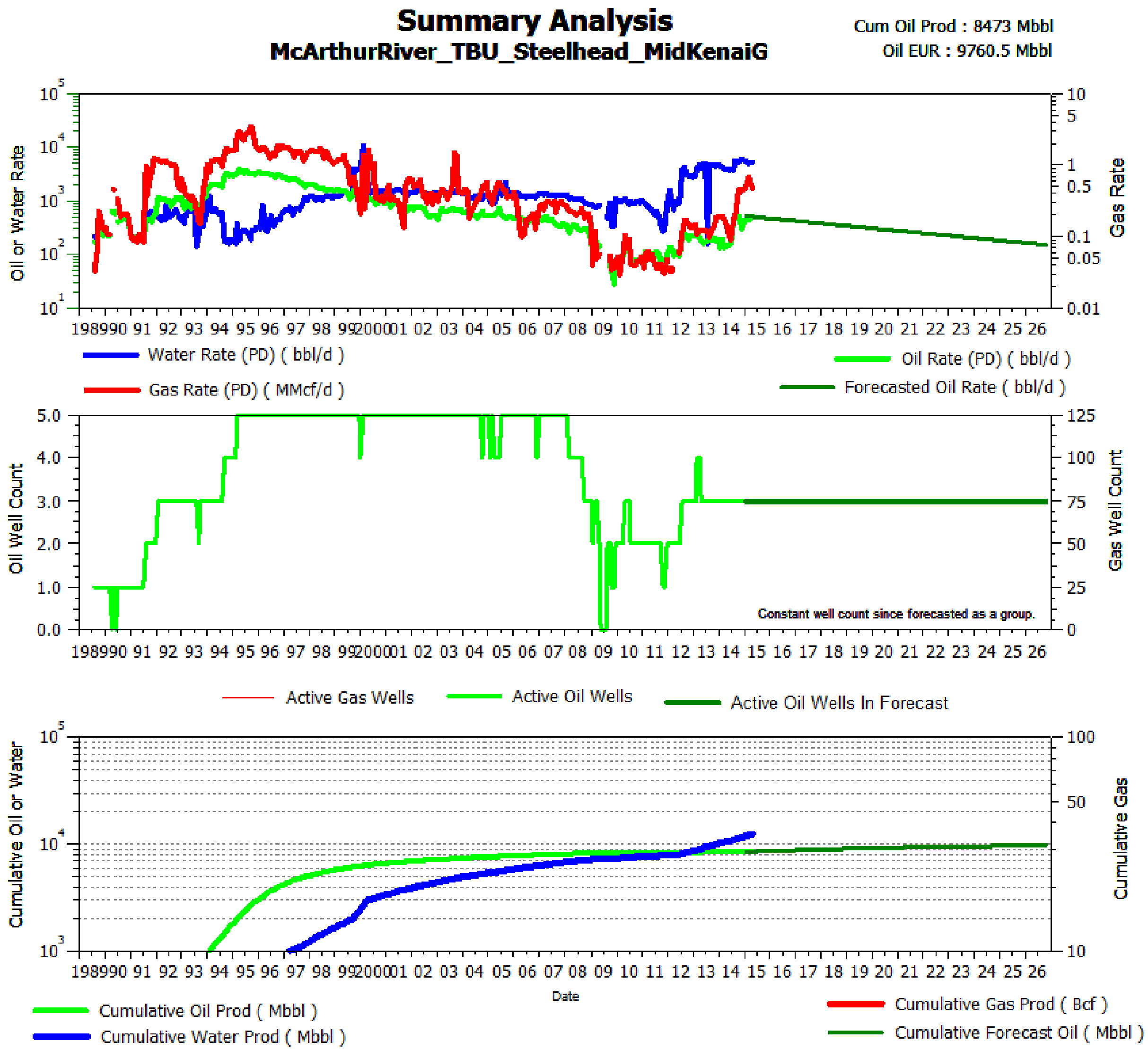

Figure C-12. McArthur River Field, with the Mid Kenai G oil pool, producing to the Steelhead platform.

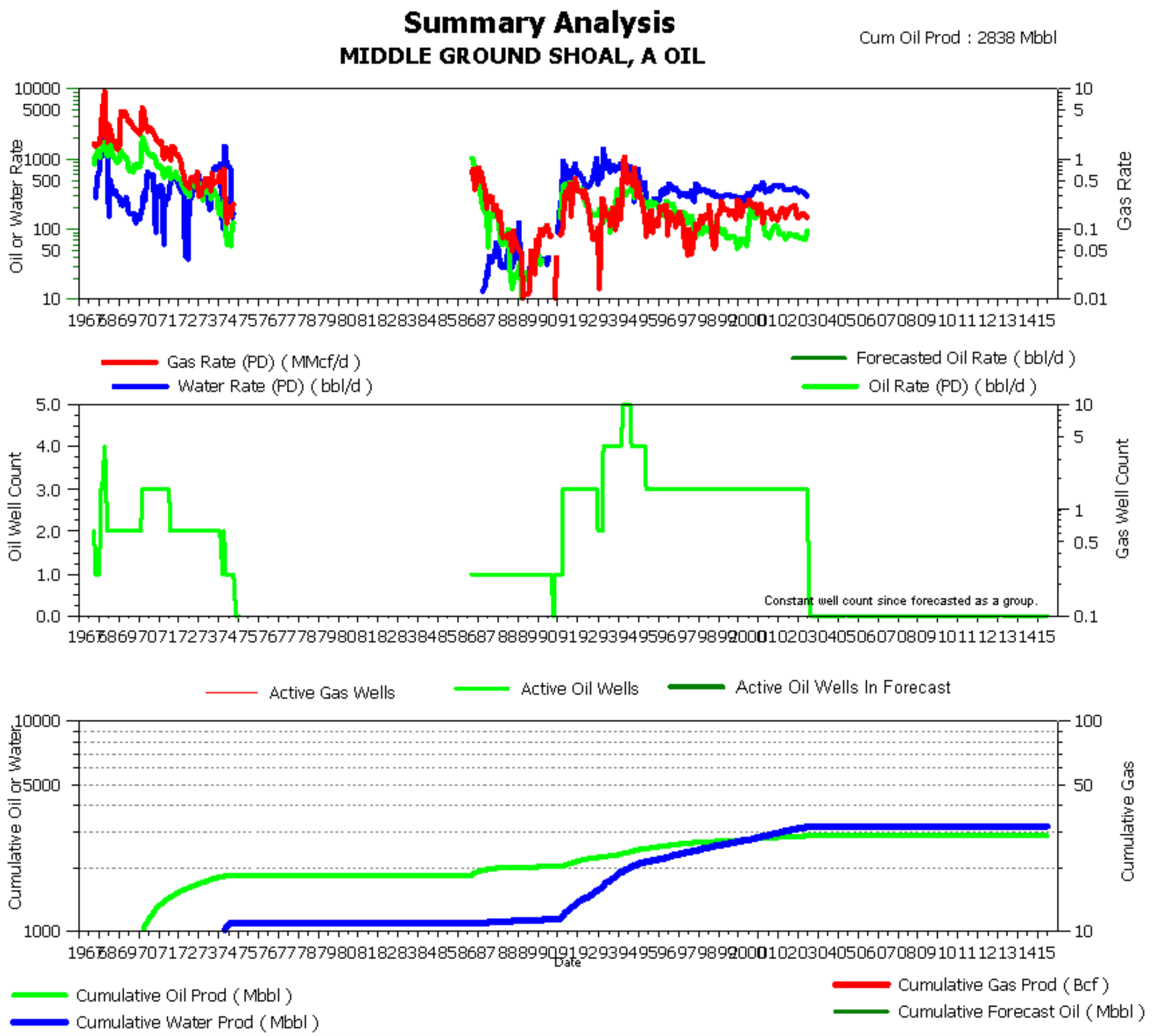

Figure C-13. Middle Ground Shoal Field, with A Oil pool. Included for completeness.

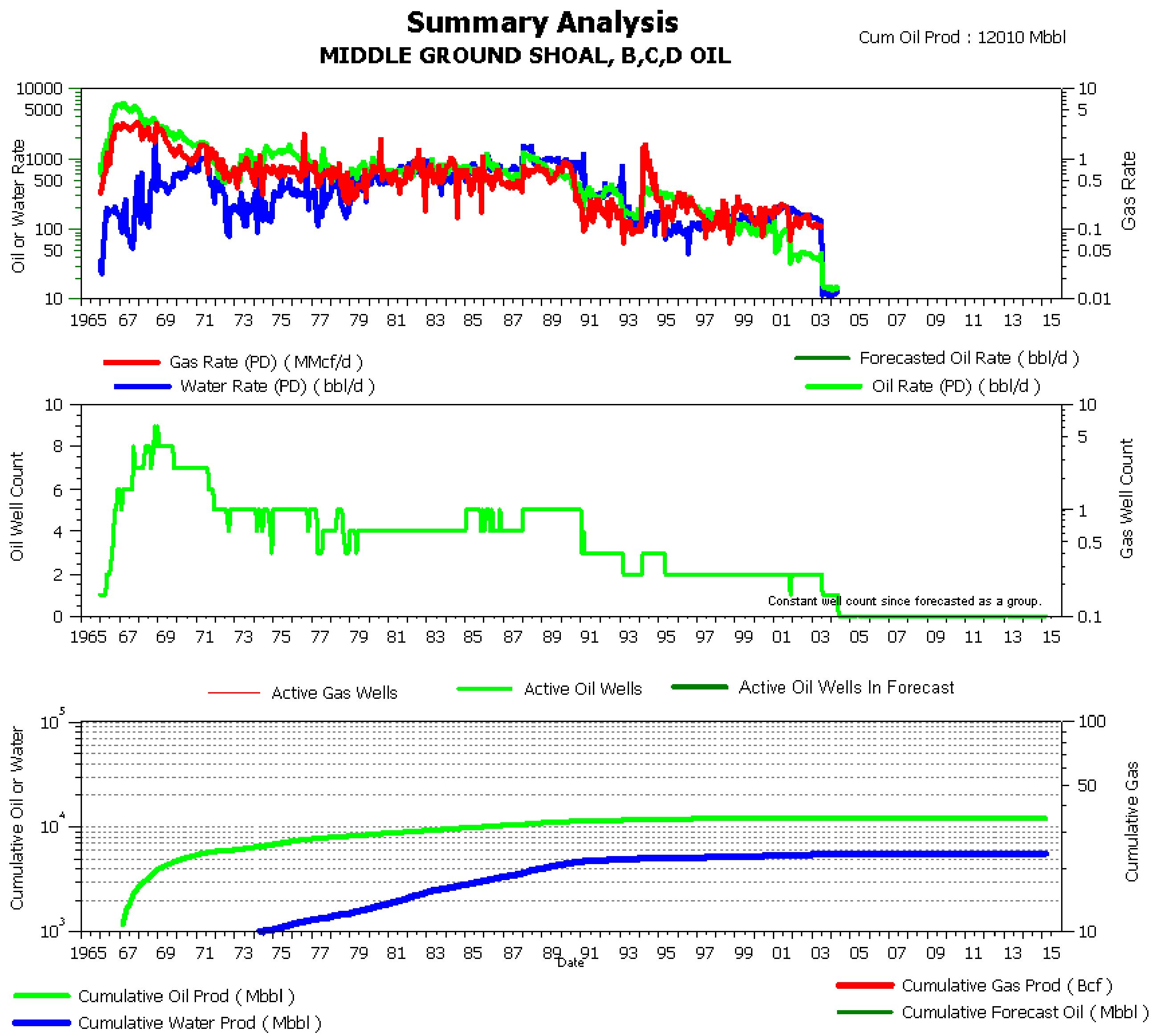

Figure C-14. Middle Ground Shoal Field, with B,C,D Oil pool. Included for completeness.

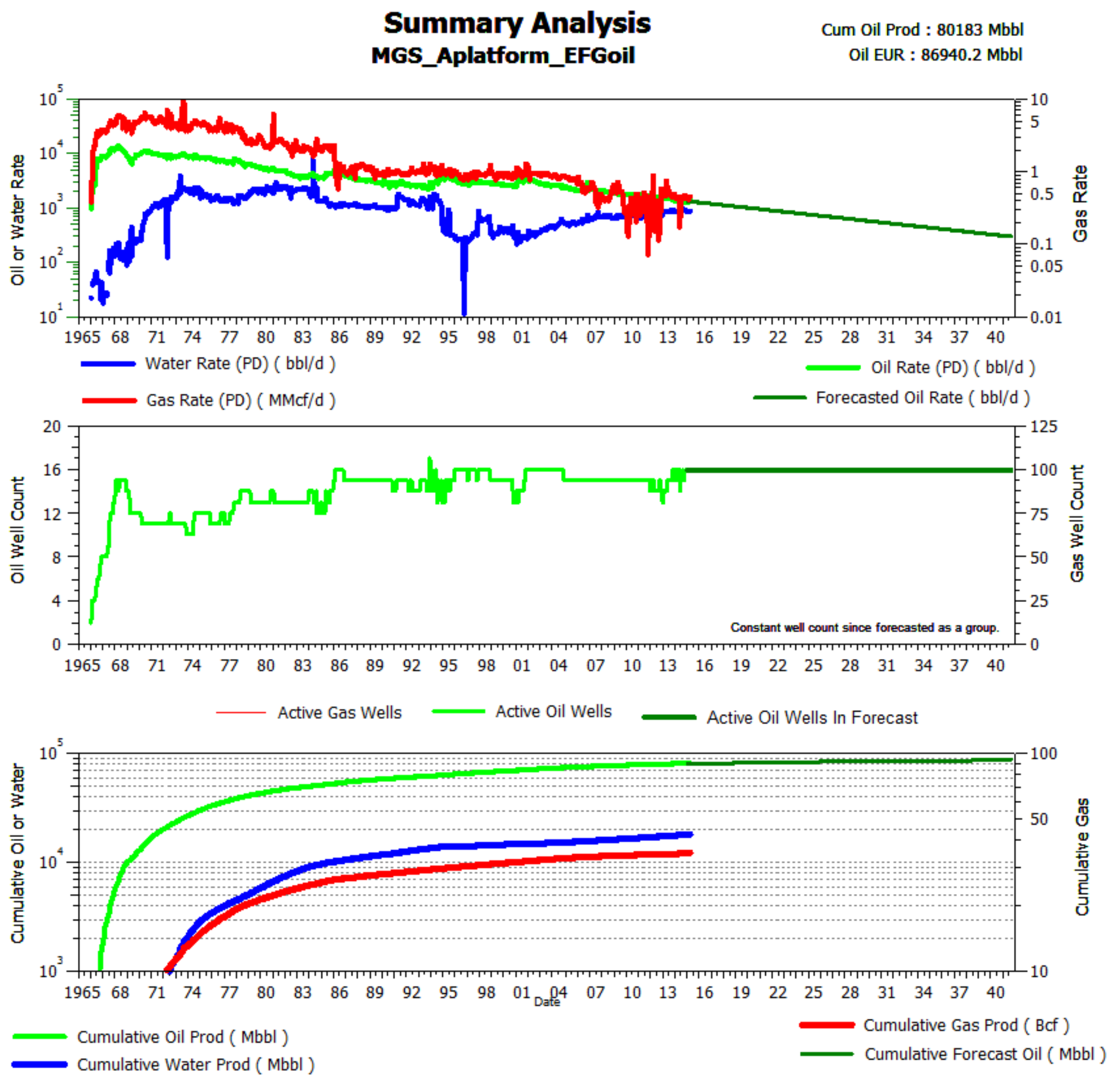

Figure C-15. Middle Ground Shoal Field, with combined E Oil, F Oil and G oil pools, producing to the “A” platform.

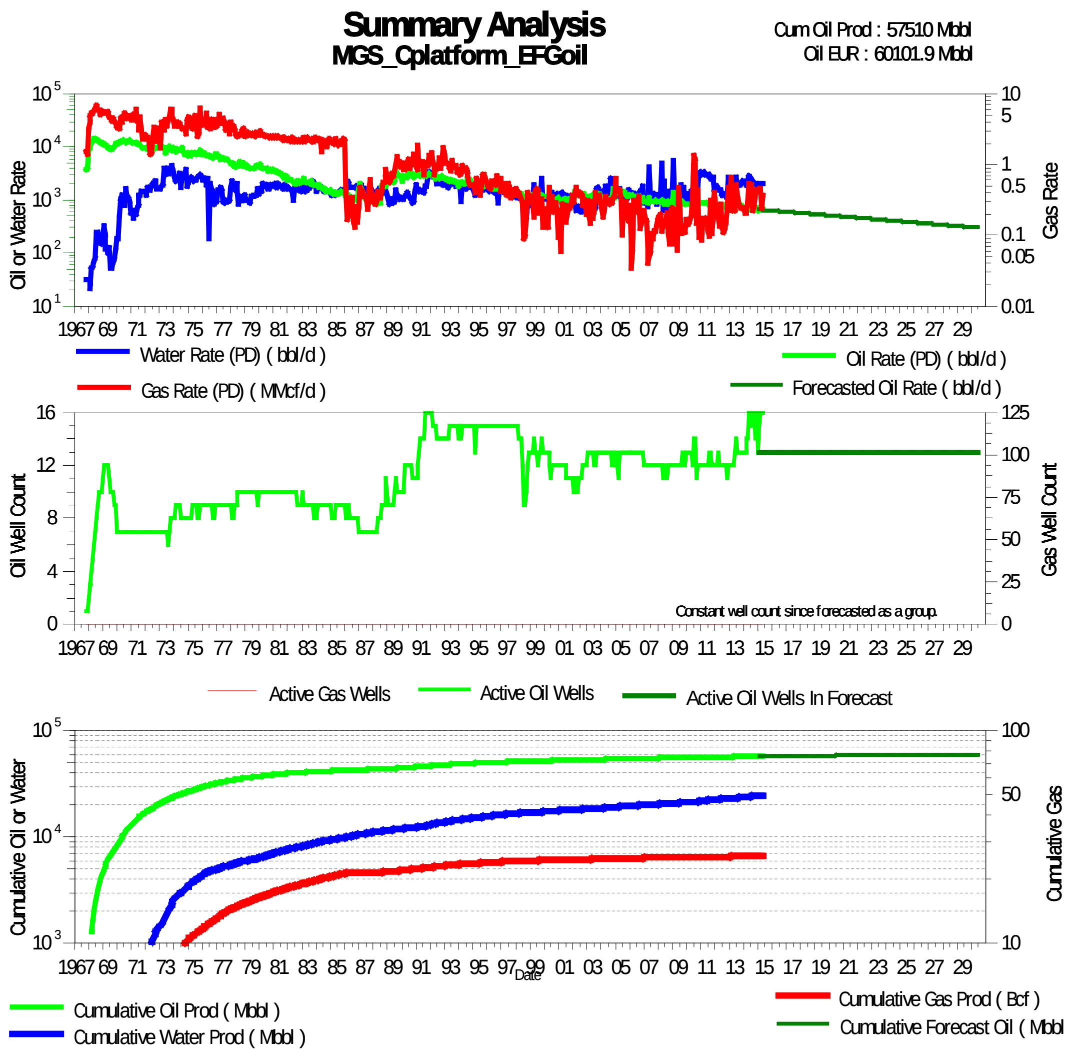

Figure C-16. Middle Ground Shoal Field, with combined E Oil, F Oil and G oil pools, producing to the “C” platform.

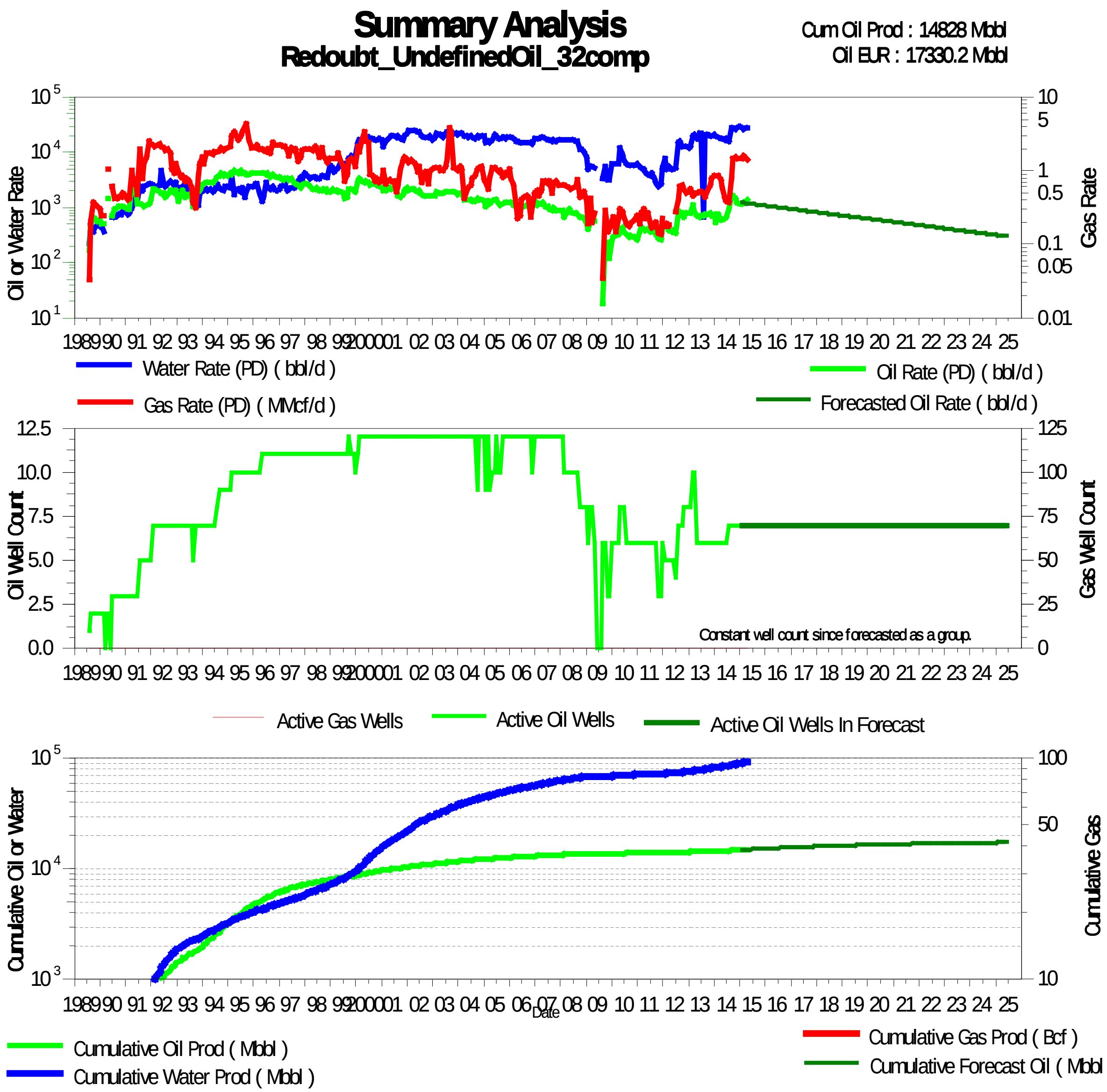

Figure C-17. Redoubt Shoal Field, Undefined Oil Pool, producing to the Osprey platform.

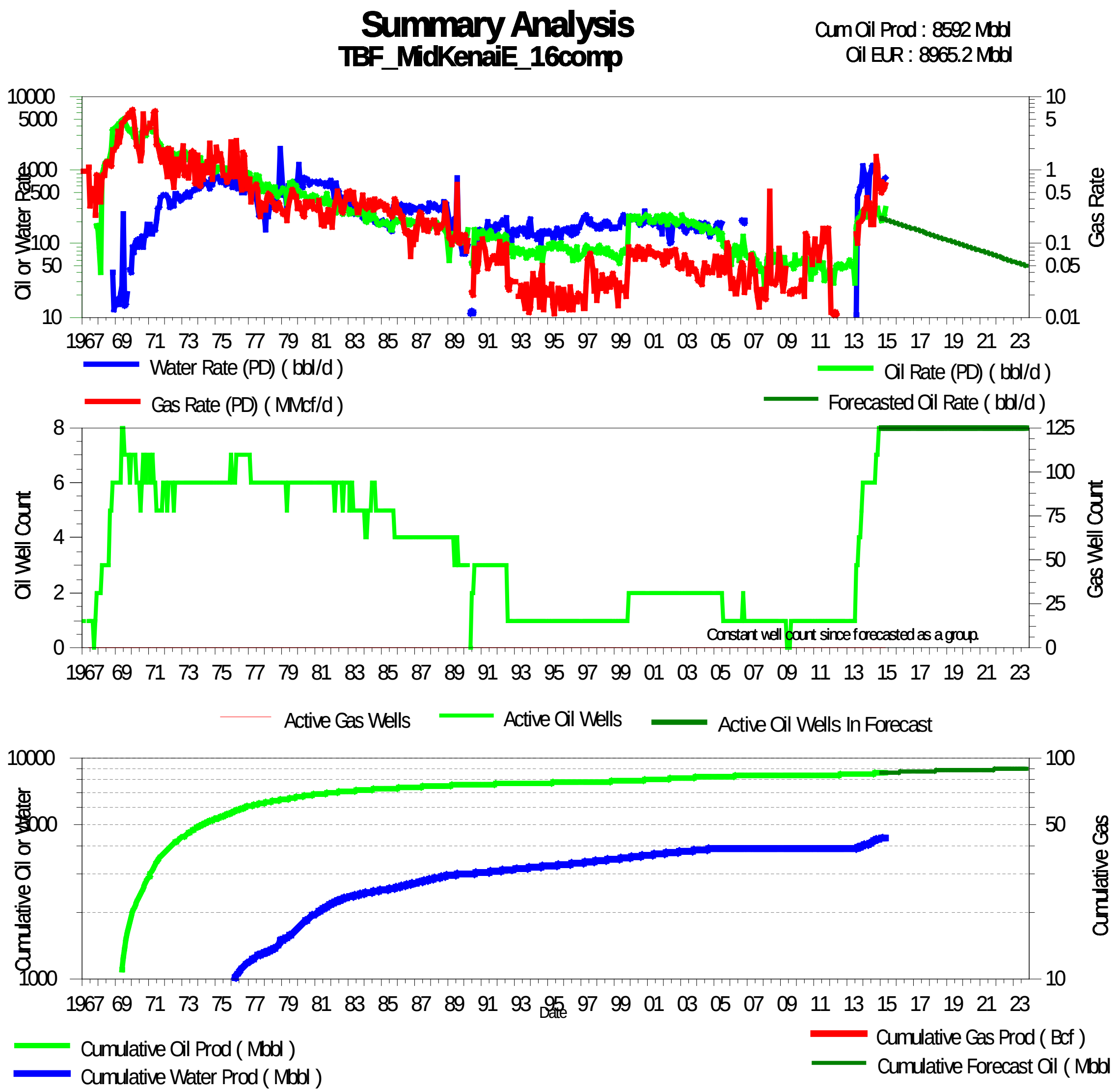

Figure C-18. Trading Bay Field, with the Mid Kenai oil pool producing to the Monopod offshore facility.

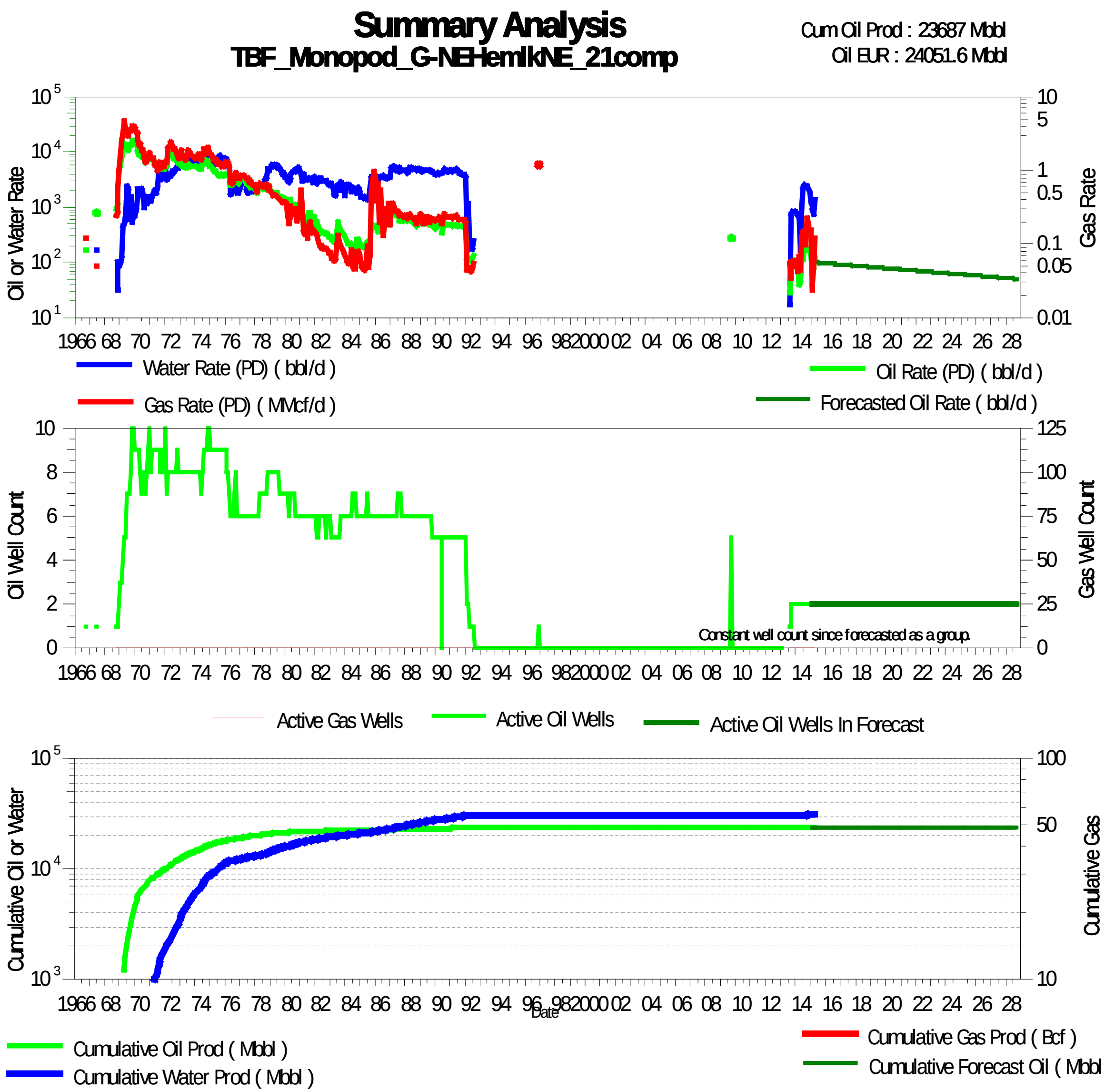

Figure C-19. Trading Bay Field, with G NE Hemlock NE, producing to the Monopod offshore facility.

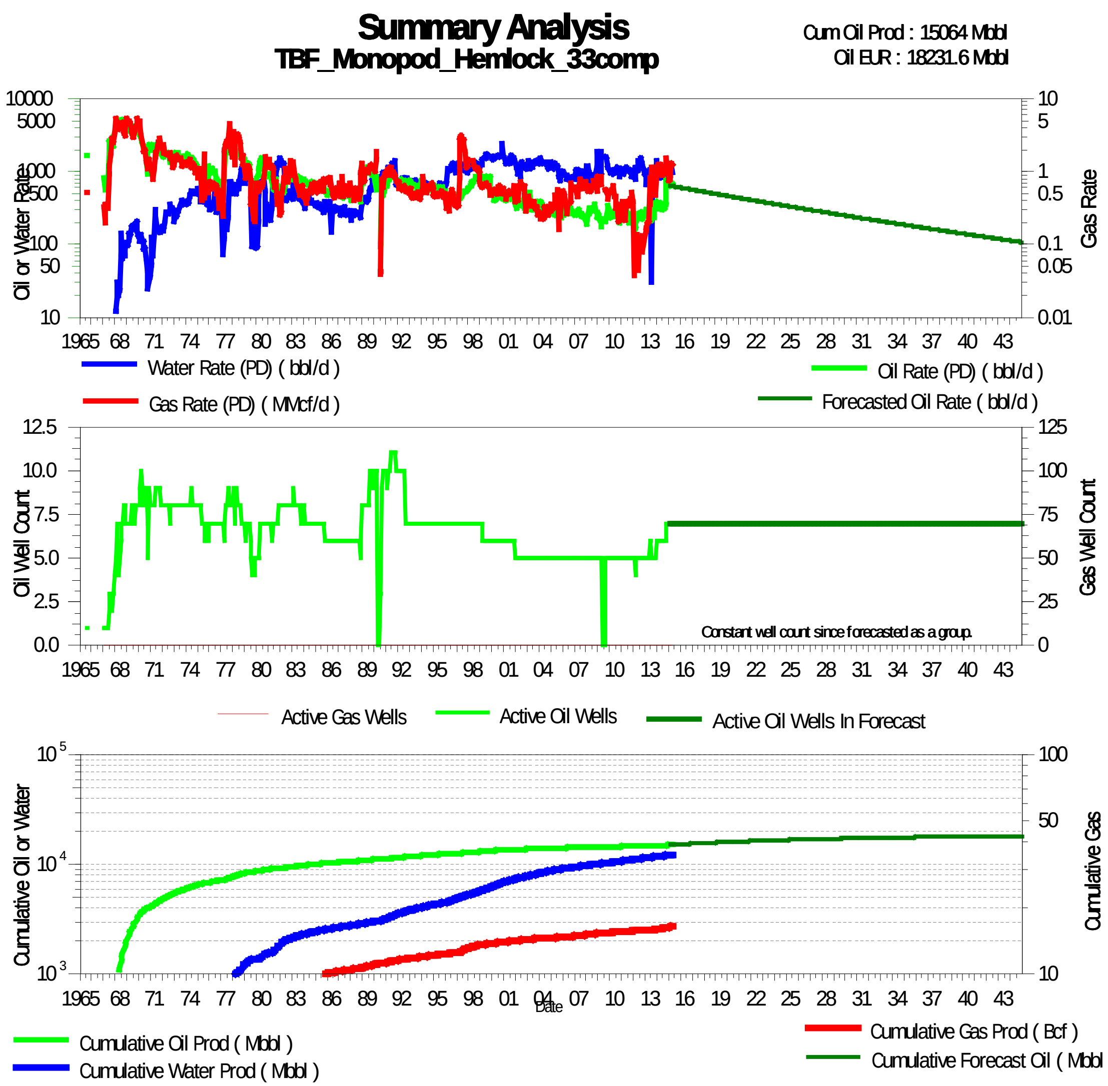

Figure C-20. Trading Bay Field, Hemlock oil pool, producing to the Monopod offshore facility.

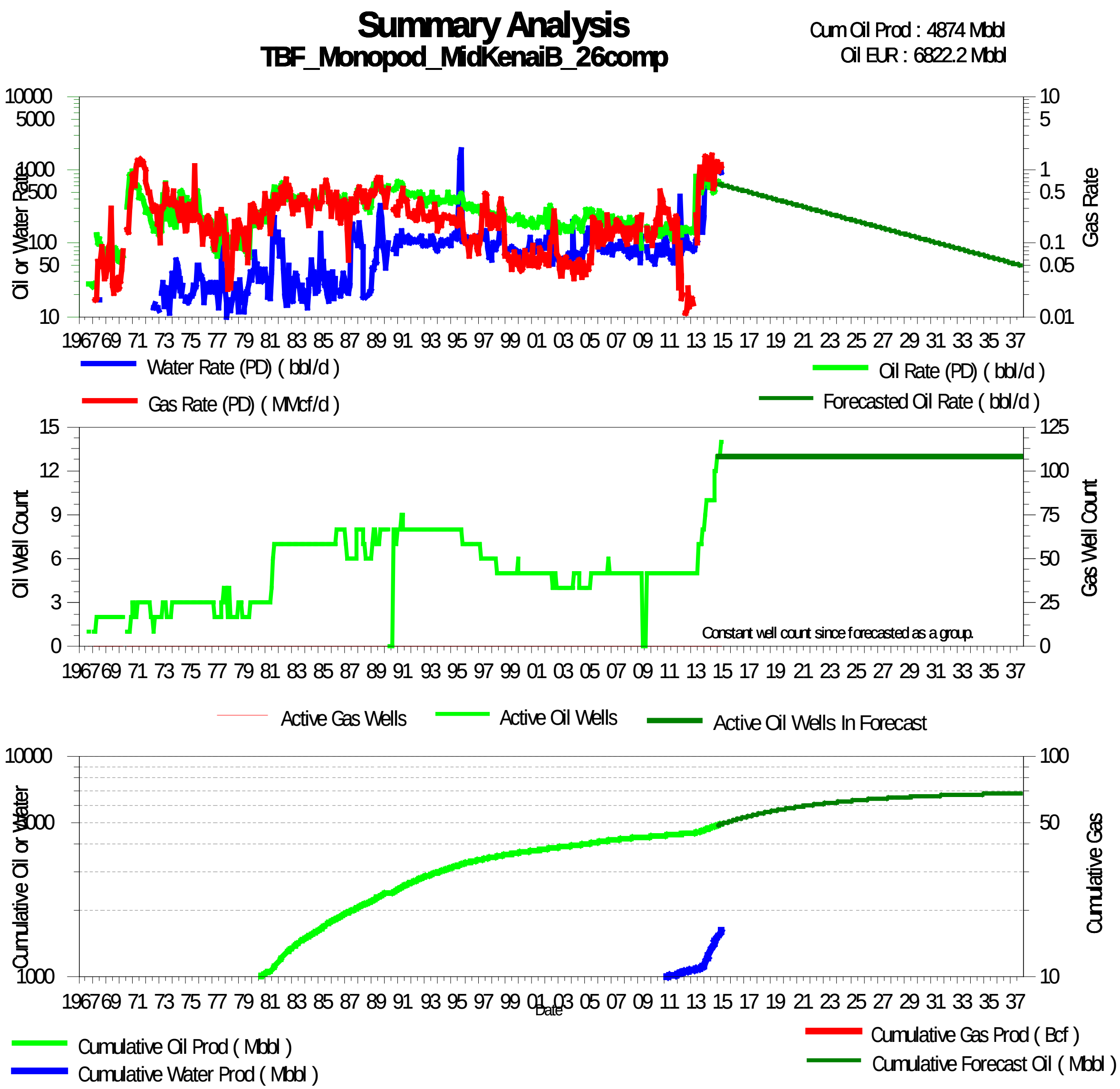

Figure C-21. Trading Bay Field, Mid Kenai B oil pool, producing to the Monopod offshore facility.

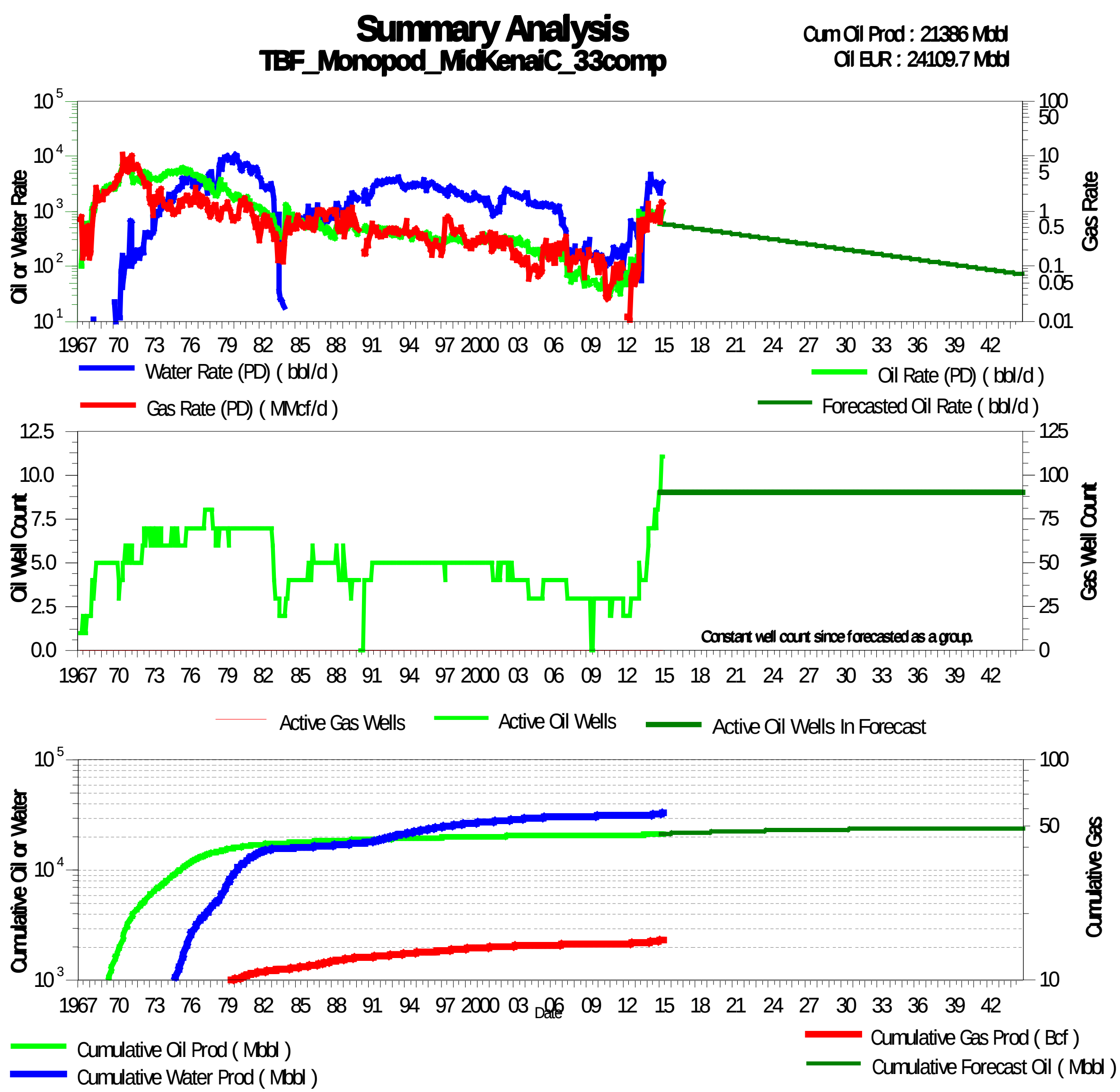

Figure C-22. Trading Bay Field, Mid Kenai C oil pool, producing to the Monopod offshore facility.

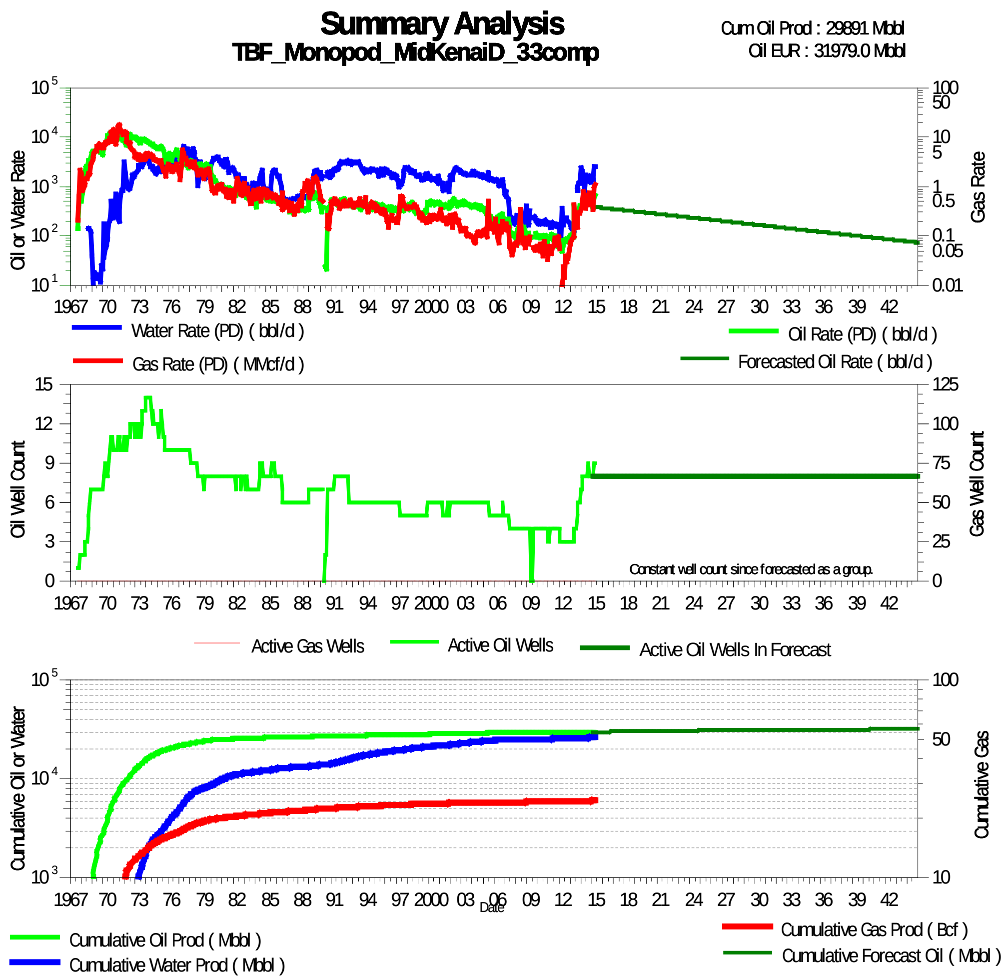

Figure C-23. Trading Bay Field, Mid Kenai D oil pool, producing to the Monopod offshore facility.

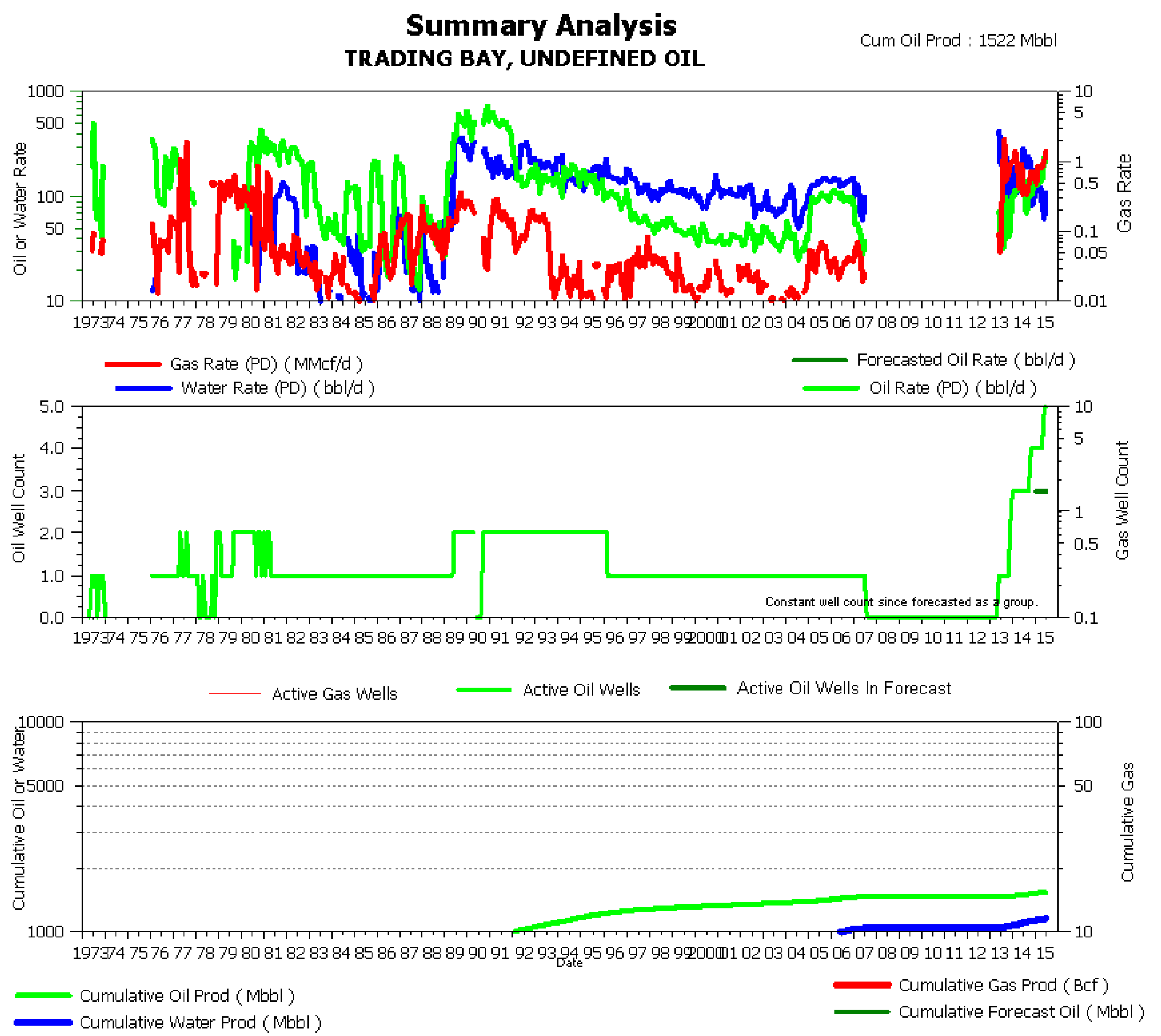

Figure C-24. Trading Bay Field, with Undefined Oil pool. Included for completeness.

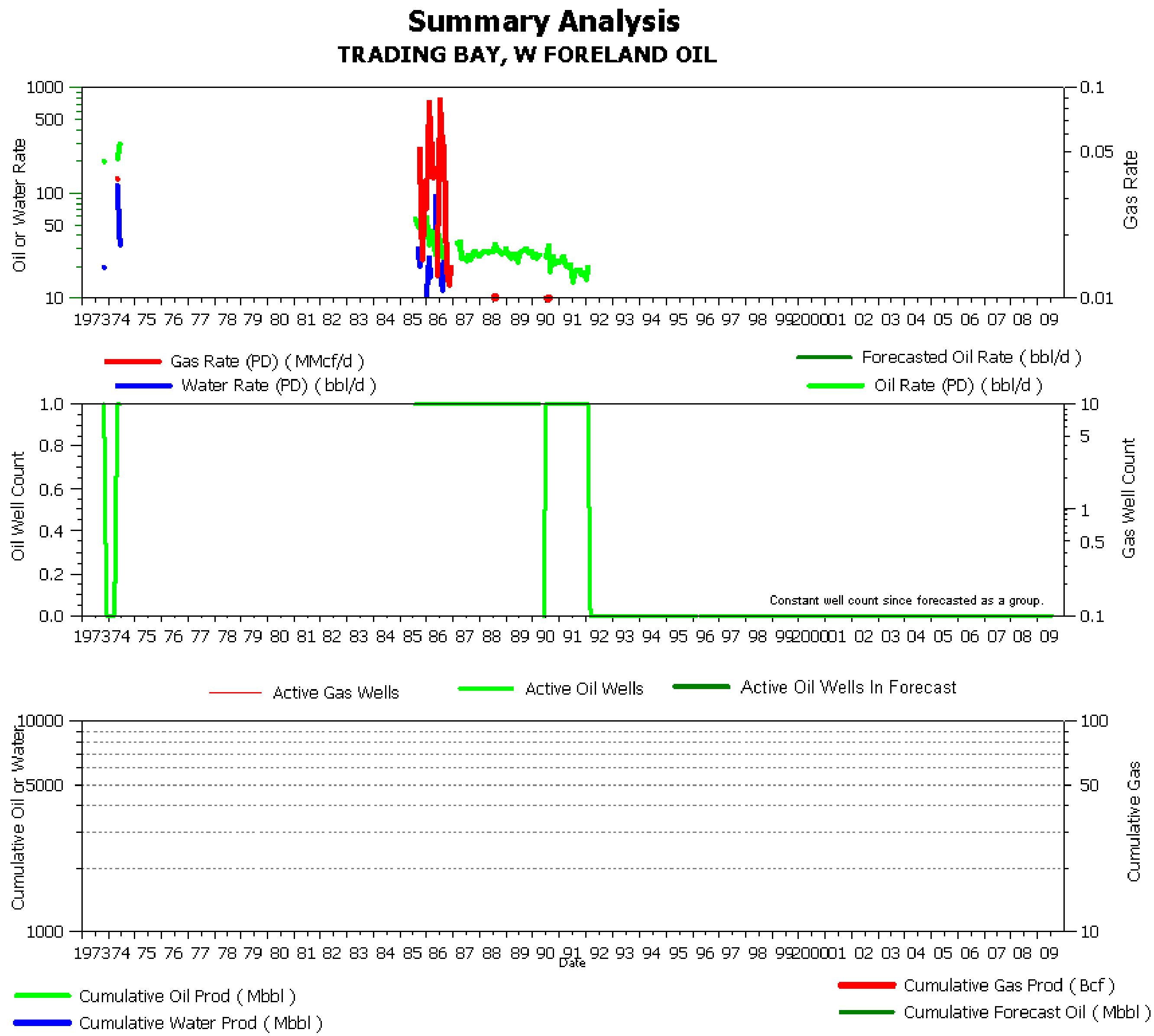

Figure C-25. Trading Bay Field, with West Foreland Oil. Included for completeness.

Appendix D. Summaries of EUR for Oil Pools Producing to Onshore Facilities in the Cook Inlet

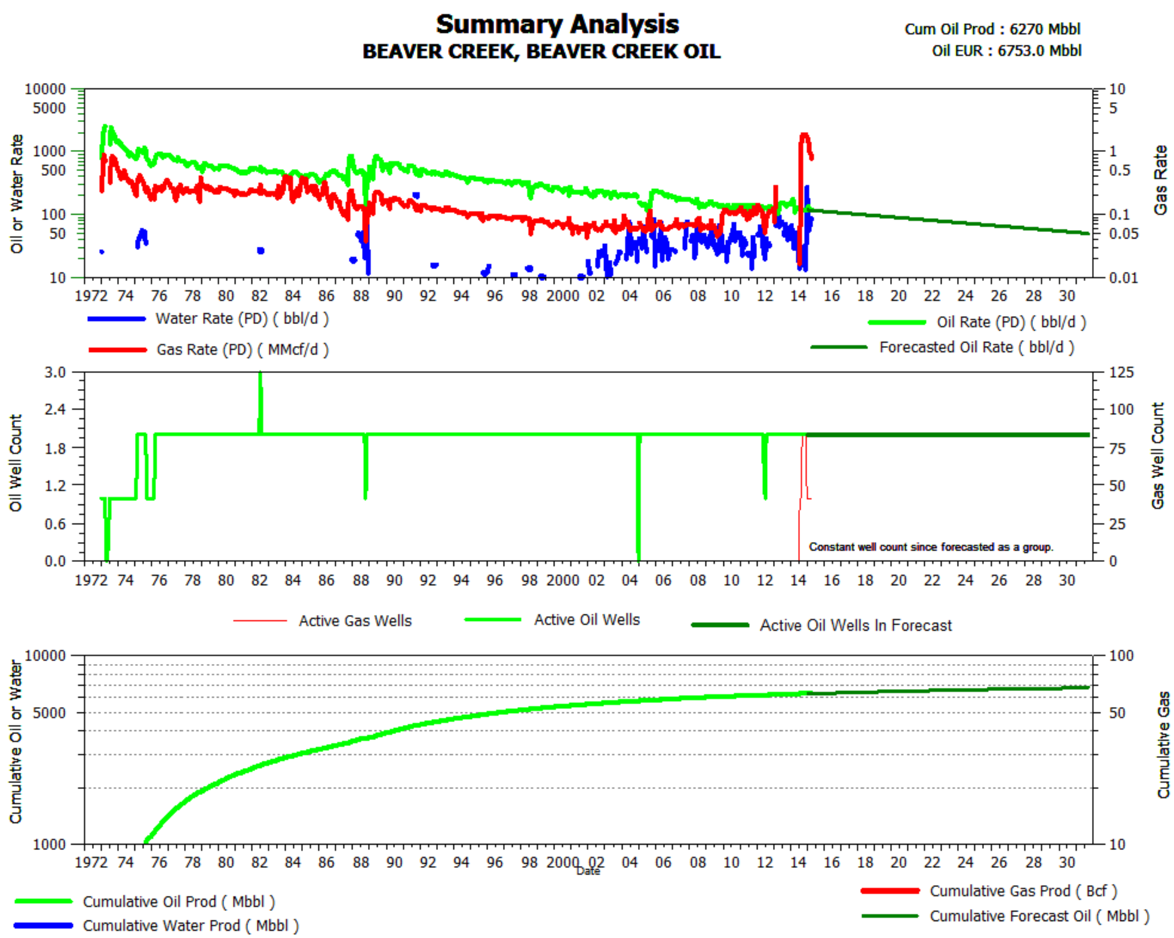

Figure D-1. Beaver Creek Field, Pool-Level Analysis of Production from the Beaver Creek oil pool.

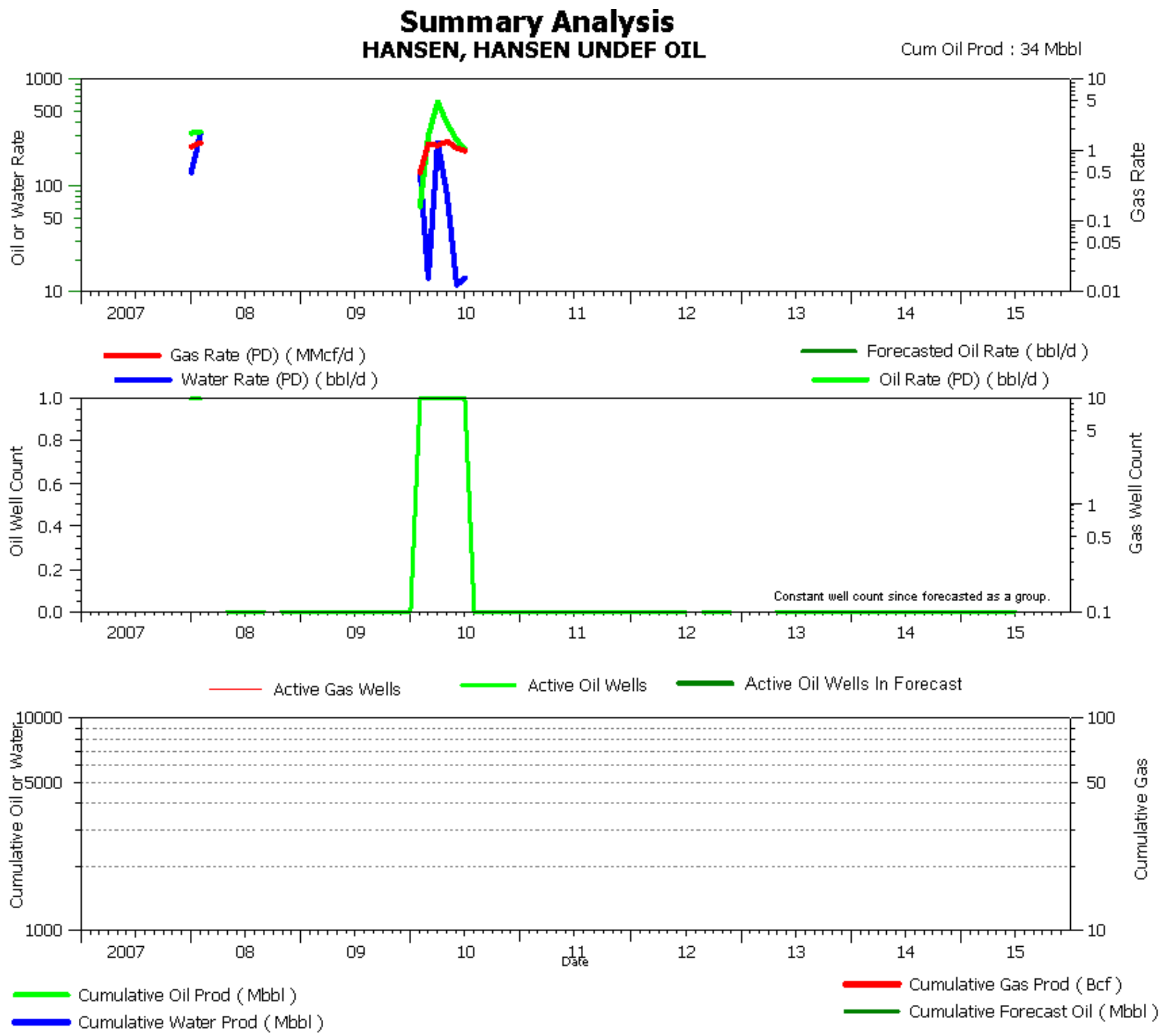

Figure D-2. Hansen Field, with Hansen Undefined Oil pool. Included for completeness.

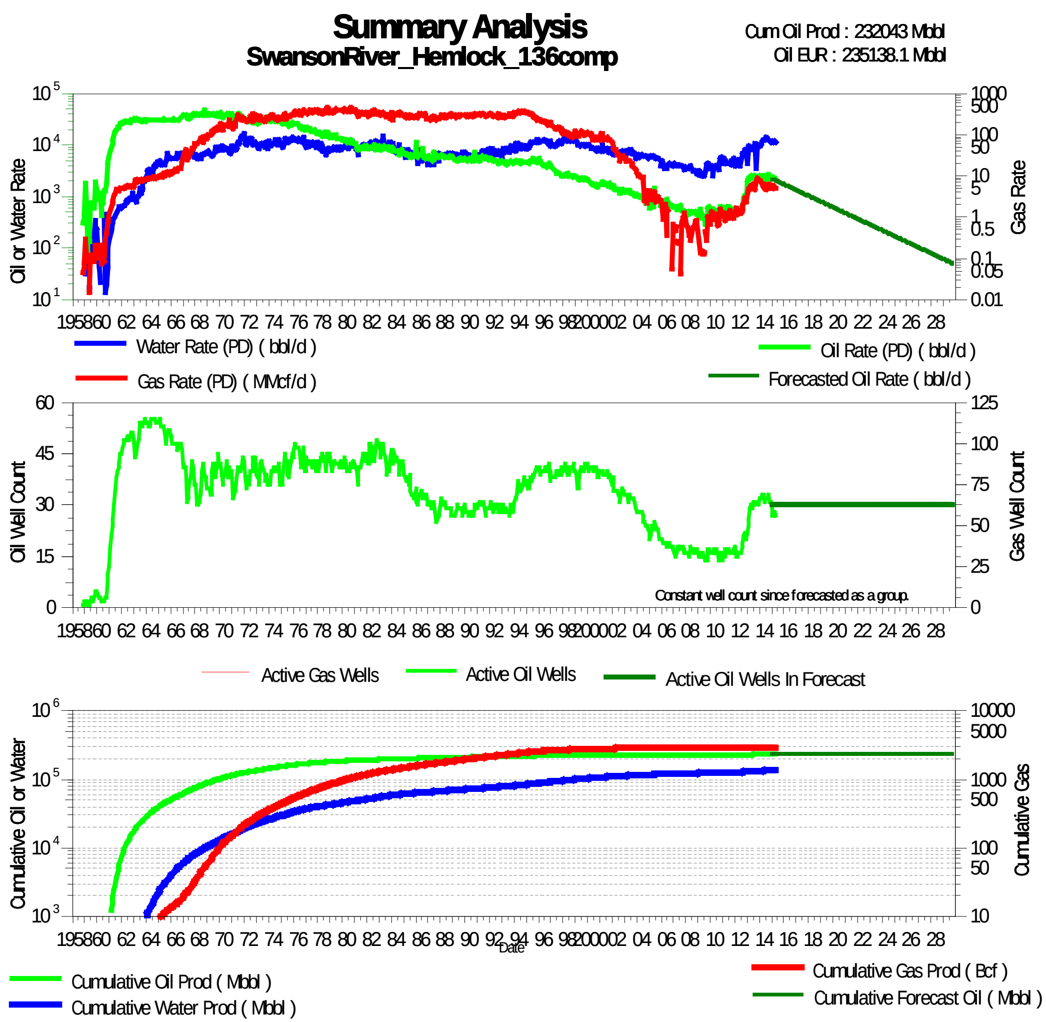

Figure D-3. Swanson River Field, Pool-Level Analysis of Production from the Hemlock oil pool.

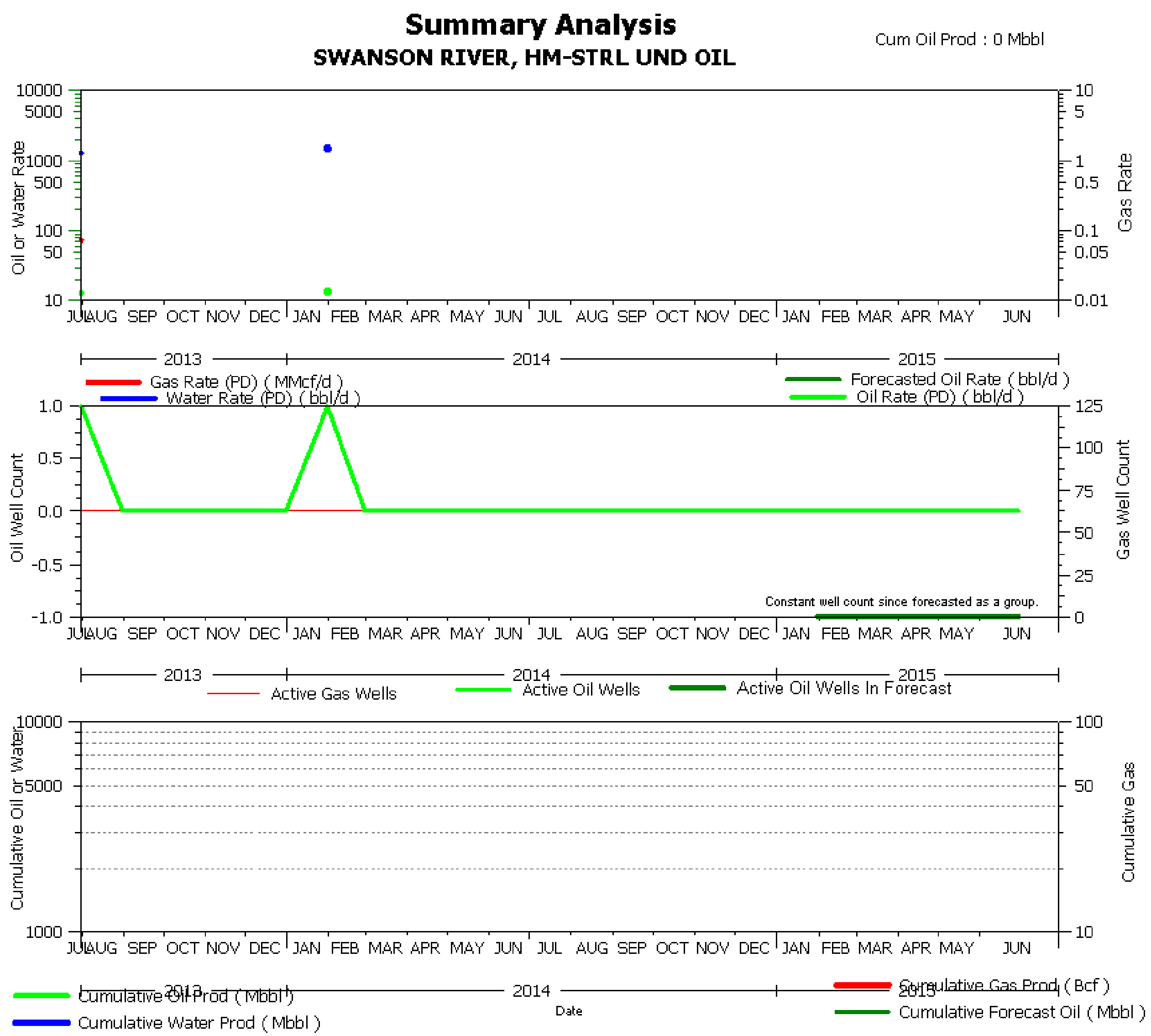

Figure D-4. Swanson River Field, Hemlock-Sterling undefined oil pool.

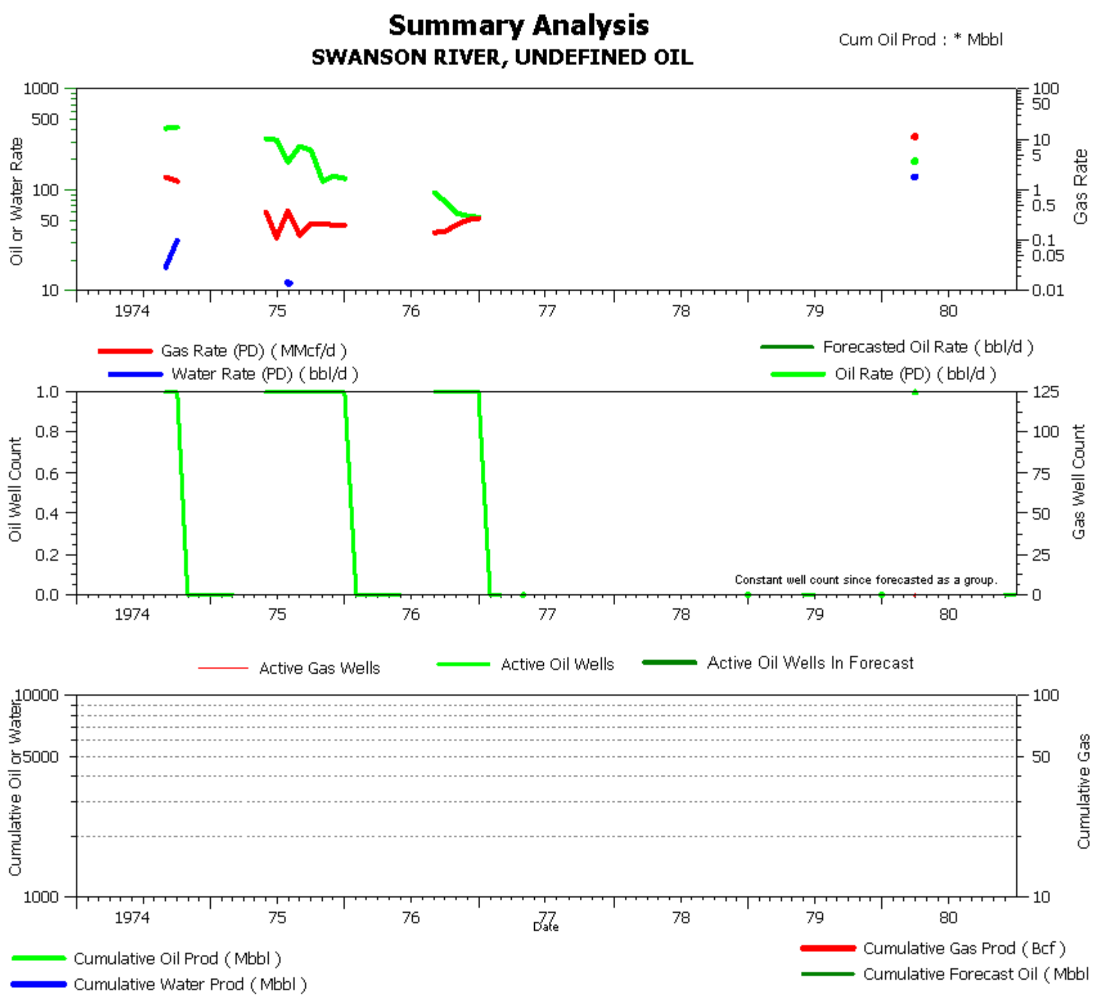

Figure D-5. Swanson River Field, Undefined oil pool.

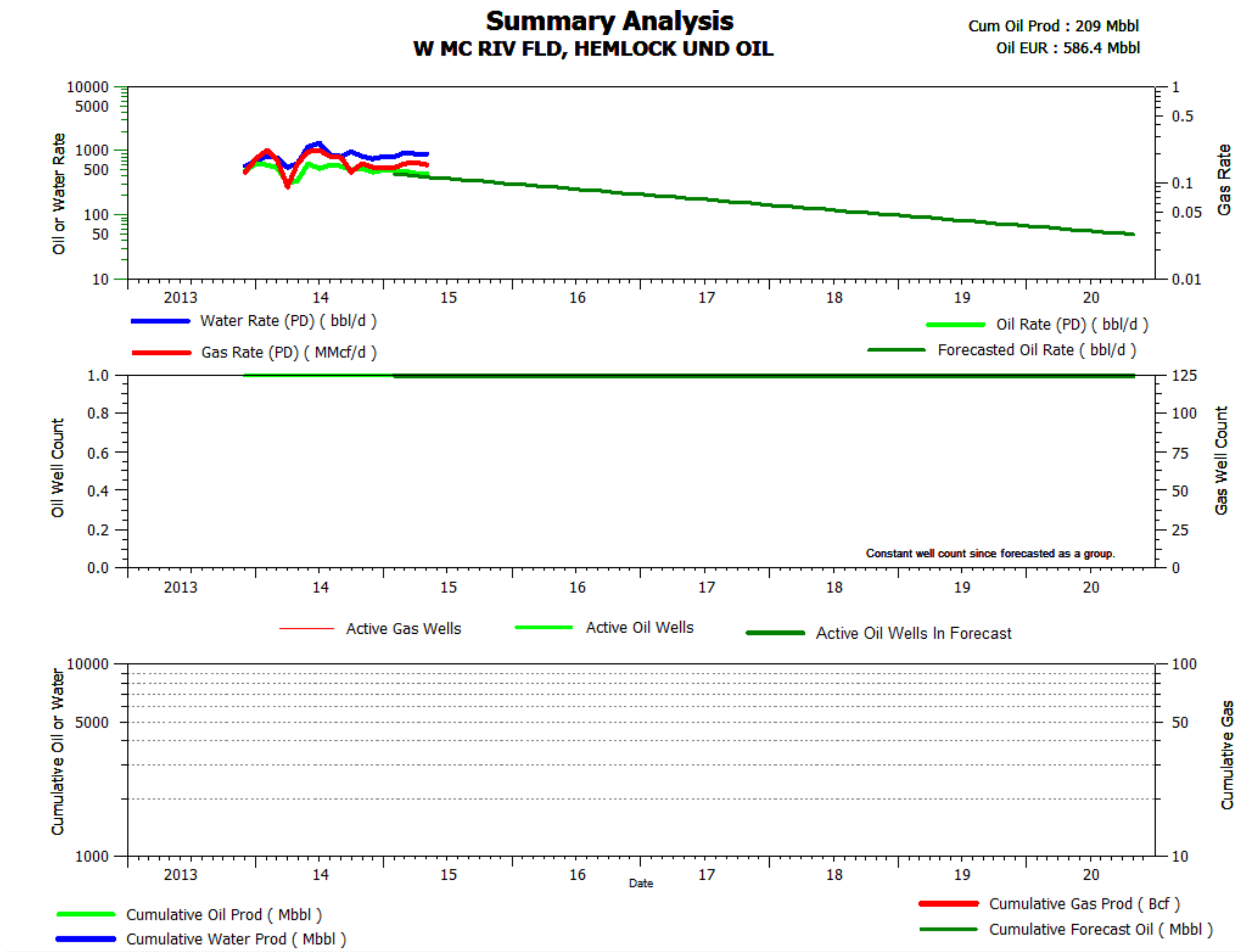

Figure D-6. West McArthur River Field, Pool-Level Analysis of Production from the Hemlock Undefined oil pool.

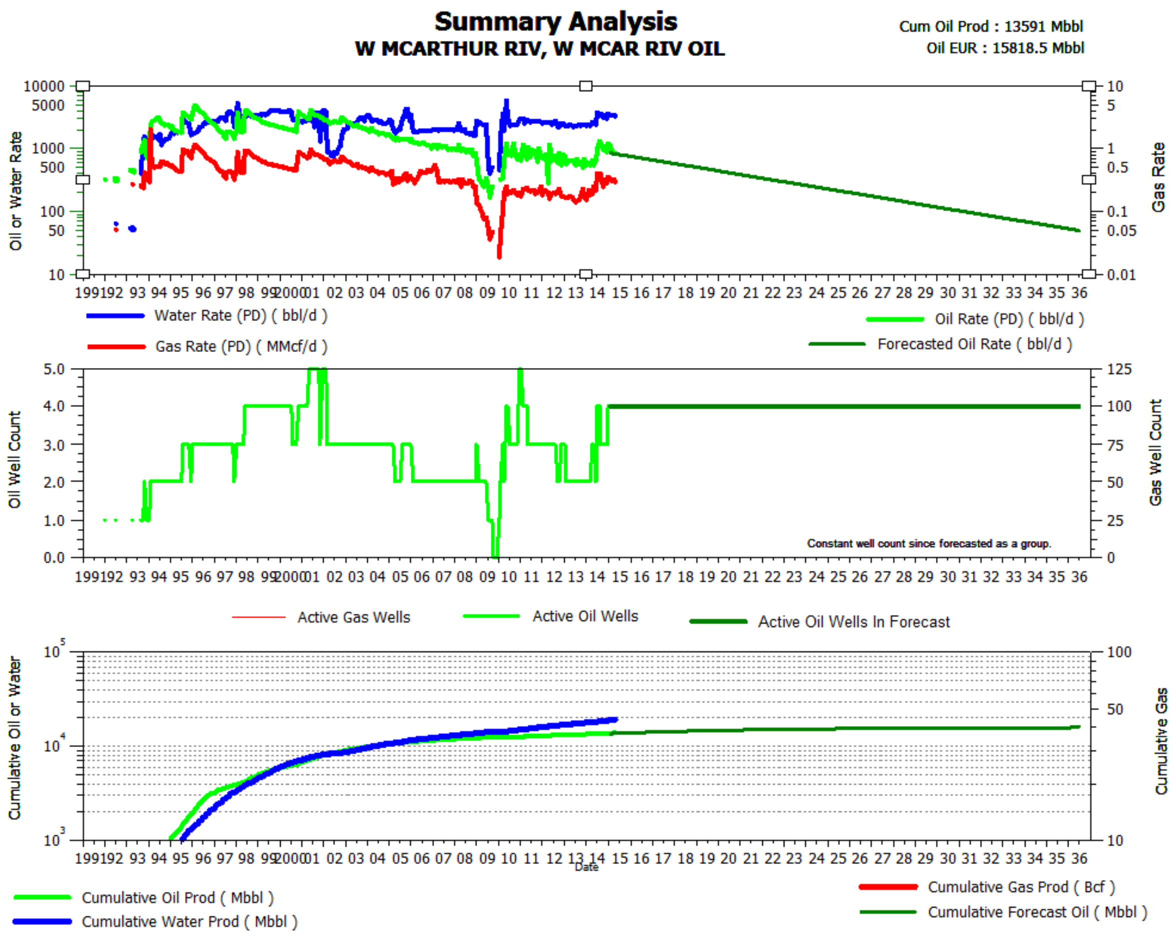

Figure D-7. West McArthur River Field, Pool-Level Analysis of Production from the West McArthur River undefined oil pool.