State of Alaska
Department of Natural Resources
Division of Oil and Gas
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Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves

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Sean Parnell, *Governor*
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Recommended reference citation for this report:

Hartz, J.D., Kremer, M.C., Krouskop, D.L., Silliphant, L.J., Houle, J.A., Anderson P.C., and LePain, D.L., 2009, Decker, P.L., ed., Preliminary engineering and geological evaluation of remaining Cook Inlet gas reserves: Alaska Division of Oil and Gas report, 37 p., available online at: http://www.dog.dnr.state.ak.us/oil/

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EXECUTIVE SUMMARY

Over the past year, there has been widespread 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. Of most immediate concern is whether there may soon be shortfalls during brief spikes in peak gas demand brought about by severe winter weather. A thorough understanding of the problem requires consideration of at least two major sets of issues. The first set includes geologic and engineering details regarding how much gas remains to be recovered from Cook Inlet fields, and what steps are required to access it. The other is a complex set of commercial and infrastructure factors that determine the ability to provide gas to the end user. This report addresses geologic and engineering issues regarding gas reserves and resources. Issues regarding the economics of drilling additional wells, recompleting existing wells, optimizing infrastructure, and the ability to sell the gas into the Cook Inlet market are beyond the scope of this paper. Nevertheless, as is the case with most maturing gas provinces, the costs and financial risk associated with accessing and producing the additional reserves and potential reserves identified by this study will increase with time, likely contributing to increases in the price of gas.

Reservoir engineering and geological analyses were undertaken independently of one another to evaluate the volumes of gas remaining in existing fields. These analyses are preliminary, based on data currently available to the Division of Oil and Gas. All 28 of the currently producing Cook Inlet gas fields were evaluated by applying decline curve analysis and material balance engineering methods to publicly available production data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC). Based on extrapolations of production trends, these engineering techniques were used to derive estimates of remaining proved and probable reserves.

Four of the gas fields judged from engineering analyses to have the greatest remaining potential were selected for further study via detailed geologic analyses: Beluga River, North Cook Inlet, Ninilchik, and the McArthur River Grayling gas sands. Development geology techniques yielded volumetric estimates of original gas-in-place and initial recoverable gas (estimated ultimate recovery) for these four large fields, drawing and preserving important distinctions between gas volumes in known pay intervals versus gas in potential pay intervals. Comparison of geologically based recoverable gas with cumulative production yielded estimates of the remaining recoverable gas in the four fields.

The independent engineering and geologic approaches pursued in this study allow the reporting of remaining gas volumes at varying levels of production certainty and readiness. The total proved, developed, producing (PDP) reserves remaining to be produced from all existing fields in the Cook Inlet is estimated at 863 BCF. This volume was identified by decline curve analyses and assumes sufficient investment to maintain existing wells. Additional probable reserves that would be recoverable by increasing investment in existing fields are estimated at 279 BCF. This volume is identified as the basin-wide difference in the results of material balance methods and decline curve analyses. Geologic evaluations of the Beluga River, North Cook Inlet, Ninilchik, and the McArthur River Grayling gas sands reservoirs indicate the potential for an additional increment of 353 BCF in high-confidence pay intervals, and another possible increment of 643 BCF (in the 50 percent-risked case) from lower-confidence pay intervals, both of which are arguably not in communication with existing wellbores, and thus cannot be estimated from the engineering methods. These incremental volumes are the difference, for these four gas fields, between the remaining recoverable gas estimated in geologically identified high-confidence pay and potential pay minus that estimated by material balance analyses.

These geologically identified volumes of known and potential nonproducing gas represent a significant energy resource, which if developed, have the potential to supply local demand well into the next decade. This forecast assumes that exports of gas from the basin will be curtailed during demand shortfalls, and cease altogether at the closure date of the current export license (March 31, 2011). It also assumes that no new significant demand will be developed until additional resources are discovered in new fields.

We also discuss higher-risk contingent resources that await confirmation and delineation in exploration prospects outside of producing areas where previous well penetrations suggest follow-up drilling may be warranted. Finally, we recognize, but have not attempted to quantify, potential undiscovered gas resources in unexplored areas or underexplored plays within the Cook Inlet basin. Significant work is underway by government and industry stakeholders to analyze this exploration potential, which could be an integral part of the region's energy portfolio well into the future. The findings of this study suggest there are a variety of short-, medium-, and long-term opportunities that have the potential to meet the energy demands of south-central Alaska over the next decade or more.

INTRODUCTION

Purpose of This Study

South-central Alaska has relied on production from Cook Inlet gas fields to meet demand for electrical power generation, heating, and industrial use since commercial production began in the 1950s. Exports of liquefied natural gas (LNG) have been another significant sector of the region's gas market since 1969. A salient characteristic of south-central Alaska's natural gas demand profile is the pronounced seasonal fluctuation in fuel consumption for heating and power generation. In addition to the highly predictable difference between average summer usage and average winter usage, there are large, less predictable demand spikes during winter cold spells. Up to this point, producers have been able to meet spikes in consumer demand by incrementally adjusting production at the field and wellhead level. Curtailing industrial consumption, for example, closure of the Agrium US, Inc. fertilizer plant in Nikiski, has also played an important role in utility load management. More recently however, as an increasing number of Cook Inlet's fields show significant decline, concern has arisen over the producers' ability to provide sufficient gas to consumers during winter demand spikes, with some predicting shortfalls beginning in 2011-2013 (Petroleum News, 2009). This report summarizes the results of engineering and geologic analyses conducted within the Alaska Division of Oil and Gas (DOG) to better quantify remaining accessible reserves in the Cook Inlet's major gas fields, and to categorize these volumes relative to readiness and certainty of production. Many closely related economic and infrastructure considerations are outside the scope of these analyses.

As Cook Inlet gas (and oil) fields mature, it is prudent to re-evaluate the original gas-in-place (OGIP) and compare that against cumulative production in order to assess remaining reserves. Most oil and gas fields in Alaska have outperformed their initial estimates for original in-place hydrocarbons (for example, Blasko, 1974), so it is critical for resource managers to continually re-evaluate the reserves picture as new data and new technology is acquired. The purpose of this study is to examine and analyze the currently available engineering and geologic data to determine if enough gas is available to meet the anticipated demand for south-central Alaska for the next decade. The analysis assumes sufficient market opportunities will exist to drive appropriate investment in more complete field development operations, infrastructure de-bottle-necking and upgrades, and commercial alignment between unit partners. Both engineering and geologic methods were employed in the analysis of existing fields, and a complete description of the methodologies can be found in the body of this report. The results of this work will help determine how much gas remains in the Cook Inlet fields so that realistic development scenarios can be formulated. The economics of drilling additional wells, recompleting existing wells and the ability to economically transport and sell the gas into the Cook Inlet market are important commercial issues that were not addressed by this work.

Although new gas found through exploration activity outside of existing field areas will be an important part of the long term reserves outlook for the Cook Inlet, those resources can take years to identify and bring on line, so they may not affect the short-term development issues addressed in this study. Nevertheless, a brief discussion on exploration potential in the basin is included in this report, and the reader is encouraged to keep up-to-date on subsequent state and federal publications that will further address exploration potential.

Regional Geology

The Cook Inlet basin is part of a northeast-trending collisional forearc setting that extends approximately from Shelikof Straight in the southwest to the Wrangell Mountains in the northeast. The basin is bounded on the west and north by granitic batholiths and volcanoes of the Aleutian volcanic arc and Alaska Range, respectively, and on the east and south by the Chugach and Kenai Mountains, which represent the emergent portion of an enormous accretionary prism (Haeussler and others, 2000; Nokleberg and others, 1994). High-angle faults, including the Bruin Bay, Castle Mountain, and Capps Glacier faults, modified the west and north sides of the forearc basin (for example, Barnes and Cobb, 1966; Magoon and others, 1976). The Border Ranges fault lies near the eastern edge of the forearc basin (fig. 1; for example, Magoon and others, 1976; Bradley and others, 1999), but is locally overlapped by Cenozoic basin-filling strata.

Mesozoic strata, having a regional composite thickness of nearly 40,000 feet, represent the foundation upon which the Cenozoic forearc basin developed (Kirschner and Lyon, 1973; fig. 2). Mesozoic strata extend continuously at depth under Tertiary nonmarine deposits and are exposed along the up-turned western and eastern margins of the forearc basin (Fisher and Magoon, 1978; Magoon and Egbert, 1986). Tertiary nonmarine strata, which are up to 25,000 feet thick in the axial region of the basin (Boss and others, 1976), consist of a complex assemblage of alluvial fan, axial fluvial, and alluvial floodbasin depositional systems (Swenson, 2002). These Tertiary nonmarine strata are the primary oil and gas reservoirs in the basin.

The Tertiary stratigraphy of the basin is complex (fig. 2) and includes a basal unnamed unit of Paleocene to early Eocene age that is correlative to parts of the Wishbone, Chickaloon, and Arkose Ridge Formations in the Matanuska Valley segment of the basin (an older uplifted segment of the forearc basin according to Trop and Ridgway, 2007). The overlying stratigraphic units were assigned to the Kenai Group by Calderwood and Fackler (1972) and originally included, in ascending order, the West Foreland Formation, the Hemlock Conglomerate, the Tyonek Formation, the Beluga Formation, and the Sterling Formation. Boss and others (1976) subsequently restricted the Kenai Group to the Tyonek, Beluga, and Sterling Formations on the basis of interpreted unconformities between the West Foreland and Tyonek. They considered the Hemlock Conglomerate a member of the Tyonek Formation. The overlapping ages of these formations shown in figure 2 demonstrates the time-transgressive nature of the Tertiary stratigraphy (McGowen and others from Swenson, 2002). Limited outcrops around the perimeter of the basin demonstrate dramatic facies changes from basin axis to basin margin locations.

Large hydrocarbon traps were formed in the Tertiary nonmarine strata of the upper Cook Inlet when the thick succession of reservoir facies were deformed into a series of north-northeast-trending, discontinuous folds arranged in an en echelon pattern. Most fold structures formed by right lateral transpressional deformation on oblique-slip faults (Haeussler and others, 2000). Many of these faults extend into underlying Mesozoic age marine rocks. These structures are attributed to the ongoing collision between the Yakutat block in southeastern Alaska and inboard terranes across much of southern and central Alaska (Trop and Ridgway, 2007). This collision is resulting in the progressive collapse of the forearc basin from the northeast toward the southwest (analogous to a closing zipper; Trop and Ridgway, 2007). All producing oil and gas fields in upper Cook Inlet are asso-

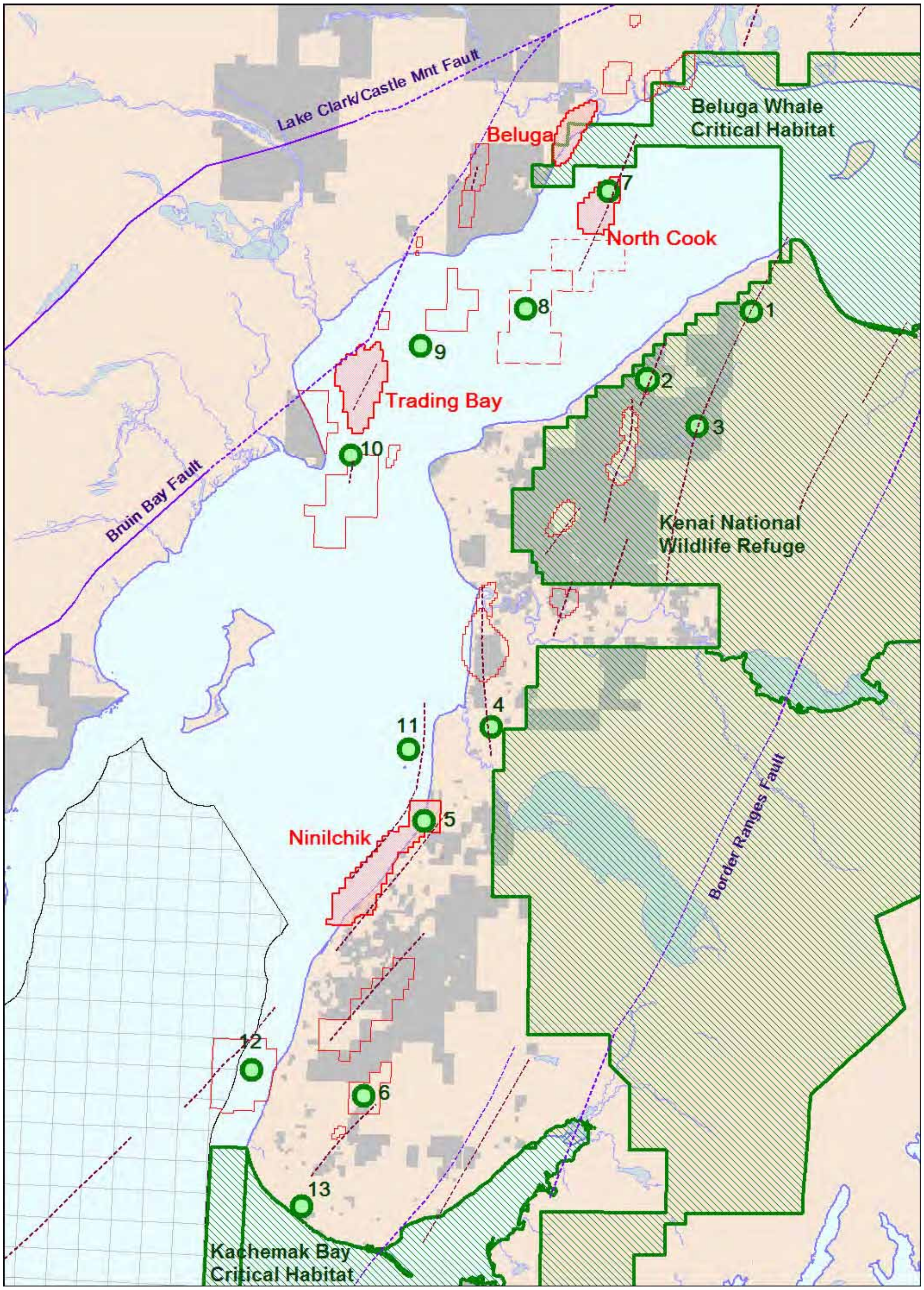

Figure 1. Location map of the central part of the Cook Inlet basin showing oil and gas producing units (the four major gas fields with geologic reserve estimates are highlighted with pink fill); major faults and fold axes; undeveloped exploration leads (numbered green dots); and areas with exploration access restrictions (green hachure).

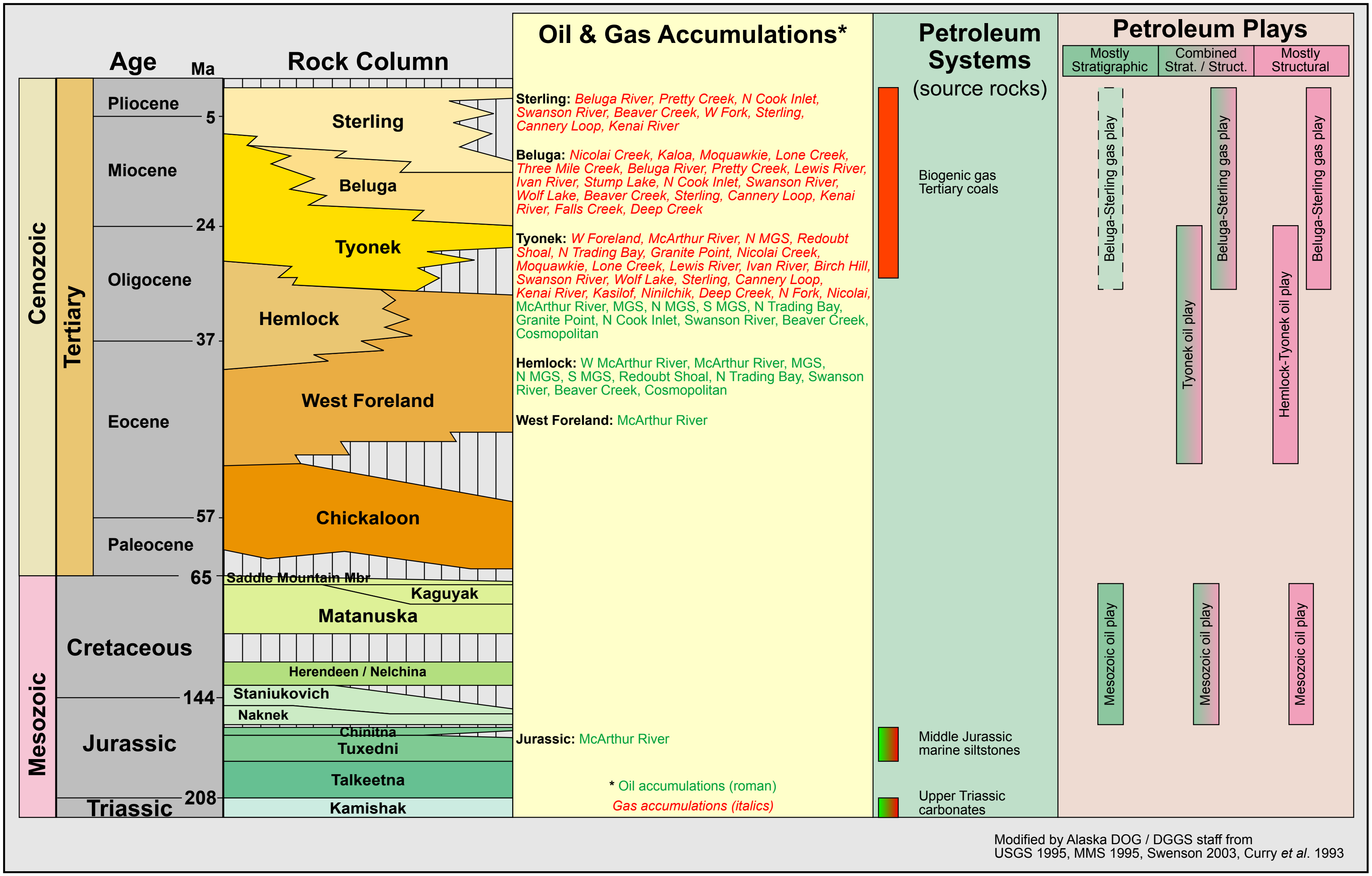

Figure 2. Chronostratigraphic and petroleum systems summary chart for the Cook Inlet basin

ciated with structural closures. Gas in most fields resulted from release of biogenic methane as thick coal-bearing successions were uplifted along fold structures.

Cook Inlet Petroleum Systems

In order to understand how a natural resource can be optimally developed, it is important to understand its origin and history. The oil and gas produced from the Cook Inlet fields (fig. 1) come from two separate and distinct hydrocarbon systems. The oil, along with minor amounts of associated gas, was generated in deeply buried Mesozoic source rocks by thermogenic (temperature-driven) processes. Expelled from the source rock under high pressure, these buoyant hydrocarbons migrated upward along faults and permeable strata into trapping geometries in Hemlock and lower Tyonek sandstones of Tertiary age (fig. 2). More than 1.3 billion barrels of oil have been discovered and produced from these reservoirs since 1958.

The petroleum system that is the focus of this paper, and has become the recent focus of many south-central Alaskans, is a biogenic system that produced dry natural gas (methane). The generation, migration, and trapping of this resource are significantly different than that of the oil. The biogenic methane, which accounts for more than 90 percent (Claypool and others, 1980) of the nearly 7.75 trillion cubic feet (TCF) of historic gas production in Cook Inlet, was sourced from the widespread coals in the shallower part of the Tertiary section. Unlike thermogenic hydrocarbon generation, biogenic gas generation relies on bacteria that thrive only at relatively shallow burial depths where temperatures are less than about 80°C. Biogenic methane begins to form by decay of organic matter in the near surface environment. As deposition proceeds and bacterial methane continues to form, large quantities dissolve in the surrounding pore waters and remain adsorbed in coal beds. In the Cook Inlet basin, late-stage uplift lowered the pore fluid pressure and liberated the gas from solution in the coals, allowing it to migrate relatively short distances into fluvial sandstone reservoirs in the Tyonek, Beluga, and Sterling Formations. The complex geometries of these Tertiary reservoir sandstones, as well as the coal-to-sand migration pathways, provide both challenge and opportunity for field development. The same geologic complexity that makes it difficult to identify all potential reserves in a field also provides ubiquitous isolated reservoirs containing a significant amount of untapped gas potential.

PROCESS, DATA, AND COMPARISON OF ANALYTICAL TECHNIQUES

This report presents preliminary findings regarding forecast production, original gas-in-place, and estimated remaining reserves for Cook Inlet natural gas fields. We estimate remaining reserves at varying levels of production certainty using reservoir engineering and development geology methods (Table 1). The two approaches are very different, both conceptually and in analytical scope, and are discussed separately. It is important that multiple analytical methods are employed in analyzing complex fluvial systems like the Cook Inlet gas reservoirs because each method evaluates a slightly different portion of the reserves picture. Because they are based on extrapolations of historical production data, the engineering approaches are limited by the extent of field development that has occurred to date, and yield the more conservative estimates. The geologic analyses calculate larger reserve estimates because they assess the entire field, including upside potential from nonproducing intervals that may be capable of produc-

Increasing Certainty of Production ←

→ *Increasing Potential and Cost*

	Engineering Analyses		Geologic Analyses	
	Decline Curve Analysis	**Material Balance**	**Geologic, PAY category only**	**Geologic, PAY + 50%-risked Potential_Pay**
Sum 4 Fields	697	860	1,213	1,856
Sum Other Fields	166	282	not analyzed	not analyzed
Total	863	1,142	--	--

Notes: All values in BCF. Other fields are 24 remaining Cook Inlet producing gas fields (see Table 2).

Table 1. Comparison showing a range of estimated remaining gas reserves based on separate engineering and geologic analyses of four fields: Beluga River, North Cook Inlet, Ninilchik, and McArthur River (Grayling gas sands). These results suggest that geologic analyses identify gas reserves in pay and potential pay intervals that have not been fully developed, and therefore, cannot be represented in the engineering-based estimates.

ing. Throughout this report, we consistently present estimated gas volumes rounded to the single BCF to facilitate comparisons with values in the tables and appendices that represent calculated results. In reality, most of these estimates carry considerable uncertainty, and many could be rounded at lower levels of apparent precision for purposes of discussion outside of this text.

The engineering approaches are introduced first, followed by a discussion of the deterministic geologic approach. Two primary reservoir engineering methods, decline curve analysis and material balance analysis, were applied to 28 producing gas reservoirs to determine proved developed producing (PDP or 1P) reserves and probable (2P) reserves (Society of Petroleum Engineers and others, 2007).

Decline curve analysis (DCA) reflects only that gas that has been in communication with producing wellbores and has been produced relatively continuously over the life of the field. It cannot account for gas shut in early in field life, gas behind pipe and never perforated, nor gas between wells with large spacing. Additionally, estimates of original gas in place (OGIP) derived from material balance techniques (MB) represent only gas that has produced into a wellbore at some point during field life. The geological analysis calculates an OGIP for the entire structure and attempts to include potential untapped gas sands that were logged in the wellbore but never produced, marginal quality reservoirs that were not perforated at initial field development, or isolated reservoirs that lie between existing wellbores because well spacing is not sufficient to encounter them.

The engineering analyses relied on public domain production and pressure data that producers report to the Alaska Oil and Gas Conservation Commission (AOGCC) on a monthly basis. Thus, in order to estimate deliverability, a daily rate must be calculated from the reported monthly values in order to predict short term demands. Decline curve analysis (DCA) was primarily used to forecast production and estimate remaining recoverable gas (RRG). Material balance methods were used to validate DCA estimates and determine OGIP and RRG. The future production rates and volumes have been compared to anticipated demand to predict gas availability in the Cook Inlet basin over the next decade.

The geologic analysis was limited to four of the five largest existing fields that are still being actively developed and that the engineering analyses indicate have the greatest share of future gas production potential. A deterministic geologic approach was used to identify pay and potential pay in the North Cook Inlet, Beluga River, Ninilchik, and the McArthur River (Grayling gas sands) fields. The geologic analysis utilized well log curves, drilling and completion history, pressure history, and production data to identify and map pay at the field scale as a basis for new calculations of original gas-in-place, initial recoverable reserves, and remaining reserves.

The Kenai gas field was not included in the geologic analyses because it is a federal unit and the State has limited well data and no seismic data over the field. We did conduct engineering analyses of the Kenai field because the production data are publicly available from the AOGCC. Of all the fields in the basin, the Kenai gas field has been subjected to the most aggressive second- and third-cycle development efforts to maximize recovery and access gas in tight reservoirs. As discussed later, the Kenai field is an excellent example of the late-life reserves growth that can be achieved with continuing development investment.

Table 1 organizes the gas reserve estimates of this study relative to readiness and certainty of production. In standardized reserves and resources nomenclature (for example, Society of Petroleum Engineers and others, 2007), our estimates derived from decline curve analysis can be considered proved reserves, whereas estimates identified from material balance represent probable reserves. The geologically derived estimates represent a mix of proved, probable, and possible reserves as well as some contingent resources. These analyses do not include economic filters, so it is not possible to draw a line between commercial reserves and subcommercial resources. Prospective resources, those remaining to be discovered, are discussed in less specific terms in the exploration potential section of this report. Estimates of exploration resources reflect a combination of in-house exploration experience, interpretation of publicly available geological and geophysical data, and resource assessments and other reports published by the U.S. Geological Survey and the U.S. Department of Energy.

RESERVOIR ENGINEERING ESTIMATES

Decline Curve Analysis

Decline curve analysis (DCA) is a standard petroleum engineering technique whereby current production trends are extrapolated into the future to estimate rates, and by integration, the remaining recoverable gas (RRG). As outlined above, DCA is based only on historically and currently producing gas that is in communication with the producing wellbores. By definition, DCA cannot measure gas reserves that exist in hydraulically isolated reservoir volumes (zones, sandbodies, or structural compartments) until that part of the reservoir is perforated for production into the well. RRG in this context is only the developed gas left in the container. A reservoir DCA will change significantly during the period it is being developed. Early estimates will under-predict RRG if the reservoir is not fully developed (fig. 3).

The decline curve analysis is a relatively conservative look at future gas production because it represents a snapshot influenced by past events, and does not fully account for future events. Therefore, the forecast is a prediction of future performance assuming past trends will remain the same and all investment to support it will remain constant. Decline curves were based on monthly AOGCC production volumes or rates plotted on a logarithmic scale versus a linear time scale in months. The semi-log plot dampens minor data fluctuation and lends itself to a linear extrapolation referred to as exponential decline. The DCA portion of this work is based on the assumption that the reservoirs exhibit volumetric (tank-like) behavior. The linear decline extrapolation yields RRG by integration of the area under the line (fig. 3).

DCA recoveries were calculated on a well basis for the larger units where wells produce nearly continuously and on a pool, reservoir, or unit basis for every field that is active. There were several cases where decline appeared hyperbolic, which, on semi-log charts, plots as a curve in early to mid-life and becomes linear in late field life. Hyperbolic decline is often characteristic of low permeability reservoir rock, but it may be masked by water production, production at rates below capacity, and other well events. Another factor affecting decline is water influx from an underlying aquifer. If the aquifer is large compared to the gas reservoir, water influx will act to partially replace the gas produced from the pore space and sustain the reservoir pressure in the early to mid-life of the reservoir. A derivative effect is that as water influx into the wellbore increases, the pressure gradient increases, resulting in a steepening of the decline rate. Water influx in the Cook Inlet basin reservoirs is complicated by fluvial depositional systems that contain stratigraphically discontinuous layers of separate productive sands. Individual layers may not be in pressure communication and most likely have different gas-water contacts, especially in the Beluga and Tyonek sands. Production performance changes as water invades some intervals, effectively shutting off production and trapping gas, resulting in decreased overall recovery.

The DCA forecast of remaining proved, developed, producing gas in the 28 Cook Inlet fields amounted to a total of 863 BCF, with 697 BCF in just four fields (Beluga River, North Cook Inlet, Ninilchik, and the McArthur River Grayling gas sands). The DCA forecast rate represents an “annual average rate forecast” as depicted in figure 4. This estimate should be viewed as fairly conservative because of certain assumptions inherent in the technique. The forecast rate is usually conservative where wells and reservoirs do not produce at maximum capacity on an annual basis. This limitation applies to the Cook Inlet gas market, which is notable for its large demand swings between summer and winter. Thus, the daily or monthly production from the reservoir or individual well does not always represent its productive capacity. Daily production rates for gas wells are dictated by daily or monthly demand, volumes specified in production contracts, and LNG export volumes. In addition, the reservoir and wells often produce at surface pressure considerably higher than pipeline conditions (choked back). Under those conditions, DCA cannot accurately predict future production capability. Another difficulty is accurate representation of future investments and projects to sustain rates such as drilling wells, remedial activity, new perforations, well workovers, and

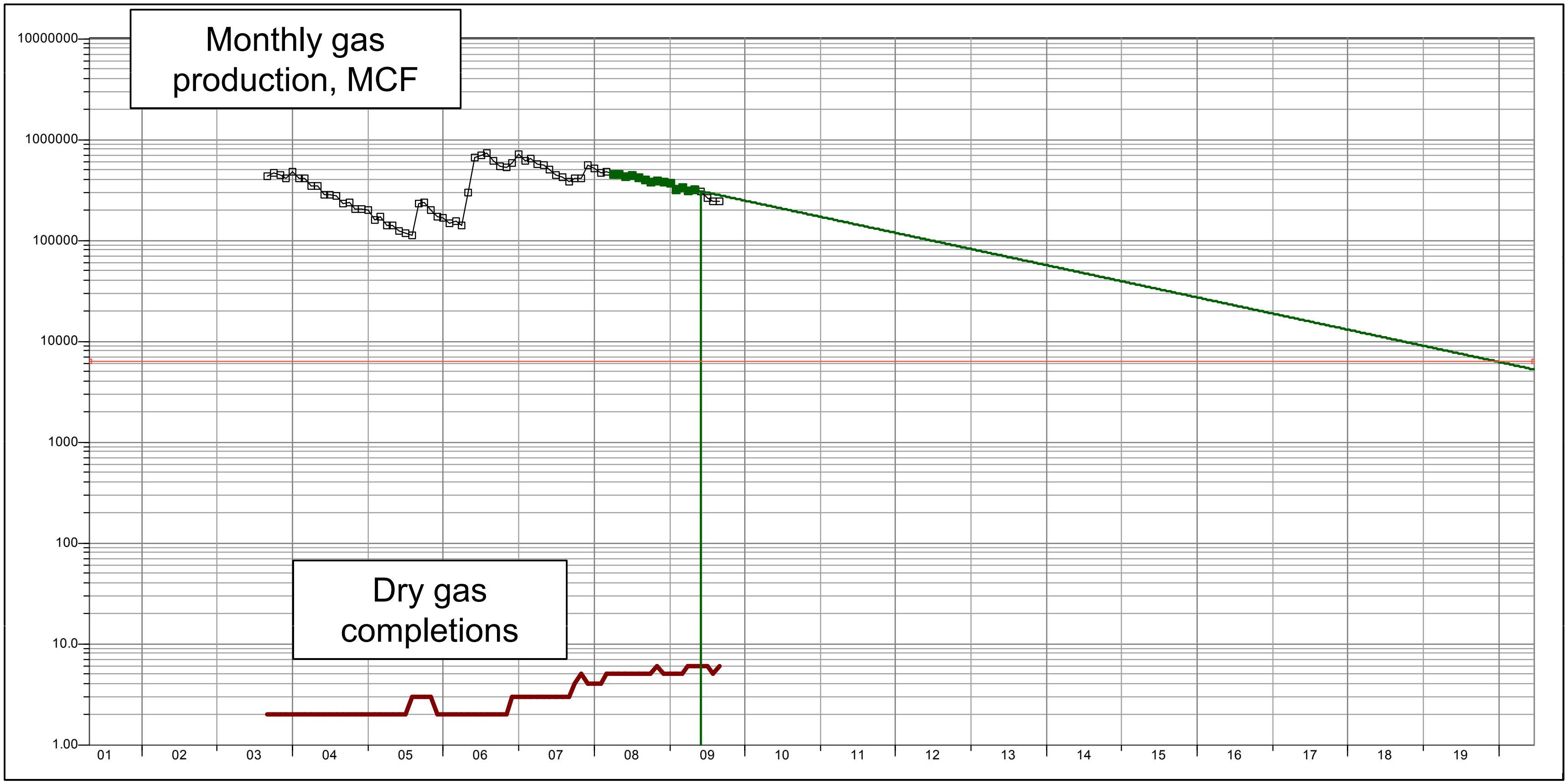

Figure 3. Typical decline plot; the Ninilchik GO Tyonek reservoir decline plot is illustrated. Horizontal axis is time (2001-2019); vertical axis is monthly production volume in thousands of cubic feet (MCF/month). Note the steep decrease from 2002 until mid 2004. As new wells are added (the lower red line on the chart) between 2004 and 2006, the production rate increased in a step fashion, then begins to decline again in 2007 to present. Some of the rate increase may be a result of perforation of new sands or stimulation of perforated sands. This chart is a good example of impacts of development activity early in the reservoir's life. When the reservoir is fully developed, it will follow the trend until depleted. Decline curve analyses are used to estimate remaining proved, developed, producing gas reserves.

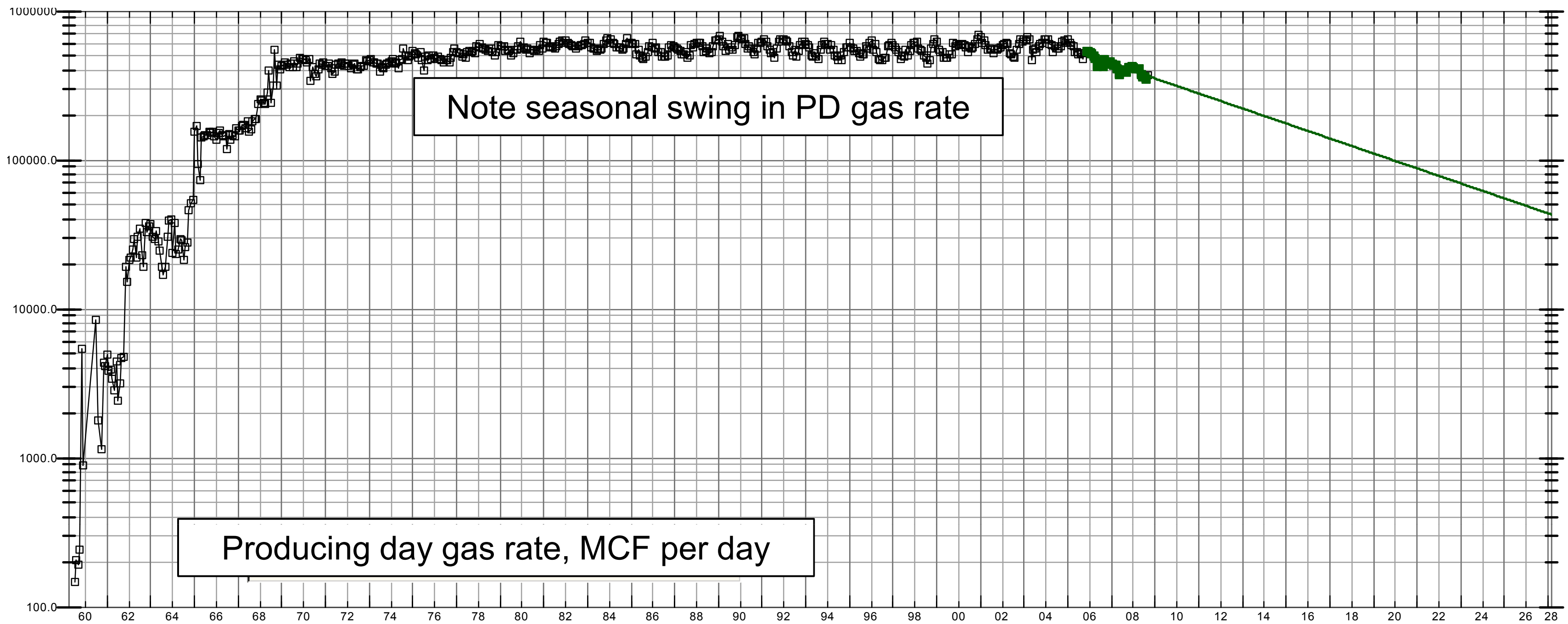

Figure 4. Decline curve projection based on data trend for production from all 28 Cook Inlet gas fields. Horizontal axis is time (1960-2028); vertical axis is producing day gas rate (MCF/day). Extrapolation line represents an annual average rate forecast, and does not illustrate seasonal fluctuation in demand.

additional compression. Figure 5 illustrates how DCA reserve estimates change after new wells are put on production. The initial rate forecast is considerably lower because it does not account for incremental production from the new completions.

If development investment does not continue in later field life, the decline trend will steepen because gas rate is dependent on regular maintenance or remediation. Changes in future economic conditions will influence gas availability affected by contract obligations, cost of maintenance, investment capital availability, and return on investment. Previous Cook Inlet rate forecasts have been subject to the same limitations.

Material Balance Analysis

Material Balance (MB) is a technique that uses the volumetric relationship between pressure, gas properties, and production to define OGIP and project remaining recoverable gas (RRG). A plot of reservoir pressure, P, divided by Z, the gas compressibility factor, yields a straight line that defines the volume of gas in the reservoir. Our MB analysis relies on reservoir pressure, reservoir characteristics, and gas production data from AOGCC databases. In most cases the linear trend can be extrapolated to zero pressure to determine the initial amount of gas in pressure communication throughout the reservoir, or OGIP. Note that material balance estimates account only for gas in pressure communication with producing wells, and cannot predict gas in isolated parts of the reservoir.

P/Z extrapolated to abandonment pressure will yield RRG for the reservoir sands that are in hydraulic (pressure) communication. A public domain spreadsheet program from Ryder Scott Company, L.P. was used to account for reservoir properties such as temperature, gas gravity, water saturation, gas composition, rock compressibility, and the Z factor for calculating P/Z based on periodic pressure measurements.

Figure 6 is an example of a typical P/Z MB plot. In this example, extrapolation to P/Z = 0 psia yields OGIP of 4.5 BCF and RRG, assuming abandonment P/Z=194 (~200 psia), is 4.2 BCF. The RRG is dependent on accurate knowledge of the abandonment pressure. Although we assumed an abandonment pressure of ~200 psia, the ultimate pressure for a given reservoir will be a function of operation costs, price of gas, and cost of compression. The surface production pressure is a function of reservoir pressure depletion and pipeline conditions. Wells in the Kenai gas field produce at surfaces pressure between 20 and 200 + psia, depending on pad location and the compressor configuration. Therefore, assuming a 200 psia abandonment pressure can underestimate RRG. In other fields in the basin the current surface producing pressure exceeds 800 to 1000 psia.

North Cook Inlet Unit (NCIU) and Beluga River Unit (BRU), had pressure data for each well going back 20-30 years. Most other pools had average pool pressures provided to AOGCC on a periodic basis. Even though the Sterling and Beluga Formations in the BRU are metered separately, the gas production is reported to AOGCC as a single commingled volume. Because gas production data for each formation are not available for the Beluga River Unit, the MB calculation is less reliable due to the uncertainty introduced by arbitrarily dividing the reported combined Beluga and Sterling Formations gas production back into two separate formations.

None of the reservoir P/Z plots showed evidence of active pressure support or water drive; however there is distinct evidence of water influx (fig. 7). Water influx steepens the

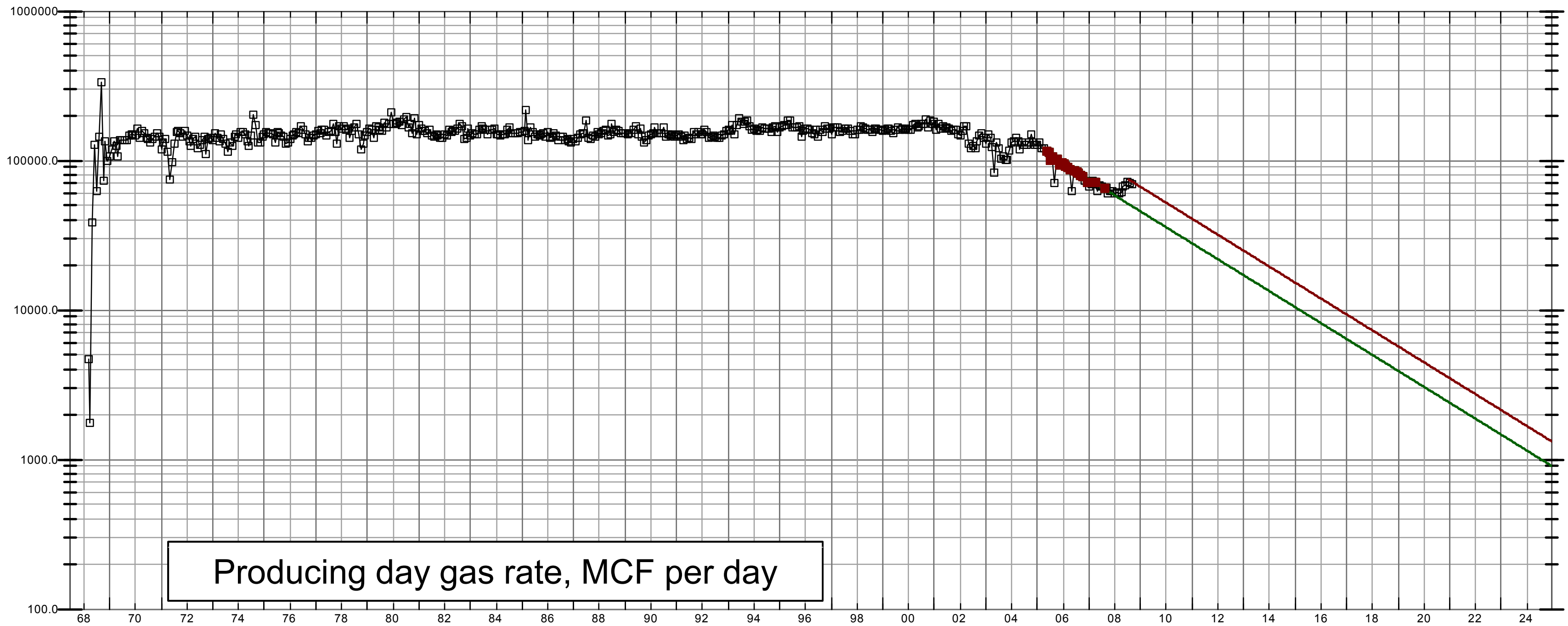

Figure 5. Example of decline curve analysis before and after new wells, North Cook Inlet Unit. Horizontal axis is time (1968-2025), vertical axis is monthly production volume in thousands of cubic feet (MCF). The well-established decline trend from 2004 to 2008 changes as new wells are added (green line versus red line trends). The remaining recoverable gas estimated from each trend will differ.

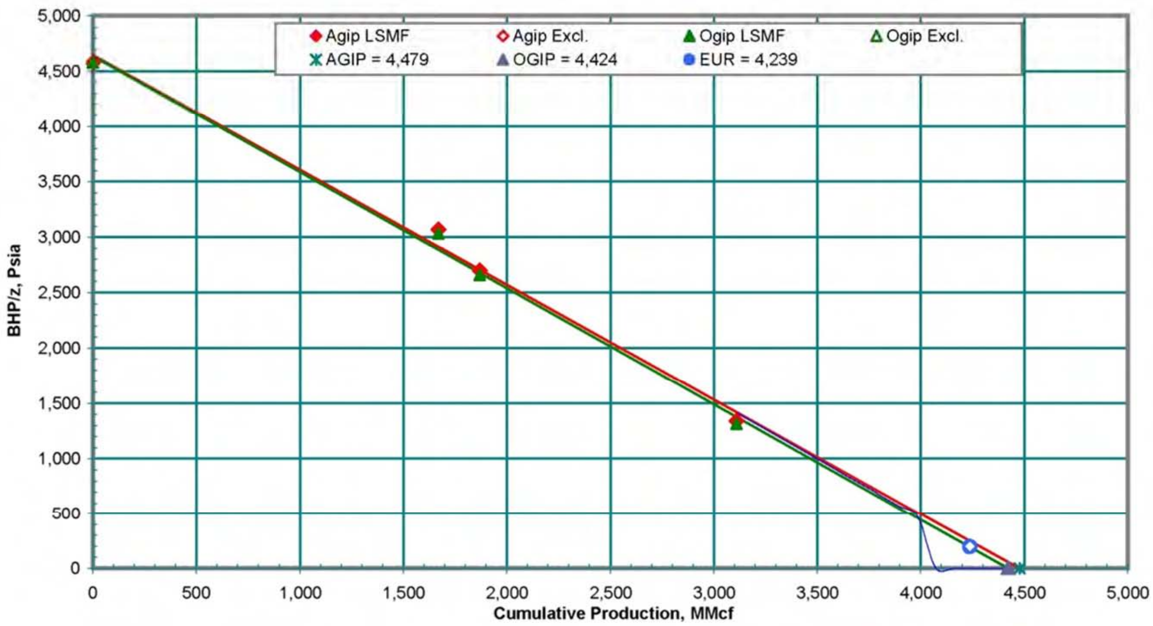

Figure 6. Typical P/Z plot. Vertical axis represents bottom hole pressure divided by Z, a dimensionless factor related to gas density, pressure, and temperature. The horizontal axis is cumulative gas volume produced at the time pressure is measured. Extrapolation of the trend will determine remaining recoverable gas and original gas in place at abandonment and 0 pressure respectively.

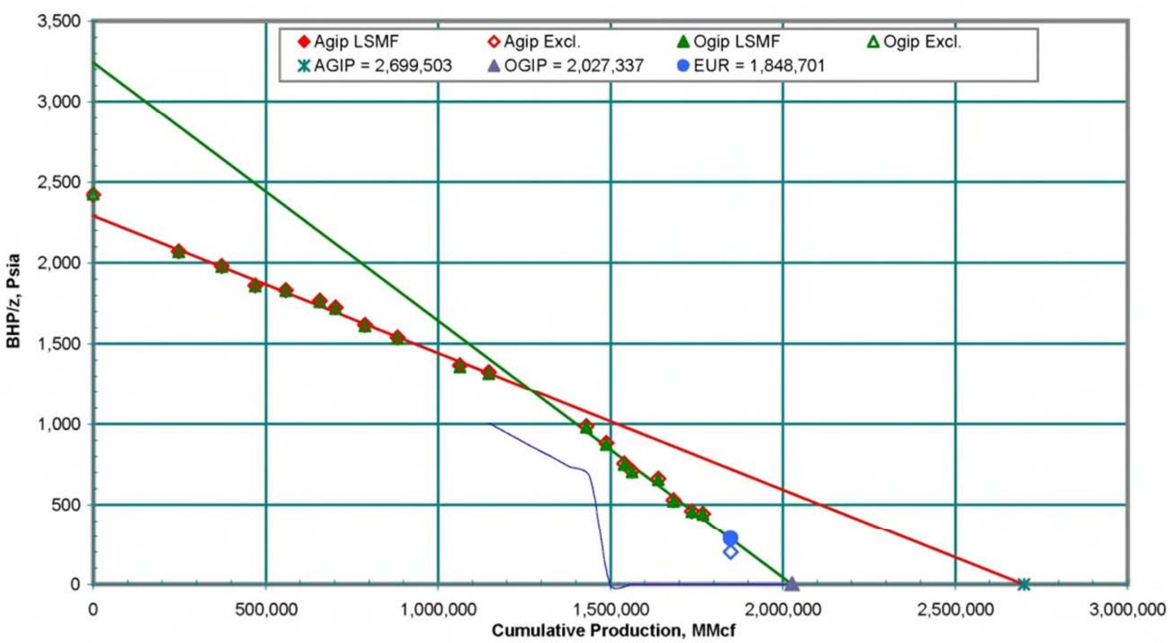

Figure 7. P/Z plot showing water influx and reservoir shrinkage. The initial trend (red line) shows a much higher in-place volume through production to about 1,300 BCF cumulative production. The later trend (green line) shows how water production has caused reservoir hydrocarbon volume to shrink by isolation of water dominated sand intervals or displacement of gas by water. Either way, the effect is reduction of hydrocarbon volume in communication within the reservoir.

slope of the linear P/Z trend. Water influx may trap gas or invade the reservoir space and replace gas, and in many cases, requires the invaded interval to be cemented off, isolating a portion of the reservoir and effectively shrinking the productive pore volume if not accessed by another well up-dip. In the example shown in figure 7, water influx has reduced the volume of gas producible at an assumed abandonment P/Z value of 200 psia by more than 600 BCF. Cases of this type were reviewed to ensure data accuracy and account for water impacts. Generally, the MB trend was either very clear, or it was unusable.

Another issue affecting the MB calculations is the validity and quality of the pressure data reported to AOGCC. The quality of pressure data depends on the type of reservoir and the method used to estimate or measure reservoir pressure. A good understanding of the common geological and engineering attributes of Cook Inlet fields, such as multi-formation pools, complex layering, discontinuous stratigraphic layers, and communication throughout the reservoirs is necessary to properly interpret the pressure data.

Some reservoirs had few points for P/Z analysis or the data were scattered, inconsistent, and subject to unstable measurement caused by insufficient shut-in time. In several cases, the P/Z results had to be disregarded because there was insufficient pressure data, no reasonable trend or the resulting RRG differed significantly from the decline analysis. There are several pools where P/Z showed less original gas-in-place than what had already been produced. Such discrepencies highlight the need for rigorous review and reiteration of MB calculations and further investigation of possible causes for questionable results. Comparison with other methods and inclusion of periphery data is also critical in order to come up with reasonable estimations.

The material balance and decline curve results were compared to look for significant inconsistencies. Analyses were reviewed and material balances or decline analyses for a given unit were repeated to account for obvious discrepancies. In some cases, the process of turning wells on and off over time creates the illusion that a pool's production is declining much slower (that is, the pool has more gas remaining) than shown by analyses of the individual wells in the pool. Although the seasonal swing is evident in a field-level production chart, it is often obscure when looking at charts for individual wells. This can be problematic for wells that do not have a long history trend and the winter to summer swing has a large influence on the decline in relation to the MB. In those cases, all available data were reviewed in order to determine which result should be used. In most instances it was possible to find trends that better suited the data or it was possible to see what caused the problem and come to a reasonable conclusion.

In many cases MB calculated significantly more gas than the DCA; we view this excess as potentially recoverable gas. Judgment and reservoir performance were required in reconciling differences between MB- and DCA-based estimates. In general, where production behavior is predictable and water influx is not an issue, the trends made sense and were used to estimate both remaining recoverable gas and additional potential.

Table 2 provides the results of the DCA forecast and the results of the MB calculations for 28 Cook Inlet gas fields. The difference between MB and DCA remaining recoverable reserves totals 279 BCF at 200 psia abandonment pressure. The difference increases by 120 BCF if estimated at 50 psia abandonment. Although abandonment pressure of 50 psia may be attainable in general, each reservoir must be evaluated for its cost-benefit at abandonment.

Field	Decline Forecast Production, BCF	Material Balance RRG - Decline, BCF	Material Balance or Decline EUR, BCF
Kenai	90	24	2,484
North Cook Inlet	145	47	2,011
Beluga River	377	96	1,622
McArthur River (Grayling gas sands)	113	20	1,509
Ninilchik	62	-	165
Beaver Creek	23	51	279
Kenai (Cannery Loop Unit)	27	18	218
Granite Point	7	2	141
Middle Ground Shoal	2	1	113
Ivan River	4	8	93
Trading Bay	1	-	89
Swanson River	1	-	61
Lewis River	1	9	23
Deep Creek	5	-	19
Stump lake	-	-	16
West Foreland	1	3	15
Sterling	1	-	14
Lone Creek	-	-	7
West Fork	-	-	6
Nicolai Creek	1	-	6
Moquawkie	0	-	4
Kasilof	-	1	4
West McArthur River	0	-	3
Albert Kaloa	-	-	3
Three Mile Creek	0	-	2
Redoubt Shoal	0	-	1
Wolf Lake	-	-	1
Kustatan	0	0	1
Total	863	279	8,910

Table 2. Decline forecast, additional potential remaining recoverable gas identified from material balance analysis, and estimated ultimate recovery for 28 Cook Inlet gas fields. Geologic volumetric analyses were prepared for the four large fields (shaded) at top of list.

The MB-DCA difference represents gas that is in communication with the current completions in a reservoir. Conceptually, MB estimates greater than DCA estimates suggest that the reservoir is not producing at its maximum capacity. Investment may be required to access the potential gas reserve additions in the form of well stimulations, installation of compression, re-drills, or other activities to improve reservoir performance.

Large Field Reserves Growth

We calculated a time series of estimated ultimate recovery (EUR) for the 28 gas fields by adding cumulative production to RRG at each interval. Tracking EUR over time is useful for observing the effect of development as a reservoir matures. Early EUR estimates are typically conservative and often increase as development progresses and more of the in-place gas resource moves to the producible reserves category. Progressive reservoir development is the rule in markets such as the Cook Inlet that can only absorb a fixed amount of gas per year. The four largest reservoirs (Kenai, Beluga River, North Cook Inlet, and the McArthur River Grayling gas sands) demonstrate this reserves growth in the EUR progression.

A review of past DCA forecasts and MB estimates (sources: DOG Annual Reports–1994, 1999, 2003, 2007, and 2009 internal estimates) showed significant growth in the last 10 years. Figure 8 is a chart showing the EUR at various stages of development since 1993. Comparison of EUR at various dates indicated reserves in three of the largest fields (Kenai, Beluga River and McArthur River Grayling gas sands reservoir) grew by more than 770 BCF; however the North Cook Inlet field appeared to decrease by about 360 BCF. It will be critical to further assess the reason for this decline. The reserves growth in all the other fields can be attributed to 42 new and redrilled wells during the period, and additional perforation and stimulation activity. The apparent decrease at North Cook Inlet may be caused by water influx and cementing off a number of intervals, effectively reducing the reservoir volume, but it is unclear with the currently available data. The EUR calculations demonstrate that even in mature fields such as Kenai, significant reserve growth is still possible after 30-40 years of production with diligent and systematic well work.

Deliverability at the Well and Reservoir Scale

In the following discussion, “deliverability” is used in the strict engineering sense of the term, which refers to the gas production capabilities of a well, or in some cases, production capabilities at the reservoir scale (for example, Lee, 2007, p. 840). This discussion does not address the much broader set of commercial and infrastructure factors that determine the ability of the entire Cook Inlet gas production and distribution network to provide gas to the end user. Determining deliverability at the well and reservoir scale is, nonetheless, a key part of predicting the overall system’s ability to satisfy peak demand.

Past and present well or reservoir deliverability. One analysis method used to mitigate decline forecast shortcomings is accurate measurement and forecasting of daily well rates on a periodic basis. This can be done with real time data, or by converting monthly data to daily figures in order to calculate producing day (PD) well rate. The most accurate PD data are production rate measurements taken on a daily basis along with producing pressure and temperature. Unfortunately, the Division of Oil and Gas does not have daily data and can

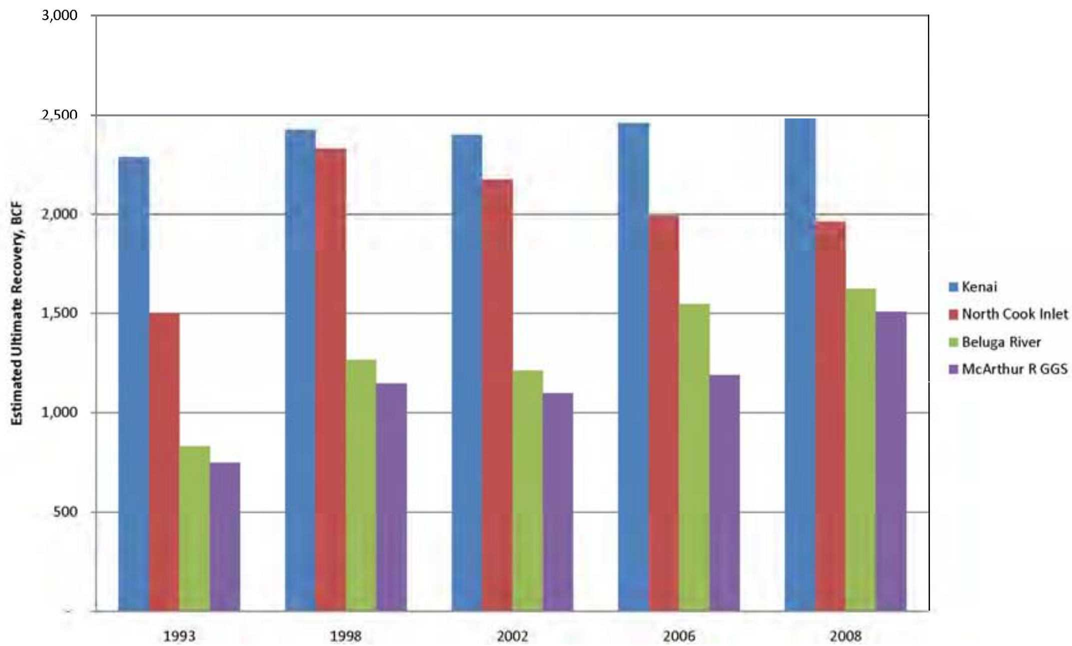

Figure 8. Reserves growth in Cook Inlet's largest gas fields, 1993-2008.

only estimate an average maximum daily rate on a monthly basis. The result is a smoothed rate profile that does not reflect the daily to weekly peaks and lows corresponding to short term demand swings.

Evaluating past well or reservoir deliverability estimates gives a hint of the relationship between average annual gas rate from DCA and peak PD gas rate from monthly volumes and producing day data. Calculations were based on a summation of producing day rates for each gas well by month (initially excluding storage production rate). A producing day rate derived from monthly data is still useful in estimating deliverability, but it smoothes through the extremes that would be evident in real time data. As an example, a well that produced 20, 10, and 5 MMCF/day for three days would average 11.7 MMCF/day over that period, which is some 40 percent below the actual peak. Given that limitation, there is still a significant swing between winter and summer PD rates when compared to annual average production rate. The peak PD rate has two components, the normal gas PD rate and the storage PD rate. Figure 9 compares the average annual rate to PD rates with and without storage from 1995 to present.

The ability to meet peak demand with real-time production has significantly diminished in the last decade because reservoir pressure has declined, water influx has increased, and not enough wells were drilled to replace reserves and maintain redundancy for peak rate capacity. Nevertheless, well workovers, additional wells, and compression have been slowly added in an attempt to meet the high-swing local demand. However, drilling high-cost wells and installing expensive new equipment to meet momentary demand spikes is economically challenging. As a result, gas storage in depleted reservoirs will become an important part of the deliverability portfolio that provides for peak capacity. In the past,

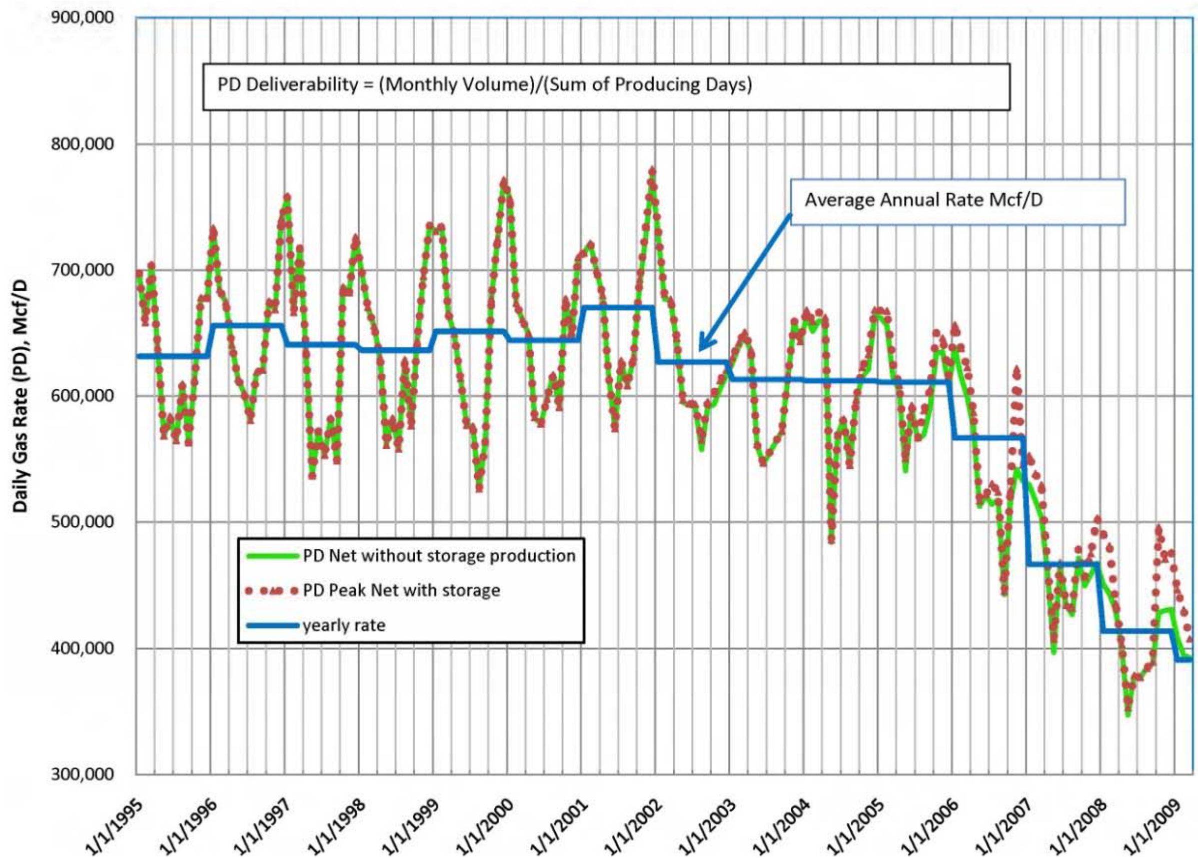

Figure 9. Producing day (PD) deliverability with and without storage, based on monthly volumes.

there was significant production capacity that lay idle during the summer months even with the fertilizer and LNG plants online. A strong seasonal swing is evident in the production histories of major fields such as BRU and NCIU, but it has diminished noticeably in recent years even though the fertilizer plant has been shut down and the LNG plant is not operating at maximum capacity. Field operators are now much closer to producing at or near apparent capacity year round. Like many other gas distribution systems, storage will emerge as a key feature necessary to meet peak demands during extreme weather periods.

As the annual production rate decreases, and producers store more gas during low demand periods, the ability to forecast excess capacity will become more complicated because storage rates are highly dependent on instantaneous demand and on the amount of gas in storage. Steps that could be taken toward meeting peak demand include adding new wells, investing in rate-sustaining work, stimulating productivity, adding compression to maintain production at lower reservoir pressures, and developing more storage capacity. All these options increase production costs and ultimately, the price needed for the commodity.

Predicting future well or reservoir deliverability. Extrapolation of maximum PD (producing day) rate data assumes that a well or reservoir can meet that maximum, at least on a periodic basis. The importance of a maximum deliverability forecast is to estimate the ability to meet peak demand on those days when temperatures are very low and gas demand is very high. Figure 10 shows the method of estimating maximum PD rate for a pool by selecting peaks and forecasting into the future. This was done for each pool in the Cook Inlet basin then summed to provide a forecast.

Figure 11 shows the PD deliverability forecast results compared to average annual rate from DCA. The forecast peak PD deliverability is higher than average annual rate; however, peak deliverability can only be sustained for a relatively short period. The PD deliverability analysis can be done well-by-well or collectively on a reservoir basis. Regardless of method, the maximum PD rate forecast is only an estimate and may be influenced by the same events that affect decline curve analysis. This method yields a more representative estimate of future peak production rate (PD deliverability) than an annual average rate derived from decline curve analysis.

An additional challenge to predicting future deliverability is the complex geology. Cook Inlet's reservoirs are challenging to evaluate because of the discontinuous fluvial sand bodies, especially in the Beluga and Tyonek Formations. The Sterling Formation contains thicker sand packages that tend to be in pressure communication. In the Beluga and Tyonek reservoir section, new drilling has added deliverability and captured previously stranded gas reserves by a combination of in-fill drilling and adding perforations in existing wells. Clearly, more drilling and well work will be required to develop enough deliverability to meet peak demand swings in the coming years.

As a rule, the Cook Inlet reserves and annual production forecast have not really changed much from forecast to forecast. The major uncertainty lies within deliverability to meet daily and peak demand. To fully understand maiximum PD rate to meet daily and peak demand, more detailed and up-to-date production data is critical. The ability to analyze daily production numbers from all producing zones would indicate which wells and reservoirs are able to respond during demand spikes caused by extreme low temperatures.

GEOLOGICAL ESTIMATES

The geologic portion of this reserves study focused on four producing gas fields in Cook Inlet: Beluga River, North Cook Inlet, Ninilchik, and McArthur River (Grayling gas sands). A deterministic log- and grid-based approach was used to analyze and map pay and potential pay thickness for numerous producing horizons and to calculate original gas-in-place (OGIP) volumes within these fields. Publicly available production data from the AOGCC were used to determine recovery factors for these four fields. The recovery factor fraction was then multiplied by the mapped OGIP to calculate the geologic estimates of original reserves for each of the four fields. Subtracting the cumulative production from each field yielded our geologic estimates of remaining reserves. The following discussion details the process used in the geologic analyses conducted for this project.

Data Sources

Much of the data used in this evaluation is publicly available from the AOGCC. Confidential data the Division of Oil and Gas receives for Unit Plans of Development were also used to augment the AOGCC data set. Information from the geological literature regarding fluvial depositional systems in Cook Inlet and elsewhere helped inform sound well log correlations and was useful in petrophysi-

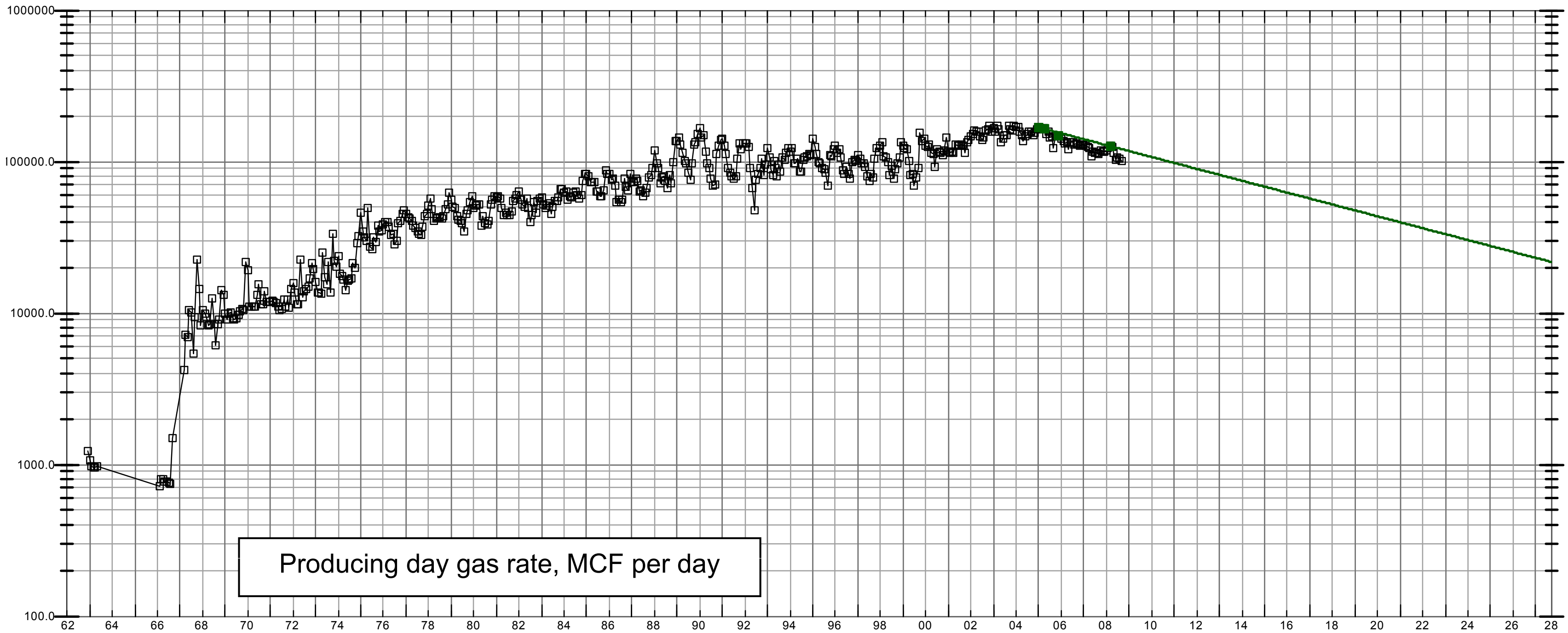

Figure 10. Example of peak deliverability forecast for a pool. Horizontal axis is time (1962-2028); vertical axis is producing day gas rate (MCF/day). Extrapolation is based on maximum PD rate only.

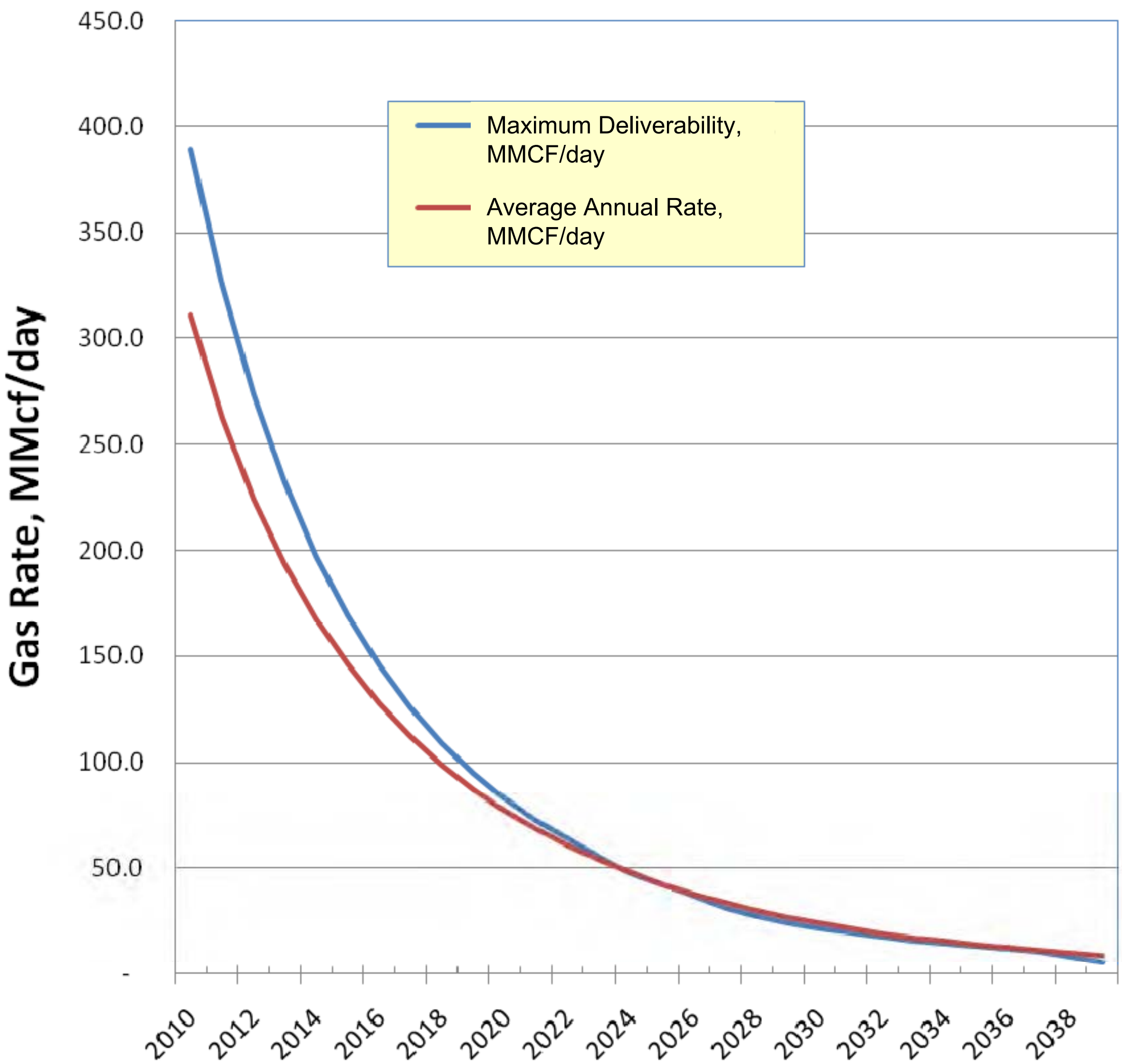

Figure 11. Peak maximum producing day deliverability compared to average annual rate from decline curve analysis.

cal interpretation (e.g., Bridge and Tye, 2000; Flores and Stricker, 1991; LePain and others, 2008).

The dataset collected and analyzed for this geologic evaluation consists of digital petrophysical well logs and directional well surveys; geologic formation tops; confidential and non-confidential structural surfaces (grids) and faults; details of well drill stem tests, perforations, reservoir and flowing pressures; gas compositional analyses; fluid contact depths; and core-based porosity, permeability, grain density, and saturation data.

Data Rendering

The data rendering process began with loading all the above data into databases used with our interpretation and mapping software

(Landmark GeoGraphix). Digital petrophysical well log data, directional well surveys, perforations, completion intervals, and drill stem test data were critical data sets that were interpreted together from the beginning stages. Most petrophysical well log suites in Cook Inlet wells contain data for spontaneous potential (SP), gamma ray, deep-, medium-, and shallow-measurement resistivity, and some combination of porosity logs such as density, neutron, and/or sonic transit time data.

After loading and interpreting the data mentioned above, criteria were established for identifying and flagging basic lithofacies (rock types). We flagged non-pay lithofacies (coal and shale) and focused attention on lithofacies that contain pay and potential pay (sandstone, argillaceous sandstone, and sandy siltstones). Coals were flagged as having a bulk density log response less than or equal to 1.9 g/cm^3 and a neutron porosity log response greater than 45 percent. Rare, very pure claystone intervals were selected to define a shale baseline on the SP log.

Pay Evaluation and Identification

We based our pay criteria on log character, mud log data, drill stem test data, and/or completion reports that identify sandstone intervals as having flowed gas with a rate that resulted in the sandstone being completed as a gas-producing interval. Two different categories were created in GeoGraphix using interval picks: PAY and Potential_Pay. These two interval picks were interpreted for each production zone (major subdivision of the reservoir formation, for example Sterling A) in all wells with a petrophysical well log suite (Figure 12). The breakout of zones varies from field to field, based on the variable characteristics of the Tyonek, Beluga, and Sterling reservoirs in different parts of the basin.

Intervals identified as PAY have the following characteristics:

a) Sandstone intervals that were completed after drilling and logging that either produced or are currently producing gas. These sandstones exhibit elevated deep resistivity relative to down-dip wet sandstones of the same producing horizon, as well as an SP shift off the shale baseline, plus sonic-neutron or neutron-density cross-over, or a decrease in sonic travel time (slower than the travel time in shales or wet sandstones).

b) Some unperforated sandstone intervals were identified as PAY if they could be reasonably correlated to sandstones perforated and producing in recent wells, or perforated as ‘by-passed pay’ in older wells that have been worked over.

c) Some unperforated sandstone intervals were identified as PAY if the log response was very similar to a perforated gas interval in the same well.

Potential_Pay was picked in intervals that have the following characteristics:

a) Sandstones that were perforated and flowed only minor gas; flowed minor gas with water during testing; thin sandstones comingled during a drill-stem-test; or stacked perforated intervals where gas was present and produced, but it was unclear which sandstones were productive. In most of these cases, gas production was accompanied by water that may have been coming from one or more of the producing horizons.

b) Sandstones in which indications of free gas (shows) on well logs are not as robust as in the PAY sandstones, but generally have elevated resistivity along with a lesser degree of gas response (cross-

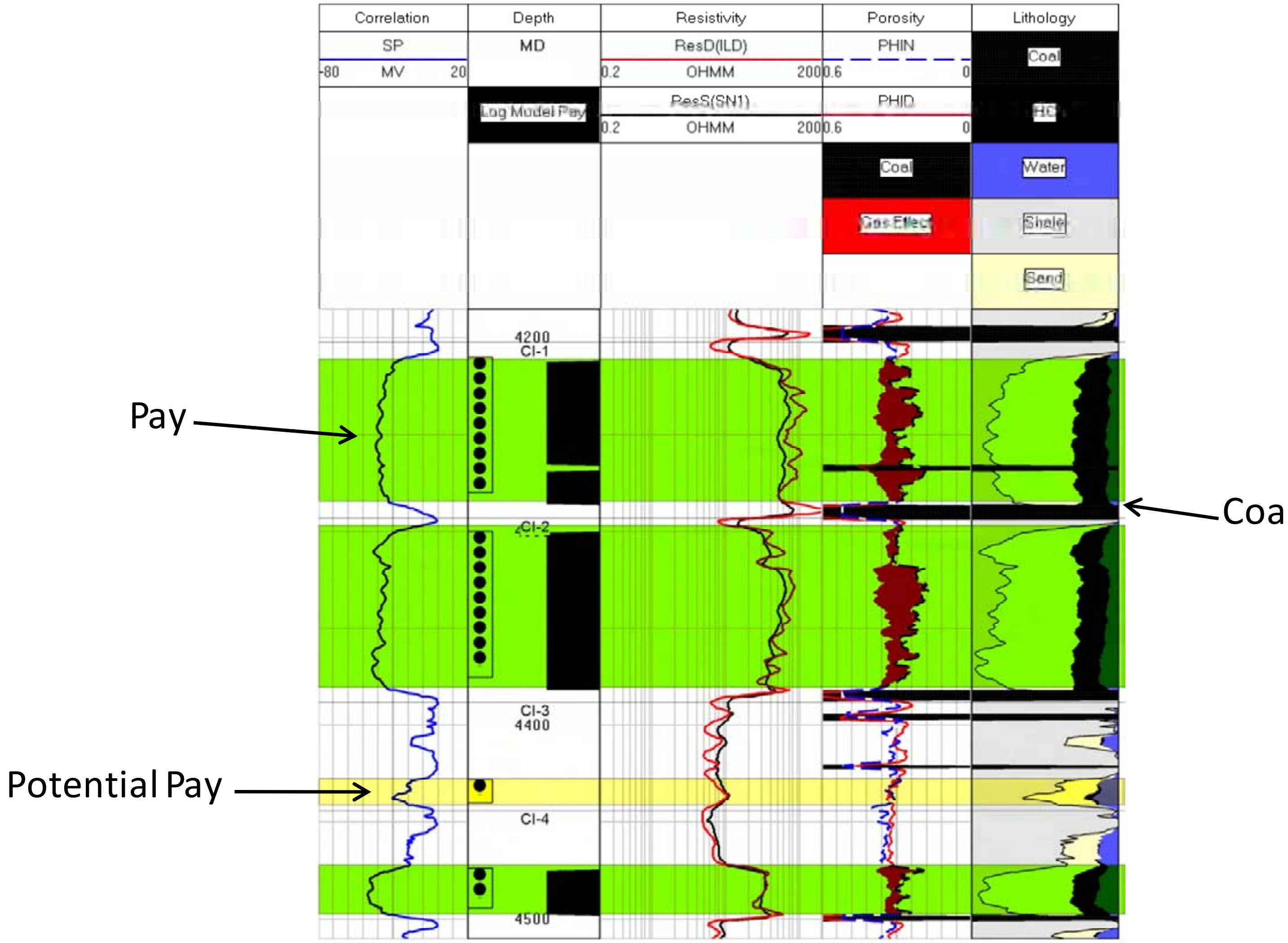

Figure 12. Well log example illustrating PAY (green) and Potential_Pay (yellow). Coal (black) is flagged as non-pay at right. Perforated intervals are shown in the depth track as black vertical dots. CI-1, CI-2, CI-3 and CI-4 are examples of zone picks in which Pay and Potential Pay were summed for each well. Petrophysical logs are noted in the log header. Depth is measured depth feet.

over or convergence) on sonic-neutron or neutron-density porosity log suites.

In addition to the PAY and Potential_Pay criteria described above, we gained information through preliminary petrophysical analysis of well log suites to calculate shale volume (Vsh), porosity, water and hydrocarbon saturations in the Beluga River, North Cook Inlet, Ninilchik, and McArthur River (Grayling gas sands) fields. Saturation analysis is highly dependent on the resistivity of the connate water (Rw) found in a sandstone interval. Given that Rw varies significantly across short distances in Cook Inlet sandstones, we did not rely on petrophysical analysis for this study. Rather, the log-based analyses helped to validate our PAY and Potential_Pay intervals identified using the criteria described above.

PAY category sandstones were color-coded green and Potential_Pay intervals were color-coded yellow on all log displays and well cross-sections. Figure 12 illustrates a typical example of the difference between the pay categories (compare the log responses in the thin, Potential_Pay sandstone at 4,430 feet measured depth relative to that in the PAY sandstone at 4,250 feet measured depth). Interbedded coals are flagged and colored black. All sandstones were evaluated and categorized as PAY, Potential_Pay, or non-pay (ignored). PAY in each well was summed in true vertical depth feet (TVD) for each zone. This cumulative sum, gross TVD feet of PAY, was stored by zone for each well as an attribute labeled PAY using the Zone Manager application in GeoGraphix. The same process was followed for summing gross TVD feet of Potential _Pay for each zone in each well.

Mapping Procedure

The digital mapping process was executed in GeoGraphix using gridding, contouring, and database tools of the GeoAtlas and Zone Manager applications. Thickness (isopach) grids of reservoir zones were made from well control by subtracting the depth of the tops of successive zones from each other and contouring them using a standard gridding algorithm (minimum curvature) to obtain gross zone thickness.

Subsea depth structure grids were prepared next, representing the top surface of each zone. This was accomplished by starting at the top of the reservoir interval and progressively subtracting the underlying isopach grid to generate the next deeper structure map. This process was continued downward throughout the zones of interest in each field. Each structure map generated this way was checked for accuracy by plotting it with zonal tops to assess surface accuracy.

Isopach grids of PAY and Potential_Pay were generated for each zone from the gross values stored in the system as described above, taking steps to limit these grids to the productive area of each zone. An example of the zonal data is shown in Table 3, representing the Beluga D zone at the Beluga River Unit. In order to limit the aerial distribution of PAY and Potential_Pay thickness grids, well logs and well history files were examined for evidence of gas-water contacts. Because numerous producing horizons do not have known gas-water contacts, the completion reports, drill stem test reports and gas mudlog readings were consulted to pick the lowest known gas (LKG) and highest known water (HKW) depths in TVD subsea for each zone. The differences between HKW and LKG depths are highly variable, sometimes differing by hundreds of feet. In most cases, we assumed an approximate gas-water contact at the midpoint depth between HKW and LKG, and clipped the Gross Pay and Gross Potential_Pay mapping grids for each zone at the intersection of the midpoint depth with the zone's top struc-

WELL NAME	OPERATOR	X	Y	MD	Isopach	Pay-TVD	PHID_PAY	Poten. PAY	PHID_Poten.PAY
BELUGA RIV UNIT - 232-04	CON-PHIL	1453670.71	2617713.76	3668.23	267	42.45		0.00	
BELUGA RIV UNIT - 14-19	SOCAL	1469252.37	2630676.94	4072.31	238	0.00		0.00	
BELUGA RIV UNIT - 212-25	CON-PHIL	1463881.80	2628088.88	3792.97	240	22.13		32.19	
BELUGA RIV UNIT - 233-27	CON-PHIL	1455964.58	2626745.47	3600.97	253	54.03		12.09	
BELUGA RIV UNIT - 212-35	CON-PHIL	1458547.40	2623360.19	3608.01	262	78.57		0.00	
BELUGA RIV UNIT - 244-04	CON-PHIL	1454192.95	2615830.39	3841.41	271	35.13	0.340	26.39	0.277
BELUGA RIV UNIT - 244-04A	SOCAL	1453475.72	2616177.84						
BELUGA RIV UNIT - 244-04PB1	PHILLIPS								
BELUGA RIV UNIT - 212-24	CON-PHIL	1463415.18	2633391.25	3762.68	258	45.53	0.299	31.87	0.342
BELUGA RIV UNIT - 241-34	CON-PHIL	1456544.42	2624038.94	3504.45	248	74.18	0.278	0.00	
BELUGA RIV UNIT - 224-13	CON-PHIL	1465607.22	2636369.71	3862.50	260	14.29	0.243	24.18	0.244
BELUGA RIV UNIT - 212-18	CON-PHIL	1468825.92	2638790.93	4009.47	256	21.98	0.254	19.78	0.281
BELUGA RIV UNIT - 221-23	CON-PHIL	1459932.22	2635193.02	3968.75	250	10.44	0.289	34.92	0.261
PRETTY CK UNIT - 1	UNOCAL	1476389.50	2640608.61	6146.56	238				
BELUGA RIV UNIT - 214-35	CON-PHIL	1458875.02	2619748.65	4608.98	277		0.285	37.26	
BELUGA RIV UNIT - 232-09	CON-PHIL	1453474.27	2612394.57	4724.05	263		0.371	25.87	
BELUGA RIV UNIT - 224-23	CON-PHIL	1460281.13	2631381.66	3713.11	254	46.14	0.371	32.41	0.248
BELUGA RIV UNIT - 232-26	CON-PHIL	1461058.61	2628988.30	4241.75	263	88.30	0.311	0.00	
BELUGA RIV UNIT - BRWD-1	CON-PHIL	1468564.59	2638657.81						
BELUGA RIV UNIT - 211-03	CON-PHIL	1455836.02	2619446.55	3637.35	272	18.97	0.284	38.44	0.331
BELUGA RIV UNIT - 224-34	CON-PHIL	1454658.34	2620478.62	3856.08	258	34.53	0.354	12.97	0.406
BELUGA RIV UNIT - 214-26	CON-PHIL	1459015.00	2626123.13	3685.74	258	50.81	0.350	0.00	
BELUGA RIV UNIT - 214-26PB1	CON-PHIL	1458268.00	2625840.43						
BELUGA RIV UNIT - 212-35T	CON-PHIL	1458158.88	2622934.28	3714.46	257	41.01	0.329	12.41	0.347
N BELUGA - 1	PELICAN HILL	1466801.82	2642345.87	4246.66	269	0.00		0.00	
SUM <None>	<None>	<None>	<None>		<None>	<None>	<None>	<None>	<None>
MAX		1476389.50	2642345.87	6146.56	277	88.30	0.371	38.44	0.406
MIN Null	Null	1453474.27	2612394.57	3504.45	238	0.00	0.243	0.00	0.244
Stnd Dev		6055.81	8840.30	573.68	11	26.35	0.042	14.95	0.055

BLUGD

Table 3. An example of zonal data for the Beluga D zone at Beluga River Unit. Zone picks were made by DNR staff. PAY and Potential_Pay were picked for each zone in each well according to criteria discussed in the text. If the well had a density porosity curve, the average density porosity was calculated within PAY and Potential_Pay intervals for that zone. Blanks appear in the table where necessary well logs were not available over the Beluga D zone.

ture surface. In reality, PAY and Potential _Pay are distributed throughout each zone, whereas in our model, they are assumed to be stacked at the top of the zone, just below the structural surface that was clipped with the approximate fluid contact. Figure 13 is an example of one zonal gross PAY map. Because there are hundreds of individual Sterling, Beluga and Tyonek Formation sandstones, it was not possible to structurally clip each individual pay interval with a LKG or HKW contact in the time frame allotted for this project.

Original Gas-in-Place and Initial Reserves

We used the following equations to calculate original gas-in-place in standard cubic feet:

$$\text{OGIP} = 43{,}560\ (\text{gross pay volume})\ (\text{N:G})\ (1\text{-Sw})\ (\text{Ø})\ /\ \text{Bgi},$$

and

$$\text{Bgi} = 0.02829\ (\text{Z})\ (\text{T})\ /\ (\text{P})$$

where gross pay volume refers to the volume of gross Pay or Potential_Pay sandstone in acre-feet, N:G is the net-to-gross ratio within the gross Pay or Potential_Pay intervals, Sw is fractional water saturation, Ø is decimal porosity, Bgi is initial gas formation volume factor, Z is a gas compressibility factor, T is temperature in degrees Rankine, and P is pressure in psia. The density log was used to determine porosity. Porosity was averaged for the pay intervals by using the PAY interval as a discriminator curve and calculating the average density porosity in PAY for each zone. This value was then gridded using the same minimum curvature algorithm and grid increment as the PAY isopach. The average porosity and

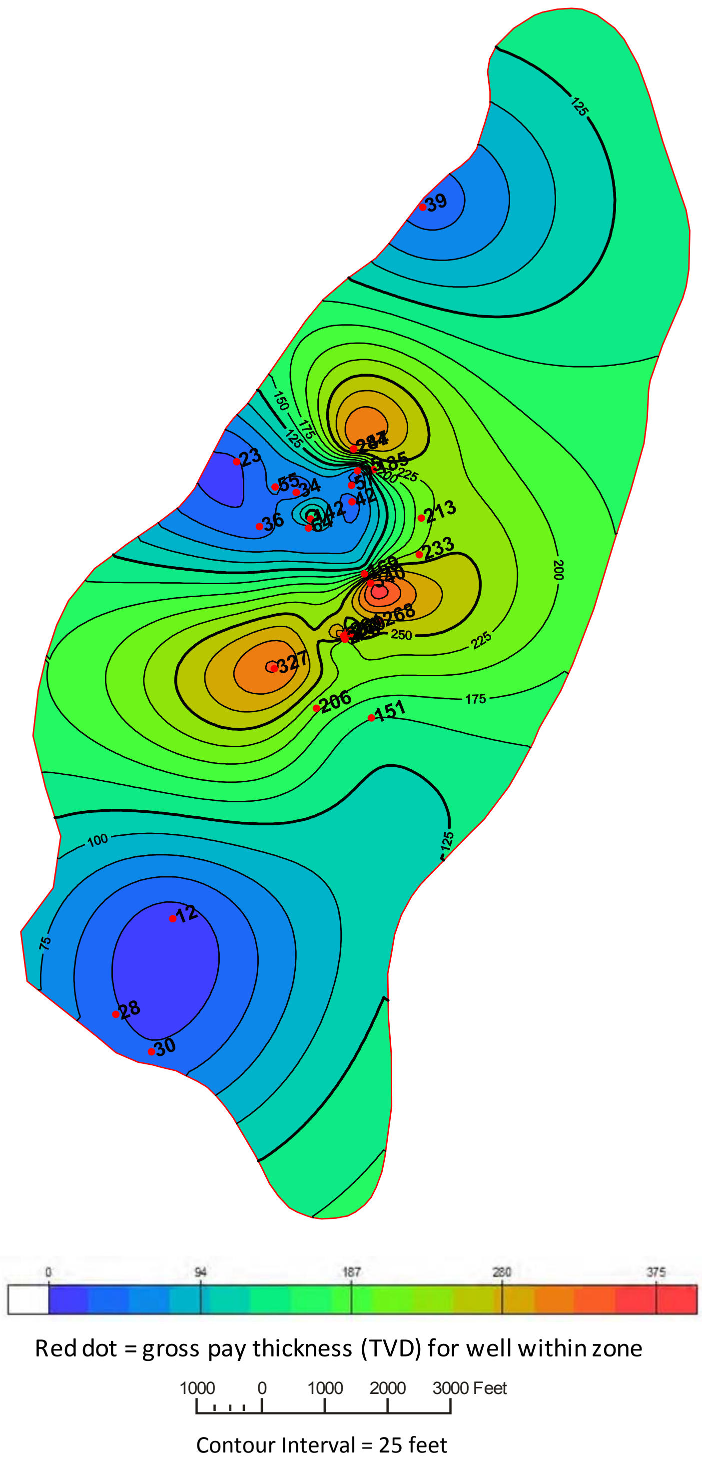

Figure 13. Example of zonal gross pay isopach map, McArthur River field Grayling gas sands.

pay isopach grids were multiplied together to create a grid of bulk pore volume contained in intervals considered as PAY. Further multiplication times the net-to-gross ratio yielded net pore volume. The same process was used to determine net pore volume in intervals counted as Potential_Pay.

Because of the inherent problems with determining water saturation in the Cook Inlet basin discussed above, we used water saturation values provided in the AOGCC annual pool reports. Reservoir pressure and the gas compressibility factor were all calculated on a zonal basis depending on temperature and subsea depth at the midpoint of the zone. There were no AOGCC pool reports for the Ninilchik Unit. For that field, we assumed 40 percent water saturation; this figure is likely pessimistic, which will lead to conservative gas reserve estimates.

Overall recovery factors were calculated for each of the four fields studied, based on production and test data. Because most individual sandstones within the Sterling and Beluga Formations have different recovery factors, a range of recovery factors is presented in Appendices 1-4. Recovery factors were decreased for zones with lower permeability based on downhole permeability measurements or calculated from porosity-permeability transforms. The recovery factors were then applied to the mapped original gas-in-place (OGIP) volumes to calculate initial recoverable gas in place (RGIP).

Table 4 presents one deterministic case of the geologically estimated reserves calculated for the four fields studied: Beluga River, Ninilchik, North Cook Inlet, and McArthur River Grayling gas sands. Values are reported in billions of cubic feet (BCF) of gas. Calculations are presented for the PAY, Potential_Pay (risked at 50 percent), and the sum of PAY + 50 percent-risked Potential_Pay in the first three columns. The next three columns present initial recoverable gas-in-place (RGIP) for those three categories. The next column lists the projected cumulative production through 12/31/2009 for each field, based on AOGCC data. The last two columns represent the calculated remaining reserves for the PAY and PAY + 50 percent-risked Potential_Pay categories, calculated by subtracting the cumulative production from the RGIP. Each column contains a total for the sum of the four fields. The sum of the reserves in the PAY category for the four fields is 1,213 BCF of gas. The sum of the reserves in the PAY + 50 percent-risked Potential_Pay is 1,856 BCF of gas. The chart demonstrates that a high percentage of remaining reserves calculated from geologicall techniques reside in the more certain PAY category and less in the Potential_Pay category. However, risking the Potential_Pay resources at 50 percent yields additional upside potential of 643 BCF.

Multiple deterministic cases could be considered. Appendices 1 through 4 present Potential_Pay calculations risked at 10 and 90 percent confidence levels.

EXPLORATION POTENTIAL OF COOK INLET BASIN

Leads – Discovered Undeveloped and Undiscovered Resources

Within the Cook Inlet region, there are several areas where publicly available geologic data, geophysical data, or reports indicate potential for discovered but undeveloped gas accumulations. A number of other areas are identified to have elevated prospectivity for undiscovered accumulations. This discussion briefly describes a list of exploration candidates or leads that have been actively pursued by industry in the past. The list discussed below is by no means comprehensive, nor all en-

Field	OGIP (BCF) PAY only	OGIP (BCF) 50%-risked Potential_Pay only	OGIP (BCF) Total, PAY + 50%-risked Potential_PAY	** RGIP = OGIP x RF (BCF) PAY only	** RGIP = OGIP x RF (BCF) 50%-risked Potential_Pay only	** RGIP = OGIP x RF (BCF) Total, PAY + 50%-risked Potential_PAY	Cumulative Production (BCF, projected through 12-31-09)	Remaining Reserves (BCF) PAY only	Remaining Reserves (BCF) Total, PAY + 50%-risked Potential_Pay
Beluga River	2,137	592	2,729	1,856	342	2,198	1,150	706	1,049
Ninilchik	182	167	349	164	117	280	104	60	177
North Cook Inlet	2,300	211	2,511	2,060	151	2,211	1,818	242	393
McArthur River	1,757	41	1,798	1,581	33	1,614	1,376	205	237
Totals	**6,376**	**1,011**	**7,386**	**5,661**	**643**	**6,304**	**4,448**	**1,213**	**1,856**

*** RGIP = initial recoverable gas-in-place = OGIP x Recovery Factor. Production and test data suggest a range in recovery factor within the Sterling and Beluga Formations*

Table 4. Geologic estimates of original gas-in-place, original recoverable gas, and year-end 2009 reserves remaining in four Cook Inlet gas fields.

compassing for the basin. These opportunities are grouped into onshore and offshore areas. It is important to note that there is a significant amount of ongoing work, in both the industry and government sectors, to identify exploration opportunities for future activity and reserves additions. The Division of Oil and Gas is currently collaborating with the Division of Geological & Geophysical Surveys in this effort in order to facilitate exploration for oil and gas in the next decade.

Onshore areas. It is estimated that identified potential candidates located onshore might yield between 40 and 120 BCF of recoverable gas (in aggregate). They are associated with identified anticlinal trends and most have at least one well that penetrates the lead, is adjacent to it, or can be projected along structural trend. The candidates described below are all located on the east side of Cook Inlet, and are listed from north to south (fig. 1).

1) Point Possession lead – lightly explored anticline trend within the within the Kenai National Wildlife Refuge, roughly along the same general trend as Sunrise lead.

2) Birch Hill structure - faulted anticline closure on-trend with Swanson River field. The reservoir is in the Tyonek Formation. Chevron is currently moving toward development.

3) Sunrise lead - lightly explored anticline trend. Marathon has acquired 2D seismic data, and has plans to drill in the winter of 2009-2010 on CIRI land within the Kenai National Wildlife Refuge.

4) Cohoe Unit – potential faulted trend down plunge from Kenai Field anticline. Potential reservoirs in the Beluga and Tyonek Formations.

5) North Ninilchik structure - faulted anticline closure down plunge from Ninilchik Unit. Potential reservoirs in the Beluga and Tyonek Formations.

6) Nikolaevsk unit - faulted anticline closure on-trend with North Fork field. Potential in the Tyonek Formation.

Offshore areas. The candidates identified below lie in state waters and it is estimated that they might yield between 100 and 400 BCF of gas (in aggregate). The majority of these candidates are associated with identified anticlinal trends and, as with the onshore plays, they have at least one well that penetrates the lead, is adjacent to it, or can be projected along structural trend. They are described generally from north to south (fig. 1).

7) North Cook Inlet Field – faulted struc-

tural nose north of the existing field. Potential reservoirs in the Beluga and Tyonek Formations.

8) Corsair (SRS) structure - faulted anticline closure. Potential reservoirs in the Sterling, Beluga and Tyonek Formations.

9) North of Middle Ground Shoal - faulted anticline trend. Potential reservoirs in the Beluga and Tyonek Formations.

10) North Redoubt - faulted structural nose up-dip from the Redoubt field. Potential reservoirs in the Sterling, Beluga and Tyonek Formations.

11) Kasilof structure – faulted anticline closure north of Ninilchik field. Potential reservoirs in the Beluga and Tyonek Formations.

12) Cosmopolitan structure - faulted anticline closure. Potential in shallow reservoirs in the Tyonek Formation.

13) South Diamond Gulch structure - faulted anticline trend within Kachemak Bay. Potential reservoirs in the Tyonek Formation.

Quantitative Assessments of Undiscovered Technically Recoverable Resources

Federal agencies are tasked with the lead responsibility for publishing estimates of undiscovered technically recoverable resources for all parts of the United States, including the Cook Inlet basin. The U.S. Geological Survey assesses the potential onshore and in state-managed waters, whereas the Minerals Management Service analyzes potential in federally-managed waters of the Outer Continental Shelf (OCS). In all cases, these agencies address the inherent uncertainty of such assessments by creating probability distributions that describe a wide range of possible values. A probabilistic estimate is best described by its mean value (expected case) accompanied by specific fractiles of its distribution, such as the F95 value (lowside case, with a 95% probability that the actual volume is greater) and the F5 value (upside case, with only a 5% chance that the actual volume is greater). The results of the most recent assessment encompassing the upper Cook Inlet producing region are presented in Table 5 (compiled from Gautier and others, 1996). These estimates will be updated in an ongoing USGS resource assessment specific to the Cook Inlet region, prepared in cooperation with the Alaska Division of Geological & Geophysical Surveys

Assessed Play and Undiscovered Resource	**Oil, MMSTB** (million stock tank barrels)			**Gas, BCF** (billion cubic feet)		
	F95	*Mean*	*F5*	*F95*	*Mean*	*F5*
Hemlock-Tyonek play Oil & Associated gas	43	647	1,337	43	647	1,337
Beluga-Sterling play NGL & Non-associated gas	0	0	0	42	738	1,923
Late Mesozoic oil play	Play was assigned a 9% chance of hosting at least one accumulation; resource volumes not quantitatively assessed.					

Table 5. Federal estimates of undiscovered technically recoverable conventional oil and gas resources of the upper Cook Inlet region (after Gautier and others, 1996).

and Alaska Division of Oil and Gas, with expected publication in late 2010.

A more recent study conducted on contract to the U.S. Department of Energy considered potential undiscovered resources using a different statistical approach as part of a larger study of natural gas supply and demand in the Cook Inlet region (Thomas and others, 2004). Noting that the distribution of field sizes within the basin does not conform to the expected lognormal state, this study estimated that there may be 13 to 17 trillion cubic feet of conventionally recoverable gas remaining to be discovered, largely in stratigraphic or combination structural traps.

Impediments to Future Exploration

There are several issues that may hamper future exploration, both in terms of further developing some of the areas with known potential described above, as well as making new discoveries in lightly explored areas. Some of the concerns are of a commercial nature, and others involve restrictions on surface access to prospective areas. Comprehensive exploration efforts in the Cook Inlet, like any area in the US, will require patience and diligence from all stakeholders in order to reduce exploration and operating costs, provide access to critical data, and provide access to surface acreage in areas of high resource potential, but sensitive wildlife habitat. All these issues must be addressed in a collaborative stakeholder effort if the Cook Inlet region is to maintain an economically and environmentally sound industry.

COMBINED ENGINEERING AND GEOLOGIC ANALYSES

The various engineering and geologic analyses of this study yield a wide range of estimated remaining reserves. Table 1 compares four different reserve estimates derived for the four fields emphasized in this study, based on 1) decline curve analysis, 2) material balance analysis, 3) the geologic estimate that includes only reserves in the PAY category, and 4) the geologic estimate that includes reserves of the PAY category plus 50 percent of the volume in the Potential_Pay category. Note that these analyses are not intended to represent any particular fractiles of a statistical distribution; for example, we do not consider them to represent F95-F50-F5 reserve values. The following discussion describes Table 1 in detail.

The most conservative estimate of reserves is based on decline curve analysis alone, which estimates a total of 697 BCF proved, developed, producing reserves remaining in the Beluga River, North Cook Inlet, Ninilchik, and McArthur River (Grayling gas sands) fields. Decline curve analysis also identifies 166 BCF of proved, developed, producing reserves remaining in the other 24 fields, for a basin-wide total of 863 BCF. Material balance analysis identifies an additional 163 BCF of probable reserves in just the four large fields, yielding a total of 860 BCF proved and probable reserves remaining there. In the other 24 fields, material balance estimates 116 BCF more than decline curve analysis, yielding 282 BCF of proved and probable reserves in those fields, and a basin-wide total of 1,142 BCF remaining proved and probable reserves.

The geologic volumetric evaluations, completely independent of the engineering techniques, yield larger reserve estimates for the four large fields. This is consistent with the probability that there is considerable gas remaining in these reservoirs that has not contributed to production, and therefore, cannot be captured by the engineering estimates. The geologic evaluation of existing well data in the four fields indicates 1,213 BCF of gas reserves remaining to be produced from just the high-confidence PAY category. Subtracting the 860 BCF that material balance indicates is already in communication with producing wells yields an estimated 353 BCF of currently non-producing gas—the "redevelopment prize"—in those four reservoirs. When recoverable gas in the Potential_Pay category are risked at 50 percent and added to those in the PAY category, the estimated reserves remaining in the four fields increase to 1,856 BCF, adding an increment of 643 BCF in those fields.

Engineering and Geological Discussion

This study addresses the fundamental question: given the currently available engineering and geologic datasets, how much additional gas resource is available for second and third cycle redevelopment efforts in producing field areas? Combining these results with forecasted demand scenarios provides a timeline that suggests how long known reserves can supply local needs. It is important to note that this study does not address which development activities will be economically feasible in future market scenarios. Nevertheless, if one assumes appropriate market conditions will exist, then investment in more complete field development operations, infrastructure de-bottlenecking and upgrades, and appropriate commercial alignment between unit partners will occur and a significant portion of the remaining reserves identified in this study will be developed to meet local demand for at least the next decade.

Figure 14 presents a schematic production forecast for the basin that includes wedges of incremental reserves identified by the various methods discussed in this report. Construction and interpretation of this diagram is complicated by the fact that the engineering estimates reflect all 28 gas fields, whereas the additional reserves estimated by geologic analyses come only from the Beluga River, North Cook Inlet, Ninilchik, and McArthur River (Grayling gas sands) fields. This forecast assumes that production will not exceed demand, which is projected flat at 90 BCF/year. It should be stressed that the point of this schematic diagram is to illustrate the additional gas volumes estimated in various reserve and resource categories identified using multiple analytical methods, and to estimate how long those volumes may be able to meet demand. The actual timing of when gas from any one of those wedges will go on production is unknown, and certain to be more complicated than can be shown here.

The most conservative wedge in red represents future production of proved, developed, producing reserves (863 BCF) identified basin-wide by decline curve analysis alone. The orange wedge represents production of additional probable reserves (279 BCF) identified as the basin-wide difference between material balance and decline curve analyses. The green wedge corresponds to the incremental production that could be achieved in just the four large fields through aggressive development of technically recoverable gas in the PAY category that we argue is not reflected in the engineering analyses because it is not currently in communication with producing wellbores (353 BCF). The yellow wedge represents the additional untapped gas from the Potential_Pay category in those four fields, risked at 50 percent (643 BCF). Finally, the gray wedge illustrates speculative future production from contingent gas resources that await confirmation, delineation, and development (an aggregated volume estimated at 300 BCF from the exploration leads identified in this report). This illustrates the likelihood that investment in more complete development of the producing Cook Inlet gas fields could yield sufficient gas to meet projected demand for years to come.

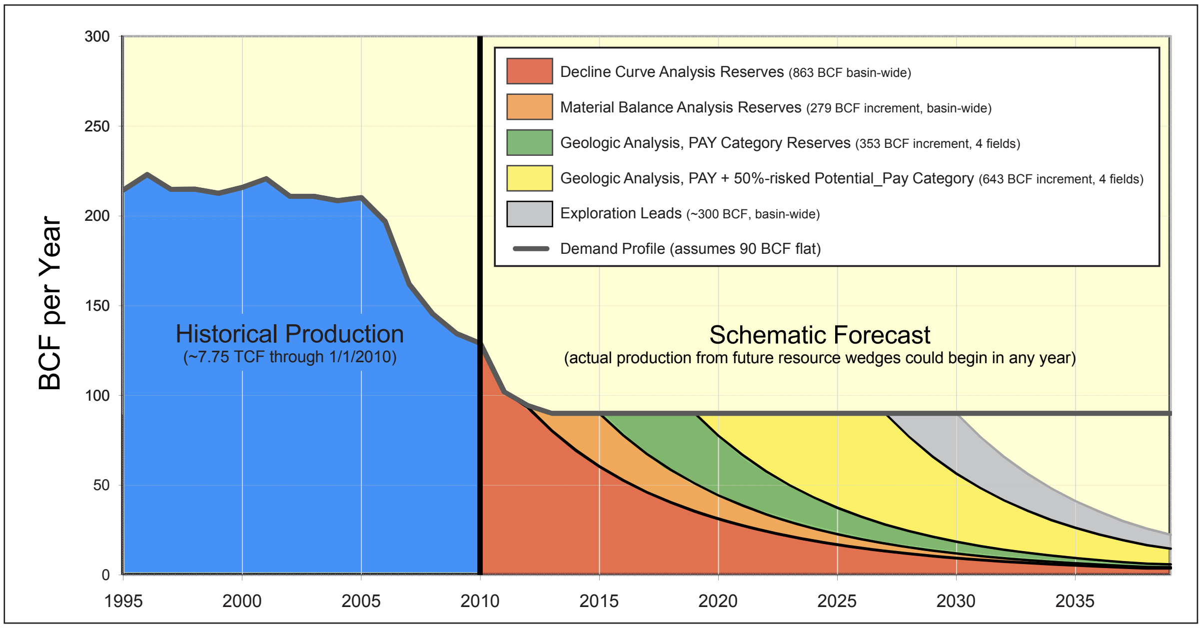

Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative estimation techniques. Successive wedges are introduced with progressively lower certainty regarding commerciality, volume, and timing of first production. Production from future resource wedges could begin in any year, resulting in a more complex forecast, and extending the production lifespan of previous wedges. On the other hand, we are unable to predict the commercial thresholds at which volumes from future wedges become economic to recover. Wedges show gas volume increments from basin-wide decline curve analyses (red), basin-wide material balance analyses (orange), deterministic geologic mapping of PAY (green), and 50 percent-risked Potential_Pay (yellow) in four large gas fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands). The last wedge (gray) is a more speculative estimate of aggregated gas volumes that may be recoverable from the exploration leads discussed in text. See text for additional discussion.

CONCLUSIONS

This report summarizes a multi-disciplinary effort to quantify remaining gas reserves in the Cook Inlet basin. Reserves have been categorized relative to readiness for and certainty of production to predict whether existing reserves are capable of meeting demand over the next decade. The following list describes important points regarding the analytical techniques employed and the findings derived from this effort.

1) Decline curve forecasts in demand-limited production situations do not always predict future rate. The rate derived from decline curve analysis represents an approximation of average annual rate.

2) Decline curve analysis (DCA) is a fair predictor of the remaining recoverable

gas (RRG) of currently producing reserves, but is limited by the underlying assumption that past performance will continue and well-related activity to sustain production will continue. Daily PD (producing day) rate deliverability based on monthly data gives a more accurate picture of peak rates from wells.

3) The best data for determining peak rates are real time data measured at the well level on a daily basis at actual demand conditions. These data are not publicly available for the fields assessed in this study.

4) Material balance (MB) methods are a good tool for predicting RRG and original gas-in-place, but only for pay intervals that are in communication with actively producing wellbores.

5) The quality of MB analyses is directly related to quality of pressure data, frequency of measurement, and accurate knowledge of the reservoirs.

6) Estimating gas maximum PD rates from proved, developed, producing (PDP) reserves is best accomplished using multiple analyses; DCA, MB, analysis of daily pressure, temperature, and production data, and maximum PD rate forecasting each play an important role. These methods could be combined in a systems model which includes pipeline parameters, field infrastructure, reservoir parameters, and economic parameters to help predict ability to meet demand under various conditions.

7) Geologic evaluation of the Beluga River, North Cook Inlet, Ninilchik, and McArthur River (Grayling gas sands) fields using interpretive pay identification and mapping techniques strongly suggests that these reservoirs contain significant additional technically recoverable gas reserves that have yet to be brought into communication with producing wellbores.

8) Geologic reserve estimates for the four fields may be conservative in some zones where, in the absence of other data, we assumed 40 percent water saturation. Reserves calculated in other zones may be either conservative or optimistic where we lacked definitive constraints on gas-water contacts with which to clip the aerial extent of the mapped PAY and Potential_Pay volumes. Improved reserve estimates would be possible by using effective porosity and calculated water saturations obtained through additional log analysis.

9) The highly productive Sterling Formation in the known fields is in decline. The remaining reserves base is primarily in the Beluga and Tyonek Formations, which in general do not have the high productivity rates of the Sterling Formation. The long term performance of wells targeting these gas sands is unknown.

Economic Considerations

The Cook Inlet gas market is isolated and relatively small when compared to other national and global markets. Gas deliverability is challenged during spikes in demand, which implies that it is difficult to make the investment necessary to meet short-duration, high-deliverability requirements. In order to engage in drilling and development projects in the Cook Inlet, local producers must internally justify doing so as an alternative to pursuing other projects worldwide. Therefore, economic viability of investment in reserves development to meet demand spikes must be evaluated in the context of an isolated market in order to fully appreciate the supply and demand relationships. Development investment is clearly being made, but investment viability in short term deliverability projects may be challenged in some cases.

The results of this study suggest enough proved and probable gas reserves exist in Cook Inlet reservoirs to satisfy local demand well into, and possibly beyond the next decade. This forecast assumes that either a significant amount of gas is found by explorers to meet industrial use, or that the export of gas out of the basin will stop at the end of the current license period. It also assumes that no new significant market demand will arise until reserves can be developed to satisfy the entire market. The higher-risk contingent and prospective resources that await confirmation and delineation in exploration prospects have the potential to play a large role in the supply-demand scenarios of the future, but will require the availability of sufficient risk-capital.

Although infill drilling, perforating undeveloped sands, and targeting marginal reservoirs are effective ways to add reserves to replace production, these activities come at a relatively high price that will need to be absorbed into a small-volume market. These cost increases will likely put upward pressure on ultimate consumer pricing. It will be critical for all stakeholders to recognize the significant impediments that will hinder development of the remaining gas resource in the Cook Inlet basin, and work together to overcome them.

ACKNOWLEDGMENTS

The authors thank Kevin Banks, Director of the Division of Oil and Gas, for realistically defining the expectations, scope, and deadlines associated with this project. Michael Heumann made significant contributions to the decline curve and material balance analyses of this study during an internship with the Division of Oil and Gas. We thank Robert Swenson, Director of the Division of Geological & Geophysical Surveys, for critical reviews and revisions of numerous drafts of this report. We relied heavily on the expertise of Mike Pritchard for help in drafting the figures and tables. Christina Holmgren and Heather Ann Heusser were instrumental in the final editing and formatting of the document in its present form.

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APPENDICES 1-4

Supporting data and alternate cases of geologically estimated reserves and risked resources for four Cook Inlet gas fields.

Appendix 1. Original gas-in-place, recovery factors, initial recoverable gas, and remaining reserves, McArthur River field, Grayling gas sands (Trading Bay Unit)

McArthur River Field, Grayling gas sands (Trading Bay Unit)	OGIP (BCF)	Recovery Factor (RF)	RGIP = OGIP x RF (BCF)	Cumulative Production (BCF, projected through 12-31-09)	Remaining Reserves (BCF)
PAY (green)	1,757	0.90	1,581	1,376	205
Potential_Pay (yellow) (**unrisked**)	81	0.80	65		
Potential_Pay (**risked at 0.10**)	8	0.80	7		
Potential_Pay (**risked at 0.50**)	41	0.80	33		
Potential_Pay (**risked at 0.90**)	73	0.80	59		
Total Pay + (0.10 x Potential_Pay)	1,765		1,588	1,376	211
Total Pay + (0.50 x Potential_Pay)	1,798		1,614	1,376	237
Total Pay + (0.90 x Potential_Pay)	1,830		1,640	1,376	264

Appendix 2. Original gas-in-place, recovery factors, initial recoverable gas, and remaining reserves, Ninilchik Unit

Ninilchik Unit	OGIP (BCF)	Recovery Factor (RF)	RGIP = OGIP x RF (BCF)	Cumulative Production (BCF, projected through 12-31-09)	Remaining Reserves (BCF)
PAY (green)	182	0.90	164	104	60
Potential_Pay (yellow) (**unrisked**)	333	0.70	233		
Potential_Pay (**risked at 0.10**)	33	0.70	23		
Potential_Pay (**risked at 0.50**)	167	0.70	117		
Potential_Pay (**risked at 0.90**)	300	0.70	210		
Total Pay + (0.10 x Potential_Pay)	215		187	104	83
Total Pay + (0.50 x Potential_Pay)	349		280	104	177
Total Pay + (0.90 x Potential_Pay)	482		374	104	270

Appendix 3. Original gas-in-place, recovery factors, initial recoverable gas, and remaining reserves, Beluga River Unit

Beluga River Unit	OGIP (BCF)	Recovery Factor (RF)[1]	RGIP = OGIP x RF (BCF)	Cumulative Production (BCF, projected through 12-31-09)	Remaining Reserves (BCF)
PAY (green)	2,137	0.8-0.9	1,856	1,150	706
Potential_Pay (yellow) (**unrisked**)	1,185	0.5-0.7	685		
Potential_Pay (**risked at 0.10**)	118	0.5-0.7	68		
Potential_Pay (**risked at 0.50**)	592	0.5-0.7	342		
Potential_Pay (**risked at 0.90**)	1,066	0.5-0.7	616		
Total Pay + (0.10 x Potential_Pay)	2,255		1,924	1,150	775
Total Pay + (0.50 x Potential_Pay)	2,729		2,198	1,150	1,049
Total Pay + (0.90 x Potential_Pay)	3,203		2,472	1,150	1,323

[1] *Production and test data suggest a range in recovery factor within the Sterling and Beluga Formations*

Appendix 4. Original gas-in-place, recovery factors, initial recoverable gas, and remaining reserves, North Cook Inlet Unit

North Cook Inlet Unit	OGIP (BCF)	Recovery Factor (RF)[1]	RGIP = OGIP x RF (BCF)	Cumulative Production (BCF, projected through 12-31-09)	Remaining Reserves (BCF)
PAY (green)	2,300	0.85-0.9	2,060	1,818	242
Potential_Pay (yellow) (**unrisked**)	422	0.65-0.8	302		
Potential_Pay (**risked at 0.10**)	42	0.65-0.8	30		
Potential_Pay (**risked at 0.50**)	211	0.65-0.8	151		
Potential_Pay (**risked at 0.90**)	380	0.65-0.8	272		
Total Pay + (0.10 x Potential_Pay)	2,342		2,090	1,818	272
Total Pay + (0.50 x Potential_Pay)	2,511		2,211	1,818	393
Total Pay + (0.90 x Potential_Pay)	2,679		2,332	1,818	514

[1] *Production and test data suggest a range in recovery factor within the Sterling and Beluga Formations*