DEPARTMENT OF
COMMERCE
COMMUNITY AND
ECONOMIC DEVELOPMENT
Regulatory Commission of Alaska

Sean Parnell, Governor
Emil Notti, Commissioner
Robert M. Pickett, Chairman

May 17, 2010

File: TA316-8
LO#: L1000175

Lee D. Thibert
Senior Vice President,
Strategic Planning and Corporate Affairs
Chugach Electric Association, Inc.
5601 Electron Drive
Anchorage, AK 99518

Dear Mr. Thibert,

Chugach Electric Association, Inc. (Chugach) filed TA316-8,[1] seeking our approval of a proposed gas supply contract between Chugach and Marathon Alaska Production, LLC (Chugach-Marathon GSA).[2] Chugach also requested we approve the addition of the Chugach-Marathon GSA, as a base supply contract, on Tariff Sheet Nos. 94, 95 and 95.5 of its tariff and that we approve the inclusion of all gas and transportation costs relating to the Chugach-Marathon GSA in the calculation of its quarterly fuel and purchased power adjustment (cost of power adjustment).[3] Chugach requested our approval of the Chugach-Marathon GSA no later than October 2, 2010.[4]

Chugach relies on natural gas to generate approximately 90 percent of the electrical power for its retail and wholesale member-customers.[5] Currently, Chugach uses 27 Bcf[6] of gas per year

[1]TA316-8, filed April 2, 2010.

[2]Chugach attached its contract with Marathon and further supported its request for approval with several appendices, which we reviewed. They included a December 2009 report and accompanying memorandum concerning Cook Inlet gas reserves prepared by the Alaska Department of Natural Resources (Appendix D) and a January 2010 study of Cook Inlet gas prepared by Petrochemical Resources of Alaska (Appendix E). Chugach also referred to its Gas Supply Report previously filed on December 23, 2008 in U-08-140.

[3]TA316-8 at 1.

[4]*Id.* Chugach states that it needs to have a schedule that allows Marathon and gas storage providers sufficient lead time to "plan, drill, and develop wells to meet Chugach's gas requirements." *Id.* Chugach states that the Chugach-Marathon GSA "in combination with expected Cook Inlet gas storage services is designed to fill the balance of Chugach's unmet needs for natural gas from April 2011 through December 2014." *Id.* at 2.

[5]*Id.* at 2.

[6]Billion cubic feet

in its power stations.[7] Chugach purchases all of the gas it uses from Cook Inlet gas fields and, presently, it has no alternative source of gas.[8] Chugach states that the volumes of gas available under its long-term gas contracts, through which it has obtained gas for more than 20 years, will run out in 2010 and 2011.[9] We recently approved a gas sales contract between Chugach and ConocoPhillips[10] that fills all of Chugach's unmet needs until April 2011 and a percentage of Chugach's unmet needs from June 2011 through 2016.[11] Chugach asserts that the Chugach-Marathon GSA will provide 100 percent of Chugach's remaining unmet natural gas needs from April 2011 through December 2014.[12]

The Chugach-Marathon GSA provides several different gas supply and deliverability periods, as well as different deliverability layers within each period during the term of the contract.[13] The deliverability layers or levels of service include Firm Gas, Firm Swing Gas, and Excess Gas.[14] The Chugach-Marathon GSA provides for a total of 42.3 Bcf over the four contract periods,[15] although there is no contractual commitment for the 16.1 Bcf of gas to be supplied under the 2013 Option and 2014 Option.[16]

During Period 1, Marathon agrees to provide Chugach with 30 to 38 MMcf[17] per day of Firm Gas and up to 10 MMcf per day of Firm Swing Gas.[18] Chugach may request Excess Gas which Marathon will provide, if available, on an interruptible basis.[19] During Period 2, Marathon will

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[7]TA316-8 at 2.

[8]Chugach asserts it has no alternative energy sources in the current time period despite having "worked diligently" with the Alaska Energy Authority on the Railbelt Integrated Resource Plan. TA316-8 at 18.

[9]TA316-8 at 18.

[10]ConocoPhillips Alaska, Inc. and ConocoPhillips, Inc. (collectively ConocoPhillips).

[11]Letter Order No. L0900456, dated August 21, 2009; TA316-8 at 2.

[12]TA316-8 at 2 and 3.

[13]TA316-8 at 9-10; Chugach-Marathon GSA at Section 16.3 and Section 16.1. The contract is divided into periods. Period 1 begins no later than April 1, 2011, and continues through the earlier of October 31, 2012, or when gas storage is commercially available. Period 2 begins the day after Period 1 ends and continues through March 31, 2013. Period 3 is referred to as the "2013 Option" which begins April 1, 2013, and ends December 31, 2013. Period 4, the "2014 Option" begins January 1, 2014, and ends December 31, 2014. TA 316-8 at 9-10. Chugach-Marathon GSA at Section 16.1, 2.41; Section 16.1, 2.53; Section 16.1, 2.36; and Section 16.1, 2.37.

[14]TA316-8 at 9-10. Chugach-Marathon GSA at Sections 16.3(i), 16.3(ii), and 16.3(iii).

[15]TA316-8 at 11.

[16]TA316-8 at 10; Chugach-Marathon GSA at Section 16.2, Modifications to Base Contract, deleting Section 12 and adding a new Section 12.3. Under the contract, Chugach is to receive notification two years in advance of the commencement of each option period if there will not be sufficient gas available for those periods, to allow Chugach the opportunity to seek alternative gas supply. TA316-8 at 10; Chugach-Marathon GSA at Section 16.2, Modifications to Base Contract, deleting Section 12 and adding a new Section 12.2.

[17]Million cubic feet.

[18]TA316-8 at 9-10; Chugach-Marathon GSA, Section 16.1 and 16.3.

[19]TA316-8 at 9-10; Chugach-Marathon GSA, Section 16.3(iii).

provide 36 to 38 MMcf per day of Firm Gas.[20] Chugach may request, and if available Marathon will provide, Excess Gas to Chugach on an interruptible basis.[21] During the 2013 Option and the 2014 Option periods, to the extent Marathon has gas available to sell, it will supply gas to meet Chugach's unmet requirements.[22]

The pricing for gas under the Chugach-Marathon GSA depends upon the contract period, the type of gas being delivered and the deliverability commitment.[23] The base price for Firm Gas is calculated using an average of the monthly NYMEX[24] futures gas contract prices for the particular contract period.[25] The Chugach-Marathon GSA establishes a price collar (a floor and ceiling price)[26] of $5.90 to $8.90 that is adjusted annually[27] and applies to all types of gas.[28] Thus, for example, the Base Gas supply is priced at the higher of the NYMEX futures gas contract prices averaged over nine or twelve months, or the collar floor which starts at $5.90 in 2011.[29] Swing Gas is priced at the higher of 125 percent of the NYMEX futures gas contract prices averaged over nine or twelve months, or the collar floor.[30] Excess Gas is priced the same as Swing Gas, but is interruptible.[31] Additionally, the Chugach-Marathon GSA provides for a 5 percent discount applied to the gas prices, beginning in Period 2, when Chugach is able to utilize commercial gas storage.[32]

In response to public notice of TA316-8,[33] we received comments supporting approval of the Chugach-Marathon GSA from Marathon Alaska Production, LLC, Mayor Dan Sullivan of the Municipality of Anchorage (at the recommendation of the Anchorage Energy Task Force), the

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[20]TA316-8 at 10; Chugach-Marathon GSA, Section 16.1 and 16.3. The contract does not provide for Swing Gas during Period 2. Chugach states it will not need Swing Gas because it will be relying on gas storage or other supplies. *Id.*

[21]TA316-8 at 9-10; Chugach-Marathon GSA, Section 16.3(iii).

[22]TA316-8 at 10; Chugach-Marathon GSA, Section 16.2, Modifications to Base Contract, deleting Section 12 and adding a new Section 12.3 and adding a new Section 12.2.

[23]TA316-8 at 11. Attachment 1 to the Chugach-Marathon GSA sets forth the specific pricing provisions for the contract.

[24]New York Mercantile Exchange.

[25]TA316-8 at 11. Depending on the period in question, the futures prices are averaged over either nine or twelve months. Chugach-Marathon GSA, Attachment 1.

[26]TA316-8 at 11-13; Chugach-Marathon GSA, Attachment 1.

[27]The annual adjustment is intended to reflect the increased cost of inflation. TA316-8 at 12-13.

[28]TA316-8 at 11 and 13; Chugach-Marathon GSA, Attachment 1. The price collar, according to Chugach, "bounds the price risk for both Chugach and [Marathon]." Chugach explains that for the consumer, "the price ceiling caps the market price, creates price certainty, and reduces price volatility" and for Marathon, the producer, "the price floor reduces the investment risk by ensuring that the price will be sufficient to warrant expansion and maintenance of its gas supplies." TA316-8 at 11.

[29]TA316-8 at 13; Chugach-Marathon GSA, Attachment 1.

[30]TA316-8 at 14; Chugach-Marathon GSA, Attachment 1.

[31]*Id.*

[32]TA316-8 at 12; Chugach-Marathon GSA, Attachment 1.

[33]*Notice of Utility Tariff and Contract Filing,* dated April 7, 2010.

Anchorage Chamber of Commerce, the Resource Development Council, and ENSTAR.[34] We also received comments from the Attorney General (AG).[35]

In his comments, the AG states that the proposed Chugach-Marathon GSA appears to meet all of Chugach's projected unmet needs for 2011-2014.[36] The AG concludes, therefore, that the GSA provides a reliable source of gas,[37] which is "an important element of the public interest."[38] The AG asserts that there is a lack of specific pricing information "which hampers the ability to perform a review for reasonableness of various critical pricing provisions that will impact consumer rates."[39] The information includes "proprietary producer company cost information" that "the law does not authorize the commission or the AG to obtain . . . .[40] However, the AG does not conclude that the pricing is unreasonable.[41] We received no comments opposing approval of the GSA. The AG specifically stated "we do not recommend an evidentiary hearing."[42]

Chugach filed information in support of TA316-8 indicating that it has unmet gas needs beginning in April 2011 and that the volumes of gas that will be provided under the Chugach-Marathon GSA are necessary to fill these unmet needs.[43] Chugach states that it "has no other means by which to fulfill its unmet gas requirements necessary to produce electric power for its wholesale and retail customers."[44] Chugach detailed its extensive efforts over a period beginning in 2004 to obtain the gas it needs to provide services to its member. They included

[34]Letter from M. Colleen Starring, ENSTAR Natural Gas Company, filed April 23, 2010; Letter from Carri Lockhart, Marathon Alaska Production LLC, filed May 7, 2010; Letter from Mayor Dan Sullivan, Municipality of Anchorage, filed May 7, 2010; Letter from Tony Izzo and Sami Glascott, Anchorage Chamber of Commerce, filed May 7, 2010; Letter from Jason W. Brune, Resource Development Council, filed May 10, 2010.

[35]Notice of Attorney General's Intent to File Comments, filed May 7, 2010; Comments of the Attorney General, filed May 11, 2010 (AG Comments).

[36]AG Comments at 1, 9, and 15.

[37]*Id.* at 2, 9, and 15.

[38]*Id.* at 9. *See also* AG Comments at 15 (reliability of supply is "a critically important component of the public interest").

[39]*Id.* at 1.

[40]*Id. at* 6.

[41]*Id.* at 2 and 15. The AG discusses the difficulty, under our current regulatory process, of assessing whether pricing of gas under GSA's is reasonable and in the public interest in light of the fact that gas producers are unregulated and, therefore, are not, and cannot be required by us to, provide cost information in support of the gas contracts. Additionally, the AG notes that even if pricing information was provided, because the gas contracts are negotiated close to the time when the gas is needed, it would be difficult to analyze the pricing information without potentially disrupting the utility's gas supply. *Id.* at 16.

[42]*Id.* at 16. The recommendation against a hearing was based in part on the commission's inability to obtain, "the information necessary to review the pricing provisions for reasonableness, because it has no authority to demand from [Marathon] information related to the costs of supplying gas to Chugach."

[43]TA316-8 at 1-2. Chugach discusses its present and forecasted gas requirements on pages 4-6 and 8 of TA316-8.

[44]*Id.* at 2.

nine Requests for Proposals. All those efforts resulted in the previously-approved Chugach-ConocoPhillips GSA and the GSA now before us.[45]

We have considered the filing presented by Chugach in support of the proposed Chugach-Marathon GSA. Based on the record presented in this tariff proceeding, we find that the public interest is served by approval of the Chugach Marathon GSA.[46] Accordingly, we approve the Chugach-Marathon GSA, approve the addition of Chugach-Marathon GSA on Chugach Tariff Sheet Nos. 94, 95 and 95.5, and approve the inclusion of the cost of gas purchased under the Chugach-Marathon GSA in the calculation of the Chugach gas cost adjustment.

Enclosed is a validated copy of the gas supply agreement between Chugach and Marathon Alaska Production, LLC, filed by Chugach in TA316-8 on April 2, 2010. Also enclosed are validated copies of Tariff Sheet Nos. 94, 95 and 95.5, filed on April 2, 2010, by Chugach in TA316-8, effective May 17, 2010.

BY DIRECTION OF THE COMMISSION
(Commissioner Paul F. Lisankie concurring, joined by Chairman Robert M. Pickett.)

Sincerely,

REGULATORY COMMISSION OF ALASKA

Robert M. Pickett
Chairman

[45]TA316-8 at 17.

[46]Our approval of the Chugach-Marathon GSA is consistent with HB 280 § 6, amending AS 42.05.141, signed into law May 12, 2010. Section 6 provides:

AS 42.05.141 is amended by adding a new subsection to read:

(d) When considering whether the approval of a rate or a gas supply contract proposed by a utility to provide a reliable supply of gas for a reasonable price is in the public interest, the commission shall (1) recognize the public benefits of allowing a utility to negotiate different pricing mechanisms with different gas suppliers and to maintain a diversified portfolio of gas supply contracts to protect customers from the risks of inadequate supply or excessive cost that may arise from a single pricing mechanism; and (2) consider whether a utility could meet its responsibility to the public in a timely manner and without undue risk to the public if the commission fails to approve a rate or a gas supply contract proposed by the utility.

RCA No.	8	94th Revision	Sheet No.	94
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		93rd Revision	Sheet No.	94

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Chugach Electric Association, Inc.

FUEL AND PURCHASED POWER ADJUSTMENT FACTORS AT G&T

e.1. Fuel Adjustment Factor: Predicted costs for the quarter beginning April 1, 2010:

Description	Total	Retail	HEA	MEA	SES	
Fuel Expense						
Beluga - AML&P	$3,225,908	$1,578,125	$659,528	$903,275	$84,980	
Beluga - Chevron	$4,051,140	$1,981,832	$828,244	$1,134,345	$106,720	
Beluga - ConocoPhillips 1989	$3,225,908	$1,578,125	$659,528	$903,275	$84,980	
Beluga - ConocoPhillips 2009	$5,196,425	$2,542,109	$1,062,394	$1,455,032	$136,890	
Beluga - Marathon 1988	$3,915,323	$1,915,390	$800,476	$1,096,316	$103,142	
Beluga - Marathon 2010	---	---	---	---	---	N
Bernice - Marathon 1988	$1,412,098	$690,803	$288,699	$395,396	$37,199	
Bernice - ConocoPhillips 2009	---	---	---	---	---	
Nikiski - Marathon 1988	$3,863,356	$1,889,967	$789,852	$1,081,764	$101,773	
International - Marathon 1988	$107,200	$52,443	$21,917	$30,017	$2,824	
International - ConocoPhillips 2009	$5,736	$2,806	$1,173	$1,606	$151	
International - ENSTAR Transport	$17,618	$8,619	$3,602	$4,933	$464	
Subtotal	$25,020,712	$12,240,219	$5,115,412	$7,005,959	$659,123	
Less Fuel Credits						
Economy Fuel Costs	---	---	---	---	---	
Economy Margins	---	---	---	---	---	
Wheeling Revenue	($46,393)	($22,696)	($9,485)	($12,990)	($1,222)	
Subtotal	($46,393)	($22,696)	($9,485)	($12,990)	($1,222)	
Net Fuel Expense	$24,974,319	$12,217,523	$5,105,927	$6,992,969	$657,900	
Generation & Purchases (MWh)	589,041.3	294,092.6	110,781.8	168,330.4	15,836.6	
Cost per MWh at Generation	$42.40	$41.54	$46.09	$41.54	$41.54	
Projected Balances as of April 1, 2010	($535,995)	$407,733	($310,520)	($633,209)	---	
Fuel Expense to be Recovered at G&T	$24,438,324	$12,625,256	$4,795,407	$6,359,760	$657,900	
Predicted Sales at G&T (MWh)	572,468.4	285,818.2	107,664.9	163,594.3	15,391.0	
Fuel Adjustment Factor per kWh at G&T	$0.04269	$0.04417	$0.04454	$0.03888	---- *	

* Not meaningful. Seward is billed for actual fuel and purchased power costs on a monthly basis.

Tariff Advice No.: 316-8

Effective: May 17, 2010

Issued by: Chugach Electric Association, Inc.
P.O. Box 196300, Anchorage, Alaska 99519-6300

By: Bradley W. Evans

Title: Chief Executive Officer

RCA No.	8	93rd Revision	Sheet No.	95
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		92nd Revision	Sheet No.	95

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Chugach Electric Association, Inc.

FUEL AND PURCHASED POWER COST ADJUSTMENT FACTORS

f.1. Actual fuel costs for the quarter ending December 31, 2009:

Description	Total	Retail	HEA	MEA	SES	
Fuel Adjustment Factor Balance						
as of September 30, 2009	($2,286,747)	($1,432,714)	($190,904)	($663,128)	---	
Fuel Balance for Quarter Ending December 31, 2009						
Fuel Expense						
Beluga - AML&P	$5,365,691	$2,666,841	$1,000,251	$1,582,699	$115,900	
Beluga - Chevron	$6,707,114	$3,333,551	$1,250,314	$1,978,374	$144,874	
Beluga - ConocoPhillips 1989	$5,730,433	$2,848,125	$1,068,244	$1,690,286	$123,778	
Beluga - ConocoPhillips 2009	---	---	---	---	---	
Beluga - Marathon 1988	$16,400,205	$8,147,872	$3,057,266	$4,840,900	$354,167	
Beluga - Marathon 2010	---	---	---	---	---	N
Bernice - Marathon 1988	$918,771	$454,247	$167,640	$277,463	$19,421	
Bernice - ConocoPhillips 2009	---	---	---	---	---	
Nikiski - Marathon 1988	$3,195,707	$1,593,872	$608,897	$922,448	$70,490	
International - Marathon 1988	$64,241	$31,946	$11,668	$19,270	$1,357	
International - ConocoPhillips 2009	---	---	---	---	---	
Natural Gas Transportation	$16,678	$8,289	$3,081	$4,950	$357	
Emergency Generator Fuel	---	---	---	---	---	
Subtotal	$38,398,841	$19,084,744	$7,167,361	$11,316,391	$830,345	
Less Fuel Credits						
Economy Fuel Costs	($4,062,159)	($2,016,712)	($756,088)	($1,201,788)	($87,571)	
Economy Margins	($445,018)	($220,687)	($83,592)	($131,074)	($9,665)	
Wheeling Revenue	($210,544)	($104,506)	($39,696)	($61,752)	($4,590)	
Subtotal	($4,717,721)	($2,341,906)	($879,376)	($1,394,613)	($101,825)	
Net Fuel Expense	$33,681,121	$16,742,839	$6,287,985	$9,921,777	$728,519	
Generation & Purchases (MWh)	714,958.9	360,670.3	125,025.6	213,554.1	15,708.9	
Cost per MWh at Generation	$47.11	$46.42	$50.29	$46.46	$46.38	
Total Fuel Cost Recovery	$34,827,930	$16,350,030	$7,013,699	$10,735,682	$728,519	
Quarter Balance	($1,146,809)	$392,809	($725,713)	($813,904)	---	

Tariff Advice No.: 316-8　　　Effective: May 17, 2010

Issued by: Chugach Electric Association, Inc.
P.O. Box 196300, Anchorage, Alaska 99519-6300

By: Bradley W. Evans　　　Title: Chief Executive Officer

RCA No.	8	29th Revision	Sheet No.	95.5
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		28th Revision	Sheet No.	95.5

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Chugach Electric Association, Inc.

	Actual - Quarter Ended December, 2009			Projected - Quarter Ended June, 2010		
Description	Volume [1]	Unit Cost	Total Cost	Volume	Unit Cost	Total Cost
Fuel Expense						
Beluga - AML&P, Mcf	1,209,706	$4.44	$5,365,691	937,764	$3.44	$3,225,908
Beluga - Chevron, Mcf	1,209,706	$5.54	$6,707,114	937,764	$4.32	$4,051,140
Beluga - ConocoPhillips 1989, Mcf	1,209,707	$4.74	$5,730,433	937,764	$3.44	$3,225,908
Beluga - ConocoPhillips 2009, Mcf	---	---	---	876,721	$5.93	$5,196,425
Beluga – Marathon 1988, Mcf	2,953,766	$5.55	$16,400,205	998,807	$3.92	$3,915,323
Beluga – Marathon 2010, Mcf	---	---	---	---	---	--- N
Beluga - Aurora Gas, LLC, Mcf [2]	---	---	---	---	---	---
Bernice - Marathon 1988, Mcf	163,479	$5.62	$918,771	360,229	$3.92	$1,412,098
Bernice - ConocoPhillips 2009, Mcf	---	---	---	---	---	---
Nikiski - Marathon 1988, Mcf	640,963	$4.99	$3,195,707	985,550	$3.92	$3,863,356
International - Marathon 1988, Mcf	12,834	$6.31	$80,919	27,347	$4.55	$124,459
International - ConocoPhillips 2009, Mcf [3]	---	---	---	569	$10.71	$6,095
Subtotal [4]	7,400,161	$5.19	$38,398,841	6,062,515	$4.13	$25,020,712
Purchased Power Expense						
Bradley Lake Purchases, MWh	44,934	$42.25	$1,898,562	47,181	$42.26	$1,993,896
Golden Valley Electric, MWh	---	---	$6,565	---	---	$0
Nikiski (HEA Fuel, O&M)	51,059	$6.95	$355,050	78,844	$6.99	$551,120
Other Purchases, MWh	103	$388.64	$40,029	---	---	$21,629
Subtotal	96,096	$23.94	$2,300,206	126,025	$20.37	$2,566,644
Total Fuel & Purch. Power Expense	----	----	$40,699,047	----	----	$27,587,356

[1] Fuel volumes from invoice.

[2] Represents emergency natural gas purchases for operation of generation units located at the Beluga Power Plant. This line item will remain blank if not used.

[3] Includes natural gas transportation.

[4] Actual Total Cost does not include fuel cost for emergency generator at Hope.

Tariff Advice No.: 316-8 Effective: May 17, 2010

Issued by: Chugach Electric Association, Inc.
P.O. Box 196300, Anchorage, Alaska 99519-6300

By: Bradley W. Evans Title: Chief Executive Officer

CHUGACH
POWERING ALASKA'S FUTURE

April 2, 2010

RECEIVED
By the Regulatory Commission of Alaska on Apr 02, 2010

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501-3469

RE: Tariff Advice Letter 316-8

Dear Commissioners:

Chugach Electric Association, Inc. ("Chugach") hereby submits the following tariff filing that includes a new gas purchase agreement in compliance with the Alaska Public Utilities Regulatory Act and 3 AAC 48.200 – 3 AAC 48.430.

Tariff Sheet Number		Cancels Sheet Number		Schedule or Rule Number
Original	Revised	Original	Revised	
94	94	94	93	Fuel and Purchased Power Recovery
95	93	95	92	
95.5	29	95.5	28	

APPROVALS REQUESTED

Pursuant to 3 AAC 52.470(e), Chugach requests Commission approval of a new gas supply contract between Chugach and Marathon Alaska Production LLC ("MAP"), entitled Base Contract for Sale and Purchase of Natural Gas, dated March 31, 2010 ("Chugach-MAP Gas Contract" or "Contract"), attached hereto as **Appendix A**. Chugach also requests Commission approval for the addition of the Chugach-MAP Gas Contract on Tariff Sheet Nos. 94, 95, and 95.5 of Chugach's Tariff as a base supply contract, as well as approval for inclusion of all fuel (gas) and transportation costs related to the Chugach-MAP Gas Contract in the calculation of the Chugach's Quarterly Fuel and Purchased Power Adjustment. The proposed tariff sheet are attached hereto as **Appendix B**.

Pursuant to the Commission's regulations (3 AAC 48.270-.300), Chugach respectfully requests a Commission ruling no later than October 2, 2010 and provides the following demonstration of good cause. First, as detailed below, Chugach needs this gas contract approved in order to meet its gas requirements at the end of the first quarter 2011. Second, Chugach needs to adhere to a schedule that provides MAP and gas storage providers adequate lead time to plan, drill, and develop wells to meet Chugach's gas requirements. Specifically, for MAP to meet Chugach's gas supply and deliverability requirements for the next two to four years, MAP needs to make capital investment commitments in October 2010 for drilling that take place in 2011 and 2012. The effectiveness of the Contract, however, is conditioned upon Commission approval.

As described below, the Contract in combination with expected Cook Inlet gas storage services is designed to fill the balance of Chugach's unmet needs for natural gas from April 2011 through December 2014. Chugach believes this Contract provides such needed gas volumes at a reasonable price on terms that are fair, just and reasonable. At this point, Chugach has no other means by which to fulfill its unmet gas requirements necessary to produce electric power for its wholesale and retail customers. Consequently, Chugach respectfully requests prompt Commission consideration of this Contract.

Given the need for relatively prompt approval, Chugach is interested in actively working with the Commission to set a schedule for this matter and otherwise assist the Commission as necessary to accommodate Chugach's request for prompt approval.

BACKGROUND

Chugach depends on natural gas to produce about 90% of the power needed to serve its retail and wholesale member-customers. At present, Chugach uses 27 Bcf of gas per year in its power stations. The gas that Chugach purchases for its fuel requirements all comes from Cook Inlet gas fields. At present, Chugach has no alternative source of fuel its generation facilities.

For more than twenty years, Chugach has obtained its gas requirements under a series of long-term gas contracts. The volumes available under these existing long-term contracts will run out in 2010 and 2011. For at least the past six years, Chugach has spent a significant amount of time and effort working to obtain replacement gas supplies for the period after the present gas supplies end. [1]

In May 2009, Chugach entered into its first significant gas supply contract in twenty years with ConocoPhillips Alaska, Inc. and ConocoPhillips, Inc. (collectively, "COP"), entitled Base Contract for Sale and Purchase of Natural Gas, dated May 12, 2009 ("Chugach-COP Gas Contract"), which it filed with the Commission for approval on the same day in TA 305A-8. The Commission approved the Chugach-COP Gas Contract on August 21, 2009 in Letter Order #LO900456. The Chugach-COP Gas Contract was designed to fill 100% of Chugach's unmet needs until April 2011, approximately 50% of Chugach's unmet needs from May 2011 through December 2014, approximately 60% of Chugach's unmet needs in 2015, and 29% in 2016. Of course, this has left Chugach with the need to procure gas for the balance of its needs from other Cook Inlet gas producers.

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[1] For details regarding the history of Chugach's gas supply situation, please see Chugach's Gas Supply Report, filed on December 23, 2008, in Commission Docket U-08-140.

In December 2009, the State of Alaska, Department of Natural Resources ("ADNR"), Division of Oil and Gas and Division of Geological & Geophysical Surveys released a report entitled "Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves" ("*ADNR Gas Reserves Report*").[2] The technical report documents the extent of the gas production decline in Cook Inlet and price and investment needed to meet regional gas needs. In his cover memorandum to the *ADNR Gas Reserves Report*, Kevin Banks, ADNR Director, summed up the findings and frankly stated the situation facing Alaska's consumers:

> Consumers relying upon Cook Inlet natural gas to meet their energy needs should know that while there is no need to panic, there is also no time to waste. Although it is apparent that sufficient reserves remain to provide for Railbelt needs for the coming decade or more, the cost of providing energy to these same consumers is likely to rise. The low-hanging fruit in the Cook Inlet has largely been picked and as such one thing seems clear – the basin is not running out of gas but it could well be running out of cheap gas. Investments in storage development, reserves replacement and pipeline infrastructure will place additional upward pressure on consumer energy prices.[3]

Consistent with ADNR's assessment of Cook Inlet gas, Chugach has now executed a gas supply agreement with MAP that balances the price of gas to investments in exploration and production, and that provides 100% of Chugach's unmet needs through 2014. Chugach is therefore pleased to file this Chugach-MAP Gas Contract for approval on terms that the Commission should find acceptable.

Pursuant to 3 AAC 52.470(e), the balance of this letter provides the Commission with:

(1) a review of Chugach's current load forecast and gas supply situation;
(2) a description of the key features of the Chugach-MAP Gas Contract; and
(3) a review of Chugach's other gas supply options.

CHUGACH'S GAS SUPPLY SITUATION

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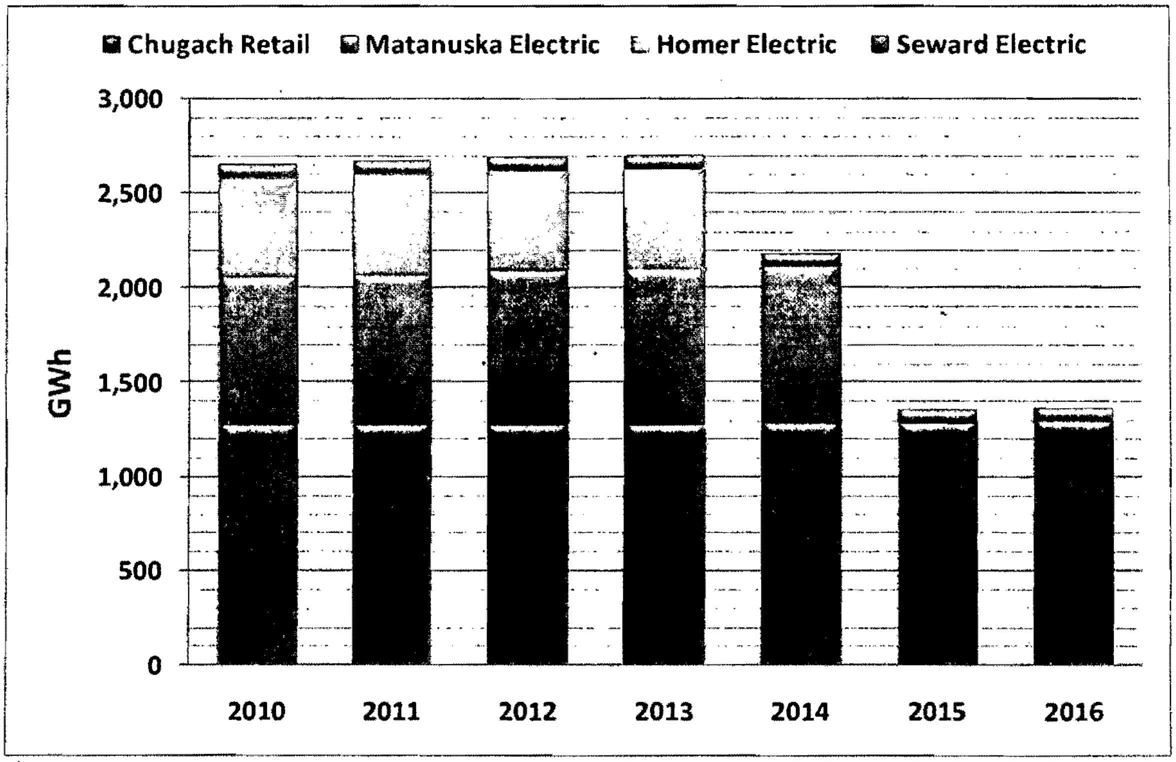
[2] Hartz, Jack D., *et al.*, State of Alaska Department of Natural Resources, Division of Oil and Gas and Division of Geological & Geophysical Surveys, *Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves* (Decker, Paul L., ed. December 2009) attached as **Appendix D.**

[3] Memorandum entitled "Cook Inlet Gas Reserves Study" from Kevin Banks, Director, State of Alaska Department of Natural Resources, Division of Oil and Gas, Department of Natural Resources to Tom Irwin, Commissioner, State of Alaska Department of Natural Resources (December 21, 2009), at 2, also attached as **Appendix D.**

Consideration of the Chugach-MAP Gas Contract starts with an identification of Chugach's present and forecasted gas requirements. **Chart 1** shows Chugach's electric load requirements necessary to meet its customers' needs from 2010 though 2016. It also shows that Chugach's electric load requirements will decrease in 2014 and 2015 due to expiration of its commitments to serve various wholesale customers: Homer Electric Association on January 1, 2014 and Matanuska Electric Association on December 31, 2014. (Note that the data supporting Chart 1 and most of the other charts in the letter are presented in tables in **Appendix C**.)

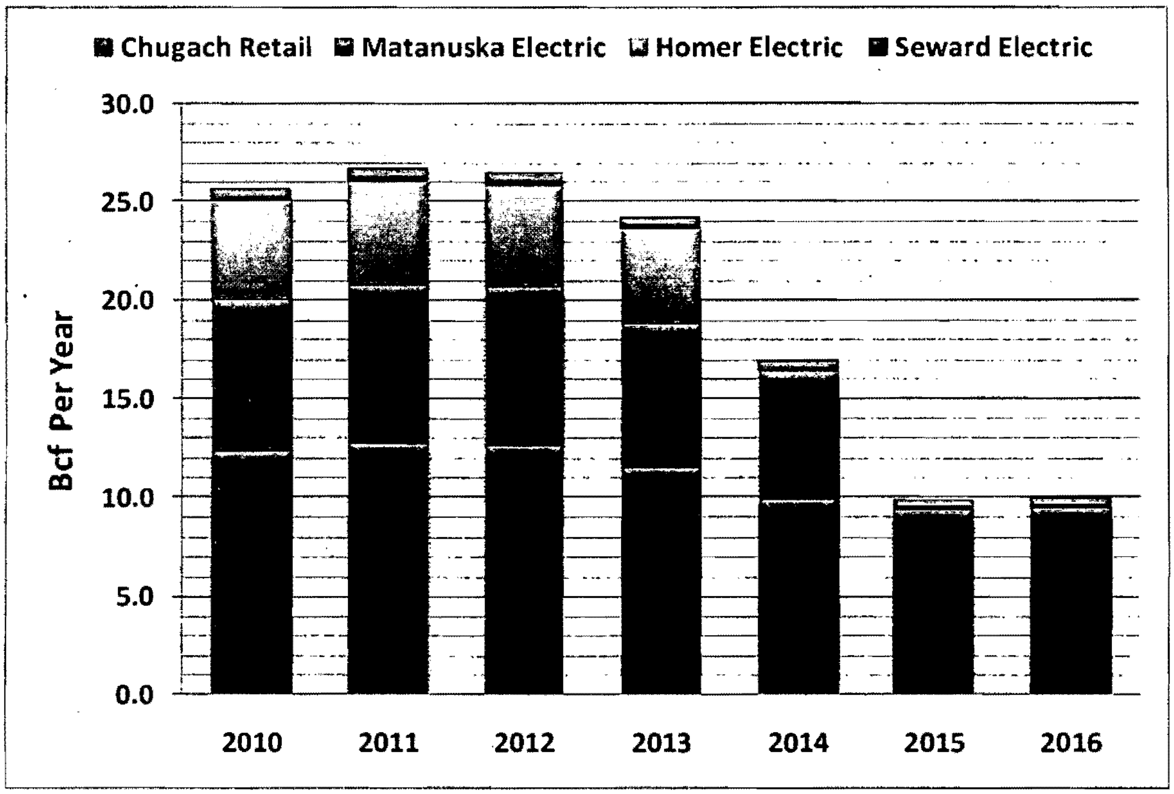
Chart 1 – Electric Load Forecast by Utility



Source: Chugach Long-Term Load Forecast

Chart 2 takes the electric load requirements summarized in Chart 1 and converts them into gas requirements using Chugach's existing and planned generation facility portfolio. As Chugach's electric load requirements decline, its gas requirements decline as well. Gas requirements in 2013 are lower than 2012 because the higher efficiency Southcentral Power Project is expected to be completed mid-2013. Lower gas requirements in 2014 reflect a combination of a full year of increased efficiency of the Southcentral Power Project and the expiration and non-renewal of the wholesale electric contract with Homer Electric Association on January 1, 2014. Lower gas requirements in 2015 reflect the expiration and non-renewal of the wholesale electric contract with Matanuska Electric Association on December 31, 2014.

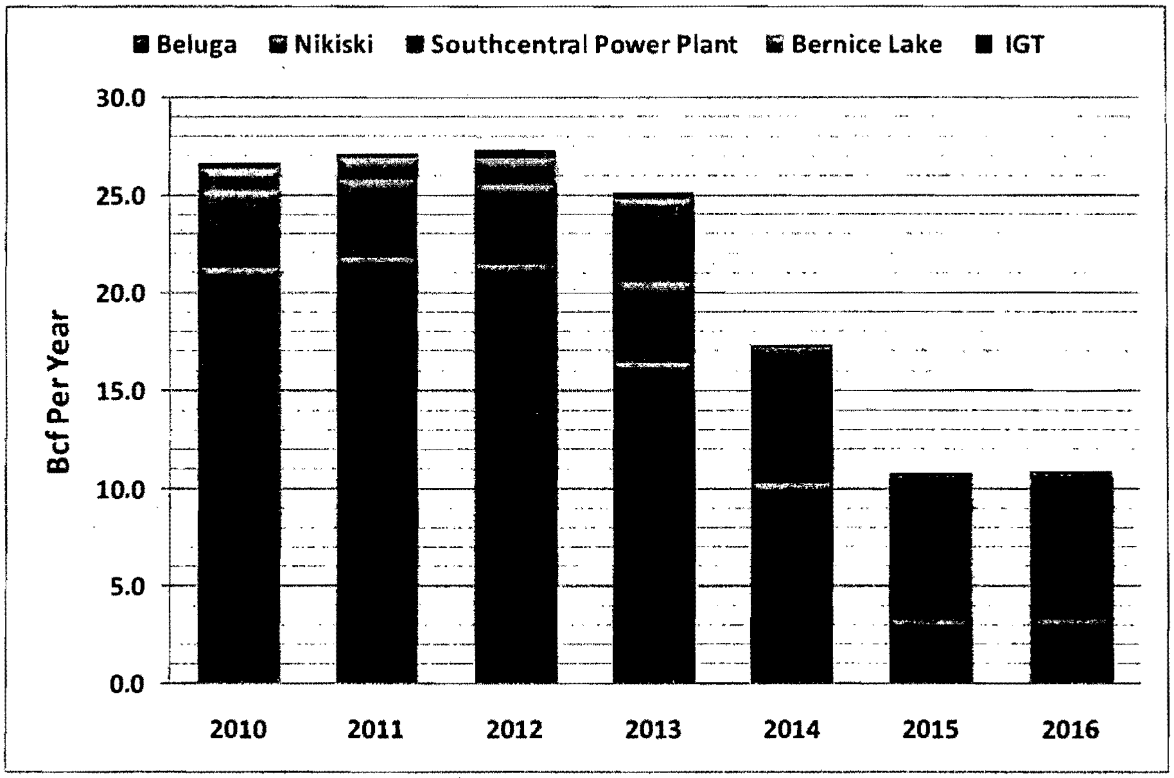
Chart 2 – Natural Gas Requirements by Utility



Source: Chugach Gas Volume Forecast

Chart 3 provides a breakdown of Chugach's requirements by generation facility for 2010 through 2016. Note that during the seven year forecast, the gas usage of various plants is expected to change as more efficient generation (Southcentral Power Project) is brought on line in mid 2013. Also gas requirements are reduced because of the expiration and non-renewal of the wholesale electric contract with Homer Electric Association and Matanuska Electric Association.

Chart 3 – Natural Gas Requirements by Power Plant



Source: Chugach Gas Volume Forecast

KEY FEATURES OF THE CHUGACH-MAP GAS CONTRACT

The most significant provisions of this Chugach-MAP Gas Contract can be summarized as follows:

1. Industry Standard Form Contract

In order to expedite contract negotiations, avoid lengthy arguments and over-lawyering of the contract, and create a stable base platform for this and future contracts, Chugach and MAP used the standard *Base Contract for Sale and Purchase of Natural Gas*, which was developed, published, and updated by the North American Energy Standards Board (NAESB). Notably, this is the exact same form of contract that Chugach and COP used in the Chugach-COP Gas Contract approved by the Commission last year.

The NAESB Form Gas Contract is one of the most common form natural gas wholesale contracts used in the United States. As described on the NAESB website, NAESB serves as an industry forum for the development and promotion of standards which is intended to "lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities."[4]

Most importantly, it reflects a fair and careful balance of the interests of buyers and sellers achieved by parties, lawyers, and regulators over many years and countless transactions. It therefore offers a well-vetted, balanced starting point for commercial negotiations. Wherever possible, Chugach and MAP used the form contract standard provisions. Several aspects of the deal regarding price, delivery points, and some other Alaska-specific conditions, however, required departure from the NAESB form contract. This is not uncommon for NAESB gas contracts, many of which have separate provisions added to modify or expand the basic NAESB provisions. Section 16 of the Contract (entitled "Special Provisions Addendum") contains those new provisions.

2. New Gas Supplier: Marathon Alaska Production LLC

As detailed in Chugach's Gas Supply Report, filed on December 23, 2008, in Commission Docket U-08-140, the owners of the gas in the Cook Inlet region have changed over the past twenty-five years. The most recent change of ownership is occurring currently as Marathon Oil Company, the original gas supplier to Chugach's 1989 contract, has transferred all of its Cook Inlet gas field assets to Marathon Alaska Production LLC. Chugach's supplier in this new contract is Marathon

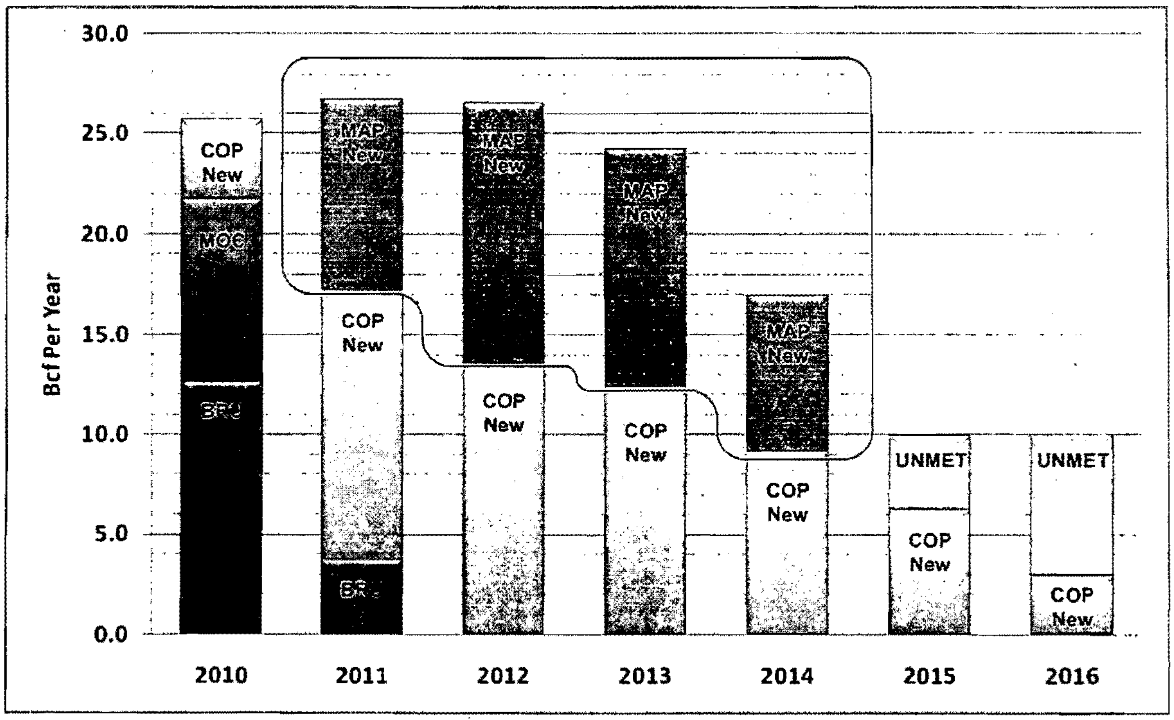
[4] *See* http://www.naesb.org/aboutus.asp.

Alaska Production LLC ("MAP"). MAP holds the reserves necessary to serve Chugach's needs for the term of this Contract.

3. Gas Volumes: 2011 - 2016

Following the Chugach-COP Gas Contract, Chugach negotiated the Chugach-MAP Gas Contract to fill the balance of 100% of Chugach's unmet needs from April 2011 through December 2014. **Chart 4** demonstrates how the volumes purchased under the Chugach-MAP Gas Contract will add substantially to Chugach's gas supplies and aid in meeting its load requirements.

Chart 4 – Natural Gas Supply by Producer



Source: Chugach Gas Volume Forecast

The Chugach-MAP Gas Contract provides several different gas supply and deliverability periods over the term of the contract. This allows Chugach and MAP to better match Chugach's requirements because it is uncertain when gas storage will be available, when the Southcentral Power Project will be on-line and if HEA needs power from Chugach in 2014. **Chart 5** provides a summary of the gas supply periods.

Chart 5 – Contract Periods of MAP Natural Gas Supply

Period Name	Period 1	Period 2	2013 Option	2014 Option
Time period	4/1/2011 thru the earlier of 10/31/2012 or when gas storage is commercially available	The day after Period 1 ends thru 3/31/2013	4/1/2013 thru 12/31/2013	1/1/2014 thru 12/31/2014

Source: Chugach-MAP Gas Contract, Section 16.3 and supplemental definitions in Section 16.1.

The Chugach-MAP Gas Contract provides different gas deliverability layers within each period. This allows the value of different levels of gas deliverability to better align with price for those levels of service: *e.g.*, Firm Gas, Swing Gas, and Excess Gas, each as defined in Section 16.3 of the Contract. **Chart 6** provides a summary of the gas deliverability layers in the Contract.

Chart 6 – Deliverability Layers of MAP Natural Gas Supply

Period Name	Period 1	Period 2	2013 Option	2014 Option
Firm Gas	30-38 MMcf/day	36-38 MMcf/day	Chugach's Unmet Requirements, to be established no later than 3/31/2011	Chugach's Unmet Requirements, to be established no later than 12/31/2011
Firm Swing Gas	≤ 10 MMcf/day	None		
Excess Gas	As needed and available on an interruptible basis	As needed and available on an interruptible basis		

Source: Chugach-MAP Gas Contract, Section 16.3 and supplemental definitions in Section 16.1.

Period 1- From the beginning of the Contract (on or before April 1, 2011), MAP will provide Chugach with 30-38 MMcf/day of Firm Gas, plus up to 10 MMcf/day of Firm Swing Gas, and Excess Gas to the extent that Chugach requests it and MAP can provide it on an interruptible basis. Chugach also has the right in Period 1 to sell and exchange gas, and make economy sales to manage

the 30-38 MMcf/day range. Period 1 ends the earlier of October 31, 2012 or when Chugach will be able to rely on the commercially available gas storage to meet its swing needs. *See* Section 2.53 – Definition of Period 1.

Period 2 - From the day after Period 1 ends and through March 31, 2013, MAP will provide Chugach with 36-38 MMcf/day of Firm Gas, plus Excess Gas to the extent that Chugach requests it and MAP can provide it on an interruptible basis. Chugach will not need Swing Gas during this period because it will rely on stored gas or other supplies if commercial storage is not available. During Period 2, Chugach has made the assumption that gas storage well be available prior to October 31, 2012. Chugach is currently in negotiations with gas storage providers to meet its storage needs.

2013 and 2014 Options – Pursuant to the new Section 12.2, to the extent that MAP has gas available for sale, MAP will supply Chugach's Unmet Requirements for the remaining portion of 2013. (MAP and Chugach anticipate that MAP will have gas sufficient to exercise the 2013 and 2014 Options, but MAP cannot contractually commit to such volumes until it invests in the gas field and deliverability improvements discussed above.) The 2013 Option runs April 1 through December 31, 2013 and Option 2014 runs for January 1, 2014 through December 31, 2014. Chugach estimates it's Unmet Requirements for the option periods will be about 8.3 Bcf of gas in 2013 and 7.8 Bcf of gas in 2014. The Contract requires MAP to notify Chugach two (2) years in advance of the 2013 and 2014 Options if MAP does not have adequate gas supplies available for 2013 and 2014. This will provide Chugach with sufficient time to pursue other arrangements.

The gas volumes for the periods and deliverability layers are shown in **Chart 7**. Excess gas volumes are expected to be minimal, and with rounding are shown as zero in the chart.

Chart 7– Estimated Gas Volumes (Bcf)

Period Name	Period 1[5]		Period 2	Period 2	2013 Option	2014 Option	Total
	4/1/2011 to 12/31/2011	1/1/2012 to ~10/31/2012	~11/1/2012 to 12/31/2012	1/1/2013 to 3/31/2013	4/1/2013 to 12/31/2013	1/1/2013 to 12/31/2014	4/1/2011-12/31/2014
Firm Gas	9.4	10.2	2.4	3.6	8.3	7.8	41.7
Firm Swing Gas	0.2	0.4	0.0	0.0	0.0	0.0	0.6
Excess Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Gas	9.6	10.6	2.4	3.6	8.3	7.8	42.3

Source: Chugach Gas Volume Forecast

4. Price of Contract Gas

Several components determine the price of gas sold by MAP to Chugach under the Chugach-MAP Gas Contract. As described below and set forth in Attachment 1 to the Contract, the Contract Price starts with a NYMEX futures index price and varies due to the application of discounts and premiums according to the time period (*e.g.*, Contract Year 1, Contract Year 2, Period 1, Period 2, 2013 Option, and 2014 Option, each as defined in the Contract) and the type of gas being delivered and the associated deliverability commitment (*e.g.*, Firm Gas, Swing Gas, and Excess Gas, each as defined in the Contract), all of which are subject to an important price collar.

A. Price Collar

The key pricing feature of the Chugach-MAP Gas Contract is the price collar. The price collar bounds the price risk for both Chugach and MAP. From an energy consumer perspective, the price ceiling caps the market price, creates price certainty, and reduces price volatility. From a gas producer perspective, the price floor reduces the investment risk by ensuring that the price will be sufficient to warrant expansion and maintenance of its gas supplies.

[5] Note that Period 1 ends the earlier of October 31, 2012 or when Chugach will be able to rely on the commercially available gas storage to meet its swing needs.

The price collar is well-matched for the business and operating environment as described in the December 2009 *ADNR Gas Reserves Report* and Mr. Banks' cover memo. Even though the *ADNR Gas Reserves Report* does not quantify the level of investment or associated gas price, the report clearly recognizes the need for investment. The report explains how the daily deliverability is becoming increasingly difficult to maintain and secure from producers without additional investments. In the following quotation, the *ADNR Gas Reserves Report* identifies various types of investments that could be used to secure deliverability during a period of peak demand:

> 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.[6]

Consistent with this caution, Chugach understands that the price floor in the Chugach-MAP Gas Contract is sufficient to warrant MAP's investment in, and development of, its Cook Inlet Gas Reserves, which will benefit Chugach's member customers and the region as a whole.

The Chugach-MAP Gas Contract floor and ceiling prices that create the price collar vary during the term of the Contract. In general, the collar prices increase over time to reflect the cost of inflation. A 5% discount, however, is applied to the price of gas when gas storage is available to represent the shift in gas storage cost to Chugach from MAP. In order to receive the discount when the gas price is below the floor price or above the ceiling price, the floor and ceiling prices are discounted 5%. The Chugach-MAP Gas Contract floor and ceiling prices are shown in **Chart 8** below.

[6] *ADNR Gas Reserves Report* (Attachment D) at 18.

Chart 8 – Contract Floors and Ceilings

	Base		5% Discount	
	Floor	**Ceiling**	**Floor**	**Ceiling**
Period 1	$5.90	$8.90	no discount	no discount
Period 2	$6.10	$9.10	$5.79	$8.65
2013 Option	$6.25	$9.25	$5.94	$8.79
2014 Option	$6.50	$9.50	$6.18	$9.03

Source: Chugach-MAP Gas Contract, Attachment 1 and computed discount.

In addition to the review of the ADNR Gas Reserves Report, Chugach gained some independent verification of the need for this price floor. Chugach and other Cook Inlet utilities asked Petrochemical Resources of Alaska (PRA) to perform a study of Cook Inlet reserves and deliverability. The components of the study included review of potential reserves and deliverability of Cook Inlet gas wells drilled between 2001 and 2009, a forecast of potential future drilled gas wells, a review of analysis of available reserves in the ADNR Gas Reserves Report, and an analysis of the potential timing for delivery of non-Cook Inlet gas resources, such as LNG imports or other in-state resources. PRA analyzed wells drilled between 2001 and 2009 and determined that producers spent between $1.0 to $1.2 billion in development cost to add reserves of approximately 519 billion cubic feet (Bcf) of natural gas. To meet future Cook Inlet utility demand, the study estimated that producers will need to invest two to three times that amount. PRA's *Cook Inlet Gas Study* is attached as **Appendix E**.

B. Firm Gas Price

Pursuant to Attachment 1 of the MAP-Chugach Gas Contract, the base price for firm gas is a simple average of prices in monthly NYMEX futures contracts for such year as reported in *Platts Gas*. The methodology the Platt uses in reporting monthly NYMEX futures contracts is set forth on page 6 of *Platts Methodology and Specifications Guide – North American Natural Gas, January 2010*, attached hereto as **Appendix F**. The firm gas price applies to about 99% of the total estimated gas contract volumes sold under the Contract.

Chart 9 demonstrates how the Contract price for Firm Gas is calculated using NYMEX Calculated Price, based on February 1, 2010 futures data in *Platts Gas Daily* on February 2, 2010. The firm price would be $5.95 per Mcf if the contract was in Period 1.

Chart 9 – NYMEX Calculated Price as of February 1, 2010

12 Month Period		NYMEX Close
1-Apr-10	$	5.405
1-May-10	$	5.450
1-Jun-10	$	5.517
1-Jul-10	$	5.591
1-Aug-10	$	5.656
1-Sep-10	$	5.689
1-Oct-10	$	5.795
1-Nov-10	$	6.110
1-Dec-10	$	6.450
1-Jan-11	$	6.680
1-Feb-11	$	6.645
1-Mar-11	$	6.455
12 Month Total	$	71.443
Divisor		12
12 Month Simple Average	$	5.954

Source: *Platts Daily* (February 2, 2010) at p. 7.

C. Firm Swing Gas Price

Under MAP-Chugach Gas Contract, MAP will provide firm swing gas for the gas volumes (up to 10 MMcf per day) above the 38 MMcf/day firm gas commitment in Period 1 of the Contract until Chugach will be able to rely on the commercially available gas storage to meet its swing needs. A 25 percent premium is applied to the NYMEX Calculated Price to compensate MAP for the value of this extra deliverability commitment. The firm gas price applies to about 1% of the total estimated gas contract volumes under the Contract.

D. Excess Gas Price

Pursuant to Section 16.3 of the MAP-Chugach Gas Contract, Chugach may also request through the nominations process to buy gas in excess of 48 MMcf/day in Period 1 of the Contract and in excess of 38 MMcf/day for Period 2 at a price that Chugach deems appropriate up to 125% of the NYMEX Calculated Price. MAP will have the option, but on the obligation, to sell such requested excess gas on an interruptible basis. The excess gas deliverability limit for the 2013 and 2014 Options will be defined in 2011. Chugach estimates that the total excess gas to be purchased under the Contract will be less than 1% of the total estimated gas contract volumes.

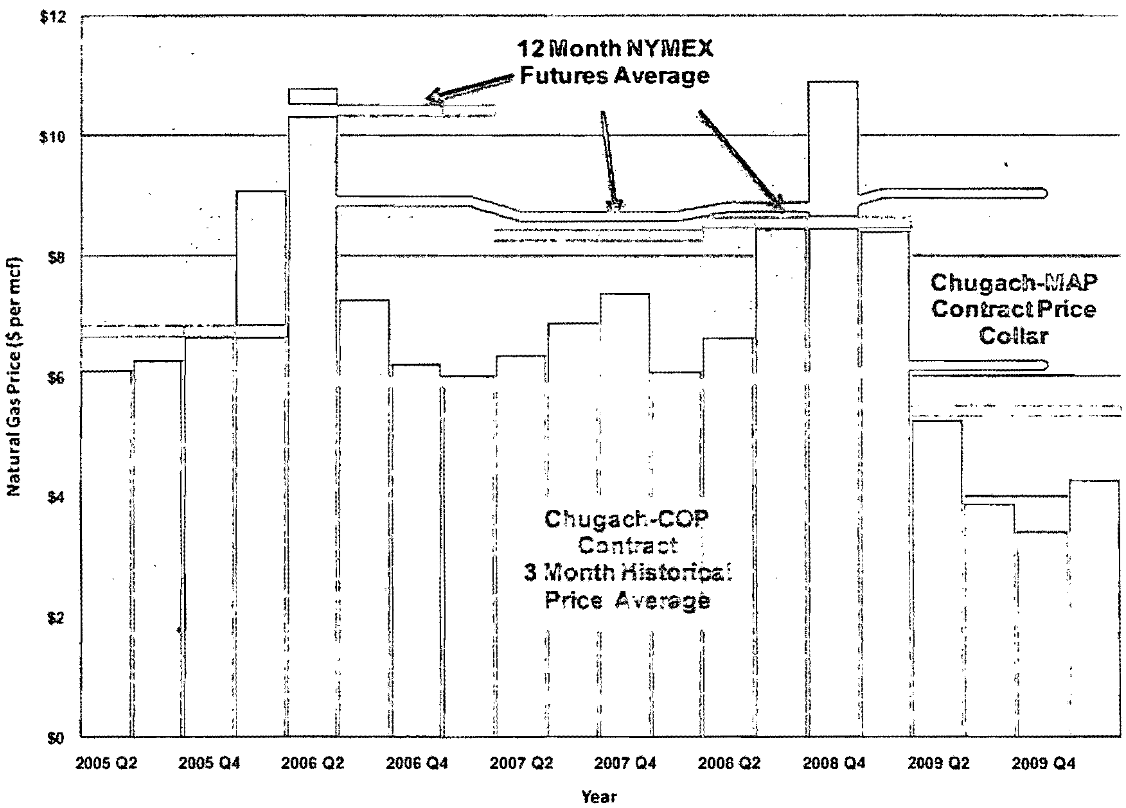
E. Comparison of Contract Gas Prices in Chugach Gas Contracts

Different prices in the Chugach-COP Gas Contract and the Chugach-MAP Gas Contract reflect the fact that the Chugach-COP Gas Contract is determined based on *historical* gas pricing data, revised on a *quarterly basis,* while the Chugach-MAP Gas Contract reflects *future* contracts prices averaged on a *yearly basis*. Chugach actively sought such pricing diversity in order to avoid concentration of price risk exposure on shorter or longer term markets, or past prices or future prices.

The Chugach-MAP Gas Contract price collar for the entire term of the Contract also has the benefit of less price volatility risk compared to the Chugach-COP Gas Contract pricing. The Chugach-COP Gas Contract pricing uses the average of historical market gas prices in the Lower 48 natural gas production areas for base gas ("Production Area Composite Index" or "PACI") for 90% of the contracted gas volume and assumes 10% of peaking gas volume that could be 100% to 200% of the base price; peaking gas is assumed to be 150% of the base price for illustrative purposes. The quarterly prices in the Chugach-COP Gas Contract are shown as columns in **Chart 10** and range from $6.04 per Mcf to $10.92 per Mcf from 2005 to 2008. With the Chugach-MAP price collar, the price range is within a range of $5.79 per Mcf to $9.03 per Mcf. Even though the methodology for pricing gas is different, the Chugach-COP and Chugach-MAP contracts provide a similar range of gas prices. This is also evident in **Chart 10**. The yellow bars indicating the gas price Chugach would have paid pursuant to the Chugach-MAP Gas Contract (average of the future 12 months as of Feb 1) are within the collar three out of the five times.

MAP and Chugach's consumers both benefit from the price floor because, with the Chugach-MAP price floor, MAP is willing to make the investment in Cook Inlet needed to meet Chugach's unmet gas needs, and in particular, provide the level of gas deliverability to meet Chugach's electric demand.

Chart 10 – Comparison of Chugach-COP and Chugach-MAP Contract Prices



5. Delivery Points and Transportation

As with the Chugach-COP Contract, all gas sold and purchased under the Chugach-MAP Gas Contract will be delivered to Chugach at one or more of the designated "Delivery Points" as provided in Sections 16.6 and Attachment 2 to the Contract. Chugach will be responsible for arranging and paying for transportation of gas from the Delivery Points to its power plants as it deems necessary.

6. Taxes and Royalties

As with the Chugach-COP Contract, under the Chugach-MAP Contract, MAP is responsible for taxes and excess royalties, subject to Alaska Department of Revenue's agreement to accept the Contract prices as the value of the State's royalty share of production. After March 31, 2013,

Chugach will reimburse MAP for any production taxes or other new taxes attributable to the operations and transactions contemplated by this Contract in excess of $0.25 per Mcf.

7. Contract Approval

As with the Chugach-COP Gas Contract, the effectiveness of the Chugach-MAP Gas Contract is expressly conditioned upon Commission approval in Section 16.2.

COMPARISON TO OTHER OPTIONS

Pursuant to 3 AAC 52.470(e)(3), Chugach provides the following information demonstrating that the Chugach-MAP Gas Contract is the most feasible means of meeting the balance of its gas requirements for its load forecast for the period of April 1, 2011 through December 31, 2014.

Beginning in late 2004, Chugach solicited offers from nine Cook Inlet natural gas leaseholders for gas to meet future unmet needs. Chugach spent significant financial and human resources negotiating for reasonable terms and cost provisions from multiple parties. During its negotiations, Chugach presented not less than nine Requests for Proposals (RFPs). In the course of those negotiations, Chugach received or drafted 29 term sheets which included the major provisions of a natural gas contract. In addition, Chugach participated in over 79 meetings, more than 30 conference calls and sent or received more than 40 letters regarding gas supply between Chugach and the Cook Inlet producers. The fruit of these substantial efforts are the Chugach-COP Gas Contract approved last year and the Chugach-MAP Gas Contract that is the subject of this filing.

Notably, because the issue may arise in this proceeding, Chugach observes that Chugach-MAP Gas Contract does not trigger the rights of first refusal set forth in Exhibit F of the (1) Agreement for the Sale and Purchase of Natural Gas between Chugach Electric Association, Inc. and Chevron U.S.A. Inc. ("Chevron"), dated April 27, 1989, as amended, and (2) the Sale and Purchase of Natural Gas between Chugach Electric Association, Inc. and Arco Alaska, Inc., dated April 21, 1989, as amended (collectively the "1989 Gas Contracts"). If the rights of first refusal apply at all, they would have applied to the Chugach-COP Gas Contract in which Chugach sought, and ultimately contracted with, COP to purchase from COP follow-on gas for as much of its unmet volumes at Beluga as possible. Any right of first refusal obligation owed by Chugach to COP was satisfied by execution of the Chugach-COP Gas Contract -- a transaction which increased COP's sales to Chugach from 20% to 50% of Chugach's total gas requirements. After it was filed with the Commission, Chugach met with Chevron to discuss the Chugach-COP Gas Contract. At no time then or after has Chevron ever asserted any right of first refusal regarding the Chugach-COP Gas Contract; Chevron simply chose not "to compete" and exercise its right of first refusal under its 1989 Gas Contract. Consequently, Chevron forewent its right of first refusal with regard to Chugach's purchase of gas following the end of 1989 Gas Contracts. Chevron does not enjoy a continuing right

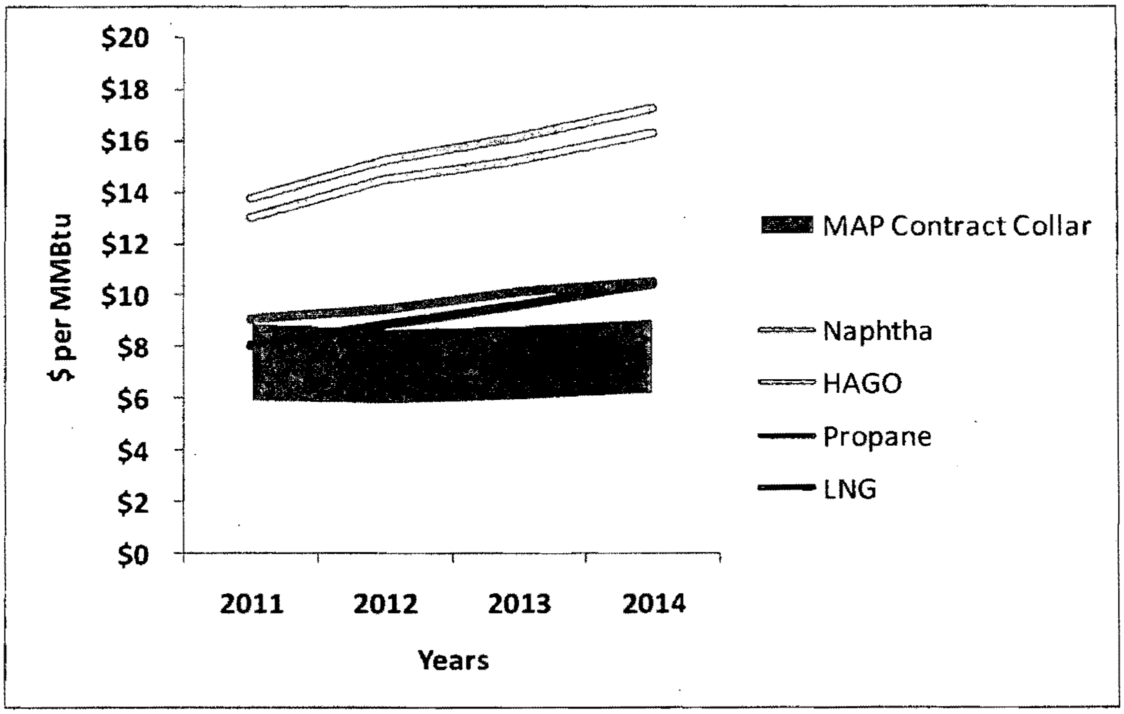
of first refusal for follow-on gas that Chevron can selectively assert against Chugach gas contracts in perpetuity.

Additionally, the Chugach-MAP Gas Contract provides that MAP will deliver gas to Chugach at delivery points at or near MAP's production fields, not at Chugach's Beluga Power Plant. The terms and intent of rights of first refusal in the 1989 Gas Contracts, however, restrict only Chugach's purchases of gas by Chugach at Beluga -- not other non-BRU gas. COP's and Chevron's rights of first refusal set forth in Section B of Exhibit F of the 1989 Gas Contracts are limited to "any gas ('Follow-On Gas') to be delivered to Chugach at Beluga . . . ." (Emphasis added.) The rights of first refusal reflect the basic construct of the 1989 Gas Contracts evident throughout the contracts that the 1989 Gas Contracts relates only to Gas delivered at Beluga for Chugach's use at Beluga, not gas delivered to Chugach elsewhere in the Cook Inlet Region. Consequently, for these and other reasons, the Chugach-MAP Gas Contract does not trigger the rights of first refusal.

Chugach worked diligently with the Alaska Energy Authority (AEA) on the Railbelt Integrated Resource Plan (RIRP) to evaluate other viable energy sources but determined that natural gas was the only option in the near term due to the lead-time for developing new energy sources. Similarly, Demand-Side Management and Energy Efficiency Resources (DSM/EE) cited in the RIRP could not be fully evaluated and implemented in a timeframe to materially change Chugach's near-term gas requirements. Chugach has undertaken numerous programs to educate its members on energy efficiency and will continue to undertake new programs that will help reduce gas demand.

Chugach also considered fuels other than natural gas to meet its unmet fuel requirements. The use of alternative fuels, however, would require additional capital investment to use these fuels in Chugach's generation and may not be practical from an operating perspective. Furthermore, the price of these fuels is generally higher than the price ceiling provided by the Chugach-MAP Gas Contract collar. The collar and the alternative fuel price forecast from the draft December 2009 RIRP report (page 7-11) is shown in **Chart 11** below.

Chart 11 – Comparison of MAP Contract Collar and Alternative Fuel Prices



NOTICES

Chugach's address for receiving notice related to this tariff filing is:

Lee D. Thibert
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Chugach Electric Association, Inc.
5601 Electron Drive
Anchorage, AK 99518
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lee_thibert@chugachelectric.com

SUMMARY

Chugach respectfully requests that the Commission:

1. Approve the Chugach-MAP Gas Contract no later than October 2, 2010;

2. Approve the Tariff Sheet Nos. 94, 95, and 95.5 and inclusion of all the transportation and fuel costs related to the Chugach-MAP Gas Contract in the calculation of the Chugach's COPA.

Very truly yours,

CHUGACH ELECTRIC ASSOCIATION, INC.

Lee D. Thibert
Senior Vice President, Strategic Planning and
Corporate Affairs

Appendices:

- A Chugach-MAP Gas Contract
- B Proposed Tariff Sheet Nos. 94, 95, 95.5
- C Chart Data
- D *ADNR Gas Reserves Report* (December 2009) and cover memo
- E *Cook Inlet Gas Study*, Petrochemical Resources of Alaska (January 2010)
- F *Platts Methodology and Specifications Guide – North American Natural Gas*, January 2010

RCA No.	8	94th Revision	Sheet No.	94
		Canceling		
		93rd Revision	Sheet No.	94

Chugach Electric Association, Inc.

FUEL AND PURCHASED POWER ADJUSTMENT FACTORS AT G&T

e.1. Fuel Adjustment Factor: Predicted costs for the quarter beginning April 1, 2010:

Description	Total	Retail	HEA	MEA	SES	
Fuel Expense						
Beluga - AML&P	$3,225,908	$1,578,125	$659,528	$903,275	$84,980	
Beluga - Chevron	$4,051,140	$1,981,832	$828,244	$1,134,345	$106,720	
Beluga - ConocoPhillips 1989	$3,225,908	$1,578,125	$659,528	$903,275	$84,980	
Beluga - ConocoPhillips 2009	$5,196,425	$2,542,109	$1,062,394	$1,455,032	$136,890	
Beluga - Marathon 1988	$3,915,323	$1,915,390	$800,476	$1,096,316	$103,142	
Beluga - Marathon 2010	---	---	---	---	---	N
Bernice - Marathon 1988	$1,412,098	$690,803	$288,699	$395,396	$37,199	
Bernice - ConocoPhillips 2009	---	---	---	---	---	
Nikiski - Marathon 1988	$3,863,356	$1,889,967	$789,852	$1,081,764	$101,773	
International - Marathon 1988	$107,200	$52,443	$21,917	$30,017	$2,824	
International - ConocoPhillips 2009	$5,736	$2,806	$1,173	$1,606	$151	
International - ENSTAR Transport	$17,618	$8,619	$3,602	$4,933	$464	
Subtotal	$25,020,712	$12,240,219	$5,115,412	$7,005,959	$659,123	
Less Fuel Credits						
Economy Fuel Costs	---	---	---	---	---	
Economy Margins	---	---	---	---	---	
Wheeling Revenue	($46,393)	($22,696)	($9,485)	($12,990)	($1,222)	
Subtotal	($46,393)	($22,696)	($9,485)	($12,990)	($1,222)	
Net Fuel Expense	$24,974,319	$12,217,523	$5,105,927	$6,992,969	$657,900	
Generation & Purchases (MWh)	589,041.3	294,092.6	110,781.8	168,330.4	15,836.6	
Cost per MWh at Generation	$42.40	$41.54	$46.09	$41.54	$41.54	
Projected Balances as of April 1, 2010	($535,995)	$407,733	($310,520)	($633,209)	---	
Fuel Expense to be Recovered at G&T	$24,438,324	$12,625,256	$4,795,407	$6,359,760	$657,900	
Predicted Sales at G&T (MWh)	572,468.4	285,818.2	107,664.9	163,594.3	15,391.0	
Fuel Adjustment Factor per kWh at G&T	$0.04269	$0.04417	$0.04454	$0.03888	---- *	

* Not meaningful. Seward is billed for actual fuel and purchased power costs on a monthly basis.

Tariff Advice No.: 316-8

Effective:

Issued by: Chugach Electric Association, Inc.
P.O. Box 196300, Anchorage, Alaska 99519-6300

By: Bradley W. Evans

Title: Chief Executive Officer

RCA No.	8	93rd Re[redacted]	Sheet No.	[redacted]
		Canceling		
		92nd Revision	Sheet No.	95

Chugach Electric Association, Inc.

FUEL AND PURCHASED POWER COST ADJUSTMENT FACTORS

f.1. Actual fuel costs for the quarter ending December 31, 2009:

Description	Total	Retail	HEA	MEA	SES	
Fuel Adjustment Factor Balance						
as of September 30, 2009	($2,286,747)	($1,432,714)	($190,904)	($663,128)	---	
Fuel Balance for Quarter Ending December 31, 2009						
Fuel Expense						
Beluga - AML&P	$5,365,691	$2,666,841	$1,000,251	$1,582,699	$115,900	
Beluga - Chevron	$6,707,114	$3,333,551	$1,250,314	$1,978,374	$144,874	
Beluga - ConocoPhillips 1989	$5,730,433	$2,848,125	$1,068,244	$1,690,286	$123,778	
Beluga - ConocoPhillips 2009	---	---	---	---	---	
Beluga - Marathon 1988	$16,400,205	$8,147,872	$3,057,266	$4,840,900	$354,167	
Beluga - Marathon 2010	---	---	---	---	---	N
Bernice - Marathon 1988	$918,771	$454,247	$167,640	$277,463	$19,421	
Bernice - ConocoPhillips 2009	---	---	---	---	---	
Nikiski - Marathon 1988	$3,195,707	$1,593,872	$608,897	$922,448	$70,490	
International - Marathon 1988	$64,241	$31,946	$11,668	$19,270	$1,357	
International - ConocoPhillips 2009	---	---	---	---	---	
Natural Gas Transportation	$16,678	$8,289	$3,081	$4,950	$357	
Emergency Generator Fuel	---	---	---	---	---	
Subtotal	$38,398,841	$19,084,744	$7,167,361	$11,316,391	$830,345	
Less Fuel Credits						
Economy Fuel Costs	($4,062,159)	($2,016,712)	($756,088)	($1,201,788)	($87,571)	
Economy Margins	($445,018)	($220,687)	($83,592)	($131,074)	($9,665)	
Wheeling Revenue	($210,544)	($104,506)	($39,696)	($61,752)	($4,590)	
Subtotal	($4,717,721)	($2,341,906)	($879,376)	($1,394,613)	($101,825)	
Net Fuel Expense	$33,681,121	$16,742,839	$6,287,985	$9,921,777	$728,519	
Generation & Purchases (MWh)	714,958.9	360,670.3	125,025.6	213,554.1	15,708.9	
Cost per MWh at Generation	$47.11	$46.42	$50.29	$46.46	$46.38	
Total Fuel Cost Recovery	$34,827,930	$16,350,030	$7,013,699	$10,735,682	$728,519	
Quarter Balance	($1,146,809)	$392,809	($725,713)	($813,904)	---	

Tariff Advice No.: 316-8 Effective:

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P.O. Box 196300, Anchorage, Alaska 99519-6300

By: Bradley W. Evans

Title: Chief Executive Officer

RCA No.	8	29th [redacted]ion	Sheet No.	[redacted]
		Canceling		
		28th Revision	Sheet No.	95.5

Chugach Electric Association, Inc.

Description	Actual - Quarter Ended December, 2009 Volume [1]	Unit Cost	Total Cost	Projected - Quarter Ended June, 2010 Volume	Unit Cost	Total Cost	
Fuel Expense							
Beluga - AML&P, Mcf	1,209,706	$4.44	$5,365,691	937,764	$3.44	$3,225,908	
Beluga - Chevron, Mcf	1,209,706	$5.54	$6,707,114	937,764	$4.32	$4,051,140	
Beluga - ConocoPhillips 1989, Mcf	1,209,707	$4.74	$5,730,433	937,764	$3.44	$3,225,908	
Beluga - ConocoPhillips 2009, Mcf	---	---	---	876,721	$5.93	$5,196,425	
Beluga – Marathon 1988, Mcf	2,953,766	$5.55	$16,400,205	998,807	$3.92	$3,915,323	
Beluga – Marathon 2010, Mcf	---	---	---	---	---	---	N
Beluga - Aurora Gas, LLC, Mcf [2]	---	---	---	---	---	---	
Bernice - Marathon 1988, Mcf	163,479	$5.62	$918,771	360,229	$3.92	$1,412,098	
Bernice - ConocoPhillips 2009, Mcf	---	---	---	---	---	---	
Nikiski - Marathon 1988, Mcf	640,963	$4.99	$3,195,707	985,550	$3.92	$3,863,356	
International - Marathon 1988, Mcf	12,834	$6.31	$80,919	27,347	$4.55	$124,459	
International - ConocoPhillips 2009, Mcf [3]	---	---	---	569	$10.71	$6,095	
Subtotal [4]	7,400,161	$5.19	$38,398,841	6,062,515	$4.13	$25,020,712	
Purchased Power Expense							
Bradley Lake Purchases, MWh	44,934	$42.25	$1,898,562	47,181	$42.26	$1,993,896	
Golden Valley Electric, MWh	---	---	$6,565	---	---	$0	
Nikiski (HEA Fuel, O&M)	51,059	$6.95	$355,050	78,844	$6.99	$551,120	
Other Purchases, MWh	103	$388.64	$40,029	---	---	$21,629	
Subtotal	96,096	$23.94	$2,300,206	126,025	$20.37	$2,566,644	
Total Fuel & Purch. Power Expense	----	----	$40,699,047	----	----	$27,587,356	

[1] Fuel volumes from invoice.

[2] Represents emergency natural gas purchases for operation of generation units located at the Beluga Power Plant. This line item will remain blank if not used.

[3] Includes natural gas transportation.

[4] Actual Total Cost does not include fuel cost for emergency generator at Hope.

Tariff Advice No.: 316-8 Effective:

Issued by: Chugach Electric Association, Inc.
P.O. Box 196300, Anchorage, Alaska 99519-6300

By: Bradley Evans
Bradley W. Evans

Title: Chief Executive Officer

Regulatory Commission of Alaska
April 2, 2010

Appendix A

Chugach-MAP Gas Contract

Base Contract for Sale and Purchase of Natural Gas

This Base Contract is entered into as of the following date: March 31, 2010

The parties to this Base Contract are the following:

PARTY A (Seller)		PARTY B (Buyer)
Marathon Alaska Production LLC	***PARTY NAME***	**Chugach Electric Association, Inc.**
3201 C Street **Anchorage, Alaska 95919-6168**	***ADDRESS***	**5601 Electron Drive** **Anchorage, AK 99519**
	BUSINESS WEBSITE	
______	***CONTRACT NUMBER***	______
______	***D-U-N-S® NUMBER***	______
☒ US FEDERAL: ______ ☐ OTHER:	***TAX ID NUMBERS***	☒ US FEDERAL: ______ ☐ OTHER:
	JURISDICTION OF ORGANIZATION	
☐ Corporation ☒ LLC ☐ Limited Partnership ☐ Partnership ☐ LLP ☐ Other: ______	***COMPANY TYPE***	☒ Corporation ☐ LLC ☐ Limited Partnership ☐ Partnership ☐ LLP ☐ Other: ______
	GUARANTOR (IF APPLICABLE)	
	CONTACT INFORMATION	
ATTN: Natural Gas Marketing Manager *TEL#:* (713) 296-2449 *FAX#:* (907)-564-3676 *EMAIL:* jksloan@marathonoil.com	***• COMMERCIAL***	*ATTN:* Lee Thibert, Senior VP, Strategic Planning & Corporate Affairs *TEL#:* (907) 762-4517 *FAX#:* (907) 762-4514 *EMAIL:* lee_thibert@chugachelectric.com
ATTN: Gas Supply and Transportation Representative *TEL#:* (907) 283-1308 *FAX#:* (907) 283-6175 *EMAIL:* fwbassetti@marathonoil.com *EMAIL:* jksloan@marathonoil.com	***• SCHEDULING***	*ATTN:* Burke Wick, Director, System Control *TEL#:* (907) 762-4779 *FAX#:* (907) 762-4540 *EMAIL:* Burke_Wick@chugachelectric.com
ATTN: *TEL#:* *FAX#:* *EMAIL:*	***• CONTRACT AND LEGAL NOTICES***	*ATTN:* General Counsel *TEL#:* *FAX#:* *EMAIL:*
ATTN: *TEL#:* *FAX#:* *EMAIL:*	***• CREDIT***	*ATTN:* *TEL#:* *FAX#:* *EMAIL:*
ATTN: *TEL#:* *FAX#:* *EMAIL:*	***• TRANSACTION CONFIRMATIONS***	*ATTN:* Lee Thibert, Senior VP, Strategic Planning & Corporate Affairs *TEL#:* (907) 762-4517 *FAX#:* (907) 762-4514 *EMAIL:* lee_thibert@chugachelectric.com
	ACCOUNTING INFORMATION	
ATTN: *TEL#:* *FAX#:* *EMAIL:*	***• INVOICES*** ***• PAYMENTS*** ***• SETTLEMENTS***	*ATTN:* Chugach Electric Association, Inc. *TEL#:* 907-762-4369 *FAX#:* 907-762-4315 *EMAIL:* Marina_Mccoy-Casey@chugachelectric.com
BANK: National City Bank *ABA:* 041000124 *ACCT:* 0000027 *OTHER DETAILS:*	***WIRE TRANSFER NUMBERS (IF APPLICABLE)***	*BANK:* FNB of A *ABA:* 125200060 *ACCT:* 1104751 *OTHER DETAILS:*
BANK: Bank of America *ABA:* 111000012 *ACCT:* 4426216636 *OTHER DETAILS:*	***ACH NUMBERS (IF APPLICABLE)***	*BANK:* FNB of A *ABA:* 125200060 *ACCT:* 1104751 *OTHER DETAILS:*
ATTN: *ADDRESS:*	***CHECKS (IF APPLICABLE)***	*ATTN:* Marina McCoy-Casey *ADDRESS:* 5601 Electron Drive Anchorage, AK 99519

Base Contract for Sale and Purchase of Natural Gas

(Continued)

This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Sale and Purchase of Natural Gas published by the North American Energy Standards Board. The parties hereby agree to the following provisions offered in said General Terms and Conditions. In the event the parties fail to check a box, the specified default provision shall apply. Select the appropriate box(es) from each section:

Section 1.2 Transaction Procedure	☐ Oral (default) OR ☒ Written	**Section 10.2** Additional Events of Default	☒ No Additional Events of Default (default) ☐ Indebtedness Cross Default ☐ Party A: ____________ ☐ Party B: ____________ ☐ Transactional Cross Default Specified Transactions:
Section 2.7 Confirm Deadline	☐ 2 Business Days after receipt (default) OR ☒ 10 Business Days after receipt		
Section 2.8 Confirming Party	☒ Seller (default) OR ☐ Buyer OR ☐		
Section 3.2 Performance Obligation	☐ Cover Standard (default) OR ☐ Spot Price Standard OR ☒ Special Provisions Section 16.2	**Section 10.3.1** Early Termination Damages	☒ Early Termination Damages Apply (default) OR ☐ Early Termination Damages Do Not Apply
Note: The following Spot Price Publication applies to both of the immediately preceding.		**Section 10.3.2** Other Agreement Setoffs	☐ Other Agreement Setoffs Apply (default) ☐ Bilateral (default) ☐ Triangular OR ☒ Other Agreement Setoffs Do Not Apply
Section 2.31 Spot Price Publication	☐ Gas Daily Midpoint (default) OR ☒ This Section has been deleted per Section 16.		
Section 6 Taxes	☒ Buyer Pays At and After Delivery Point (default) OR ☐ Seller Pays Before and At Delivery Point		
Section 7.2 Payment Date	☒ 25th Day of Month following Month of delivery (default) OR ☐ Day of Month following Month of delivery	**Section 15.5** Choice Of Law	Alaska
Section 7.2 Method of Payment	☒ Wire transfer (default) ☐ Automated Clearinghouse Credit (ACH) ☐ Check	**Section 15.10** Confidentiality	☐ Confidentiality applies (default) OR ☒ Confidentiality does not apply
Section 7.7 Netting	☒ Netting applies (default) OR ☐ Netting does not apply		

x **Special Provisions** Number of sheets attached: 13 pages
☐ **Addendum(s):** ______________________

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

Marathon Alaska Production LLC	*PARTY NAME*	**Chugach Electric Association, Inc.**
[signature]	*SIGNATURE*	[signature] Bradley Evans
David M. Risser	*PRINTED NAME*	Bradley Evans
Vice President	*TITLE*	CEO

General Terms and Conditions
Base Contract for Sale and Purchase of Natural Gas

SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas. The entire agreement between the parties shall be the Contract as defined in Section 2.9.

The parties have selected either the "Oral Transaction Procedure" or the "Written Transaction Procedure" as indicated on the Base Contract.

Oral Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means within three Business Days of a transaction covered by this Section 1.2 (Oral Transaction Procedure) provided that the failure to send a Transaction Confirmation shall not invalidate the oral agreement of the parties. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party. If the Transaction Confirmation contains any provisions other than those relating to the commercial terms of the transaction (i.e., price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions), which modify or supplement the Base Contract or General Terms and Conditions of this Contract (e.g., arbitration or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 1.3 but must be expressly agreed to by both parties; provided that the foregoing shall not invalidate any transaction agreed to by the parties.

Written Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of nonconflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2, such receiving party shall notify the sending party via facsimile, EDI or mutually agreeable electronic means by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. In the event of a conflict among the terms of (i) a binding Transaction Confirmation pursuant to Section 1.2, (ii) the oral agreement of the parties which may be evidenced by a recorded conversation, where the parties have selected the Oral Transaction Procedure of the Base Contract, (iii) the Base Contract, and (iv) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

1.4. The parties agree that each party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other party. Each party shall obtain any necessary consent of its agents and employees to such recording. Where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, the parties agree not to contest the validity or enforceability of telephonic recordings entered into in accordance with the requirements of this Base Contract.

SECTION 2. DEFINITIONS

The terms set forth below shall have the meaning ascribed to them below. Other terms are also defined elsewhere in the Contract and shall have the meanings ascribed to them herein.

2.1. "Additional Event of Default" shall mean Transactional Cross Default or Indebtedness Cross Default, each as and if selected by the parties pursuant to the Base Contract.

2.2. "Affiliate" shall mean, in relation to any person, any entity controlled, directly or indirectly, by the person, any entity that controls, directly or indirectly, the person or any entity directly or indirectly under common control with the person. For this purpose, "control" of any entity or person means ownership of at least 50 percent of the voting power of the entity or person.

2.3. "Alternative Damages" shall mean such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the Transaction Confirmation, in the event either Seller or Buyer fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer.

2.4. "Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein and any Special Provisions and addendum(s) as identified on page one.

2.5. "British thermal unit" or "Btu" shall mean the International BTU, which is also called the Btu (IT).

2.6. "Business Day(s)" shall mean Monday through Friday, excluding Federal Banking Holidays for transactions in the U.S.

2.7. "Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Day a Transaction Confirmation is received or, if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

2.8. "Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.

2.9. "Contract" shall mean the legally-binding relationship established by (i) the Base Contract, (ii) any and all binding Transaction Confirmations and (iii) where the parties have selected the Oral Transaction Procedure in Section 1.2 of the Base Contract, any and all transactions that the parties have entered into through an EDI transmission or by telephone, but that have not been confirmed in a binding Transaction Confirmation, all of which shall form a single integrated agreement between the parties.

2.10. "Contract Price" shall mean the amount expressed in U.S. Dollars per MMBtu to be paid by Buyer to Seller for the purchase of Gas as agreed to by the parties in a transaction.

2.11. "Contract Quantity" shall mean the quantity of Gas to be delivered and taken as agreed to by the parties in a transaction.

2.12. "Cover Standard", as referred to in Section 3.2, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing party shall use commercially reasonable efforts to (i) if Buyer is the performing party, obtain Gas, (or an alternate fuel if elected by Buyer and replacement Gas is not available), or (ii) if Seller is the performing party, sell Gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the nonperforming party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the nonperforming party.

2.13. "Credit Support Obligation(s)" shall mean any obligation(s) to provide or establish credit support for, or on behalf of, a party to this Contract such as cash, an irrevocable standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, guaranty, or other good and sufficient security of a continuing nature.

2.14. "Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter in a particular transaction.

2.15. "Delivery Period" shall be the period during which deliveries are to be made as agreed to by the parties in a transaction.

2.16. "Delivery Point(s)" shall mean such point(s) as are agreed to by the parties in a transaction.

2.17. "EDI" shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.

2.18. "EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm", provided that a party's excuse for nonperformance of its obligations to deliver or receive Gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.

2.19. "Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.

2.20. "Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane.

2.21. "Guarantor" shall mean any entity that has provided a guaranty of the obligations of a party hereunder.

2.22. "Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.

2.23. "Indebtedness Cross Default" shall mean if selected on the Base Contract by the parties with respect to a party, that it or its Guarantor, if any, experiences a default, or similar condition or event however therein defined, under one or more agreements or instruments, individually or collectively, relating to indebtedness (such indebtedness to include any obligation whether present or future, contingent or otherwise, as principal or surety or otherwise) for the payment or repayment of borrowed money in an aggregate amount greater than the threshold specified in the Base Contract with respect to such party or its Guarantor, if any, which results in such indebtedness becoming immediately due and payable.

2.24. "Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3 related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.

2.25. "MMBtu" shall mean one million British thermal units, which is equivalent to one dekatherm.

2.26. "Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

2.27. "Payment Date" shall mean a date, as indicated on the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.

2.28. "Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

2.29. "Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

2.30. "Specified Transaction(s)" shall mean any other transaction or agreement between the parties for the purchase, sale or exchange of physical Gas, and any other transaction or agreement identified as a Specified Transaction under the Base Contract.

2.31. "Spot Price " as referred to in Section 3.2 shall mean the price listed in the publication indicated on the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.32. "Transaction Confirmation" shall mean a document, similar to the form of Exhibit A, setting forth the terms of a transaction formed pursuant to Section 1 for a particular Delivery Period.

2.33. "Transactional Cross Default" shall mean if selected on the Base Contract by the parties with respect to a party, that it shall be in default, however therein defined, under any Specified Transaction.

2.34. "Termination Option" shall mean the option of either party to terminate a transaction in the event that the other party fails to perform a Firm obligation to deliver Gas in the case of Seller or to receive Gas in the case of Buyer for a designated number of days during a period as specified on the applicable Transaction Confirmation.

2.35. "Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular transaction.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the Contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm or Interruptible basis, as agreed to by the parties in a transaction.

The parties have selected either the "Cover Standard" or the "Spot Price Standard" as indicated on the Base Contract.
Cover Standard:
3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s) excluding any quantity for which no replacement is available; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s) excluding any quantity for which no sale is available; and (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available for all or any portion of the Contract Quantity of Gas, then in addition to (i) or (ii) above, as applicable, the sole and exclusive remedy of the performing party with respect to the Gas not replaced or sold shall be an amount equal to any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the quantity of such Gas not replaced or sold. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

Spot Price Standard:
3.2. The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

3.3. Notwithstanding Section 3.2, the parties may agree to Alternative Damages in a Transaction Confirmation executed in writing by both parties.

3.4. In addition to Sections 3.2 and 3.3, the parties may provide for a Termination Option in a Transaction Confirmation executed in writing by both parties. The Transaction Confirmation containing the Termination Option will designate the length of nonperformance triggering the Termination Option and the procedures for exercise thereof, how damages for nonperformance will be compensated, and how liquidation costs will be calculated.

SECTION 4. TRANSPORTATION, NOMINATIONS, AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the pressure, quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either "Buyer Pays At and After Delivery Point" or "Seller Pays Before and At Delivery Point" as indicated on the Base Contract.
Buyer Pays At and After Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.
Seller Pays Before and At Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT, AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2. Buyer shall remit the amount due under Section 7.1 in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 Days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3. In the event payments become due pursuant to Sections 3.2 or 3.3, the performing party may submit an invoice to the nonperforming party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the nonperforming party will be due five Business Days after receipt of invoice.

7.4. If the invoiced party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced party will pay such amount as it concedes to be correct; provided, however, if the invoiced party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed without undue delay. In the event the parties are unable to resolve such dispute, either party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section.

7.5. If the invoiced party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6. A party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records, and telephone recordings of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This right to examine, audit, and to obtain copies shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for under- or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7. Unless the parties have elected on the Base Contract not to make this Section 7.7 applicable to this Contract, the parties shall net all undisputed amounts due and owing, and/or past due, arising under the Contract such that the party owing the greater amount shall make a single payment of the net amount to the other party in accordance with Section 7; provided that no payment required to be made pursuant to the terms of any Credit Support Obligation or pursuant to Section 7.3 shall be subject to netting under this Section. If the parties have executed a separate netting agreement, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 8. TITLE, WARRANTY, AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 15.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury (including death) or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury (including death) or property damage from said Gas or other charges thereon which attach after title passes to Buyer.

8.4. The parties agree that the delivery of and the transfer of title to all Gas under this Contract shall take place within the Customs Territory of the United States (as defined in general note 2 of the Harmonized Tariff Schedule of the United States 19 U.S.C. §1202, General Notes, page 3); provided, however, that in the event Seller took title to the Gas outside the Customs Territory of the United States, Seller represents and warrants that it is the importer of record for all Gas entered and delivered into the United States, and shall be responsible for entry and entry summary filings as well as the payment of duties, taxes and fees, if any, and all applicable record keeping requirements.

8.5. Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payment instructions, and other communications made pursuant to the Base Contract ("Notices") shall be made to the addresses specified in writing by the respective parties from time to time.

9.2. All Notices required hereunder shall be in writing and may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.

9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is

not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered five Business Days after mailing.

9.4. The party receiving a commercially acceptable Notice of change in payment instructions or other payment information shall not be obligated to implement such change until ten Business Days after receipt of such Notice.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. If either party ("X") has reasonable grounds for insecurity regarding the performance of any obligation under this Contract (whether or not then due) by the other party ("Y") (including, without limitation, the occurrence of a material change in the creditworthiness of Y or its Guarantor, if applicable), X may demand Adequate Assurance of Performance. "Adequate Assurance of Performance" shall mean sufficient security in the form, amount, for a term, and from an issuer, all as reasonably acceptable to X, including, but not limited to cash, a standby irrevocable letter of credit, a prepayment, a security interest in an asset or guaranty. Y hereby grants to X a continuing first priority security interest in, lien on, and right of setoff against all Adequate Assurance of Performance in the form of cash transferred by Y to X pursuant to this Section 10.1. Upon the return by X to Y of such Adequate Assurance of Performance, the security interest and lien granted hereunder on that Adequate Assurance of Performance shall be released automatically and, to the extent possible, without any further action by either party.

10.2. In the event (each an "Event of Default") either party (the "Defaulting Party") or its Guarantor shall: (i) make an assignment or any general arrangement for the benefit of creditors; (ii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iii) otherwise become bankrupt or insolvent (however evidenced); (iv) be unable to pay its debts as they fall due; (v) have a receiver, provisional liquidator, conservator, custodian, trustee or other similar official appointed with respect to it or substantially all of its assets; (vi) fail to perform any obligation to the other party with respect to any Credit Support Obligations relating to the Contract; (vii) fail to give Adequate Assurance of Performance under Section 10.1 within 48 hours but at least one Business Day of a written request by the other party; (viii) not have paid any amount due the other party hereunder on or before the second Business Day following written Notice that such payment is due; or ix) be the affected party with respect to any Additional Event of Default; then the other party (the "Non-Defaulting Party") shall have the right, at its sole election, to immediately withhold and/or suspend deliveries or payments upon Notice and/or to terminate and liquidate the transactions under the Contract, in the manner provided in Section 10.3, in addition to any and all other remedies available hereunder.

10.3. If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right, by Notice to the Defaulting Party, to designate a Day, no earlier than the Day such Notice is given and no later than 20 Days after such Notice is given, as an early termination date (the "Early Termination Date") for the liquidation and termination pursuant to Section 10.3.1 of all transactions under the Contract, each a "Terminated Transaction". On the Early Termination Date, all transactions will terminate, other than those transactions, if any, that may not be liquidated and terminated under applicable law ("Excluded Transactions"), which Excluded Transactions must be liquidated and terminated as soon thereafter as is legally permissible, and upon termination shall be a Terminated Transaction and be valued consistent with Section 10.3.1 below. With respect to each Excluded Transaction, its actual termination date shall be the Early Termination Date for purposes of Section 10.3.1.

The parties have selected either "Early Termination Damages Apply" or "Early Termination Damages Do Not Apply" as indicated on the Base Contract.

Early Termination Damages Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the Market Value, as defined below, of each Terminated Transaction. The Non-Defaulting Party shall (x) liquidate and accelerate each Terminated Transaction at its Market Value, so that each amount equal to the difference between such Market Value and the Contract Value, as defined below, of such Terminated Transaction(s) shall be due to the Buyer under the Terminated Transaction(s) if such Market Value exceeds the Contract Value and to the Seller if the opposite is the case; and (y) where appropriate, discount each amount then due under clause (x) above to present value in a commercially reasonable manner as of the Early Termination Date (to take account of the period between the date of liquidation and the date on which such amount would have otherwise been due pursuant to the relevant Terminated Transactions).

For purposes of this Section 10.3.1, "Contract Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the Contract Price, and "Market Value" means the amount of Gas remaining to be delivered or purchased under a transaction multiplied by the market price for a similar transaction at the Delivery Point determined by the Non-Defaulting Party in a commercially reasonable manner. To ascertain the Market Value, the Non-Defaulting Party may consider, among other valuations, any or all of the settlement prices of NYMEX Gas futures contracts, quotations from leading dealers in energy swap contracts or physical gas trading markets, similar sales or purchases and any other bona fide third-party offers, all adjusted for the length of the term and differences in transportation costs. A party shall not be required to enter into a replacement transaction(s) in order to determine the Market Value. Any extension(s) of the term of a transaction to which parties are not bound as of the Early Termination Date (including but not limited to "evergreen provisions") shall not be considered in determining Contract Values and

Market Values. For the avoidance of doubt, any option pursuant to which one party has the right to extend the term of a transaction shall be considered in determining Contract Values and Market Values. The rate of interest used in calculating net present value shall be determined by the Non-Defaulting Party in a commercially reasonable manner.

Early Termination Damages Do Not Apply:

10.3.1. As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract.

The parties have selected either "Other Agreement Setoffs Apply" or "Other Agreement Setoffs Do Not Apply" as indicated on the Base Contract.

Other Agreement Setoffs Apply:

Bilateral Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff any Net Settlement Amount against (i) any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; and (ii) any amount(s) (including any excess cash margin or excess cash collateral) owed or held by the party that is entitled to the Net Settlement Amount under any other agreement or arrangement between the parties.

Triangular Setoff Option:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option, and without prior Notice to the Defaulting Party, the Non-Defaulting Party is hereby authorized to setoff (i) any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract; (ii) any Net Settlement Amount against any amount(s) (including any excess cash margin or excess cash collateral) owed by or to a party under any other agreement or arrangement between the parties; (iii) any Net Settlement Amount owed to the Non-Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Non-Defaulting Party or its Affiliates to the Defaulting Party under any other agreement or arrangement; (iv) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party to the Non-Defaulting Party or its Affiliates under any other agreement or arrangement; and/or (v) any Net Settlement Amount owed to the Defaulting Party against any amount(s) (including any excess cash margin or excess cash collateral) owed by the Defaulting Party or its Affiliates to the Non-Defaulting Party under any other agreement or arrangement.

Other Agreement Setoffs Do Not Apply:

10.3.2. The Non-Defaulting Party shall net or aggregate, as appropriate, any and all amounts owing between the parties under Section 10.3.1, so that all such amounts are netted or aggregated to a single liquidated amount payable by one party to the other (the "Net Settlement Amount"). At its sole option and without prior Notice to the Defaulting Party, the Non-Defaulting Party may setoff any Net Settlement Amount against any margin or other collateral held by a party in connection with any Credit Support Obligation relating to the Contract.

10.3.3. If any obligation that is to be included in any netting, aggregation or setoff pursuant to Section 10.3.2 is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and net, aggregate or setoff, as applicable, in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained. Any amount not then due which is included in any netting, aggregation or setoff pursuant to Section 10.3.2 shall be discounted to net present value in a commercially reasonable manner determined by the Non-Defaulting Party.

10.4. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Net Settlement Amount, and whether the Net Settlement Amount is due to or due from the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of the Net Settlement Amount, provided that failure to give such Notice shall not affect the validity or enforceability of the liquidation or give rise to any claim by the Defaulting Party against the Non-Defaulting Party. The Net Settlement Amount as well as any setoffs applied against such amount pursuant to Section 10.3.2, shall be paid by the close of business on the second Business Day following such Notice, which date shall not be earlier than the Early Termination Date. Interest on any unpaid portion of the Net Settlement Amount as adjusted by setoffs, shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

10.5. The parties agree that the transactions hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code and that Buyer and Seller are each "forward contract merchants" within the meaning of the United States Bankruptcy Code.

10.6. The Non-Defaulting Party's remedies under this Section 10 are the sole and exclusive remedies of the Non-Defaulting Party with respect to the occurrence of any Early Termination Date. Each party reserves to itself all other rights, setoffs, counterclaims and other defenses that it is or may be entitled to arising from the Contract.

10.7. With respect to this Section 10, if the parties have executed a separate netting agreement with close-out netting provisions, the terms and conditions therein shall prevail to the extent inconsistent herewith.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment(s) due under Section 7, Section 10.4, and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.

11.2. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars, or acts of terror; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation unless primary, in-path, Firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship, to include, without limitation, Seller's ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer's ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Contract; (iv) the loss of Buyer's market(s) or Buyer's inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (v) the loss or failure of Seller's gas supply or depletion of reserves, except, in either case, as provided in Section 11.2. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be within the sole discretion of the party experiencing such disturbance.

11.5. The party whose performance is prevented by Force Majeure must provide Notice to the other party. Initial Notice may be given orally; however, written Notice with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written Notice of Force Majeure to the other party, the affected party will be relieved of its obligation, from the onset of the Force Majeure event, to make or accept delivery of Gas, as applicable, to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.

11.6. Notwithstanding Sections 11.2 and 11.3, the parties may agree to alternative Force Majeure provisions in a Transaction Confirmation executed in writing by both parties.

SECTION 12. TERM

This Contract may be terminated on 30 Day's written Notice, but shall remain in effect until the expiration of the latest Delivery Period of any transaction(s). The rights of either party pursuant to Section 7.6, Section 10, Section 13, the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any transaction.

SECTION 13. LIMITATIONS

FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY. A PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

SECTION 14. MARKET DISRUPTION

If a Market Disruption Event has occurred then the parties shall negotiate in good faith to agree on a replacement price for the Floating Price (or on a method for determining a replacement price for the Floating Price) for the affected Day, and if the parties have not so agreed on or before the second Business Day following the affected Day then the replacement price for the Floating Price shall be determined within the next two following Business Days with each party obtaining, in good faith and from non-affiliated market participants in the relevant market, two quotes for prices of Gas for the affected Day of a similar quality and quantity in the geographical location closest in proximity to the Delivery Point and averaging the four quotes. If either party fails to provide two quotes then the average of the other party's two quotes shall determine the replacement price for the Floating Price. "Floating Price" means the price or a factor of the price agreed to in the transaction as being based upon a specified index. "Market Disruption Event" means, with respect to an index specified for a transaction, any of the following events: (a) the failure of the index to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading on the exchange or market acting as the index; (c) the temporary or permanent discontinuance or unavailability of the index; (d) the temporary or permanent closing of any exchange acting as the index; or (e) both parties agree that a material change in the formula for or the method of determining the Floating Price has occurred. For the purposes of the calculation of a replacement price for the Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged.

SECTION 15. MISCELLANEOUS

15.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party (and shall not relieve the assigning party from liability hereunder), which consent will not be unreasonably withheld or delayed; provided, either party may (i) transfer, sell, pledge, encumber, or assign this Contract or the accounts, revenues, or proceeds hereof in connection with any financing or other financial arrangements, or (ii) transfer its interest to any parent or Affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any such assignment, transfer and assumption, the transferor shall remain principally liable for and shall not be relieved of or discharged from any obligations hereunder.

15.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.

15.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.

15.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective transaction(s). This Contract may be amended only by a writing executed by both parties.

15.5. The interpretation and performance of this Contract shall be governed by the laws of the jurisdiction as indicated on the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.

15.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or transaction or any provisions thereof.

15.7. There is no third party beneficiary to this Contract.

15.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.

15.9. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the parties and shall not be used to construe or interpret the provisions of this Contract.

15.10. Unless the parties have elected on the Base Contract not to make this Section 15.10 applicable to this Contract, neither party shall disclose directly or indirectly without the prior written consent of the other party the terms of any transaction to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the party, or prospective purchasers of all or substantially all of a party's assets or of any rights under this Contract, provided such persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable law, order, regulation, or exchange rule, (ii) to the extent necessary for the enforcement of this Contract , (iii) to the extent necessary to implement any transaction, (iv) to the extent necessary to comply with a regulatory agency's reporting requirements including but not limited to gas cost recovery proceedings; or (v) to the extent such information is delivered to such third party for the sole purpose of calculating a published index. Each party shall notify the other party of any proceeding of which it is aware which may result in disclosure of the terms of any transaction (other than as permitted hereunder) and use reasonable efforts to prevent or limit the disclosure. The existence of this Contract is not subject to this confidentiality obligation. Subject to Section 13, the parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. The terms of any transaction hereunder shall be kept confidential by the parties hereto for one year from the expiration of the transaction.

In the event that disclosure is required by a governmental body or applicable law, the party subject to such requirement may disclose the material terms of this Contract to the extent so required, but shall promptly notify the other party, prior to disclosure,

and shall cooperate (consistent with the disclosing party's legal obligations) with the other party's efforts to obtain protective orders or similar restraints with respect to such disclosure at the expense of the other party.

15.11. The parties may agree to dispute resolution procedures in Special Provisions attached to the Base Contract or in a Transaction Confirmation executed in writing by both parties

15.12. Any original executed Base Contract, Transaction Confirmation or other related document may be digitally copied, photocopied, or stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the Transaction Confirmation, if introduced as evidence in automated facsimile form, the recording, if introduced as evidence in its original form, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings will be admissible as between the parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the recording, the Transaction Confirmation, or the Imaged Agreement on the basis that such were not originated or maintained in documentary form. However, nothing herein shall be construed as a waiver of any other objection to the admissibility of such evidence.

DISCLAIMER: The purposes of this Contract are to facilitate trade, avoid misunderstandings and make more definite the terms of contracts of purchase and sale of natural gas. Further, NAESB does not mandate the use of this Contract by any party. **NAESB DISCLAIMS AND EXCLUDES, AND ANY USER OF THIS CONTRACT ACKNOWLEDGES AND AGREES TO NAESB'S DISCLAIMER OF, ANY AND ALL WARRANTIES, CONDITIONS OR REPRESENTATIONS, EXPRESS OR IMPLIED, ORAL OR WRITTEN, WITH RESPECT TO THIS CONTRACT OR ANY PART THEREOF, INCLUDING ANY AND ALL IMPLIED WARRANTIES OR CONDITIONS OF TITLE, NON-INFRINGEMENT, MERCHANTABILITY, OR FITNESS OR SUITABILITY FOR ANY PARTICULAR PURPOSE (WHETHER OR NOT NAESB KNOWS, HAS REASON TO KNOW, HAS BEEN ADVISED, OR IS OTHERWISE IN FACT AWARE OF ANY SUCH PURPOSE), WHETHER ALLEGED TO ARISE BY LAW, BY REASON OF CUSTOM OR USAGE IN THE TRADE, OR BY COURSE OF DEALING. EACH USER OF THIS CONTRACT ALSO AGREES THAT UNDER NO CIRCUMSTANCES WILL NAESB BE LIABLE FOR ANY DIRECT, SPECIAL, INCIDENTAL, EXEMPLARY, PUNITIVE OR CONSEQUENTIAL DAMAGES ARISING OUT OF ANY USE OF THIS CONTRACT.**

TRANSACTION CONFIRMATION
FOR IMMEDIATE DELIVERY

EXHIBIT A

Letterhead/Logo	Date: ____________________, ______ Transaction Confirmation #: ________

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer dated, March 31, 2010.

SELLER:	BUYER:
Marathon Alaska Production, LLC	Chugach Electric Association, Inc.
Attn: ____________	Attn: Lee Thibert, Senior VP, Strategic Planning & Corporate Affairs
Phone: ( ) -	Phone: (907) 762-4517
Fax: ( ) -	Fax: (907) 762-4514
Base Contract No. ____________	Base Contract No. ____________
Transporter: ____________	Transporter: ____________
Transporter Contract Number: ____________	Transporter Contract Number: ____________

NYMEX Calculated Price: ____________
Floor: ________ and Cap ________ applicable to [PERIOD NAME]
Pricing Premiums and Discounts applicable to [PERIOD NAME]: ____________

[PERIOD NAME]
Begin: ____________
End: ____________

Maximum Daily Quantity applicable to [PERIOD NAME]: ____________
Minimum Daily Quantity applicable to [PERIOD NAME]: ____________

Delivery Point(s): See Section 16 of Base Agreement and Attachment B for conditions regarding Delivery Points
(If a pooling point is used, list a specific geographic and pipeline location):

Special Conditions: See Section 16 of Base Agreement

Seller: ____________	Buyer: ____________
By: ____________	By: ____________
Title: ____________	Title: ____________
Date: ____________	Date: ____________

Special Provisions Addendum

SECTION 16. SPECIAL PROVISIONS

16.1. Supplemental Definitions

2.36 "2013 Option" shall mean Seller's option to sell Gas to Buyer for the period commencing on April 1, 2013 and expiring on December 31, 2013.

2.37 "2014 Option" shall mean Seller's option to sell Gas to Buyer for the period commencing on January 1, 2014 and expiring on December 31, 2014.

2.38 "Alaska Intertie" shall mean the transmission interconnection system and related facilities that deliver energy between the Buyer's electric system and the Golden Valley Electric Association's electric system.

2.39 "Buyer Shortfall Quantity" shall mean the Cover Quantity for a Day less the amount that Buyer actually takes and purchases in such Day at the Delivery Points.

2.40 "Cover Quantity" shall mean for an applicable Day the lesser of: (i) 60% of Buyer's daily Day ahead forecast for Gas volumes to be used at Beluga Power Plant to meet the requirements for Existing Wholesale Load and Retail Load requirements; and (ii) 95% of the total Gas nominated by Buyer in its first nomination to Seller for Gas deliveries for such Day pursuant to Section 16.5.

2.41 "Delivery Start Date" shall mean the date on which Deliveries of Gas commence, which shall occur no earlier than March 1, 2011 and no later than April 1, 2011, unless otherwise agreed to by the Parties.

2.42 "DOR Price" shall mean the prevailing weighted average price of significant sales of Gas to publicly regulated utilities in Cook Inlet for a calendar quarter for Gas delivered in the Cook Inlet area, published by the State of Alaska Department of Revenue on the 15th Day of each calendar quarter.

2.43 "Early Termination Volumes" shall mean the sum of: (i) 26.2 Bcf, plus (ii) 8.3 Bcf (or as otherwise agreed pursuant to Section 12.3) for the 2013 Option if such option has been exercised pursuant to Sections 12.2 and 12.3 prior to the Early Termination Date; and (iii) 7.8 Bcf (or as otherwise agreed pursuant to Section 12.3) for the 2014 Option if such option has been exercised pursuant to Sections 12.2 and 12.3 prior to the Early Termination Date, less all Gas already purchased and sold under this Contract as of the Early Termination Date.

2.44 "Existing Wholesale Load" shall mean the Seller's total electric load necessary to meet energy requirements for Homer Electric Association, Inc., Matanuska Electric Association, Inc., and the City of Seward pursuant to contracts in effect as of the first date written above.

2.45 "Gas Reserves" shall mean the total quantity of Seller's Proved Developed Reserves, Proved Undeveloped Reserves, and a percentage of Probable Gas Reserves as determined in accordance with sound petroleum reservoir engineering practices.

2.46 "Interruptible Hourly Gas" shall mean the Gas described in Section 16.3(iv).

2.47 "Liquidation Price" shall mean for each of the Months remaining in the Term as of the Early Termination Date, as may be extended by an Option Period, if such Option Period has been exercised pursuant to Sections 12.2 and 12.3 prior to the Early Termination Date, the simple average of the prices of the NYMEX natural gas futures contracts for each of the Months remaining in the Term (as may be so extended), as reported on the Early Termination Date in "Platts Gas Daily", and subject to upward or downward adjustment by applying the "Floor" price and "Ceiling" Price as set forth for Contract Year 2 on Table 1 of Attachment 1.

2.48 "Maximum Daily Quantity" shall mean, as applicable, 38 MMcfd during Period 1, 38 MMcfd during Period 2, and the Option Maximum Daily Quantity, if applicable.

2.49 "Minimum Daily Quantities" shall mean, as applicable, 30 MMcfd during Period 1, 36 MMcfd during Period 2, and the Option Maximum Daily Quantity, if applicable.

2.50 "Option Period" shall mean the period during which either the 2013 Option or the 2014 Option is in effect.

2.51 "Option Maximum Daily Quantity" shall mean the maximum daily amount of Gas sold by Seller to Buyer during an Option Period as agreed to between the Parties as determined in accordance with Section 12.3.

2.52 "Option Minimum Daily Quantity" shall mean the minimum daily amount of Gas sold by Seller to Buyer during an Option Period as agreed to between the Parties as determined in accordance with Section 12.3.

2.53 "Period 1" shall mean the period during which Seller sells Gas to Buyer commencing with the Delivery Start Date and ending on the earlier to occur of (i) October 31, 2012, or (ii) the date upon which (a) Gas storage service is commercially

available in the Cook Inlet Gas pipeline system, (b) Buyer has injected 2.4 Bcf of Gas into such Gas storage service reservoir, and (c) Buyer has the commercial right to withdraw from such storage reservoir Gas at a rate of at least ten (10) MMcfd for a period of one hundred fifty-two (152) consecutive Days.

2.54 "Period 1 Firm Gas" shall mean the volume of Gas during Period 1 in an amount equal to or greater than thirty (30) MMcf per Day and no more than thirty-eight (38) MMcf per Day.

2.55 "Period 1 Firm Swing Gas" shall mean an additional volume of Gas up to ten (10) MMcf per Day more than Period 1 Firm Gas.

2.56 "Period 2" shall mean the period during which Seller sells Gas to Buyer commencing on the Day after the last Day of Period 1 and ending on March 31, 2013.

2.57 "Period 2 Firm Gas" shall mean the volume of Gas during Period 2 in an amount equal to or greater than thirty-six (36) MMcf per Day and no more than thirty-eight (38) MMcf per Day.

2.58 "Retail Load" shall mean the total electric load necessary to serve all of Seller's retail electric customers within Seller's electric service territory.

2.59 "Seller Shortfall Quantity" shall mean the Cover Quantity for a Day less the amount that Seller actually delivers and sells in such Day at the Delivery Points.

2.60 "Unmet Requirements" shall mean volumes of Gas required to produce energy to meet Buyer's retail and wholesale power sales for the Option Periods that have not been committed under the Base Contract for the Sale and Purchase of Natural Gas between ConocoPhillips Company, and ConocoPhillips Alaska, Inc. and Chugach Electric Association, Inc., dated May 12, 2009.

16.2. Modifications to the Base Contract

- Section 1.2 (**Written Transaction Procedure**) is deleted and replaced as follows:

  For all transactions under this Contract, the parties will use the following Transaction Confirmation procedure. At least thirty (30) Days prior to the commencement of the Delivery Start Date, Period 2, Contract Year 2, and the Option Periods (if any), the Buyer shall deliver a Transaction Confirmation for the following such period to Seller by facsimile, EDI or mutually agreeable electronic means. Seller shall respond within five (5) Business Days by confirming the Transaction Confirmation or identifying any issues with Buyer's Transaction Confirmation. In the event that Seller identifies issues, the parties shall meet and agree on the final Transaction Confirmation at least five (5) Business Days prior to the commencement of the relevant period. The parties acknowledge and agree that any Transaction Confirmation shall be used to reflect the Contract Price and other relevant terms set forth in the Base Contract that are applicable to Gas deliveries and purchases during the Delivery Period.

- Section 1.4 is deleted.
- Section 2.31 is deleted.
- Section 2.34 is deleted.
- Section 3.2 is deleted and replaced as follows:

  (i) Buyer's sole remedy for Seller's failure to deliver the Cover Quantity is payment by Seller of an amount equal to the positive difference (if any) between: (a) the sum of (1) the cost actually incurred by Buyer utilizing the Cover Standard in a contemporaneous replacement purchase of the amount of Gas from a third party (or, if Gas is not reasonably available, the equivalent amount of electric power from third party electric power producers) necessary to cover the Seller Shortfall Quantity, plus (2) the costs to transport such Seller Shortfall Quantity (or an equivalent amount of electric power) to Buyer's facilities; and (b) the sum of (1) the Seller Shortfall Quantity multiplied by the applicable Contract Price, plus (2) the transportation costs Buyer would have incurred if Seller had met its Cover Quantity delivery obligation. If Buyer is not able to acquire replacement Gas (or electric power) utilizing the Cover Standard in a contemporaneous replacement sale, Buyer's sole remedy for Seller's failure to deliver the Gas shall be the result of the calculation set forth above, but the then applicable Contract Price shall be deemed to be the price after applying the Cover Standard. If the result of the calculation set forth above is a negative number, no such remedy shall be required.

  (ii) Seller's sole remedy for Buyer's failure to take the Cover Quantity is payment by Buyer of an amount equal to the positive difference (if any) between: (a) the sum of (1) the revenues actually received by Seller utilizing the Cover Standard in contemporaneous replacement sales to third parties for the amount of Gas equal to the Buyer Shortfall Quantity, plus (2) the costs to transport such Buyer Shortfall Quantity under such replacement sales; and (b) the sum of (1) the Buyer Shortfall Quantity multiplied by the applicable Contract Price, plus (2) the transportation costs Seller would have incurred if Buyer had met its Cover Quantity obligation. If a contemporaneous replacement sale with a third party is not available that complies with the Cover Standard, Seller may enter into a replacement sale with an Affiliate of Seller and the amount received by Seller (for purposes of clause (a)(1) this calculation) shall be deemed to be the product of (x) the then applicable DOR Price and (y) the Buyer Shortfall Quantity. If Seller is not

able to enter into a replacement sale of Gas with a third party or an Affiliate (or otherwise does not enter into a replacement sale, but instead enters into another disposition or use for the Gas, for instance, the storage or exchange of Gas), Seller's sole remedy for Buyer's failure to take the Cover Quantity shall be the result of the calculation set forth above, but the then applicable Contract Price shall be deemed to be the price after applying the Cover Standard. If the calculation set forth above is a negative number, no such remedy shall be required.

(iii) Imbalance Charges shall not be recovered under this Section 3.2 but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3.

(iv) Any amount payable under this Section 3.2 shall be payable fifteen (15) Business Days after presentation of the Non-Defaulting Party's invoice, which shall set forth the basis upon which such amount was calculated.

- Section 3.4 is deleted.
- The first sentence of Section 6 shall be deleted and replaced as follows: "Seller shall pay or cause to be paid all Taxes on or with respect to the Gas prior to the Delivery Point(s)."
- Section 10.3.1 is deleted and replaced as follows:

  As of the Early Termination Date, the Non-Defaulting Party shall determine, in good faith and in a commercially reasonable manner, (i) the amount owed (whether or not then due) by each party with respect to all Gas delivered and received between the parties under Terminated Transactions and Excluded Transactions on and before the Early Termination Date and all other applicable charges relating to such deliveries and receipts (including without limitation any amounts owed under Section 3.2), for which payment has not yet been made by the party that owes such payment under this Contract and (ii) the amount equal to the product of (a) the sum of Early Termination Volumes of the Contract (which shall include any Days in the Option Periods if Seller has exercised its rights under Sections 12.2 and 12.3), multiplied by (b) the Liquidation Price.

- In Section 11.2(iii), the phrase "(iii) interruption and/or curtailment of Firm transportation and/or storage by Transporters" is replaced with the following phrase: "(iii) interruption and/or curtailment of Firm transportation, Gas storage and/or transmission of electricity on the Alaska Intertie".
- A new item (viii) is inserted into the first sentence in Section 11.2, as follows: "(viii) volcanic eruptions, which necessitate the preventative shutdown of equipment or machinery."
- Section 11.3 items (iv) and (v) are to be moved, in their entirety, into Section 11.2, and added into the first sentence as items (vi) and (vii), but, in each case, with the deletion of the phrase "except, in either case, as provided in Section 11.2".

- Section 12 is deleted and replaced as follows:

  12.1 This Contract shall commence on the date of execution of this Contract and shall terminate on March 31, 2013 (the "Term") unless extended pursuant to Section 12.2, in which case the "Term" shall end on the last Day of the 2013 Option or the 2014 Option, as applicable, unless earlier terminated in accordance with the terms of this Contract. The rights of either party pursuant to Section 7.6, Section 10, Section 13, the obligations to make payment hereunder, and the obligation of either party to indemnify the other party, shall survive the termination of the Contract or any transaction.

  12.2 To the extent that Seller has Gas available for sale to Buyer, Seller may extend the term of this Contract: (i) for the period of the 2013 Option; or (ii) for the period of the 2014 Option. To exercise such option, Seller shall deliver written notice to Buyer no later than (a) March 31, 2011 with respect to the 2013 Option; and (b) December 31, 2011 for the 2014 Option.

  12.3 As of the date of this Base Contract, Buyer currently anticipates that its Unmet Requirements during the 2013 Option period are 8.3 Bcf and during the 2014 Option period are 7.8 Bcf. The parties acknowledge and agree that these amounts represent estimates only and may change from time to time, and are not binding on either party. To the extent Buyer's estimates of its Unmet Requirements for the Option Periods change, Buyer shall notify Seller periodically of such change in the Unmet Requirements estimate. At least one hundred twenty (120) Days prior to the election date set forth in Section 12.2 for the 2013 Option or the 2014 Option, as applicable, the parties shall exchange information about Buyer's Unmet Requirements and daily Gas needs, and Seller's Gas that it desires to make available for sale during the applicable Option Period(s), if any. At least ninety (90) Days prior to the election date set forth in Section 12.2 for the 2013 Option or the 2014 Option, as applicable, the parties shall meet and exercise good faith efforts to agree on the Option Period Minimum Daily Quantity, Option Period Maximum Daily Quantity, and the estimated Option Period volumes during the applicable Option Period(s).

- The following new paragraph shall be added as Section 15.13:

  15.13 Approval of this Contract by the Regulatory Commission of Alaska ("RCA") is a condition precedent for the effectiveness of the obligations of the parties to sell and purchase Gas under this Contract. Such approval means a final order of the RCA, without conditions or modifications unacceptable to either Party. Approval will be deemed to have occurred on the date that a RCA order approving the Contract without conditions or modifications unacceptable to the Parties becomes final and is not subject to further reconsideration. If the RCA issues an order that approves (conditionally or otherwise) this Contract and imposes terms and conditions or modifications unacceptable to Buyer or Seller, each acting in its sole and absolute discretion, Buyer or Seller may terminate this Contract upon written notice to the other party, such termination to take effect on the date outlined in any such written notice of termination. If RCA Approval has not been obtained by October 2, 2010, either party may terminate this Contract upon notice to the other party, such termination would be effective immediately upon receipt by the other party of such termination notice.

16.3. The obligation of Seller to make available and sell, and the obligation of Buyer to nominate, take and purchase, Gas pursuant to the terms of this Contract shall commence on the Delivery Start Date and terminate on the last Day of the Term following Period 1, Period 2, and the Option Periods, if applicable:

(i) Firm Gas. Subject to the terms and conditions of this Contract, Buyer shall nominate, take and purchase, and Seller shall deliver and sell, (a) an amount equal to Period 1 Firm Gas on each Day during Period 1, (b) an amount equal to Period 2 Firm Gas on each Day during Period 2, and (c) if an Option Period is in effect, on each Day during such Option Period, at least the Option Minimum Daily Quantity and no more than Option Maximum Daily Quantity.

(ii) Firm Swing Gas. Subject to the terms and conditions of this Contract, on each Day during Period 1, Buyer may nominate, take and purchase, and Seller shall deliver and sell Period 1 Firm Swing Gas. Period 1 Firm Swing Gas shall not be utilized by Buyer for any purpose other than to generate electricity for sale to its Retail Load, Existing Wholesale Load or to inject Gas into a Gas storage facility during the months of April through October unless otherwise agreed to by the parties. To verify the usage of Period 1 Firm Swing Gas under this Contract, an independent third party, selected by Seller and reasonably acceptable to Buyer, may perform an audit in accordance with Section 7.6, subject to reasonable confidentiality terms, and report the audit findings to Buyer and Seller. The costs of such independent third party shall be borne by Seller, unless such person determines that Buyer violated the provisions of this Section 16.3(ii) in which case, Buyer shall reimburse Seller for the costs associated with such independent third party.

(iii) Excess Gas. If Buyer determines that its Gas requirements for any Day are in excess of (a) for any Day in Period 1, the aggregate of Period 1 Firm Gas and Period 1 Firm Swing Gas volumes, (b) for any Day in Period 2, the Period 2 Firm Gas volume, and (c) for any Day in an Option Period, the Option Maximum Daily Quantity, Buyer may submit a separate nomination in accordance with the provisions of Section 16.5 with the amount of Gas that it desires to purchase from Seller. Such nomination shall include the price at which Buyer proposes to purchase such Excess Gas (in accordance with the limitations set forth in Attachment 1). Seller, in its sole discretion, will have the option, but not the obligation, to confirm such nomination and price, and make available for sale to Buyer all or any portion of the Excess Gas nominated by Buyer at the Delivery Point(s) under the terms hereof. Subject to the availability of Gas, Seller may make available such Excess Gas, provided that any such confirmation and delivery of Excess Gas will be made on an Interruptible basis and may be curtailed or interrupted by Seller for any reason at any time. In the event that Seller curtails or interrupts for any or all of a Confirmed Nomination, Seller shall use commercially reasonable efforts to provide a two (2) hour notification of such curtailment or interruption.

(iv) Hourly Gas Limit; Interruptibility. Buyer shall exercise commercially reasonable efforts to nominate and take delivery of Gas on a uniform hourly basis. In the event that Buyer desires to nominate in any one (1) hour period an amount of Gas in excess of the Maximum Daily Quantity divided by twenty-four (24), Buyer may issue a separate nomination for such excess amount ("Interruptible Hourly Gas") at the then applicable Contract Price. Subject to availability of the Gas, Seller may make available such Interruptible Hourly Gas at the Contract Price; provided that any such confirmation and delivery of such Interruptible Hourly Gas is made on an Interruptible basis and may be curtailed or interrupted by Seller for any reason at any time.

(v) Resale; Storage; Exchange. Buyer shall have the right to resell Gas purchased under this Contract or make energy sales (using Gas purchased under this Contract to generate such electrical energy) to Anchorage Municipal Light and Power and/or make energy sales (using Gas purchased under this Contract) to Golden Valley Electric Association to maintain the Minimum Daily Quantities of Gas purchased under this Section 16.3. Subject to the limitation in Section 16.3(ii), Buyer shall have the right, for any reason, to store or exchange Gas purchased under this Contract.

(vi) Excused Failures. The following potential failure shall be excused and shall not constitute a default of an obligation under this Contract:

(a) The failure of Seller to meet its obligations in Sections 3, 16.3 and 16.5 shall be an excused failure under this Contract, and Seller shall not be in default of this Contract and Buyer shall not have any remedy against Seller under this Contract, including under Section 3.2, if Seller's failure to meet its obligations resulted from (a) Buyer's

failure to meet its obligation to take the Minimum Daily Quantity on a Day(s) in the Term, (b) as a result of Buyer's failure as described in clause (a), Seller is required to shut-in, ramp down or otherwise curtail its production activities at a particular Gas producing location, and (c) when Seller commences a restart or ramp up of its production activities at such location, Seller is not able to achieve the same level of production from such location; provided that (x) Seller has used commercially reasonable efforts to avoid having to shut-in, ramp down or curtail its production activities at such location; and (y) this Section 16.3(vi) shall only excuse Seller from its obligations under Sections 3, 16.3 and 16.5 up to the amount of such decreased production at such location.

(b) The failure of Buyer to meet its obligations in Sections 3, 16.3 and 16.5 shall be an excused failure under this Contract, and Buyer shall not be in default of this Contract and Seller shall not have any remedy against Buyer under this Contract, including under Section 3.2, if Buyer's failure to meet its obligations resulted from Buyer's Gas requirements being decreased because it is required to purchase electric power from qualifying facilities pursuant to the Public Utilities Regulatory Policies Act of 1978 (PURPA) and 3 AAC 50.50.770(a)-(g); provided that (a) Buyer has not entered into an agreement with a qualifying facility in accordance with 3 AAC 50.50.770(h) unless ordered to do so by an order of a government agency or court of competent jurisdiction, and (b) any excused failure that Buyer seeks under this Section 16.3(vi) shall be split proportionately among all Gas supply contracts that Buyer has at the time of such excused failure.

16.4 Pricing for all Gas sold under this Contract shall be in accordance with **Attachment 1**.

16.5 Buyer will nominate to Seller in writing (via electronic means) each calendar Day in advance of the next calendar Day the hourly volumes of Gas by power plant location that Buyer desires for that entire next calendar Day. Seller retains the right to select the Delivery Point(s), but Seller shall use commercially reasonable efforts to deliver Gas to Buyer at the Delivery Points in the order of preference listed in **Attachment 2** to meet Buyer's nomination request and minimize Buyer's transportation costs, subject to availability of Gas at points that can accommodate Buyer's requested nominations. Seller and Buyer shall communicate throughout the Day in order to properly effect any nominations to the relevant Transporters. Any and all nominations submitted by Buyer in accordance with this Section 16.5 must be confirmed by Seller, with such confirmation, including the Delivery Point(s) for such nominated Gas, to be made to Buyer before such nomination takes effect. If Seller informs Buyer that it is unable to confirm a nomination, Buyer shall re-nominate at a level set forth by Seller, and such nomination shall be subject to the confirmation provisions of this Section 16.5. Seller's nomination confirmation or alternative response shall be sent to Buyer in writing via electronic means at a time that reasonably allows Seller and Buyer to plan the flow of Gas for the relevant calendar Day. If the timing of the nominations no longer meets the timing requirements of Transporter(s), then Buyer and Seller will work together to adjust the nomination timing.

In the event that Seller or Buyer needs to make changes to the nomination and confirmations on or within the current Day, the parties will give at least one hour notice for nomination changes that are considered "complex nominations" by the relevant Transporter, and at least thirty (30) minutes notice for nomination changes that are considered "simple nominations" by the relevant Transporter. If a party gives such timely notice, the other party will exercise commercially reasonable efforts to effect the nomination change with the relevant Transporter. The parties acknowledge that notice given in less than such time period may result in the Transporter rejecting any such nomination change, but the parties agree to exercise commercially reasonable efforts to effect any such change even if made with less than such timely notice.

In the case of an emergency condition at Buyer's facilities or Seller's facilities, the affected party shall exercise best efforts to give immediate telephone or other notice to the other party of such emergency and an estimate of the extent of curtailment of its takes from Seller or deliveries to Buyer, but in any event on the next half hour occurring after the commencement of an emergency condition. If such emergency condition constitutes a Force Majeure, the parties shall be relieved of their obligations during the period of such Force Majeure under this Contract as specified in Section 11. To the extent possible, Buyer shall endeavor to give Seller as much advance notice as is reasonably practicable of Buyer's anticipated resumption of operations following any emergency condition at a Buyer's Facility, and Seller shall provide Buyer with as much advance notice as is reasonably practicable or Seller's anticipated resumption of supply of Gas to Buyer, in the event Seller's supply is curtailed. Such notices shall be given in order to enable each party, as circumstances may permit, to minimize any costs, expenses and damage such party might incur or sustain in case of failure by Buyer to take Gas as provided for herein or Seller to deliver Gas as provided for herein.

16.6 It is Buyer's responsibility to secure the necessary transportation for the Gas at and after the Delivery Point(s). It is Seller's responsibility to secure the necessary transportation to transport the Gas to the Delivery Point(s). The costs necessary to be paid to Transporters associated with transporting Gas before, at and after the Delivery Point(s) shall be borne by the Buyer as further described on **Attachment 3**. In order to minimize Buyer's transportation costs, Buyer and Seller commit to meet periodically (at least once each calendar quarter) to forecast Buyer's Gas supply requirements by facility and jointly formulate plans for transporting the required volumes of Gas in a cost effective manner.

16.7 If it is at any time determined that Seller's Available Gas Reserves are insufficient to permit Seller to make available Gas under this Contract and meet its obligations to Alaska Pipeline Company under the Gas Purchase Agreement dated May 1, 1988 (the "Alaska Pipeline Company Agreement"), Gas deliveries under this Contract may be reduced or terminated by

Seller in its sole discretion. "Seller's Available Gas Reserves" will be determined in accordance with the Alaska Pipeline Company Agreement. Seller commits to provide Buyer with as much Notice as is practicable to this extent that Seller reasonably believes Gas deliveries under this Contract may be reduced or terminated by Seller.

16.8 Royalties

Seller will be responsible for the payment of all royalties, and any fees, penalties and assessments attributable to the royalties, on Gas delivered under this Contract provided that the Alaska Department of Natural Resources agrees that the price paid under this Contract is the value of the State of Alaska's royalty share of production under AS 38.05.180 (aa) (with the exception of production covered by a royalty settlement agreement). The parties will work together to obtain acceptance by the Alaska Department of Natural Resources of the price paid under this Contract as the value of the State of Alaska's royalty share of production under AS 38.05.180(aa) (with the exception of production covered by a royalty settlement agreement) within 90 Days of the effective date of this Contract. If the parties are not successful in obtaining such acceptance, Buyer will reimburse Seller for any royalty payments which exceed the royalty payments that would be payable, for Gas not covered by a royalty settlement agreement, if the price paid under this Contract was equal to the value of the State of Alaska's royalty share of such production as determined by the Alaska Department of Natural Resources.

16.9 Reserves Determination

On or before December 15th of each year during the Term, Seller will provide to Buyer a written determination of (i) Seller's Gas Reserves; and (ii) Seller's commitments to deliver Gas (a) to third parties under Gas contracts in effect at the time of delivery of the determination, and (b) this Contract. Upon reasonable request by Buyer, Seller will make such data and information (and reasonable access to relevant personnel of Seller) as may be reasonably necessary for Buyer to evaluate the written determination of Seller's Gas Reserves. Buyer will take all reasonable steps to preserve the confidentiality of the data received from Seller under this Section 16.9.

16.10 New Taxes

Notwithstanding anything in Section 6 to the contrary; after March 31, 2013, Buyer will reimburse Seller for any Production Taxes (as defined and set by AS 43.55.011, as amended, replaced, or supplemented from time to time) or other new taxes attributable to the operations and transactions contemplated by this Contract in excess of $0.25 per Mcf of Gas.

16.11 Arbitration

Any dispute arising, in whole or in part, with respect to billing or Contract Price and not otherwise resolved by the parties will be settled by arbitration in accordance with the CPR Rules for Non-Administered Arbitration then currently in effect ("CPR Rules") of the International Institute for Conflict Prevention & Resolution, and judgment on the award rendered by the arbitrator(s) may be entered and enforced in any court of competent jurisdiction. Any provisions available within the CPR Rules to expedite the proceeding will apply to the proceeding unless otherwise agreed by the parties.

16.12 Court

Except as provided in Section 16.11, all disputes arising under this Contract not otherwise resolved by the parties will be resolved in the state or federal courts of Alaska in Anchorage, Alaska. Each party, to the extent permitted by law, knowingly, voluntarily, and intentionally waives its right to a trial by jury in any action or other legal proceeding arising out of or relating to this Contract and the transactions it contemplates. This waiver applies to any action or legal proceeding, whether sounding in contract, tort, or otherwise.

16.13 Royalty In Kind

If the State of Alaska elects to take its royalty in kind, then Seller will have the right, in its sole discretion, to reduce Seller's Gas delivery obligations under this Contract by notifying Buyer, within sixty (60) Days after Seller receives formal notice from the state that it intends to take its royalty in kind, of the quantities of Gas that Seller is unable to commit to deliver as a consequence of the royalty Gas diversion. Seller's notice will include new Transaction Confirmations for the relevant period establishing adjusted Period 1 Firm Gas, Period 1 Firm Swing Gas and Period 2 Firm Gas. Any reduction under this paragraph in Seller's Gas delivery obligations will be proportionate to all of Seller's local end-user delivery obligations from Cook Inlet production.

16.14 In the event that it either is required or becomes standard in the Cook Inlet to price Gas using the heating value of such Gas (i.e., on a MMBtu basis) as opposed to a volumetric basis (i.e., on a MCF basis), the Parties agree that the Gas under this Contract will be priced on a MMBtu basis, and will enter into necessary revisions and amendments to this Contract in order to effectuate such conversion. Unless and until such conversion occurs, for pricing purposes, it shall be assumed that each MCF of Gas contains one (1) MMBtu.

Attachment 1
Pricing Determinations

The Contract Price for Gas made available by Seller to Buyer under this Contract shall be determined in accordance with the following calculation.

For purposes of this Attachment 1:

"Contract Year 1" shall mean the period during which Seller has an obligation to make Gas available to Buyer pursuant to this Contract commencing on the Delivery Start Date and ending on March 31, 2012.

"Contract Year 2" shall mean the period during which Seller has an obligation to make Gas available to Buyer pursuant to this Contract commencing on April 1, 2012 and ending on March 31, 2013.

NYMEX Calculated Price

On the February 1 prior to Contract Year 1 and Contract Year 2, Seller shall calculate the average NYMEX reference price (the "NYMEX Calculated Price") for such Contract Year by taking the simple average of the prices of the twelve (12) Monthly NYMEX natural gas futures contracts for the twelve (12) Month period commencing on April 1 of such Contract Year, as reported in "Platts Gas Daily".

The NYMEX Calculated Price for the 2013 Option shall be determined on the February 1 prior to the commencement of the 2013 Option by taking the simple average of the prices of the nine (9) Monthly NYMEX natural gas futures contracts for the period commencing on April 1, 2013, as reported in "Platts Gas Daily". The NYMEX Calculated Price for the 2014 Option shall be calculated on November 1, 2013 and shall be calculated by taking the simple average of the prices of the twelve (12) Monthly NYMEX natural gas futures contracts for the twelve (12) Month period commencing on January 1, 2014, as reported in "Platts Gas Daily".

Price Limitations

If the NYMEX Calculated Price per MMBtu for any Contract Year or Option Period is (i) less than the floor price set forth in Table 1 for such Contract Year or Option Period, the NYMEX Calculated Price shall be deemed to be such floor price per MMBtu, or (ii) greater than the ceiling price set forth in Table 1 for such Contract Year or Option Period per MMBtu, the NYMEX Calculated Price shall be deemed to be such ceiling price per MMBtu.

Table 1 – Price Collars

	Floor	Ceiling
Contract Year 1	$5.90	$8.90
Contract Year 2	$6.10	$9.10
2013 Option	$6.25	$9.25
2014 Option	$6.50	$9.50

Pricing Premiums and Discounts

For Gas made available by Seller during Period 1, Period 2 or the Option Periods, Seller shall take the product of (i) the NYMEX Calculated Price determined by Seller for the Contract Year or Option Period in which such Gas is made available, and (ii) the Price Factor as set forth below in Table 2.

Table 2 – Pricing Premiums and Discounts

Category	Price
Period 1 Firm Gas	100%
Period 1 Firm Swing Gas	125%
Period 2 Firm Gas	95%
Gas Delivered during the 2013 Option	95%
Gas Delivered during the 2014 Option	95%
Excess Gas	up to 125% of the NYMEX Calculated Price

Period 1 Price Calculation Example:

Example 1:
Assume that on February 1, 2011, the settlement prices for the Monthly NYMEX natural gas futures contracts for the period of April 2011 – March 2012 are:

	Settlement
Apr	*5.749*
May	*5.712*
Jun	*5.664*
Jul	*5.707*
Aug	*5.773*
Sep	*5.848*
Oct	*5.913*
Nov	*5.943*
Dec	*6.043*
Jan	*6.343*
Feb	*6.673*
Mar	*6.893*

1. The simple average of the above settlement prices is $6.02.
2. Since $6.02 is greater than the floor price for Contract Year 1 and less than the ceiling price for Contract Year 1, **the NYMEX Calculation Price for Contract Year 1 = $6.02.**
3. Prices for Contract Year 1 would be as follows:
   Period 1 Firm Gas = NYMEX Calculated Price = **$6.02/mcf**
   Period 1 Firm Swing Gas = NYMEX Calculated Price * 125% = **$7.53/mcf**

Example 2:
Assume that on February 1, 2011, the settlement prices for the Monthly NYMEX natural gas futures contracts for the period of April 2011 – March 2012 are:

	Settlement
Apr	*5.749*
May	*5.712*
Jun	*5.664*
Jul	*5.707*
Aug	*5.773*
Sep	*5.848*
Oct	*5.913*
Nov	*5.943*
Dec	*6.143*
Jan	*6.211*
Feb	*6.125*
Mar	*5.856*

1. The simple average of the above settlement prices is $5.89.
2. Since $5.89 is less than the floor price for Contract Year 1, **the NYMEX Calculation Price for Contract Year 1 = $5.90.**
3. Prices for Contract Year 1 would be as follows:
   Period 1 Firm Gas = NYMEX Calculated Price = **$5.90/mcf**
   Period 1 Firm Swing Gas = NYMEX Calculated Price * 125% = **$7.38/mcf**

Period 2 Price Calculation Examples:

Example:
Assume that Period 2 has commenced and on February 1, 2012, the settlement prices for the Monthly NYMEX natural gas futures contracts for the period of April 2012 – March 2013 are:

	Settlement
Apr	*5.749*
May	*5.712*
Jun	*5.664*
Jul	*5.707*
Aug	*5.773*
Sep	*5.848*
Oct	*5.913*
Nov	*5.943*
Dec	*6.043*
Jan	*6.343*
Feb	*6.673*
Mar	*6.893*

1. The simple average of the above settlement prices is $6.02.
2. Since $6.02 is less than the floor price for Contract Year 2, **the NYMEX Calculation Price for Contract Year 2 = $6.10.**
3. Prices for Contract Year 2 would be as follows:
   Period 2 Firm Gas = NYMEX Calculated Price * 95% = **$5.80/mcf**

Attachment 2
Delivery Points

All Gas sold and purchased under this Contract for the Beluga Power Plant will be delivered by Seller into one or more of the following designated "Delivery Points".

1. CIGGS to Beluga Pipeline 8106 interconnect meter, as described in CIGGS Pipeline Tariff RCA No. 711.

2. The Kenai-Anchorage Pipeline – Kenai Unit Area Connection (ENSTAR/APC Meters 500 and 502). At the upstream flange of the Alaska Pipeline Company's master meter located at or near the inlet of the Alaska Pipeline Company's Kenai-Anchorage pipeline in Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

3. The Kenai Kachemak Pipeline – KKPL-APC Interconnection Point (MSN 601). At the downstream weld of the 8-inch electronic isolation fitting, located just outside of KKPL's meter building, between the northern terminus of the KKPL and the APL's lateral to the inlet of the APC's Kenai-Anchorage pipeline in Southeast ¼ of Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

4. The Kenai-Anchorage Pipeline –
   - Sterling Unit Connection (ENSTAR/APC Metering station 677, 9100). At the upstream flange of the Transporter's meter at or near the connection of the Transporter's Royalty Pipeline located within the Northeast ¼ of Section 9, Township 5 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.
   - West Fork (ENSTAR/APC Station K676, 2200). West Fork Connection (ENSTAR/APC Station K676, Meters 924 & 925). At the upstream flange of Alaska Pipeline Company's meter at or near the connection of the pipeline from the West Fork field and Alaska Pipeline Company's Kenai-Anchorage pipeline located in the South 60 feet of the Northwest 1/4 of the Northwest 1/4 of Section 12, Township 5 North, Range 9 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

5. APC Royalty Line (ENSTAR/APC Meter Beaver Creek 1100). At the upstream flange of transporter's meter at or near Transporter's existing pipeline within the Northwest 1/4 , Southwest ¼, Section 7, Township 6 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, Alaska.

6. The Kenai Kachemak Pipeline – KKPL-KNPL 600 interconnect meter, as described in the KKPL Tariff RCA No. 668.

7. The Kenai Nikiski Pipeline – KNPL Receipt Points (301, 303, 400), as described in the KNPL Tariff RCA No. 689
   - Cannery Loop (301, 303).
   - Kenai Gas Field (400).

8. CIGGS to KNPL 401 interconnect meter at the upstream flange of the CIGGS and KNPL pipelines located in the Northeast 1/4 of the Northeast 1/4 of Section 21, Township 7 North, Range 12 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

All Gas sold and purchased under this Contract for the Southcentral Power Plant/International Power Plant and Bernice Lake Power Plant will be delivered by Seller into one or more of the following designated "Delivery Points". The Delivery Points are listed below in order of Buyer's preference, which order may be changed by written notice from Buyer to Seller's representative listed in the relevant Transaction Confirmation.

Southcentral Power Plant and International Power Plant

1. The Kenai-Anchorage Pipeline – Kenai Unit Area Connection
   - Sterling Unit Connection (ENSTAR/APC Metering station 677, 9100). At the upstream flange of the Transporter's meter at or near the connection of the Transporter's Royalty Pipeline located within the Northeast ¼ of Section 9, Township 5 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

- West Fork (ENSTAR/APC Meters, 2200). West Fork Connection (ENSTAR/APC Station K676, Meters 924 & 925) At the upstream flange of Alaska Pipeline Company's meter at or near the connection of the pipeline from the West Fork field and Alaska Pipeline Company's Kenai-Anchorage pipeline located in the South 60 feet of the Northwest 1/4 of the Northwest 1/4 of Section 12, Township 5 North, Range 9 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

2. APC Royalty Line (ENSTAR/APC Meter Beaver Creek 1100). At the upstream flange of transporter's meter at or near Transporter's existing pipeline within the Northwest 1/4 , Southwest ¼, Section 7, Township 6 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, Alaska.

3. The Kenai-Anchorage Pipeline – Kenai Unit Area Connection (ENSTAR/APC Meters 500 and 502). At the upstream flange of the Alaska Pipeline Company's master meter located at or near the inlet of the Alaska Pipeline Company's Kenai-Anchorage pipeline in Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

4. The Kenai Kachemak Pipeline – KKPL-APC Interconnection Point (MSN 601). At the downstream weld of the 8-inch electronic isolation fitting, located just outside of KKPL's meter building, between the northern terminus of the KKPL and the APL's lateral to the inlet of the APC's Kenai-Anchorage pipeline in Southeast ¼ of Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

5. The Kenai Kachemak Pipeline – KKPL-KNPL 600 interconnect point, as described in the KKPL Tariff RCA No. 668.

6. The Kenai Nikiski Pipeline – KNPL Receipt Points (301, 303, 400), as described in the KNPL Tariff RCA No. 689
   - Cannery Loop (301, 303).
   - Kenai Gas Field (400).

7. CIGGS to Beluga Pipeline 8106 interconnect meter, as described in CIGGS Pipeline Tariff RCA No. 711.

Bernice Lake Power Plant

1. The Kenai-Anchorage Pipeline – Kenai Unit Area Connection
   - Sterling Unit Connection (ENSTAR/APC Metering station 677, 9100). At the upstream flange of the Transporter's meter at or near the connection of the Transporter's Royalty Pipeline located within the Northeast ¼ of Section 9, Township 5 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.
   - West Fork (ENSTAR/APC Meters, 2200). West Fork Connection (ENSTAR/APC Station K676, Meters 924 & 925) At the upstream flange of Alaska Pipeline Company's meter at or near the connection of the pipeline from the West Fork field and Alaska Pipeline Company's Kenai-Anchorage pipeline located in the South 60 feet of the Northwest 1/4 of the Northwest 1/4 of Section 12, Township 5 North, Range 9 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

2. APC Royalty Line (ENSTAR/APC Meter Beaver Creek 1100). At the upstream flange of transporter's meter at or near Transporter's existing pipeline within the Northwest 1/4 , Southwest ¼, Section 7, Township 6 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, Alaska.

3. The Kenai-Anchorage Pipeline – Kenai Unit Area Connection (ENSTAR/APC Meters 500 and 502). At the upstream flange of the Alaska Pipeline Company's master meter located at or near the inlet of the Alaska Pipeline Company's Kenai-Anchorage pipeline in Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

4. CIGGS to KNPL 401 interconnect meter at the upstream flange of the CIGGS and KNPL pipelines located in the Northeast 1/4 of the Northeast 1/4 of Section 21, Township 7 North, Range 12 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

5. The Kenai Nikiski Pipeline – KNPL Receipt Points (301, 303, 400), as described in the KNPL Tariff RCA No. 689

- Cannery Loop (301, 303).
- Kenai Gas Field (400).

6. The Kenai Kachemak Pipeline – KKPL-KNPL 600 interconnect meter, as described in the KKPL Tariff RCA No. 668.

Additional Delivery Points may be added by mutual written consent of Buyer and Seller. In the event that any of the descriptions of these Delivery Points change in the applicable pipeline tariff, this Attachment 2 shall be updated accordingly.

Attachment 3
Transportation Costs Borne by Buyer

With respect to the following Delivery Points, Buyer shall reimburse Seller for the costs incurred by Seller to transport Gas on the CIGGS Pipeline, in accordance with the tariff rates as set forth in the CIGGS Tariff, as may be in effect and applicable to transportation of Gas when the Gas was transported:

1.CIGGS to Beluga Pipeline 8106 interconnect meter, as described in CIGGS Pipeline Tariff RCA No. 711.

2.CIGGS to KNPL 401 interconnect meter at the upstream flange of the CIGGS and KNPL pipelines located in the Northeast 1/4 of the Northeast 1/4 of Section 21, Township 7 North, Range 12 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

With respect to the following Delivery Points, Buyer shall reimburse Seller for the costs incurred by Seller to transport Gas on the KKPL Pipeline, in accordance with the transport agreement for Zone 1 as set forth in the KKPL and Marathon Oil Company Firm Transport Agreement No. KKPL-FT-002 as may be in effect and applicable to transportation of Gas when the Gas was transported:

1. Kenai Kachemak Pipeline – KKPL-APC Interconnection Point (MSN 601). At the downstream weld of the 8-inch electronic isolation fitting, located just outside of KKPL's meter building, between the northern terminus of the KKPL and the APL's lateral to the inlet of the APC's Kenai-Anchorage pipeline in Southeast ¼ of Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

2. Kenai Kachemak Pipeline – KKPL-KNPL 600 interconnect meter, as described in the KKPL Tariff RCA No. 668.

Regulatory Commission of Alaska
April 2, 2010

Appendix B

Proposed Tariff Sheet No. 94, 95, 95.5

Regulatory Commission of Alaska
April 2, 2010

Appendix C

Chart Data

Chart 1 Data - Electric Load Forecast by Utility

Year	Chugach Retail	Matanuska Electric	Homer Electric	Seward Electric	Total
			(GWh)		
2010	1,278	787	521	65	2,730
2011	1,281	802	524	65	2,750
2012	1,283	811	527	65	2,793
2013	1,286	821	531	65	2,815
2014	1,290	832	0	66	2,223
2015	1,294	0	0	66	1,380
2016	1,299	0	0	66	1,384

Chart 2 Data - Natural Gas Requirements by Utility

Year	Chugach Retail	Matanuska Electric	Homer Electric	Seward Electric	Total
			(Bcf)		
2010	12.4	7.6	5.0	0.6	25.7
2011	12.8	8.0	5.2	0.7	26.7
2012	12.7	8.0	5.2	0.6	26.6
2013	11.5	7.4	4.8	0.6	24.3
2014	10.0	6.4	0.0	0.5	16.9
2015	9.5	0.0	0.0	0.5	10.0
2016	9.5	0.0	0.0	0.5	10.0

Chart 3 Data - Natural Gas Requirements by Power Plant

Year	Beluga	Bernice Lake	IGT	Nikiski	Southcentral Power Plant	Total
	(Bcf)					
2010	21.0	0.6	0.0	4.0	0.0	25.7
2011	22.2	0.6	0.0	3.9	0.0	26.7
2012	21.7	0.9	0.0	3.9	0.0	26.6
2013	16.5	0.5	0.0	3.9	3.3	24.3
2014	10.1	0.0	0.0	0.2	6.7	16.9
2015	2.1	0.0	0.0	0.5	7.3	10.0
2016	2.0	0.0	0.0	0.6	7.3	10.0

Chart 4 Data - Natural Gas Supply by Producer

Year	Beluga River Producers	Marathon Oil Co.	New ConocoPhillips Contract	New Marathon Alaska Production	Unmet Volumes	Total
	(Bcf)					
2010	12.6	9.1	4.0	0.0	0.0	25.7
2011	3.7	0.0	13.4	9.6	0.0	26.7
2012	0.0	0.0	13.6	13.0	0.0	26.6
2013	0.0	0.0	12.4	11.9	0.0	24.3
2014	0.0	0.0	9.1	7.8	0.0	16.9
2015	0.0	0.0	6.2	0.0	3.8	10.0
2016	0.0	0.0	2.9	0.0	7.1	10.0

Chart 10 Data - Comparison of Chugach-COP and Chugach- MAP Contract Prices

Y/Qtr	COP Price	MAP Price	MAP Floor	MAP Ceiling
	$/Mcf			
2005 Q2	6.11	6.75		
2005 Q3	6.29	6.75		
2005 Q4	6.81	6.75		
2006 Q1	9.11	6.75		
2006 Q2	10.80	10.43	5.90	8.90
2006 Q3	7.30	10.43	5.90	8.90
2006 Q4	6.22	10.43	5.90	8.90
2007 Q1	6.04	10.43	5.90	8.90
2007 Q2	6.38	8.34	5.79	8.65
2007 Q3	6.92	8.34	5.79	8.65
2007 Q4	7.39	8.34	5.79	8.65
2008 Q1	6.10	8.34	5.79	8.65
2008 Q2	6.66	8.56	5.94	8.79
2008 Q3	8.53	8.56	5.94	8.79
2008 Q4	10.92	8.56	5.94	8.79
2009 Q1	8.43	8.56	6.18	9.03
2009 Q2	5.28	5.42	6.18	9.03
2009 Q3	3.89	5.42	6.18	9.03
2009 Q4	3.42	5.42	6.18	9.03
2010 Q1	4.28	5.42		

Regulatory Commission of Alaska
April 2, 2010

Appendix D

ADNR Gas Reserves Report (December 2009) and cover memo

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES

State of Alaska

DIVISION OF OIL AND GAS

TO: Tom Irwin
Commissioner

DATE: December 21, 2009

FILE NO:

THRU:

TELEPHONE: 269-8781

FROM: Kevin Banks
Director

SUBJECT: Cook Inlet Gas Reserves Study

Over the course of the past 18 months, Alaskans along the railbelt have listened as varying opinions of the state of the Cook Inlet oil and gas basin have been presented. In the spring of this year, I asked our Resource Evaluation staff to conduct a scientific analysis of the remaining reserves in the Cook Inlet so that this important issue could be examined with as much information as was available. The attached report is the result of this analysis. In addition to the results themselves, the report includes a description of the methodology used in performing that analysis.

The availability of reliable and affordable energy is a concern shared by all Alaskans. Residents of south-central Alaska and, to a lesser degree, along the railbelt have for decades enjoyed the benefits of access to abundant and relatively cheap Cook Inlet natural gas for home heating and power generation. Recent years have seen a significant decline, however, in the reserves-to-production (R/P) ratio for natural gas. Predictably this decline has become a source of concern for energy consumers in the region. There are also concerns about the capability of the natural gas infrastructure to meet seasonal and peak demand in the winter. I am sure you would agree that fear and panic can create an urgency that frustrates the problem solving process. It is against that backdrop that we initiated the attached study, in an effort to identify the severity of the problems associated with gas reserves decline and provide a tool from which reasoned decisions can be made.

Our Resource Evaluation staff enlisted the involvement of staff from the Division of Geological & Geophysical Surveys. The analysis that has resulted from this collaboration is purely scientific in nature and focuses on the one critical aspect of a complex system that must be assessed first: available natural gas reserves. Great care has been taken to ensure that the report we provide to you and to affected Alaskans is fact-based and data-driven. Engineering analysis of well data and geological and geophysical review of well-log, production, and seismic data provide the clearest picture of the challenges we face. The methodologies employed in arriving at the scientific conclusions herein were determined based upon the data available to the Department's energy industry experts. In cases where confidential data were used in the analysis, the utmost care has been taken to protect those data.

Other equally important issues such as the capacity of the Cook Inlet natural gas market and the reliability of the infrastructure to supply seasonal and peak demand should be scrutinized in similar detail. The economic overlay necessary to determine the cost of increased deliverability

is a separate analysis involving specific expertise and data distinct from the current effort. Additionally, an engineering analysis of existing natural gas transportation infrastructure could identify potential opportunities to improve system deliverability on peak days. Finally, the highly complex issue of local demand must be understood. Continuing current efforts at energy conservation and efficiency will create economic benefits. Steady and deliberate conversion to alternative energy sources will result long-term in a more diverse and reliable energy grid. The local market took some time to degrade and will take a bit of time and a lot of effort to recover. Cooperation and coordination among all of the stakeholders is critical.

Consumers relying upon Cook Inlet natural gas to meet their energy needs should know that while there is no need to panic, there is also no time to waste. Although it is apparent that sufficient reserves remain to provide for railbelt needs for the coming decade or more, the cost of providing energy to these same consumers is likely to rise. The low-hanging fruit in the Cook Inlet has largely been picked and as such one thing seems clear—the basin is not running out of gas but it could well be running out of cheap gas. Investments in storage development, reserves replacement and pipeline infrastructure will place additional upward pressure on consumer energy prices.

The dedicated professionals in the DOG/DGGS have a wealth of knowledge and decades of experience in analyzing the technical challenges associated with hydrocarbon resource development. They did not have the luxury of setting aside their important day-to-day duties in order to tackle this assignment. It is because of their willingness to work tirelessly and to put in extra hours to complete this analysis that I am able to present it to you now. Should you require additional detail from staff, please do not hesitate to ask.

State of Alaska
Department of Natural Resources
Division of Oil and Gas
and
Division of Geological & Geophysical Surveys

Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves

by

Jack D. Hartz[1], Meg C. Kremer[1], Don L. Krouskop[1], Laura J. Silliphant[1], Julie A. Houle[1], Paul C. Anderson[1], and David L. LePain[2]

edited by

Paul L. Decker[1]

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December, 2009

State of Alaska
Department of Natural Resources
Division of Oil and Gas
and
Division of Geological & Geophysical Surveys

Sean Parnell, *Governor*
Tom Irwin, *Commissioner*
Kevin Banks, *Director*[1]
Robert Swenson, *Director*[2]

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December, 2009

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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-

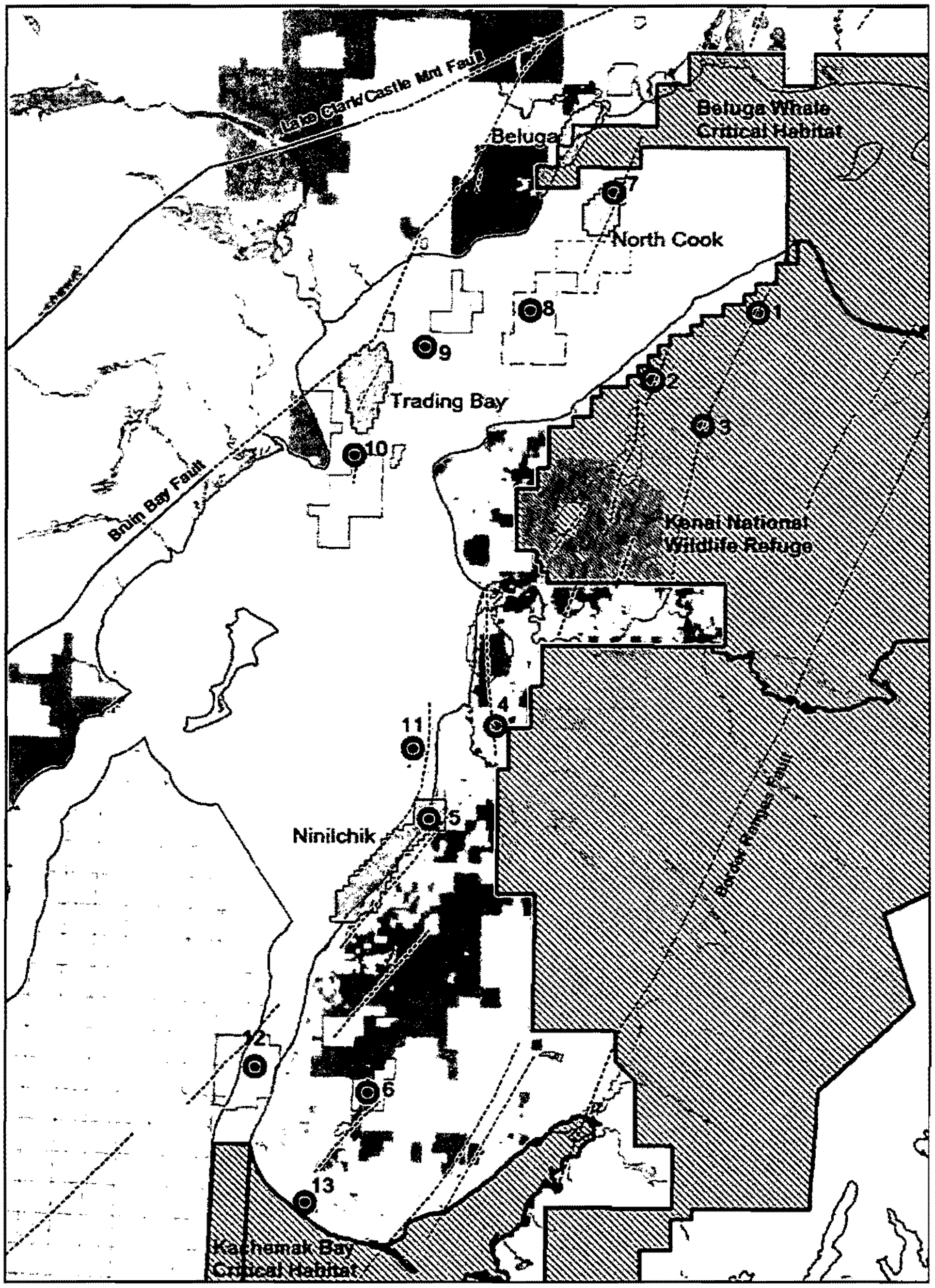

Figure 1. Location map of the central part of the Cook Inlet basin showing oil and gas producing units (the four major gas fields with geologic reserve estimates are highlighted with pink fill); major faults and fold axes; undeveloped exploration leads (numbered green dots); and areas with exploration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

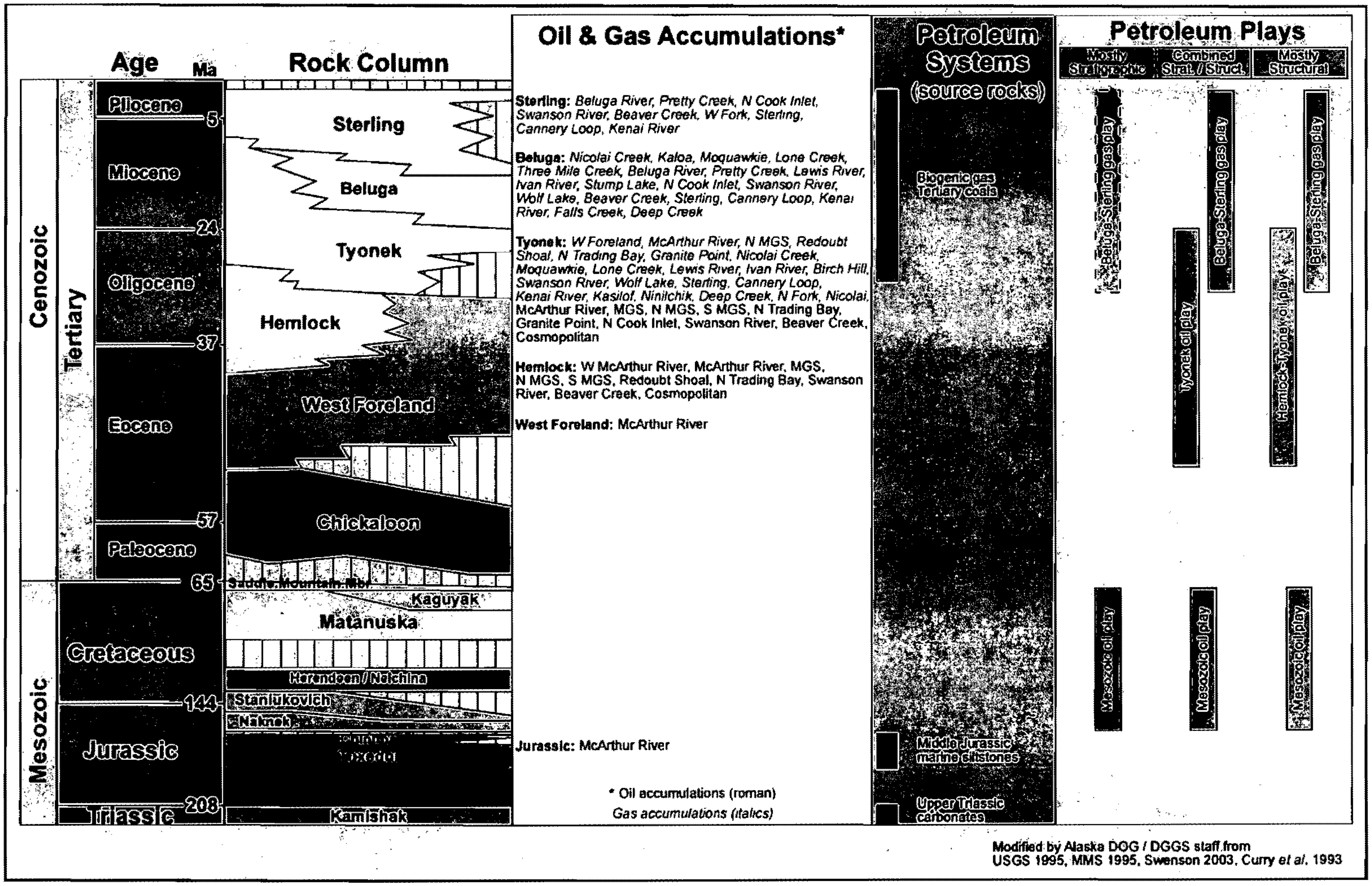

Figure 2. Chronostratigraphic and petroleum systems summary chart for the Cook Inlet basin

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 pub-

lic 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

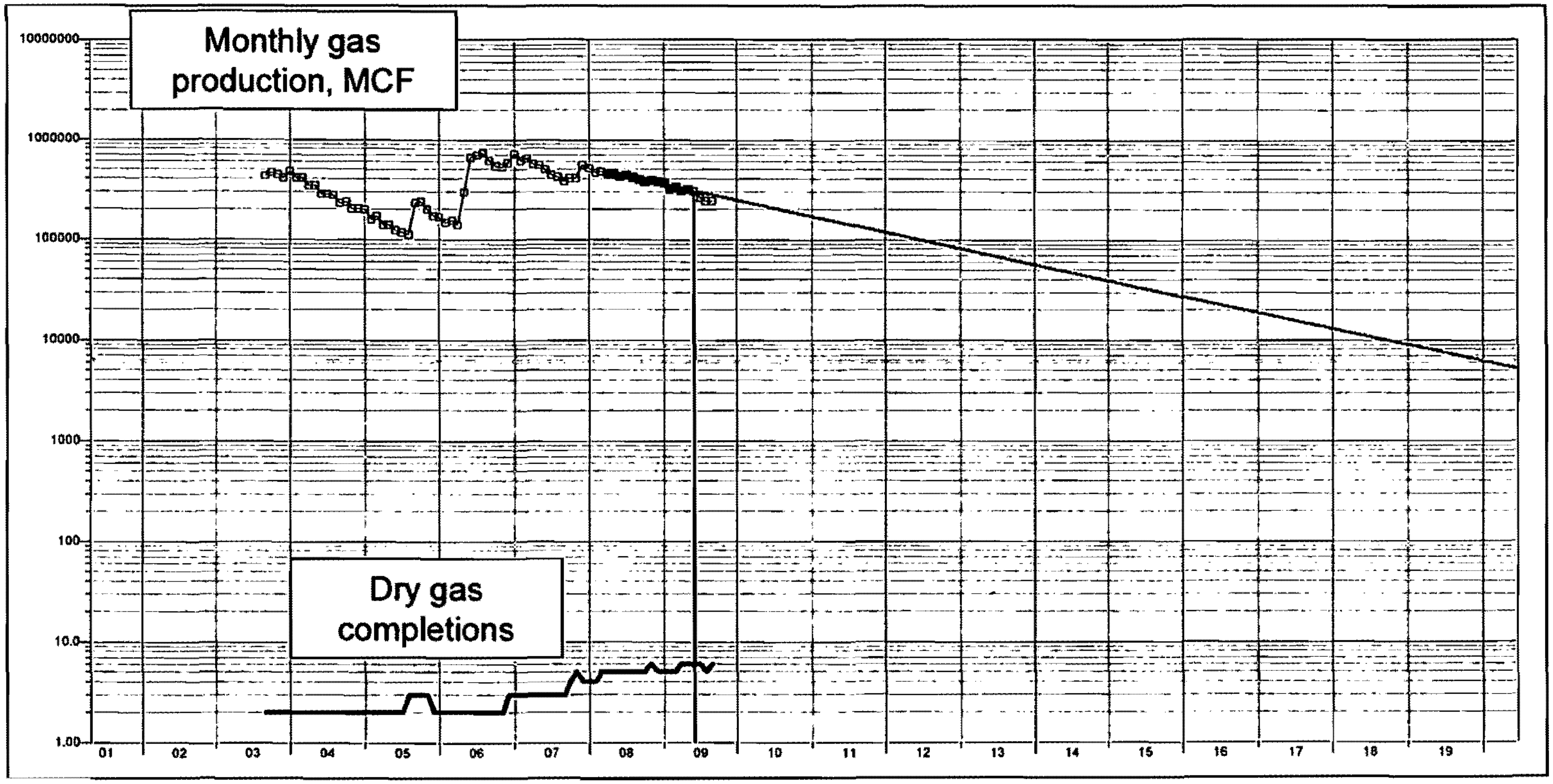

Figure 3. Typical decline plot; the Ninilchik GO Tyonek reservoir decline plot is illustrated. Horizontal axis is time (2001-2019); vertical axis is monthly production volume in thousands of cubic feet (MCF/month). Note the steep decrease from 2002 until mid 2004. As new wells are added (the lower red 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.

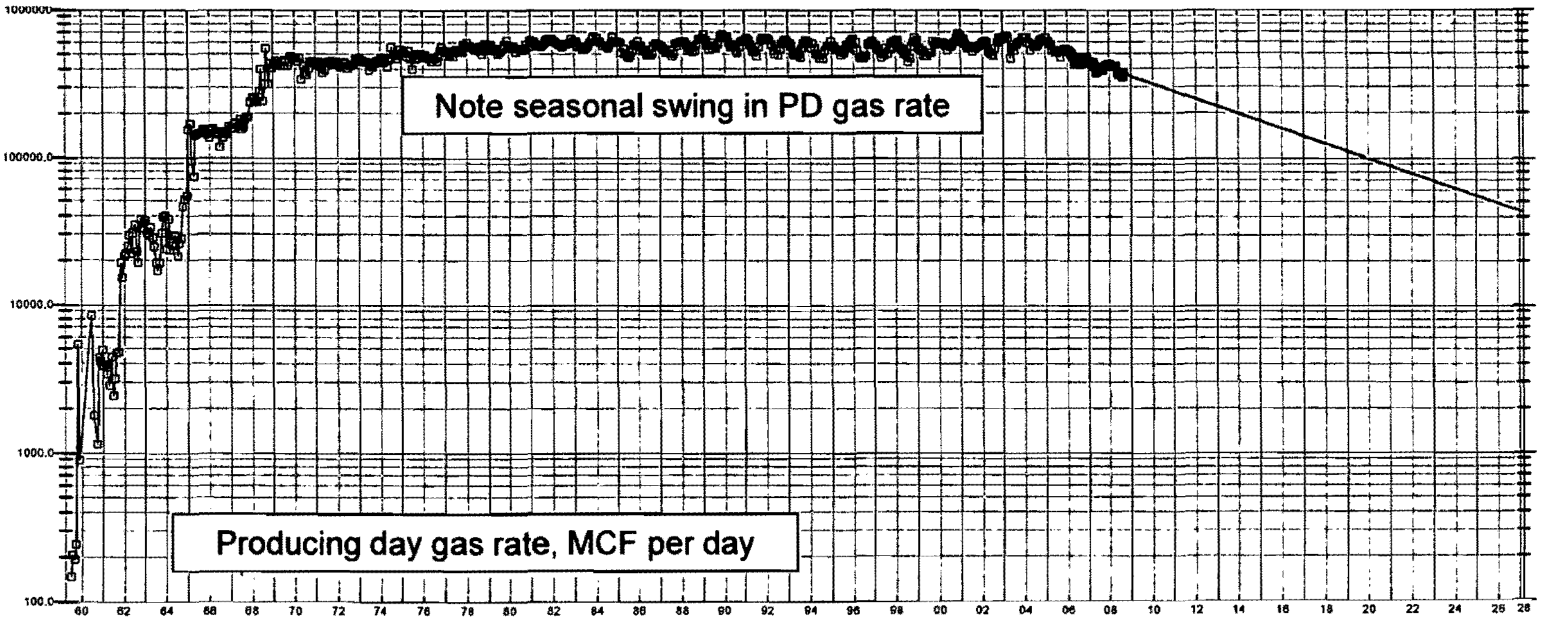

Figure 4. Decline curve projection based on data trend for production from all 28 Cook Inlet gas fields. Horizontal axis is time (1960-2028); vertical axis is producing day gas rate (MCF/day). Extrapolation line represents an annual average rate forecast, and does not illustrate seasonal fluctuation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

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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

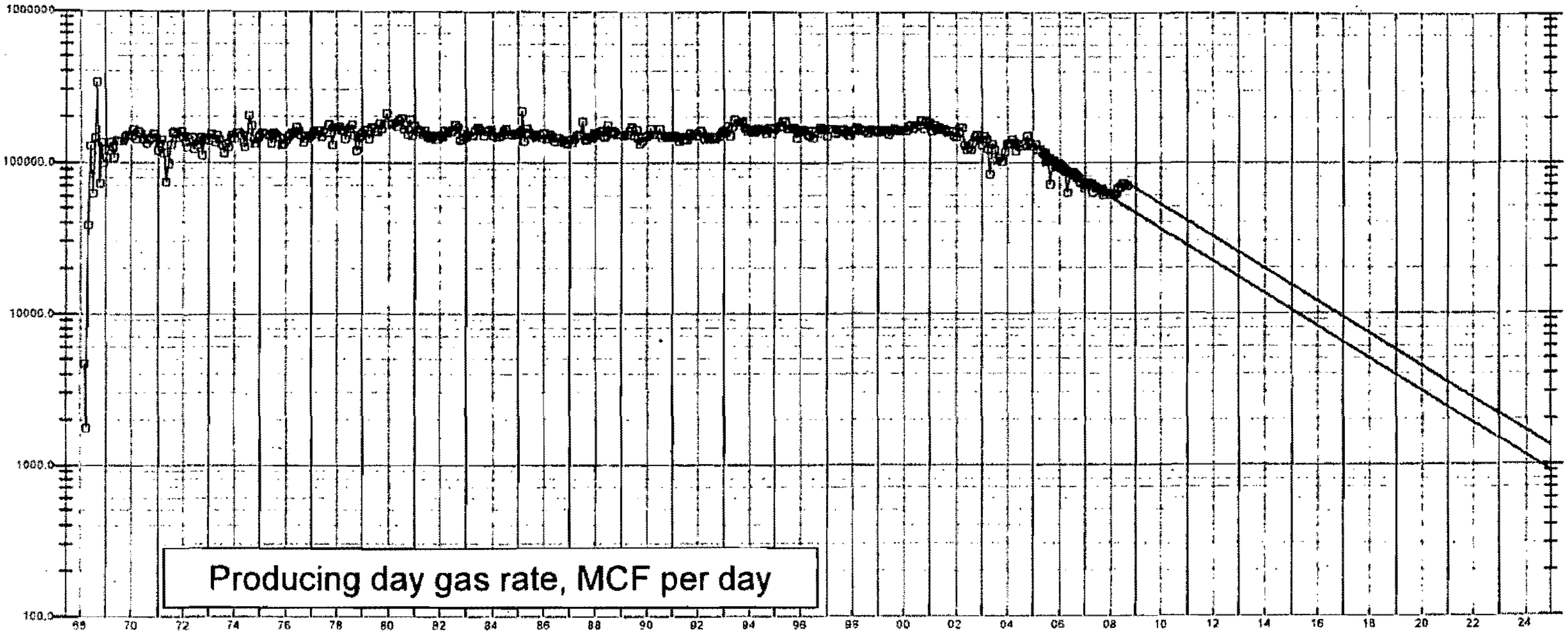

Figure 5. Example of decline curve analysis before and after new wells, North Cook Inlet Unit. Horizontal axis is time (1968-2025), vertical axis is monthly production volume in thousands of cubic feet (MCF). The well-established decline trend from 2004 to 2008 changes as new wells are added (green line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

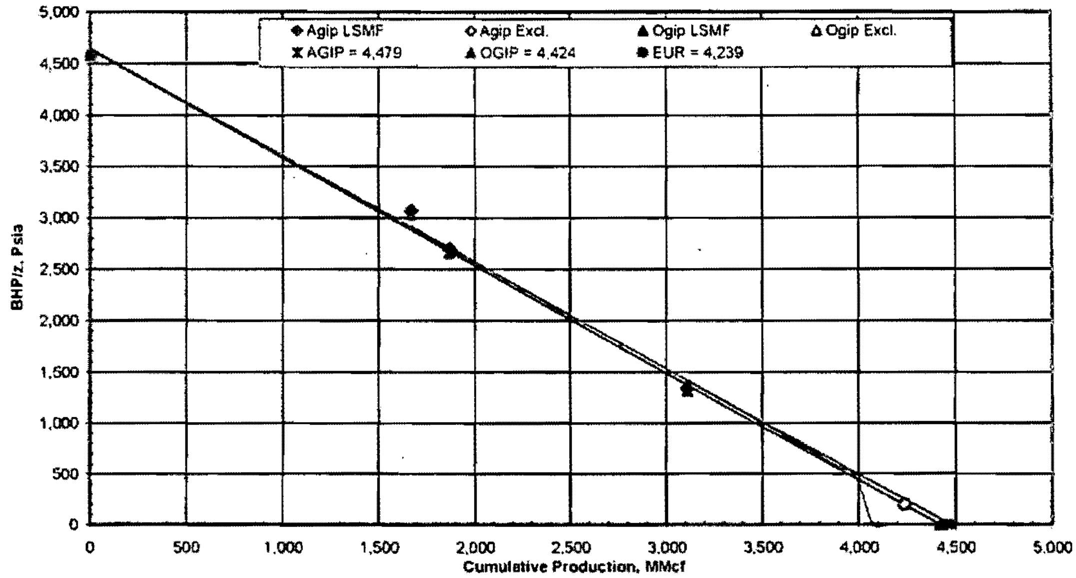

Figure 6. Typical P/Z plot. Vertical axis represents bottom hole pressure divided by Z, a dimensionless factor related to gas density, pressure, and temperature. The horizontal axis is cumulative gas volume produced at the time pressure is measured. Extrapolation of the trend will determine remaining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

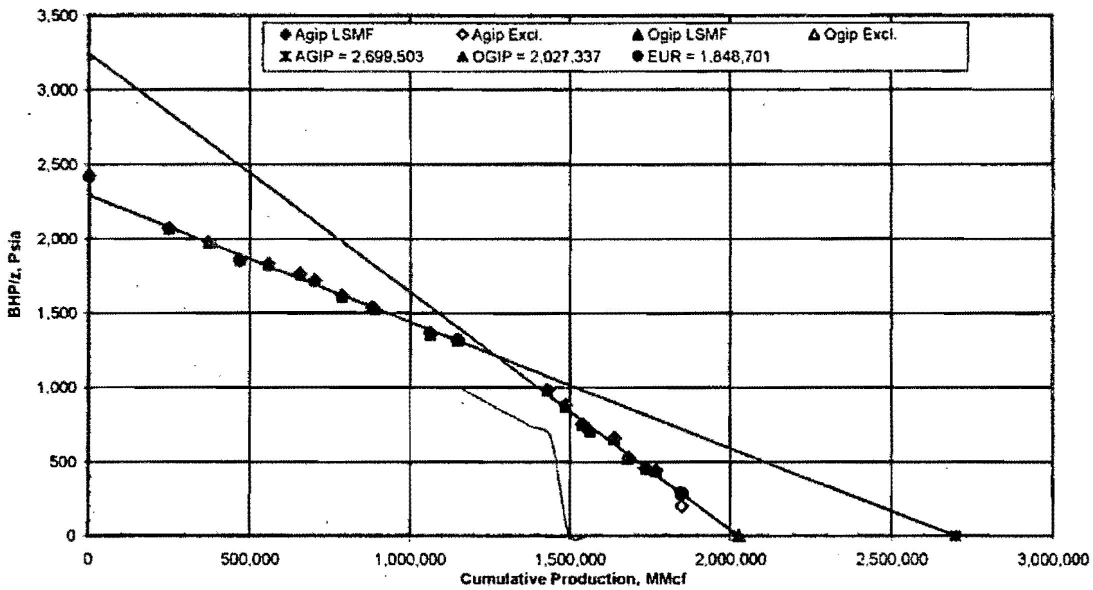

Figure 7. P/Z plot showing water influx and reservoir shrinkage. The initial trend (red line) shows a much higher in-place volume through production to about 1,300 BCF cumulative production. The later trend (green line) shows how water production has caused reservoir hydrocarbon volume to shrink by isolation 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

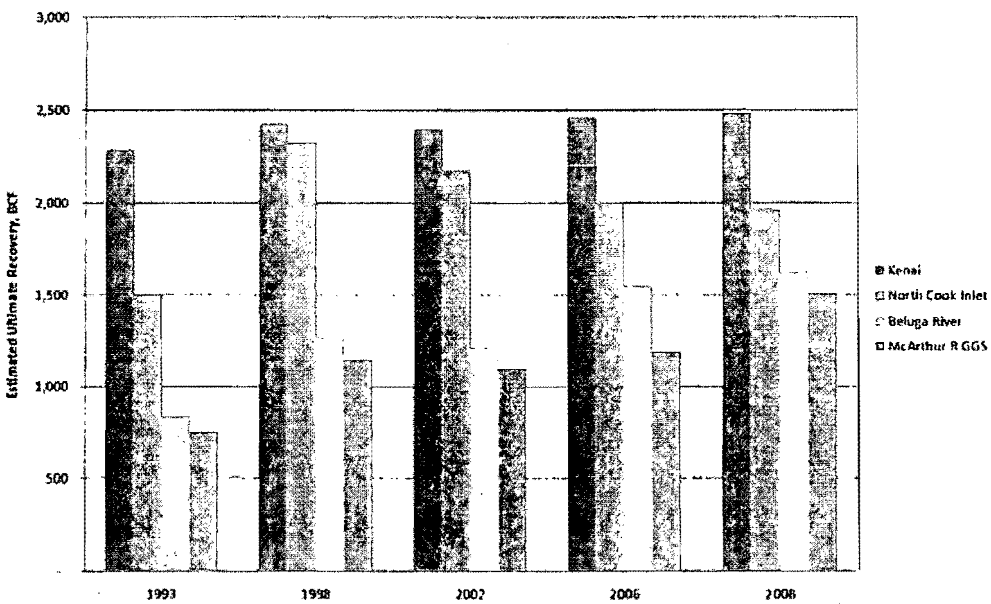

Figure 8. Reserves growth in Cook Inlet's largest gas fields, 1993-2008.

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,

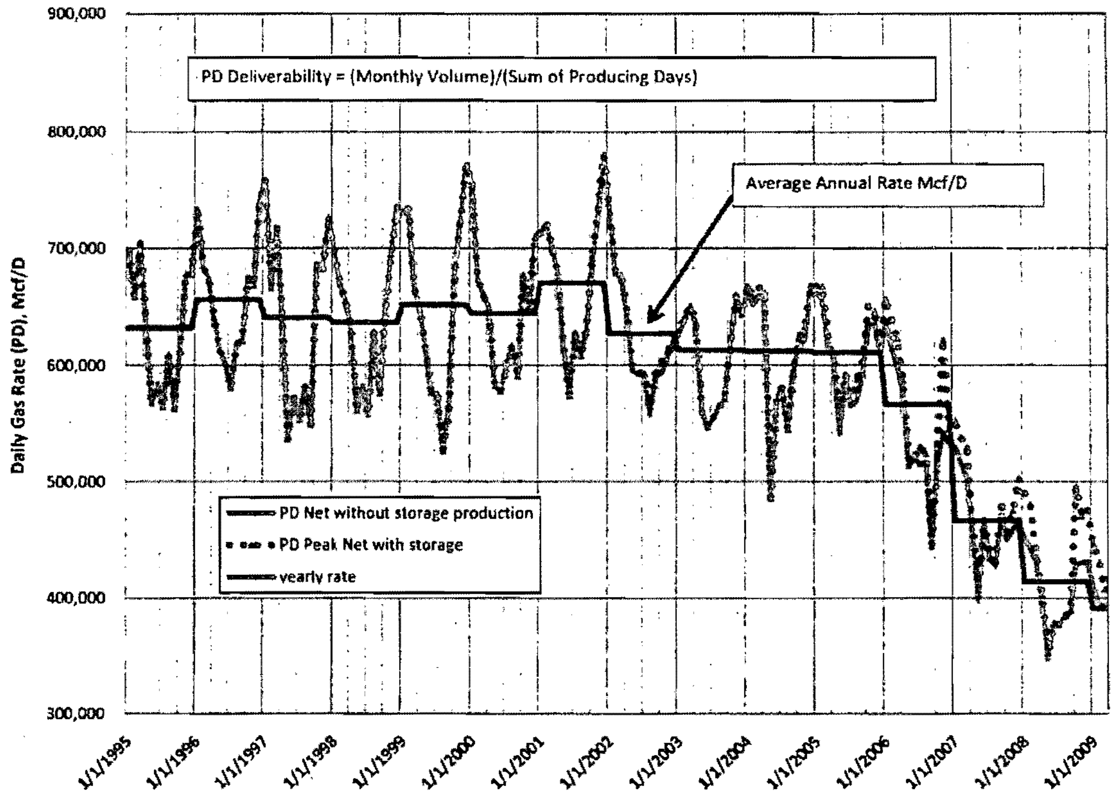

Figure 9. Producing day (PD) deliverability with and without storage, based on monthly volumes.

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-

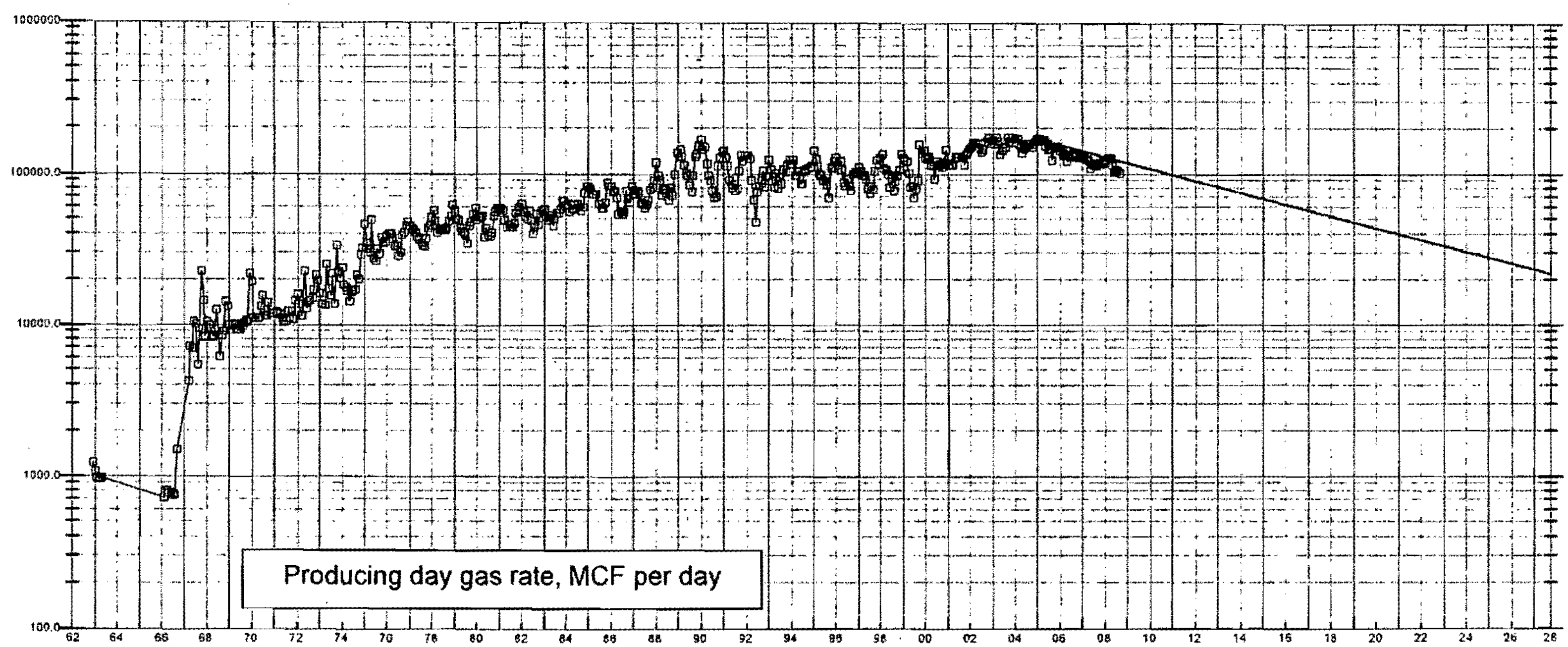

Figure 10. Example of peak deliverability forecast for a pool. Horizontal axis is time (1962-2028); vertical axis is producing day gas rate (MCF/day). Extrapolation is based on maximum PD rate only.

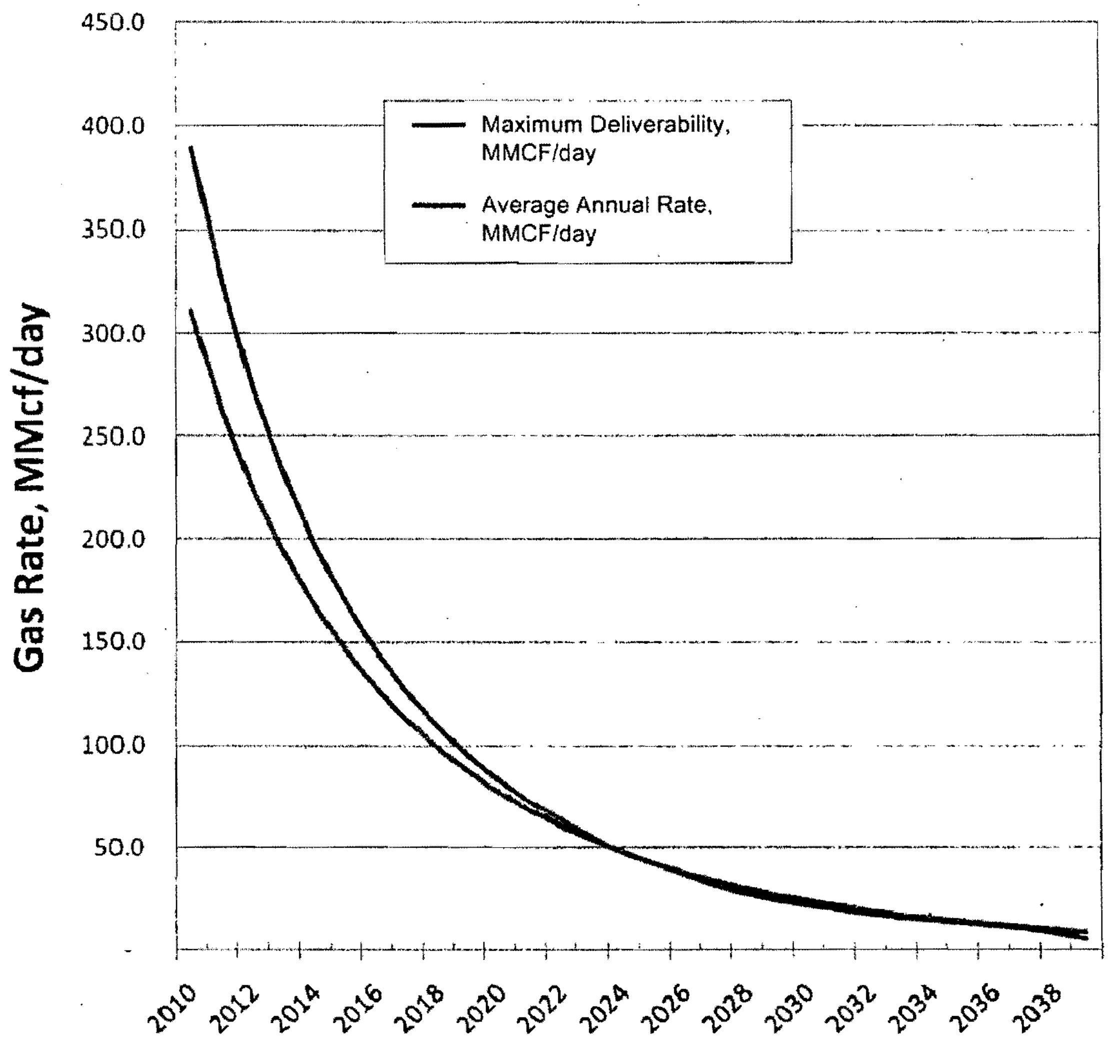

Figure 11. Peak maximum producing day deliverability compared to average annual rate from decline curve analysis.

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-

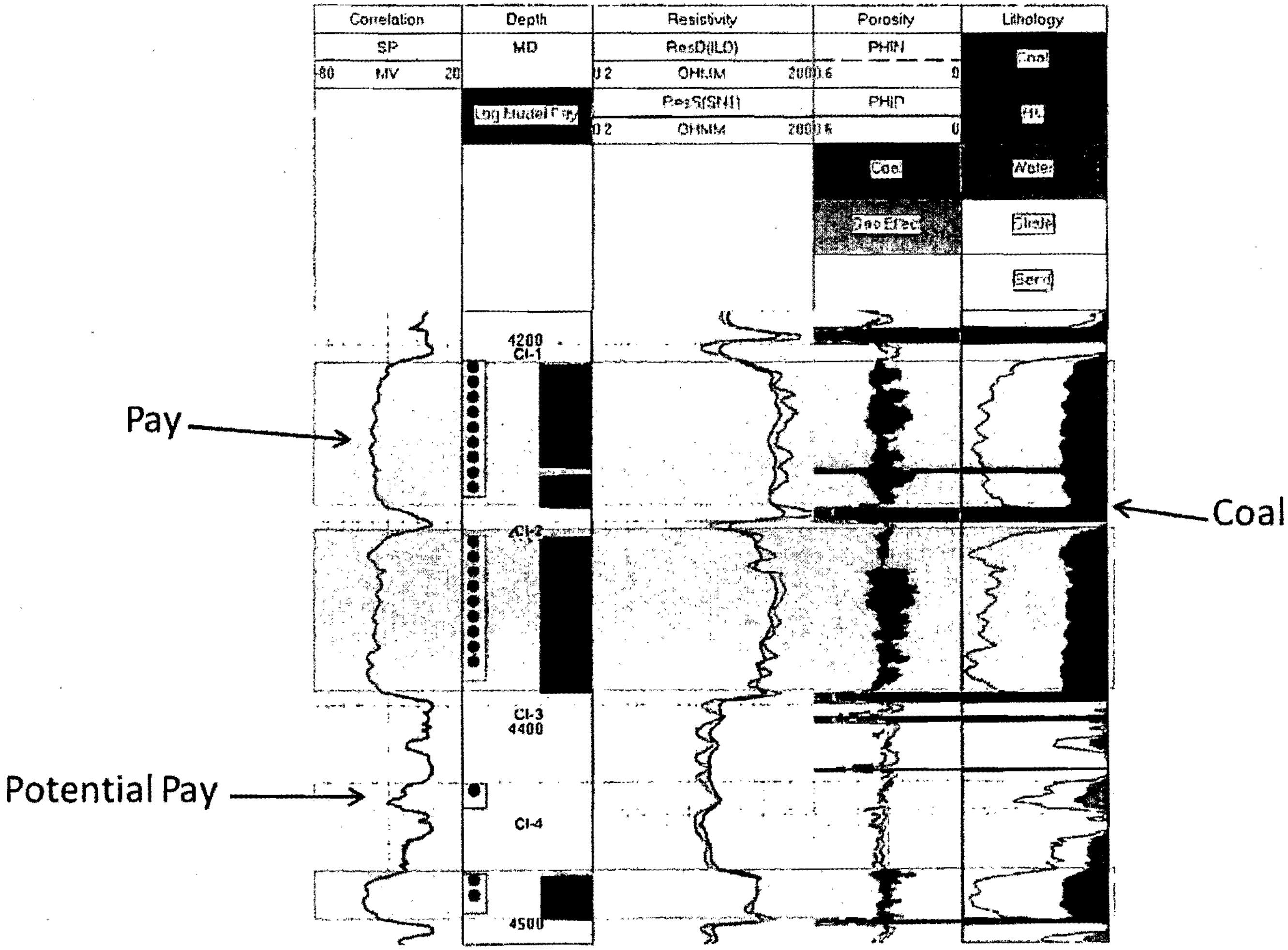

Figure 12. Well log example illustrating PAY (green) and Potential_Pay (yellow). Coal (black) is flagged as non-pay at right. Perforated intervals are shown in the depth track as black vertical dots. CI-1, CI-2, CI-3 and CI-4 are examples of zone picks in which Pay and Potential Pay were summed for each 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	0.743	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:

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

and

$$Bgi = 0.02829\ (Z)\ (T)\ /\ (P)$$

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-

	OGIP (BCF)			** RGIP = OGIP x RF (BCF)				Remaining Reserves (BCF)	
Field	PAY only	50%-risked Potential_Pay only	Total, PAY + 50%-risked Potential_PAY	PAY only	50%-risked Potential_Pay only	Total, PAY + 50%-risked Potential_PAY	Cumulative Production (BCF, projected through 12-31-09)	PAY only	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**	**7,886**	**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.

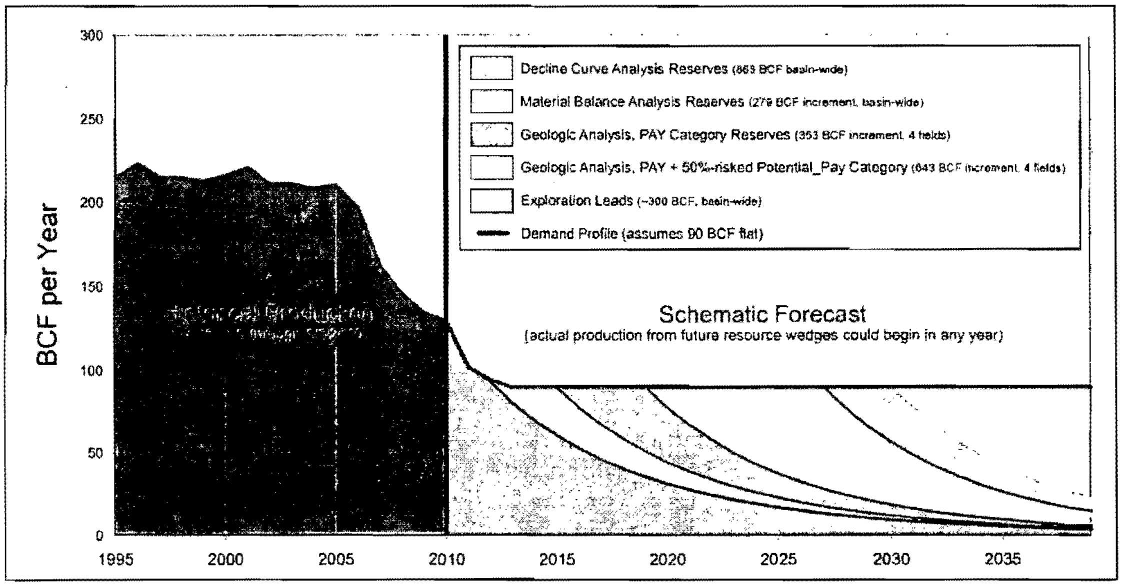

Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative 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

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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*

Regulatory Commission of Alaska
April 2, 2010

Appendix E

Cook Inlet Gas Study, Petrochemical Resources of Alaska (January 2010)

Cook Inlet Gas Study - An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers

prepared for

ENSTAR
Natural Gas Company

CHUGACH
POWERING ALASKA'S FUTURE

75 ML&P

March 2010

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PRA
Petrotechnical Resources Alaska

Due to the uncertainties of drilling and producing activities of operating and exploration companies and what Alaska state agencies do and do not do in influencing those activities, this study should be considered a best estimate based on current data. It was prepared using generally accepted engineering and geological predictive methods. As such, Petrotechnical Resources of Alaska can make no warranty as to actual future Cook Inlet gas drilling and production.

Executive Summary prepared by Cook Inlet Utilities

ENSTAR Natural Gas Company, Chugach Electric Association, and Anchorage Municipal Light and Power (Cook Inlet Utilities) commissioned Petrotechnical Resources of Alaska (PRA) to study Cook Inlet natural gas reserves and forecast annual natural gas production. We asked PRA to estimate the cost of the development necessary to meet the immediate needs of Cook Inlet utility customers from 2010 to 2020. The PRA study includes a review of estimated reserves and deliverability of Cook Inlet gas wells drilled between 2001 and 2009, scenarios for potential development activity, a review of a December 2009 Alaska Department of Natural Resources (DNR) reserves analysis, and an analysis of when it might be necessary to rely on non-Cook Inlet natural gas sources, such as liquefied natural gas (LNG) imports or other in-state resources.

In the future, Cook Inlet utility customers should expect to pay more for the gas used by Cook Inlet Utilities to generate heat and electricity. PRA examined results from all of the gas wells drilled in Cook Inlet between 2001 and 2009 and determined that producers spent approximately $1.0 to $1.2 billion in development costs to add reserves of approximately 519 billion cubic feet (Bcf) of natural gas. If the current trends for well success rates and costs continue, producers will need to spend two to three times that amount, an estimated $1.9 to $2.8 billion, to meet projected Cook Inlet utility demand from 2010 to 2020. Producers will invest the necessary capital in future drilling activity only if they have a reasonable expectation of a return that is competitive with other investment opportunities. In order to assure continued drilling activities, increased development costs must be reflected in the market price utilities pay for the gas and ultimately pass onto their customers. Cook Inlet Utilities will also require storage services to deliver gas to their customers on the coldest days and enable producers to optimize gas production rates. The estimated cost of a storage facility is $150 to $200 million[1]. These storage costs will also be borne by utility customers.

[1] Storage cost estimates based on ENSTAR's development assessment.

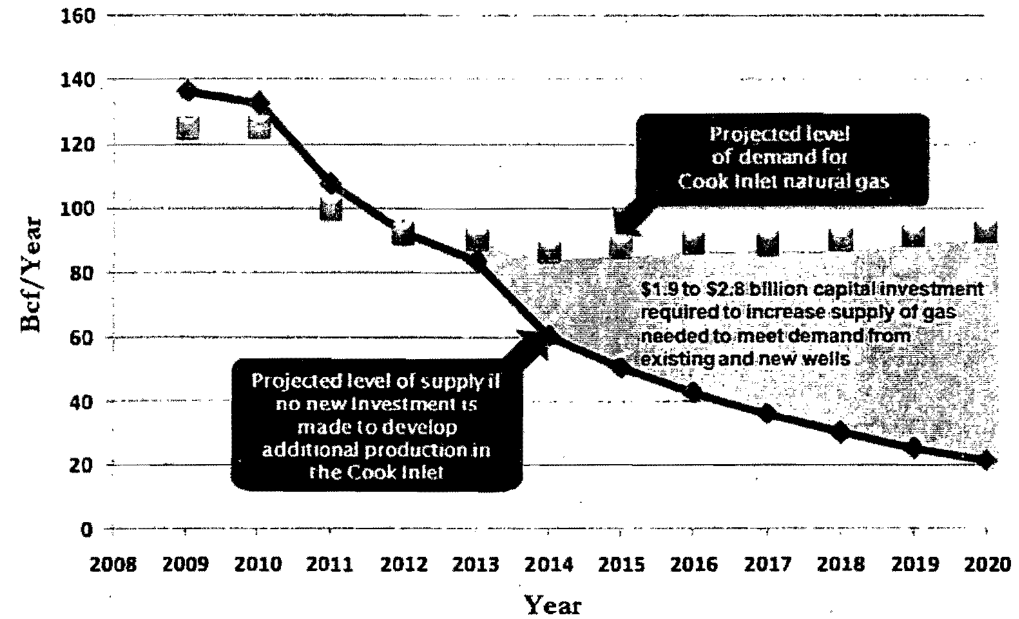

Figure 1 – Cook Inlet Supply & Demand

PRA used a decline curve analysis to review the same underlying data analyzed in the 2009 DNR reserves study and reached a similar conclusion regarding when the supply of gas from existing wells will not meet demand[2]. The PRA study took the next step, estimating the cost of bringing the undeveloped gas resources to market[3]. PRA determined that if significant efforts are undertaken to develop gas from the resources identified by DNR and if the current trends in drilling success rates continue, gas might be available through 2020. However, even if an aggressive development effort were undertaken immediately, that effort may fail to bring new gas to market quickly enough to provide needed gas when demand is projected to exceed supply as soon as 2013. Utilities need to plan for an alternative supply to meet their customers' needs. Having undeveloped gas resources in the ground will not enable Cook Inlet Utilities to provide heat and power to their customers. The gas resources will only be developed and brought to market at prices that incentivize the producers to justify their investment. Contracts with these higher prices will require RCA approval.

Cook Inlet Utilities need a viable option if additional Cook Inlet development does not materialize. To provide a stable gas supply, non-Cook Inlet sources such as gas delivered from the North Slope or LNG imports, are alternatives that must be pursued. The "easy" gas has been found in the challenging geology of Cook Inlet. The future costs of developing additional reserves will be substantial. As the cost of continued Cook Inlet gas production increases, alternative gas supply sources may become more economically attractive. Regulatory uncertainty has also discouraged Cook Inlet producers from

[2] PRA's study estimates remaining reserves of 729 Bcf from existing wells, compared with DNR's forecast of 863 Bcf of Proven Developed Producing reserves.
[3] The DNR study did not address the cost of bringing undeveloped resources to the market. (see DNR Study Figure 14 Description)

exploring for and developing Cook Inlet reserves[4]. In the current regulatory environment, two of the three major Cook Inlet producers have publicly stated that they intend to drill only to meet current contract obligations. Future development depends on a change in the regulatory climate to one where consistent standards are applied to approve negotiated utility gas supply agreements, even if those agreements reflect the increased costs of resource development.

The Cook Inlet market is in transition. Current gas fields are in decline and the loss of industrial customers has reduced the producers' incentives to do anything but meet existing contractual obligations. In order for utilities to be able to continue to supply current customers and to accommodate future growth, Cook Inlet Utilities and others must take action.

Immediate Actions Needed:

- New gas supply agreements between Cook Inlet Utilities and Producers must be signed to ensure continued development of Cook Inlet reserves.
- There must be predictable timelines and standards for regulatory approval of gas supply agreements. The Regulatory Commission of Alaska must be willing to approve gas supply contracts negotiated at arm's length, even if prices under those contracts increase.
- Cook Inlet Utilities must develop gas storage to assure deliverability on the coldest days and optimize gas production throughout the year.
- Cook Inlet Utilities should continue raising customer awareness, conservation efforts, and curtailment plans, to prepare for potential shortfalls.
- Additional well-capitalized exploration and development companies must commit to develop Cook Inlet and other Alaska gas reserves.
- To assure certainty of supply, Cook Inlet Utilities must determine how they will bring gas into Cook Inlet within the next five years to ensure the needs of their customers are met. Alternative gas supply sources include LNG imports and North Slope gas delivered by pipeline to south central Alaska.
- Additional regional industrial gas demand must be found to encourage the development of Cook Inlet reserves and spread the increased costs of production.
- Land management processes must be streamlined to encourage and accelerate reserve and infrastructure development.

[4] Recent favorable regulatory decisions on utility gas supply agreements may be a positive sign.

Technical Summary

ENSTAR Natural Gas Company, Chugach Electric Association, and Anchorage Municipal Light and Power (Cook Inlet Utilities) hired Petrotechnical Resources of Alaska (PRA) to perform a study of Cook Inlet reserves and deliverability. The components of the study included:

- Review the deliverability of Cook Inlet gas wells drilled between 2001 and 2009
- Forecast potential deliverability of future drilled gas wells
- Review Alaska Department of Natural Resources (DNR) reserves analysis
- Analyze timing of demand for a delivery of potential non-Cook Inlet gas sources, such as liquefied natural gas (LNG) imports or other in-state resources

High level findings of the study are:

Cook Inlet Well Drilling Results – 2001 to 2009

- Drivers for Cook Inlet well drilling between 2001 and 2009 included:
    - Newly executed gas contracts
    - Reserves development associated with negotiated gas contracts rejected by the RCA
    - LNG Exports and License Extensions
    - Increasing Regional Natural Gas Prices
    - Industrial Fertilizer Operations
- Results for Cook Inlet well drilling between 2001 and 2009:
    - 128 gas wells were drilled between 2001 and 2009, of which, 105 were completed with an average rate of 3.6 MMSCF/D for the first 12 months of production
        - 97 wells were permitted and drilled as Gas Development wells; 88 of these were completed as gas wells, for a 90.7% success rate
        - 31 wells were permitted and drilled as Gas Exploration wells; 18 were completed as gas wells, for a 58.1% success rate
        - An estimated 519 BCF of gas was developed by these wells
        - Ninilchik, Kenai and Deep Creek Units had the most drilling activity during this period; Ninilchik was very successful; Kenai wells were average and Deep Creek wells were marginal
        - The estimated costs for drilling and facilities of these 128 gas wells are between $1.0 and $1.2 billion

Review of DNR Analysis of Available Reserves

- The DNR completed a Cook Inlet Gas Reserves Study in December 2009
- In the DNR study, reserves and resources are systematically estimated, but as stated in the report, the timing of the development of undeveloped reserves is only an estimate as shown in DNR's Figure 14, a "Hypothetical production forecast for Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analysis discussed in text."

- In the DNR study, the only firm deliverabilities are for reserves estimated by decline curve analysis and material balance. The material balance resources would be realized through the spending of additional capital for development (Beaver Creek) or for compression (Ninilchik). Timing is determined by economic drivers.
- The DNR study forecasted 863 BCF of Proven Developed Producing reserves compared to the decline curve analysis performed by PRA forecasting 729 BCF[5] of reserves.
    - A major difference in decline curve analysis performed by PRA was apparent at Beluga River Field where the DNR study estimated 377 BCF remaining reserves and PRA estimated 207 BCF.
    - The predicted production from decline curve analysis was similar in both studies; both DNR and PRA showed decline curve analysis predictions from existing wells falling below projected demand in the 2012-2013 timeframe.
- The DNR study forecasted Additional Probable Reserves of 279 BCF based on material balance calculations, while PRA did not perform material balance calculations.
- In both studies, the four (4) Fields identified as having greatest remaining potential and selected for detailed geological analysis were: Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands. Reported were:
    - Potential gas resources (from geologic analysis of 4 fields above) estimated to be 353 BCF
    - Possible gas resources of 643 BCF (50% Risked case) estimated from lower confidence pay intervals

<u>Potential of Future Gas Wells in Cook Inlet:</u>

- Drivers required for future Cook Inlet reserve development include:
    - Execution and RCA approval of gas contracts
    - Predictable timeline and standard for regulatory approval of negotiated gas pricing structures
    - Additional regional industrial gas demand, including LNG exports.
    - Additional well-capitalized exploration and development companies committed to develop Alaskan resources
    - Government action to facilitate and accelerate development of necessary infrastructure and permitting
- Challenges facing future Cook Inlet development include:
    - Possible discontinuation of LNG exports from the region
    - Reduced industrial demand (e.g., regional fertilizer manufacturing)
    - Success rates in exploration and development
    - Higher relative regional costs for exploration, development, and production
    - High level of activity in reserve development needed to meet demand

[5] 762 BCF in Report included 33.7 BCF estimated for 4 remaining 2009 Wells

    - Probable decline in production rates from future wells in existing fields
- Minimum requirements to meet demand in Cook Inlet gas market until 2020:
    - A new source of gas, such as imported LNG or other in-state reserves, could be required as early as 2013, if ongoing drilling or drilling success does not continue at the 2007-2009 pace.
    - Gas storage will maximize Cook Inlet gas deliverability potential and more closely match local demand curves and production rates.
    - To meet projected demand for the next decade, 185 new wells will be needed, which is a 45% increase over the number of wells drilled in the 2001-2009 period
    - Development costs for this time period are estimated at $1.85 to $2.8 billion, an increase in total capital investment of 54-180%
    - To incent this substantive increase in investment levels, or to bring a new source of gas to Cook Inlet, utility customers should expect to pay significantly higher gas prices

Figure 2 shows recent history and future wells estimated to meet CI gas demands through 2020. The well count assumes average well performance of 2007-2009 wells, with initial rates and developed reserves degraded by 4.3% per year.

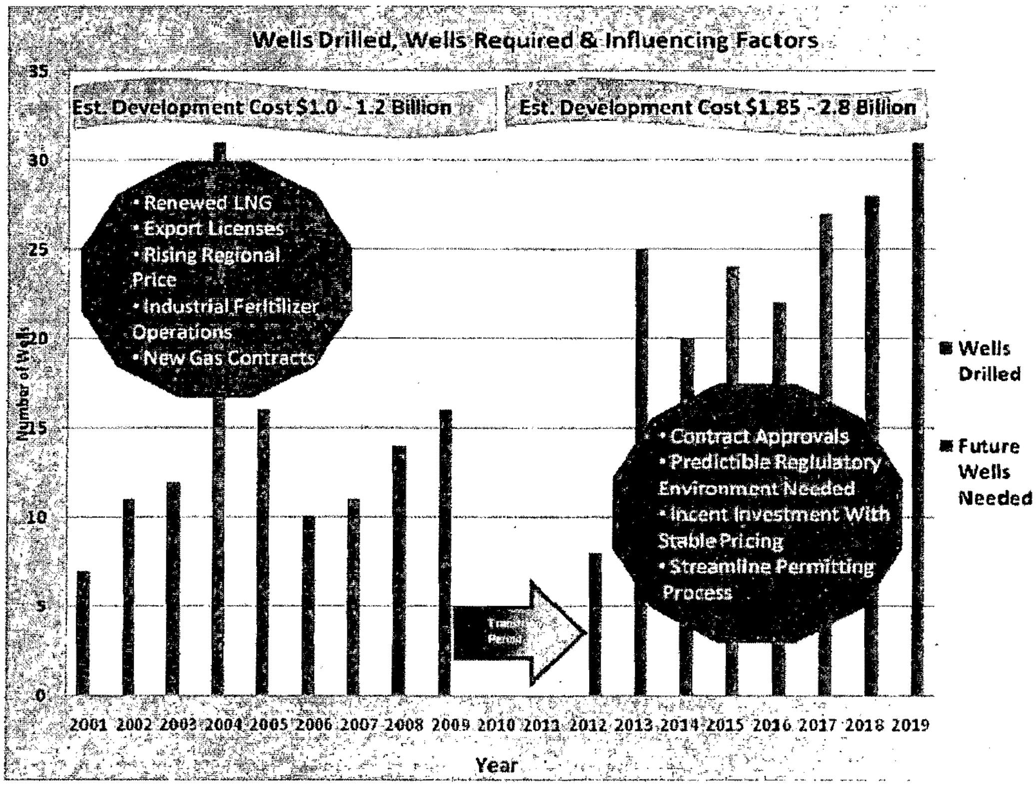

Figure 2:Wells Drilled, Future Wells Required & Influencing Factors

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I. Introduction

Over the last 10 years, the deliverability profile of gas supply in Cook Inlet has changed. Historically Cook Inlet utilities were not impacted by deliverability shortages. However, in recent years, deliverability shortages have occurred on the coldest winter days. Cook Inlet gas production has declined and if the trend continues, average annual gas production will be less than annual average gas demand before 2020. To meet demand, new sources of gas must be identified. New gas must either come from undeveloped or undiscovered Cook Inlet reserves or from non-Cook Inlet sources, such as the importation of Liquefied Natural Gas (LNG) or other in-state resources.

Development of new or undiscovered reserves in Cook Inlet is hindered by significant challenges that are all likely to increase the prices consumers will pay for gas:

- The most likely undiscovered reserves will be in the offshore, and it takes a large financial commitment to bring in an offshore jack-up rig to explore for gas and expensive infrastructure to develop offshore discoveries. Mobilization costs for an offshore jack-up drilling rig have been estimated to be $156 million for a 3 year contract (Petroleum News 4/20/08)
- The Cook Inlet region is a small market with few customers and few suppliers. Offshore exploration and development investments require high risk, large capital commitments dependent on contracts.
- In recent years, the RCA has rejected several new contracts based on their pricing structures. These rulings create additional risk for producers who are required to invest capital looking for new gas, thus further increasing the cost of production.
- Existing onshore fields have been developed and most of the economical gas has been developed. Other potential onshore resources are on land where development is not permitted.
- Future offshore developments may be restricted, or costs significantly increased if Beluga whales are classified as endangered under federal law[6].

Alaska Department of Natural Resources Division of Oil and Gas (DNR) are land owners that approve Plans of Exploration on Exploration Units and Plans of Development on producing properties (leases or units), but they have little immediate control over timing and actual finding of new reserves. Exploration incentives, capital tax credits, and favorable tax treatment for Cook Inlet Gas have all helped to spur exploration, but the economic drivers are still very challenging for development of new gas reserves.

DNR presented a supply demand curve (Figure 3) to the House Energy Committee in March, 2009 that showed that gas demands in Cook Inlet could be met until 2018 with existing and new developments. This was anecdotally based on the Netherland, Sewell & Assoc. reserves study prepared for ConocoPhillips Alaska (CPAI) and Marathon for the LNG export license extension.

[6] Drilling may be precluded in some areas of Cook Inlet and the additional permitting and environmental costs may be substantial.

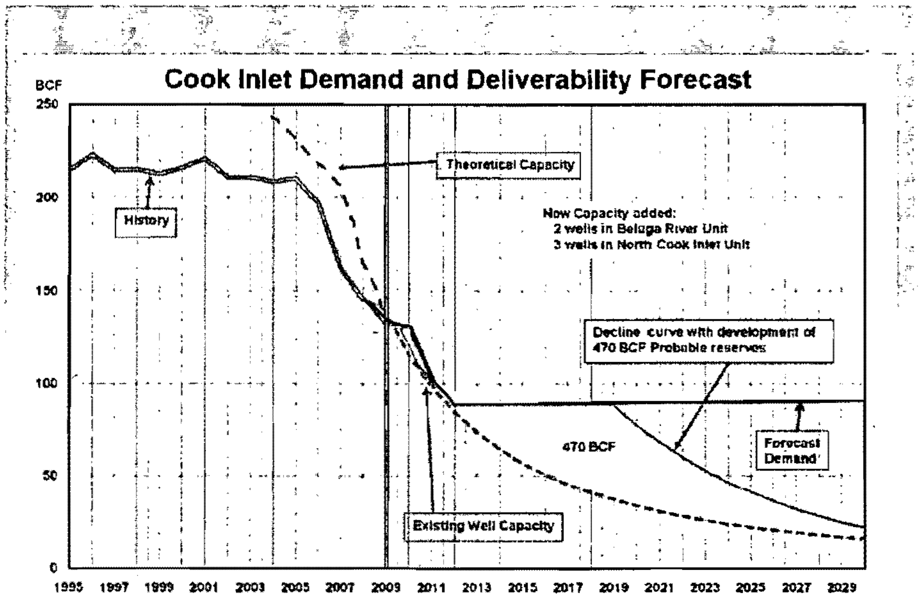


Figure 3: Supply Demand Curve presented by the DNR to the House Energy Committee March 2009

A new study was released by the DNR in December, 2009 that reviews gas reserves in the Cook Inlet basin. The preliminary findings of the new study include the prediction that the average supply from existing wells, assumed from decline curve analysis, will not meet the average annual South Central Alaska demand as early as 2013 as shown in Figure 4.

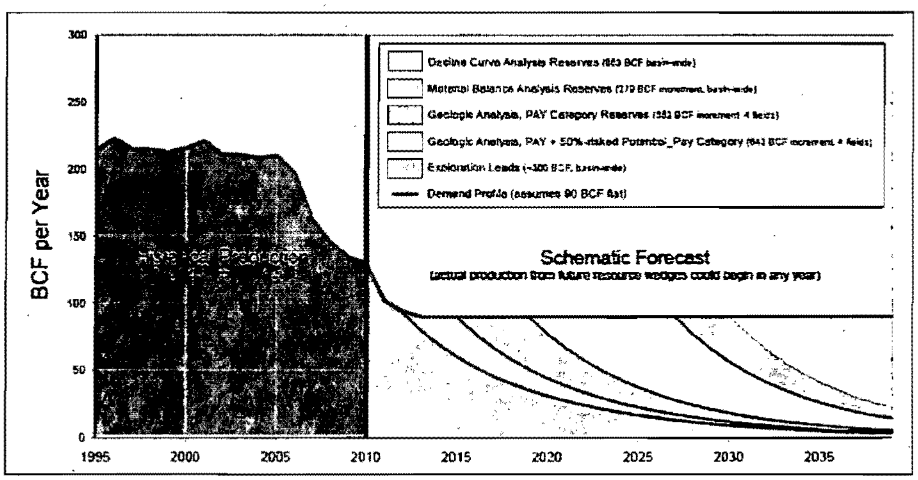


Figure 4: Supply Demand Curve from DNR December 2009 CI Gas Study

The DNR study addressed the question of what gas reserves were physically present, but did not evaluate the economic factors that would result in production of those reserves.

PRA was engaged by the Cook Inlet Utilities to compare the existing supply with current and future demand for gas in the Cook Inlet region and to identify the potential and economic drivers for future reserves development. This study concludes that meeting future utility demand will require a significant level of investment and appropriate price incentives.

Table 1 shows the comparison between the DNR and PRA decline curve analysis estimate. The biggest difference is in the Beluga River Field, where DNR estimates 171 BCF or 45% more reserves than PRA. There are no details in the DNR study showing how decline curve analysis was calculated so differences could not be explained.

Field	DNR Decline Forecast Production, BCF	PRA, BCF	DNR minus PRA, BCF	DNR % Greater than PRA
Kenai	90	74	16	18%
North Cook Inlet	145	129	17	11%
Beluga River	377	207	171	**45%**
McArthur River (Grayling gas sands)	113	163	-50	**-44%**
Ninilchik	62	38	24	39%
Other Fields	76	118	-42	-56%
Total	**863**	**729**	**135**	16%

Table 1: Comparison of DNR Decline Curve Analysis reserves to PRA prediction

Figure 5 shows the comparison of the annualized production potential of DNR's forecast and PRA's. There does not appear to be a large difference, although PRA predicts higher deliverability in 2010-2012 and lower in years after 2013. It is important to distinguish between annual production potential and daily deliverability. Utilities need deliverability to meet their customers' needs. The planned storage facility will improve utility's ability to manage their loads when it is completed. As of the date of this report, however, there are no firm plans to construct a storage facility.

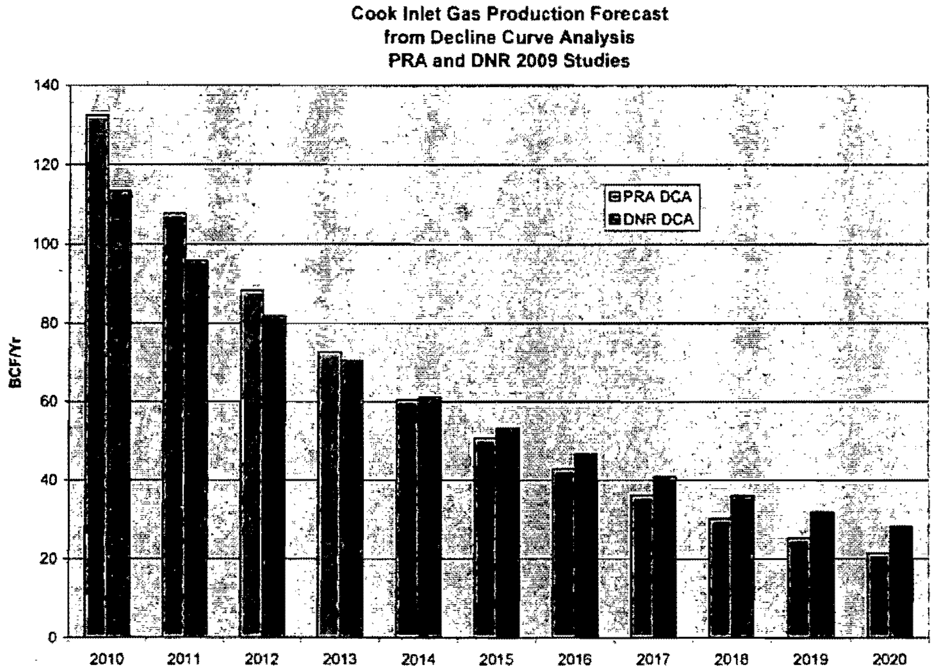


Figure 5: Comparison of DNR decline curve annual production forecast to PRA

II. History of Cook Inlet Gas Development

Twenty nine gas fields have been discovered in Upper Cook Inlet and a total of 7 TCF of non-associated gas has been produced from these fields through December of 2008. Existing Cook Inlet developments are shown in Figure 6. The gas is biogenic methane generated from extensive coal beds in the Tertiary non-marine stratigraphic section. Solution gas production associated with Cook Inlet oil fields is not included in these totals. The four largest gas fields, Beluga River, Kenai, McArthur River and North Cook Inlet have yielded 6.35 TCF or 90% of the produced gas. Appendix A, Table 1 lists the 29 fields in order of discovery and includes other details about the fields. This information is publicly available through the AOGCC and the ADNR Division of Oil and Gas. The following summary of information was largely drawn from the South Central Alaska Natural Gas Study by Thomas, et al. (2004) and the Cook Inlet Oil and Gas power point slides prepared by Director of the Division of Oil and Gas, Kevin Banks (2009).

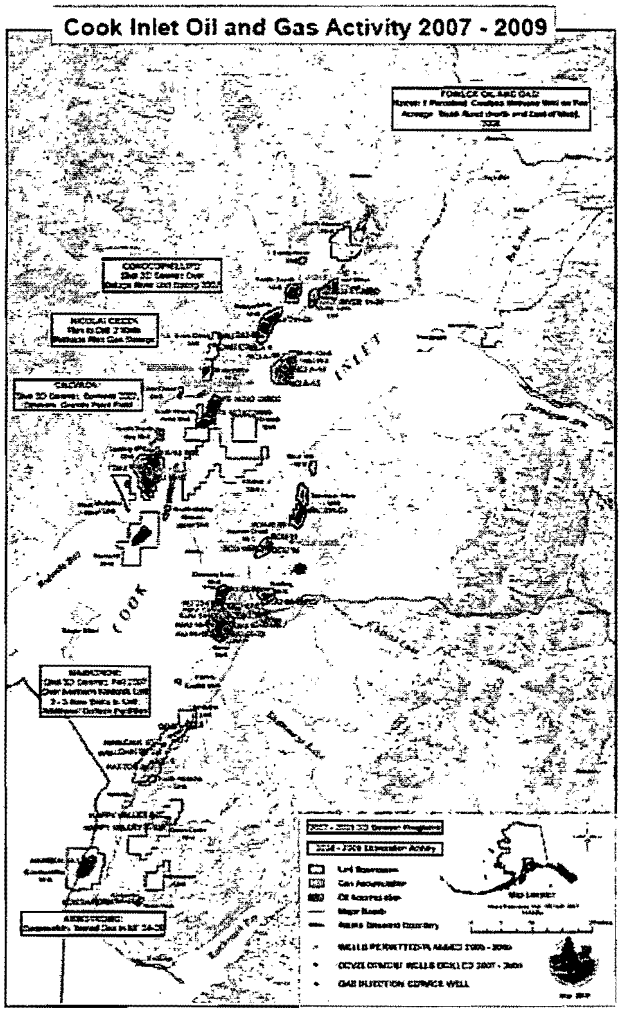


Figure 6: Oil and Gas Fields in Cook Inlet (DNR website)

Exploration History

Aggressive exploration for oil in Upper Cook Inlet began in 1955 and continued to 1968, at which time the discovery of oil at Prudhoe Bay shifted the focus of oil exploration to the North Slope, where it is still concentrated today. Twenty of the twenty-nine gas fields in Upper Cook Inlet were discovered during this initial 13 year period. The exploration, however, was focused on oil, not gas, and all the gas fields discovered were incidental to the oil drilling. Since 1968, the exploration effort in Cook Inlet has been modest, resulting in the basin being under-explored. Most of this exploration was directed toward oil, and only in the late 1990's did gas-first exploration begin in the Cook Inlet. During this aggressive phase of oil exploration, 94% of the current gas reserves were discovered. Because the focus was on oil, some wells drilled early in the exploration history were plugged and abandoned and later re-examined and found to

contain 'by-passed' or 'missed' gas or gas that was purposely left un-tested because gas was not an economic objective.

There is a trimodal distribution of gas field sizes in the Cook Inlet. The estimated ultimate recoverable reserves for the largest four fields range from 1.1 to 2.3 TCF, six fields range from 100 to 250 BCF and the remaining fields range from 3 to 90 BCF. This gap in field sizes suggests there should be more mid-sized fields yet to be discovered. Exploring, discovering, producing and developing new fields is a multi –year process. Even if an aggressive exploration effort were undertaken immediately, it would not bring new gas to market quickly enough to provide the gas that will be needed when demand exceeds supply, even in the most optimistic forecasts.

As discussed in the 2003 Cook Inlet Gas Study, recognized gas reserve volumes increase as a result of continued evaluation and development of the fields. In early 1980 the proved reserves in Cook Inlet were considered to be 3,544 BCF. In January of 1998 the proved reserves were 6,730 BCF, an increase of over 3 TCF. Such increases are accomplished through enhanced recovery techniques, new seismic acquisition and reprocessing, and infill and extension drilling. Additional reserve growth will probably continue to occur in the Cook Inlet fields as development continues (although continued development depends on economic factors), but these cannot be quantified and considered proven for supply/demand assessment purposes.

Geology

Cook Inlet is a forearc basin formed by subduction of the Pacific tectonic plate beneath the North American plate. The basin is filled with Mesozoic dominantly marine and Tertiary non-marine rocks. The Upper Cook Inlet basin sedimentary rocks are separated from the igneous arc rocks to the west by the Bruin Bay fault, the sediments in the Susitna Basin to the north by the Castle Mountain fault, the metamorphic rocks of the Chugach Terrane to the east by the Border Ranges fault and the Lower Cook Inlet sediments to the south by the Augustine-Seldovia arch.

Stratigraphy. Figure 7 shows the Mesozoic and Cenozoic stratigraphy of Cook Inlet. The Mesozoic section was penetrated by some of the deeper wells in Upper Cook Inlet and was a primary objective during the early basin exploration in the 1950's and 1960's. The section contains oil prone source rocks but poor reservoirs. No oil or gas has been produced from the Mesozoic section.

The Upper Cook Inlet Tertiary locally exceeds 25,000' in thickness and consists of five non-marine formations, the West Foreland, Hemlock, Tyonek, Beluga and Sterling. The type sections for these formations are defined in 5 different wells in the basin. The section is thickest in the north central part of the basin and thins to both the east and west sides. The formations overlap in age and do not form a simple layer-cake stratigraphy.

The Eocene and Oligocene aged West Foreland is the basal formation and has generally poor reservoir quality but does locally contain some oil. The Oligocene aged Hemlock Conglomerate is the main oil reservoir and ranges in thickness from 570' in the Swanson River Field to 750' at Middle Ground Shoal. It consists dominantly of sandstone and conglomerate with good reservoir quality. The Oligocene and Miocene aged Tyonek is 7,650' thick in the type section well and consists of thick sandstone beds and thick (30-40' up to 80') bituminous and sub-bituminous coal beds separated by siltstone and claystone interbeds. Because of their thickness, the coals tend to be laterally continuous over tens of miles. The Tyonek sandstones are both oil and gas bearing with oil in the lower and gas in the upper part of the formation. The Miocene aged Beluga formation is 4150' thick in the type section well and is removed by pre-Sterling erosion on the east and west sides of the basin. It consists predominantly of siltstones interbedded with channelized sandstones and lignitic to sub-lignitic thin (5'thick) coal beds and tuffs. The Upper Beluga channel sands are gas reservoirs. The Miocene and Pliocene aged Sterling Formation is 4,490' thick in the type section well and consists of massive sandstones and conglomeratic sandstones interbedded with siltstone and thin coals. The sandstones are stacked fluvial channels that are excellent gas reservoirs.

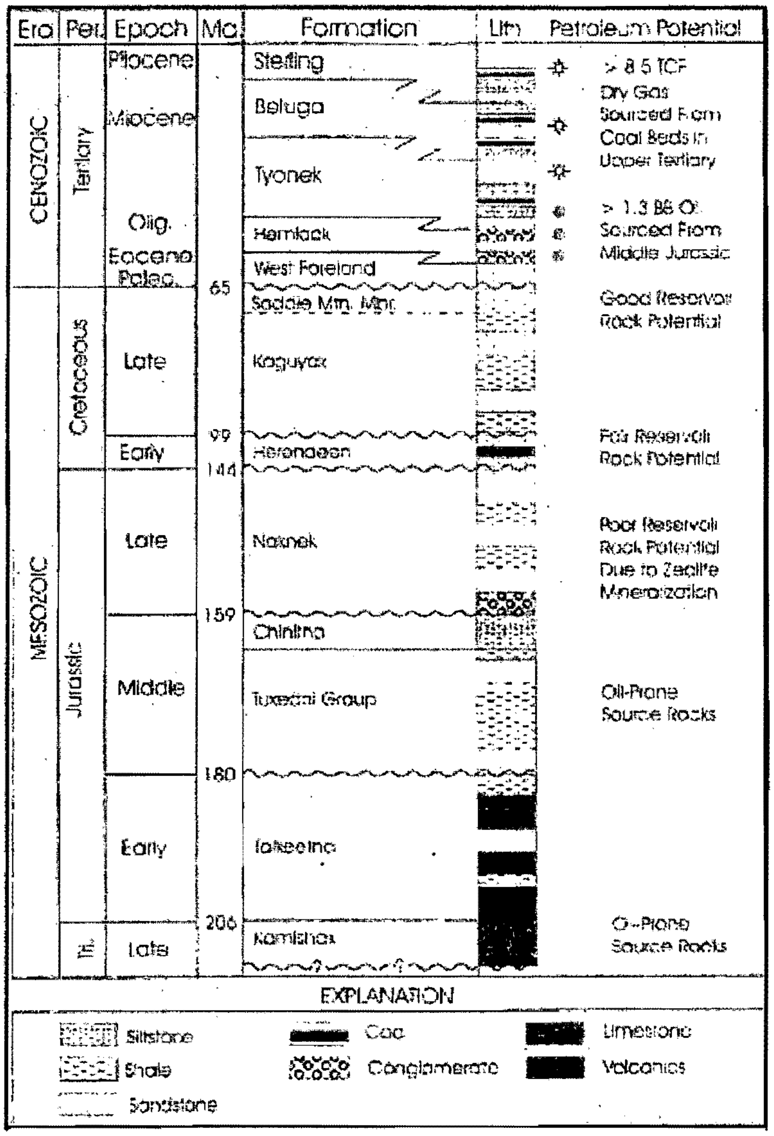


Figure 7: Cook Inlet Stratigraphic Column. FromThomas, et.al., 2004

<u>Hydrocarbon Source Rocks</u>. There are two independent hydrocarbon systems in Upper Cook Inlet. The oil and associated gas produced from the Hemlock and lower Tyonek reservoirs is thermogenic in origin and is sourced from the Middle Jurassic Chinitna member of the Tuxedni Group. All the oil fields are undersaturated with gas so all associated gas is dissolved in the oil and comes out of solution when produced. This associated gas produced with the oil is not included in the proven gas reserves. The gas produced from the upper Tyonek, Beluga and Sterling formations isn't associated with the oil and is biogenically derived from the coals and carbonaceous siltstones.

Reservoirs. Reservoir data are presented in Appendix A, Tables 2 and 3 for the 29 gas fields. Reservoir sandstones are predominantly fluvial, consisting of channels and channel belt deposits of both meandering and braided types of the axial fluvial system and alluvial fan deposits nearer the basin margins. Deposit types include point bar, meandering and braided channel fill, crevasse splay, channel lag, levee, and flood plain deposits as shown in Figure 8. The sands are encased in the overbank flood-plain interbedded siltstones and mudstones which form good seals for trapping hydrocarbons.

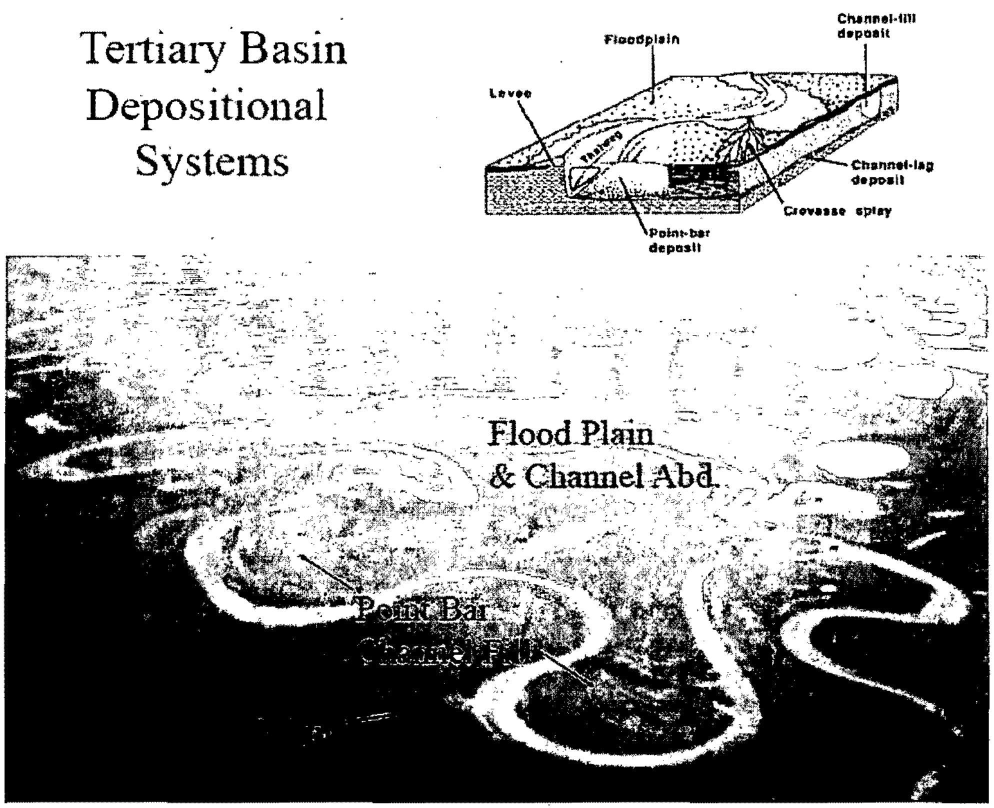


Figure 8: Tertiary Basin Depositional Systems (DNR)

Individual sand packages tend to have limited lateral extent but often overlap or are stacked and may or may not have connectivity over the areal extent of the gas fields or between the spacing of the wells. Sterling and to a lesser extent Tyonek reservoir sands tend to be thicker and more well connected. Beluga reservoir sands are thinner, less well connected and more frequently isolated. The lateral discontinuity of sands can lead to erroneous correlations between wells. New, untested reserves can be found within established fields because of the discontinuous and laterally heterogeneous nature of the reservoir sands. Figure 9 from a DNR presentation shows a stratigraphic cross section over the Beluga River Gas field. The upper portion of the section represents the Sterling Formation and the lower portion represents the Beluga Formation. The section shows the

lateral thickness changes and discontinuous nature of the sands and the difficulty in correlating between wells. This is representative of these formations throughout the Inlet.

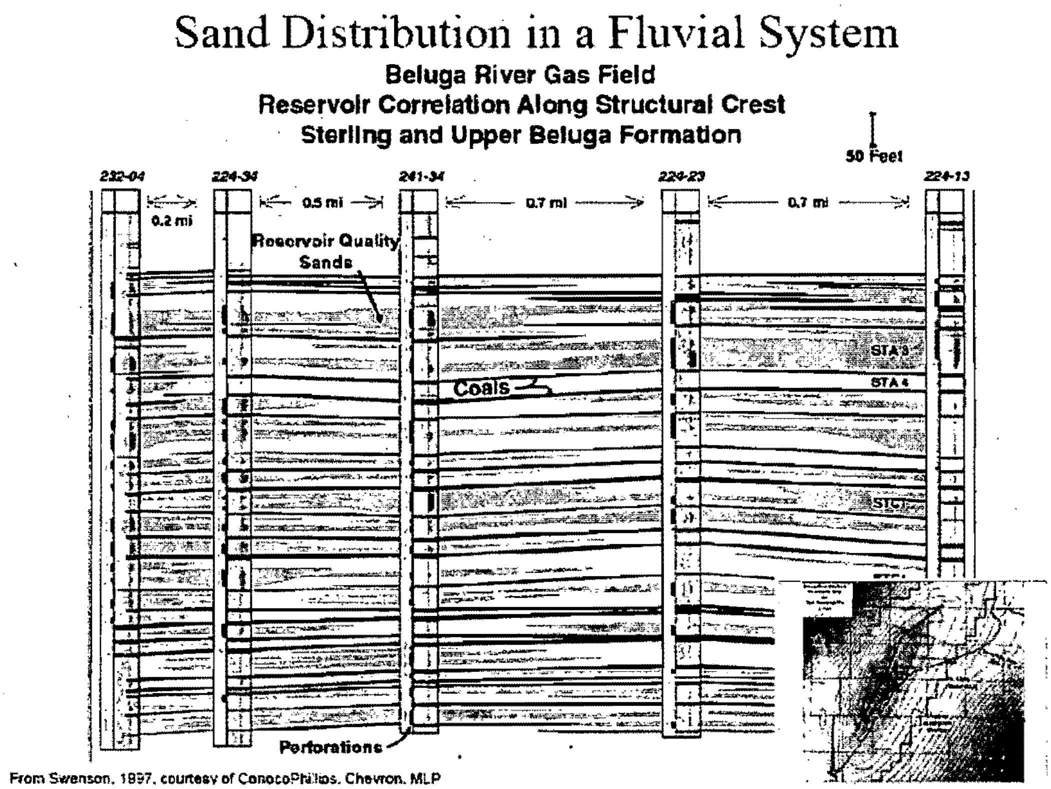


Figure 9: Beluga River Stratigraphic Section

Porosity, permeability and net pay thicknesses from the AOGCC annual report are shown in Appendix A, Tables 2 and 3. Porosity generally decreases with the depth of the reservoirs. Identification of pay on wire line logs can be difficult. Tight gas sands have been productive with effective porosities greater than 10% and less than 1md permeability (Figure 10). Also, low resistivity sands, 10 ohms, can be productive. Detailed petrophysical analysis can identify these possible types of pay.

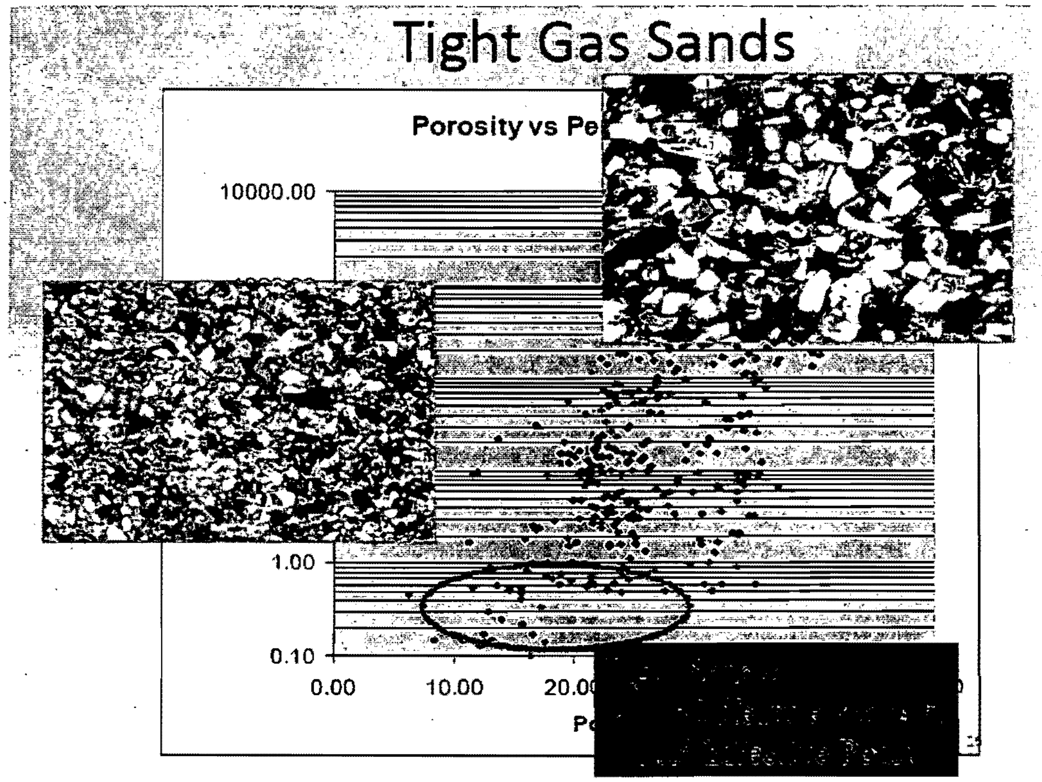


Figure 10: Tight Gas Sands in Cook Inlet (DNR 031709)

Structure. Structures in Cook Inlet are asymmetrical anticlines oriented in northeast-southwest direction due to the northwest-southeast compression of the basin. The folds range from broad and gentle to very tight with some having vertical to overturned limbs. The tighter folds are typically mapped with a high angle reverse fault on their steeper flank. These high angle reverse faults are typically interpreted on seismic data which often cannot image the steep dips that are present and such faults may actually be zones of poor data caused by steep dip. Because the gas reservoirs are in the upper part of the stratigraphic section they are not as affected by steep dips as the oil reservoirs in the deeper cores of the folds. Some of the structures are cross-cut by systems of normal or reverse faults which can be seals to hydrocarbon migration resulting in isolated pay zones. This compartmentalization of the structures by secondary fault systems can lead to the discovery of new untested reserves in old established fields. All of the gas fields were originally mapped using 2D seismic data. Some fields have been re-mapped using 3D seismic techniques which can better image the structural complexity and possible cross-cutting fault systems and potentially identify untested fault blocks.

Traps. All the gas fields in the basin are structural traps and none are filled to spill point. Most of the traps are four-way dip closures that range from <100' to >1000' of structural

closure. Some fields such as Swanson River, Granite Point, Middle Ground Shoal and McArthur River have systems of small normal and reverse faults that cross cut the structures and act as seals to migration of gas and form isolated fault traps within the larger structures. Most four way dip structures in the basin have some gas trapped in them no matter how subtle the dip.

<u>Challenges facing Cook Inlet gas business</u>

- Formation damage due to sensitive clay cements
- Drilling and seismic costs are very high
- Fines migration and unconsolidated sands cause production problems in some reservoirs
- Gas is difficult to identify on wire line logs (difficult petrophysical analysis) R_{wa} & S_w varies throughout the stratigraphic section.
- Low resistivity pay can be overlooked or by-passed. Careful petrophysical analysis and re-examination of mud logs and wire line logs can identify such missed pay.
- Tight gas sands can be overlooked on the initial drilling.
- Sands are discontinuous and disconnected (especially Beluga & some Tyonek). Pay can be mis-characterized without additional infill drilling, especially in Beluga reservoirs.
- Correlations are difficult.
- Structures are difficult to image seismically due to steep dips.
- Coal beds in the Sterling, Beluga and upper Tyonek form prominent reflectors on seismic data, absorbing seismic energy, and causing poor imaging of the deeper formations with the only prominent deep reflector often being the unconformity at the Tertiary/Mesozoic boundary.
- 3D seismic improves interpretation of structural complexity significantly over 2-D data.
- Dominance of coals and poorly consolidated sands cause drilling problems.
- Seasonal drilling and seismic acquisition limitations
- Permitting and land access issues are limiting
- Dipmeter data in older wells is suspect due to steep dips – the correlation angle was often insufficient to see true dip.

Specific Field Descriptions, including maps and production forecasts are shown in Appendix B.

III. Analysis of the "gap" between supply and demand

a. Review of Drilling during 2001 to 2009

According to AOGCC records, a total of 128 wells were drilled in the Cook Inlet basin in the period 2001 to 2009. The results, shown in the table below, are that 105 wells were completed.

The wells with the highest 12 month average production were drilled at Beluga River, Cannery Loop, Ninilchik and Trading Bay Unit.

Well-level reserve analysis was made for the wells and the reserves developed per well are shown in Table 2.

As observed, the average reserves developed per well in this period is 4.4 BCF/well.

Summary of Cook Inlet Gas Wells Drilled 2001-2009

Field	Number of Gas Wells Drilled	Number Currently Producing	Average 12 Month Rate MMSCF/D	Cum Production BCF	Estimate of Reserves BCF	Reserves per Producing Well, BCF	Reserves per all Wells, BCF
Beaver Creek	9	7	2.5	15.6	29.1	4.2	3.2
Beluga River	3	3	3.6	4.4	32.3	10.8	10.8
Cannery Loop	7	6	6.9	45.3	70.0	11.7	10.0
Happy Valley	12	12	1.0	13.6	18.4	1.5	1.5
Kenai	28	25	3.1	59.6	108.5	4.3	3.9
No. Cook Inlet	4	4	4.2	14.5	36.2	9.1	9.1
Ninilchik	19	18	5.0	84.1	119.9	6.7	6.3
Sterling Unit	2	2	1.6	1.0	2.7	1.3	1.3
Swanson River Unit	3	2	3.6	3.6	4.2	2.1	1.4
Trading Bay Unit	6	6	8.0	45.6	98.1	16.4	16.4
Other*	35	20	2.6	25.8	43.3	2.2	1.2
Total	**128**	**105**	**3.6**	**313.0**	**562.7**	**5.4**	**4.4**

Table 2: Drilling of Gas Wells in Cook Inlet 2001 to 2009

Table 3 shows the wells that were drilled in the period 2007 to mid-2009. An average of 13.6 wells per year were drilled and completed in the period 2007-09 group of wells and the average well forecast of production will be used as a proxy for the various supply forecasts.

Summary of Cook Inlet Gas Wells Completed 2007-2009

Field	Number of Gas Wells Completed	Number Currently Producing	Average 12 Month Rate MMSCF/D	Cum Production BCF	Estimate of Reserves BCF	Reserves per Producing Well, BCF	Reserves per all Wells, BCF
Beaver Creek	3	3	2.3	3.4	12.0	4.0	4.0
Beluga River	3	3	3.6	4.4	32.3	10.8	10.8
Cannery Loop	0	0	0.0	0.0	0.0		
Happy Valley	2	2	0.7	0.2	0.9	0.4	0.4
Kenai	9	9	3.0	10.2	36.1	4.0	4.0
No. Cook Inlet	3	3	3.5	2.0	20.3	6.8	6.8
Ninilchik	5	5	3.2	6.3	16.9	3.4	3.4
Sterling Unit	2	2	1.6	1.0	2.7	1.3	1.3
Swanson River Unit	0	0	0.0	0.0	0.0		
Trading Bay Unit	3	3	8.4	4.4	30.6	10.2	10.2
Other	4	4	1.7	0.7	9.2	2.3	2.3
Total	**34**	**34**	**3.1**	**32.6**	**161.0**	**4.7**	**4.7**

Table 3: Drilling of Gas Wells in Cook Inlet 2007 to 2009

Table 4 shows the number of net wells (company share of wells) drilled by the most active producer/explorers during the 2001-09 and 2007-09 periods.

Summary of Cook Inlet Gas Wells Drilled 2001-2009

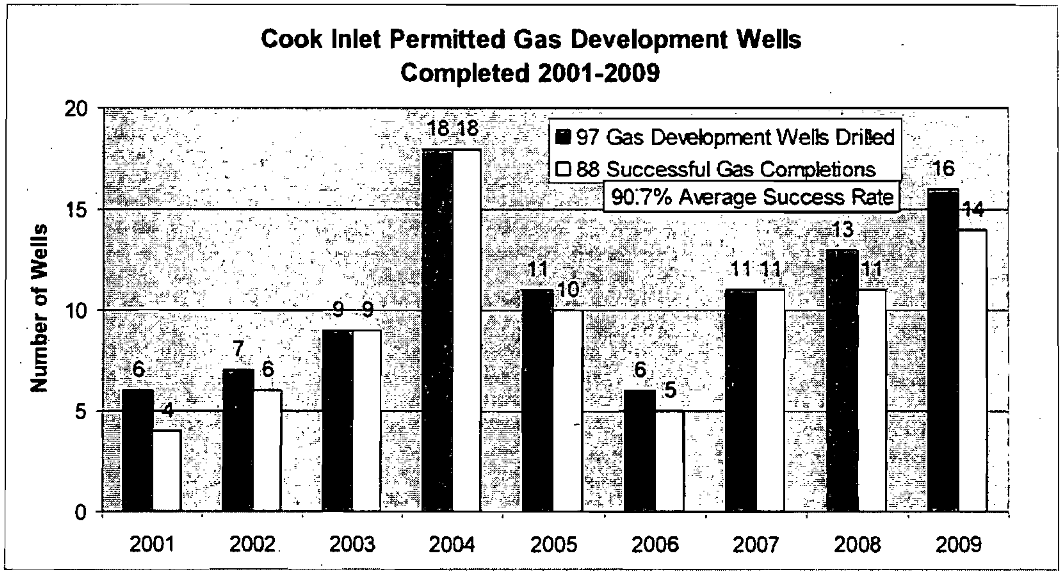
Field	Number of Gas Wells Drilled	Marathon Net Wells	Chevron Net Wells	Conoco Net Wells	MOA Net Wells	Aurora Net Wells	Forest/PERL Net Wells	Other Co. Net Wells
Beaver Creek	9	9.0						
Beluga River	3		1.0	1.0	1.0			
Cannery Loop	7	7.0						
Happy Valley	12		12.0					
Kenai	28	28.0						
No. Cook Inlet	4			4.0				
Ninilchik	19	11.4	7.6					
Sterling Unit	2	2.0						
Swanson River Unit	3		3.0					
Trading Bay Unit	6	3.1	2.9					
Other	35	5.0	10.0			15.0	2.0	3.0
Total	**128**	**65.5**	**36.5**	**5.0**	**1.0**	**15.0**	**2.0**	**3.0**

Summary of Cook Inlet Gas Wells Completed 2007-2009

Field	Number of Gas Wells Completed	Marathon Net Wells	Chevron Net Wells	Conoco Net Wells	MOA Net Wells	Aurora Net Wells	Forest/PERL Net Wells	Other Co. Net Wells
Beaver Creek	3	3.0						
Beluga River	3		1.0	1.0	1.0			
Cannery Loop	0	0.0						
Happy Valley	2		2.0					
Kenai	9	9.0						
No. Cook Inlet	3			3.0				
Ninilchik	5	3.0	2.0					
Sterling Unit	2	2.0						
Swanson River Unit	0		0.0					
Trading Bay Unit	3	1.5	1.5					
Other	4	1.0	1.0			1.0		1.0
Total	**34**	**19.5**	**7.5**	**4.0**	**1.0**	**1.0**	**0.0**	**1.0**

Table 4: Wells drilled 2001-09 and 2007-09 by Company

Figures 11 and 12 show the drilling levels for 2001-2009 for development wells and exploration wells as permitted with AOGCC, respectively. As can be seen the success rate for development was 90.7% and the success rate for gas exploration wells was 58.1%. Appendix E lists the wells with permit numbers and completion status.



.Figure 11: Gas wells drilled 2001-09 permitted as Development wells (AOGCC well database)

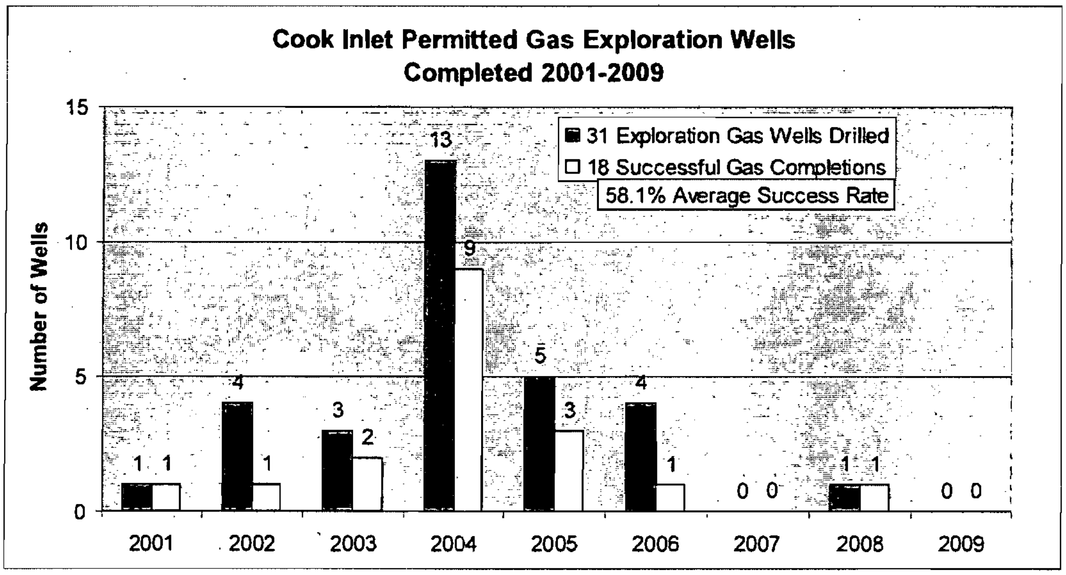
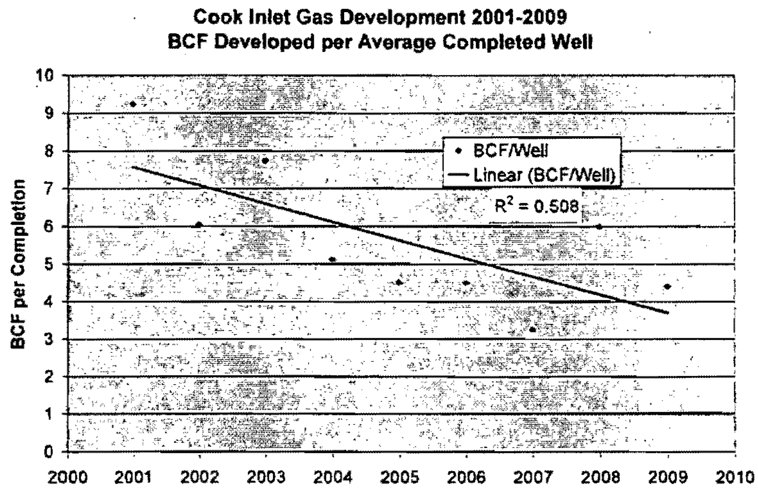


Figure 12: Gas wells drilled 2001-09 permitted as Exploration wells (AOGCC well database)

Factors that have contributed to drilling activity during this time period include the LNG export license renewal extending the license from 2004 to 2009, and again from 2009 to 2011, a new gas contract with Unocal/Chevron was approved in 2001 and Chevron drilled to meet their contractual obligation, Marathon Oil performed activities in conjunction with the potential ENSTAR/APL-5 contract, and the Kenai-Kachemak Pipeline (KKPL) was constructed. It may also be worth noting that regional gas prices climbed more than 140% from 2001 to 2004 and climbed more than 120% from 2004 to 2007.

Figure 13 is shows an estimate of gas developed per well 2001-2009, with a decreasing trend in ultimate recoverable gas.



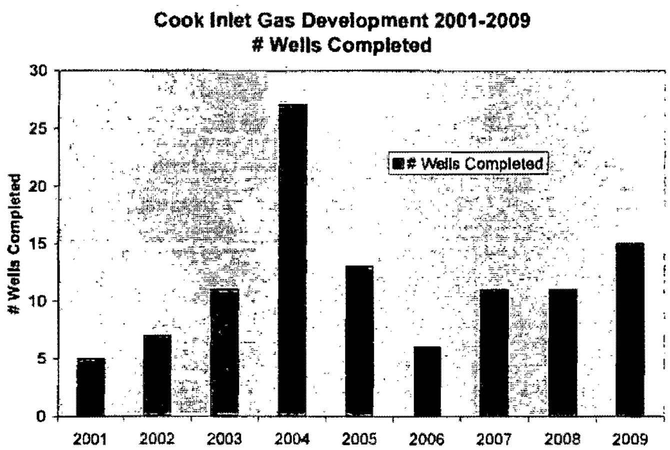


Figure 13: Cook Inlet gas development 2001-2009

i. Recent Well Costs

While there are no public sources for well costs, the bullets below summarize information that has been shared publicly.

- Chevron
  - Spent $250 million in capital on gas projects from 1999-2007
  - Had working interests in 52 wells, 14 were exploratory and 38 were development
  - Had disappointing results at Happy Valley and in exploration further south
  - Elected to decrease annual volumes to ENSTAR from 19.5 Bcf to 13.5 Bcf.
- Marathon
  - Has spent >$450 million on gas projects from 2002-2008
  - Drilled 65 producing wells
  - Extended the LNG export License to 2011
- Conoco-Phillips
  - Recent well at Beluga River Field cost $23 million, which included fracture stimulation and gravel packed completion
  - Extended the LNG export license to 2011
  - Chugach contract recently approved by RCA

Table 5 is an estimate of 2001-2009 gas well and facility costs from published information and estimates where information was not available.

It is estimated that $1.0 to 1.2 billion was spent between 2001 and 2009 to develop an estimated 563 BCF of gas in Cook Inlet, or a capital cost of $1.78 to $2.06 per MCF. Estimates of future capital costs are estimated to range from $2.50 to $4.30 for wells drilled 2010 to 2019.

Estimate of Cook Inlet Gas Development Costs 2001 to 2009

Net Wells Drilled from AOGCC Records

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Marathon	3.6	5.2	6.1	13.8	8.8	6.2	8.9	6.8	6	
Chevron/Unocal	3.4	4.8	2.9	13.2	1.2	0.8	2.1	3.9	4.3	
ConocoPhillips			1					0.7	3.3	
MOA								0.7	0.3	
Aurora		1	2	2	5	2			3	
Armstrong								1		
Others				2	1	1				**Total**
Total	7	11	12	31	16	10	11	13.1	16.9	**128**

Average Cost Per Well Capital and Facilities Estimate, million*

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009
Marathon	$ 5.0	$ 5.1	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 9.1
Chevron/Unocal	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.4	$ 8.6
ConocoPhillips			$ 5.0					$ 23.0	$ 23.0
MOA								$ 23.0	$ 23.0
Aurora		$ 3.0	$ 3.1	$ 3.1	$ 3.2	$ 3.2			$ 3.3
Armstrong								$ 8.0	
Others				$ 6.8	$ 6.8	$ 6.8			

** - Assumes 2% Inflation, $5,000,000 per initial well, except for Auroro at $3,000,000 per well, "Others" use yearly average cost*
Chevron/Unocal 2001-2007 and Marathon 2003-2008 ore estimates from publicolly discussed expenditures.
MOA & ConocoPhillips are from publically discussed well costs for Beluga River Unit.

Baseline Annual Cost Per Well Estimate, million

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Marathon	$ 18	$ 27	$ 54	$ 123	$ 78	$ 55	$ 79	$ 60	$ 54	
Chevron/Unocal	$ 28	$ 40	$ 24	$ 109	$ 10	$ 7	$ 17	$ 33	$ 37	
ConocoPhillips	$ -	$ -	$ 5	$ -	$ -	$ -	$ -	$ 16	$ 76	
MOA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 7	
Aurora	$ -	$ 3	$ 6	$ 6	$ 16	$ 6	$ -	$ -	$ 10	
Armstrong	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ -	
Others	$ -	$ -	$ -	$ 14	$ 7	$ 7	$ -	$ -	$ -	**Total**
Total Baseline	$ 46	$ 69	$ 89	$ 252	$ 111	$ 75	$ 97	$ 134	$ 184	**$ 1,057**
High Estimate 110% of Baseline	**50.7**	**76.2**	**98.3**	**276.9**	**122.0**	**82.6**	**106.2**	**146.9**	**202.6**	**1162.4**
Low Estimate 95% of Baseline	**43.8**	**65.8**	**84.9**	**239.1**	**105.3**	**71.3**	**91.7**	**126.9**	**175.0**	**1003.9**

Table 5: Cost estimate of Cook Inlet gas development 2001-2009.

The current cost for onshore wells is typically $5-10 million; offshore wells can be $10-20 million. Costs vary based on remoteness of location and how exotic a completion is required for the well.

ii. Drivers for future gas Exploration and Development

Based on conversations with current gas producers and public data, the following are required drivers to explore for and develop gas in Cook Inlet:

- Marathon needs certainty in contract approvals & larger markets to enable growth
  - Market is too small to support 10-15 wells in Cook Inlet (Peninsula Clarion 1/17/10)

- Chevron needs better exploration success
    - Had recent success on TBU Grayling Gas sands, but poor results at Deep Creek
    - Concerned about meeting future winter deliverabilities
    - No future exploration planned (Peninsula Clarion 1/17/10)
- Conoco Phillips does not view the market as large enough to commit major capital to new reserves exploration and development costs.
    - Not looking to explore or develop other than to service LNG and Chugach contracts.

b. Decline curve analysis

Base Case: Current Producing Wells

PRA evaluated existing decline and made a future forecast for the major units in the Cook Inlet Basin. The decline analysis for a unit total was used for the following units:

	2010 Avg. Rate, MMSCF/D	Annual Decline, %	Remaining BCF 1/1/10
Beaver Creek Unit	10.9	10%	35.8
Cannery Loop Unit	13.5	22%	21.8
Deep Creek Unit	5.0	17%	9.0
Sterling Unit	2.4	14%	4.4
Swanson River Unit	2.4	15%	5.5
Other Cook Inlet Fields	14.4	12%	41.8

Units that had recent drilling activity showed decline rates that reflected the new wells. Using production declines on a unit that had recent activity overstates future production as declines are lower due to activity. To predict the current production capacity of each of these units, a well by well decline analysis was made for the following units:

	2010 Avg. Rate, MMSCF/D	Annual Decline, %	Remaining BCF 1/1/10
Beluga River Unit	99.1	17%	206.5
Kenai Unit	39.6	21%	74.4
Ninilchik Unit	36.0	35%	38.0
North Cook Inlet Unit	58.1	16%	128.7
Trading Bay Unit	65.7	15%	162.7
2009 Wells to be Drilled	16.6		33.7
Cook Inlet Total	**363.7**		**762.3**

Production curves and forecasts for each of the units above are shown in the field descriptions in Appendix B. The individual well decline curves for Beluga River, Kenai, Ninilchik, North Cook Inlet and Trading Bay units are shown in Appendix D. For the purposes of this study, individual wells were determined to have reached an economic limit at 250 mscf/d.

Figure 14 shows the estimate of annual supply from the existing wells in the current units. It is an estimate from decline curve analysis and may be conservative as the data showed seasonal variation. It also includes 4 wells recently permitted to be drilled in 2009 and forecasts production based on the average for the wells drilled in their respective field during the period 2001 to 2009.

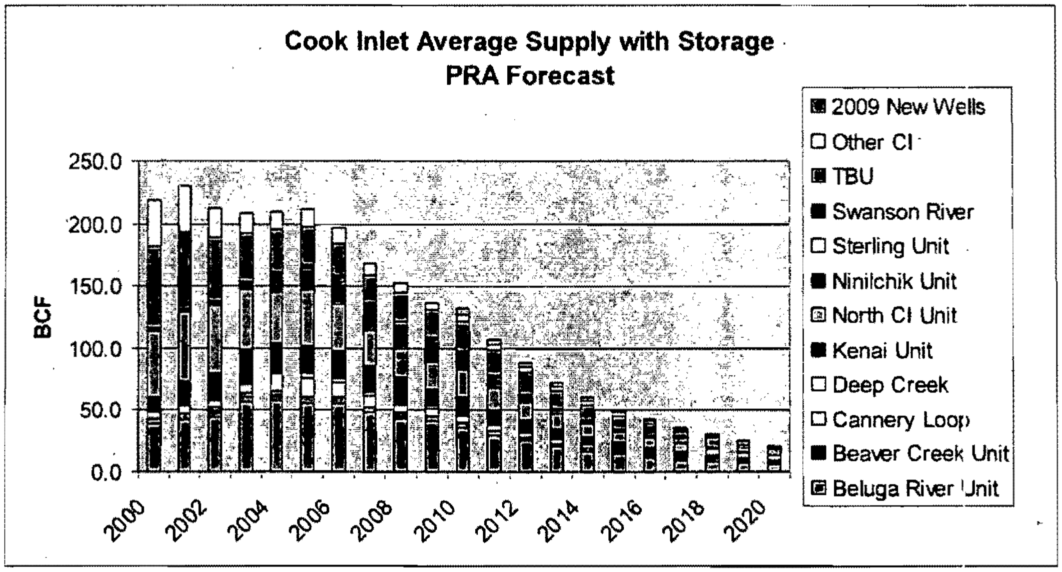


Figure 14: Cook Inlet Gas Production 2000-2009 and 2010-2020 Forecast

The 4 undrilled wells permitted in 2009 and their expected reserves are as follows:

Well	Estimate of Reserves, BCF
Trading Bay Unit M-08	15.7
Moquawkie 5	1.0
Nicolai Creek 11	1.3
Trading Bay Unit M-20	15.7
Total	**33.7**

Reserve estimates are based on the average of wells drilled in 2001-2009 in the respective unit, degraded by 4.3%.

c. Well Flowing Pressures in Major CI Units

Well flowing pressures were reviewed in the following major Cook Inlet units:

- Beluga River Unit
- Kenai Unit
- Ninilchik Unit
- North Cook Inlet
- Trading Bay Unit - Grayling Gas Sand Wells

The well flowing histories of each well in the above units are displayed on the production decline curves in Appendix D. Table 6 summarize the flowing tubing pressures of the wells, by productivity of the well using June 2009 production rates and pressures.

Beluga River Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
300-400	5	33.25
400-500	7	42.89
500-600	3	24.08

Kenai Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
<100	3	0.83
100-300	12	12.02
300-500	8	13.18
500-700	3	7.77
700-900	1	0.87
>900	1	0.81

Ninilchik Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
300-600	8	14.94
600-900	3	8.65
900-1200	3	20.14

TBU Grayling Gas Sand Wells		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
100-200	7	29.61
200-300	1	6.56
300-400	0	0.00
400-500	2	5.00

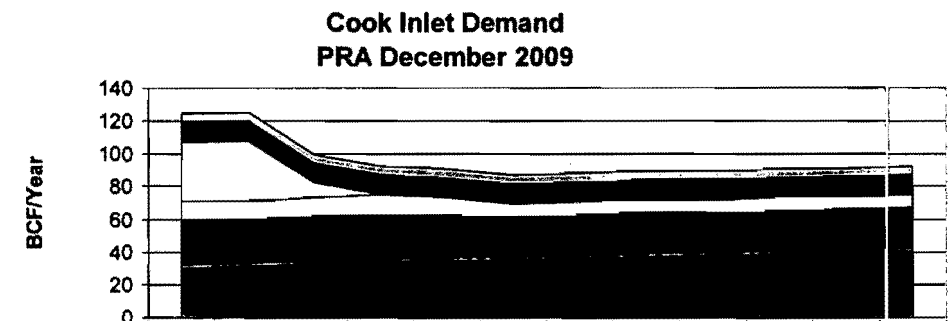
North Cook Inlet Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
100-200	9	22.39
200-300	4	15.64
300-400	2	6.28

Table 6: Tubing Pressures for Major Cook Inlet Units

As can be observed, there may be potential for increasing production significantly on high pressure wells in Beluga River and Ninilchik Units through the installation of compression. This analysis is preliminary, as each well should be considered separately for its ability to increase production by lowering tubing pressure and whether there is the potential for damaging the well due to higher production rates.

IV. When gas from outside Cook Inlet may be needed
Scenarios have been developed to show when gas will need to be imported to Cook Inlet. Imports could be in the form of gas from other areas of the state or imported LNG.

a. Demand Curve



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
□ Tesoro	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
■ Field Operations	12	12	12	12	12	12	12	12	12	12	12	12
□ LNG	36.4	36.4	9.1									
□ ML&P	11.54	11.56	11.58	11.62	11.07	8.05	8.06	8.09	8.11	8.14	8.20	8.20
■ CEA/Railbelt	27.5	26.3	26.9	27.7	25.4	23.8	24.2	25	23.9	24.2	24.5	25
■ ENSTAR	32.1	33.7	34.9	35.8	36.6	37.4	38.2	39.0	39.8	40.6	41.4	42.2

Figure 15: Forecasted Annual Demand for Cook Inlet Gas

Figure 15 shows the current forecasted demand for the users of Cook Inlet gas. Sources of the data are as follows:

- ENSTAR – M. Slaughter (08/27/09)
- Chugach Electric – M. Fouts (09/24/09)
- ML&P – B. Davies (09/11/09)
- LNG is from projection of Jan-Jun 2009 average shipments through the end of the export license 3/31/11
  (EIA website: http://tonto.eia.doe.gov/dnav/ng/ng_move_expc_s1_m.htm)
- Tesoro is from testimony against the LNG license extension (Tesoro FERC 4/9/07)
- Fuel, Shrinkage and Flare is from the AOGCC records using 2007-08 averages.

b. Supply vs. Demand

This study evaluated Cook Inlet Supply and Demand for three supply cases:

1) Base Case: Normal Decline of existing wells.

2) Case A: Assume same annual drilling activity as the average activity for 2007-2009, which averaged 11.2 wells per year.
3) Case B: Additional wells to meet demand from 2010-2020.
4) Case C: Additional wells to meet demand from 2010-2015.
5) Case D: Additional wells to meet contracted demand 2010-2020

i. Base Case: Current Producing Wells

Figure 16 shows PRA's estimate of current supply vs. demand for Cook Inlet Gas.

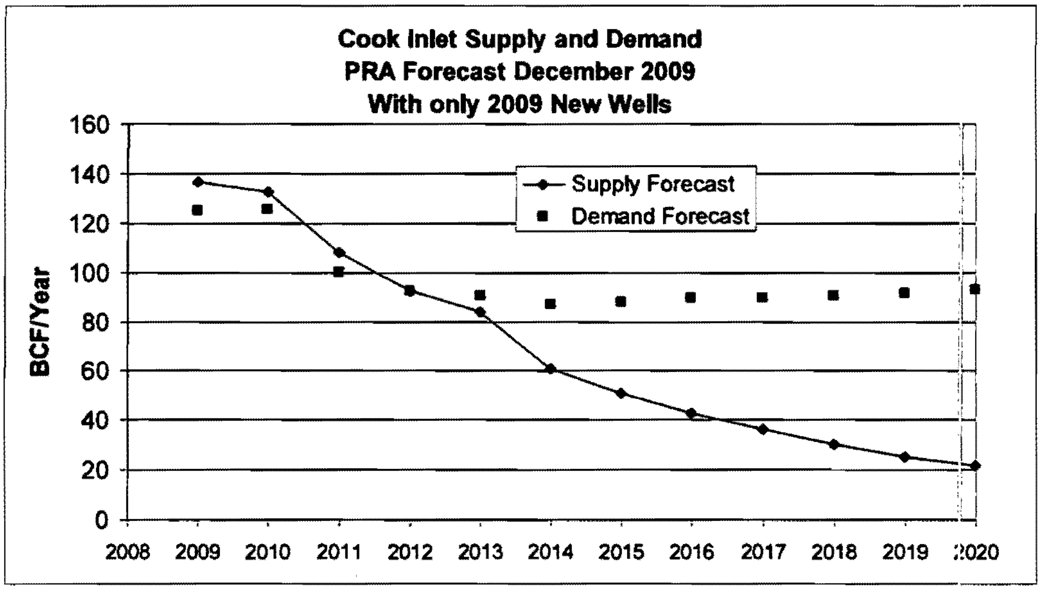


Figure 16: Supply vs. Demand for Cook Inlet Gas – Base Case

Analysis of the base case (production from existing wells) indicates that if no additional wells are drilled by 2013, South Central Alaska will not have enough natural gas supply to meet demand. The current wells are adequate to meet current contract obligations. Therefore, if no new contracts are approved or new customers enter the market, the base case is the likely future scenario.

During 2010 and 2011, analysis indicates equal supply and demand; there will likely be enough cushions (with wells not at peak capacity and the LNG plant being able to divert gas in the coldest periods) to meet the demands in winter. 2012 will be a year with no LNG plant operation and most of the "peaking capacity" of existing wells will be exhausted.

If no additional wells are drilled there should be plans to bring new gas into Cook Inlet by 2012 or 2013. This can be in the form of LNG imports or additional development of existing reserves, if available.

<u>ii. Case A: Current Producing Wells plus Continued 2007-09 Activity Level</u>

This case assumes that the drilling activity during 2007 to mid 2009, averaging 13.6 wells completed per year, will continue through 2019. This number of wells would be in excess of current contract demand and, therefore, inconsistent with public statements made by Chevron and ConocoPhillips.

There were 34 wells drilled and completed in the 2 ½ years from 2007 to mid 2009, an average of 13.6 wells per year. The wells used to model the production are shown in Table 3.

The estimated first year of production from the 13.6 wells was 13.0 BCF/year and the production declined at average of 21% per year. In the forecast, the initial rate is degraded by 4.3% per year for future drilling, based on the trend of average initial rate degradation shown in Appendix D.

Figure 17 shows Cook Inlet (CI) Supply vs. Demand with an assumed 2007-09 average drilling activity level, for a total of 136 wells completed 2010 to 2019.

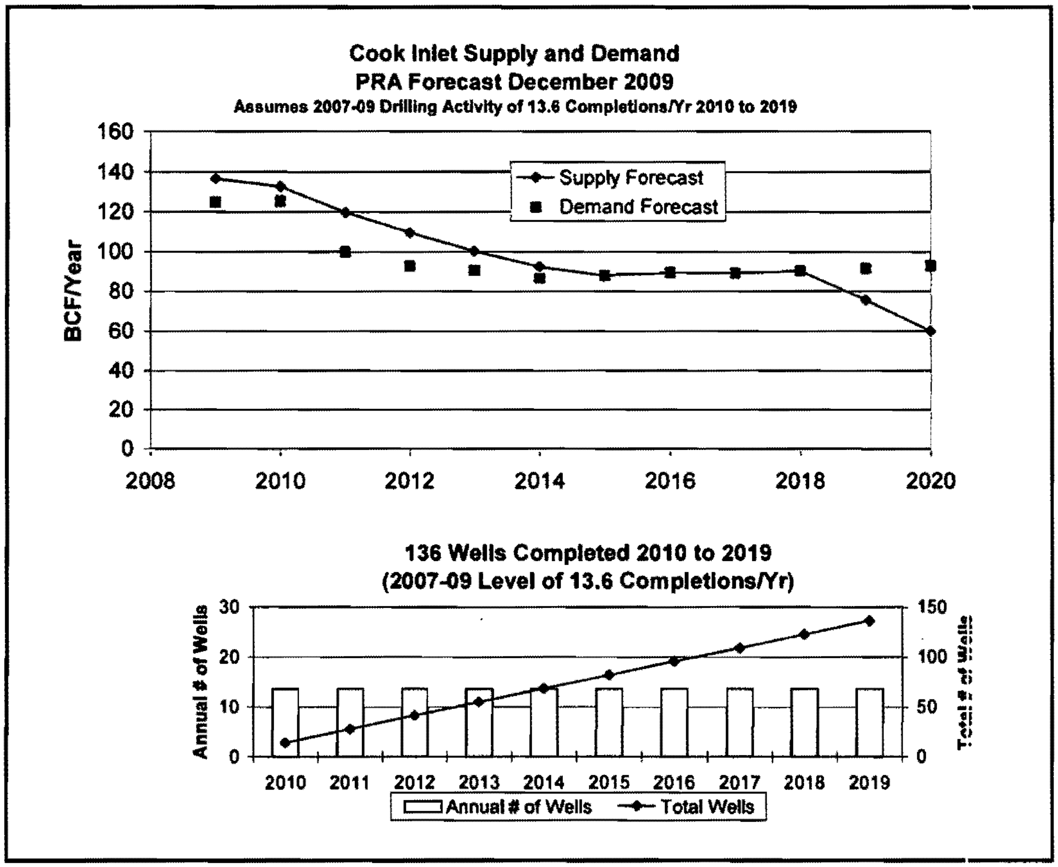


Figure 17: CI Supply-Demand assuming 2007-09 drilling of 13.6 completions per year 2010-2019

For the case of 2007-09 activity levels projected into the future, the demand exceeds supply in 2019.

Assuming $10-15MM per well, this would require $1.4 to 2.1 Billion in unrisked capital to drill these wells, resulting in capital costs of $2.67 to $4.00 per MCF, as compared to an estimated $1.78 to $2.06 /MCF capital cost for 2001-2009.

<u>iii. Case B: Drilling to Meet Demand through 2020</u>

Case B assumes that wells will be drilled and completed from 2010 to 2019 to fully meet demand through 2020. This example is inconsistent with current leaseholders' public statements and is offered for illustrative purposes. It assumes the 2007-09 wells are a proxy for the production rates of future wells, with a degradation of initial production of 4.3% per year for future drilling, based on the trend of average initial rate degradation shown in Appendix F.

Figure 18 shows CI Supply vs. Demand with an assumed drilling level to meet demand through 2020.

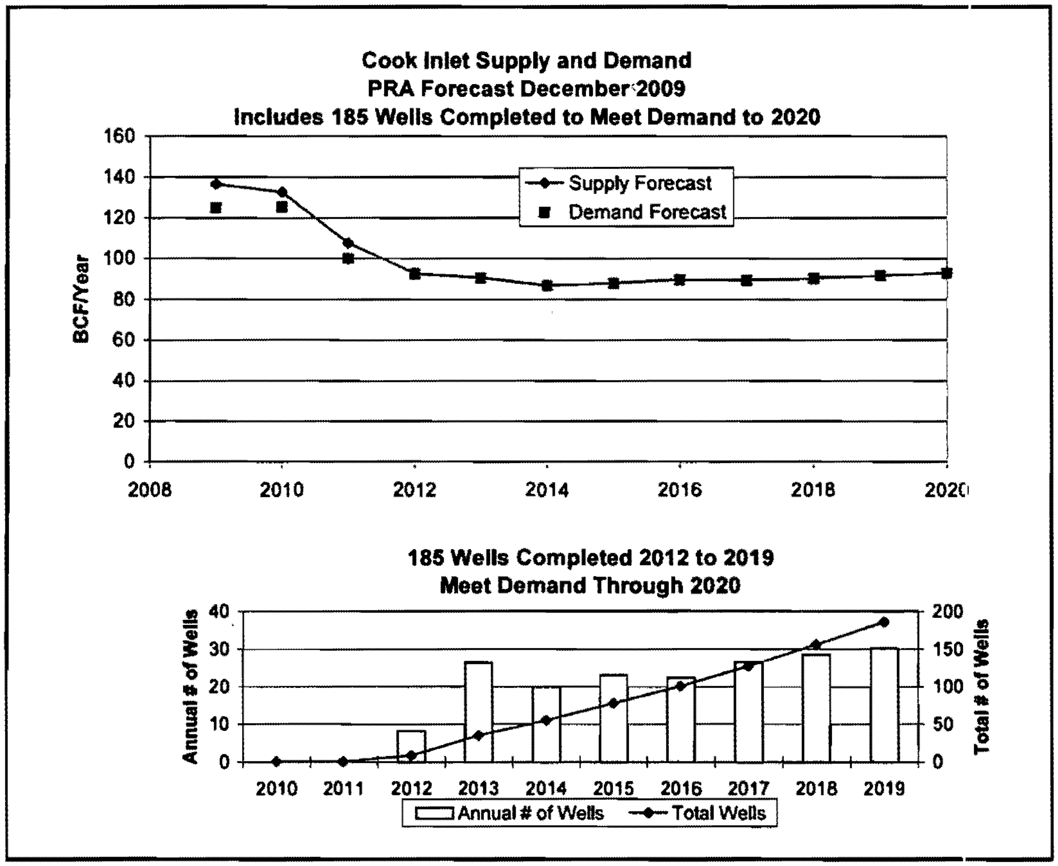


Figure 18: CI Supply-Demand assuming drilling activity to meet Demand 2010-2020

There are a total of 185 completed wells required to fully meet demand through 2020, which will develop 648 BCF of gas.

Assuming $10-15MM per well, this would require $1.85 to 2.8 Billion in unrisked capital to drill these wells resulting in capital costs of $2.86 to $4.29 per MCF, as compared to an estimated $1.78 to $2.06 /MCF capital cost for 2001-2009. Actual costs to customers would include a risk premium and deliverability cost; making the potential contract price upwards of two to three times the development cost.

<u>iv. Case C: Drilling to Meet Demand through 2015</u>

Case C assumes that wells will be drilled and completed from 2010 to 2014 to fully meet demand through 2015. It assumes the 2007-09 wells are a proxy for the production rates

of future wells, with a degradation of initial production of 4.3% per year for future drilling, based on the trend of average initial rate degradation shown in Appendix D.

Figure 19 shows CI Supply vs. Demand with an assumed drilling level to meet demand through 2015.

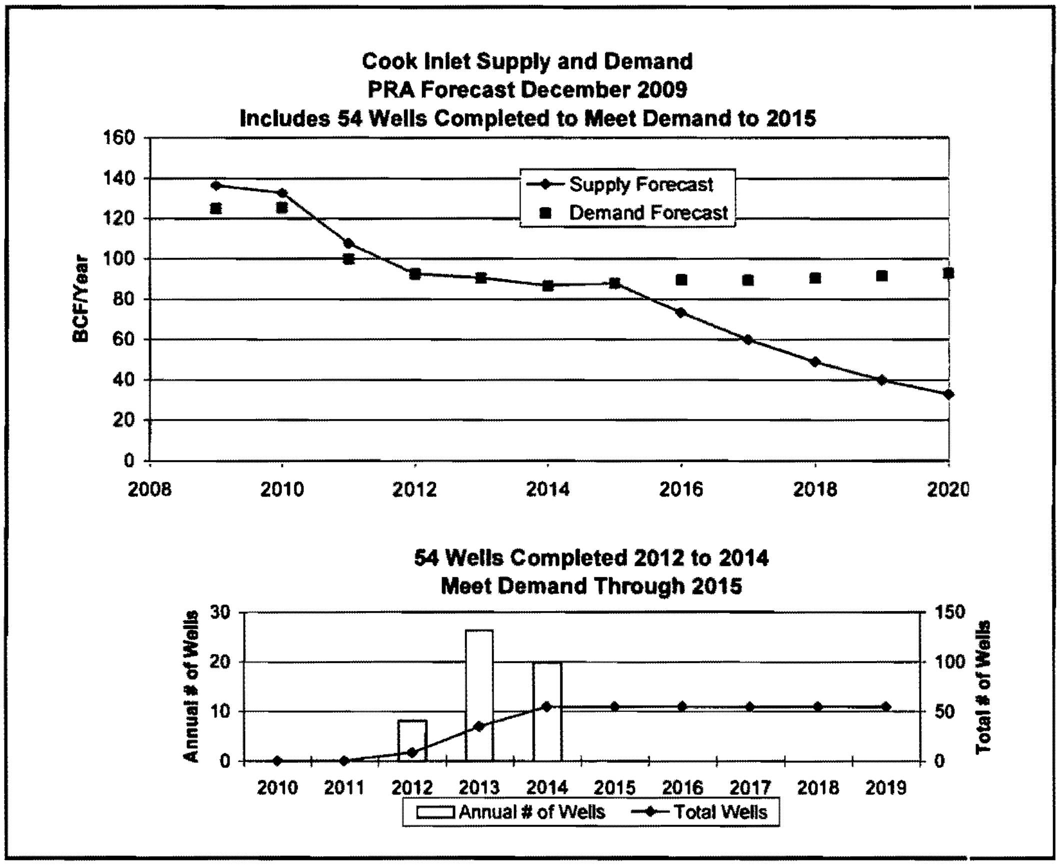


Figure 19: CI Supply-Demand assuming drilling activity to meet Demand 2010-2015

There are a total of 54 completed wells required to fully meet demand through 2015.

Assuming $10-15MM per well, this would require $0.5 to 0.8 Billion in unrisked capital to drill these wells, resulting in capital costs of $2.54 to $3.81 per MCF, as compared to an estimated $1.78 to $2.06 /MCF capital cost for 2001-2009.

v. Case D: Drilling to meet existing contracts through 2020

Case D assumes that wells will be drilled and completed from 2010 to 2014 to fully meet existing contracts through 2020. As can be seen in Figure 20, on average for Cook Inlet, there appears to be sufficient supply to meet existing contracts through 2020. This

average analysis is obviously not appropriate to understand the situation of each producer or individual contracts.

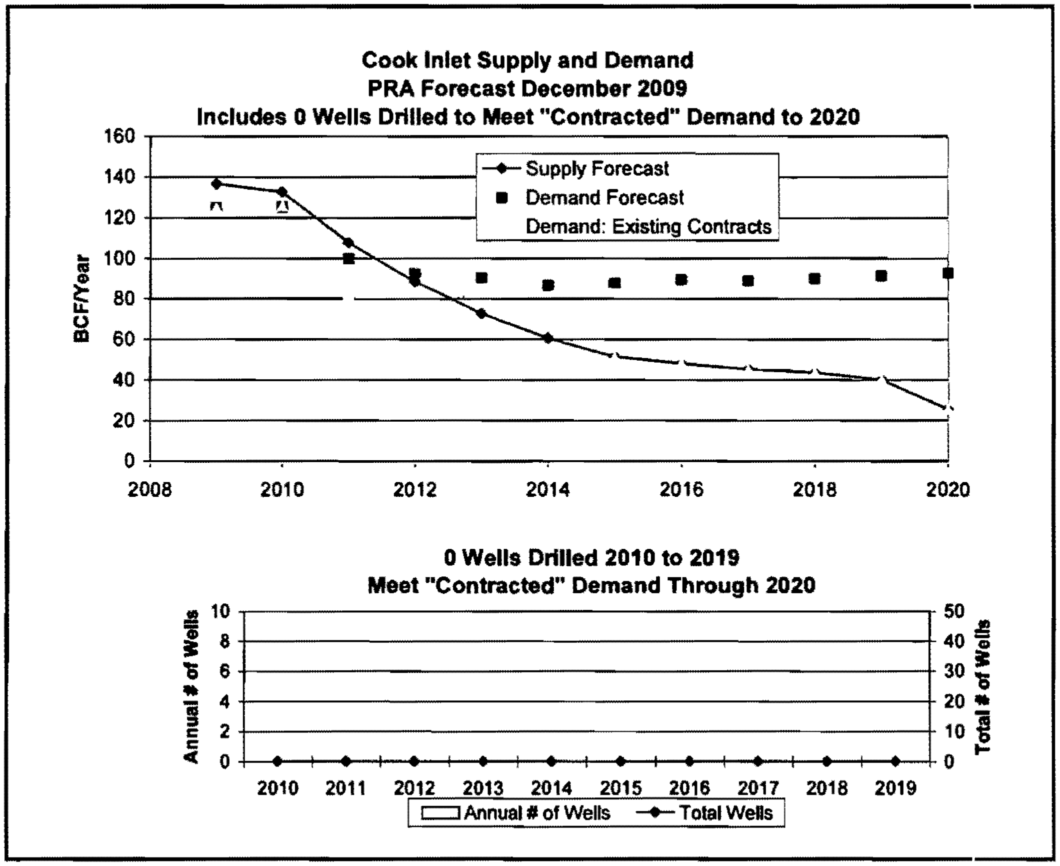


Figure 20: CI Supply-Demand assuming drilling activity to meet Existing Contracts 2010-2020

c. Review of Current Unit Plan of Developments

To understand future activity planned for Cook Inlet gas development, the Unit Plan of Developments (PODs) of the five units with the highest recent drilling activity were reviewed. Drilling and completions planned in the current POD's are as follows:

- Beluga River Unit – ConocoPhillips: 47th POD (6/18/09 to 6/17/10) for BRU approved by BLM on 5/29/09. Two new wells, 211-26 and 243-34 are planned.
- Kenai Unit – Marathon: 51st POD (2/8/09 to 2/7/10) for KU approved by BLM on 1/27/09. Four wells, KBU 11-17X, KBU 23-08, KBU 42-06X and KU 31-06 are planned to be drilled and completed.
- Ninilchik Unit – Marathon submitted 6th POD (1/1/10 to 12/31/10) to AK DNR/DOG on 10/12/09; approval pending. Plans are to drill Paxson #3 and if successful, Paxson #4. Compression will be installed on the Paxson pad.

- North Cook Inlet Unit – ConocoPhillips submitted 2010 POD (1/1/10 to 12/31/10) to AK DNR/DOG on 10/1/09; approval pending. No wells planned, will evaluate feasibility of lowering wellhead pressures.
- Trading Bay Unit (Grayling Gas Sands) – Chevron: 44th POD (8/26/09 to 8/25/10) for TBU was approved by AK DNR/DOG on 7/17/09. One new well, M-20, will be completed, one new well, M-10 will be drilled and completed and two workovers will be undertaken, M-1 and M-5.

In summary, there will be the following new wells or workovers in the major CI gas units, according to current POD's:

Beluga River Unit	2
Kenai Unit	4
Ninilchik Unit	2
No Cook Inlet Unit	0
TBU Gas Sands	4
Total	12

This is at a comparable activity level as the 34 wells drilled in the 2007 to mid 2009 period., although recent statements at a Kenai forum have indicated that this pace is not likely to continue (Peninsula Clarion 1/17/10). Appendix F reviews POD's for the last 3 annual periods for the units shown above.

d. DNR Reserves/Deliverability Study

In December 2009, the DNR published a preliminary study looking at total remaining reserve potential in the major fields in Cook Inlet as well as the deliverability of current wells. Their deliverability study is similar to the PRA findings in that with existing wells DNR shows supply from existing wells will not meet demand in 2015. The DNR estimated reserve potential shows that there is an abundance of undeveloped reserves in Cook Inlet, but in the conclusion of the report it is stated "In order to engage in drilling and development projects in Cook Inlet, local producers must internally justify doing so as an alternative to other projects worldwide." While there may be large undiscovered gas reserves in Cook Inlet as the DNR concludes, it is unlikely that these reserves will be developed soon enough to avoid the necessity of importing gas into south-central Alaska.

The DNR study approaches are discussed in Appendix C.

V. Summary

With existing producing fields in Cook Inlet and the current forecasted demand, there will be a critical shortage of natural gas supply starting in 2013.

If drilling activity remains at the 13.6 wells completed per year level that occurred during 2007-mid 2009, the shortage of gas will occur after 2018. The most recent unit POD's showed 12 wells to be drilled in the POD period, although statements by gas producers at recent Cook Inlet oil and gas industry forum would indicate that continuation at this level of activity is not likely.

To meet demand through 2020, a total of 185 wells will be required to be drilled at an estimated total cost of $1.8 to $2.8 billion.

Given the limited remaining development reserves in Cook Inlet and the long timeframe required to bring new discoveries on-line, further combined with the paucity of true gas exploration in recent years, it is likely that a source of gas outside of the Cook Inlet, such as LNG importation or other in-state reserves, will be required starting between 2013 and 2016.

In order for Cook Inlet gas requirements to be met, either by additional development of Cook Inlet gas or gas imported as LNG or from other areas of the state, adequate gas storage will be required to meet the winter deliverability swings.

Appendices

Appendix A: Cook Inlet Field and Reservoir Data

Table 1: Cook Inlet Gas Fields in order of discovery (AOGCC 2008 Annual Report).

	Gas Field	Discovery Date	Discovery Well	Current Operator	TD MD/TVD	Production (BCF) to 1/1/2009
1	Kenai	10/11/1959	Unocal Kenai Unit #14-6	Marathon	12037/12037	2353
2	Cannery Loop	10/11/1959	Unocal Kenai Unit #14-6	Marathon	12037/12037	171
3	Swanson River	5/18/1960	SOCAL SRU 212-10	Chevron	12029/11566	50
4	West Fork	9/26/1960	Halbouty King Oil, Inc #1-B	Marathon	14019/14019	6
5	Ninilchik-Falls Ck	6/21/1961	SOCAL Falls Creek Unit #1	Marathon	13795/13382	23
6	Sterling -Sterling	8/4/1961	Unocal Sterling Unit #23-15	Marathon	14832/14832	4
7	West Foreland	3/27/1962	Pan Am West Foreland No. 1	Forest	13500/13500	10
8	North Cook Inlet	8/22/1962	Pan Am Cook Inlet St 17589 #1	ConocoPhps	12237/12237	1798
9	Beluga River	12/1/1962	SOCAL BRU # 1 (212-35)	ConocoPhps	16429/16429	1107
10	Birch Hill	6/14/1965	SOCAL Birch Hill Unit #22-25	ConocoPhps	15500/15500	0.1
11	Moquawkie	11/28/1965	Mobil-Atlantic Moquawkie #1	Aurora	11364/11364	4
12	North Fork	12/20/1965	SOCAL North Fork Unit # 41-35	Gas-Pro	12812/12812	0.1
13	Nicolai Creek	5/12/1966	Texaco Nicolai Ck. St. #1-A	Aurora	8338/7979	5
14	Ivan River	10/8/1966	SOCAL Ivan River Unit #44-1	Chevron	15269/15269	79
15	Beaver Creek	2/10/1967	Marathon Beaver Ck. Unit #1	Marathon	13595/12911	199
16	Albert Kaloa	1/4/1968	Pan Am Albert Kaloa #1	Aurora	13600/13600	3
17	McArthur River	12/2/1968	Unocal Trading Bay Unit G-18	Chevron	6390/4510	1095
18	Lewis River	9/2/1975	Cities Lewis River #1	Chevron	9480/9480	12
19	Stump Lake	5/1/1978	Chevron Stump Lake Unit 41-33	Chevron	11660/11660	6
20	Pretty Creek	2/20/1979	Unocal Pretty Ck Unit #2	Chevron	12025/12025	9
21	Trading Bay	10/5/1979	Texaco NTB Unit SPR-3	Marathon	10250/10094	6
22	Middle Ground Shoals	7/14/1982	Amoco MGS 17595 No. 14	Chevron	10445/9031	16
23	Granite Point	6/10/1993	Unocal Granite Pt. St. 17586 9	Chevron	5905/4170	1
24	Lone Creek	10/12/1998	Anadarko Lone Creek #1	Aurora	11487/11269	7
25	Wolf Lake	10/31/1998	Marathon Wolf Lake No. 2	Marathon	14451/14086	0.8
	Sterling - UP Bel	11/9/1998	Unocal Sterling Unit No. 32-09	Marathon	6858/6336	7
	Ninilchik-Oskolkoff	7/31/2001	Marathon Grassim Oskolkoff #1	Marathon	11600/8510	24
	Ninilchik-S.Dionne	7/30/2002	Marathon Susan Dionne #3	Marathon	10255/8102	38
26	Redoubt Shoal	4/23/2003	Forest Redoubt Shoal No. 3	Forest	16940/13016	0.5
27	Deep Creek	7/9/2003	Unocal Happy Valley #1	Chevron	10872/9700	12
28	Kasilof	3/25/2004	Marathon Kasilof South 1	Marathon	17545/9642	3

29	Three Mile Creek	1/23/2005	Aurora Three Mile Creek Unit 1	Aurora	8180/8011	2
	Sterling-LW Beluga/Tyonek	9/12/2007	Marathon Sterling Unit 41-15RD	Marathon	11655/9517	0.6
					TOTAL	**7052**

Table 2: Reservoir Characteristics of 10 Cook Inlet Gas Fields (AOGCC 2008)

Gas Field	Gas Pool	Production Depth (ss)	Production (BCF) to 1/1/2009	Net Pay Thickness (feet)	Por. (%)	Perm. (md)	Swi %
Beaver Creek	Sterling	5000	126	110	30	2000	40
	Beluga	8100	67.4	50	10		
	Tyonek Undef	9847	5.5	45			
Beluga River	Undefined Sterling	3450	1107	107	31	50-199	37
	Beluga	4500		106	24	20-49	42
Cannery Loop	CLU Sterling undef.	4965	21.4	76			40
	CLU Beluga	5175	76.2	33	20	25	45
	CLU U Tyonek	8700	72.0	17	21	250	45
	CLU Tyonek D	10000	1.3	35	23		45
Deep Creek	Beluga/Tyonek	5984	11.9	NA	28	4	40
Kenai	Sterling 3	3700	333	88	31		35
	Sterling 4	3960	452	60	33		35
	Sterling 5.1	4025	485	113	33		35
	Sterling 5.2	4125	44	53	33		35
	Sterling 6	4565	534	110	28		40
	Beluga Undef	4900	0	213	19		45
	U Tyonek Beluga	6600	318	120			45
	Tyonek	9000	189	100	19		45
North Cook Inlet	Tertiary (Ster./Bel.)	4200	1798	130	23	178	40
Ninilchik							
Falls Creek	Tyonek (und)	4690	23.0	189	15-25	6	
G. Oskolkoff	Tyonek (und)	3496	24.2	210	15-21	14	
Susan Dionne	Tyonek (und)	3338	37.6	44	15-20	8	
Sterling	Sterling	5030	3.74	25	26	125	40
	Beluga Undef	8104	0.44	100	10	0.1	
	UP Beluga Undef	5400	6.85				
	LW Bel/Tyonek		0.58				
	Tyonek Undef	9449	0.14	55	12	1.5	
Swanson River	Sterling	2720-3060	30.6		30	650	35
	Beluga	4676	1.3	22	30	110	50
	Tyonek Undefined	5600-7500	18.5	13-40	25-29	5-500	37-55
Trading Bay (McArthur River)	Tyonek	1518-8982	1095	375	12-32	900	36
		TOTAL	**6882**				

Table 3: Reservoir Characteristics of the 19 Other Cook Inlet Gas Fields (AOGCC 2008)

Gas Field	Gas Pool	Production Depth (ss)	Production (BCF) to 1/1/2009	Net Pay Thickness (feet)	Por. (%)	Perm. (md)	Swi %
Albert Kaloa	Undef (Beluga)	3141	3.2	139	20	60	40
Birch Hill	Undef (Tyonek)	7960	0.1	31	25	5 to 6	NA
Granite Point	Undef (Tyonek)	4088	0.9				
Ivan River	Undef (Tyonek)	7800	79.5	37	20	1600	45
Kasilof	Tyonek Undef		3.1				
	Tyonek 2 Undef		0				
Lewis River	Undef (Beluga)	4700	11.8	85	22		45
Lone Creek	Undef (Tyonek)	1958	6.8	53	19	100	30
Middle Ground Shoal	Undef (Tyonek)	3550	16.4				
Moquawkie	Undef (Tyonek)	2250	4.11	106	22	20-50	35-40
Nicolai Creek	Undef North (Tyonek)	1935	2.22	128	17		50
	Undef South (Tyonek)		0.98				
	Beluga		1.48				
North Fork	Undef (Tyonek)	7200	0.1	40	18	3.5	50
Pretty Creek	Undef (Beluga)	3364	9.44	60	22		45
Redoubt Shoal	Tyonek (undefined)		0.45				
Stump Lake	Undef (Beluga)	6740	5.64	91	24	5	45
Three Mile Creek	Beluga Undef		1.7				
Trading Bay	Undef (Tyonek)	9000	5.7	250	13	15	40
West Foreland	L. Tyonek 4.0	4250	7.32				
	L. Tyonek 4.2		3.05				
West Fork	Sterling A	4700	1.23	22	32	200	50
	Sterling B	4700	1.44				
	Undefined	7148	3.12				
Wolf Lake	Undef (Tyonek)	6749	0.82				
		TOTAL	**170.62**				

Appendix B-1: Beaver Creek Unit Gas Field Description

Geological Introduction. The Beaver Creek gas field is located onshore Kenai Peninsula about 50 miles south-southwest of Anchorage and 10 miles east-northeast of Kenai. It was discovered in 1967 by the Marathon Beaver Creek Unit No. 1 well which blew out at a depth of 9,134' and the well was plugged and abandoned. The well discovered gas in the Sterling and Beluga formations. It is currently operated by Marathon. Gas is produced from three pools, the Sterling, Beluga and Tyonek undefined. Production began in 1972 from the Sterling, 1990 from the Beluga and 1996 from the Tyonek. Production depths are at 5,000'ss, 8,100'ss and 9,874'ss, respectively. Table 2 shows reservoir characteristics. Gas production is from 7 of the 14 wells in the field with 2 wells producing oil, 1 used for disposal and 4 abandoned. A cumulative total of 201 BCF has been produced through June 2009.

The structure is a slightly asymmetrical anticline with a high angle reverse fault bounding the eastern side (Figure B1.1). The permeability barrier shown on the Sterling B-3 structure map could be a stratigraphic pinchout, facies change, localized tight streak, small scale fault or some other lateral discontinuity in the reservoir. Such reservoir heterogeneities tend to be more common in the Beluga and Tyonek sands and can isolate pay zones that can be revealed by ongoing field development. 3-D seismic has been shot over the field but no revisions have been made to the publically available structure map.

The 18 and 24 year time gaps between the start of Sterling production and production from the Beluga and Tyonek, respectively, demonstrates that, as field development progresses, reserve growth occurs. Future additional reserve growth potential exists, especially in the Beluga and Tyonek, because of the discontinuous nature, potentially poor connectivity to existing perforations, and often low porosity and permeability of these reservoirs. The low porosity and permeability 'tight-sands' were often over-looked or considered non-economic during the early development of the obvious 'easy' gas in the high porosity and permeability 'good' reservoirs. The 'tight-sands' require fracture stimulation to be productive.

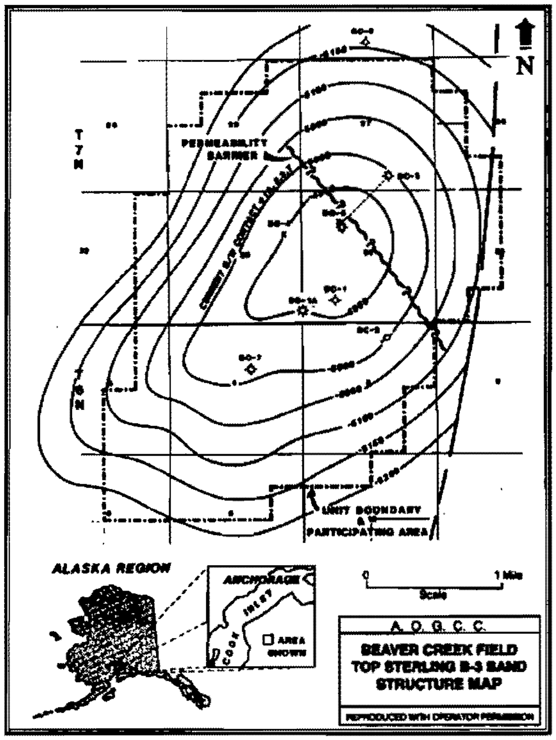


Figure B1.1: Beaver Creek Unit Structure Map (AOGCC)

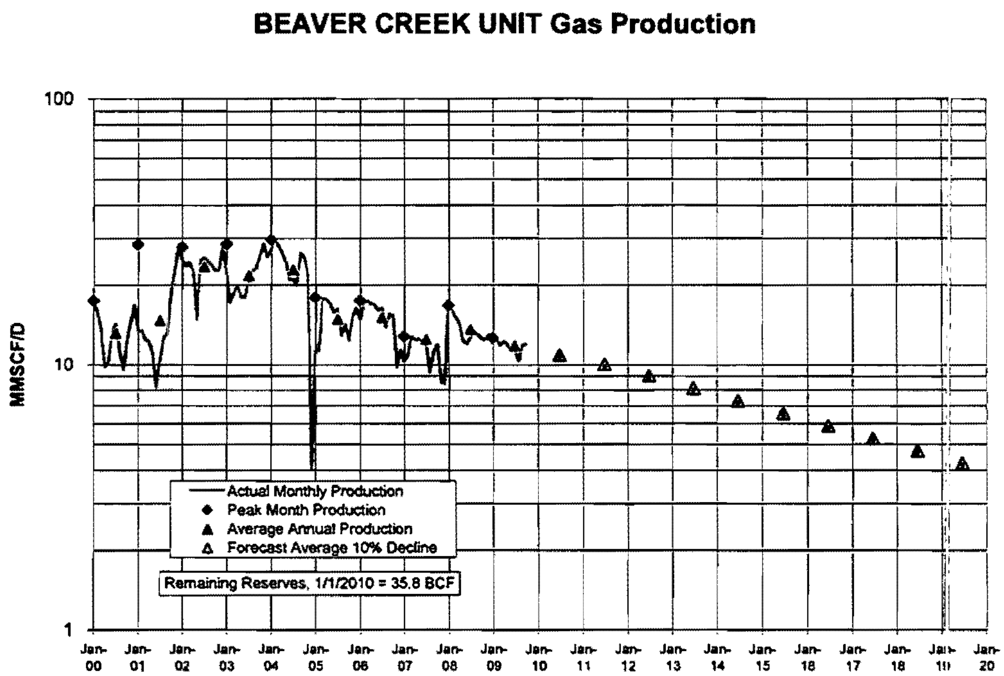


Figure B1.2 Field Production Curve 2000-2009 and Forecast

Appendix B-2: Beluga River Unit Gas Field Description

Geological Introduction. The Beluga River field is located on the coastline of the west side of Cook Inlet, about 40 miles west of Anchorage. It was discovered in 1962 by the Socal Beluga River Unit No. 1 (212-35) well which was drilled to a depth of 16,429' (MD and TVD) to explore for deep oil objectives. It is currently operated by ConocoPhillips. Gas is present in both the Sterling and Beluga formations at average subsea depths of -3,300' and -4,000', respectively. Multiple pay zones are produced in both formations but the gas production from the Sterling and Beluga is comingled. The Sterling is subdivided into three zones, A, B and C and the Beluga is subdivided into 7 zones, D, E, F, G, H, I and J. Total net pay is 107' and 108', respectively. Correlation of sands is difficult because of lateral variability in thickness and sand quality and wide well spacing. Detailed correlation of the laterally more continuous coals is critical to determining sandstone body geometry. Gas production began in 1968. Out of a total of 22 wells in the field, 19 have produced gas, 14 of which are currently producing. The total cumulative production through June 2009 was 1,128 BCF.

The structure shown in figure B2.1 is a relatively broad, asymmetrical fault propagation fold oriented in a northeast-southwest direction with a steeper northwest limb. The structure as mapped is relatively simple, without a system of cross-cutting faults found in some of the other Cook Inlet fields. The structure is about 7 miles long and 3 miles wide. ConocoPhillips conducted a 3D seismic survey over the field in 2007. This was done to improve structural mapping which was problematic using the relatively widely spaced, older 2D data. When I worked the field for ARCO with Blaine Campbell in 1994, our volumetric calculation of reserves was less than the reserves calculated by material balance, indicating probable inaccurate structural mapping. Re-mapping of the field may reveal structural complexities such as small faults or separate structural highs with intervening saddles that could isolate pay from existing well infrastructure.

A reservoir modeling study by Rick Levinson and others at ConocoPhillips was published as an abstract and presented at AAPG in May of 2006. A focus of the study was to identify gas that might not be drained by the existing perforations. They conducted a connectivity analysis and determined that Sterling sands are 99% connected to existing perforations and Beluga sands are 81% connected. Connected OGIP in the model is 28% greater than determined by P/Z analysis suggesting potential for accessing through well work or new drilling isolated pay sands, mainly in the Beluga formation. This was tested in two work over operations (pre May 2006) resulting in new pay sands identified and perforated leading to increased gas production. Two wells drilled in 2008 tapped reservoirs that added 9.7 BCF new production per well. Ongoing field development will likely result in identification of similarly isolated pay sands.

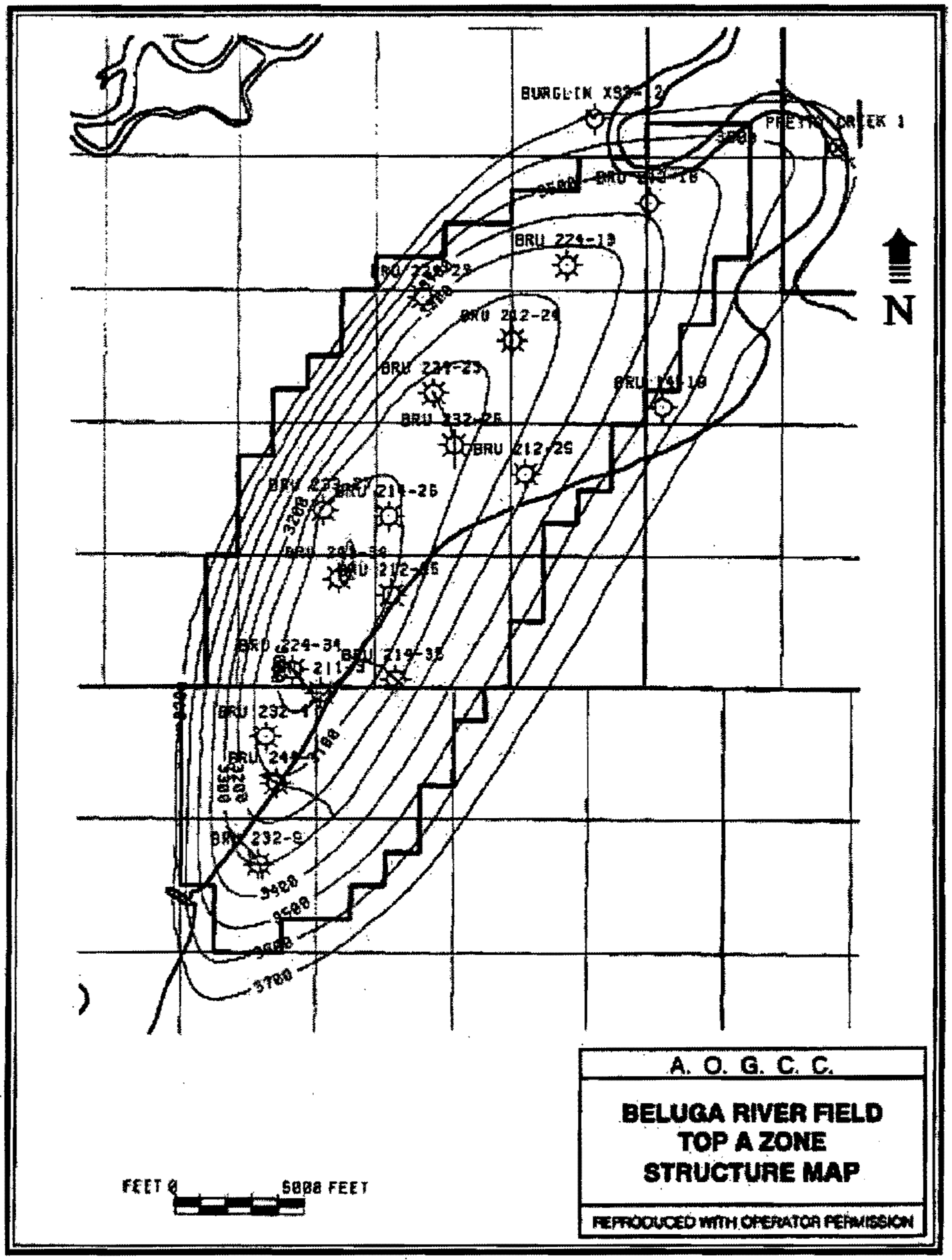


Figure B2.1: Beluga River Field Structure Map (AOGCC)

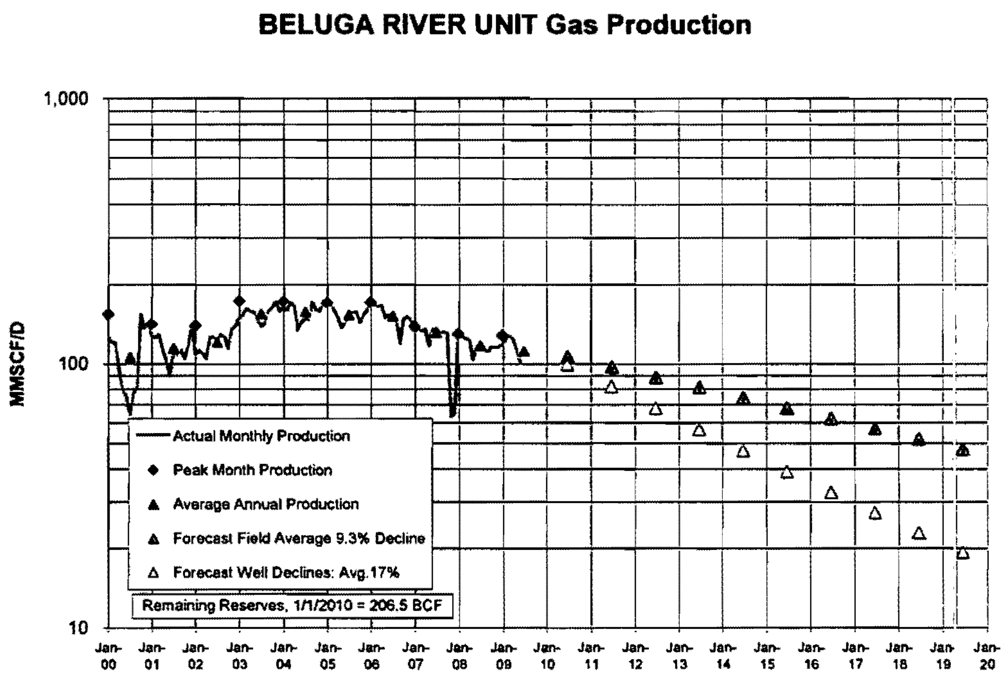


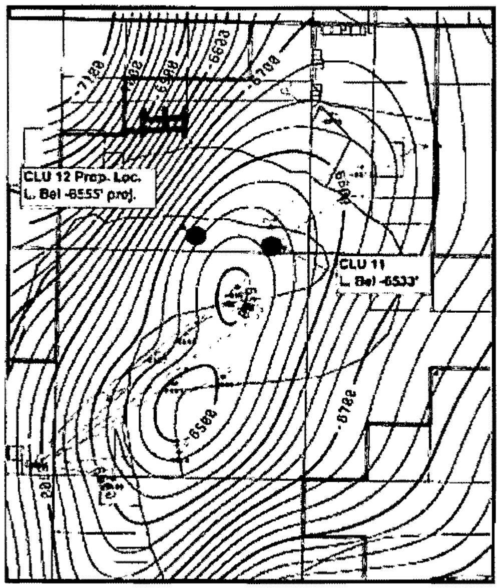
Figure B2.2: Field Production Curve 2000-2009 and Forecast

Appendix B-3 Cannery Loop Unit Gas Field Description

Geological Introduction. Cannery Loop Unit (CLU) is located on the eastern shoreline of the Kenai Peninsula and straddles the mouth of the Kenai River. Its southern unit boundary is adjacent to the northern boundary of the Kenai Unit. Because the AOGCC includes the CLU as part of the Kenai Field the Unocal Kenai Unit 14-6 well is listed as the discovery well for both Units. The Cannery Loop Unit No. 1 well may better be considered the discovery well for the CLU since the CLU anticline is structurally separated from the Kenai anticline. It was directionally drilled by the current operator, Marathon, in 1979 to a depth of 12,010' MD (10,215' TVD. Production is from four gas pools, Sterling undefined, Beluga, Upper Tyonek and Tyonek Deep with pool top depths at 4,965'ss, 5,175'ss, 8,700'ss and 10,000'ss, respectively. Net pay for each pool is 76', 33', 17' and 35' respectively. Reservoir characteristics are shown in Table 2. Gas production began in 1988 in the Beluga and Upper Tyonek Gas pools and in 2000 in the Sterling Undefined pool. Tyonek Deep produced briefly in 1988-1989 but was stopped due to high water production. Production is from 14 completions in 10 wellbores and of the 13 wells in the field two are P&A'd, one is suspended and the other ten are actively producing. A cumulative total of 174 BCF has been produced through June 2009.

The structure is a gentle, slightly asymmetrical anticline separated from the Kenai field anticline by a structural saddle (Figure B3.1). The structure is about 3 miles long and 2 miles wide, trends north-northeasterly and is slightly steeper on the west side.

The relatively thick productive stratigraphic interval, including the Sterling, Beluga and upper to middle Tyonek, provides the potential for new isolated pay discoveries. Reservoir heterogeneities resulting in isolated and disconnected pay and possible 'tight-sands' are likely to be discovered with ongoing field development.



Top Lower Beluga Structure Map
Cannery Loop, Alaska
CI = 25 ft
0.5 mile

Figure B3.1: Cannery Loop Unit Structure Map (AOGCC)

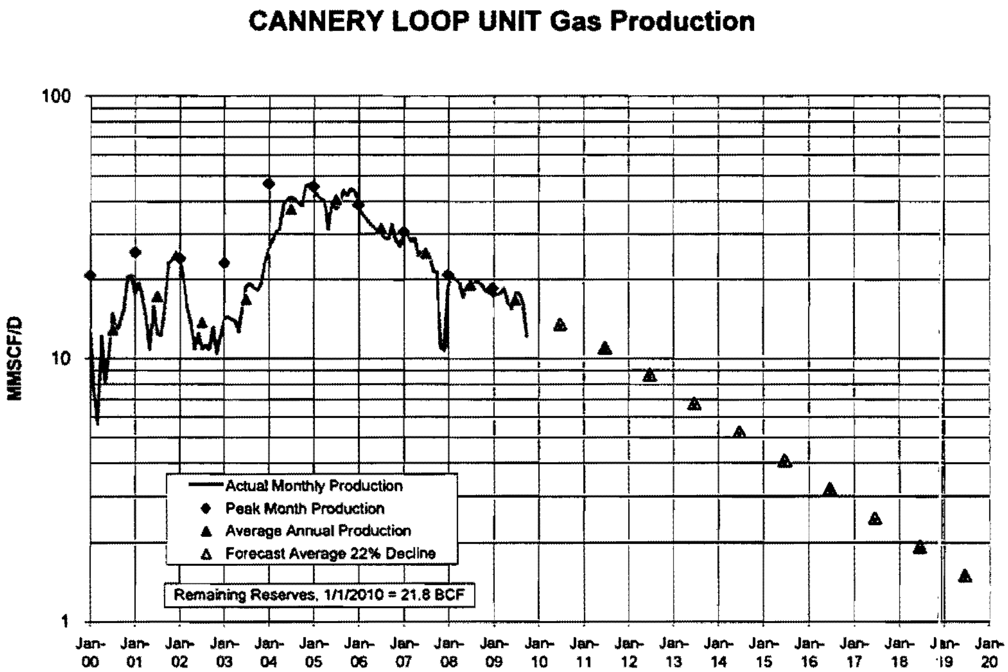


Figure B3.2: Field Production Curve 2000-2009 and Forecast

Appendix B-4: Deep Creek Unit Gas Field Description

Geological Introduction. The Deep Creek Unit gas field is located on the Kenai Peninsula about 8 miles east-southeast of Ninilchik. It was discovered in 2003 by the Unocal Happy Valley 1 well which was drilled to a depth of 10,871' MD (9,700' TVD) in search of gas up dip of sands with gas shows penetrated in the Happy Valley 31-22 well in 1963. The field is currently operated by Chevron and produces from the Beluga/Tyonek gas pool. Both Beluga and Tyonek sands are productive. Production is from low permeability sands, 1-4md. Other reservoir characteristics are shown in Table 2. Production is currently from 6 of 11 wells from an average depth of 6,012'ss. Total cumulative production was 12.9 BCF through June 2009.

The structure is an elongate anticline 13 miles long and 3 to 4 miles wide. No structure maps are publicly available.

Future potential lies in discovery of reservoir discontinuities such as small scale faults or stratigraphic changes and testing of additional low porosity and permeability 'tight-sands'. Fracture stimulation (with resulting additional capital expenditure) will be required to produce future 'tight-sands'.

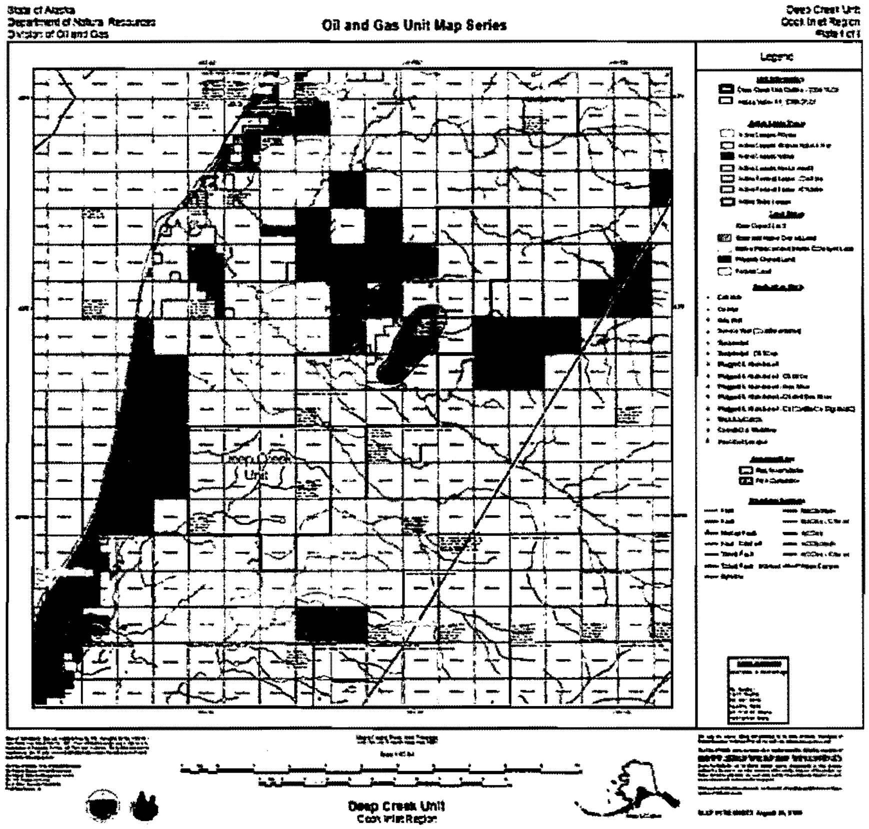


Figure B4.1: Deep Creek Unit Location Map (DNR)

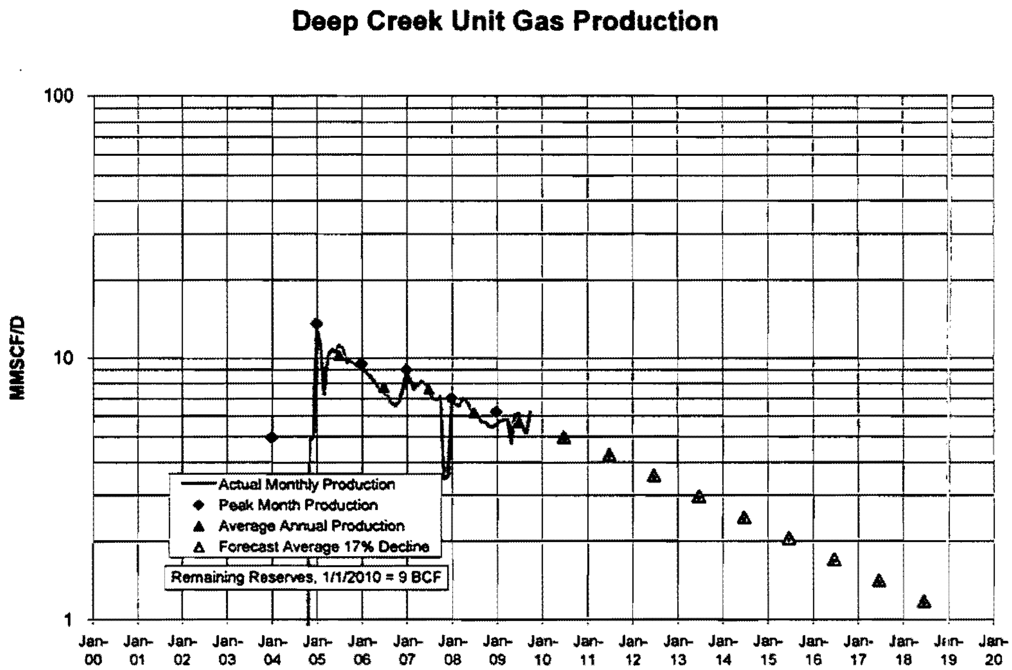


Figure B4.2: Field Production Curve 2000-2009 and Forecast

Appendix B-5: Kenai Unit Gas Field Description

Geological Introduction. The Kenai Gas field and the Cannery Loop Unit are considered part of the same gas field by the AOGCC and Marathon operates them both as part of the same Kenai Field area. The DOG considers them two separate fields and subdivides them into separate Kenai and Cannery Loop Units. They will be separated for purposes of this study. Although both are part of the same anticlinal fold they are separated by a structural saddle.

The Kenai Gas field is located on the coast of the Kenai Peninsula just south of the Kenai River and about 70 miles southwest of Anchorage. The Kenai field was discovered in 1959 by the Unocal Kenai Unit No 14-6 well which was drilled to a depth of 15,047' MD to explore for deep oil objectives. Gas production began in 1963 and has been from 7 gas pools, Sterling 3, 4, 5.1, 5.2, 6, Upper Tyonek-Beluga, and Tyonek, however, from 2000 to 2009, only the Sterling 3, 4, 6, Upper Tyonek-Beluga and Tyonek have been produced, with the other pools shut-in. The Sterling 6 pool is used for gas storage. The Sterling gas pools were discovered in 1959 but the Tyonek pool was discovered in November 1967 by the Unocal Kenai Deep Unit #1 well. Production started from the different pools at different times. Initial test production in the Sterling 3, 4 and 6 began July 1965, April 1965 and November 1960 with continuous production beginning in 1966, 1968 and 1961, respectively. Tyonek continuous production began in 1968. Upper Tyonek-Beluga production began in December 1967 and was combined in 2003 for production reporting purposes. Reservoir depths range from about 3,700'ss to 9,000' ss. Field reservoir statistics are shown in Table 2. The field has produced, through June 2009, a cumulative total of 2,361 BCF.

The structure is a broad, gently folded, asymmetrical anticline with a slightly steeper west flank (Figure B5.1). The fold axis is oriented north-south in the Kenai field but curves slightly to the north-northeast in the Cannery Loop unit. No faults are shown on the publicly available maps.

The thick pay section involving multiple pools offers good potential for new reserve discoveries. Additional reserve growth is most likely to come from the Beluga and Tyonek pools through discovery of isolated sands near the edges of the field. Also, testing of 'tight-sands' not previously considered economically viable may lead to new reserves.

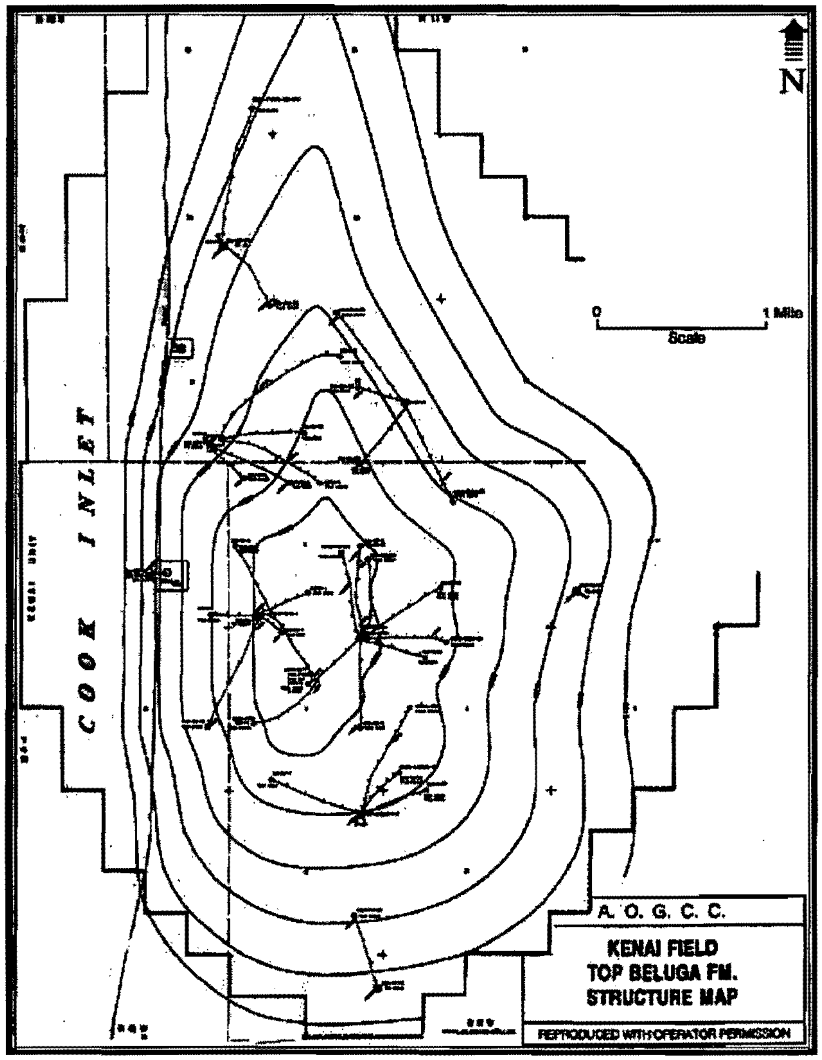


Figure B5.1: Kenai Unit Structure Map (AOGCC)

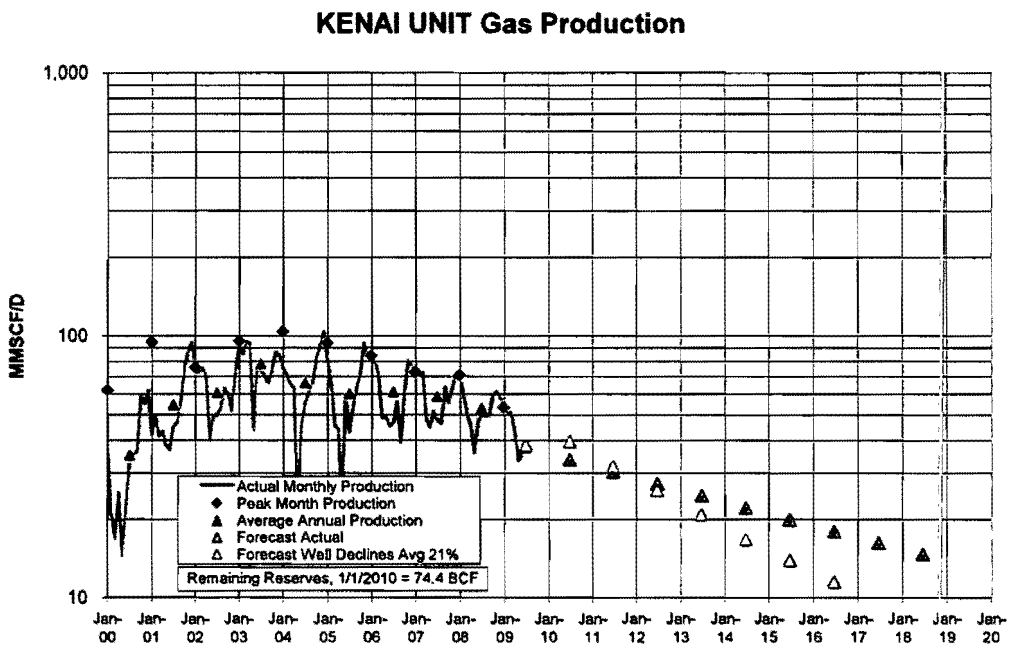


Figure B5.2: Kenai Unit Production Curve 2000-2009 and Forecast

Appendix B-6: North Cook Inlet Unit Gas Field Description

Geological Introduction. The North Cook Inlet gas field is located offshore Cook Inlet about 38 miles southwest of Anchorage and 38 miles north-northeast of Kenai. It was discovered in 1962 by the Pan American Cook Inlet St.17589 No.1well which was drilled to a depth of 12,237' MD to explore for deep oil objectives. The well blew out and was never tested. The field is currently operated by ConocoPhillips. There are 16 total wells in the field, 12 are currently producing and 3 are shut-in. Gas production began in 1969 form both the Sterling and Beluga formations, with the production combined into a single pool. Production depths range from about 3,500'ss to 7,000'ss. Multiple pay zones are produced from both formations. Conoco Phillips subdivides the Sterling into 13 productive zones designated A, B and Cook Inlet 1 through 11 and the Beluga into 21 sands designated A through U for a total of 34 zones. Total net pay is 310 feet. Log derived porosities range from the low 30%'s in the Cook Inlet sands to mid 20%'s in the upper Beluga to the low 20%'s to high teens in the lower Beluga. The total cumulative production through June 2009 was 1,808 BCF.

The structure is a broad, gently folded, slightly asymmetrical anticline with steeper dips on the west side and with the fold axis trending in a north-northeast direction (Figure B6.1). The structure is about 6 miles long and 4 miles wide. No small scale faults are shown on the publicly available structure map.

The multiple pay zones provide good opportunities for future reserve growth similar to the new pay sands discovered at the Beluga gas field. Additional reserves are likely to be found in the Beluga formation at the edges of the field where sands are disconnected from existing perforations due to reservoir heterogeneities.

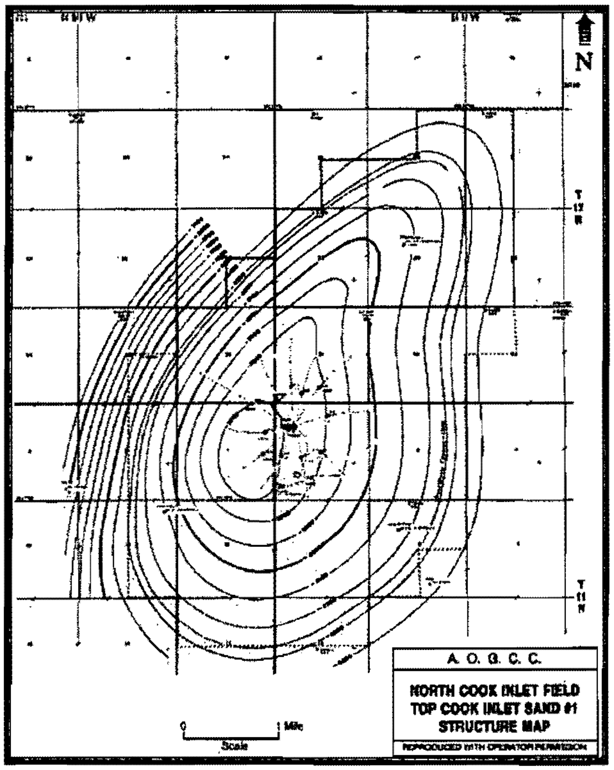


Figure B6.1: North Cook Inlet Field Structure Map (AOGCC)

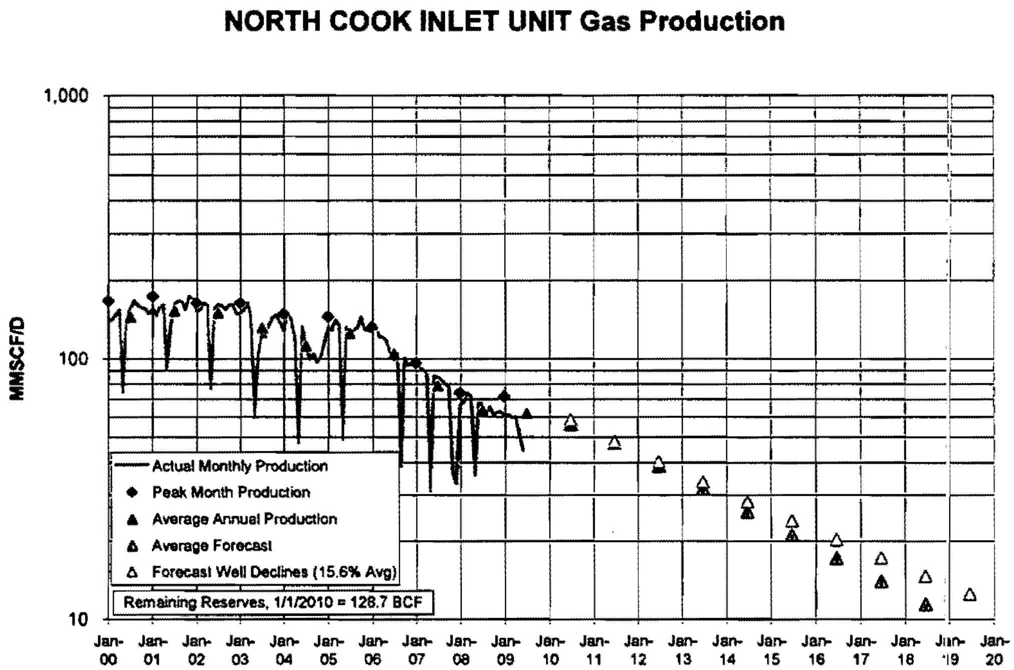


Figure B6.2: North Cook Inlet Unit Production Curve 2000-2009 and Forecast

Appendix B-7: Ninilchik Unit Gas Field Description

Geological Introduction. The Ninilchik gas field is located partly onshore and partly offshore on the Kenai Peninsula between Clam Gulch and Ninilchik. There are three Participatng Areas (PAs) within the Ninilchik Unit: Falls Creek; Grassim Oskolkoff; and Susan Dionne. The Falls Creek part of the field was discovered in 1961 by the Socal Falls Creek No. 1 well which was drilled to a total depth of 13,795' MD (13,382' TVD) in search of deep oil objectives. This was initially called the Falls Creek gas field and the Falls Creek Unit was established. The G. Oskolkoff part of the field was discovered in 2001 by the Marathon Grassim Oskilkoff No. 1 well which was drilled to 11,600' MD (8,510' TVD). The Susan Dionne part of the field was discovered in 2002 by the Marathon Susan Dionne No. 3 well drilled to 10,255' MD (8,102' TVD). The current operator of the unit is Marathon. Production is from three pools in the Tyonek formation, Falls Creek Tyonek undefined gas pool, G. Oskolkoff undefined gas pool and the S. Dionne undefined gas pool from depths of 4,690'ss, 3,496'ss and 3,338'ss, respectively. Production began in September of 2003 in the Falls Creek and G. Oskolkoff pools and in December 2003 in the S. Dionne pool. Reservoir characteristics are shown in Table 2. Gas production is currently form 3 wells at Falls Creek, 5 wells at G. Oskolkoff, and 6 wells at S. Dionne. A cumulative total of 94.8 BCF has been produced through June 2009.

The structure is an anticline 17 miles long and 3 miles wide with the crest about 1 mile offshore and parallel to the shoreline. No structure contour maps are publically available for the field. 3-D seismic was acquired by Marathon over part of the structure. The field straddles the transition zone between onshore and offshore resulting in somewhat difficult seismic acquisition and merger with the onshore and offshore data.

Since the Ninilchik field has been produced for only 6 years, future reserve growth will likely come from additional 'tight-sand' Tyonek reservoirs that are yet to be tested. Also shallow Beluga reservoirs could be new reserve targets. The 3-D seismic should allow detailed mapping of the structure with identification of possible small scale cross-faults forming isolated fault blocks.

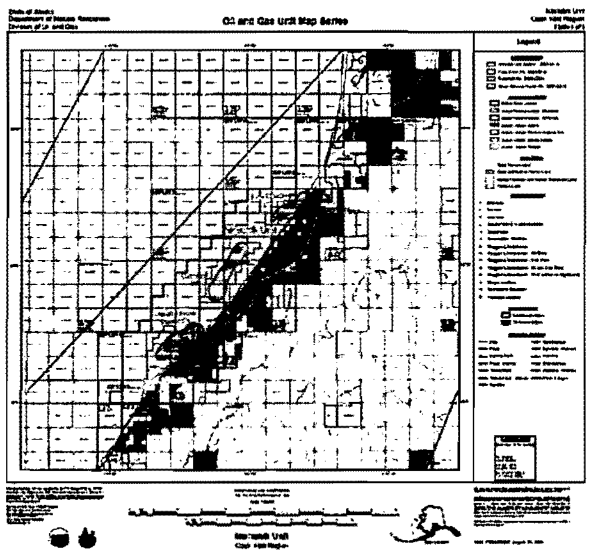


Figure B7.1: Ninilchik Unit Location Map (DNR)

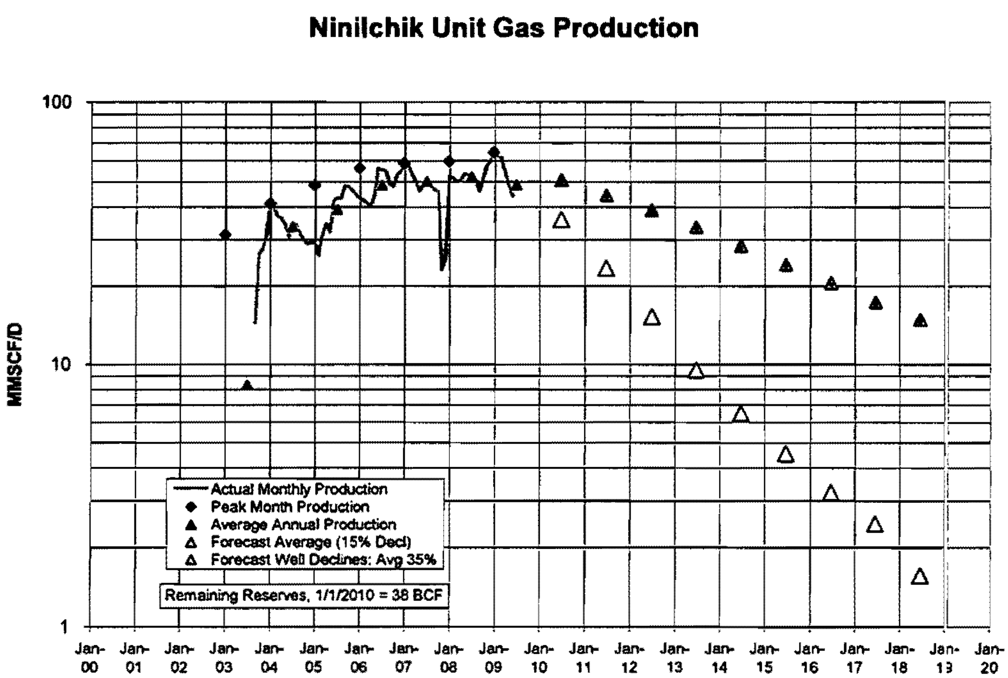


Figure B7.2: Ninilchik Unit Production Curve 2000-2009 and Forecast

Appendix B-8: Sterling Unit Gas Field Description

Geological Introduction. The Sterling gas field is located on the Kenai Peninsula about 60 miles southwest of Anchorage and about 8 miles east of Kenai. It was discovered in 1961 by the Unocal Sterling Unit 23-15 well which was drilled to a depth of 14,832' (MD and TVD) in search of deep oil objectives. From 1962 through 1998 production was from the Sterling undefined gas pool. In 1999 two additional pools were added, Beluga undefined and Tyonek undefined and in 2008, two more, Upper Beluga undefined and Lower Beluga Tyonek undefined, were added and the production volumes were corrected to reflect the re-assignment. These new pools expanded the unit boundary and added new participating areas to the unit. The field was shut in between 1986-1994 and Marathon took over as operator in 1994. The Upper Beluga undefined pool was discovered in 1998 by the Marathon Sterling Unit No. 32-09 which was drilled to a depth of 6,858' MD (6,336' TVD). Production depths are at 5,030' ss, 5,400' ss, 8,104' ss, 9,449'ss for the Sterling, Upper Beluga, Beluga undefined and Tyonek undefined pools. Reservoir characteristics are shown in Table 2. Gas production is currently from three wells. Total cumulative production is 12.3 BCF through June 2009.

The structure is a subtle, low relief, four way dip anticline, about 2.5 miles wide and with only about 100 feet of closure (Figure B8.1). 3-D seismic led to the drilling of the Sterling 32-09 well and the discovery of the Upper Beluga pool.

The addition of the upper Beluga and Lower Beluga Tyonek pools in 2008 demonstrates the kind of reserve growth that occurs through ongoing field development. Additional reserve growth will likely come from the Beluga and Tyonek as more potential 'tight-sands' are tested and additional wells are drilled. Development will likely require fracture stimulation with associated capital expenditure.

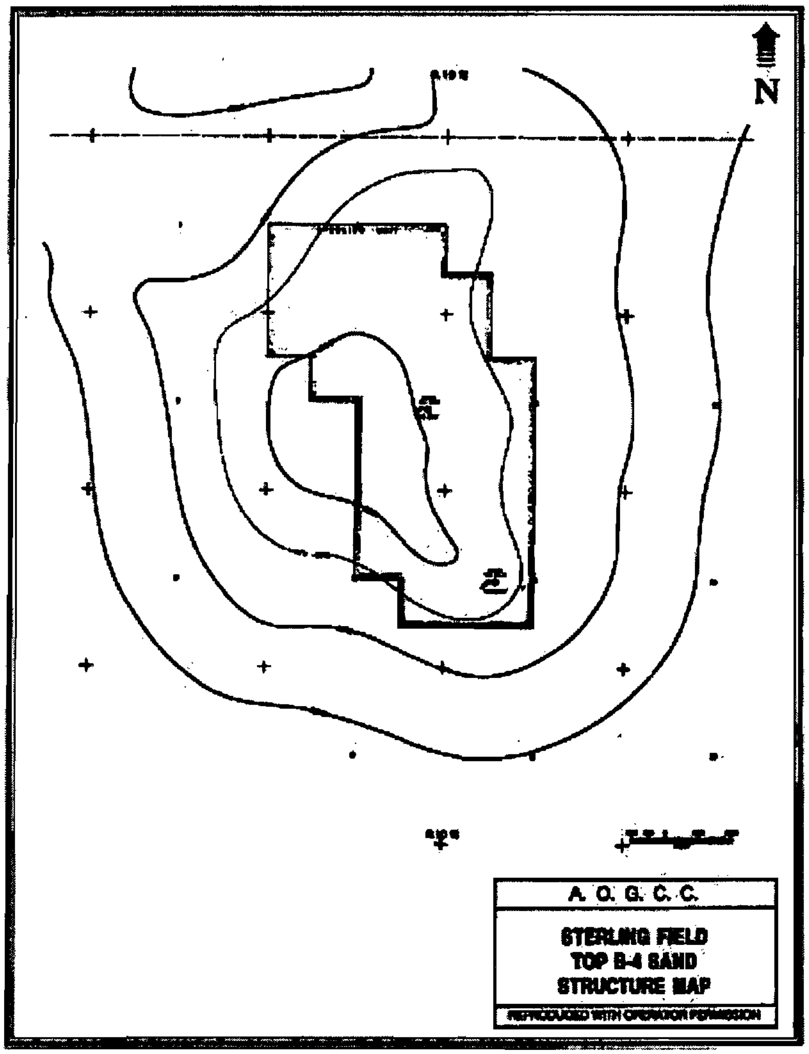


Figure B8.1: Sterling Field Structure Map (AOGCC)

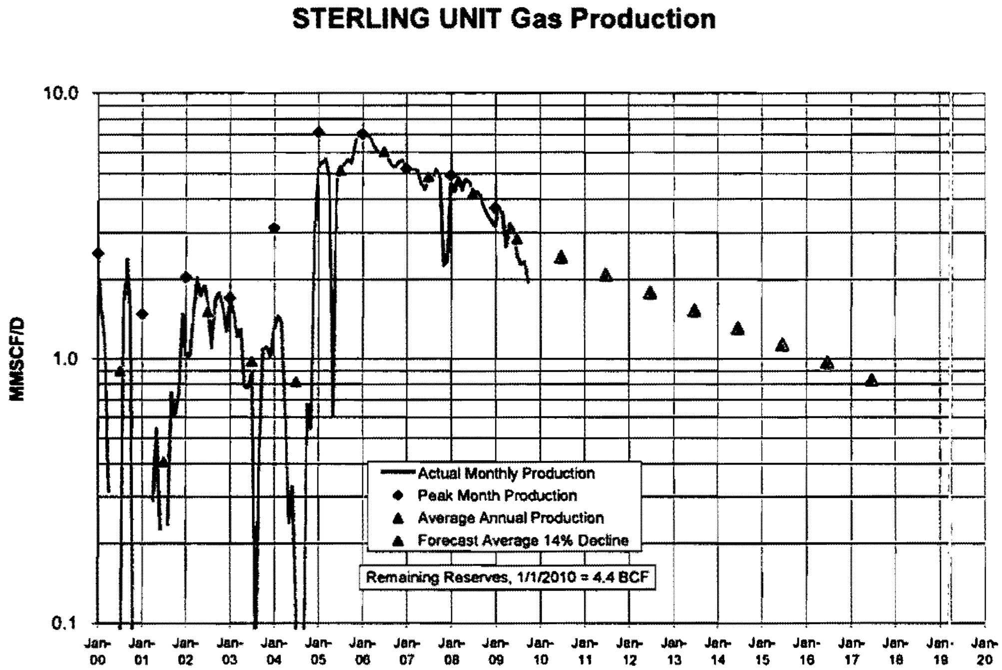


Figure B8.2: Sterling Unit Production Curve 2000-2009 and Forecast

Appendix B-9: Swanson River Unit Gas Field Description

Geological Introduction. The Swanson River gas field is located on the Kenai Peninsula about 45 miles southwest of Anchorage and about 15 mile northeast of Kenai. It is subdivided into a northern Swanson River Unit and a southern Soldotna Creek Unit. The oil field, discovered in 1957, was the first oil field discovered in Cook Inlet and it began producing oil in 1958 from the Hemlock formation. Associated gas produced with the oil was re-injected beginning in 1962 for pressure maintenance. Gas from other fields was also injected. Gas was discovered in the Swanson River field in 1960 by the Unocal Swanson River Unit 212-10 well which was drilled to 12,029' MD (11,526 TVD) as an oil development well. Chevron is the current operator. Intermittent production occurred in 1960, 1962 through 1966, 1979 and continuous production began in 1987. Production from 1960 to 2005 was from the Sterling and Tyonek formations and was assigned to a single undefined gas pool. In 2005 the gas was re-assigned to 3 pools, Sterling undefined, Beluga undefined and Tyonek undefined, producing from sands at 2,720', 2,974' and 3,060' in the Sterling, 4,676' in the Beluga, and 5,600'-7,500' in the Tyonek. Current production is from 2 wells in the Sterling, 1 well in the Beluga and 2 wells in the Tyonek. Individual pool production and reservoir characteristics are shown in Table 2. The Swanson River field is used by Chevron for gas storage. Total cumulative production for all three pools through December 2008 was 50.3 BCF.

The Swanson River structure is a slightly asymmetrical anticline, with the fold axis oriented in a north-south direction. The structure is 8 miles long and 2 to 3 miles wide and is cross-cut by several normal faults, some of which are sealing and subdivide the reservoirs into separate fault blocks. 3-D seismic shot over the structure has allowed more accurate mapping of the cross faults and identification of previously untested fault blocks.

Future reserve growth will likely come from future drilling of untested isolated fault blocks identified on the 3-D seismic data. Also, with the re-assignment of the gas into 3 pools in 2005 and production from the Beluga sands being added, potential exists for additional Beluga sands being tested as well as isolated pay being discovered in the Beluga and Tyonek sands due to stratigraphic isolation.

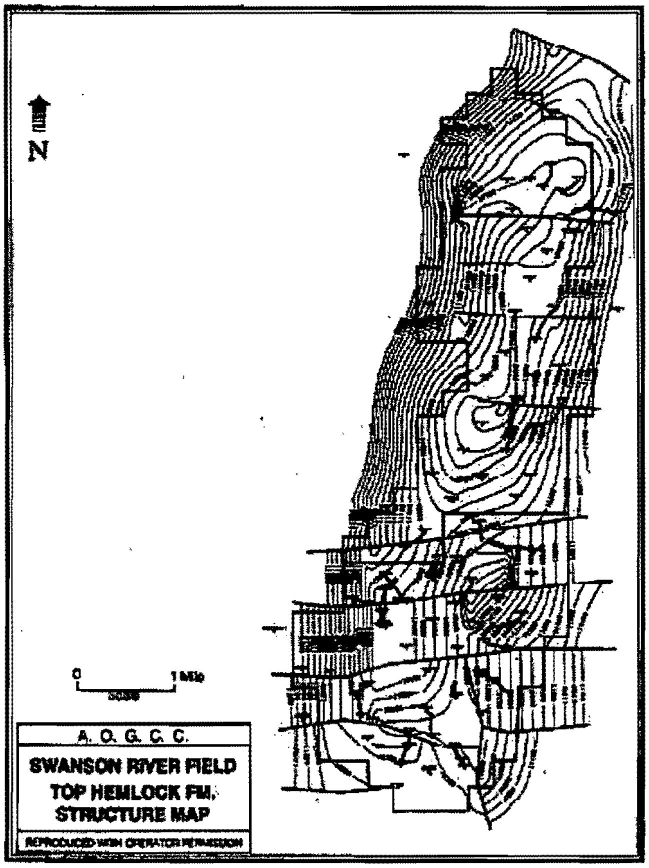


Figure B9.1: Swanson River Field Structure Map (AOGCC)

SWANSON RIVER Gas Production

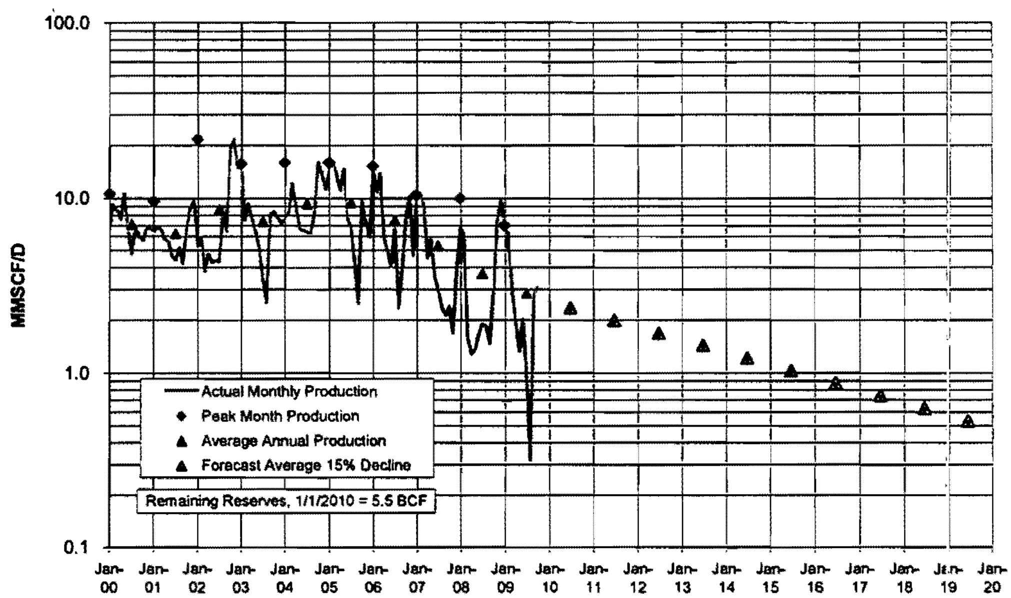


Figure B9.2: Swanson River Unit Production Curve 2000-2009 and Forecast

Appendix B-10: Trading Bay Unit Gas Field Description

Geological Introduction. The McArthur River field is located offshore on the western side of Cook Inlet 64 miles southwest of Anchorage and about 20 miles southwest of Tyonek. The McArthur River oil field was discovered in 1965 by the Unocal Grayling 1A well which found oil in the Lower Tyonek (Middle Kenai G), Hemlock and West Foreland formations. The mid Kenai gas pool was discovered in 1968 by the Unocal Trading Bay Unit G-18 well which was drilled to a depth of 6,930' MD (4,510' TVD). Gas production began in December 1968 from the Grayling platform and soon thereafter from the Dolly Varden and King Salmon platforms. This initial production was "wet" gas associated with the oil produced from the oil pools. Most of this associated gas was not sold commercially but was used for gas lift and field operations. In 1988 the Steelhead platform was constructed to produce the dry (biogenic) gas from the Middle Kenai gas pool also called the Grayling sands. These sands are in the Chuitna and Middle Ground Shoal members of the upper Tyonek formation and are defined as the sands correlative with the interval between a measured depth of 1,518' in the Trading Bay unit M-1 well to 8,982' in the Trading Bay Unit M-14 well. The reservoirs are sandtones labeled zones A through F and G through O above the G zone oil pool and are conglomeratic, thin (20-50') thick and range in porosity from 12 to 32%. The gas is currently produced from 16 wells with about 4% of it used for field operations and the remainder sold commercially. Total cumulative production was 1,105 BCF through June 2009.

The structure is a faulted anticline 4 miles long and 1.5 miles wide oriented north-northeasterly (Figure B10.1). The two normal faults that intersect the structure do not affect the limits of the gas in the reservoir.

The relatively thick stratigraphic interval containing pay sands provides good opportunities for isolated, disconnected pay at the fringes of the field. Also, reserves could be added through future testing of 'tight-sands' in the Tyonek which have not been the target of existing development as well as petrophysical examination of the Beluga section for potential low resistivity pay.

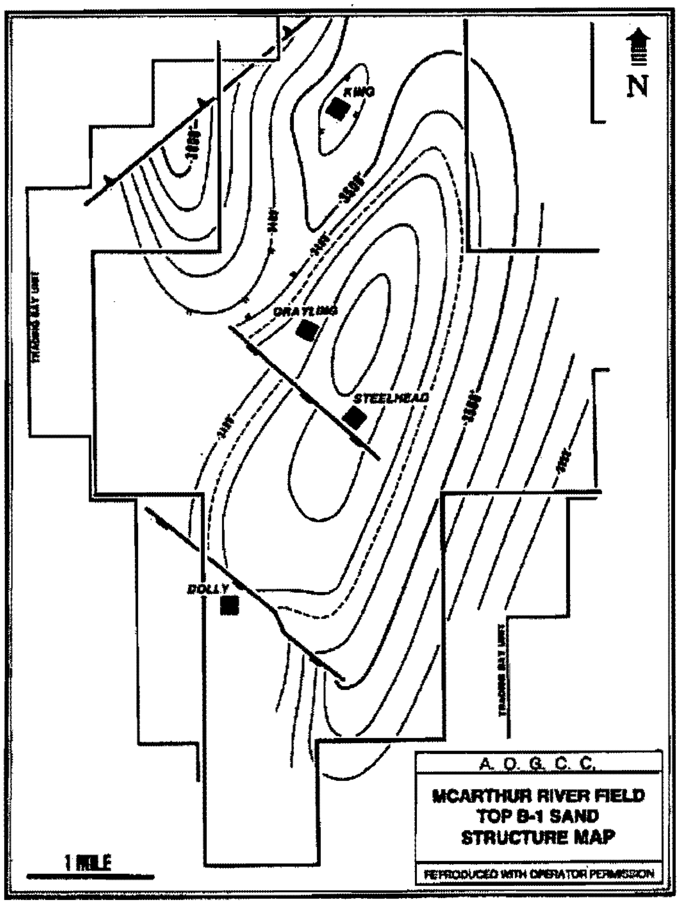


Figure B10.1: Trading Bay Unit Structure Map (AOGCC)

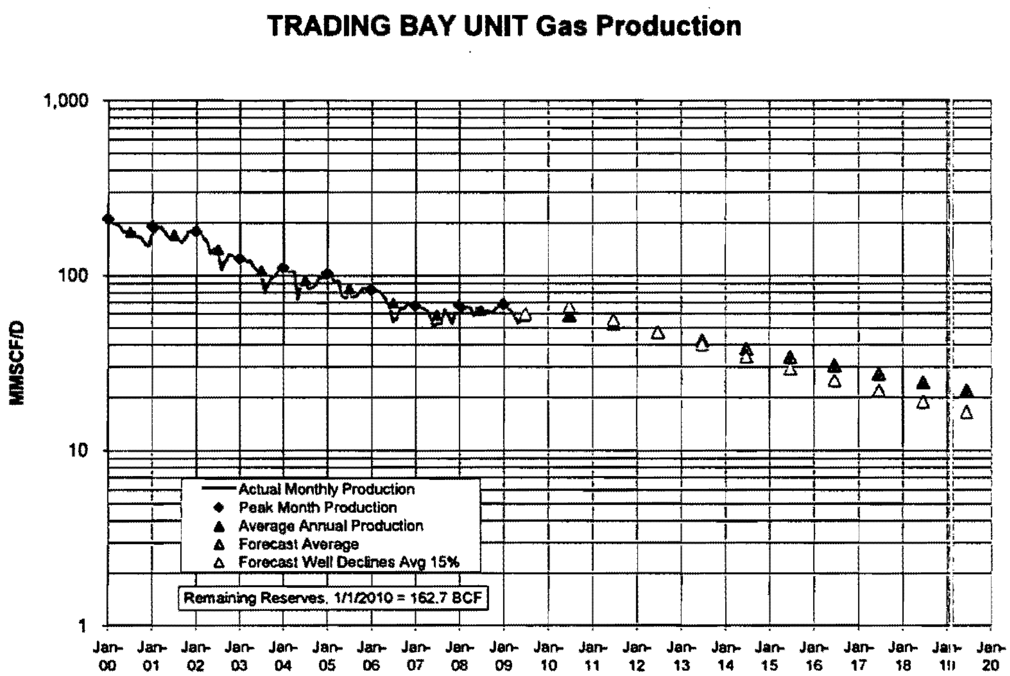


Figure B10.2: Trading Bay Unit Production Curve 2000-2009 and Forecast

Appendix B-11: Other Cook Inlet Gas Fields

The Remaining gas fields are shown in Table 3 with cumulative reserves and reservoir characteristics. Also included in the "Other" category is gas associated with oil production in Cook Inlet.

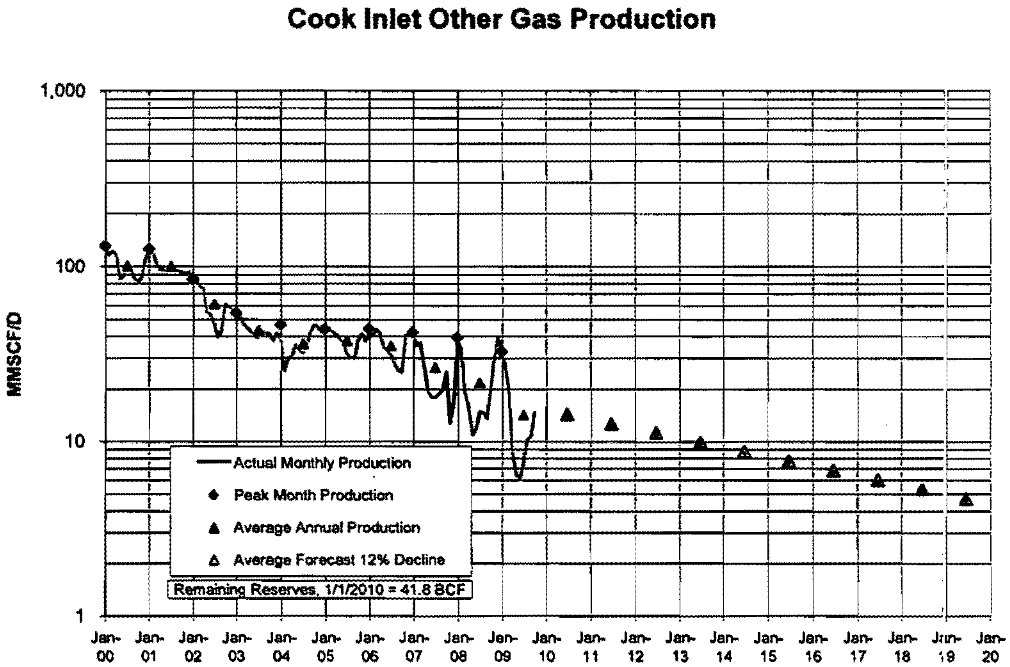


Figure B11.1 "Other" Cook Inlet Production Curve 2000-2009 and Forecast

Appendix C-1 DNR Geologic Reserves Study

The DNR is conducting a detailed volumetric calculation of original gas in place (OGIP) for four Cook Inlet fields, Beluga River (BRU), North Cook Inlet (NCI), (Kenai,) Ninilchik, and Trading Bay (Grayling sands). The work is being done by Meg Kremer (BRU, Ninilchik and Trading Bay), Laura Silliphant (NCI), with Paul Anderson providing geophysical support and Don Kroskoph preparing stratigraphic cross-sections. Trading bay has not been assigned to anyone as yet. Jack Hartz is conducting a detailed decline curve and material balance analysis of all the gas fields in Cook Inlet. The results of the two approaches will be compared and will yield an estimate of the proved reserves remaining in the Cook Inlet gas fields. This work is expected to be published in mid-December.

Following is the process used by Meg Kremer for the Beluga River Field. The same process was used for the other fields as well.

1. Construct cross-sections containing all 23 wells in the field and showing all the wire line curves and perforated intervals. Correlate the sands and coal beds between the wells. (Thicker coals can be correlated over the area of the field and are better in the Sterling than in the Beluga. The coal correlations can help with adjacent sand correlations but sands vary in thickness and can pinch out laterally and disconnected sands can be erroneously correlated as the same sand. Post the log tops and bases provided by ConocoPhillips for all wells in all 10 productive zones, Sterling A, B, C and Beluga D, E, F, G, H, I, and J. Identify two categories of reserves using definitions approved by SPE and WPC:
Pay = Proved (1P) reserves, colored green on the cross sections
Pay Low confidence = Probable (2P) and Possible (3P) reserves, colored yellow.

2. Apply the following criteria to identify pay. Pay consists of all zones that have been perforated or are currently perforated and have produced or are producing gas. Those same zones usually show and elevated resistivity response greater than 10 ohmm (deep resistivity) along with an SP shift off shale baseline, sonic-neutron crossover or neutron-density crossover or a decrease in sonic travel time (slower than the sonic in shales or 'other sandstones'). Some zones are labeled pay that have not been perforated if correlated to sandstones that are now being perforated in newer wells. Some zones are labeled pay that have not been perforated if the log response looks very similar to a perforated interval in the same or offset well. Completion reports available through the AOGCC were examined for production and test information. This analysis does not include production history information or deliverability. Those factors will be addressed when the volumetric analysis is compared to the decline curve/material balance analysis by Jack Hartz. Pay will include cemented off pay that can't be produced without additional capital expenditure. A log analyst in Houston, conducted petrophysical analysis to help with water saturation and porosity estimates as well as pay identification from the log data. His work will be incorporated in the study when complete. Petrophysical identification of pay is difficult in Cook Inlet due to variable clay

cementation in the sandstones which makes Rw vary throughout the section. Standard petrophysical models are not reliable in the Inlet and must be modified on a well-by-well and field-by-field basis.

3. Apply the following criteria to identify low confidence pay. Low confidence pay consists of perforated intervals that flowed minor gas with water; small sandstones in long perforated intervals where gas was present but it is unclear which sandstones produced, generally with some fluid recovery as well; and gas 'shows' on logs not as robust as Pay (lower resistivity but still over 10 ohmms, less crossover on porosity logs.

4. Sum the pay for each well and use Geographix to generate pay isopach maps for each of the 10 Sterling and Beluga zones. This essentially stacks the pay in each zone and treats it as a single sand within the zone. Meg Kremer applied a N10E bias to the computer mapping in the Sterling sands because the contouring suggested a N10E channel belt orientation. No bias was used in the Beluga sands. Computer contouring programs tend to produce 'bullseye' maps especially where well data points are few and widely spaced. Geologically biasing the contouring can produce more realistic maps.

5. Using formation tops and limited structure maps provided by ConocoPhillips create (in Geographix) additional structure maps for each of the ten zones. Using the top zone structure maps and gas water contact (GWC) depths clip the isopach maps using a polygon formed by the structure map contoured down to the G/W. This clipping method results in excess pay at the edges of the maps because it does not account for the wedge zone at the edges of the reservoir where the GWC causes the pay to taper to zero. Meg chose not to adjust for this wedge area. The Sterling A and B were clipped at a GWC of -3,590'ss and the Sterling C was clipped at GWC of -3,670'ss. The Beluga sands GWC's, gas-down-to's (GDT's) and water-up-to's (WUT') were all different, requiring review of DST and completion data to determine where to clip pay. Within some beluga zones there were three or four different possible contacts that could be up to 400' apart. Often the contact was picked by splitting the difference. Use Geographix to calculate the bulk reservoir volume from the pay isopachs

5. Use the following OGIP equation to calculate reserves.

$$OGIP = \frac{43560Ah\text{Ø}(1-Sw)(N/G)(0.98)}{Bgi}$$

Where	Ah	= bulk reservoir volume (from clipped isopachs)
	Ø	= Porosity (from density logs)
	Sw	= Water saturation (fraction)
	N/G	= Net sand to Gross sand
	0.98	= Adjustment for produced gas being 98% methane
	Bgi	= Initial gas formation volume factor

Porosity. Geographix was used to calculate average porosity of pay in each well and for each zone. These porosities were used to create a grid for each zone over the field. For

most zones the creation of the grid resulted in more pore volume than calculations without the grid. This method may be more valid in fields with closer well spacing. North Cook Inlet spacing is less than BRU. Petrophysicist is supposed to provide his input to log derived porosity.

Water Saturation. For Beluga River Field Water Saturations used were .37 for the Sterling and .42 for the Beluga. Meg believes the Sterling should be closer to .25. This may change with petrophysical input.

Net/Gross. This factor was applied after removing tight streaks, etc. on the logs. The factors applied in Beluga River Field were 0.95 for the Sterling and 0.80 for the Beluga.

Bgi. Calculated by averaging the zone tops from all wells in each zone.

Appendix C-2 DNR Engineering Production Prediction

DNR is made a rigorous study of deliverability and reserves from existing producing wells. It has been tied into the DNR geologic study to identify proved and probably reserves with a "Hypothetical Production Forecast" from Figure 14 of the December 2009 report shown below.

The reservoir analysis being performed in the study includes material balance (P over Z plots) and well, pool and field decline curve analysis. As was the case in the PRA analysis, a big issue is how to determine current deliverability due to the seasonal demand.

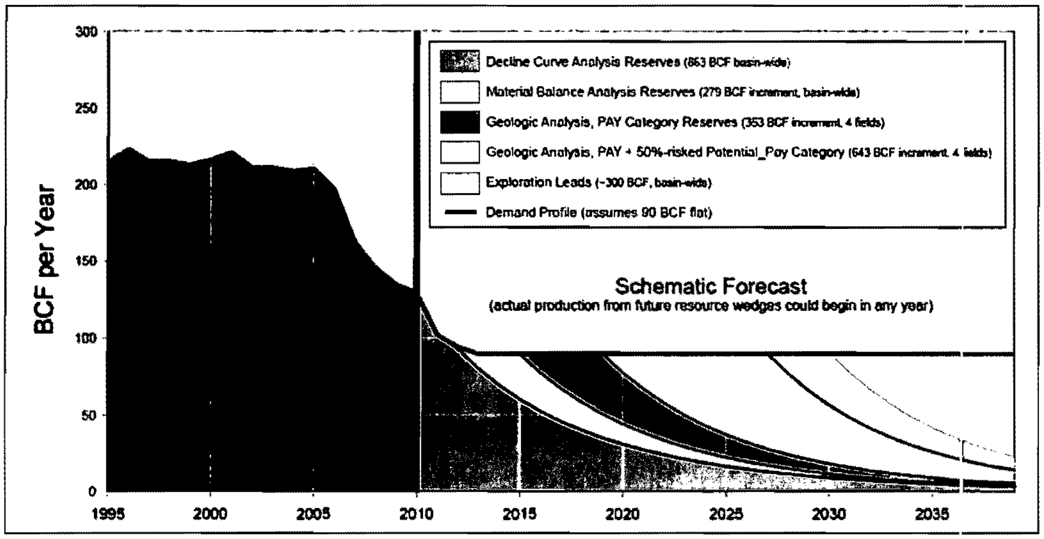
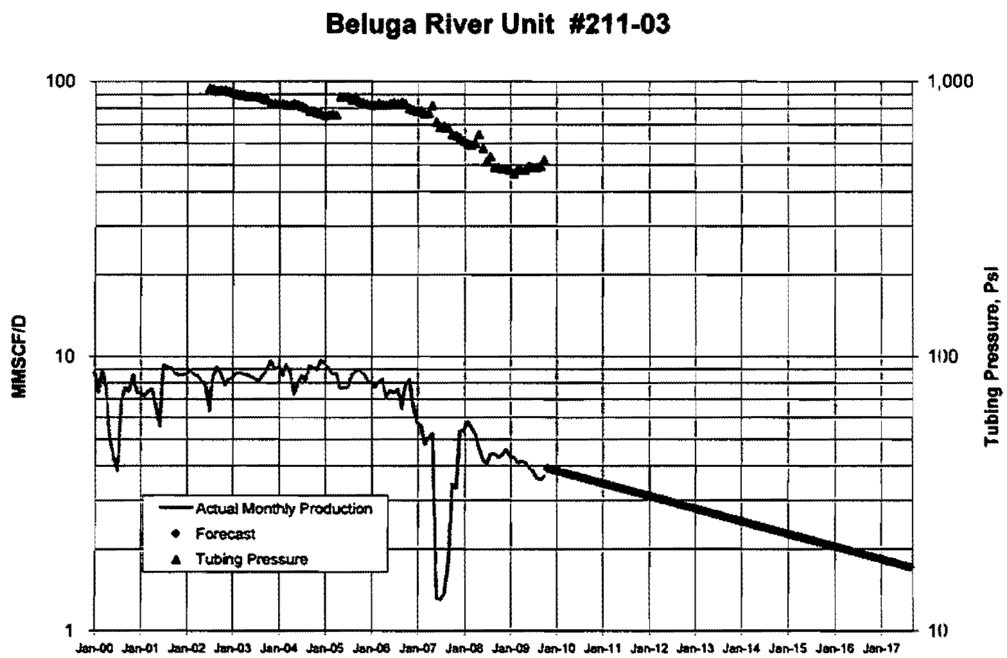
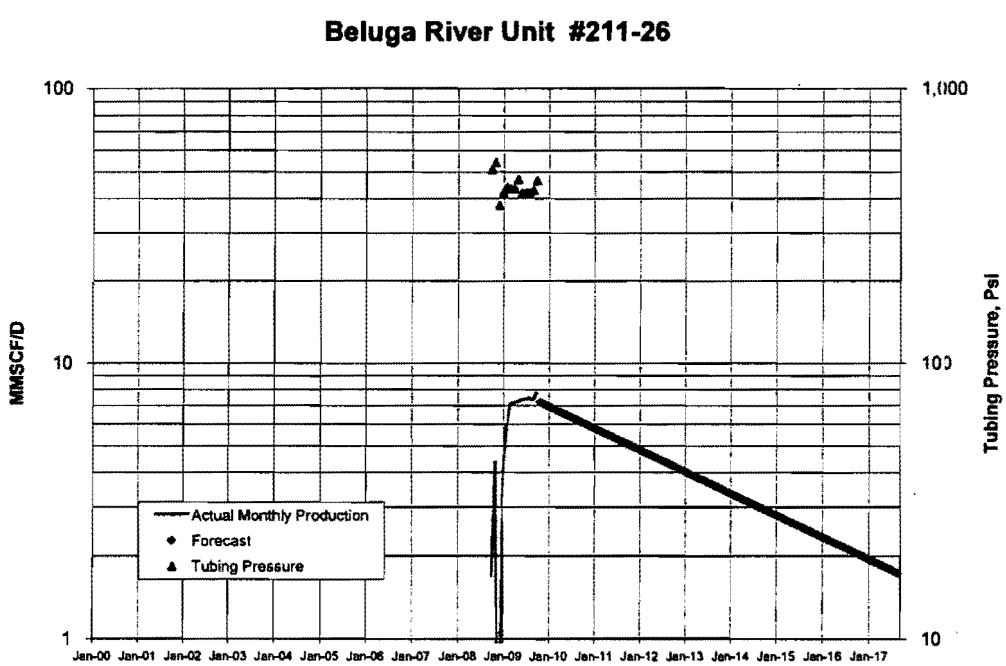


Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative estimation techniques. Successive wedges are intro-duced 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), determinis-tic 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.

Figure 14 from DNR "Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Reserves", December 2009.

Appendix D-1 Beluga River Unit Well Decline Curves





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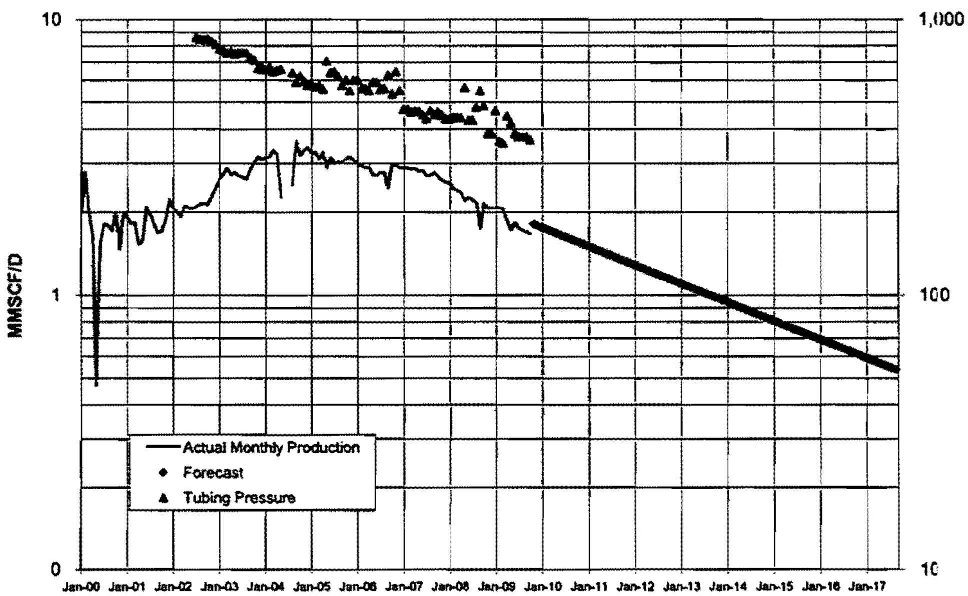

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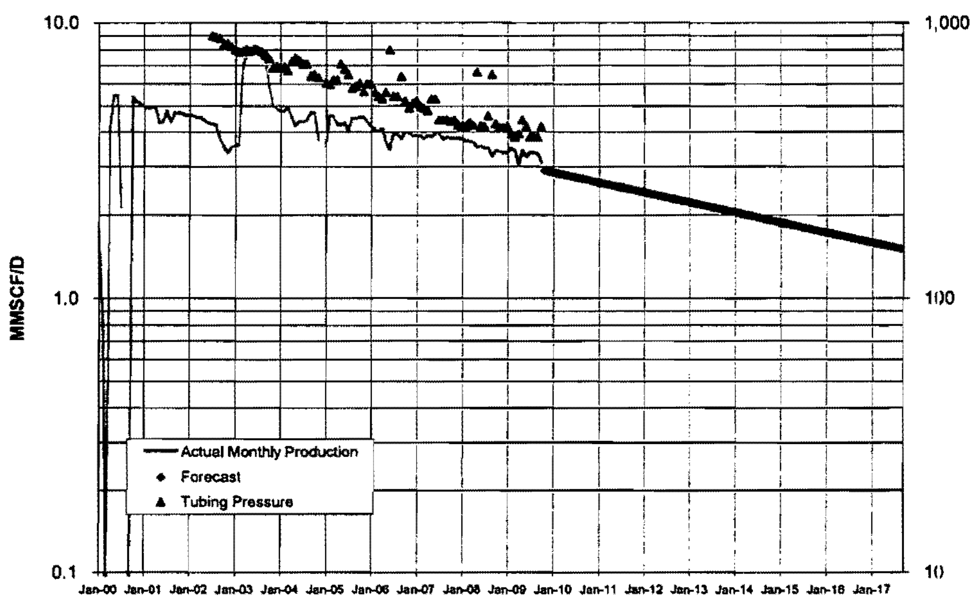

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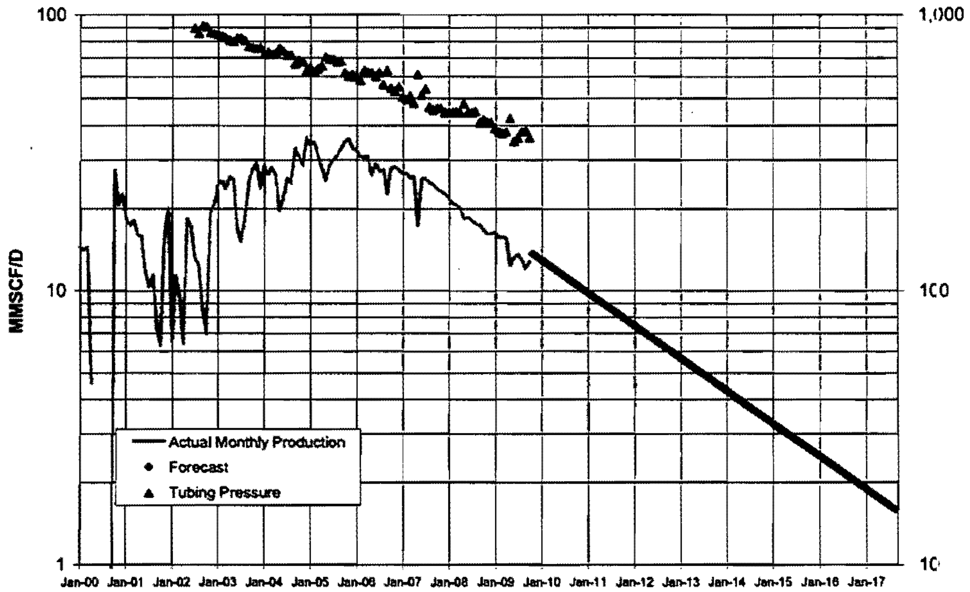

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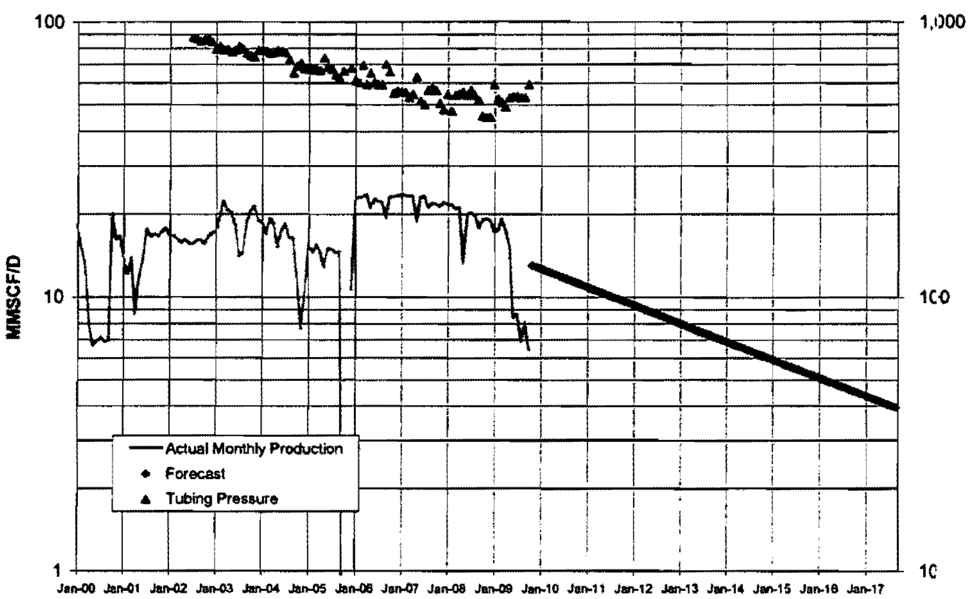

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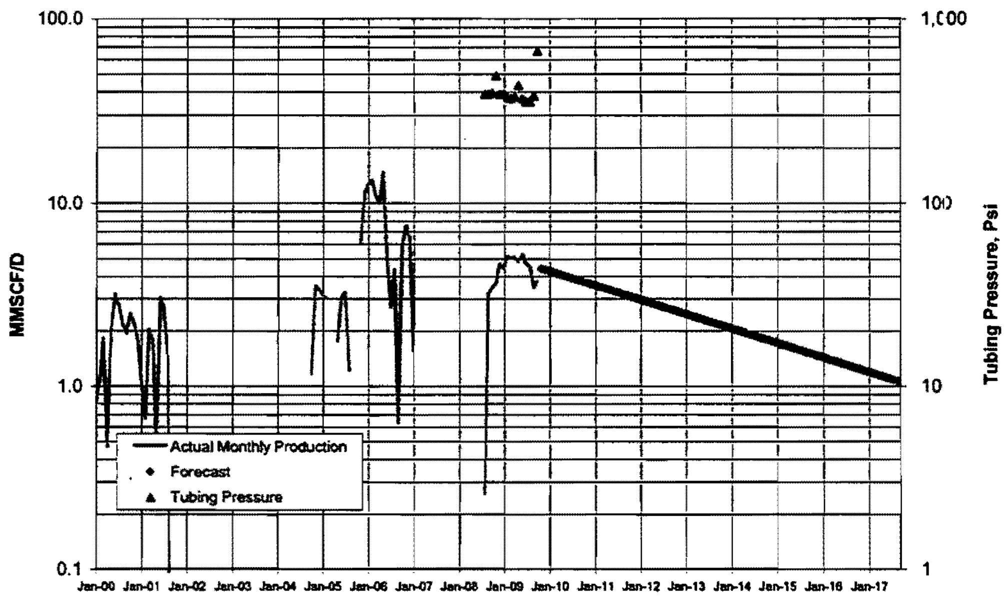

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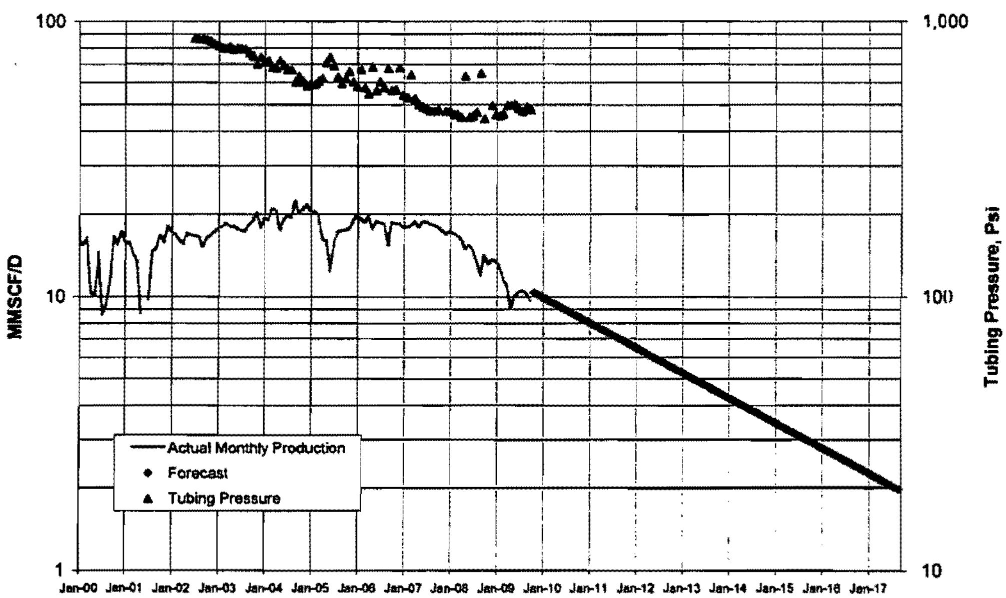

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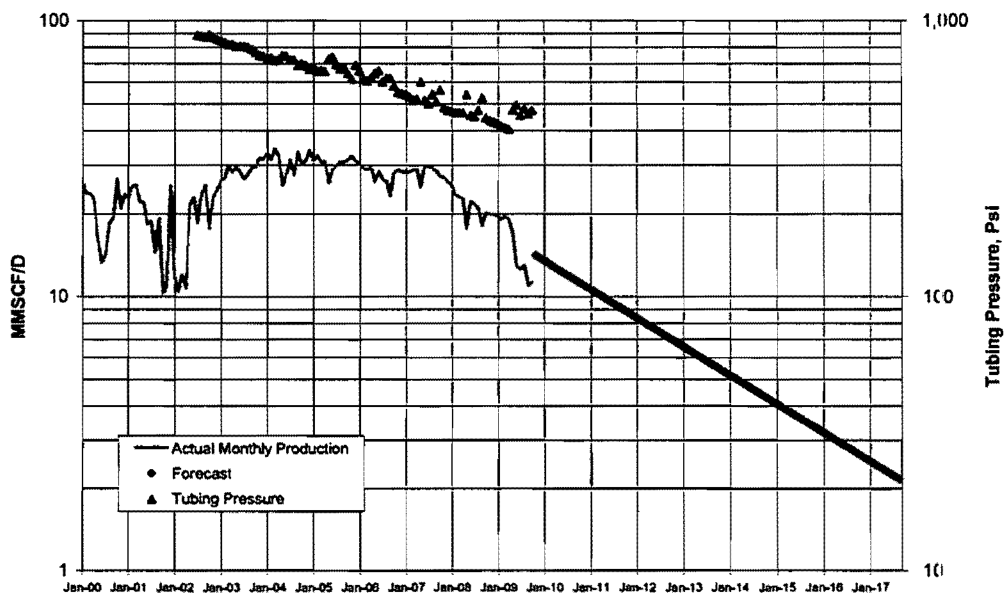

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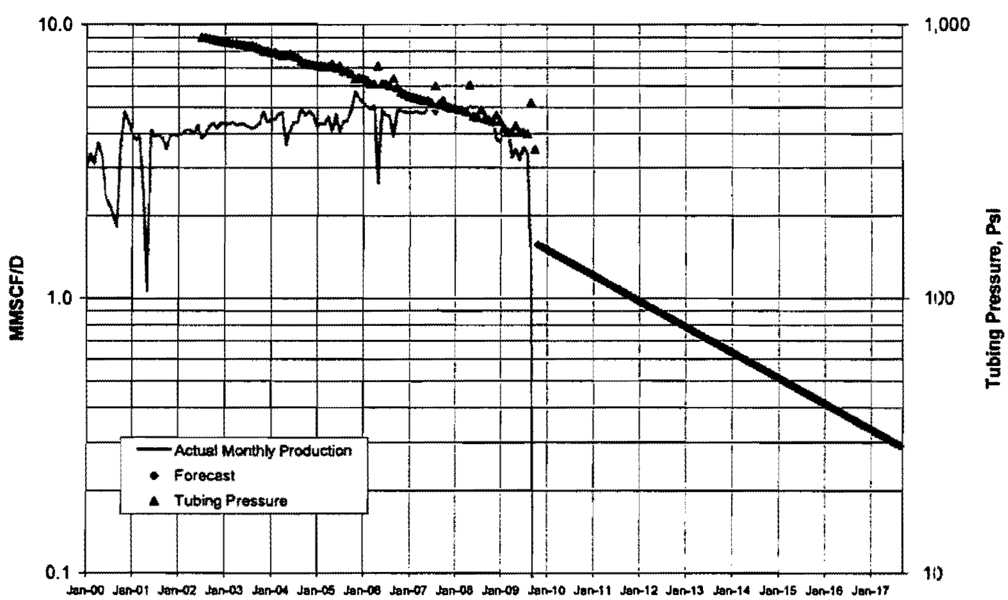

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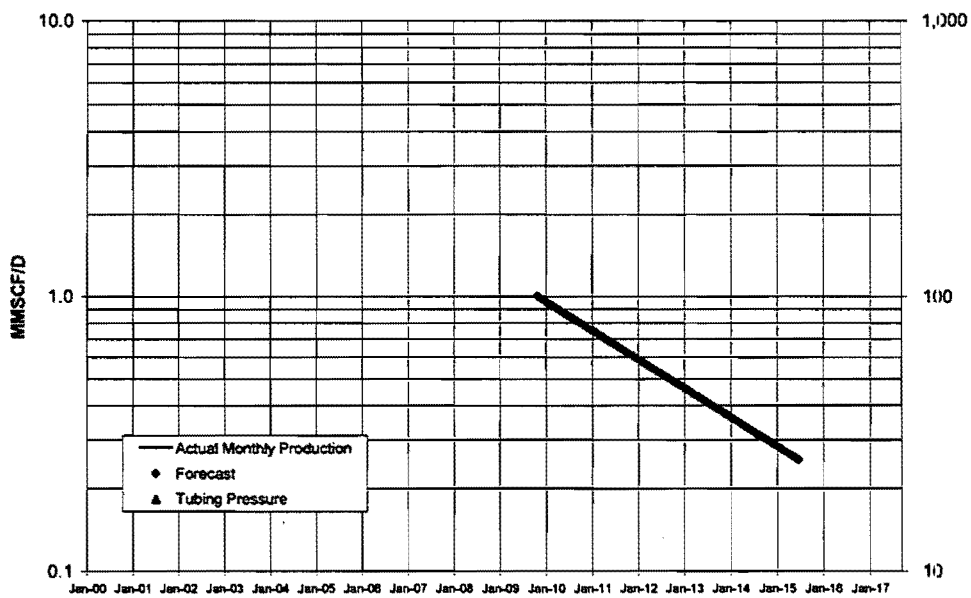

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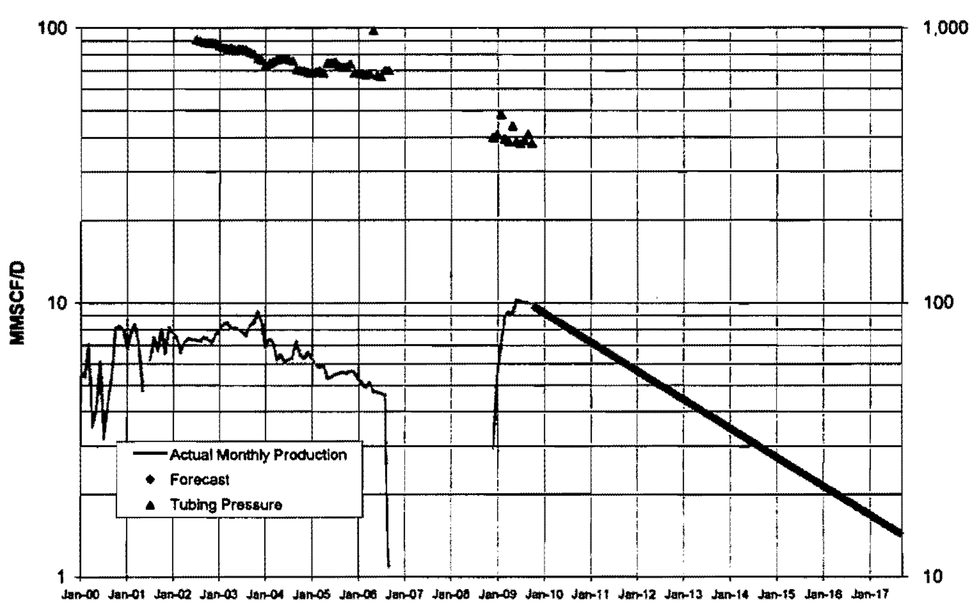

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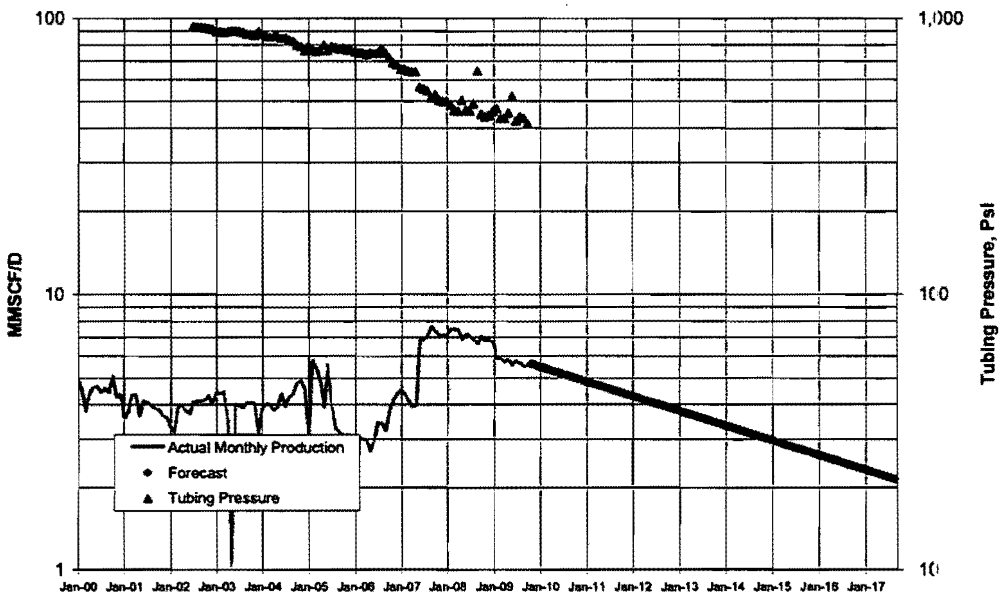

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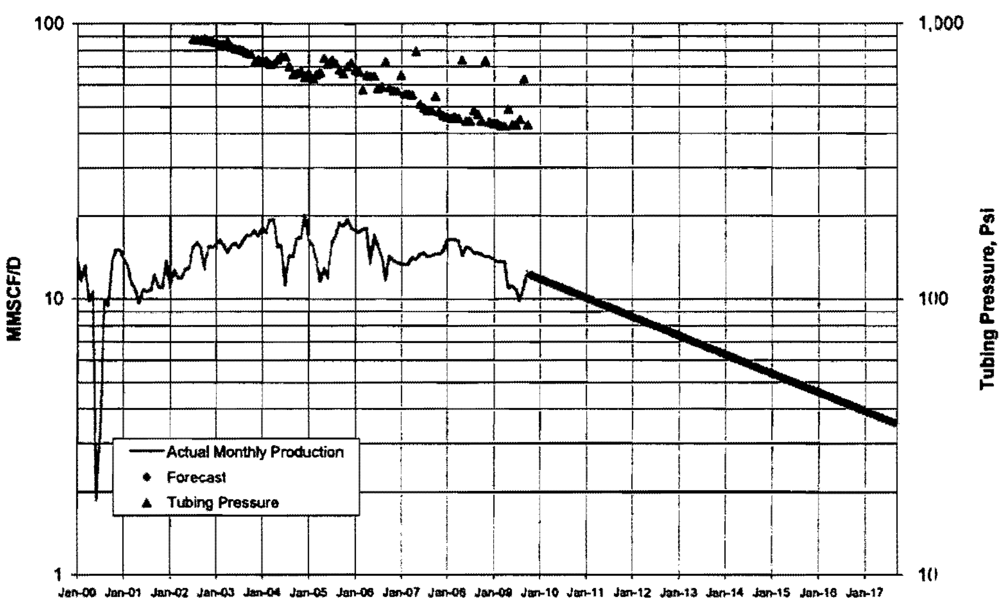

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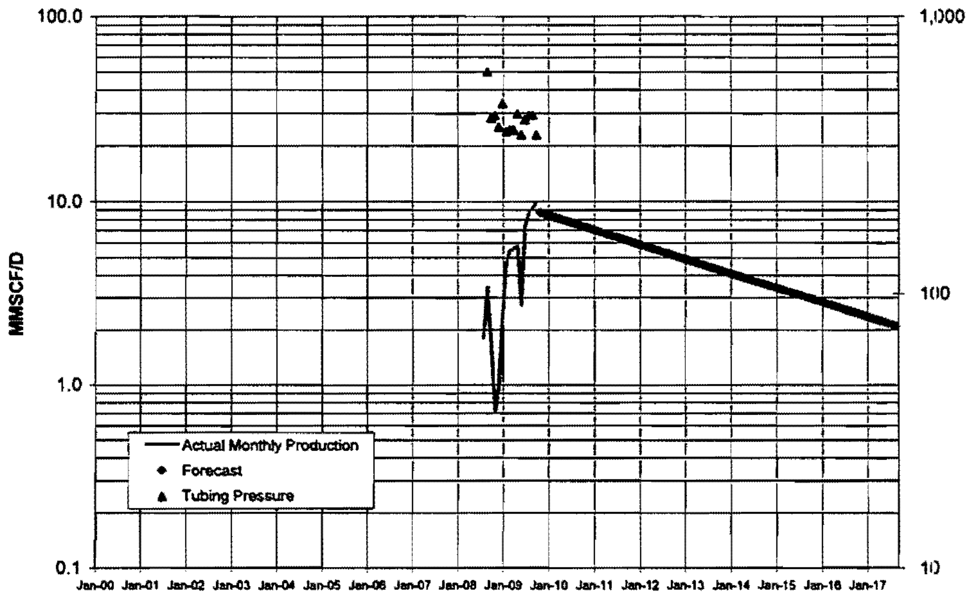

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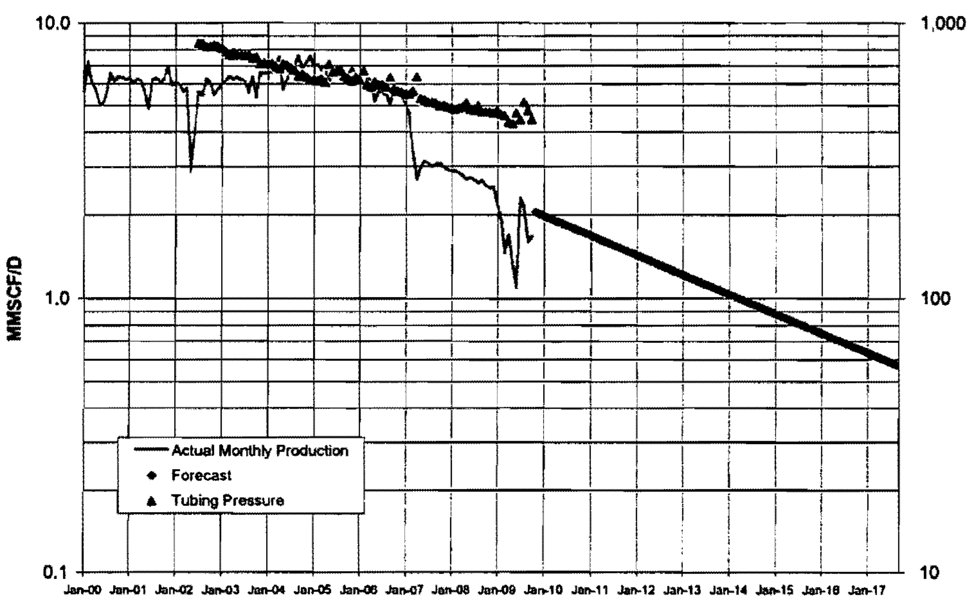
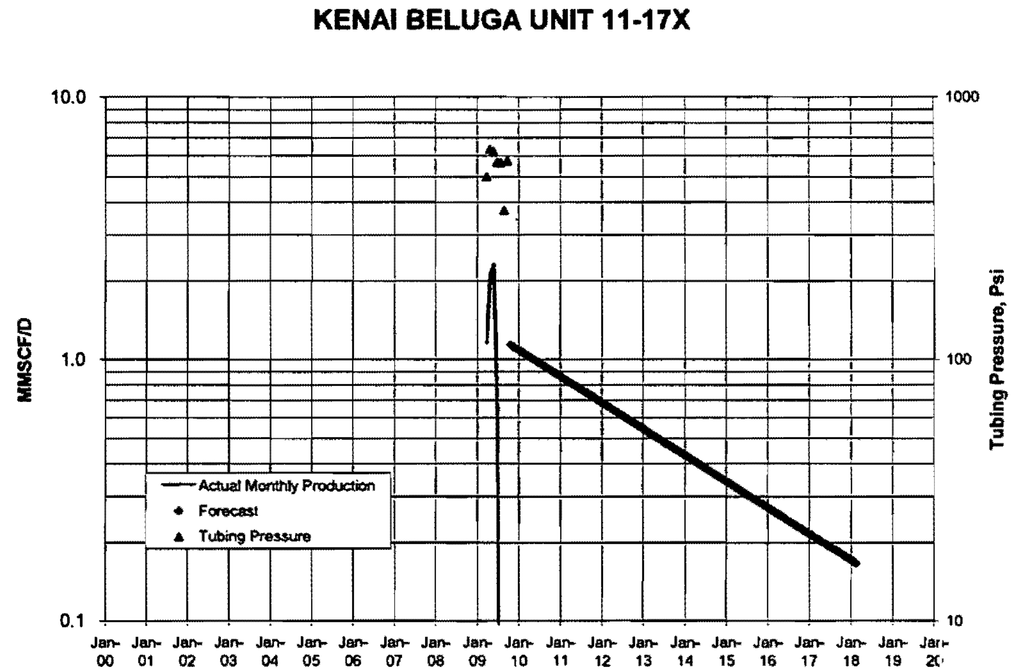
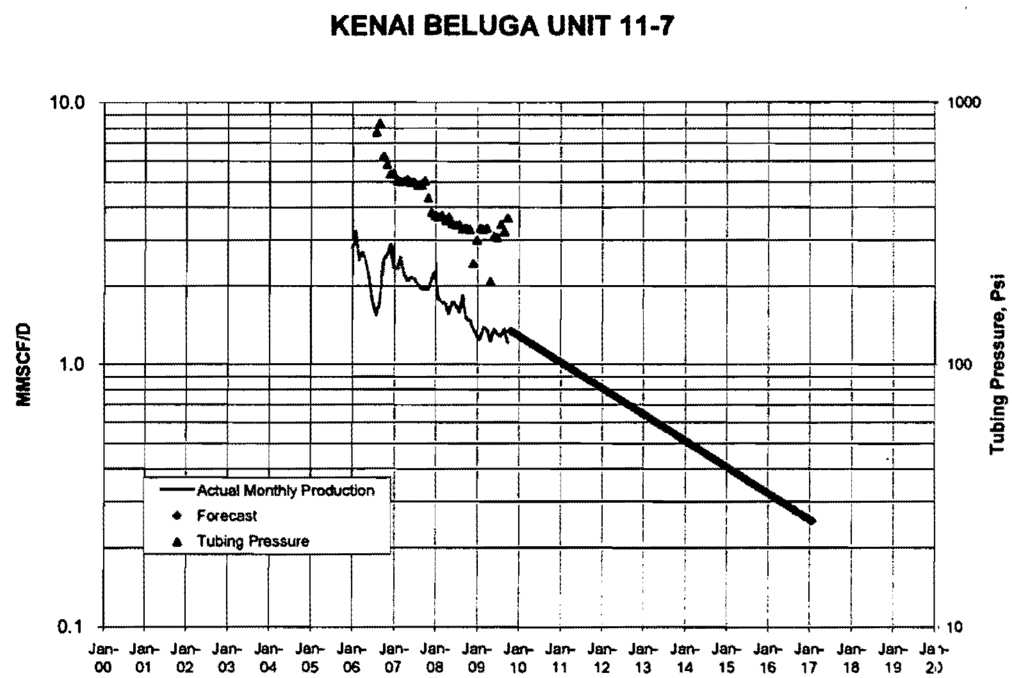


Appendix D-2: Kenai Unit Well Decline Curves





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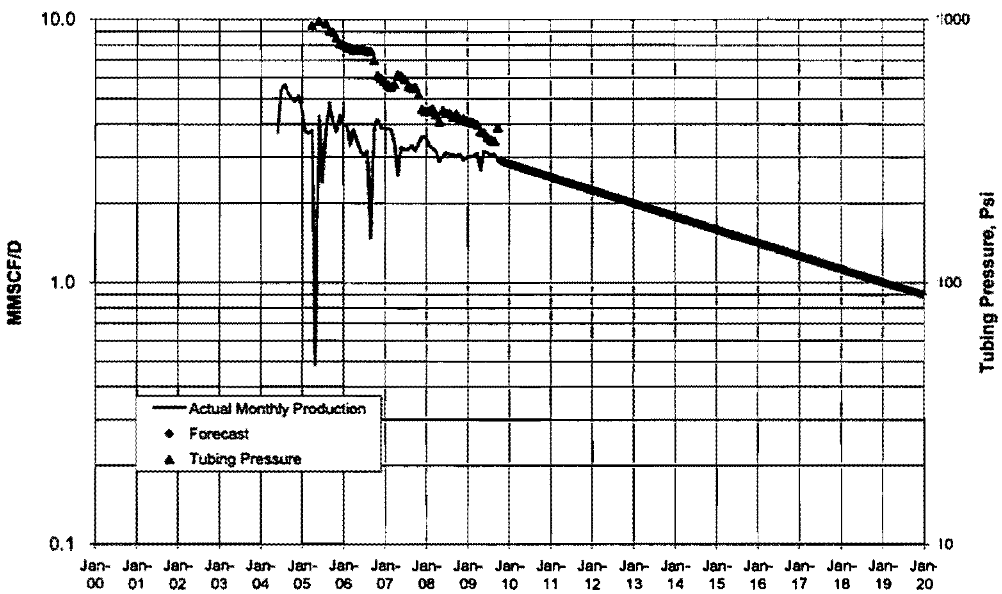

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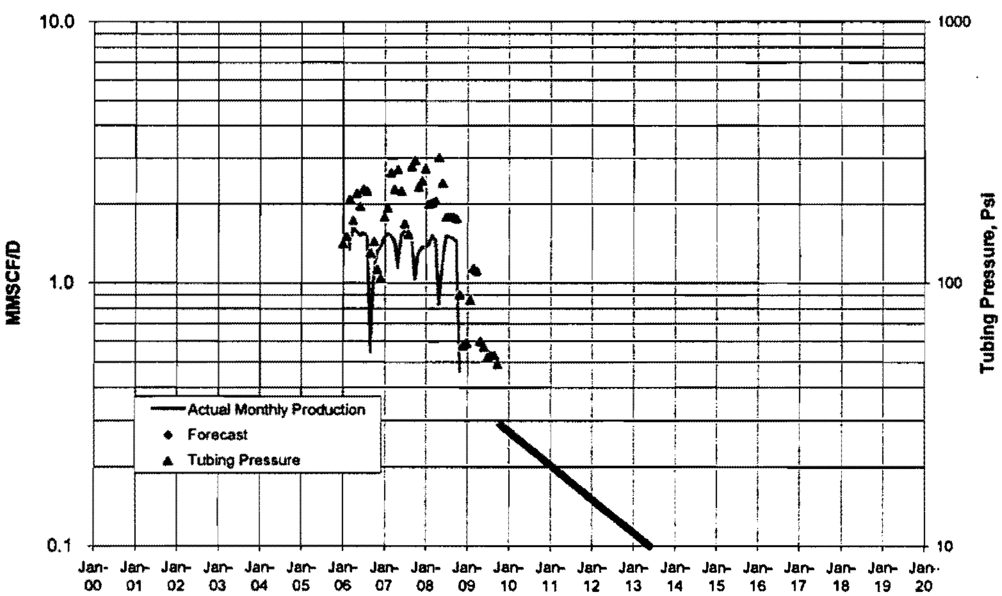

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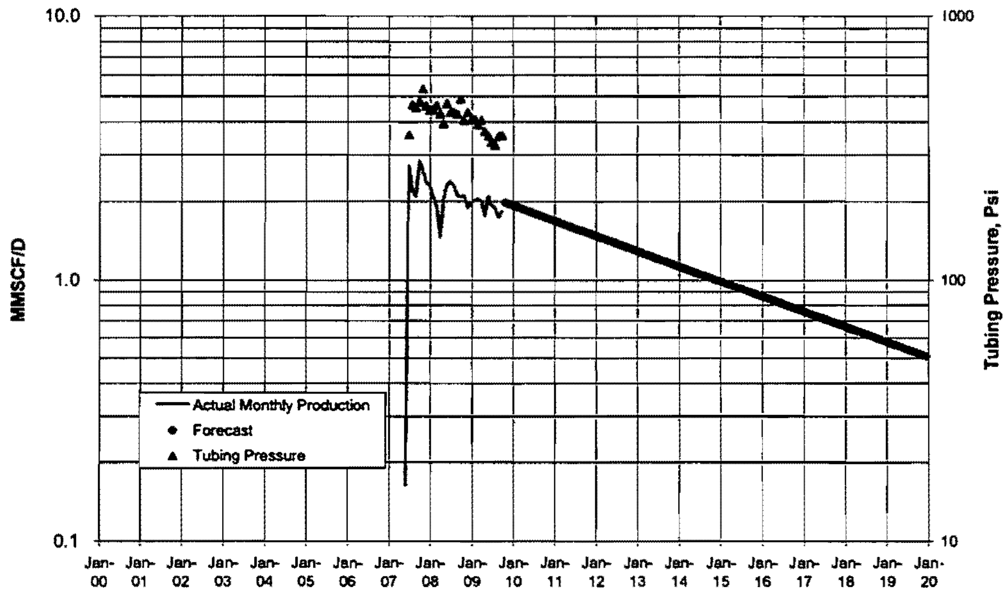

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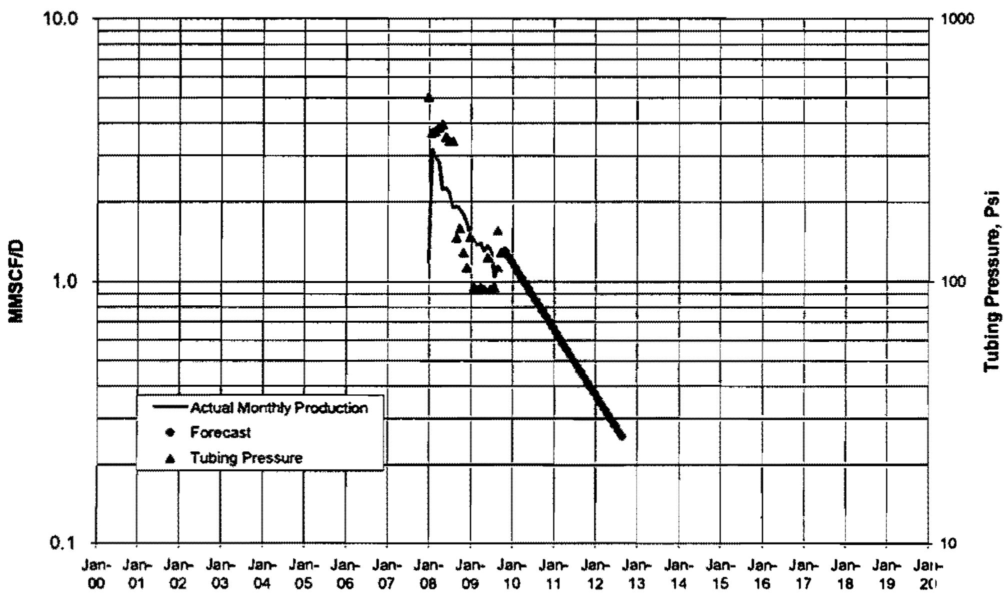

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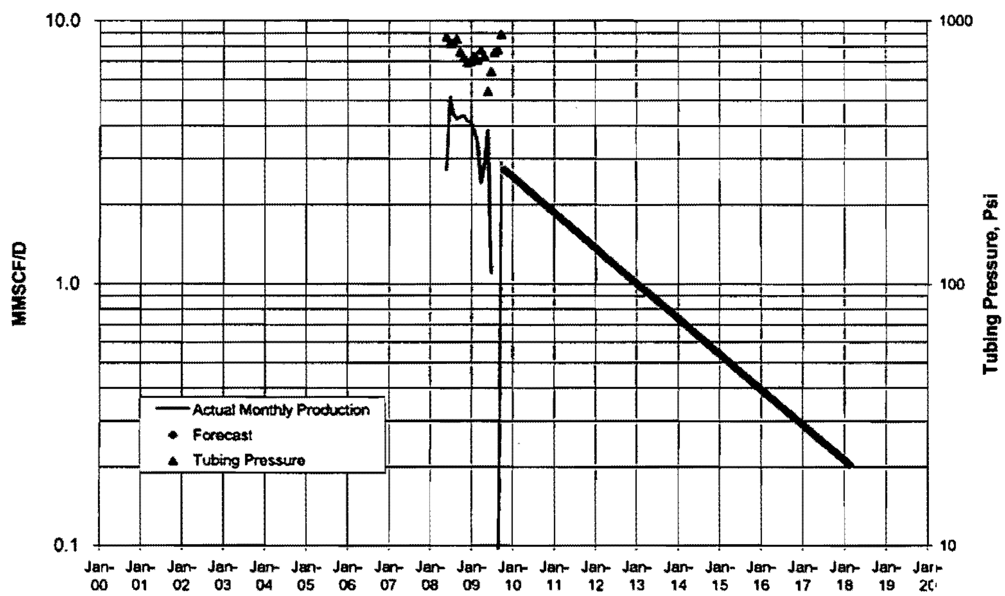

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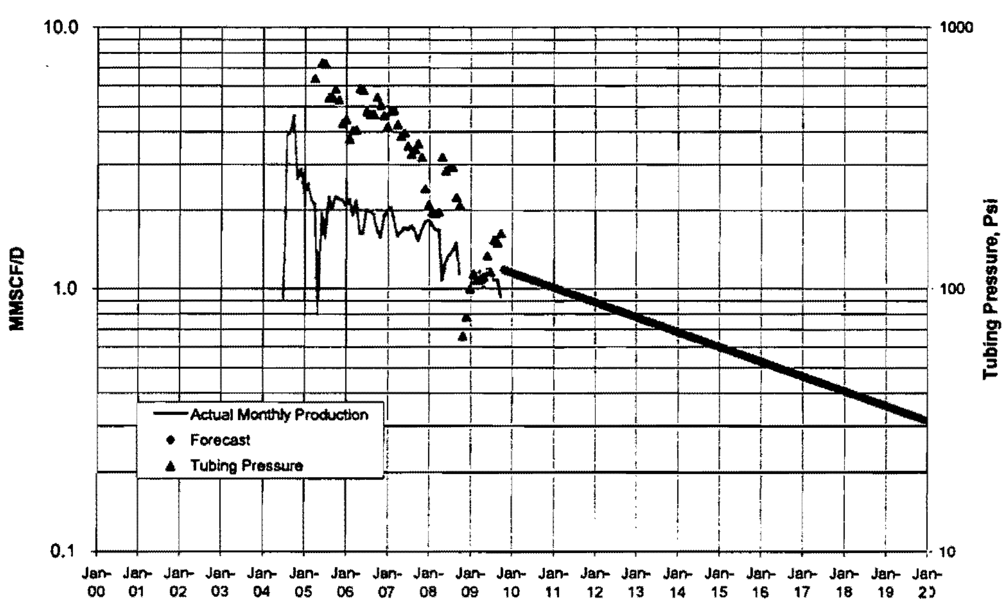

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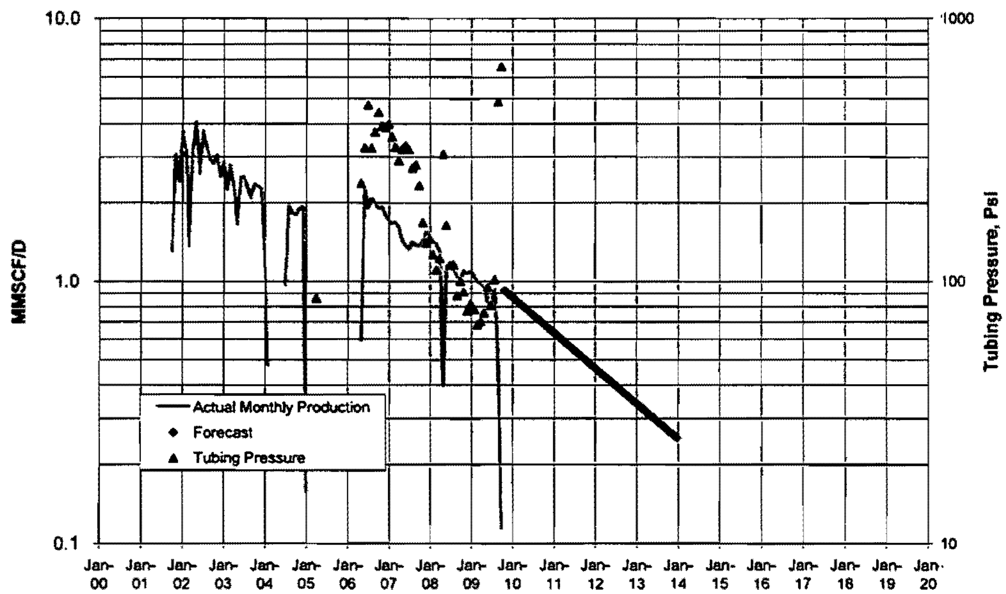

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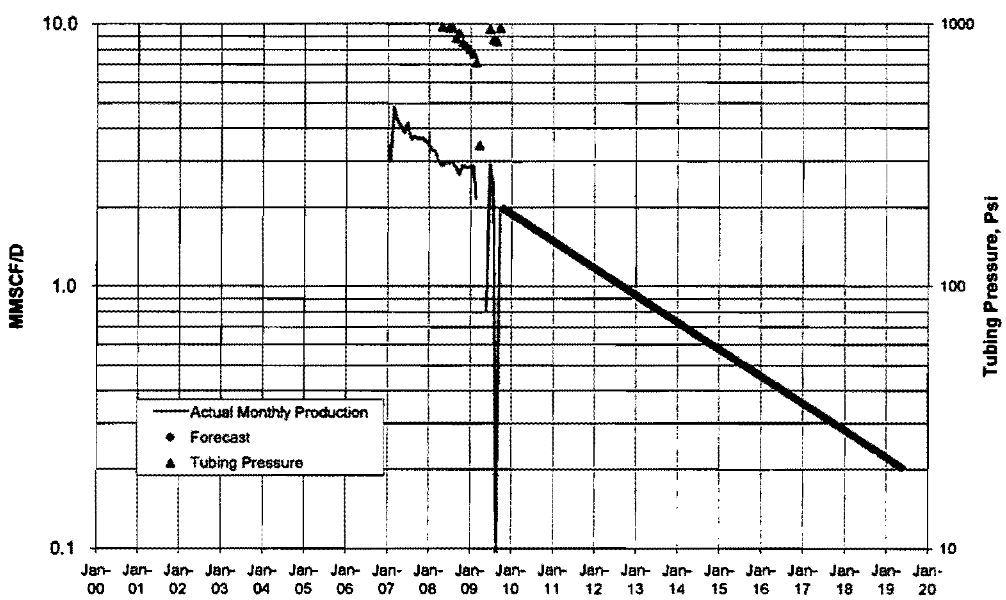

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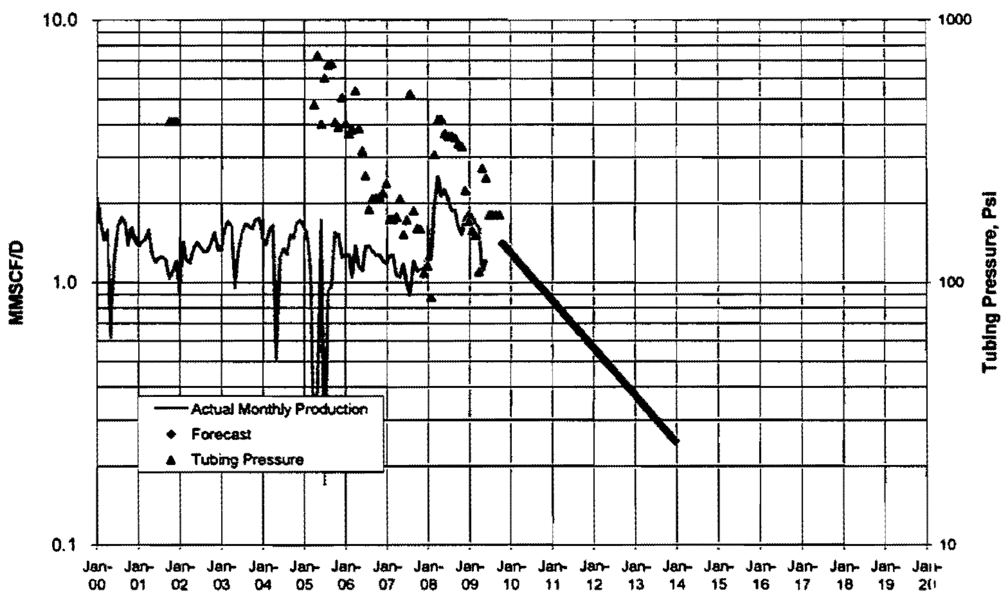

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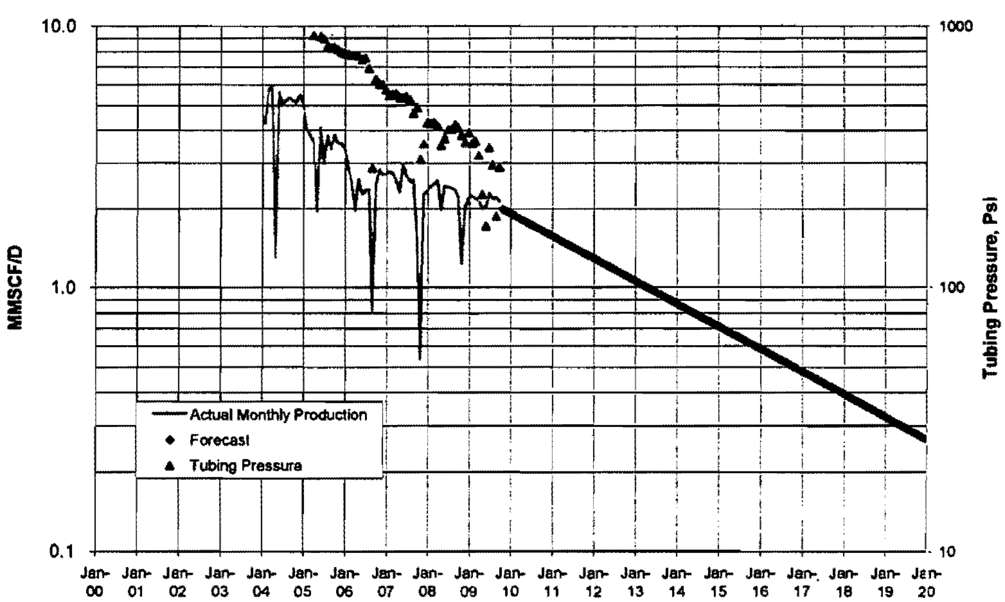

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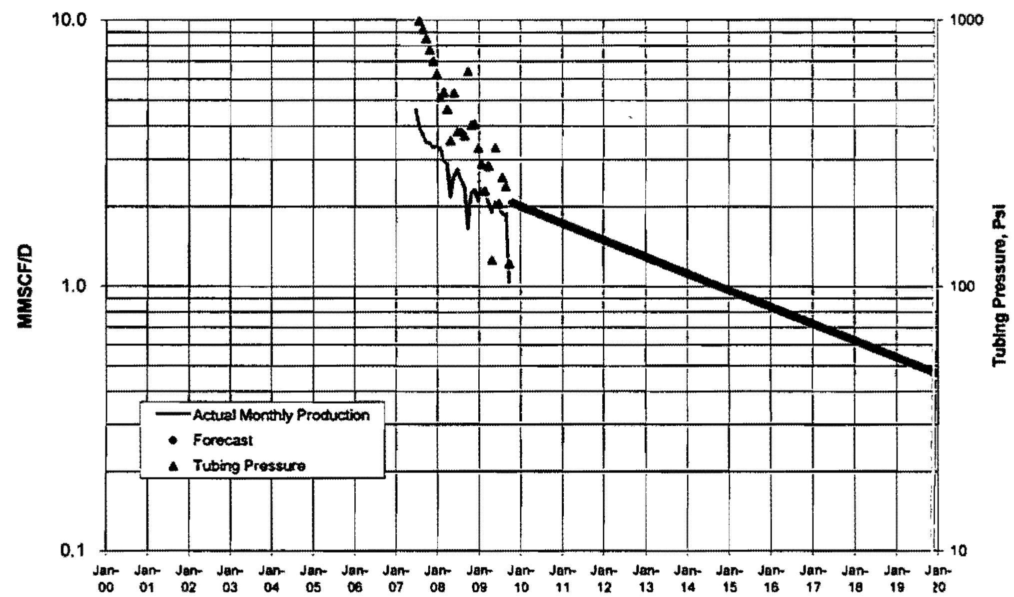

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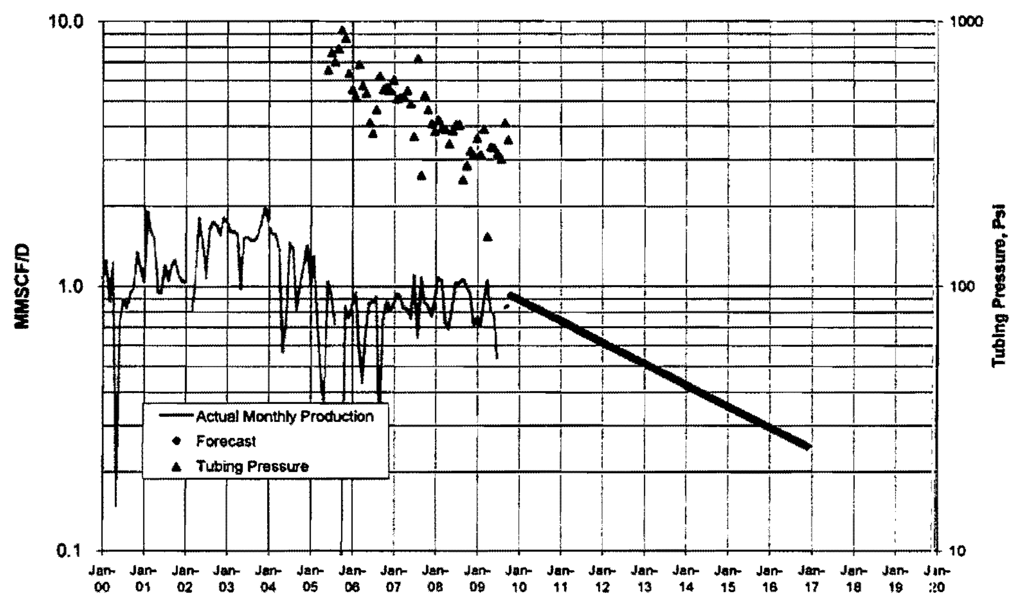

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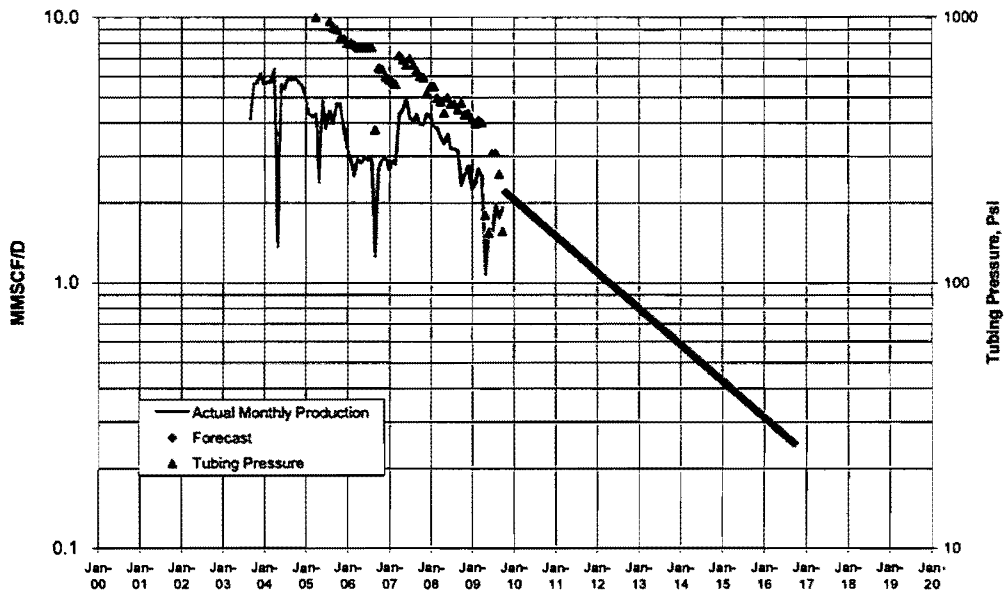

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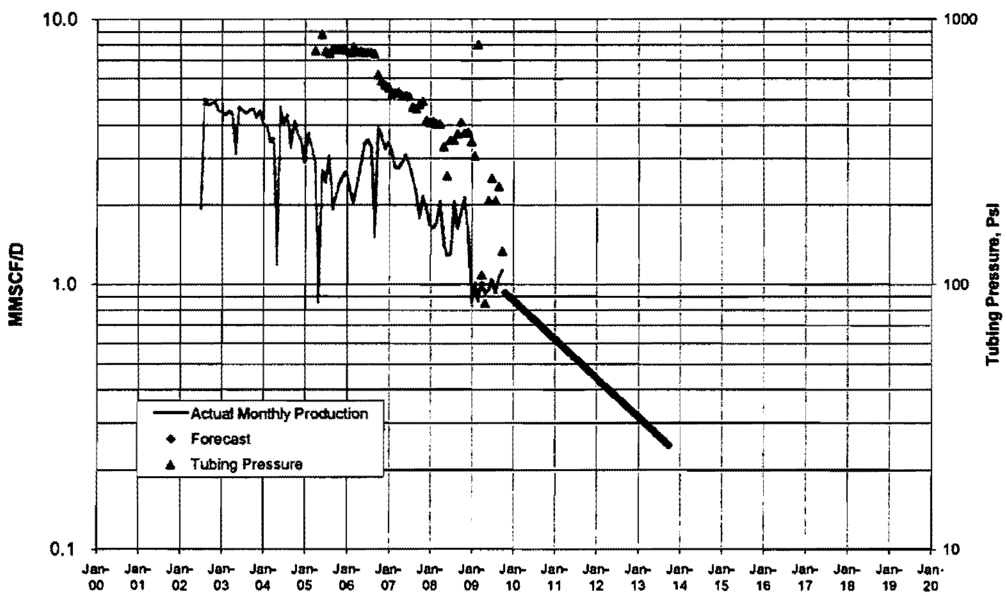

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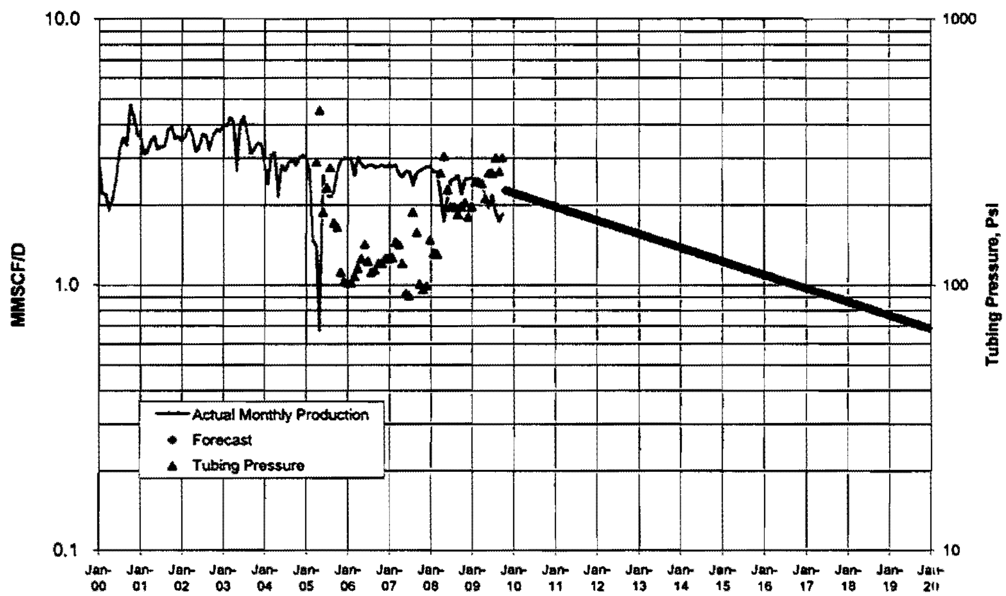

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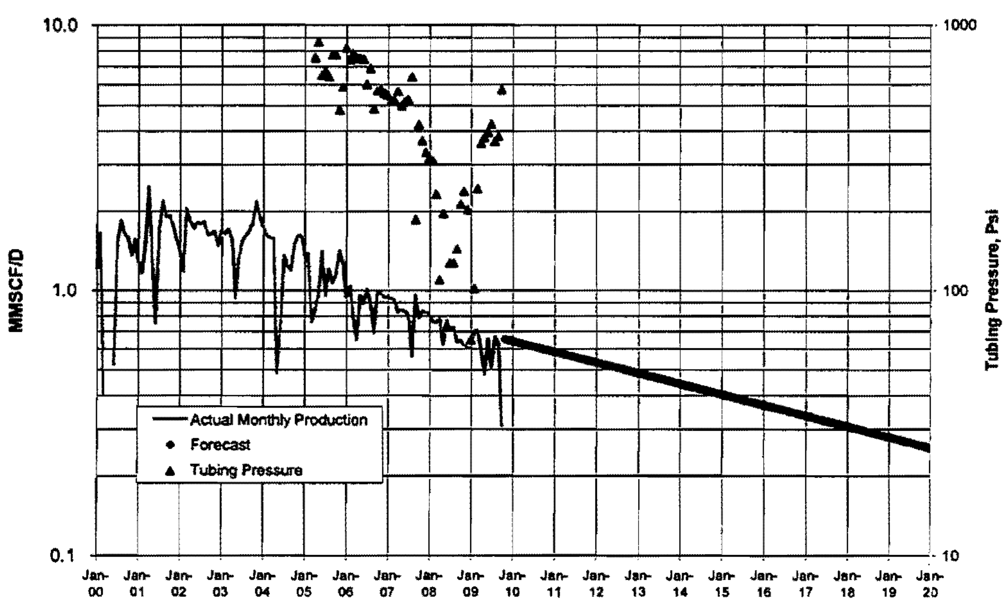

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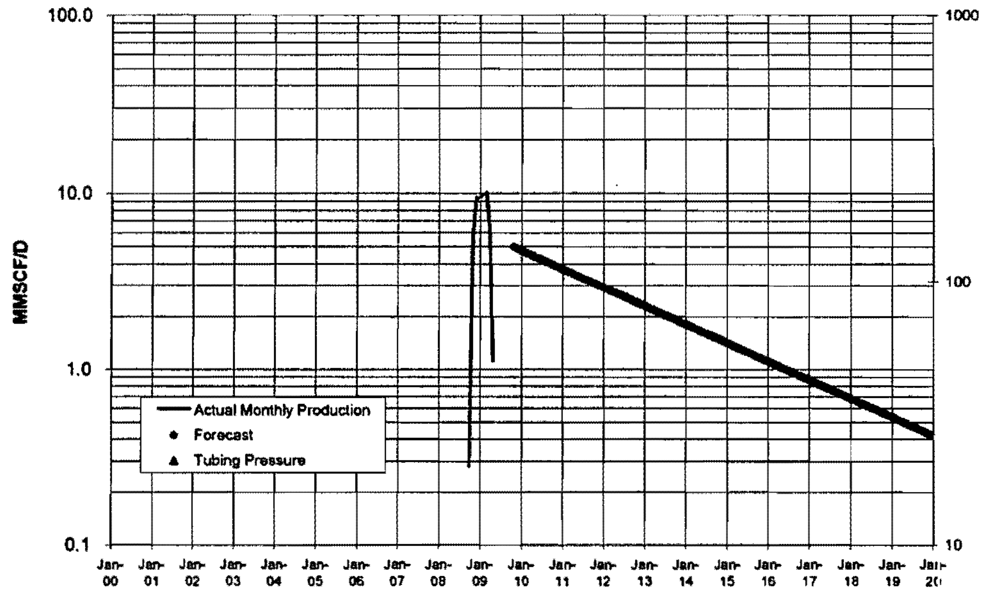

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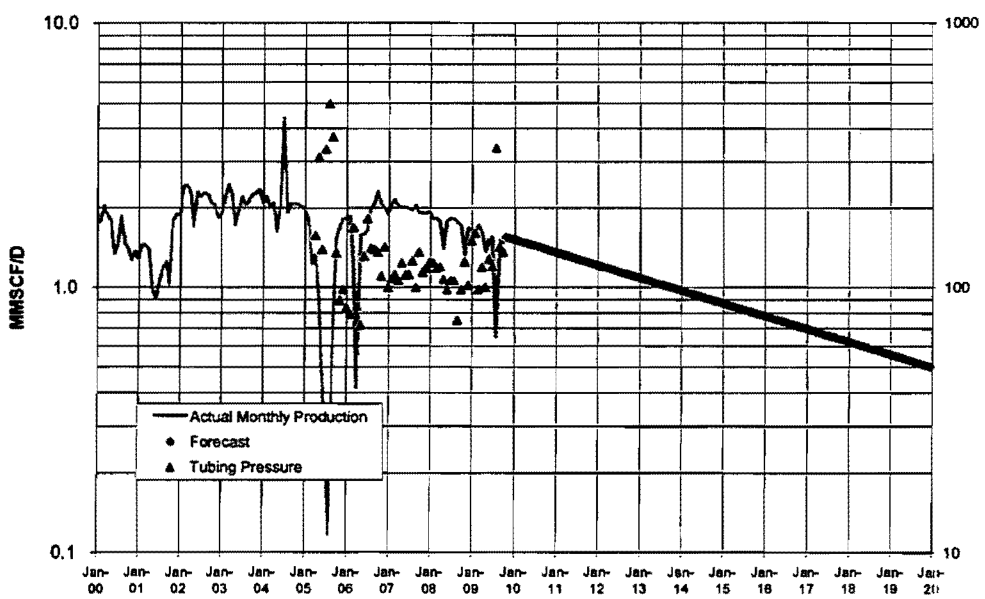

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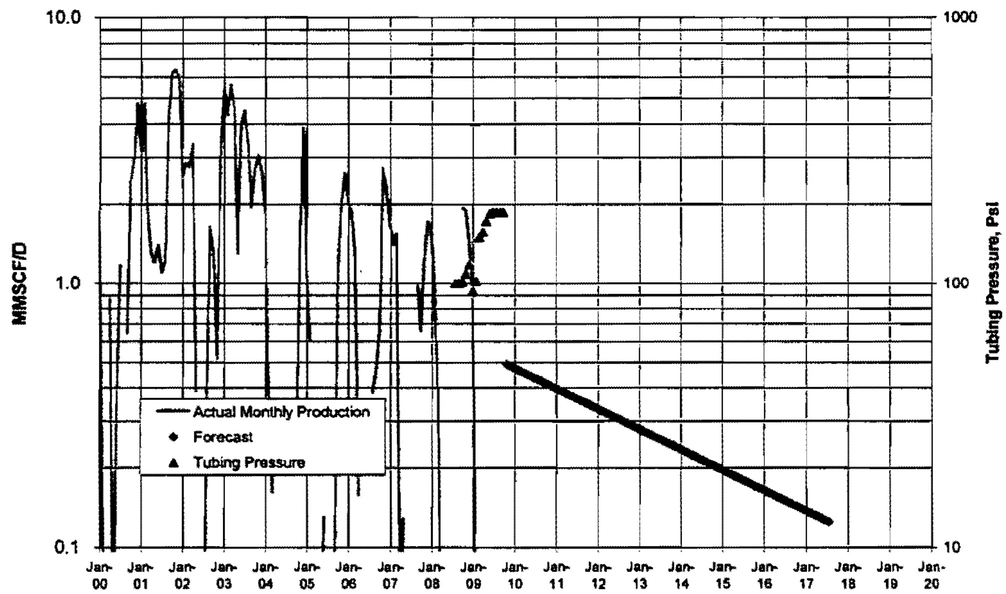

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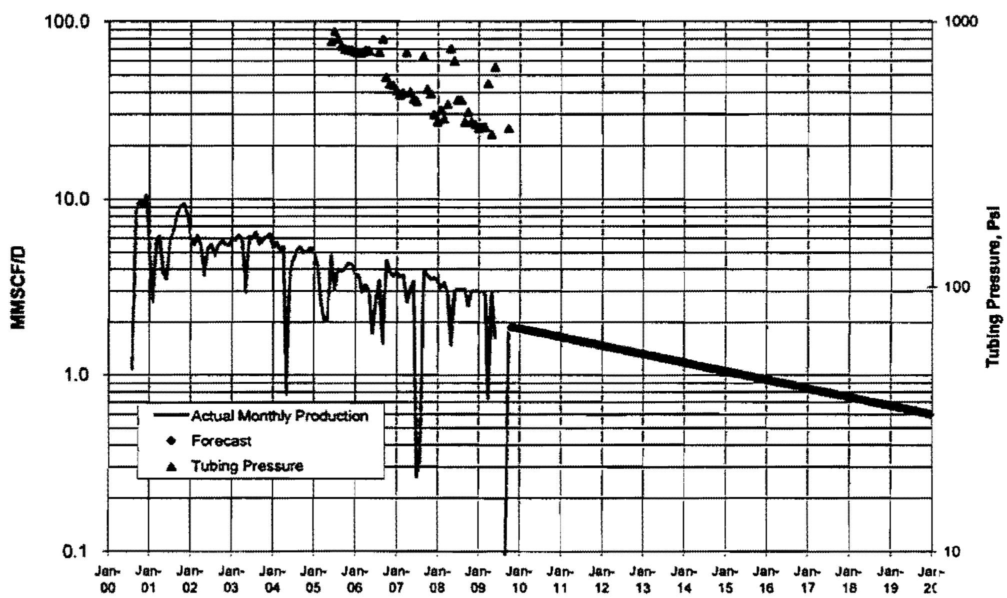

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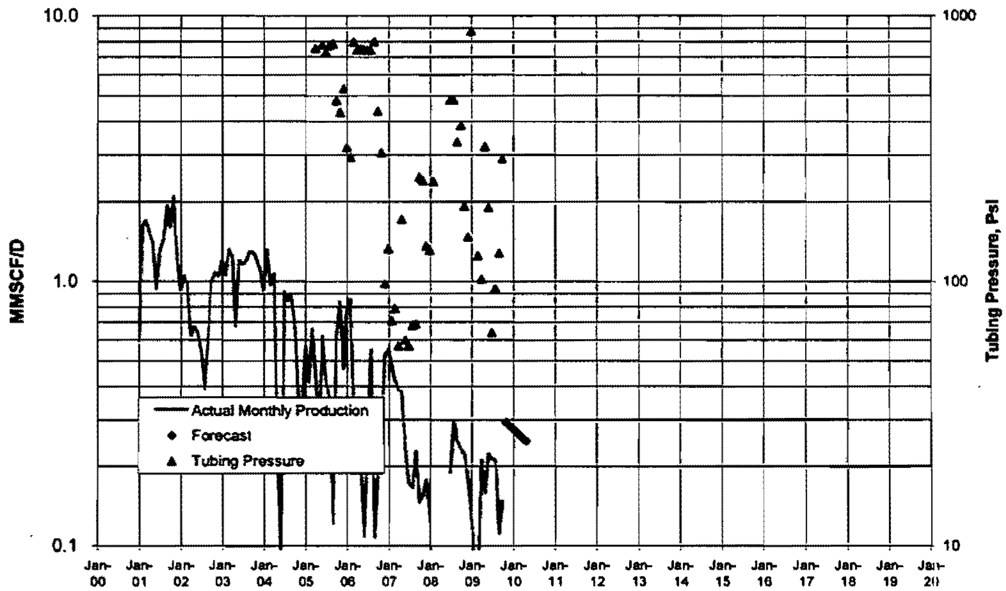

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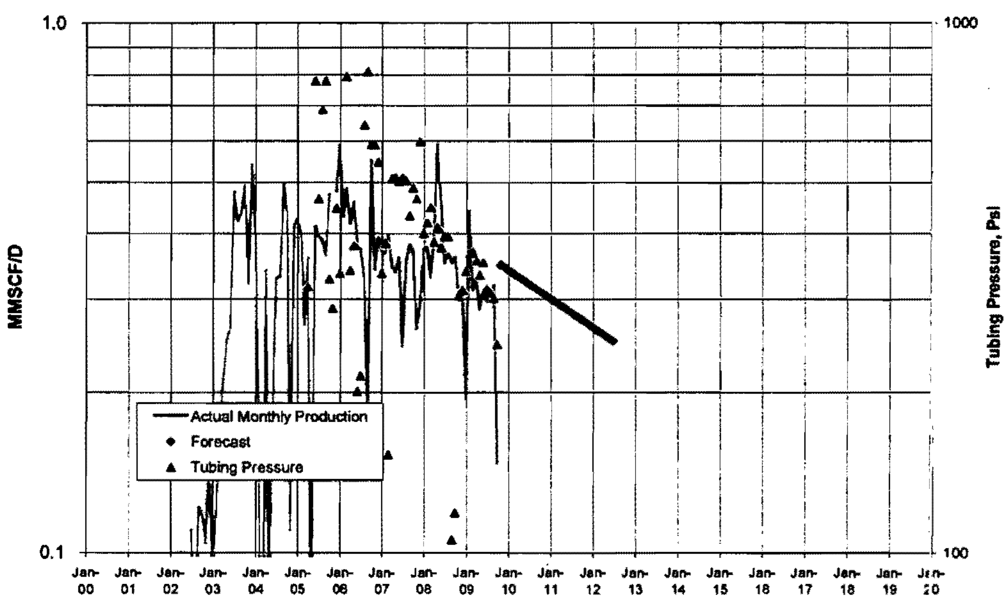

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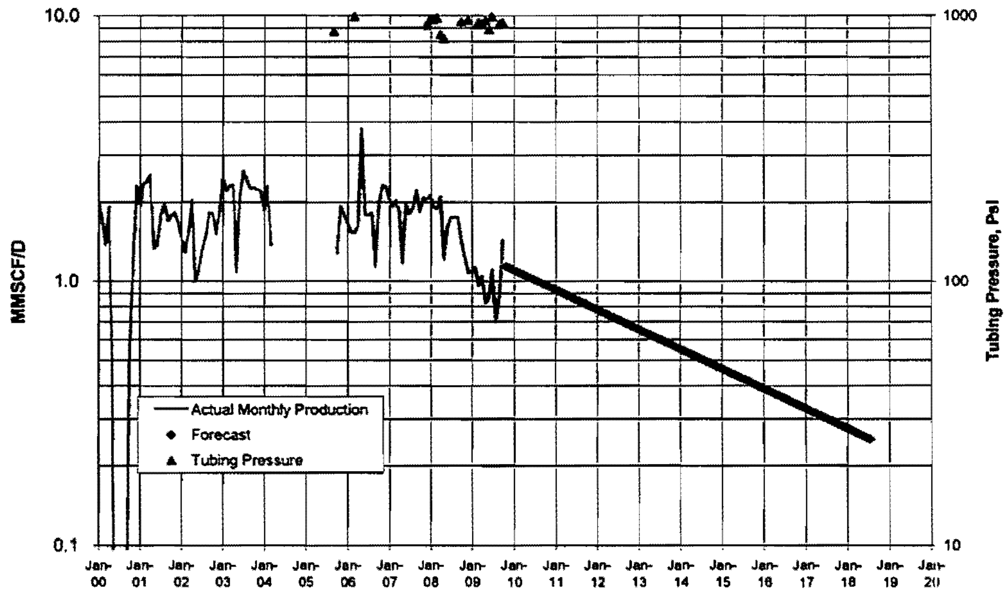

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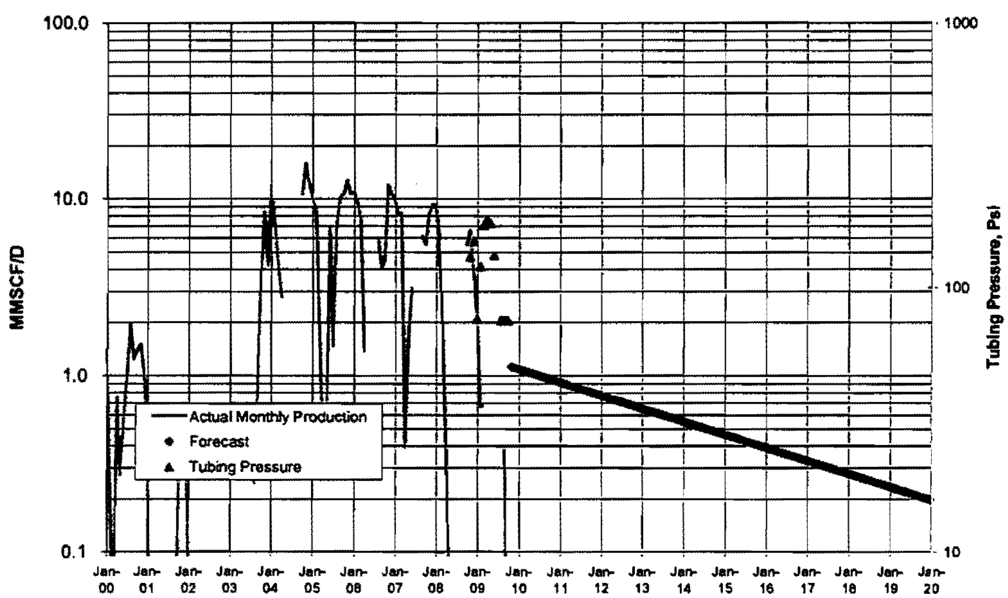

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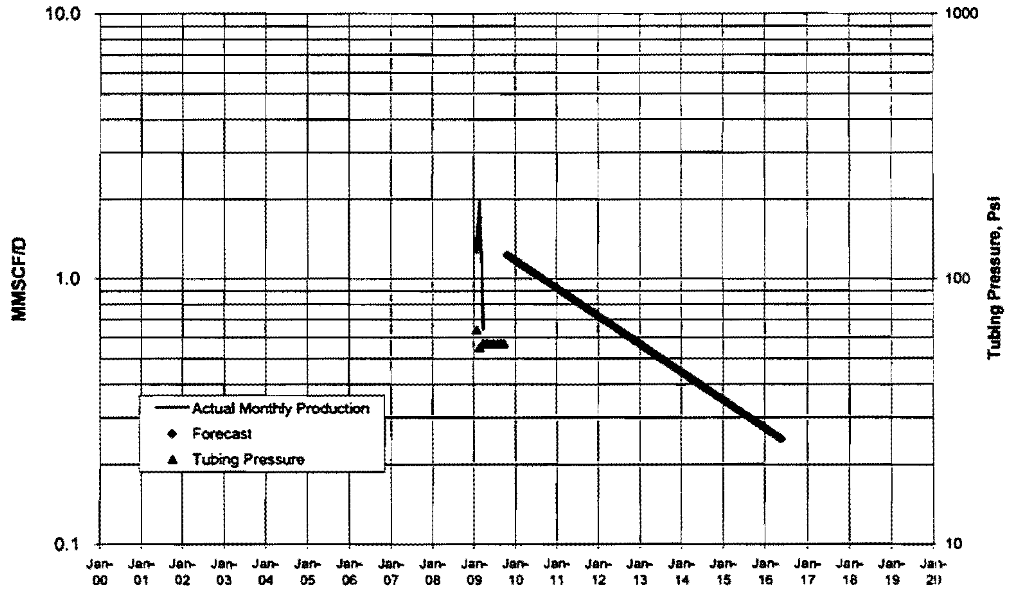

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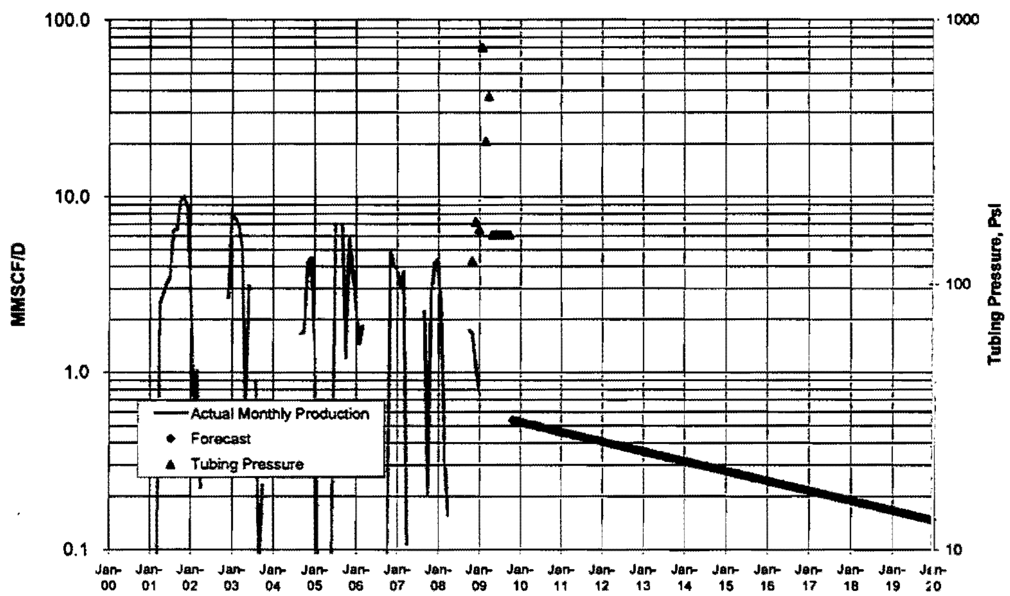

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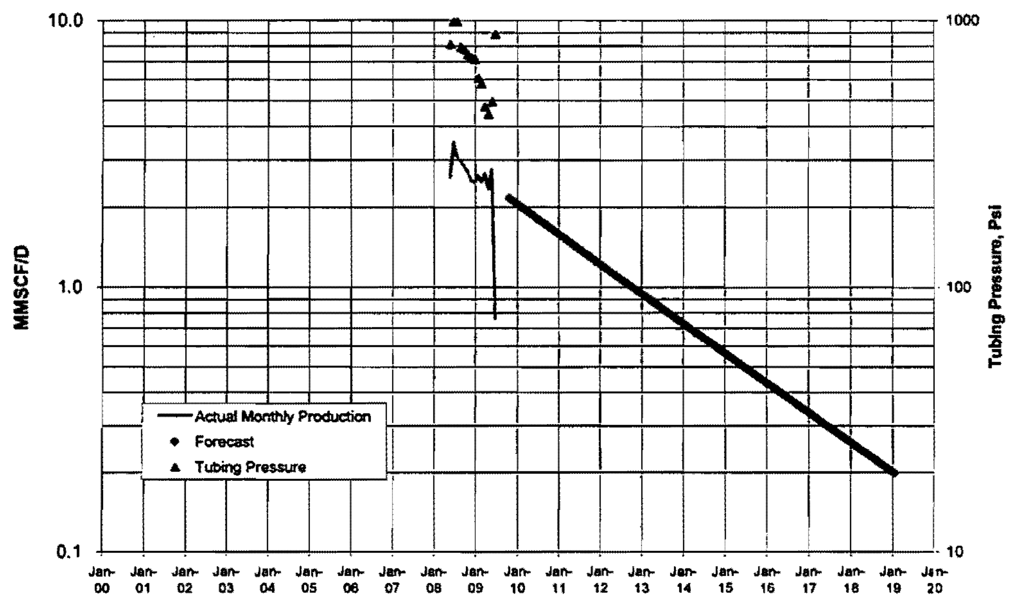
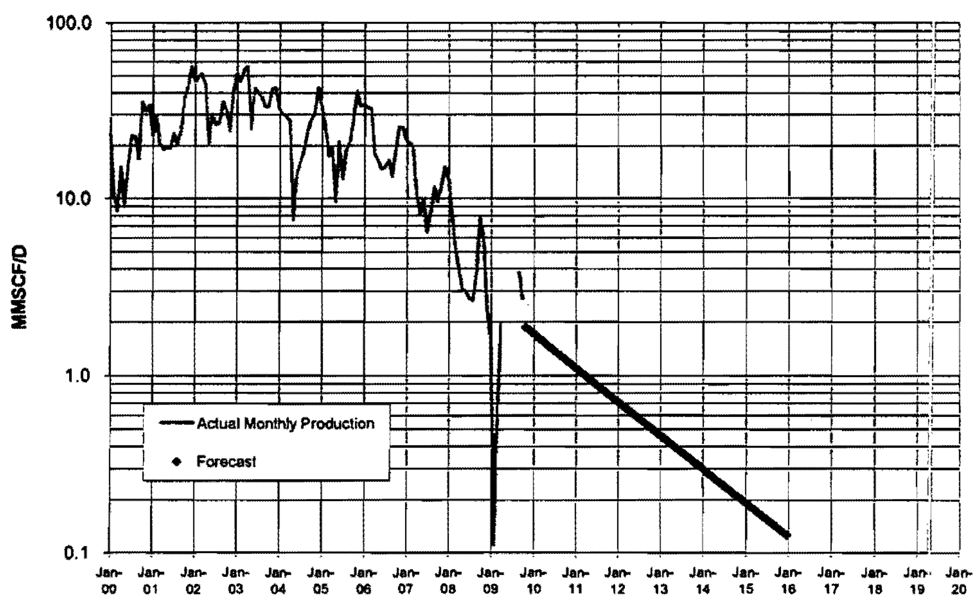
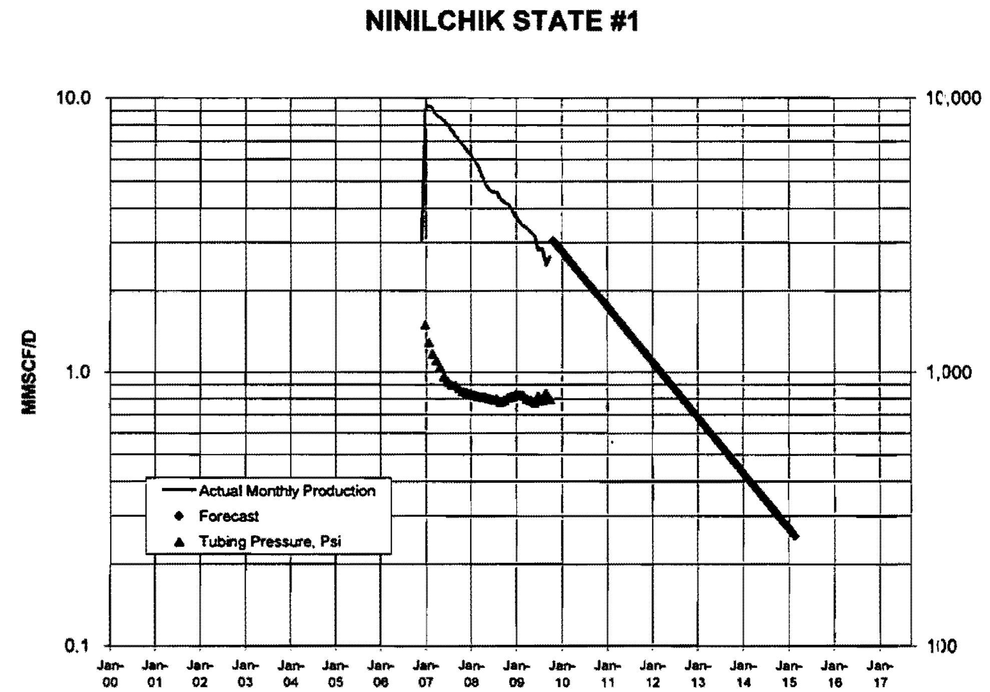
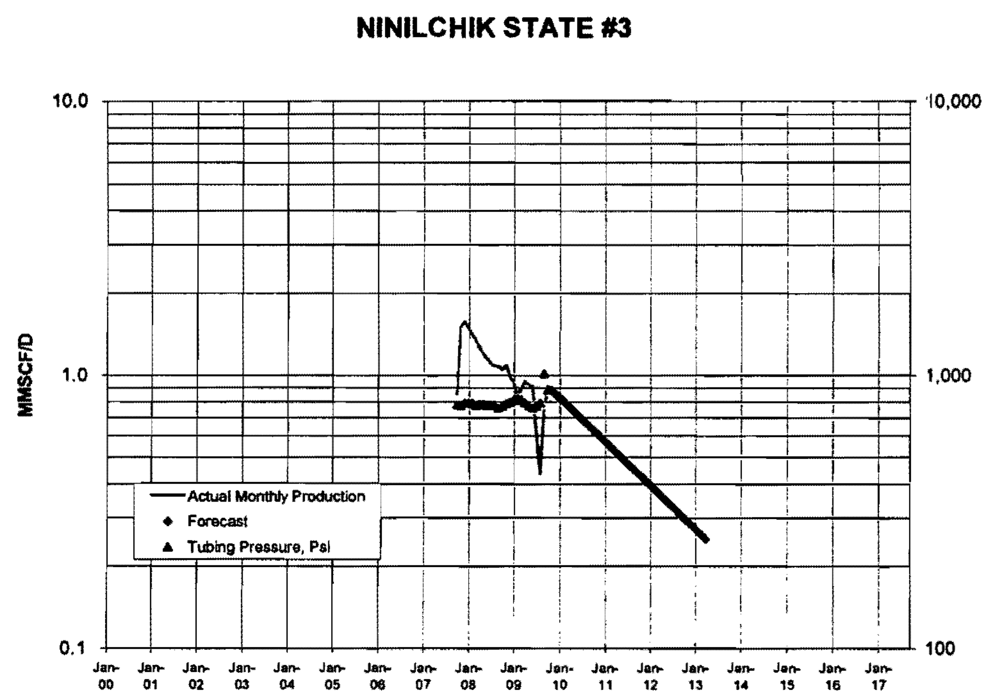


Other KU Wells

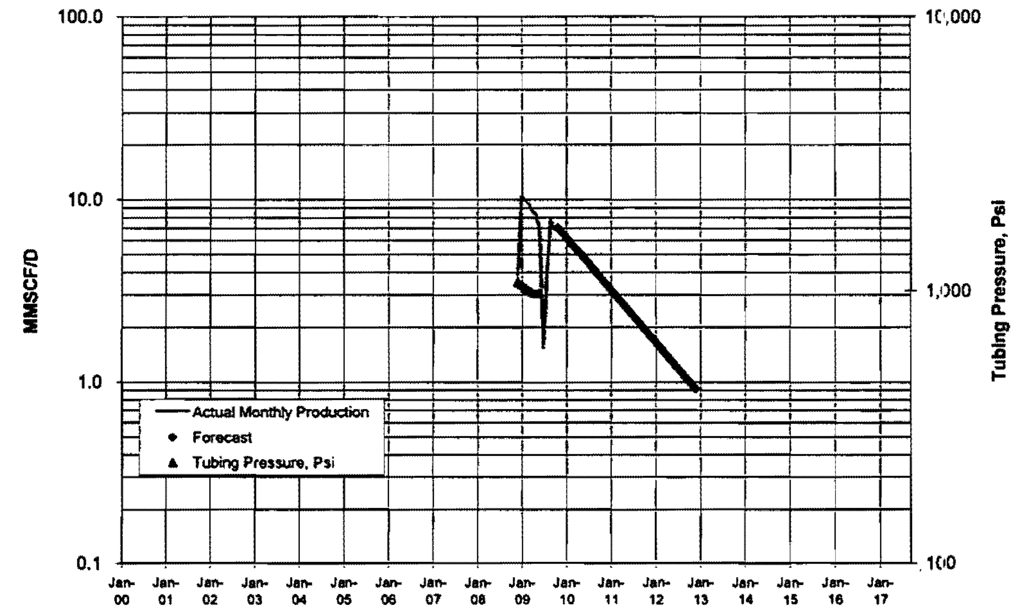


Appendix D-3: Ninilchik Unit Well Decline Curves

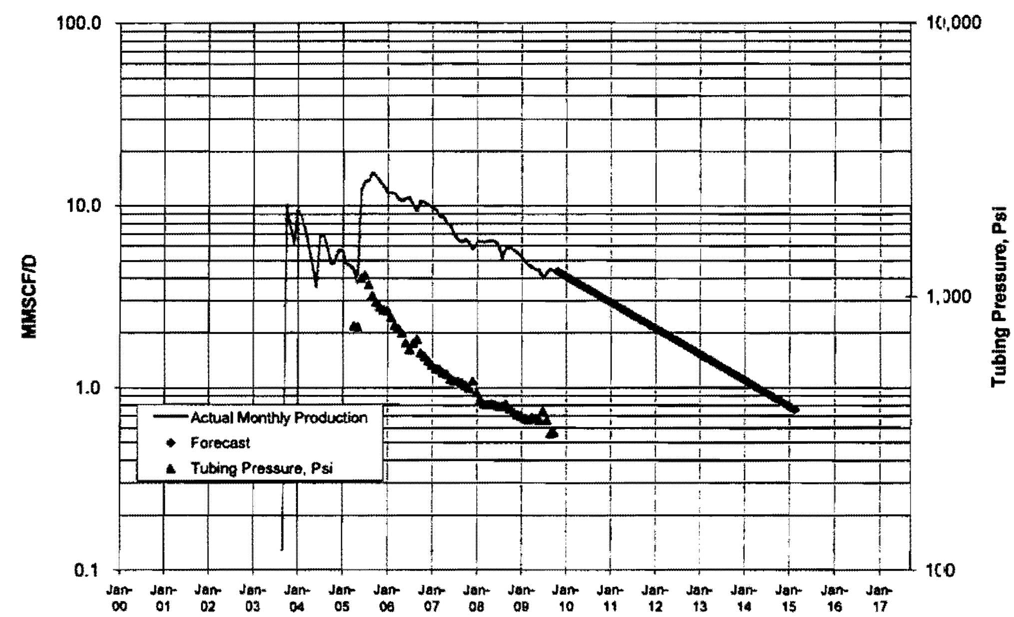




NINILCHIK UNIT #SD-6



NINILCHIK UNIT FALLS CK #1RD



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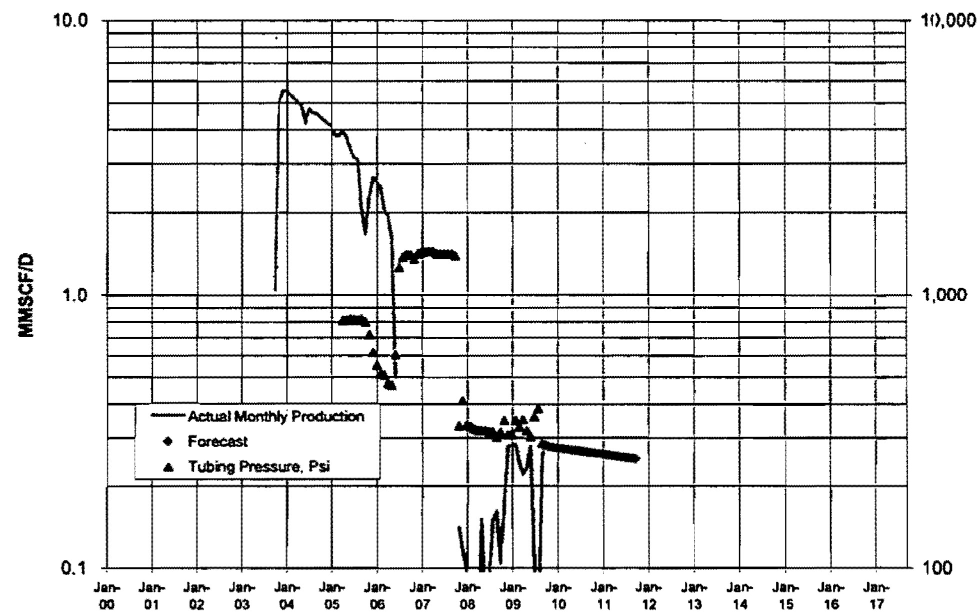
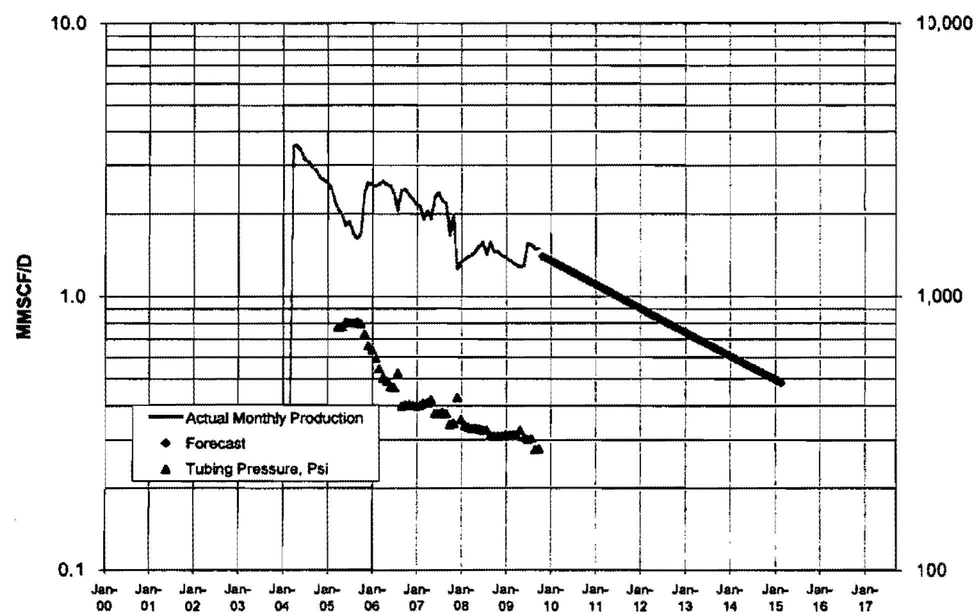


NINILCHIK UNIT FALLS CK #4



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 ### #### ###    ####   ### ### #####    #####  #####     ###    ####    ####
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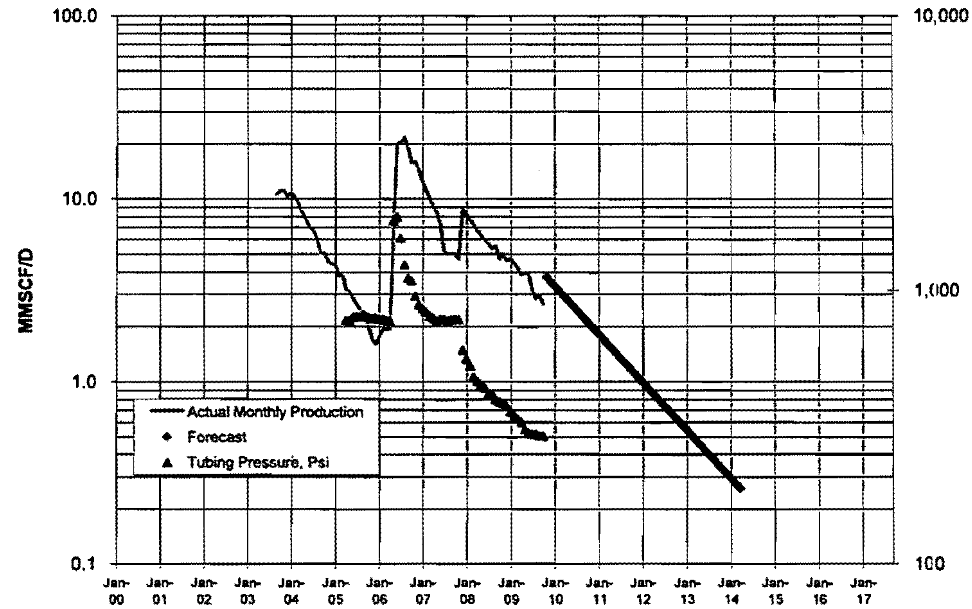
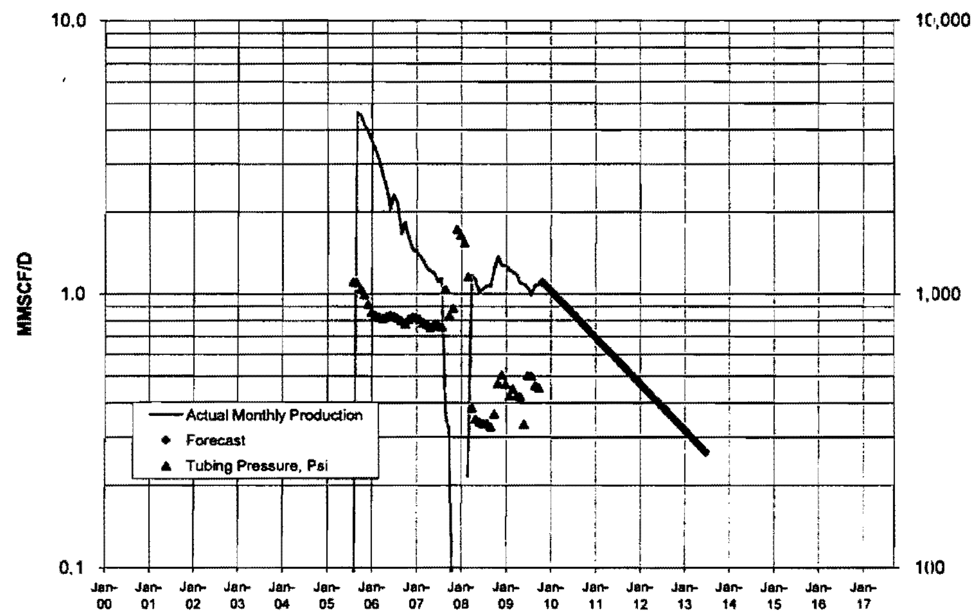
NINILCHIK UNIT G OSKOLKOFF #1



NINILCHIK UNIT G OSKOLKOFF #3



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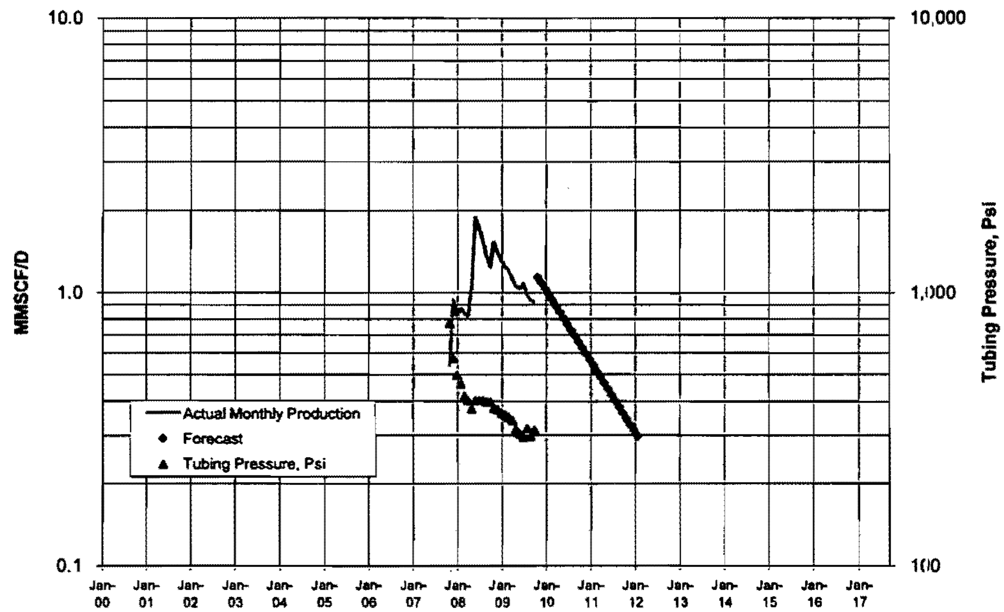

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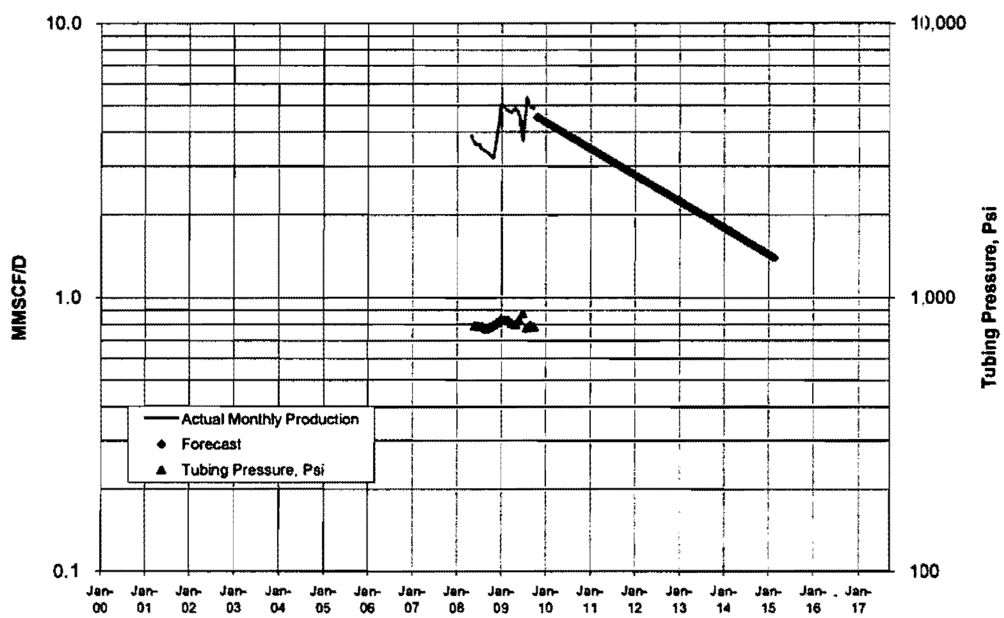

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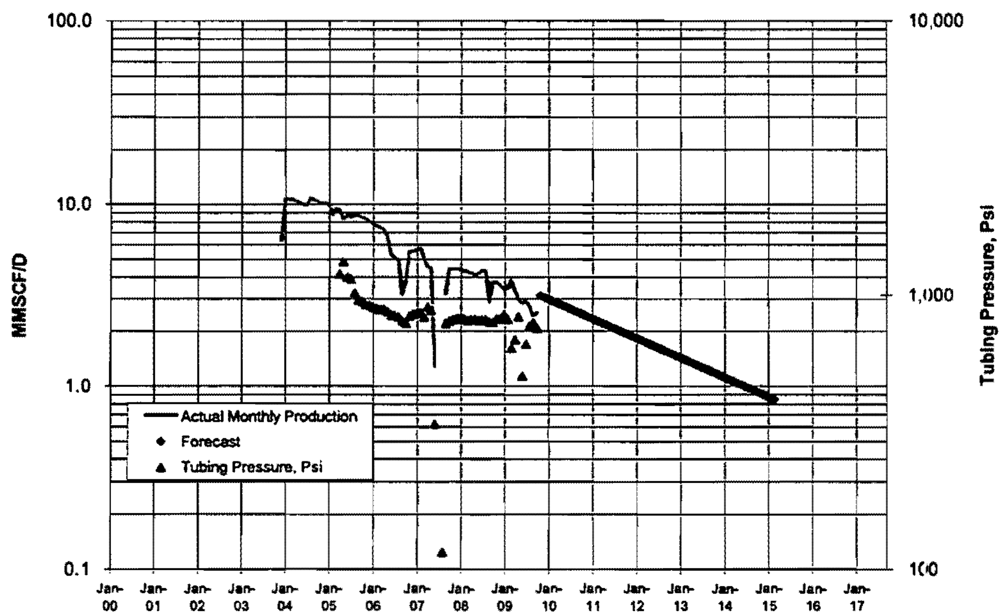

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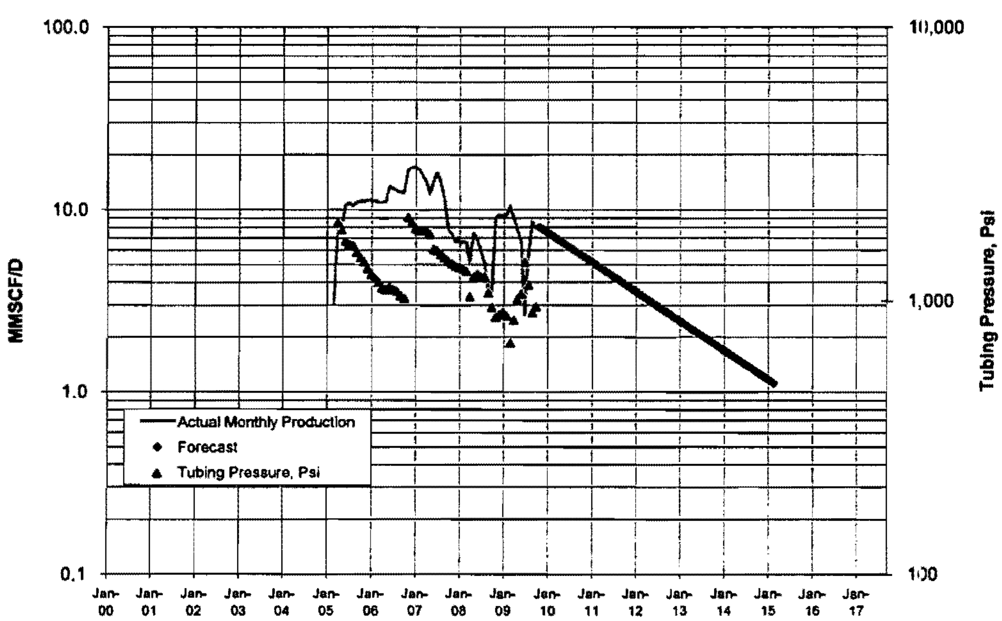

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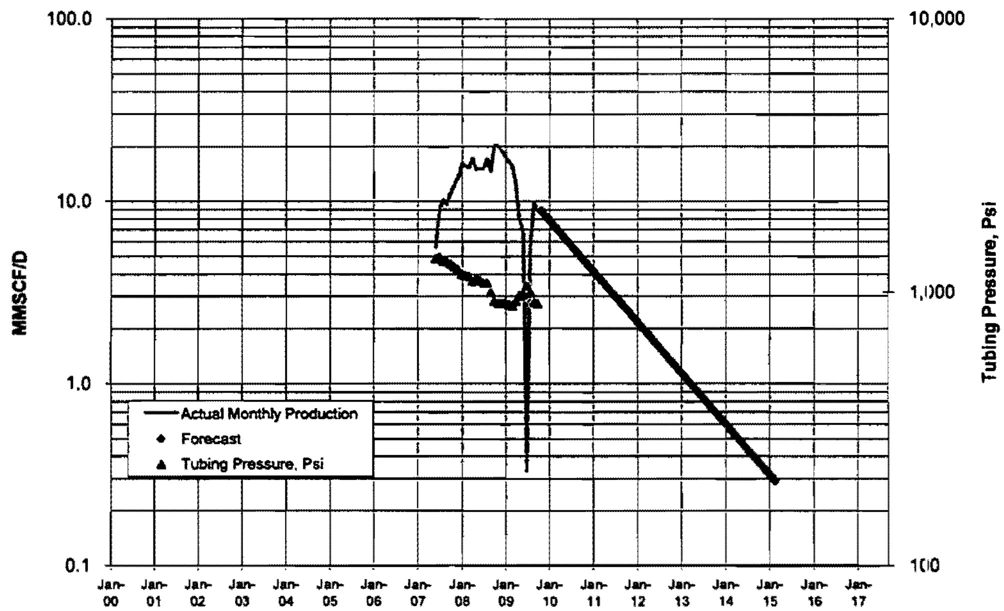
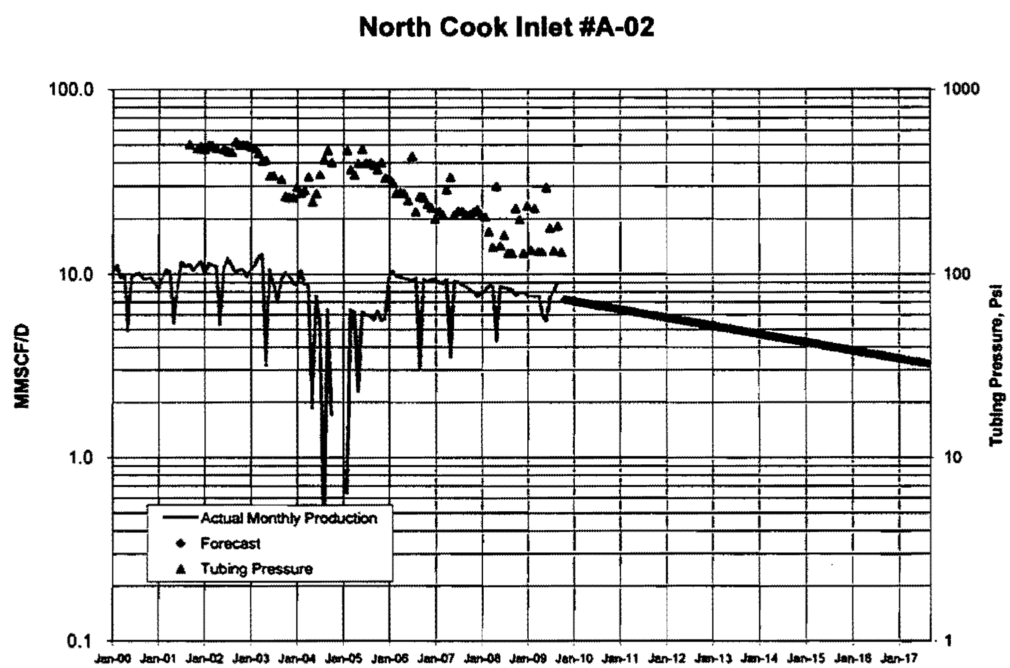
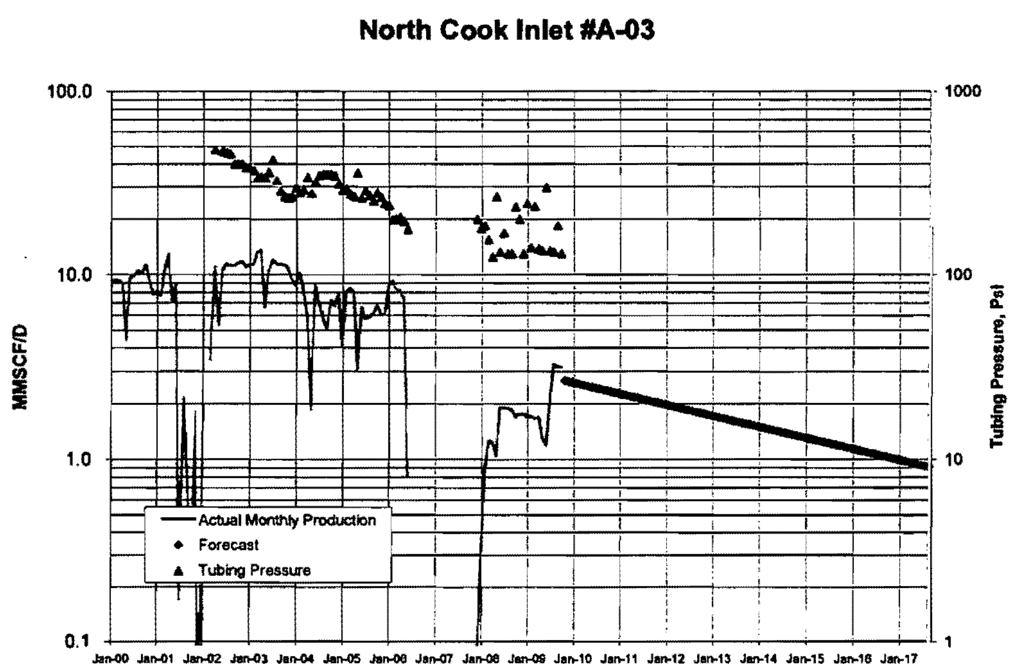
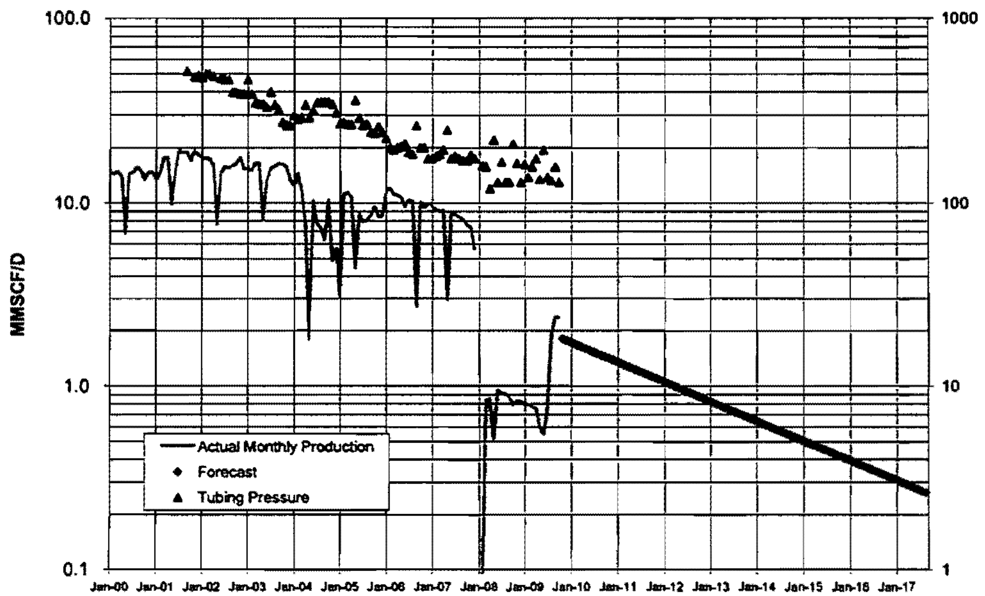


Appendix D-4: North Cook Inlet Well Decline Curves





North Cook Inlet #A-04



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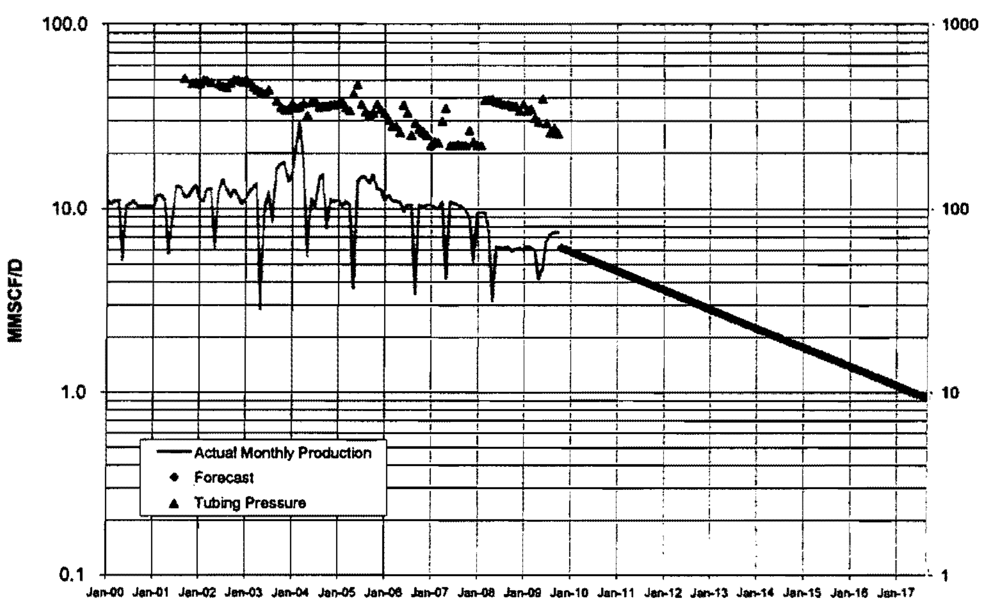

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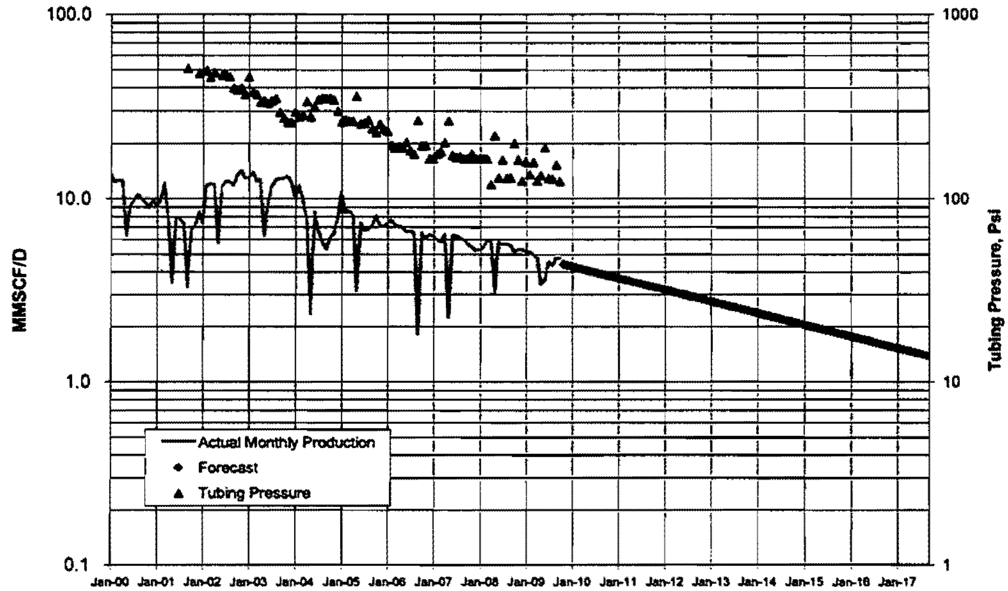

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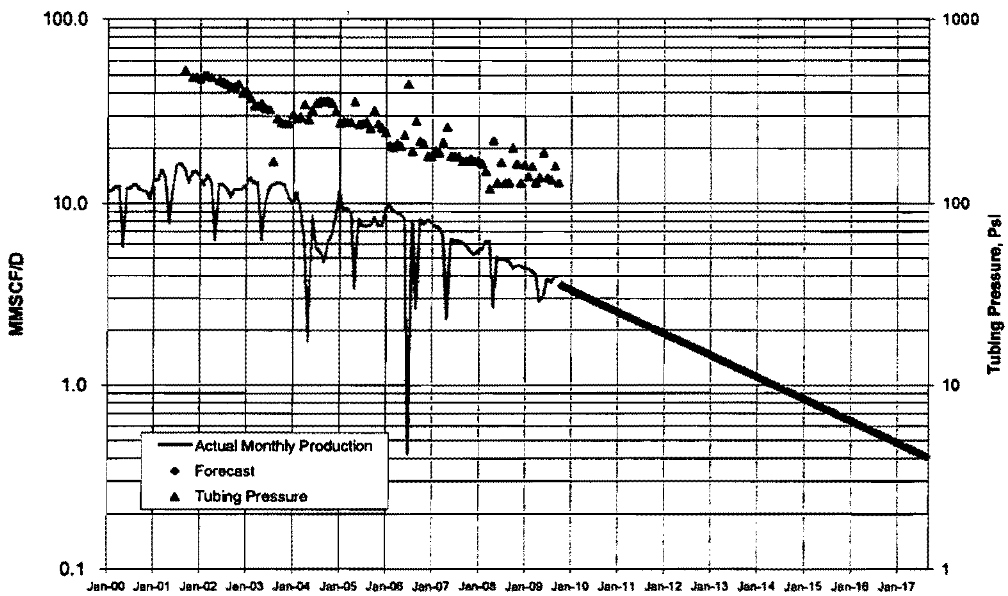

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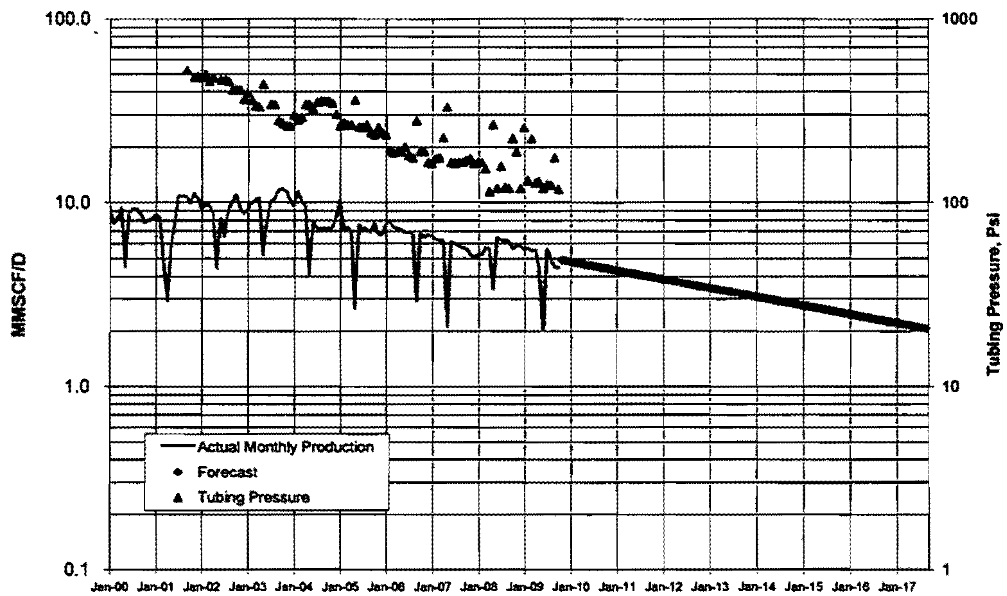

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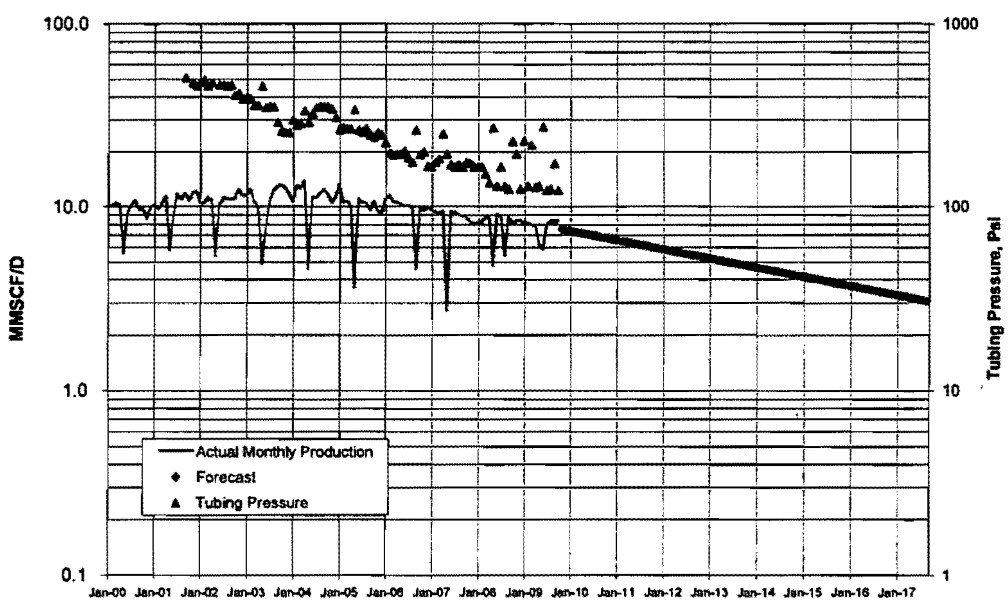

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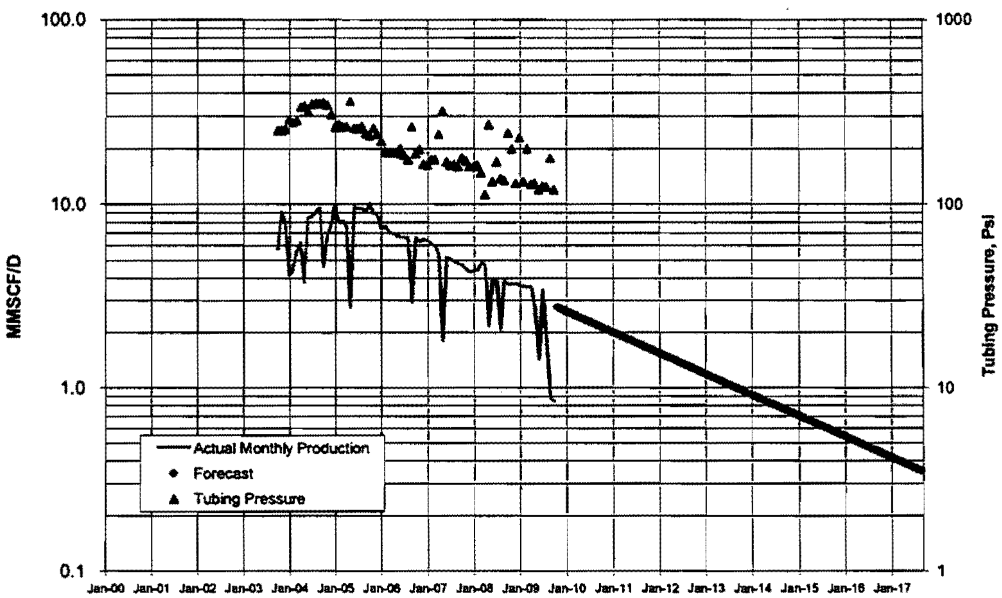

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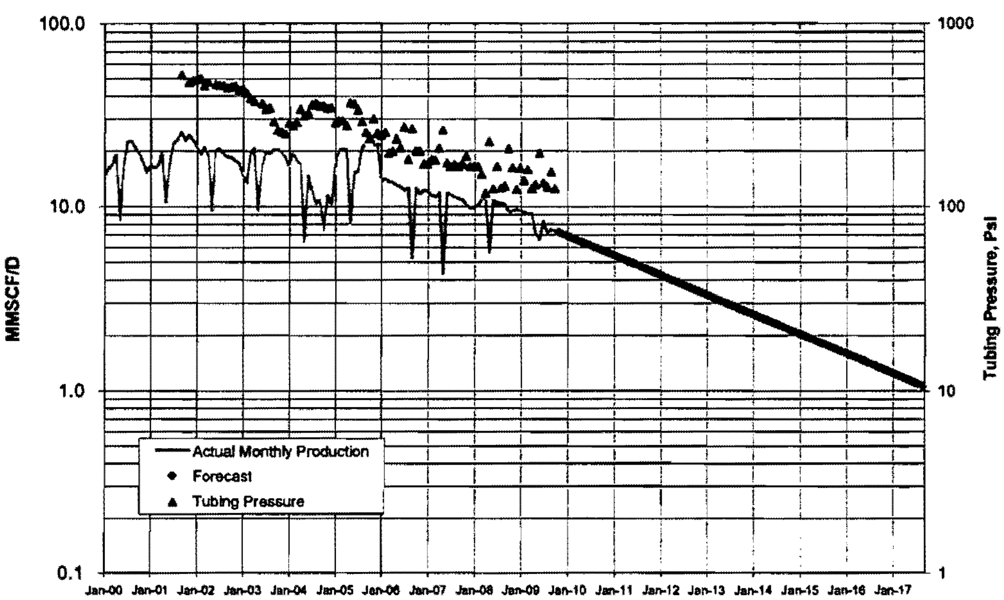

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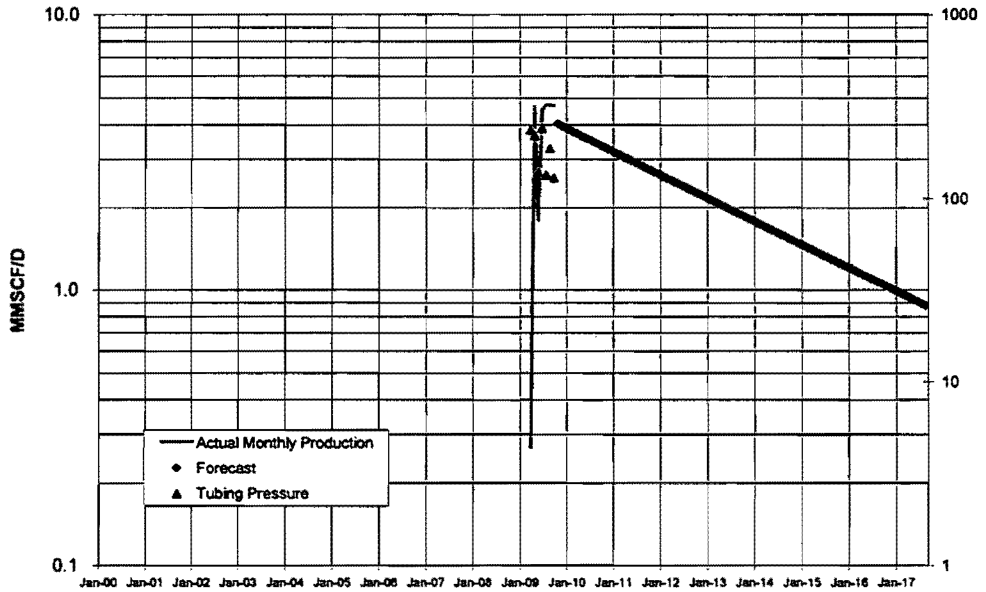

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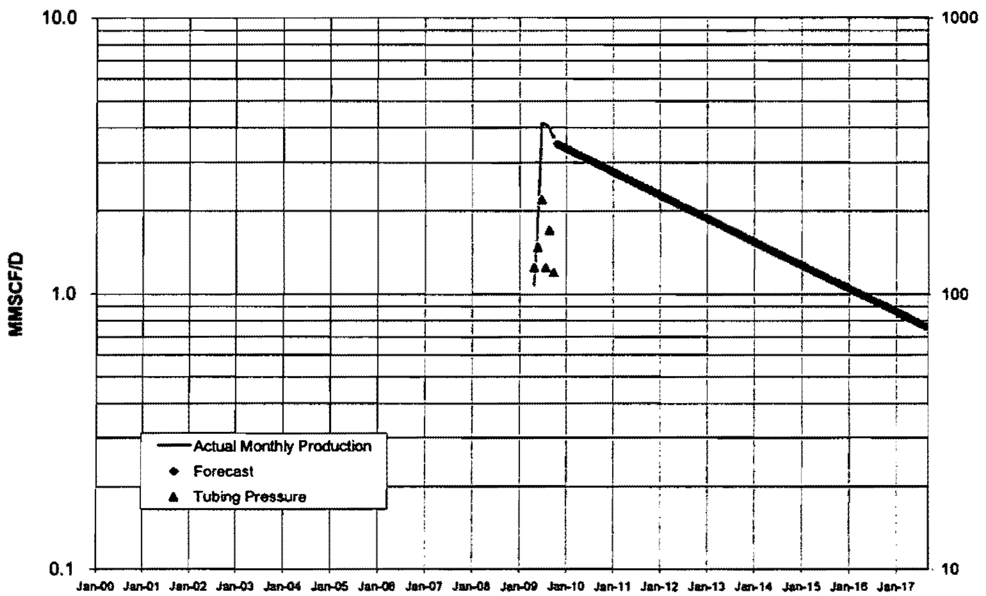
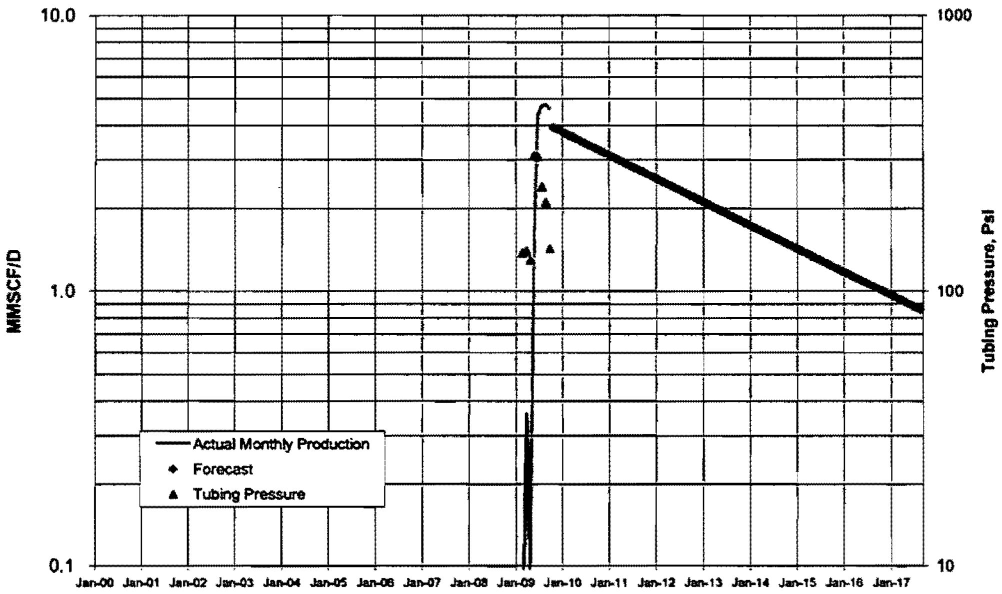
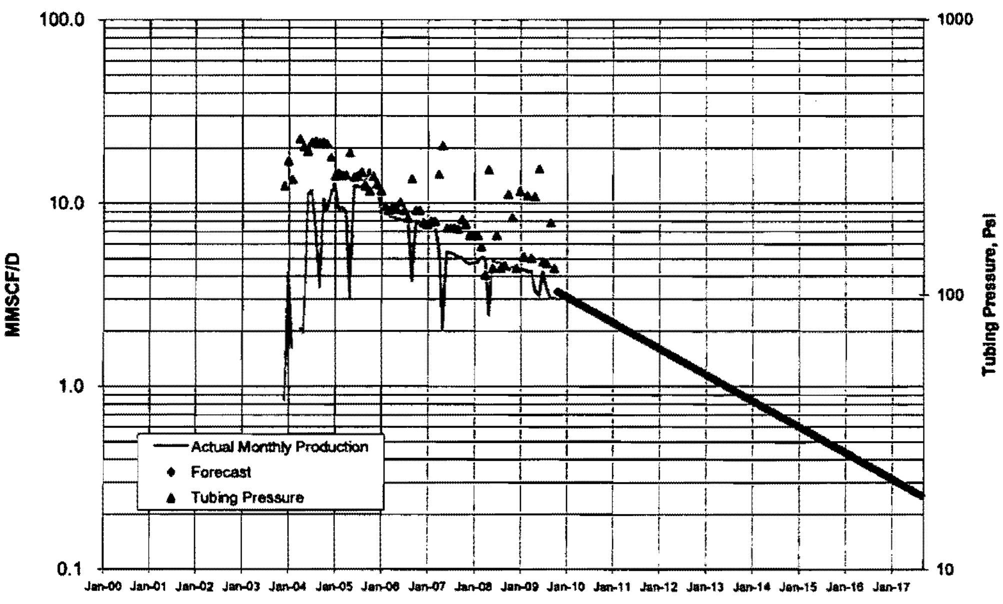


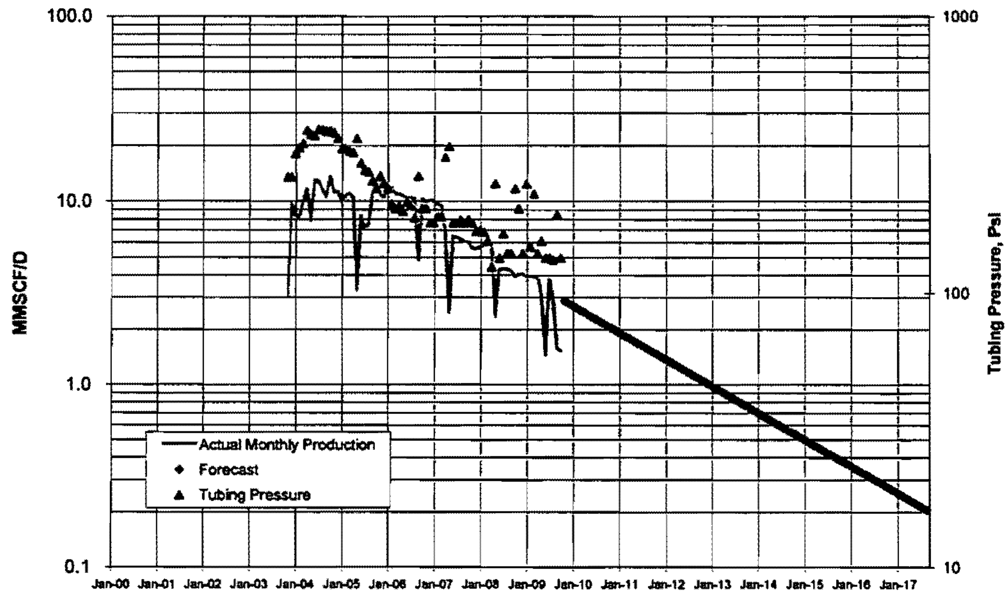
North Cook Inlet #A-16



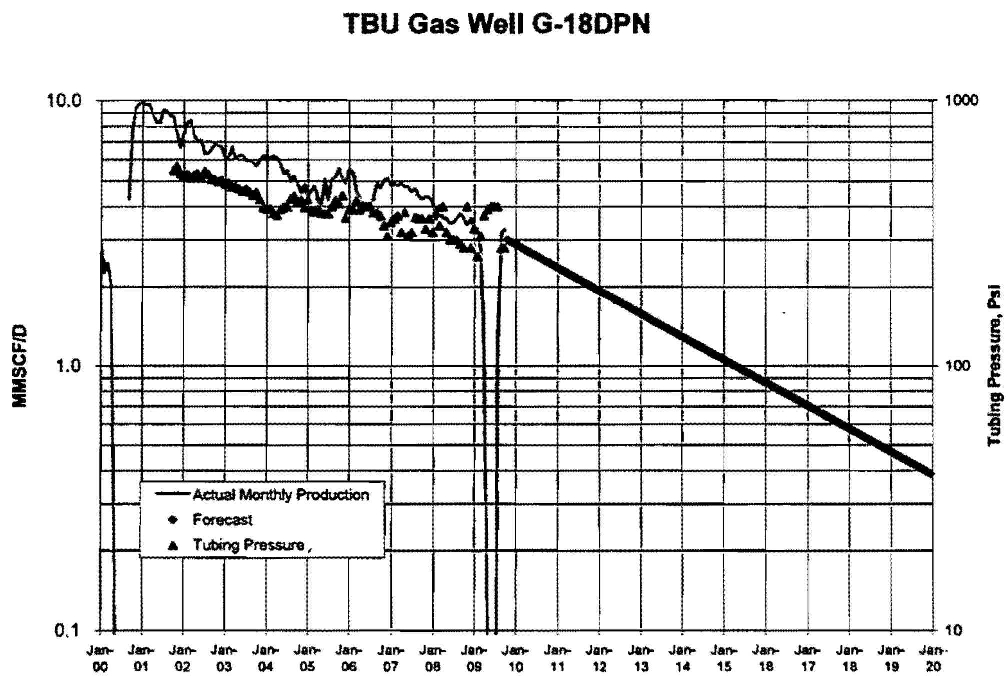
North Cook Inlet #B-01A

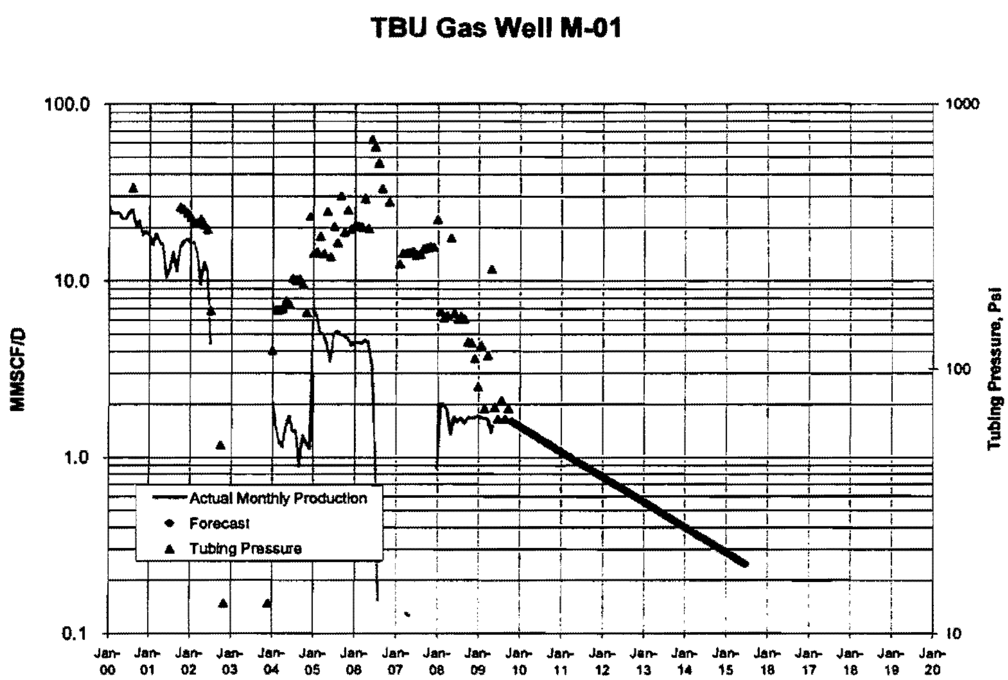


North Cook Inlet #B-03

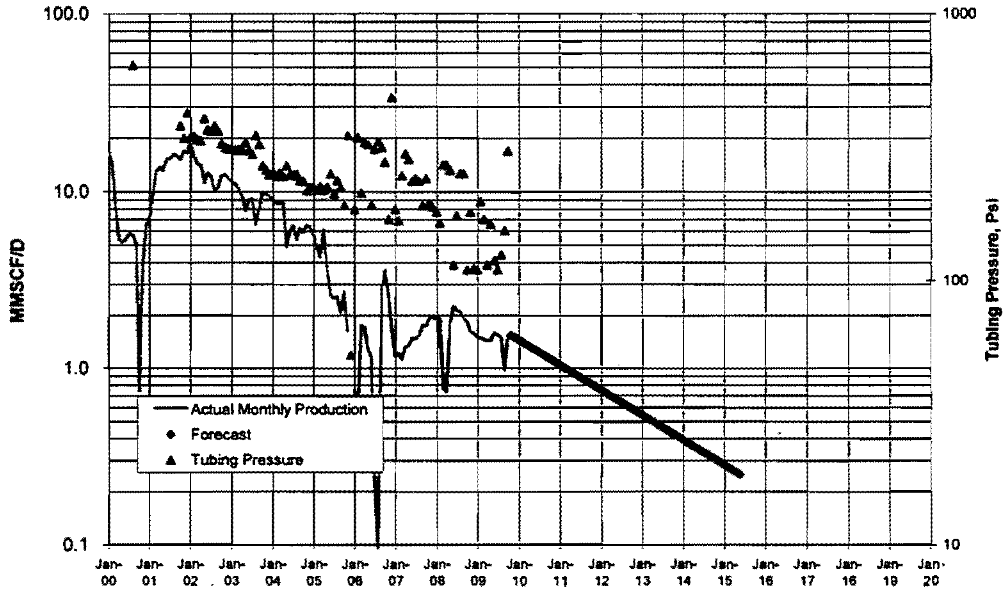


Appendix D-5: Trading Bay Unit Gas Well Decline Curves





TBU Gas Well M-02



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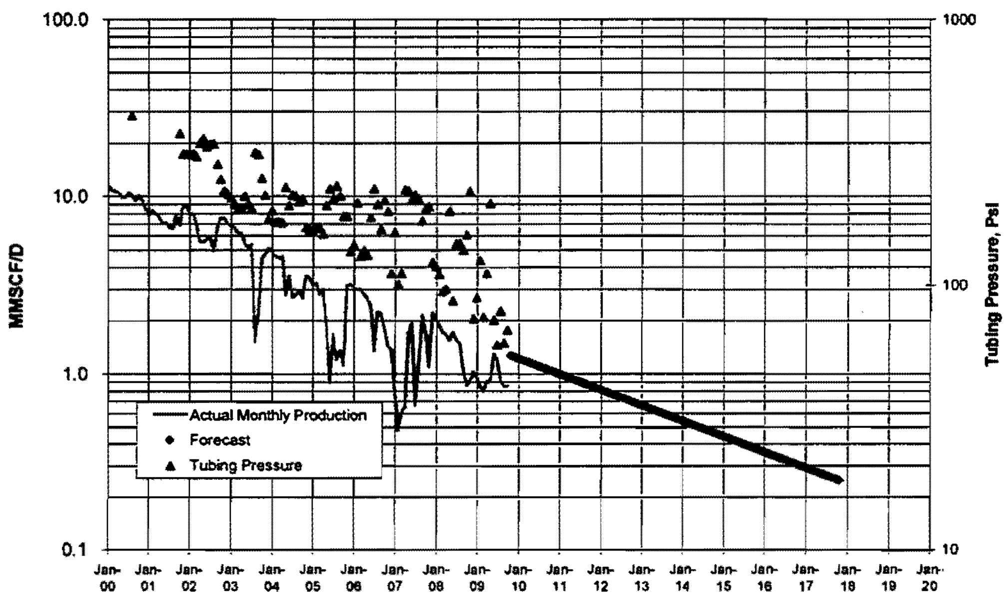

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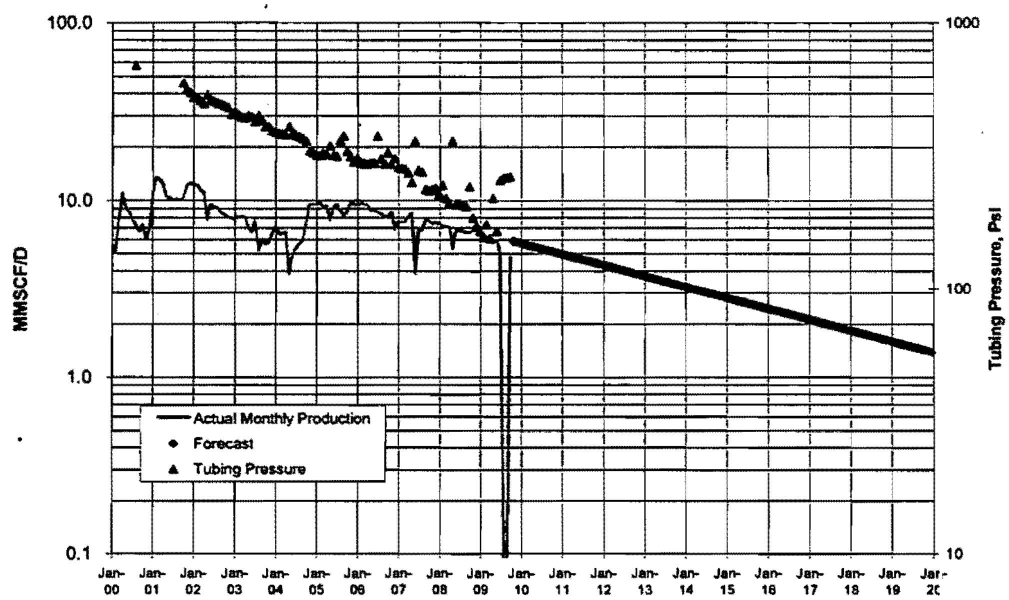

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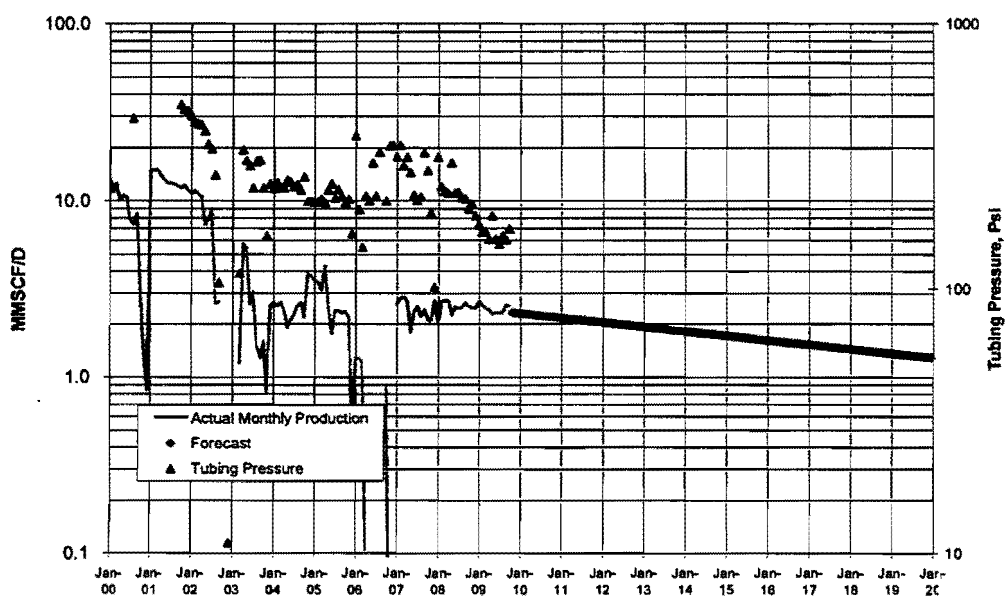

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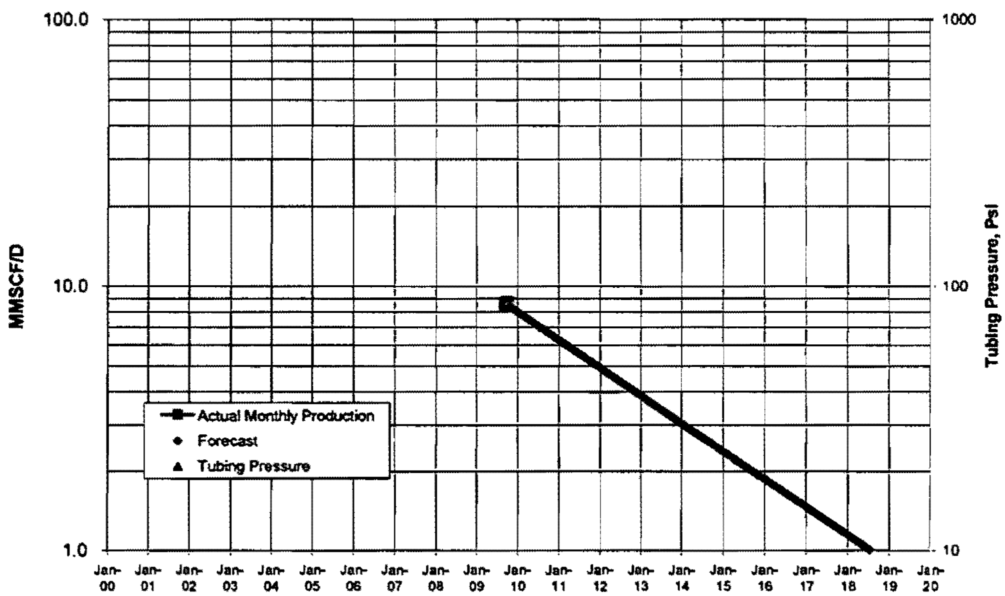

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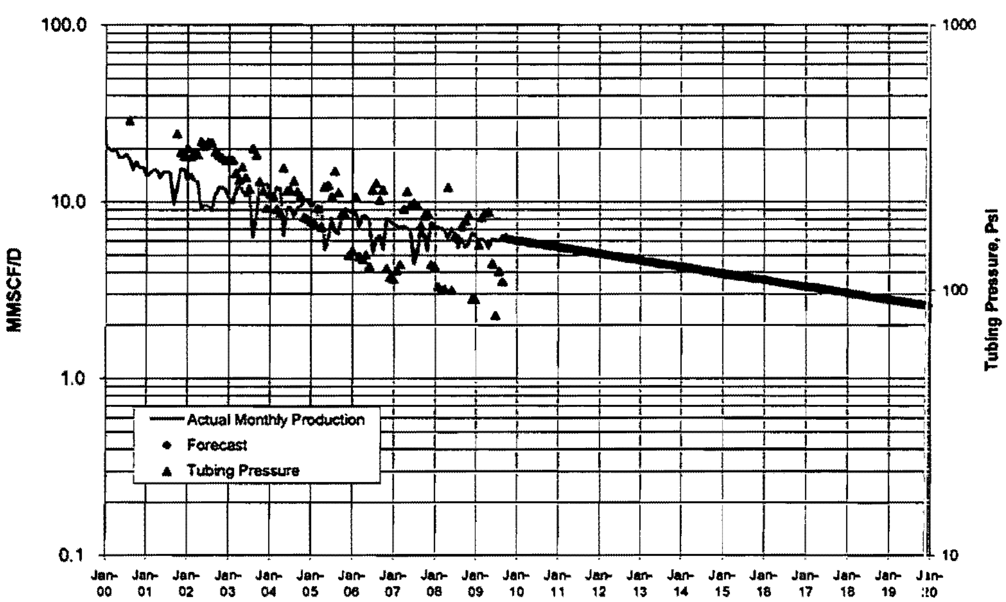

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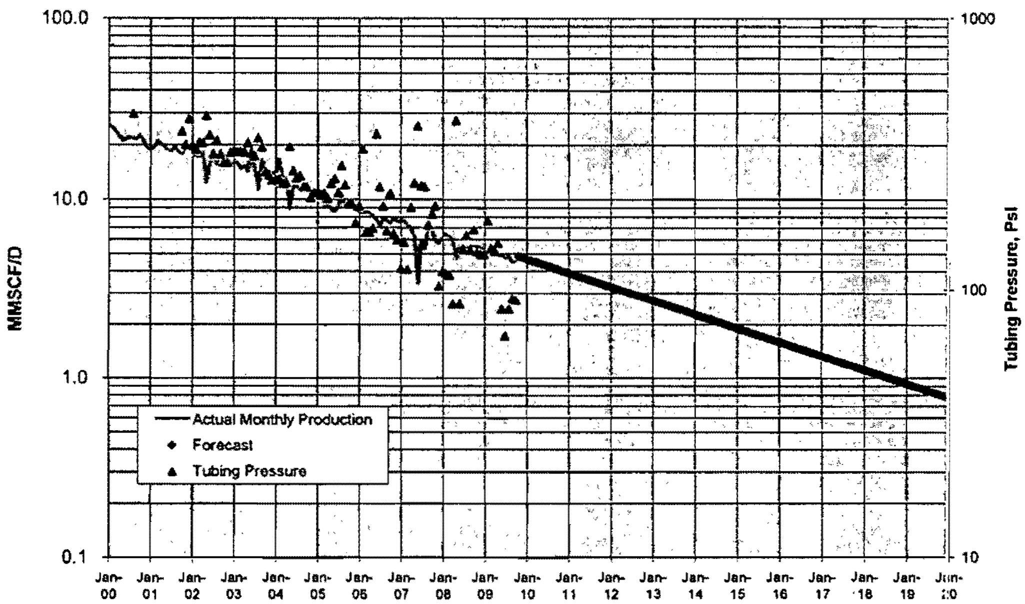
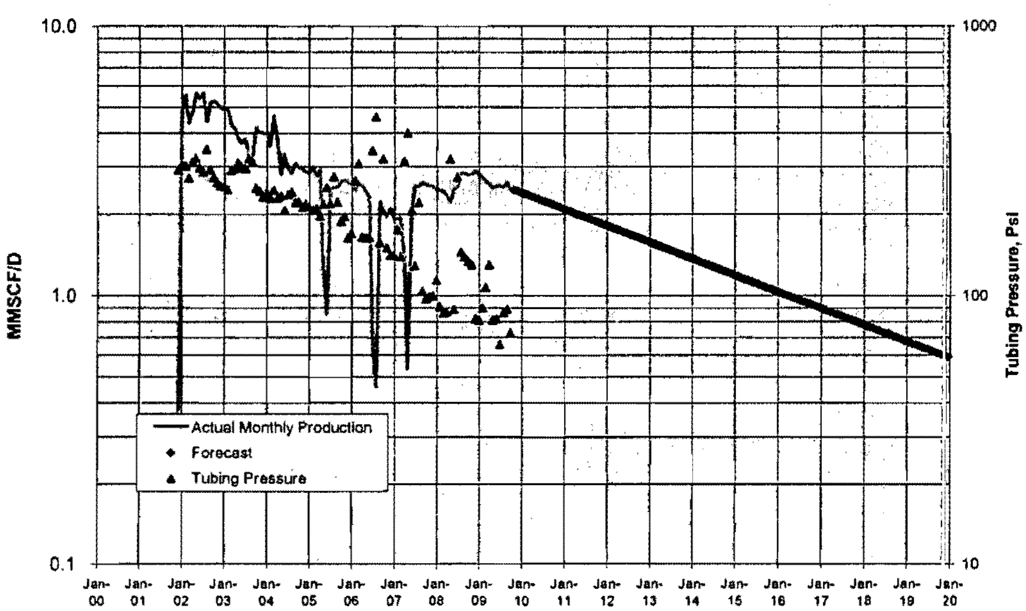


TBU Gas Well M-12



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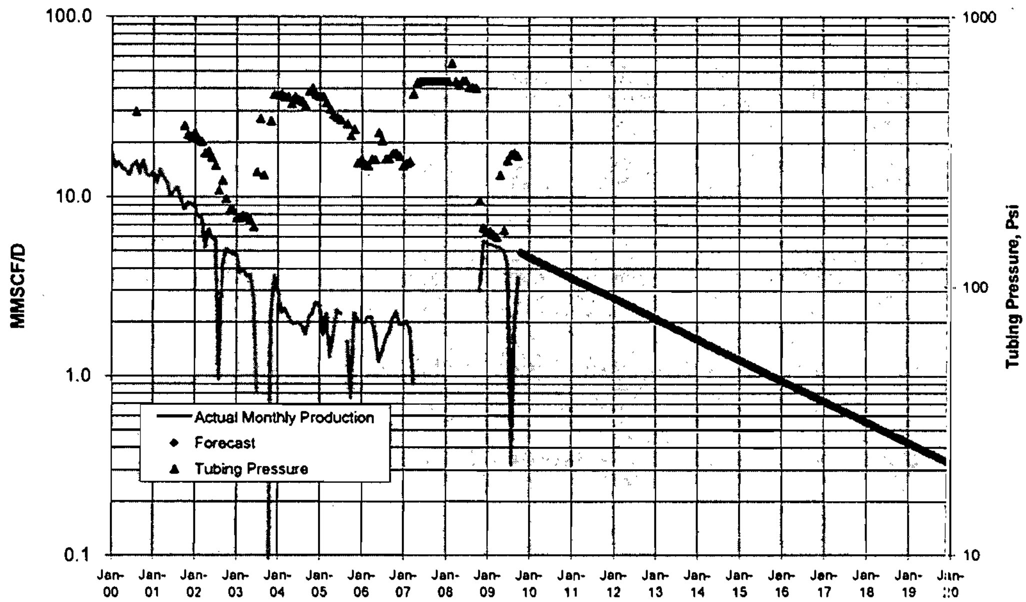

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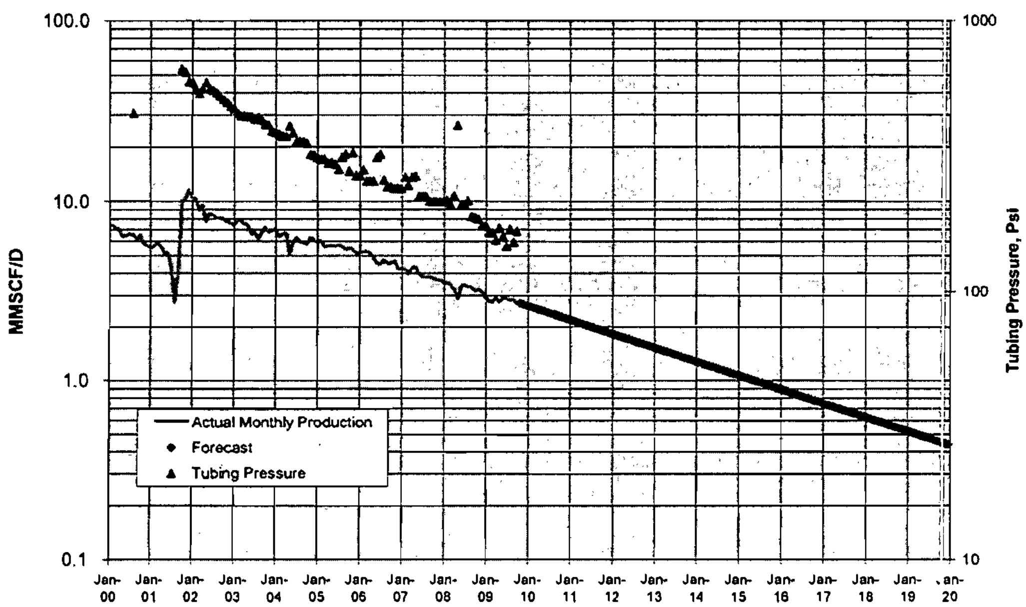

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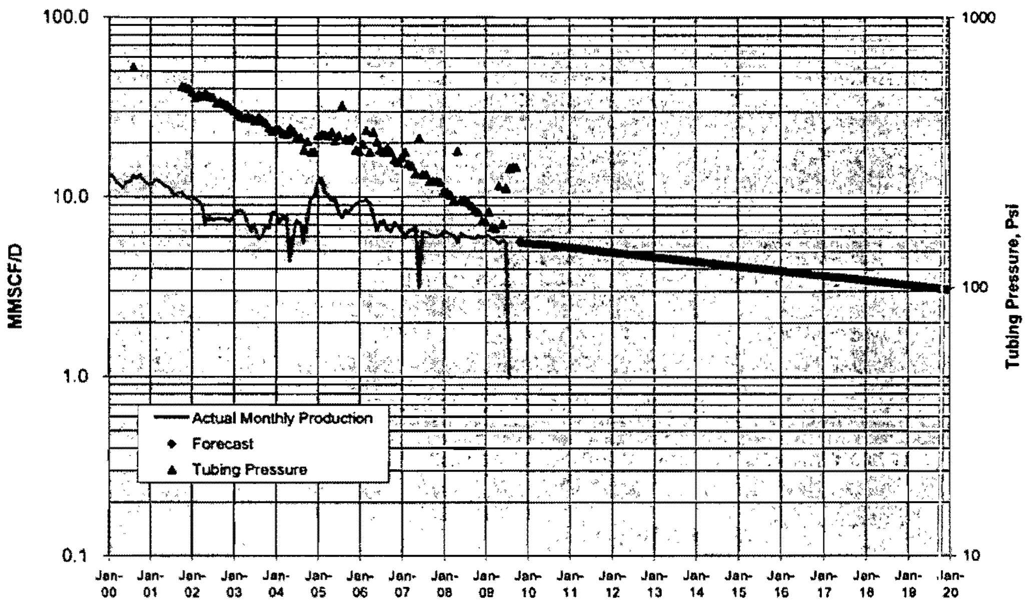

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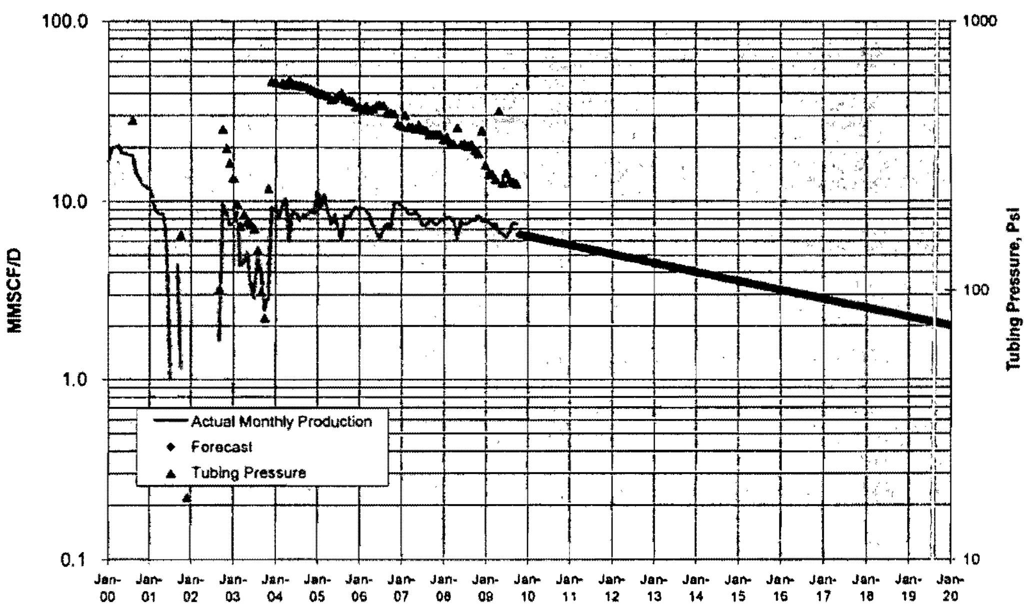
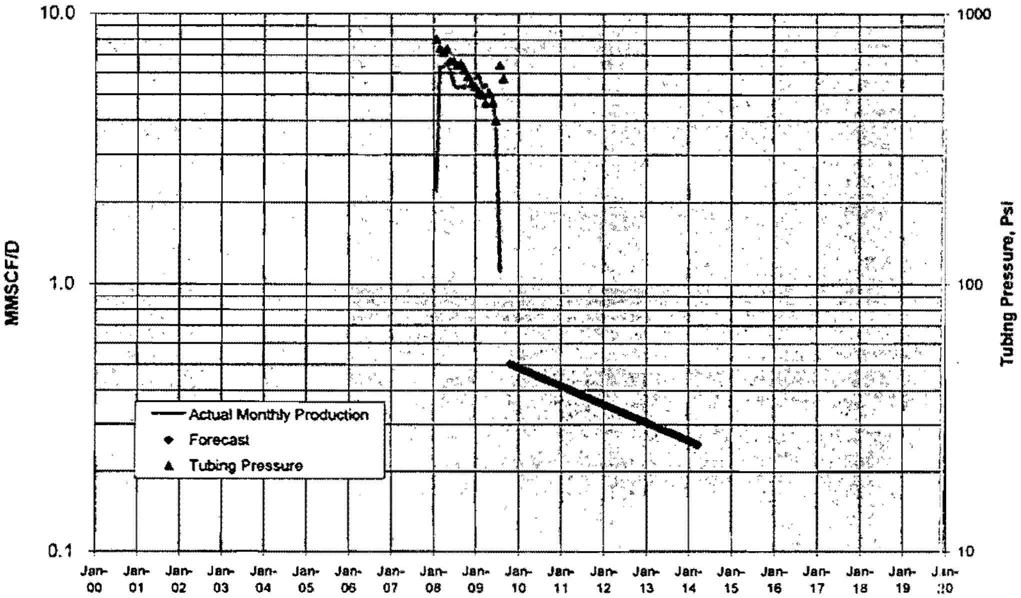
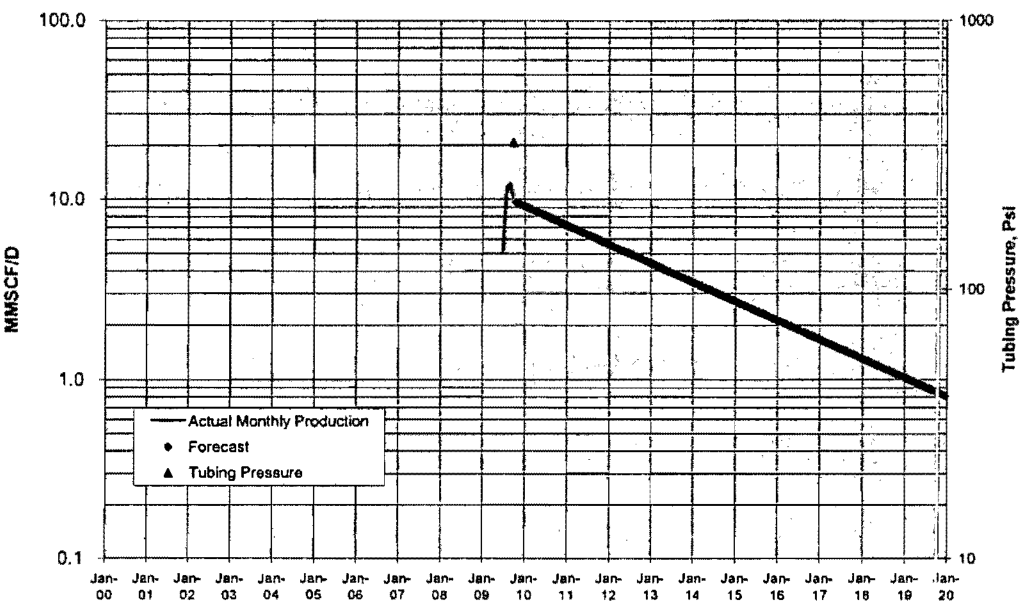


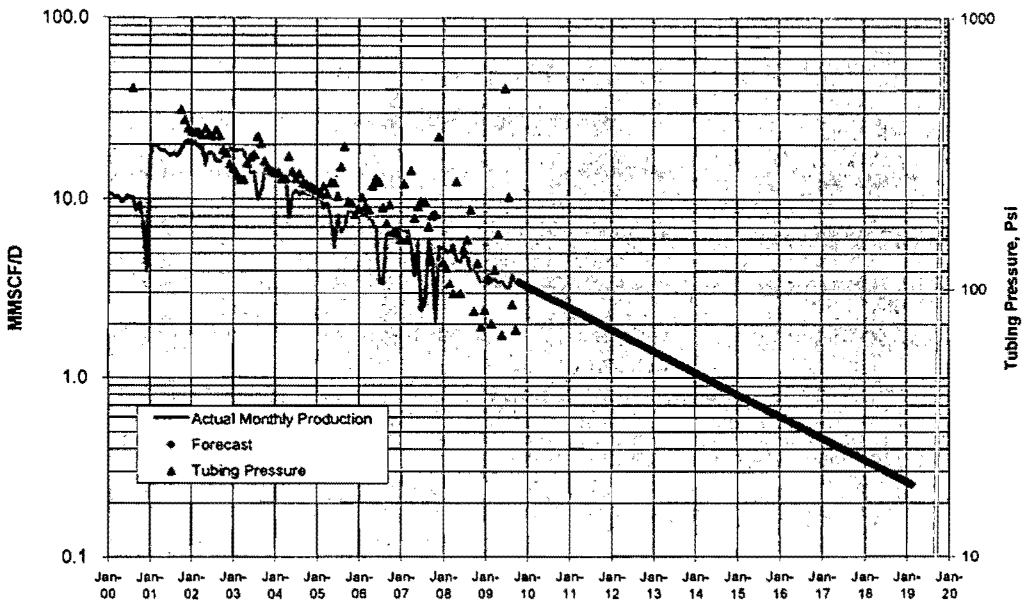
TBU Gas Well M-17



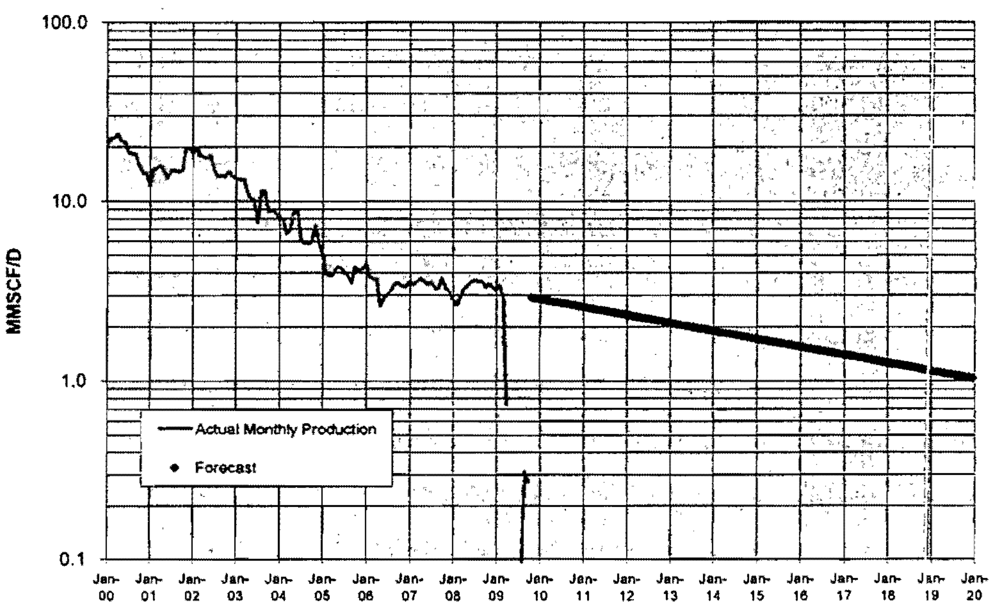
TBU Gas Well M-18



TBU Gas Well M-19RD



TBU Oil Wells



Appendix E: Listing of Gas Wells Drilled 2001-09

Well List by Name	Permit to Drill Number	Current Well Status	Current Status Date	Total Depth	Permit Class	Permit Status	Operator Name
TRADING BAY UNIT M-14RD	201-171-0	1-GAS	9/10/2001	6690	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI UNIT 21-06RD	201-097-0	1G-GS	5/8/2006	5650	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 2	201-096-0	1-GAS	7/3/2003	12026	EXP	1-GAS	MARATHON OIL CO
PRETTY CK UNIT 4	201-193-0	2G-GS	11/15/2005	9580	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
LEWIS RIVER UNIT C-01RD	201-168-0	1-GAS	12/9/2001	6469	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
TRADING BAY UNIT M-12	201-176-0	1-GAS	12/20/2001	10732	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI UNIT 24-05RD	201-144-0	1-GAS	12/22/2001	4816	DEV	1-GAS	MARATHON OIL CO
DEEP CREEK NNA 1	201-215-0	WDSP2	12/13/2004	10590	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI UNIT 43-06RD	201-231-0	1G-GS	5/8/2006	5740	DEV	1-GAS	MARATHON OIL CO
PEARL 1	202-011-0	P&A	4/11/2003	8000	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT FALLS CK 1RD	201-155-0	1-GAS	7/3/2003	8900	DEV	1-GAS	MARATHON OIL CO
GRINER 1	202-041-0	P&A	4/21/2003	6880	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI TYONEK UNIT 32-07H	202-043-0	1-GAS	5/20/2002	11857	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 41-07X	202-025-0	1-GAS	6/4/2002	5300	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT S DIONNE 3	202-070-0	1-GAS	7/3/2002	10255	EXP	1-GAS	MARATHON OIL CO
SWANSON RIV UNIT 213-10	202-118-0	1-GAS	8/4/2002	4105	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
NICOLAI CK UNIT 1B	202-162-0	1-GAS	9/22/2002	3672	DEV	1-GAS	AURORA GAS LLC
WOLF LAKE 1RD	202-088-0	1-GAS	10/8/2002	8770	DEV	1-GAS	MARATHON OIL CO
ABALONE 1	202-129-0	SUSP	3/9/2003	10356	EXP	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 11	203-025-0	1-GAS	6/30/2003	8931	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-1	203-072-0	1-GAS	7/9/2003	10872	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
BEAVER CK UNIT 3RD	203-044-0	1-GAS	7/16/2003	10005	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-2	203-113-0	1-GAS	8/4/2003	10225	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT FALLS CK 3	203-102-0	1-GAS	8/11/2003	10668	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 43-07X	203-066-0	1-GAS	9/5/2003	8610	DEV	1-GAS	MARATHON OIL CO
N COOK INLET UNIT A-10A	203-075-0	1-GAS	9/28/2003	8840	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
NICOLAI CREEK 9	202-208-0	1-GAS	10/3/2003	2102	DEV	1-GAS	AURORA GAS LLC
MOQUAWKIE 1	203-069-0	1-GAS	10/17/2003	3000	DEV	1-GAS	AURORA GAS LLC
TRADING BAY UNIT M-16RD	203-182-0	1-GAS	11/19/2003	3958	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
CANNERY LOOP UNIT 1RD	203-129-0	1-GAS	11/27/2003	10835	DEV	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 13	203-138-0	1-GAS	1/26/2004	10500	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 33-06X	203-183-0	1-GAS	2/5/2004	8405	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 7	203-191-0	1-GAS	2/21/2004	10864	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-3	203-222-0	1-GAS	3/12/2004	11345	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY A-4	203-223-0	1-GAS	3/23/2004	10620	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KASILOF SOUTH 1	202-256-0	1-GAS	3/25/2004	17545	EXP	2-GAS	MARATHON OIL CO
NINILCHIK UNIT FALLS CK 4	203-221-0	1-GAS	3/26/2004	7910	EXP	1-GAS	MARATHON OIL CO
KASILOF SOUTH 1L1	202-257-0	SUSP	4/15/2004	17665	EXP	2-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 8	204-005-0	1-GAS	4/28/2004	9777	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT PAXTON 1	204-010-0	1-GAS	5/29/2004	10115	EXP	1-GAS	MARATHON OIL CO
SWANSON RIV UNIT 241-16	204-088-0	1-GAS	6/10/2004	4264	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 11-8X	204-035-0	1-GAS	6/11/2004	7659	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-6	204-044-0	1-GAS	6/15/2004	11798	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KALOA 2	204-096-0	1-GAS	7/16/2004	3720	EXP	1-GAS	AURORA GAS LLC
RED 1	204-084-0	1-GAS	7/17/2004	12458	EXP	2O-2G	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 23-7	203-217-0	1-GAS	7/23/2004	9320	DEV	1-GAS	MARATHON OIL CO
STAR 1	204-117-0	P&A	6/10/2005	9130	EXP	2-GAS	UNION OIL CO OF CALIFORNIA
BEAVER CK UNIT BC-12	203-188-0	1-GAS	8/12/2004	8839	DEV	1-GAS	PELICAN HILL OIL AND GAS INC.
HAPPY VALLEY A-7	204-106-0	1-GAS	8/25/2004	10274	DEV	2-GAS	UNION OIL CO OF CALIFORNIA
LONG LK 1	203-068-0	SUSP	8/25/2004	3550	EXP	1-GAS	AURORA GAS LLC
HAPPY VALLEY A-8	204-114-0	1-GAS	8/27/2004	8900	DEV	2-GAS	UNION OIL CO OF CALIFORNIA
RED 2	204-148-0	1-GAS	9/5/2004	10100	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
ILIAMNA 1	203-172-0	P&A	9/5/2004	3530	EXP	1-GAS	PELICAN HILL OIL AND GAS INC.
BEAVER CK UNIT 14	204-086-0	1-GAS	9/22/2004	9361	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 9	204-161-0	1-GAS	11/3/2004	9100	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-9	204-170-0	1-GAS	11/5/2004	8478	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY A-10	204-186-0	1-GAS	11/19/2004	8420	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY A-11	204-207-0	1-GAS	11/30/2004	10082	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT S DIONNE 2	204-107-0	1-GAS	12/6/2004	11094	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 42-6	204-209-0	1-GAS	12/9/2004	8624	DEV	1-GAS	MARATHON OIL CO
W FORELAND 2	204-143-0	2-GAS	12/11/2004	11387	DEV	1-GAS	FOREST OIL CORP
W FORK 03	204-156-0	1-GAS	1/11/2005	10620	DEV	1-GAS	MARATHON OIL CO
THREE MILE CK UNIT 1	204-183-0	1-GAS	1/23/2005	8180	EXP	1-GAS	AURORA GAS LLC
N BELUGA 1	204-226-0	P&A	1/28/2005	5122	EXP	1-GAS	PELICAN HILL OIL AND GAS INC.

Well List by Name	Permit to Drill Number	Current Well Status	Current Status Date	Total Depth	Permit Class	Permit Status	Operator Name
NINILCHIK UNIT S DIONNE 4	204-233-0	1-GAS	3/18/2005	11953	DEV	1-GAS	MARATHON OIL CO
MOQUAWKIE 3	205-080-0	1-GAS	6/26/2005	2560	EXP	1-GAS	AURORA GAS LLC
KENAI BELUGA UNIT 11-8Y	205-091-0	1-GAS	7/20/2005	8220	DEV	1-GAS	MARATHON OIL CO
LONE CREEK 3	205-097-0	1-GAS	7/25/2005	3025	EXP	1-GAS	AURORA GAS LLC
KENAI BELUGA UNIT 22-06	205-054-0	1-GAS	8/3/2005	8855	DEV	1-GAS	MARATHON OIL CO
NINILCHIK STATE 1	205-023-0	1-GAS	8/25/2005	10221	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 3	204-255-0	1-GAS	9/1/2005	13771	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 10	205-106-0	1-GAS	9/1/2005	8450	DEV	1-GAS	MARATHON OIL CO
KENAI TYONEK UNIT 43-6XRD2	205-117-0	1-GAS	10/1/2005	9470	DEV	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 16	205-116-0	P&A	9/26/2007	6422	DEV	1-GAS	MARATHON OIL CO
KALOA 4	205-131-0	P&A	10/6/2005	4431	EXP	1-GAS	AURORA GAS LLC
THREE MILE CK UNIT 2	205-143-0	1-GAS	11/25/2005	5307	DEV	1-GAS	AURORA GAS LLC
KENAI BELUGA UNIT 41-6	205-141-0	1-GAS	12/8/2005	8733	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 11-7	205-165-0	1-GAS	1/6/2006	7900	DEV	1-GAS	MARATHON OIL CO
MIDDLE LK UNIT 1A	205-149-0	SUSP	1/16/2006	9350	EXP	1-GAS	PACIFIC ENERGY RESOURCES LTD
NINILCHIK UNIT G OSKOLKOFF 4	205-190-0	1-GAS	2/3/2006	8175	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 24-06RD	206-013-0	1-GAS	4/27/2006	7830	DEV	1-GAS	MARATHON OIL CO
ENDEAVOUR 1	205-213-0	P&A	5/13/2006	9225	EXP	2O-1G	AURORA GAS LLC
LONG LAKE 2	206-061-0	P&A	7/27/2006	3843	EXP	1-GAS	AURORA GAS LLC
KENAI UNIT 21-7X	206-029-0	1-GAS	9/1/2006	5032	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 12	206-121-0	SUSP	9/8/2006	10415	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 11	206-058-0	1-GAS	9/28/2006	9305	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT S DIONNE 5	206-088-0	1-GAS	10/3/2006	9600	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 24-7X	206-127-0	1-GAS	2/11/2007	8303	DEV	1-GAS	MARATHON OIL CO
NINILCHIK STATE 2	206-066-0	1-GAS	2/13/2007	11500	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 5	207-001-0	1-GAS	5/31/2007	10364	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 12-5	207-042-0	1-GAS	6/27/2007	8920	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 34-6	207-064-0	1-GAS	6/30/2007	7739	DEV	1-GAS	MARATHON OIL CO
STERLING UNIT 43-09X	207-073-0	1-GAS	8/8/2007	6185	DEV	1-GAS	MARATHON OIL CO
STERLING UNIT 41-15RD	207-088-0	1-GAS	9/12/2007	11655	DEV	1-GAS	MARATHON OIL CO
NINILCHIK STATE 3	207-018-0	1-GAS	10/5/2007	11962	DEV	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 16RD	207-125-0	1-GAS	10/31/2007	9421	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 6	207-096-0	1-GAS	11/22/2007	12069	DEV	1-GAS	MARATHON OIL CO
TRADING BAY UNIT M-17	207-120-0	1-GAS	12/29/2007	7670	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 14-6Y	207-149-0	1-GAS	1/18/2008	7600	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT PAXTON 2	207-164-0	1-GAS	3/8/2008	8436	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 42-07RD	208-052-0	1-GAS	5/27/2008	7926	DEV	1-GAS	MARATHON OIL CO
KENAI UNIT 41-18X	208-026-0	1-GAS	6/5/2008	8737	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 14-8	208-048-0	1-GAS	6/6/2008	8072	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 7	208-023-0	SUSP	6/12/2008	13500	DEV	1-GAS	MARATHON OIL CO
BELUGA RIV UNIT 243-34	208-079-0	1-GAS	7/28/2008	7005	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
NORTH FORK 34-26	208-063-0	1-GAS	9/23/2008	9021	EXP	1-GAS	ARMSTRONG RESOURCES LLC
BELUGA RIV UNIT 211-26	208-112-0	1-GAS	7/27/2008	7786	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
KENAI DEEP UNIT 9	208-106-0	1-GAS	10/23/2008	9850	DEV	1-GAS	MARATHON OIL CO
MOQUAWKIE 4	207-084-0	1-GAS	11/9/2008	3450	DEV	1-GAS	AURORA GAS LLC
SWANSON RIV UNIT 211-33	208-152-0	P&A	6/3/2009	4760	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT SD-6	208-160-0	1-GAS	12/21/2008	6737	DEV	1-GAS	MARATHON OIL CO
KENAI UNIT 22-6X	208-135-0	1G-GS	2/7/2009	5989	DEV	1-GAS	MARATHON OIL CO
N COOK INLET UNIT A-16	208-098-0	1-GAS	2/24/2009	9314	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
BEAVER CK UNIT 19	208-123-0	1-GAS	4/2/2009	9068	DEV	1-GAS	MARATHON OIL CO
IVAN RIVER UNIT 11-06	208-184-0	1-GAS	4/4/2009	10060	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
BEAVER CK UNIT 18	208-185-0	1-GAS	4/7/2009	9244	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 11-17X	209-016-0	1-GAS	4/15/2009	8055	DEV	1-GAS	MARATHON OIL CO
N COOK INLET UNIT A-14	208-096-0	1-GAS	4/23/2009	11501	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
N COOK INLET UNIT A-15	208-097-0	1-GAS	5/7/2009	8867	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
KALOA 3	209-047-0	P&A	6/20/2009	4709	DEV	1-GAS	AURORA GAS LLC
TRADING BAY UNIT M-18	208-162-0	1-GAS	7/16/2009	9930	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
STUMP LK UNIT 41-33RD	209-010-0	1-GAS	7/23/2009	10160	DEV	1G-GS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 42-6X	209-040-0	1-GAS	7/29/2009	10278	DEV	1-GAS	MARATHON OIL CO
TRADING BAY UNIT M-06	209-004-0	1-GAS	9/17/2009	12502	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
BELUGA RIV UNIT 232-23	209-057-0	1-GAS	10/7/2009	7587	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
HAPPY VALLEY B-13	207-151-0	1-GAS	4/3/2008	7747	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY B-12	207-123-0	1-GAS	6/1/2009	10400	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
LONE CREEK 4	207-091-0	UN			DEV	1-GAS	AURORA GAS LLC

Appendix F. Cook Inlet Unit POD's 2006-2009

Unit	**Beluga River**	
Operator	**ConcoPhillips**	
2009-10 Period		
POD #	**47th**	
Term	6/18/09 to 6/17/10	
Approved	5/29/2009	
Agency	BLM	
Wells	211-26	
	243-34	
Other		
2008-09 Period		
POD #	**46th**	**Review of projects**
Term	6/18/08 to 6/17/09	**at 47th POD appl.**
Approved	5/8/2008	
Agency	BLM	
Wells	232-26 WO	Recompl: Ster/Bel
	211-26 Drl & Cmpl	D&C: Ster/Bel
	243-34 Drl & Cmpl	D&C: Ster/Bel
2007-08 Period		
POD #	**45th**	**Review of projects**
Term	6/18/07 to 6/17/08	**at 46th POD appl.**
Approved	5/15/2007	
Agency	DNR/DOG	
Wells	No drilling	
	Planned 3D seismic acquisition	3D Seismic aquired

Unit	**Kenai**	
Operator	**Marathon**	
2009-10 Period		
POD #	**51st**	
Term	2/8/09-2/7/10	
Approved	1/27/2009	
Agency	BLM	
Wells	KBU 11-17X KBU 23-08 KBU 42-06X KU 31-06 Gas Stor	
Other		
2008-09 Period		
POD #	**50th**	**Review of projects**
Term	2/8/08-2/7/09	**at 51st POD appl.**
Approved	??	
Agency		
Wells	KBU 14-8	Drl & Cmpl: Bel/Tyon
	KBU 41-18X	Drl & Cmpl: Bel/Tyon
	KBU 42-7RD	Drl & Cmpl: Bel/Tyon
	KBU 41-6X EXCAPE	
	KU 31-7Y	
	KGF WDW2	KU 12-17 Drd & Cmpl as Cl II inj KDU-09 Drl & Cmpl: Tyonek KU 22-06X: D&C: Strlng P-6 Storage Rig WO KBU 42-07 RD
2007-08 Period		
POD #	**49th**	**Review of projects**
Term	2/8/08-2/7/09	**at 50th POD appl.**
Approved		
Agency		
Wells		KBU 12-5 D&C: Bel/Tyon KBU 34-6 D&C: Bel/Tyon KBU 24-7X comp 2/07: Bel/Tyon KU 23-6 recompl P-6 Storage KBU 41-7X recomp Sterling

Unit	**Ninilchik**	
Operator	**Marathon**	
2009-10 Period		
POD #	**6th**	**Dec 09 Status of Projects**
Term	1/1/10 to 12/31/10	
Approved	Pending	
Agency	DNR/DOG	
Wells	Paxson #3 Paxson #4	
Other		
2008-09 Period		
POD #	**5th**	**Review of projects at 6th POD appl.**
Term	1/1/09 to 12/31/09	
Approved		
Agency		
Wells	New wells planned on Corea Creek pad and Abalone pad; locations dependent on new seismic.	No wells drilled. Compression installed Susan Dionne pad. Compression will be installed on Paxson and Ninilchik State pads by late Q4-09
2007-08 Period		
POD #	**4th**	**Review of projects at 5th POD appl.**
Term	1/1/08 to 12/31/08	
Approved		
Agency		
Wells	Additional wells at Paxson S. Dionne G. Oskolkoff New Comp at S. Dionne pad	Paxson #2 cmpl Tyon GO #7 Drld, P&A Const in progress

Unit	**North Cook Inlet**	
Operator	**ConcoPhillips**	

2009-10 Period

POD #	**2010**	
Term	1/1/10 to 12/31/10	
Approved	Pending	
Agency	DNR/DOG	
Wells		
Other	Will evaluate feasibility of lowering wellhead pressures.	

2008-09 Period

POD #	**2009**	**Review of projects**
Term	1/1/09 to 12/31/09	**at 2010 POD appl.**
Approved	?	
Agency		
Wells	Drill 2 wells if previous wells are successful	Three new wells A-14, A-15, A-16 were completed. No additional drlg potential

2007-08 Period

POD #	2008	**Review of projects**
Term	1/1/09 to 12/31/09	**at 2009 POD appl.**
Approved	12/28/2007	
Agency	DNR/DOG	
Wells	Drilling only if needed for delivery	A-14 Drilled A-15 Drilled A-16 Drilled

Unit	**TBU Grayling Gas**	
Operator	**Chevron**	
2009-10 Period		
POD #	44th	
Term	8/27/09 to 8/26/10	
Approved	7/17/2009	
Agency	DNR/DOG	
Wells	M-20 Cmpl 10/09 M-10 Drl & Cmpl 1/10 M-1 WO 11/09 M-5 WO 12/09 2 other wells being evaluated for drilling & 2 others for WO.	
Other		
2008-09 Period		
POD #	**43rd**	**Review of projects**
Term	8/27/07 to 8/25/09	**at 44th POD appl.**
Approved	7/17/2007	
Agency	DNR/DOG	
Wells	Drill M-17 Evaluated other drilling potential.	M-18 drilled M-13 WO M-2 WO M-18 Compl 5/09 M-6 Drill & Compl 6/09 M-8 Drill & Compl 8/09
2007-08 Period		
POD #	**42nd**	**Review of projects**
Term	8/26/06 to 8/25/07	**at 43rd POD appl.**
Approved	6/29/2006	
Agency	DNR/DOG	
Wells	No drilling planned.	M-5 Gravel packed and B-5 & B-6 sands were perf'd. WO M-32RD to replace failed ESP.

Regulatory Commission of Alaska
April 2, 2010

Appendix F

Platts Methodology and Specifications Guide – North American Natural Gas, January 2010

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Methodology and Specifications Guide

North American Natural Gas

LATEST UPDATE: JANUARY 2010

The McGraw·Hill Companies

INTRODUCTION

This statement of methodology for Platts' North American natural gas price indexes and assessments reflects core principles that long have provided the foundation for Platts' price reporting in North American gas markets. It also includes detailed information on the submission of price data from market participants, the formation of indexes and assessments, and the publication of index-related information, including volumes and deal counts.

Platts' methodology will continue to evolve as natural gas markets change. The revisions in this update include clarifications to the two SoCal Gas locations in the appendix to the methodology and routine updates in the body of the methodology, such as changes in the contact information for Platts compliance staff.

The statement continues to incorporate price reporting standards that went into effect July 1, 2003, and also takes into consideration standards for price reporting stated in the Federal Energy Regulatory Commission's July 24, 2003, policy statement on US natural gas and electricity price indexes (PL03-3).

If you have questions concerning reporting to Platts or our statement of methodology, or would like to discuss any gas price reporting issues, please call or e-mail one of our editors: Brian Jordan, editorial director for North American natural gas and electricity markets, 202-383-2181 (brian_jordan@platts.com); Tom Castleman, daily markets editor, 713-658-3263 (tom_castleman@platts.com); Kelley Doolan, monthly bidweek markets editor, 202-383-2145 (kelley_doolan@platts.com); and Mike Wilczek, forward markets editor, 202-383-2246 (mike_wilczek@platts.com).

Platts also has a compliance staff independent of the editorial group. The compliance staff conducts regular reviews of editorial staff to check for adherence to published methodologies. For more information, contact Director of Compliance John Burnett, 212-904-6943 (john_burnett@platts.com).

Platts discloses publicly the days of publications of its price assessments and indexes, and the times during each trading day in which Platts considers transactions in determining its assessments and index levels. The dates of publications and the assessment periods are subject to change in the event of outside circumstances that affect Platts' ability to adhere to its normal publication schedule. Such circumstances include network outages, power failures, acts of terrorism, and other situations that result in an interruption in Platts' operations at one or more of its worldwide offices. In the event that any such circumstance occurs, Platts will endeavor, whenever feasible, to communicate publicly any changes to its publication schedule and assessments periods, with as much notice as possible.

HOW THIS METHODOLOGY STATEMENT IS ORGANIZED

This description of methodology for natural gas indexes in North America is divided into five sections (I-V) that parallel the entire process of producing the benchmarks. A separate appendix is a list of definitions of the trading locations for which Platts publishes daily, monthly bidweek and/or forward indexes and assessments.

- Part I describes what data goes into Platts' natural gas indexes and assessments, including details on what market participants are expected to submit, and the process for submitting data as well as the components of published data.
- Part II describes the security and confidentiality practices that Platts uses in handling and treating data.
- Part III is a detailed account of what Platts does with the data to formulate its daily, monthly bidweek and forward natural gas indexes and assessments, and includes descriptions of the statistical and editorial tools Platts uses to convert raw data into indexes and assessments. This section also describes the process for screening outliers.
- Part IV lays out the verification and correction process for revising published prices and the criteria Platts uses to determine when it publishes a correction.
- Part V explains the process for verifying that published prices comply with Platts' standards.

PART I: DATA QUALITY AND SUBMISSION

Platts' standards for data quality are at the heart of its process to produce reliable indexes and assessments and are designed to ensure that market participants provide complete and accurate information.

To that end, Platts' standards call for formalized reporting relationships with market participants in which data is submitted from a central point in the mid- or back office (a segment of the reporting entity that does not have a commercial interest in the reported prices). The reporting entity must certify that it is making a good-faith effort to report completely and accurately and will have staff assigned to respond to questions concerning data submittals. The entity also is obligated to make reasonable efforts to inform Platts in the case of any errors or omissions.

Daily and monthly bidweek price indexes are based on original reporting and do not incorporate publicly available price surveys. Prices for those indexes are collected firsthand by Platts from actual buyers and sellers.