Cook Inlet Natural Gas Reservoir & Storage

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Executive Summary

The seasonal variation in South-central Alaska natural gas demand is large, about 1.75 times the yearly average demand on the peak demand day in the winter for total gas demand (utility natural gas for residential and commercial heating and electric utility use for power generation) and about 2.5 for utility gas only. Historically the swing in gas demand has been met by spare production capacity from the Cook Inlet gas fields. As Cook Inlet production capacity has declined, the capability of the existing gas fields has decreased to the point that gas storage has been developed by the operators to provide contracted quantities and to provide the peak capacity needed on the coldest days. On January 9, 2007 a record was set by ENSTAR that required that natural gas be diverted from the liquefied natural gas (LNG) plant to meet the peak requirement (ENSTAR 2007). In the future, unless additional natural gas resources are developed in the Cook Inlet basin, natural gas from other sources will have to be developed to meet the demand for natural gas. Options include a spur pipeline to bring North Slope natural gas to South-central Alaska or gas from interior basins (e.g., the Nenana Basin) or imported LNG. Other options to reduce the demand such as coal plants, wind farms, hydropower, geothermal, and tidal power opportunities in the Railbelt region may reduce the demand for natural gas for power generation but will not offset the need for natural gas for home and business heating unless customers convert home heating to electric heating.

The objective of this study is to identify potential locations for underground natural gas storage in the Cook Inlet region. Storage is anticipated to be essential to achieve the capacity and deliverability required to meet the regional need for load balancing, operational balancing, and efficient management of the spur line system supply.

The reservoir characteristics and the production infrastructure for the existing and potential gas storage reservoirs in the Cook Inlet provide the basis for the evaluation and determination of the most likely candidates for possible future underground storage. It is assumed that a spur pipeline connecting an Alaska Gas Pipeline transporting North Slope natural gas to markets outside Alaska with offtake points in Alaska will be operational in 2020. The storage volume and deliverability rate required to meet the anticipated natural gas demand for utility gas and electric power generation are estimated from historical production and demand data. The characteristics of an ideal underground natural gas storage facility (base-load and peaking-load gas storage facilities) are described as are the three existing underground Cook Inlet storage facilities and the characteristics of potential underground storage facilities in the Cook Inlet. Finally, the potential Cook Inlet storage fields and pools are compared to the ideal storage characteristics to arrive at a ranking of the potential gas storage reservoirs. A general description and estimate of the costs related to conversion of a gas production reservoir to a gas storage facility are presented.

Overview of Cook Inlet Reservoirs

The Cook Inlet area has been the subject of oil and gas exploration since the early 20th Century, and the initial commercial discovery was made in 1957 at the Swanson River oil field on the Kenai Peninsula. Over the next decade additional oil accumulations were discovered and developed. During the oil exploration and subsequently, 30 gas fields were discovered ranging in size from less than 1.0 billion cubic feet (Bcf) of gas to more than 2.3 trillion cubic feet (Tcf) of gas. There are currently 30 gas fields and 57 individual pools recognized by the Alaska Oil and Gas Conservation Commission.

Storage Volume, Rate of Delivery Requirements and Estimates

A Railbelt natural gas demand forecast developed by ANGDA based on historical and projected demands for the use sectors is used for this assessment (ANGDA 2006). This demand forecast is for the entire Railbelt and includes regions of the state that will be served by an Alaska Natural Gas Pipeline from the North Slope and a spur pipeline to South-central Alaska. However, some of these regions will not be directly served by the spur pipeline; i.e., Fairbanks, North Pole, Delta Junction, Healy, Tok, Valdez).

The future of industrial use of natural gas in the Cook Inlet area will be determined by availability and price of natural gas for industrial purposes in the South-central Alaska. Agrium closed its nitrogen fertilizer operations due to a shortage of natural gas supply in Alaska's Cook Inlet basin. The balance of the historical industrial natural gas usage is for the ConocoPhillips/ Marathon LNG plant at Nikiski. The export license expires March 31, 2009. The plant owners have applied to the U.S. Department of Energy for a 2-year extension of this export license but the outcome of that assessment is not known at this time.

Continued industrial use of natural gas to provide an industrial base in South-central Alaska such as continued LNG operations and petrochemical industry will be determined by the availability and price of gas in the Cook Inlet from gas produced in the Cook Inlet or delivered through a spur pipeline from the North Slope (Thomas et al. 2004, Thomas et al. 2006, ANGDA 2006).

The minimum gas storage based on future estimated demand ranges from 11.1 Bcf in 2020 to 15.7 Bcf in 2040. Depending on the minimum gas storage required to meet demand in South-central Alaska is considered **too risky** because of the serious consequences of any shortfall that would cause a disruption in service in winter. There are currently **no alternative sources** of natural gas for heating and other essential services so a shortage causing a disruption of service to large portions of service area would be very costly and highly disruptive. Therefore, a safety factor of 1.5 was applied to arrive at the amount of gas storage required to meet seasonal swings in demand and possible longer-term disruptions that could result from equipment failures or pipeline breaks requiring several days to weeks to repair. Use of the 1.5 safety factor results in estimated gas storage capacity requirements of 16.7 Bcf in 2020 increasing to 23.5 Bcf in 2040. The selected gas storage reservoirs must be capable of providing the daily delivery rates during peak-demand season or multiple gas storage reservoirs or peaking reservoirs must be developed. Gas storage must also be able to deliver the incremental rates needed on the coldest highest demand days.

Although it is not possible to accurately predict the supply and demand situation that will exist in 2020, the estimated demand implies that a 300 MMcf/d spur pipeline will be needed in 2020. This assumes no new additional sources of gas from the Cook Inlet and no offsetting reduction in demand that could result from power generation from sources other than natural gas. This spur pipeline capacity will need to be expanded to 350 MMcf/d in 2030, 400 MMcf/d in 2035 and 450 MMcf/d in 2040 to meet the anticipated demand growth. Future industrial demand is not included in these capacity volumes.

The design withdrawal rates for base storage requirements range from 120 MMcf/d in 2020 to 169 MMcf/d in 2040. Unless the base storage reservoirs are capable of providing adequate deliverability through additional wells to meet the anticipated peak-day demands, peaking storage facilities may need to come on line between 2020 and 2025 and increase to a minimum deliverability rate of about 80 MMcf/d.

Ranked Candidates for Base Load Storage

The ranking of potential future base load storage sites will be determined by the following considerations.

- Reservoir size near the ideal volume–excessive capacity may require large volumes of cushion gas in order to achieve optimum operating rates. Capacity significantly below the ideal would require high existing reservoir pressures to minimize cushion gas and maximize working gas. Excessive storage concerns may be offset by using a greater number of wells to keep withdrawal rates at required levels. Reservoir size less than the ideal volume will require multiple facilities, which may be an advantage, when taking disruptions into consideration.
- Deliverability of a reservoir is a function of the number of wells, reservoir pressure, and communication. In the scenario analyzed, the number of wells in each potential storage site is taken to be two times the number of wells utilized during that pools historically high production stage (Appendix A, Table A.2). It may be possible to achieve greater deliverability by drilling more infill wells and adding compression.
- Gas volume can be a very costly component of the storage economics. The amount of working gas is taken as a constant (20 Bcf) and the variable is the volume of cushion gas required, which is based largely on the reservoir pressure. Large low pressure reservoirs may require several 100 Bcf of gas to achieve the necessary pressure.
- Depletion prior to 2015 is preferred and prior to 2020 is a virtual necessity. This provides adequate time to plan and prepare the site for gas storage. Those that are depleted after 2020 would need to be deferred or some agreement with the lease holders/operators would need to be negotiated to use part or all the field/pool for storage.

The large Kenai Field pools and the Beluga River Undefined pool were excluded from the final list because they have very large reservoir size (capacity) and require excessive volumes of cushion gas, 146 to 179 Bcf (Appendix A, Table A.1) to achieve pressures equivalent to the ambient pipeline pressure.

The Beluga River Undefined pool is somewhat unique. It includes numerous pay sandstones (more than 40) in the Sterling and Beluga formations. These pays are cut by an unknown number of the wells, probably ranging from 2 or 3 per pay to perhaps as many as 10 per pay interval. Individual wells may penetrate and produce from as many as 50 pays. The volume of cushion gas required is nearly 650 Bcf (Appendix A, Table A.2). The issues regarding well integrity, communication between pay zones, and depletion status of individual sandstones indicate that using any of these horizons for storage is not feasible based on current knowledge. The operators continue to delineate and refine their understanding of the interrelations among pays, wells, and production. Hence, there may come a time when specific, depleted horizons are viable candidates for storage.

The rankings for the potential base load storage site candidates are shown in Table 1 and the locations are shown on Figure1. They are compared to the "Ideal Storage Pool" criteria.

The Swanson River Sterling pool is ranked as number one primarily because it has good-to-high deliverability, is expected to be depleted by 2020, and requires moderate amounts of cushion gas. The reservoir size is adequate but falls in the mid-range of the preferred size class, and expansion of storage capacity is limited to about 10 Bcf over the estimated requirement.

Table 1. Ranked Candidates for Cook Inlet Base Load Storage

Rank	Pool	Reservoir Size (Bcf)	Deliverability[1] (MMcf/d)	Cushion Gas Required (Bcf)	Depletion Date (Year)
	IDEAL POOL	**25-50**	**120-169**	**0.0**	**2010-2015**
1	Swanson River/Sterling	39	60 (160)	9.0	2019
2	Beaver Creek/Beluga	92	61 (106)	16.0	2028
3	Ivan River	97	34 (65)	8.0	2019
4	Kenai/Sterling # 5.2	66	30 (36)	0.0	1981
5	Swanson River/Tyonek	28	29 (89)	6.0	2006
6	Beaver Creek/Sterling	140	33 (51)	24.0	1994

1. The number in the column is the 'adjusted" low deliverability, which is the value used to rank the candidate sites; the number in parenthesis is the "adjusted" high deliverability and can be achieved but is not sustainable for the entire demand season (Appendix A, Table A.2).

The Beaver Creek Beluga site has excellent reservoir size, the highest deliverability, but requires more cushion gas and is not expected to be depleted until 2028. These latter two factors prevent it from being ranked No. 1 and could drop it below the Ivan River pool.

The Ivan River pool is rated as the third choice due to the capacity and moderate volume of cushion gas required. The expected depletion date of 2019 is an additional plus. The primary negative factor is the relatively low deliverability of only 34 MMcf/d under the assumed development scenario.

The Kenai Sterling # 5.2 has been depleted since 1981 and has good-to-excellent reservoir size. The capacity is in excess of the requirements and no cushion gas is required to achieve ambient pipeline pressures. The chief problem is deliverability of only 30 MMcf/d using the one-to-one producing well scenario. There are suggestions that water encroachment has been detected, which may have the potential to reduce deliverability.

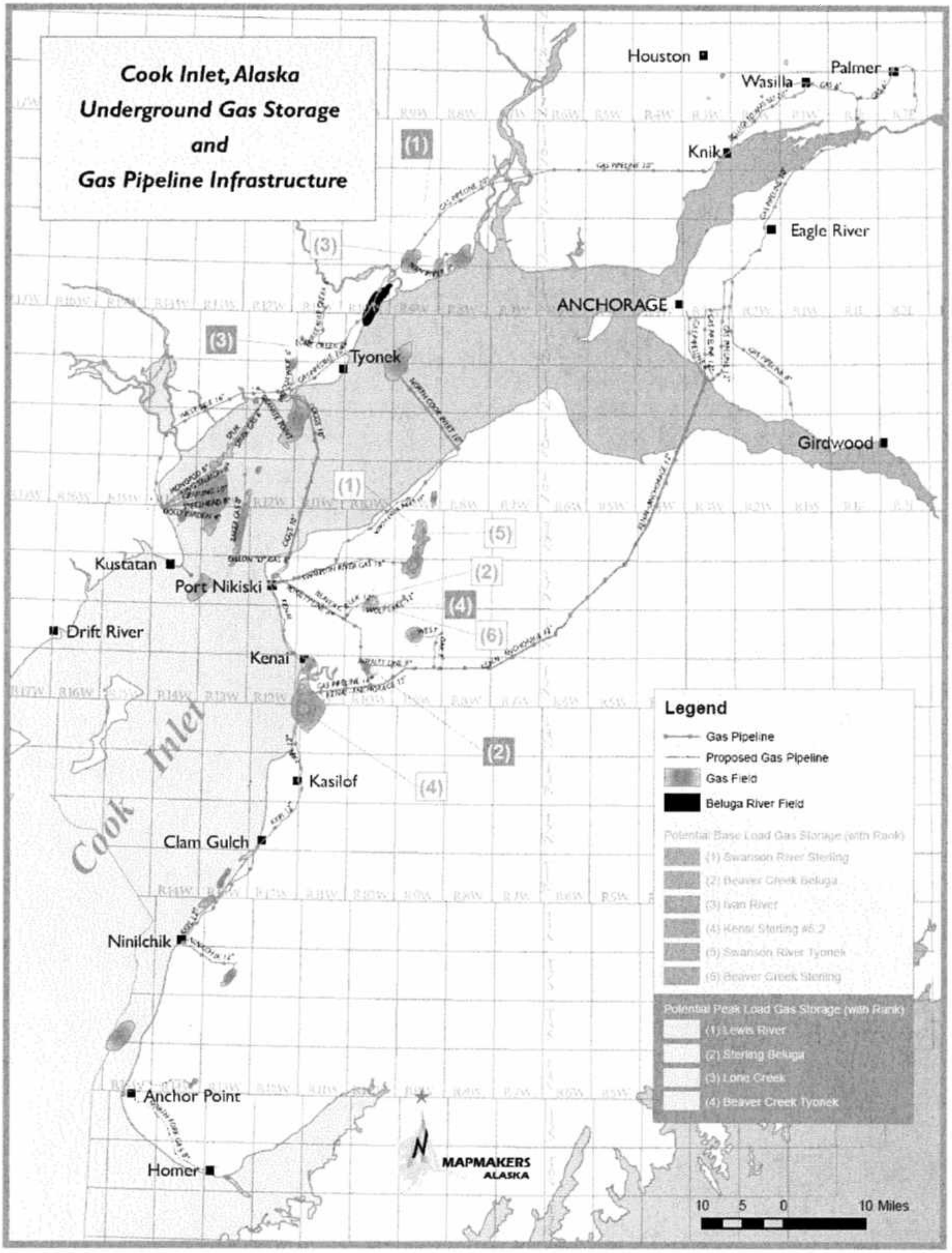
The Swanson River Tyonek pool is the smallest of the top six candidates at 28 Bcf, which is at the low end of the preferred size range. It requires a moderate amount of cushion gas, but has a projected deliverability in the one-to-one infill well case of only 29 MMcf/d.

The Beaver Creek Sterling pool is ranked No. 6 because of the problems with water encroachment, which requires a large volume of cushion gas and also reduces the deliverability. There is a large capacity for gas storage, and an early depletion date, but unfortunately that is due largely to the fact the pool watered out. The anticipated deliverability is about 33 MMcf/d.

The results of these evaluations indicate that there are viable potential future underground natural gas storage sites in the Cook Inlet gas fields that will meet the anticipated need for base load gas storage. However, among the leading candidates there are no true stand-alone reservoirs with regard to sustainable deliverability. Each of the candidate pools meets the capacity needs but under the proposed development none of them are capable of achieving the 120 to 169 MMcf/d design withdrawal rates (see Table 2.6 and Section 3.1).

Unless future detailed studies indicate otherwise, these pools in some combination should provide adequate storage for any reasonably forecast seasonal storage needs and achieve the deliverability needs for peak season demand. Under certain conditions, multiple base load storage facilities may negate the need for separate peak load storage, at least for the initial years of the pipelines existence.

Figure 1. Cook Inlet Potential Underground Gas Storage Locations and Gas Pipeline Infrastructure



Ranked Candidates for Potential Peak Load Storage Sites

The need for a separate peak load facility or facilities depends on the ultimate nature of the base load storage facilities. At this time the working scenario requires peak load storage for the short, very high demand periods resulting from conditions of extreme cold weather. Five pools were identified that would be candidates for potential peak load storage as shown in Table 2. The total storage capacity of these pools ranges from 6.2 Bcf to 15.1 Bcf (Appendix A, Table A.3). These pools are all on the pipeline system and are within 50 to 100 miles of the major consumers. Three key factors were utilized to rank or eliminate the pools: reservoir size, deliverability, and cushion gas requirements.

Table 2. Cook Inlet Ranked Peaking Load Storage Candidates

Rank	Pool	Reservoir Size (Bcf)	Cushion Gas Required (Bcf)	Deliverability[1] (MMcf/d)
1	Lewis River Undefined	14.3	1.6	130
2	Sterling Beluga Undefined	15.1	2.0	125+
3	Lone Creek Undefined	6.2	0	62
4	Beaver Creek Tyonek Undefined	6.3	0.5	58

1. 1% of the working gas volume (reservoir size minus cushion gas).

The existing Cook Inlet gas storage facilities have gas volumes of this size or smaller and average deliverability rates are about one percent of the total working gas. Based on these averages, maximum deliverability rates may range from a low of 58 MMcf/d for the Beaver Creek Tyonek undefined pool to a high of 131 MMcf/d for the Sterling Beluga Undefined pool. This assumes the reservoirs are filled to capacity and the cushion gas has been discounted.

Using the one percent of working gas volume (reservoir size minus cushion gas) as average daily deliverability, only two of the remaining pools are capable of achieving the 80 MMcf/d maximum anticipated peak gas requirements in 2040. The Lone Creek Undefined and the Beaver Creek Undefined pools are fall below the margin of 70 MMcf/d in 2025 for the assumed spur pipeline rates. Both the Lewis River and Sterling Beluga undefined pools have capability to achieve the desired deliverability in 2040 with potentials of approximately 125 to 130 MMcf/d each.

The Lone Creek and Lewis River sites are located on the west side of the Cook Inlet and could easily supply the electrical generation plant, while the Beaver Creek and Sterling Beluga sites are located on the east side and could be dedicated to the gas utilities.

The location and ranking of the potential peak load gas storage reservoirs/pools are shown in Figure 1.

Summary of Potential Cook Inlet Storage Sites

Six potential base load storage and four peak load storage sites are identified in the study. All the base load storage candidates are of sufficient size that, even with the anticipated cushion gas requirements of the various pools, they retain the capacity for the requisite volume of about 20 Bcf of working gas. At the calculated low sustainable deliverability rates none of them are gauged to have rates that are sufficient to serve as the sole storage facility and multiple storage pools are required. At the calculated high deliverability rates the Beaver Creek Beluga (120 MMcf/d) and the Swanson River Sterling (160 MMcf/d) can meet the demand, but not for sustained periods or for the duration of the high demand winter season.

The four potential peak storage sites are equally distributed between the west and east sides of Cook Inlet and the Lewis River and Sterling Beluga undefined pools have the potential to meet any anticipated peak demand needs. The Lone Creek and Beaver Creek Tyonek, as a pair could also meet that demand.

Cost of Potential Storage Facilities

The total capital costs for a 20 Bcf working gas storage facility, requiring the purchase of 20 Bcf of cushion gas, drilling of four new wells at $7 million each, and capable of delivering a maximum rate of 100 MMcf/d are estimated to be $8.1 million/Bcf. This compares to values given in a study by the Federal Energy Regulatory Commission (FERC 2004) of $5 to $6 million/Bcf for a typical depleted natural gas reservoir storage field in the Lower 48. The costs will vary depending on the specific sites chosen. The average cost-of-service for 20 storage operator tariffs collected by FERC (2004) indicated a median cost-of-service of $0.64/Mcf. A determination of the regulatory framework that the spur pipeline and gas storage facilities in the Cook Inlet will need to be determined as well as site-specific requirements to provide an accurate estimate of the tariff. A cost-of service estimate is not included in this study.

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Acronyms and Abbreviations

ADNR	Alaska Department of Natural Resources
ADOG	Alaska Division of Oil and Gas
ANGDA	Alaska Natural Gas Development Authority
AOGCC	Alaska Oil and Gas Conservation Commission
Bcf	billion cubic feet of natural gas
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
LNG	liquefied natural gas
md	millidarcies
MD	Measured depth
MMcf	million cubic feet natural gas
MMcf/d	million cubic feet per day
NETL	National Energy Technology Laboratory
RCA	Regulatory Commission of Alaska
Tcf	trillion cubic feet of natural gas
TVDss	True Vertical Depth sub-sea

Storage Measures

Total capacity is the maximum volume of gas that can be stored in an underground storage facility and is determined by the physical characteristics of the reservoir.

Base gas (or **cushion gas**) is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.

Working gas capacity is, by definition, total capacity minus base gas.

Working gas is the volume of gas in the reservoir above the designed level of the base gas. Working gas is that which is available to the marketplace.

Deliverability is a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity, deliverability is most often measured in terms of million cubic feet or dekatherms per day. The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the amount of base and working gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.

1 Introduction

The seasonal variation in South-central Alaska natural gas demand is large, about 1.75 times the yearly average demand on the peak demand day in the winter for total gas demand (utility natural gas for residential and commercial heating and electric utility use for power generation) and about 2.5 for utility gas only. Historically the swing in gas demand has been met by spare production capacity from the Cook Inlet gas fields. As Cook Inlet production capacity has declined, the capability of the existing gas fields and pools has decreased to the point that gas storage has been developed by the operators to provide contracted quantities and to provide the peak capacity needed on the coldest days. On January 9, 2007 a record was set by ENSTAR that required that natural gas be diverted from the liquefied natural gas (LNG) plant to meet the peak requirement (ENSTAR 2007). In the future, unless additional natural gas resources are developed in the Cook Inlet basin natural gas from other sources will have to be developed to meet the demand. Options include a spur pipeline to bring North Slope natural gas to South-central Alaska or gas from interior basins (e.g., the Nenana Basin) or imported LNG.

ANGDA is a major driving force to construct a pipeline to deliver North Slope gas into the Cook Inlet area to meet the energy needs of South-central Alaska. The need for a pipeline to bring natural gas to South-central Alaska is based on the declining natural gas reserves in the Cook Inlet from the currently developed fields. The critical nature of this need has been described in several recent reports and studies (Thomas et al. 2004, Thomas, et al. 2006, ANGDA 2006). The issues facing South-central Alaska future natural gas needs and sources were discussed in great detail by numerous presenters at the Alaska Oil and Gas Conservation Commission's (AOGCC) South Central Alaska Energy Forum held in Anchorage, Alaska, September 20-21, 2006.[1]

When a spur pipeline is used to deliver natural gas to South-central Alaska, it will be essential that the pipeline operate at a constant rate matching the nominated and contracted rate. This can be achieved by developing one or more of the depleted or nearly-depleted Cook Inlet gas reservoirs as gas storage facilities.

1.1 Objective

The objective of the project is to identify potential locations for underground natural gas storage in the Cook Inlet region. Storage is anticipated to be essential to meet storage capacity and deliverability required to meet the regional need for load balancing, operational balancing, and efficient management of the spur line system supply. The reservoir characteristics and the production infrastructure for the existing and potential gas storage reservoirs in the Cook Inlet provide the basis for the evaluation and determination of the most likely candidates for possible future underground storage.

1.2 Scope and approach

Section 2 of the report contains an analysis of the storage volume and deliverability rate required to meet the anticipated natural gas demand for utility gas for residential/commercial heating, and electric power generation. Section 3 contains a description of the characteristics of an ideal underground natural gas storage facility including base-load and peaking-load gas

[1] http://www.aogcc.alaska.gov/homeogc.shtml

storage facilities. Section 4 contains a description of the three existing underground Cook Inlet storage facilities. Section 5 describes the characteristics of potential underground storage facilities in the Cook Inlet. In Section 6 the potential storage facilities are compared to the ideal storage characteristics to arrive at a ranking of the potential gas storage reservoirs. Section 7 includes a general description and estimate of the costs related to conversion of a gas production reservoir to a gas storage facility to provide a general guideline for the costs on a unit volume basis.

The data used to analyze Cook Inlet oil and gas reservoirs were obtained from the publicly available sources including the AOGCC, Alaska Department of Natural Resources (ADNR), and the Regulatory Commission of Alaska (RCA). Chevron and Marathon currently operate gas storage facilities in the Cook Inlet at Swanson River, Pretty Creek and Kenai River Sterling Pool #6. These operators were contacted and they all provided general overviews of their operations and experiences in operating gas storage reservoirs in the Cook Inlet.

1.3 Overview of Cook Inlet Petroleum Geology and Reservoirs

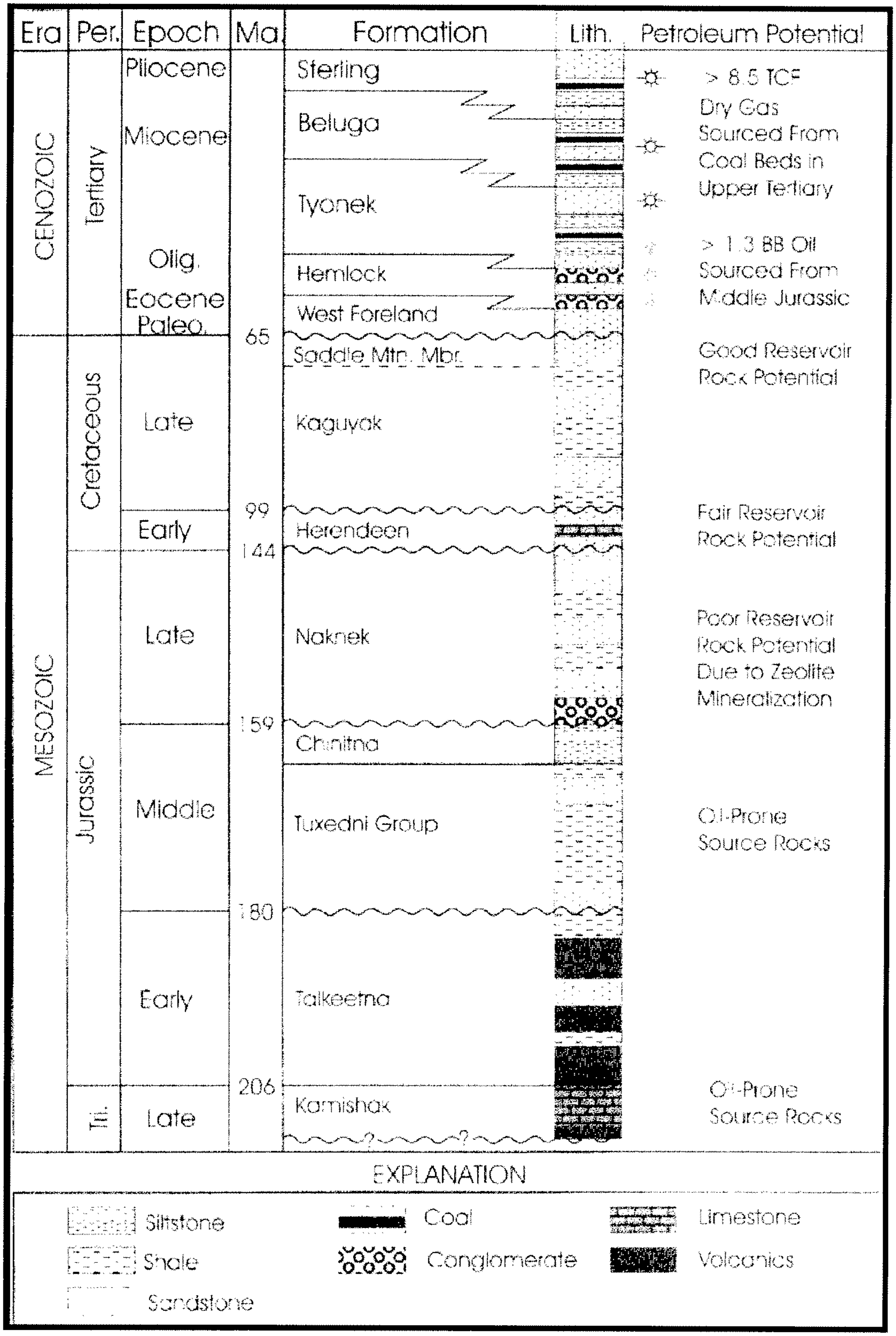
The effort to identify and evaluate potential Cook Inlet natural gas storage facilities is focused on the nearly depleted or depleted oil and gas reservoirs of the Cook Inlet Tertiary Basin. Prior to the discussion of the character and criteria required for Cook Inlet natural gas storage, it is informative to provide a very rudimentary over-view of the geological setting and petroleum geology of the Cook Inlet basin.

The Cook Inlet area has been the subject of oil and gas exploration since the early 20th Century, and the initial commercial discovery was made in 1957 at the Swanson River oil field on the Kenai Peninsula. Over the next decade additional oil accumulations were discovered and developed. During the oil exploration and subsequently, 30 gas fields were discovered ranging in size from less than 1.0 billion cubic feet (Bcf) of gas to more than 2.3 trillion cubic feet (Tcf) of gas (Thomas, et al. 2004, Table 2.5). The basin geological framework, character of the petroleum systems, the age, depositional framework, and distribution of hydrocarbons are discussed in considerable detail in Thomas, et al. (2004) and only a brief overview is provided here.

The entire Cook Inlet Tertiary section was deposited under non-marine conditions. The sub-aerial fans and a variety of fluvial channel systems constitute the reservoirs for the known, commercial oil and gas accumulations of the basin. The alluvial fan complexes provide thick, relatively continuous reservoirs and are best developed along the margins of the basin. The fluvial reservoirs have varying geometries and degrees of heterogeneity, depending upon the type of steam (braided, meandering, etc.) responsible for their formation. Consequently, these reservoirs have varying degrees of potential to serve as storage reservoirs depending on the nature of fluvial system and the degree to which they inter-finger with and migrate across the various overbank and flood plain facies (coals, mudstones, etc).

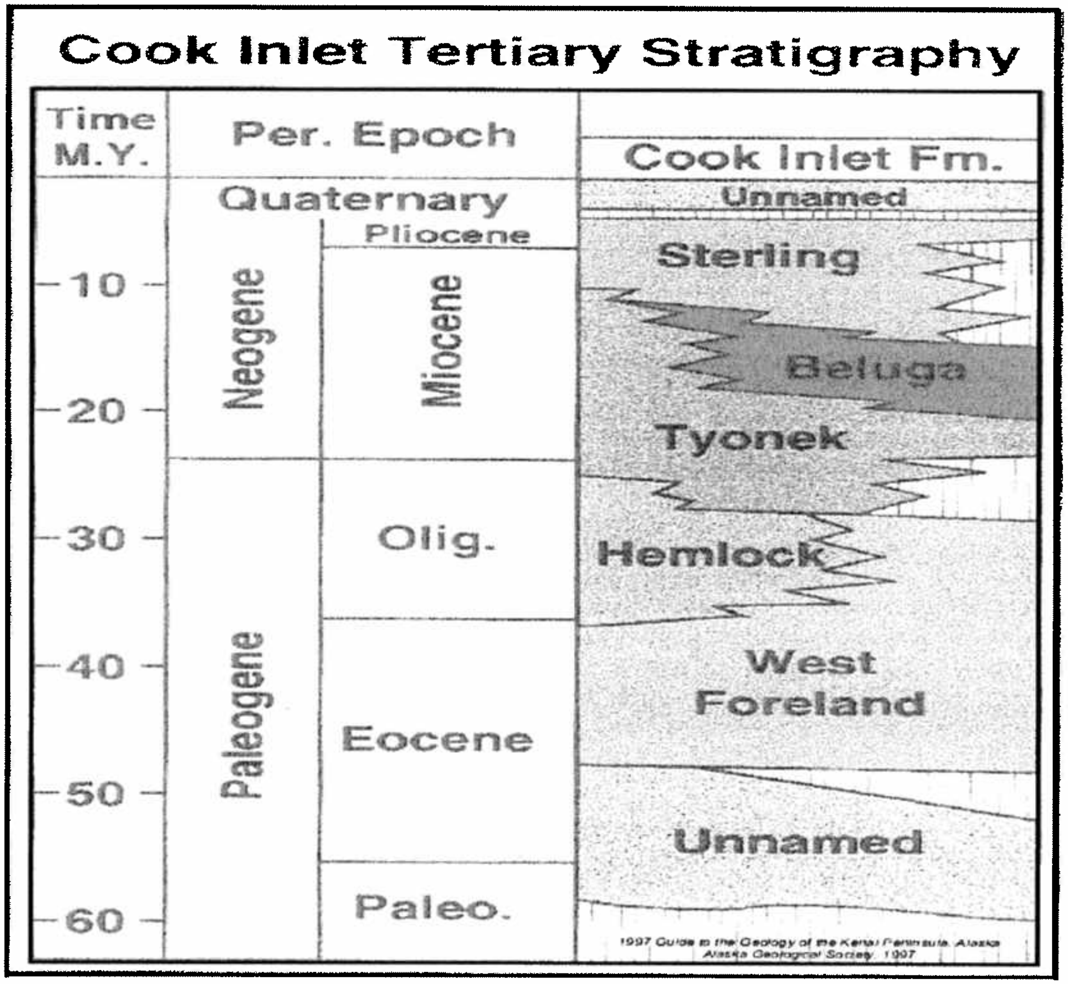
The Cook Inlet stratigraphic section (Figure 1.1) depicts both the Mesozoic and Cenozoic rocks of the Cook Inlet Basin and indicates the source intervals for oil and gas. The bulk of the gas is non-associated gas and is in no way related to the rocks or processes that generated the oil and associated gas. As can be seen from Figure 1.1 the oil is sourced thermogenically, from older Mesozoic rocks, and has accumulated in the lower portion of the Tertiary interval–in the West Foreland, Hemlock and lower Tyonek formations. Many of these oil-bearing reservoirs of the lower portion of the Tertiary section are of fan origin and hence thick and widespread in nature. This is especially true of the most important oil-bearing unit, the Hemlock Conglomerate.

Figure 1.1. Cook Inlet Basin Alaska–Stratigraphic Column & Oil and Gas Reservoirs



The non-associated gas was sourced biogenically, from the coals and coaly mudstones of the upper Tyonek, Beluga, and Sterling Formations. This gas has accumulated in reservoirs of the same age and system. These reservoirs are predominantly of fluvial origin, are more limited in distribution, and possess greater lateral heterogeneity. Figure 1.2 shows the stratigraphic and temporal relationships of the various formations of the Kenai Group (Swenson, R. F., 1997).

Figure 1.2 Cook Inlet Tertiary Section



There are currently 30 gas fields and 57 individual pools recognized by the Alaska Oil and Gas Conservation Commission (AOGCC 2006a). These Cook Inlet gas fields and pools, the cumulative production through 8/31/2007, and the remaining reserves estimates using a 10 MMcf/mon production cutoff for each pool are shown in Table 1.1. The reserves estimates were made using standard reservoir engineering material balance methodology (Slider 1983). The material balance data and the production rate versus pressure data for the field/pool are also used to estimate to estimate the amount of cushion gas required to return the pools to a pressure condition required to provide the required production rates. These estimated reserves total 1,102.4 Bcf in this analysis and do not include Probable/Under-development reserves. The ADNR Division of Oil and Gas (ADOG) 2007 Annual Report Table III.2 (ADNR 2007) lists gas reserves as 1,269.0 Bcf, without Probable/Under-development reserves, and 1,684.6 Bcf with

Probable/Under-development reserves. These reserves and production forecasts are close enough to the same that the ADOG production forecast (Table III.9. ADNR 2007) is used as a basis for estimating the gas storage capacity and deliverability rate required for gas storage in the Cook Inlet and the individual pool assessments performed in this study were used for individual pool estimates for the year when production is expected to stop and to determine the volumes of cushion gas required and associated pressures and deliverability rates.

The bulk of the Cook Inlet pools are in sandstone deposited by the fluvial channel systems of the upper Tyonek, Beluga, and Sterling formations. The sandstones of the lower part of the Sterling Formation constitute the best gas reservoirs in the basin and reflect the development of a thick succession of superposed fluvial channel systems. Consequently, it can be predicted, that all other factors being equal, the Sterling fields and pools should rank high in the ultimate listing of potential natural gas storage facilities.

The gas pools of the area are typically defined in one of two ways; 1) named after a specific sandstone within a formation as the Kenai #5.1 or #6 pools in the Kenai gas field, or 2) termed undefined, meaning there are multiple productive zones through the section and are named after the field or formation in which they occur, as Beluga River Undefined (produces from interval throughout the Beluga and Sterling formations) and Beaver Creek Tyonek Undefined (produces from intervals throughout the Tyonek).

Thomas et al. (2004) present a table derived from AOGCC data (2003) that provides porosity and permeability data for the three primary gas-bearing formations. While the number of samples is small, these data indicate the relative quality of the units as storage targets. In the most attractive unit, Sterling Formation, this sampling yields a porosity range of 10 to 33 percent with an average of 28 percent, and the permeability ranges from 125 to 2000 md with an average of 579 md. The upper Tyonek Formation has a porosity range of 12 to 29 percent with an average of 20.7 percent, and the permeability range is 0.25 to 1600 md with an average of 312 md. The Beluga Formation is the least prospective interval having a porosity range of 10 to 28 percent, with an average of 21.7 percent, but the permeabilities are much lower, ranging from 0.1 to 300 md, with an average of only 75 md. As stated earlier, the Sterling Formation gas pools should provide the most attractive options for future natural gas storage facilities.

Table 1.1. Cook Inlet Gas Fields and Pools (as of 08/31/2007)

Field	Pool	Cumulative (8/31/2007) (MMcf)	Remaining Reserves (10 MMcf/mon production cutoff)
Albert Kaloa	Undefined	2,933.1	1308.0
Beaver Creek	Beluga	60,379.6	22846.2
Beaver Creek	Sterling	125,952.9	0.0
Beaver Creek	Tyonek Undefined	5,498.4	0.0
Beluga River	Undefined	1,044,081.8	408665.2
Birch Hill	Undefined	65.3	0.0
Granite Pt	Undefined	872.8	0.0
Ivan River	Undefined	78,654.4	4666.0
Kasilof	Tyonek Undefined	1,868.2	398.4
Kenai	Beluga Undefined	0.1	0.0
Kenai	Sterling 3	332,329.2	5598.0
Kenai	Sterling 4	451,659.9	3892.8
Kenai	Sterling 5.1	484,638.7	0.0
Kenai	Sterling 5.2	44,031.6	0.0
Kenai	Sterling 6	530,063.8	12556.4
Kenai(1)	Sterling 6 Storage	488.5	N.A.
Kenai	Tyonek	187,060.5	8238.0
Kenai	Upper Tyonek Beluga	297,761.4	113899.6
Kenai C.L.U.	Beluga	64,121.5	37262.0
Kenai C.L.U.	Sterling Undefined	19,943.9	9538.4
Kenai C.L.U.	Tyonek D	1,399.4	0.0
Kenai C.L.U.	Upper Tyonek	71,898.7	8748.8
Kustatan	Undefined	311.4	0.0
Lewis River	Undefined	11,589.8	0.0
Lone Creek	Undefined	5,335.3	228.0
McArthur River(2)	Middle Kenai	1,066,396.2	111268.0
Middle Ground Shoal	Undefined	16,393.6	0.0
Moquawkie	Undefined	3,716.7	470.4
Nicolai Creek	Beluga Undefined	2,286.5	714.8
Nicolai Creek	North Undefined	1,123.2	0.0
Nicolai Creek	South Undefined	855.6	333.2
Ninilchik	Deep Undefined	8,767.0	15791.6
Ninilchik	Fc Tyonek Undefined	18,931.1	15714.8
Ninilchik	Go Tyonek Undefined	16,758.2	13870.8
Ninilchik	Pax Tyonek Undefined	1,319.8	2452.4
Ninilchik	Sd Tyonek Undefined	21,317.3	43967.6
North Cook Inlet(3)	Tertiary	1,763,222.1	231704.0
North Fork	Undefined	104.6	0.0
Pretty Creek	Undefined	9,402.2	0.0
Pretty Creek(1)	Beluga Storage	114.2	N.A.
Pretty Creek	Tyonek Undefined	3.0	0.0
Pioneer	Tyonek Undefined	3.0	0.0
Redoubt Shoal	Undefined	451.9	0.0
Redoubt Shoal	Tyonek Undefined	0.0	0.0
Sterling	Beluga Undefined	5,597.4	7911.2
Sterling	Sterling Undefined	3,699.9	0.0
Sterling	Tyonek Undefined	175.3	0.0
Stump Lake	Undefined	563.3	0.0
Swanson River	Beluga Undefined	1,018.4	1662.8
Swanson River	Sterling Undefined	30,248.2	4758.0
Swanson River(1)	Tyonek Undefined	18,347.1	N.A.
Three Mile Creek	Beluga Undefined	1,342.6	1586.0
Trading Bay	Undefined	5727.9	0.0
W Foreland	Tyonek Undefined 4.0	6,444.6	7289.6
W Foreland	Tyonek Undefined 4.2	2,839.1	3437.2
W Fork	Sterling A	1,230.8	0.0
W Fork	Sterling B	1,519.6	0.0
W Fork	Undefined	2,716.0	1649.6
Wolf Lake	Beluga-Tyonek Undefined	872.0	0.0

1. Current Gas Storage Fields/Pools
2. McArthur River Production Cutoff rate = 50 MMcf/mon
3. North Cook Inlet Production Cutoff rate = 100 MMcf/mon

2 Storage Volume and Rate of Delivery Requirements

The seasonal variation in South-central Alaska natural gas demand is large, about 1.75 times the yearly average demand on the peak demand day in the winter for total gas demand (utility natural gas for residential/commercial heating and electric utility gas for power generation) and about 2.5 for residential/commercial utility gas only. Historically the swing in gas demand has been met by spare production capacity from the Cook Inlet gas fields. When a spur pipeline is used to deliver natural gas to South-central Alaska, it will be essential that the pipeline operate at a constant rate matching the nominated and contracted rate. This can be achieved in the Cook Inlet by developing one or more of the depleted or nearly-depleted gas reservoirs as gas storage facilities. The basis for estimating the natural gas volumes and delivery rates from gas storage reservoirs needed to meet the seasonal fluctuations in natural gas demand throughout the year are described in this section.

2.1 South-central Alaska Demand Forecast

A Railbelt natural gas demand forecast developed by ANGDA based on historical and projected demands for the use sectors is used for this assessment (ANGDA 2006). This demand forecast is for the entire Railbelt and includes regions of the state that will be served by an Alaska Natural Gas Pipeline from the North Slope and a spur pipeline to South-central Alaska. However, some of these regions will not be directly served by the spur pipeline; i.e., Fairbanks, North Pole, Delta Junction, Healy, Tok, Valdez). The utilities and service areas are defined as shown in Table 2.1.

Table 2.1. Railbelt Gas and Electric Utilities and Service Areas (ANGDA 2006)

Electric Utility	Service Area
Anchorage Municipal Light & Power (AML&P)	**Central Anchorage**
Chugach Electric Association (Chugach)	Anchorage, Kenai Peninsula, Whittier, Tyonek
Homer Electric Association (HEA)	Homer, Soldotna, Seldovia, Kenai
Matanuska Electric Association (MEA)	Chugiak, Eagle River, Palmer, Wasilla, Talkeetna
Golden Valley Electric Association (GVEA)	Fairbanks, North Pole, Delta Junction, Healy
Seward Electric System (SES)	Seward
Copper Valley Electric Association (CVEA)	Copper River Basin, Valdez
Alaska Power Company (APC)	Tok, Dot Lake
Gas Distribution Utility	**Service Area**
ENSTAR	South-central Alaska/Anchorage Area
Fairbanks natural Gas (FNG)	Portion of Fairbanks
Independents and Direct	Anchorage area in addition to ENSTAR

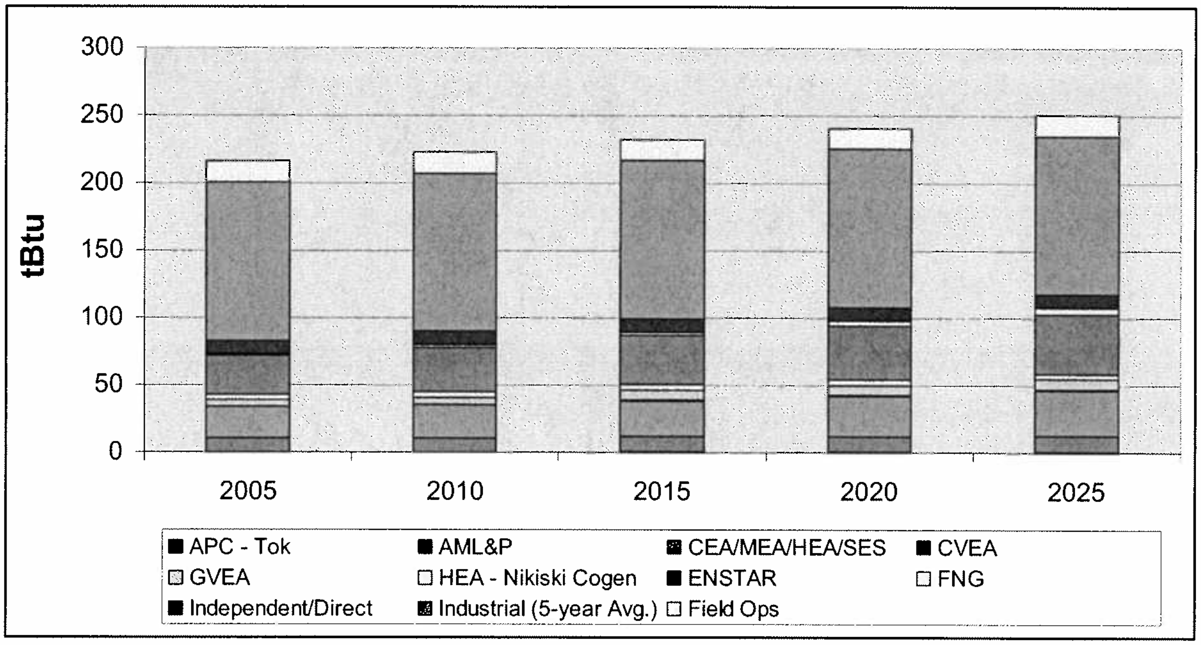
The forecast is described in the ANGDA (2006) report in Section 4.2 Gas Demand and is shown in Table 2.2 and Figure 2.1. The natural gas used for electrical power generation by Railbelt power utilities are shown in columns B through G and the gas utilities are shown in columns H thought J. The 5-year industrial average represents the historical use by the LNG plant and the Agrium fertilizer plant. The estimate for the gas used for operation of the natural gas production and delivery system is shown in column L. Column M shows the total natural gas demand in trillions of BTUs (tBtu). Some of these demand components, APC-Tok, CVEA, and FNG, will not be connected to the anticipated spur pipeline but their impact is minor relative to other uncertainties in long-term demand forecasting and these demand components are not removed from this assessment.

Table 2.2. Railbelt Natural Gas Demand (trillion Btu–tBtu)

A	B	C	D	E	F	G	H	I	J	K	L	M
Year	APC Tok	Anch. ML&P	CEA/ MEA/ HEA/ SES	CVEA	GVEA	HEA - Nikiski Cogen	ENSTAR	FNG	Indep/ Direct	Industrial (5-year Avg.)	Field Ops	Total tBtu
2005	0	10.5	23.5	0	5	4.1	29.0	0.9	10	117.7	15.4	216.1
2010	0	10.9	25.1	0	5	4.1	33.1	1.6	10	117.7	15.4	222.9
2015	0.4	11.4	27.1	0.3	7.5	4.1	36.2	2.2	10	117.7	15.4	232.3
2020	0.4	12.1	29.9	0.3	7.6	4.1	40.2	3.2	10	117.7	15.4	240.9
2025	0.4	12.7	33.5	0.4	7.7	4.1	44.2	4.6	10	117.7	15.4	250.7

Source: ANGDA

Figure 2.1. Railbelt Natural Gas Demand (Source: ANGDA)



2.1.1 Industrial Demand

The future of industrial use of natural gas in the Cook Inlet will be determined by availability and price of natural gas for industrial purposes in the South-central Alaska. Agrium announced in a September 25, 2007 statement that it was closing its nitrogen fertilizer operations at the end of September due to a shortage of natural gas supply in Alaska's Cook Inlet basin (PN 2007). The balance of the historical industrial natural gas usage is for the ConocoPhillips/Marathon LNG plant at Nikiski. The export license to continue operation of this facility expires March 31, 2009. The plant owners have applied to the U.S. Department of Energy for a 2-year extension of this export license but the outcome of that assessment is not known at this time.

Continued industrial use of natural gas to provide an industrial base in South-central Alaska such as continued LNG operations and petrochemical industry will be determined by the availability and price of gas in the Cook Inlet from gas produced in the Cook Inlet or delivered through a spur pipeline from the North Slope (Thomas et al. 2004, Thomas et al. 2006, ANGDA 2006).

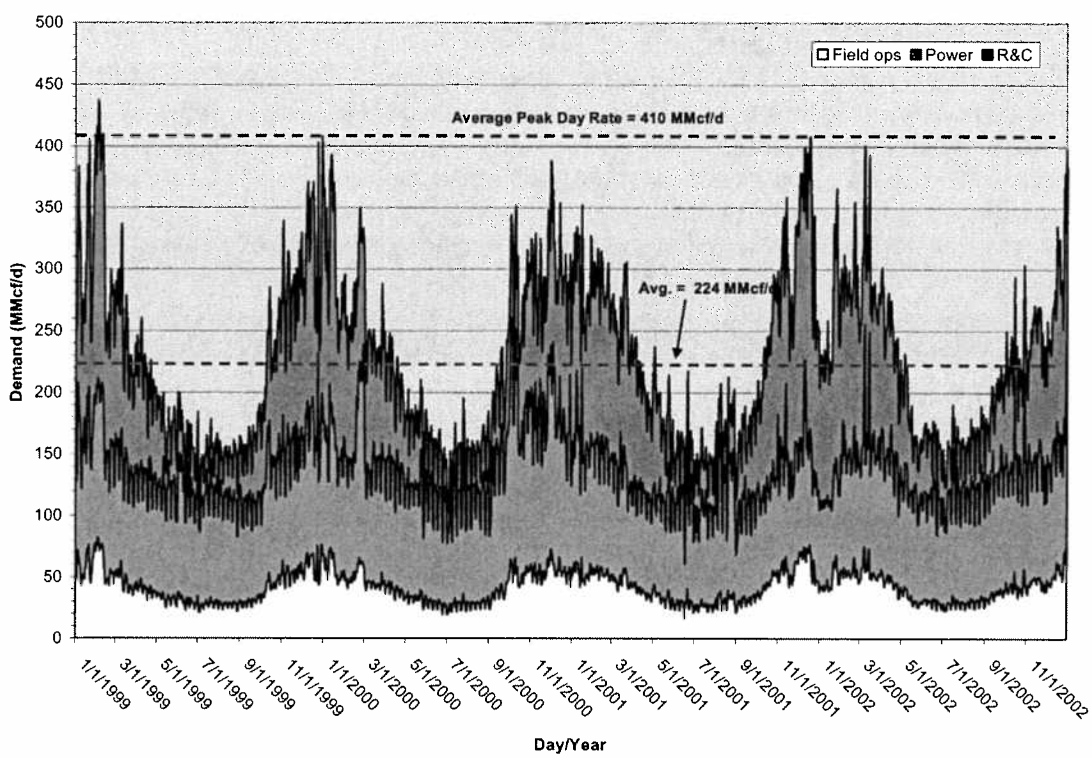
2.1.2 Seasonal Variations in Gas Demand

The seasonal fluctuation in gas demand is a function of ambient conditions and the balancing of available gas production, transmission, and end-user requirements of the South-central and Railbelt demand. Any industrial customers for natural gas from the spur pipeline will require a steady supply of natural gas and would be expected contract for constant delivery rates of gas and would not contribute to the seasonal fluctuations.

Historically, Cook Inlet gas fields have had adequate excess production capacity to meet seasonal demands. Ideally, the industrial users would not be called on to curtail industrial operations to meet peak-day demands from the gas utility and electric generation sectors. However, on January 6, 2007 natural gas was diverted from the LNG plant to meet a surge in demand due to cold weather (ENSTAR 2007). A properly designed spur pipeline and gas storage operation would alleviate the need for curtailing any future industrial operations.

The seasonal changes in demand that cause the need for gas storage are illustrated in Figure 2.2. Swings in utility gas demand (residential and commercial) are much larger than the power generation sector These data, which show daily demand for the 1999 to 2002 time period, are provided to illustrate the daily and seasonal demand swings and **should not be relied upon for decision purposes** because some of the data were generated by scaling to yearly average data from ADNR (2007). The natural gas from a spur pipeline that is not required to meet demand in the summer is available for injection into gas storage facilities for withdrawal to meet the shortfall in winter. This would allow a spur pipeline to be operated at a constant flow rate, which is highly desirable.

Figure 2.2. Illustrative South-central Alaska Daily Demand-1999-2002



Data sources: ENSTAR, AML&P and scaled to match yearly data by segment are reported by ADNR 2007, Table III.10, Division of Oil and Gas 2007 Report.

2.1.3 Gas Demand Forecasts to 2040

Forecasts for the time period from 2020 to 2040 were developed by extending the forecast shown in Table 2.2 for electricity generation (Columns B to G), residential/commercial (columns H to J), and field operations Column L). Gas storage to make up for any short fall in spur pipeline delivery in these demand components is essential. Fro simplicity, utility gas is assumed to be 1000 Btu/Mcf, the results are shown in Table 2.3.

Table 2.3. Railbelt Natural Gas Demand to 2040 (1000 Btu/Mcf)

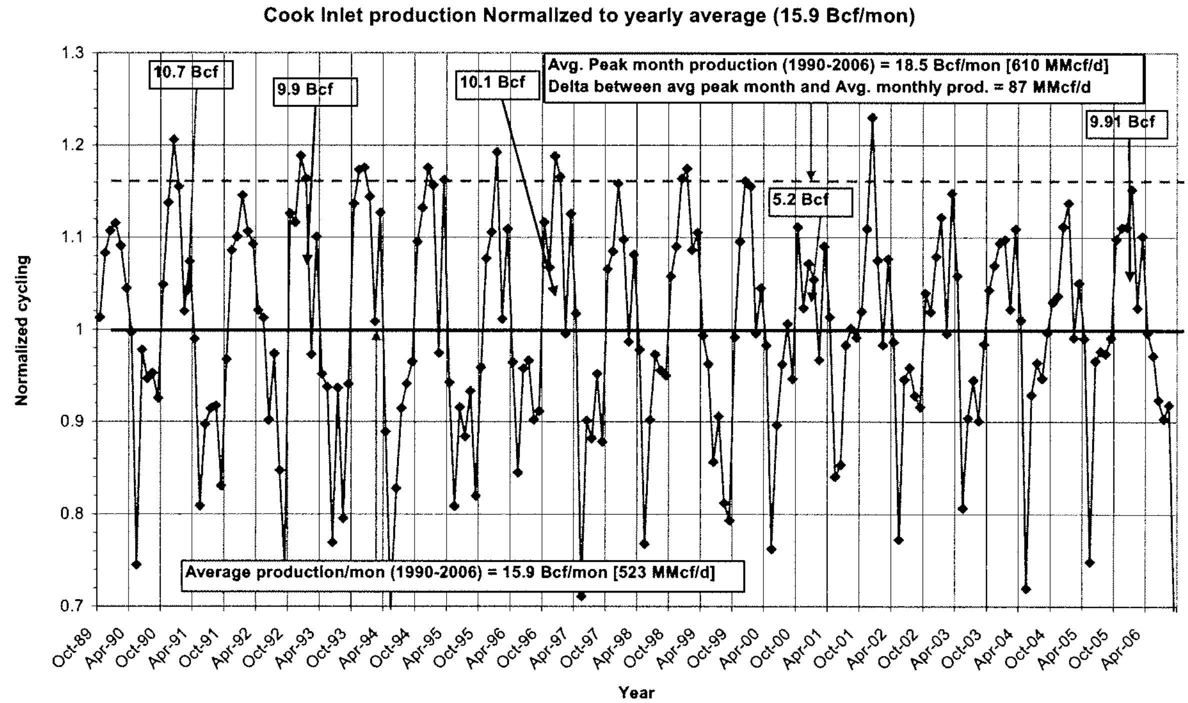
A	B	C	D	E	F	G	H
Year	Electric Utilities (Bcf/yr)	% increase Elec. Utilities	Gas Utilities (Res. and Commercial) (Bcf/yr)	% increase Gas Utilities	Field Ops (Bcf/yr)	Electric & Gas Utilities and Field Ops (Bcf/yr)	% increase Electric and gas Utilities and Field Ops
2005	43.1		39.9		15.4	98.4	
2010	45.1	4.64%	44.7	12.03%	15.4	105.2	6.91%
2015	50.8	12.64%	48.4	8.17%	15.4	114.6	8.89%
2020	54.4	7.09%	53.4	10.44%	15.4	123.2	7.55%
2025	58.8	8.09%	58.8	10.11%	15.4	133.0	7.95%
2030	63.5	8.00%	64.7	10.00%	15.4	143.6	7.96%
2035	68.6	8.00%	71.2	10.00%	15.4	155.1	8.04%
2040	74.1	8.00%	78.3	10.00%	15.4	167.7	8.12%

Source: SAIC based on ANGDA forecast (2006)

2.2 Storage Volumes and Rate of Delivery to Meet Seasonal Fluctuations

An analysis of Cook Inlet production history from 1990 to 2006 provides a long-term view of the year-to-year variation in production to meet total demand (industrial, residential/commercial, electricity production, and field operations and other) over a longer history. These data were normalized to the average monthly production rate of 15.9 Bcf/mon over this period and are shown in Figure 2.3. The volume of gas above the monthly average ranges from a high of 10.7 Bcf in the 1990-1991 winter season to a low of 5.2 Bcf in the 2000-2001 winter season. The average of the peak monthly production during this time period is 18.5 Bcf/mon. The difference between the average peak month and monthly average is 87 MMcf/d.

Figure 2.3. Normalized Cook Inlet Production (1990 to 2006)



2.2.1 Storage Volumes Based on Total Cook Inlet Production from 1990 to 2006

The average of gas for the peak-season months above the monthly average from 1990 to 2006 is 8.2 Bcf. In 2006 the volume was 9.6 Bcf. Using these volumes and the projected percentage increases in Table 2.2, Column H, the volume required for storage would range from 10.3 Bcf in 2020 to 14.0 Bcf in 2040 as shown in Table 2.4.

Table 2.4. Base Gas Storage Capacity Estimate from Historical Production

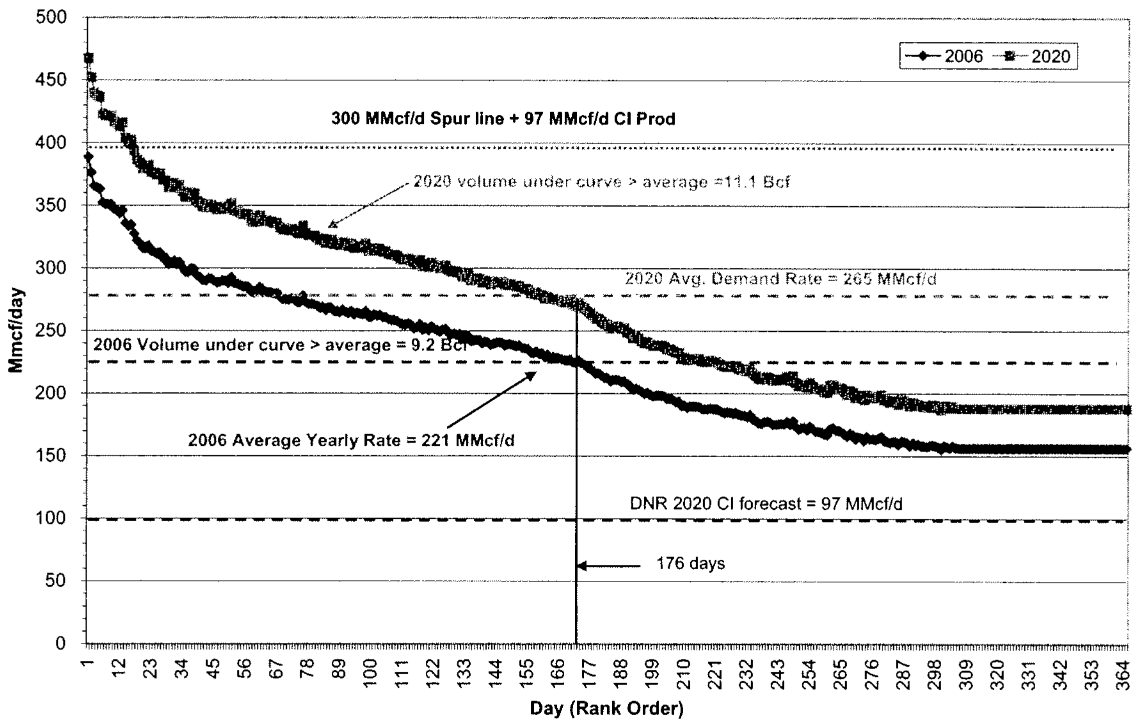
Year	Gas Storage Estimate (Bcf/yr)
2005	8.2
2010	8.8
2015	9.6
2020	10.3
2025	11.1
2030	12.0
2035	13.0
2040	14.0

2.2.2 Storage Volumes Based on Daily Gas Utility and Electric Utility Demand

Cook Inlet daily demand data are available from various sources for the Residential/Commercial and Electric Generation segments and have been complied for 2006 and forecasts developed through 2020 (Dunmire 2007). These data are shown in Figure 2.4. These demand volumes do not include the Fields Ops segment included in the Railbelt Demand included in Table 2.2.

The volume of gas above the average demand to meet Residential/Commercial and Electricity Generation demand for 2006 is 9.2 Bcf and 11.1 Bcf for 2020.

Figure 2.4. South-central Alaska Natural Gas Demand (Gas Utility and Power Generation)



The data used to develop Figure 2.4 also provide the peak-day demand for these demand segments (Dunmire 2007). The gas storage estimates, the average daily demand rate, and peak daily demand rate to 2040 are estimated based on the 2020 estimates using the percentage increases from Table 2.3 Column C for Electric Utilities (power generation) and Column E for Gas Utility (residential/commercial). These estimates are shown in Table 2.5. These estimates are about 10% larger than the volumes shown in Table 2.4 that were based on total Cook Inlet production. Gas storage reservoirs must be capable of supplying the volumes and deliverability rates to meet demand above the average daily rate throughout the high-demand season of the year. The daily demand analysis indicates this is about 176 days per year.

Table 2.5. Base Storage Estimate from Daily Demand

Year	Gas Storage Estimate (Bcf/yr)	Avg. Daily Demand (MMcf/d)	Peak daily Demand (MMcf/d)
2006	9.2	221	389
2020	11.1	265	467
2025	12.1	290	511
2030	13.2	316	559
2035	14.4	344	611
2040	15.7	376	668

The consequences to South-central Alaska utility gas customers of deliverability falling below demand for even one day in the winter makes it imperative that a safety factor be included in the planning for gas storage requirements. A longer disruption of several days or weeks resulting from events such as equipment failure or pipeline breaks is always a possibility. Hence, the base storage capacity is increased by 1.5 times the base gas storage estimate to provide a safety factor for evaluating potential gas storage reservoirs as shown in column C in Table 2.6. The gas storage volumes increase from 16.7 Bcf/yr in 2020 to 23.5 Bcf/yr in 2040. Table 2.6 also includes the average withdrawal rate for the base storage and the proposed design withdrawal rates of 1.9 times the average withdrawal rates, columns D and E, respectively.

Table 2.6. Base Gas Storage and Average Withdrawal Rates for Gas and Electric Utilities

A	B	C	D	E
Year	Gas Storage Estimate (Bcf/yr)	1.5 times Required Gas Storage (Bcf/yr)	Avg. Withdrawal Rate[1] (MMcf/d)	Design Withdrawal Rate[2] MMcf/d)
2006	9.2	--	--	--
2020	11.1	16.7	63.1	120
2025	12.1	18.2	68.9	131
2030	13.2	19.8	75.0	142
2035	14.4	21.6	81.8	155
2040	15.7	23.5	89.0	169

1. Average withdrawal rate = Required gas storage/176 days
2. The design withdrawal rates are 1.9 times the daily average withdrawal rates

It is essential that the spur pipeline and Cook Inlet production provide the **average daily demand** throughout the year and that gas storage or some other alternative source of gas be available to meet the daily demand above the average. The average daily demand must also include the volumes required for Field Ops to operate the natural gas supply system. Any Industrial demand would be in addition to the volumes presented in these tables. The minimum required throughput rate for a spur pipeline to meet this average requirement is shown in Table 2.7. However, a higher spur pipeline rate will be required in the first few years to provide gas to build cushion gas and working gas volumes required to meet the capacity and deliverability required.

Table 2.7. Minimum Spur Pipeline Rate to Meet Average Demand

Year	Average Daily Gas and Elec. Utility Demand (MMcf/d)	Average Daily Field Ops Demand (MMcf/d)[1]	Average Daily Demand (Gas and Elec. Utility & Field Ops) (MMcf/d)	Cook Inlet Production Forecast[2] (MMcf/d)	Spur Pipeline Rate Required for Average Daily Demand[3] (MMcf/d)
2006	221	42	263	--	--
2020	265	42	307	97	210
2025	290	42	332	52	280
2030	316	42	358	30	328
2035	344	42	386	17	369
2040	376	42	418	10	408

1. From Table 2.2.
2. ADNR 2007 Annual Report (Forecast extended to 2040 from 2036)
3. Spur pipeline rate = Average Daily Demand – Cook Inlet Production

Before a spur pipeline will be operational in 2020, South-central Alaska must have additional natural gas for power generation and residential/commercial use to meet the short fall from existing Cook Inlet reserves. This shortfall can be offset by successful Cook Inlet natural gas exploration; switching a portion of the power generation from natural gas to alternatives such as coal, wind, hydropower, or tidal power; import of LNG; or some combination of all of these options including energy efficiency and conservation measures. When a spur pipeline is available those options that have been put in place for the interim need will still be available. For example, if LNG import is part of the solution, it may need to be continued until gas storage has been built to a level to meet the winter season demand.

In addition, gas storage deliverability must be available to meet the peak-day demands. Gas storage reservoir characteristics, operational design, and costs will determine whether this can be accomplished by spare capacity from the base storage facility or if a peaking-load storage facility will be required to meet the demand.

Due to the necessity to nominate spur pipeline rates on a long-term basis and to build gas storage (cushion gas and working gas), it is assumed that the spur pipeline rate will initially be 300 MMcf/d. Because of the uncertainty of the alternatives, described above, that will have been put in place this assumption is only one possible scenario out of numerous possible scenarios. In addition, if there are industrial users for spur pipeline gas, the rate will need to be higher by that amount unless industrial users would be willing to be curtailed on high demand days.

The assumed initial rate of 300 MMcf/d would need to be increased in increments to meet growing demand and it is anticipated that the spur pipeline will be designed such that additional compression can be added to increase the throughput rate as needed. This also means that there must be opportunities to nominate higher off-take rates from the Alaska Gas Pipeline in the future as currently anticipated. The gas storage withdrawal rates needed for peak-day deliveries for the assumed spur pipeline rates of 300 MMcf/d in 2020 increasing to 450 MMcf/d by 2035 are shown in Table 2.8. These volumes would allow for a significant build up of gas storage of a full year's supply for Cook Inlet consumers or industrial use.

The peak-day demand shown in Table 2.6 has been increased by the average daily demand for the Field Ops demand segment (42 MMcf/d) for these calculations. The Field Ops demand will also vary on a daily basis throughout the year but volumes for that variation are not available.

Table 2.8. Gas Storage Deliverability Required for Peak-Day Rate

Year	Avg. Daily Demand (MMcf/d)	Estimated Peak day rate(1) (MMcf/d)	Cook Inlet Production Forecast(2) (MMcf/d)	Spur Pipeline Rates(3) (MMcf/d)	Gas Storage Withdrawal Rate Req'd for Peak Day(4) (MMcf/d)	Design Withdrawal Rate(5) (1.9 times Avg. Rate) (MMcf/d)	Max. rate req'd from peaking storage(6) (MMcf/d)	Yrly Volume Available for Cushion and Working Gas(7) (Bcf/yr)
2006	263	–	–	–	–	–	–	–
2020	307	509	97	300	112	120	-8	33
2025	329	553	52	300	201	131	70	8
2030	352	601	30	350	221	142	79	10
2035	377	653	17	400	236	155	81	15
2040	404	710	10	450	250	169	81	20

1. Peak day rates from Table 2.5 are increased by 42 MMcf/d to include the Field Ops volumes.
2. ADNR 2007 Annual Report (Forecast extended to 2040)
3. Assumed Nominated Spur Pipeline rates
4. Gas Storage Withdrawal Rate reqd. for Peak Day = Est. Peak Day rate – Cook Inlet Production – Spur Pipeline Rate
5. From Table 2.6.
6. Max. Rate for Peaking Storage = Gas Storage Withdrawal Rate Reg'd on peak Day – Design Withdrawal Rate
7. Gas Volume available for Building Cushion & Working Gas Volumes = (Cook Inlet Prod. + Spur Pipeline Rate – Avg. Daily Demand)*365 days

2.3 Summary of Storage Volume and Rate of Delivery Estimates

Historical Cook Inlet production and seasonal demand data were both analyzed and indicate a similar gas storage requirement. The minimum gas storage based on future estimated demand ranges from 11.1 Bcf in 2020 to 15.7 Bcf in 2040. Depending on the minimum gas storage required to meet demand in South-central Alaska is considered too risky because of the serious consequences of any shortfall because there are **no alternative sources** of gas for heating and other essential services totally dependent on natural gas at this point in time. Therefore, a safety factor of 1.5 was applied resulting in an estimated gas storage capacity of 16.7 Bcf in 2020 increasing to 23.5 Bcf in 2040. The spur pipeline must have a delivery rate high enough to build up the cushion gas and working gas required for the selected reservoir to meet the base storage requirement plus the 50% safety factor in volume and provide the daily delivery rates during peak-demand season.

Gas storage must also be able to deliver the incremental rates needed on the coldest days. Based on an assumed 300 MMcf/d spur pipeline in 2020, with expansion to 350 MMcf/d in 2030, 400 MMcf/d in 2035 and 450 MMcf/d in 2040, the incremental delivery from gas storage required to meet the peak-day demand estimates ranges from 112 MMcf/d in 2020 to 250 MMcf/d in 2040. The design withdrawal rates for base storage requirements range from 120 MMcf/d in 2020 to 169 MMcf/d in 2040. Unless the base storage reservoirs are capable of providing adequate deliverability through additional wells to meet the anticipated peak demands, peaking storage facilities may need to come on line between 2020 and 2025 and increase to a minimum deliverability rate of about 80 MMcf/d.

The potential gas storage reservoirs are described in the Section 3.

3 Characteristics of Ideal Natural Gas Storage Facility

An ideal natural gas storage system is described that will meet the optimum base load and peaking load conditions for the Cook Inlet area. The characteristics of this storage system are based on gas volumes that are largely determined by an anticipated constant spur line capacity and seasonally variable usage volumes (residential, commercial, and industrial) in the Cook Inlet area. With these assumptions is place, both the ideal base load and peak load storage facilities are described within the constraints of the known geologic and engineering characteristics of the reservoir intervals of the Cook Inlet Tertiary section (Figure 1.1 and 1.2).

Ideal storage facilities are the products of a complementary interaction of geological, engineering, and logistical elements that are present within the Cook Inlet area. Essential parameters include proximity and connection to existing pipeline system(s), existing gas producing infrastructure, potential storage volume, reservoir geometry and heterogeneity, porosity, permeability, water saturation, water influx characteristics, access to potential storage site, and reservoir pressure/depth. The criteria necessary for the "ideal' storage facility or facilities are described below. The concept of a dual storage system requires that the base load and peak load storage sites/systems possess somewhat different characteristics.

3.1 Base Load Storage Facility Criteria

The base-load storage facility must be of sufficient size to accommodate the excess gas delivered during the low-demand summer months and have the characteristics that will facilitate the withdrawal of the gas during the winter season in quantities and at rates sufficient to meet the average expected demand. This storage facility is not intended or designed to meet the extreme volumes required for short periods during very high use days. The following criteria describe the ideal base-load storage reservoir for Cook Inlet.

- To meet the anticipated storage needs required to offset annual seasonal fluctuations in residential/commercial and power generation demand, at a proposed start-up date of 2020, the storage facility has a working gas capacity of 16.7 BCF (Table 2.8). The facility needs to be capable of expansion to 23.5 BCF or more by 2040, to satisfy the demands of a growing population. The storage system must be capable of delivering an average of 120 MMcf/d in 2020 and 169 MMcf/d in 2040.

  The storage volume discussed above represents only the working gas with a 150% safety factor and does not include the volume of cushion gas required. The cushion gas volume, depending on the reservoir conditions, may be zero to one, or more, times the working gas volume. Consequently, the target storage sites should be viewed as having a total storage capacity (cushion plus base load) of 25 to 50 Bcf gas-in-place.
- Trapped and capped with tank-like characteristics, distinct structure, and evidence of pressure depletion without support.
- Low to moderate water encroachment is preferred. Gas storage in a water-saturated sandstone may cause production problems if water is produced thereby decreasing gas flow rate and increasing water handling problems at the surface. Formation water may potentially trap gas when injection displaces it and then resaturates it during production operations (AOGCC 2005a).
- Gas field/pool near depletion but with enough residual gas to act as cushion gas and provide base-line pressure (≈ 1000 psi) at or near existing pipeline pressures, thus requiring little, if any, compression to get gas into distribution network.

- All wells in good condition, including injectors, producers, and any plugged wells within the area of storage; the production infrastructure is in place.
- Storage site located on and with access to an existing pipeline, with sufficient capacity to deliver required volumes on demand. The pipeline must not have bottlenecks that can compromise its ability to meet demand.
- Storage reservoir porosity of 15 percent or more and permeability in the range of 400 to 1,000 md. These parameters provide sufficient volumes for storage and guarantee high production rates
- Good lateral reservoir continuity, adequate net pay thickness (50 ft or more), and high net to gross ratios in the storage formation (0.75 to 1.0), to facilitate injection, communication, and withdrawal.
- Access to storage site must be unencumbered, no operator or environmental/refuge issues.
- Proximal to market(s) – generation plants, distribution systems, etc.

These criteria describe a storage reservoir that is capable of holding enough natural gas to satisfy long term seasonal demand requirements, provide a buffer should a disruption in delivery from the spur pipeline occur, and guarantee a prolonged steady supply of natural gas for months without the need to cycle additional gas into the storage facility.

3.2 Peak Load Storage Criteria

If a peak load storage facility is required, it may be met two ways. It may be provided by a separate storage site that is designed to produce high volumes of gas for short intervals, a few days at a time. After this short period of high production the facility may be exhausted and require recharging in preparation for the next interval of high demand. Many of the characteristics of an ideal peak load storage facility are similar to that of base load storage but some important differences exist and are highlighted in the following listing.

- Storage capacity of **6 to 8 Bcf** and capability of producing 6**0 MMcf/d** in 2020 with ability to increase to **80 MMcf/d** by 2040 (Table 2.8).
- Trapped and capped with tank-like characteristics, distinct structure, and evidence of pressure depletion without support.
- No water encroachment.
- Gas field/pool at or near depletion, but with pressures equal to or above those of the pipeline system – preferably a deep reservoir to assist with high pressure requirement.
- All wells in good condition as with the base-load case and production infrastructure is in place.
- Storage site with **access to high volume pipeline.**
- Porosities and permeabilities of 15 percent and 400 to 1000 md respectively
- Good lateral continuity and reservoir homogeneity and high net-to-gross ratio and adequate pay thickness (50 ft) as in the base load case.
- Access to storage site must be unencumbered.
- Proximal to markets/customers.

These criteria describe a relatively small, well-defined reservoir, which has an existing infrastructure capable of both compressing and injecting significant volumes of gas at high pressure over a period of one to two weeks and producing similar volumes over the same period of time.

4 Characteristics of Existing Cook Inlet Underground Storage Facilities

There are currently three natural gas storage facilities in Cook Inlet. Two are operated by Chevron, Pretty Creek on the west side of Cook Inlet and Swanson River on the east side of the inlet as show in Figure 4.1. The third is operated by Marathon at the Kenai gas field on the east side of Cook Inlet. The operators of these facilities produce the gas and store it for times of high demand. This is unlike the situation that would exist if these facilities or other fields/pools operated by the Cook Inlet gas producers were to be utilized by the owners of North Slope natural gas delivered to the Cook Inlet area by a spur line. These third-party issues are beyond the scope of this study and will need to be evaluated by others at a later date.

4.1 Swanson River Natural Gas Storage Facility

The oldest natural gas storage facility in Cook Inlet is operated by Chevron at the Swanson River field (Figure 4.1). This storage facility was approved and the Storage Injection Order No. 2 was issued in 2001 (AOGCC 2001). The facility was later expanded to include a second reservoir (AOGCC 2005b). The facility stores dry gas from the Swanson River field and other Cook Inlet fields. The storage intervals are the 64-5 and 77-3 sandstones of the Tyonek Formation (AOGCC 2001, AOGCC 2005b, and Havelock 2006). The facility is situated on a major gas pipeline network, near the intended market. The facility has met all state requirements regarding integrity of wells, infrastructure, and stratigraphic isolation of the storage horizons and is located on a 16-inch gas pipeline (Figure 4.1)

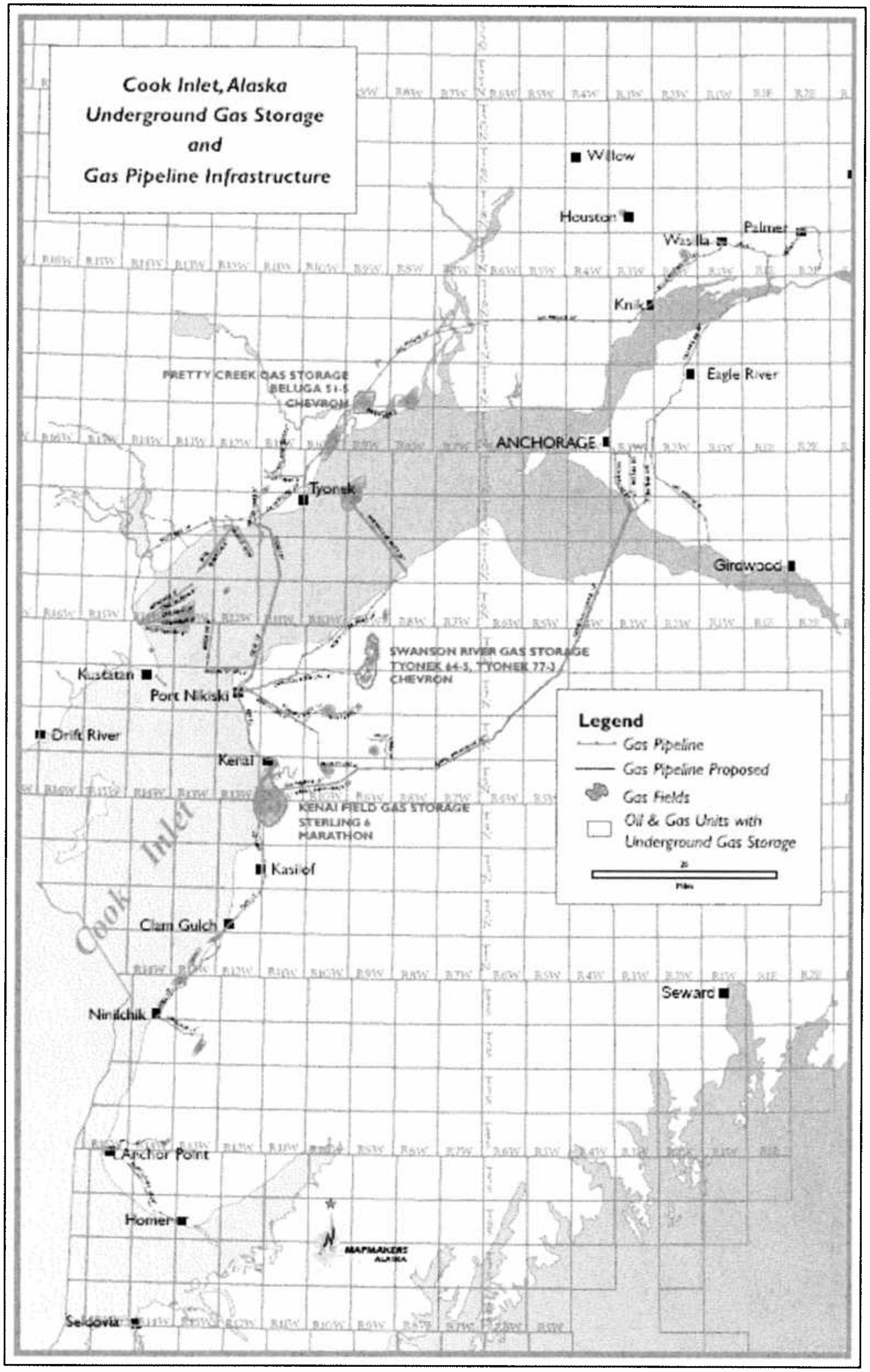
The original storage interval was the Tyonek 64-5 sandstone, defined as the sandstone between measured depths of 6,375 ft and 6,443 ft in the SRU #43-28 well. The SRU #43-28 well has a gas/water contact at a measured depth of 6,390 ft, providing for a net pay of approximately 12 ft (AOGCC 2006). The calculated porosity ranges from 10 to 36 percent, water saturation from 51 to 55 percent, and the permeability ranges to several hundred millidarcies. The reported average values for porosity and permeability in the AOGCC 2004 Annual Report on pool statistics are 29 percent and 200 md respectively (AOGCC 2006a). While the injection orders do not provide a depositional environment for the Tyonek 64-5 sandstone, the description of the encasing sediments strongly suggest that the unit is the product of deposition by meandering streams.

The reservoir pressure as of December 4, 2004 was 2,850 psi. The estimated maximum daily injection volume is 10 MMcf/d and peak production is also 10 MMcf/d.

The second storage reservoir at Swanson River is the Tyonek 77-3 sandstone, which is defined as the sandstone found in the SCU #42A-05 well between 7,972 and 8,001 ft measured depth (MD). The Tyonek 77-3 interval was approved in 2005 (AOGCC 2005b). Based on core data this sandstone has an average net reservoir porosity of 28 percent (AOGCC 2005b), permeability ranges to several hundred millidarcies, and average water saturation is 50 percent. Gross sandstone thicknesses range from 25 to 40 ft based on well control. The reservoir sandstone is interpreted as a meandering stream deposit, which is laterally equivalent to flood plain mudstones and coals.

The original reservoir pressure within the 77-3 sandstone was 4,774 psi and the average injection pressure is 3,500 psi (AOGCC 2005b). The estimated maximum injection rate is expected to be 42 MMcf/d (AOGCC 2005b) and peak production rate is about 10 MMcf/d (Havelock 2006).

Figure 4.1. Cook Inlet Map of Existing Storage Locations



The working gas capacity and deliverability of the two Tyonek storage reservoirs at Swanson River are provided by Havelock (2006) in his presentation to the South Central Alaska Energy Forum. The working gas capacity is 2.2 Bcf/yr. The total daily average deliverability is 7.4 MMcf/d, and total daily peak deliverability is 20.8 MMcf/d, from two wells, one producing from the 64-5 and the other from the 77-3 sandstone.

The operator, Chevron,[2] has provided an update on the Swanson River storage facility, which revises the deliverability of the facility. There are now four production wells in the storage facility, two in the Tyonek 64-5 reservoir and two in the Tyonek 77-3 reservoir. These wells are expected to be capable of peak deliverability rates of 60 to 70 MMcf/d from a total storage volume of ~ 30 Bcf.

4.2 Pretty Creek Natural Gas Storage Facility

Chevron has developed a second gas storage facility at Pretty Creek (Figure 4.1), designed as a periodic peak demand producer (AOGCC 2005a). The storage gas is predominantly from the Middle Kenai Gas Pool in the McArthur River field, but may also include some gas from other fields on the west side of the inlet. The Pretty Creek storage facility is connected to a major 20-inch gas pipeline (Figure 4.1) and is in close proximity to the electrical generation facility at Beluga. The facility has met all the state requirements regarding well integrity, infrastructure, and isolated nature of storage reservoir. The isolated nature of the reservoir was established by material balance analysis.

The storage interval is the Beluga 51-5 sandstone, which is defined as lying between 5,144 ft MD (-3,585 ft TVDss) and 5,173 ft MD (-3,605 TVDss) in the PCU #4 well. Data regarding the nature of the 51-5 sandstone is not included in Injection Order No. 4 (AOGCC 2005a) but Chevron (2007) supplied the following information. The net pay is 16 ft and the net-to-gross ratio is 0.80. Porosity ranges from 18 to 30 percent with an average of 28 percent and permeability is 132 md based on a pressure buildup in the storage sandstone. The water saturation is poorly known but estimated to be about 45 percent. The general depositional environment is described as stream sediments deposited in a low energy environment (AOGCC 2005a). The injection order further states that these Beluga sandstones "are commonly lenticular and often discontinuous over interwell distances."

The estimated original pressure was 1,674 psi at a true vertical depth (TVD) of 3,686 ft. The average wellhead injection pressure is 1,550 psi. The estimated maximum injection rate is 20 MMcf/d (AOGCC 2005a).

The facility is small with limited storage capacity and deliverability. Havelock (2006) places the working gas volume at only 0.70 Bcf/yr and the total daily peak delivery at 7.3 MMcf/d. Chevron[2] has provided revised numbers for the Pretty Creek Beluga 31-5 storage facility. The storage volume is given as ~ 2.0 Bcf and a peak delivery rate of 10 MMcf/d when the reservoir is full.

4.3 Kenai Natural Gas Storage Facility

The third natural gas storage facility in the Cook Inlet area is the most recently developed and the largest established to date. It is operated by Marathon at the Kenai gas field. The storage interval is the Sterling #6 pool (Figure 4.1). This facility has a much greater storage potential than the Pretty Creek and Swanson River facilities combined. Gas from the Kenai and Cannery

[2] Chevron – personally communication, December 2007.

Loop fields are stored during the summer for withdrawal during the high demand months of the winter.

The facility is connected to a 12-inch gas pipeline that supplies Anchorage (Figure 4.1). It has met all state requirements regarding infrastructure, reservoir isolation, and performance. However, there is a necessary qualifier; the storage facility meets the requirements for well integrity at the limited operating pressures and volumes, mandated by the Alaska Oil and Gas Conservation Commission. Caution was dictated by the lack of cement bond logs, for some wells, that are typically used to determine isolation of the injection zone in all wells penetrating the confining layer (AOGCC 2006).

The gas is stored in two thick fluvial sandstones, the C-1 and C-2 sandstones of the Sterling #6 gas pool. The sandstones are comprised of friable to unconsolidated sandstone to clayey sandstone, with minor inter-bedded siltstone and coal (AOGCC 1969). These sandstones are defined in the KU 31-07X well. The C-1 sandstone occurs between 4,366 ft and 4,500 ft TVDss and the C-2 interval is between 4,530 ft and 4,569 ft TVDss. The two sandstones have a total of 110 ft of net pay (AOGCC 2006a) and a net-to-gross ratio of 0.64. The two sandstones are in pressure communication, have porosities that range from 4 to 16 percent, permeabilities that range from 400 to 1000 md, and original water saturations of about 32 percent.

The original reservoir pressure was 2,138 psi at a datum of 4,565 ft TVDss (AOGCC 1969) and the maximum pressure at which the Sterling #6 gas storage will operate is 300 psi (AOGCC 2006b). The storage unit is currently operating at less than 200 psi. A typical injection cycle will consist of 6 Bcf stored during the summer and produced during the winter.

Peak delivery rates vary widely at the Sterling Pool #6. Pool #6 working gas capacity is currently 6 Bcf/yr, but may be expanded to 11 Bcf/yr or more. The total gas-in-place is limited to 50 Bcf under the current lease (Havelock 2006). Prior to being designated a storage interval, the Sterling #6 pool had produced more than 523 Bcf and OGIP is modeled to have been at least 563 Bcf (AOGCC 2006b). Thus, the true potential of this pool as a storage facility has not been realized and at some time in the future it could potentially be expanded to provide storage for 100 Bcf or more.

4.4 Summary of Existing Natural Gas Storage

The three existing natural gas storage facilities in the Cook Inlet area provide seasonal storage for their operators, who store surplus production during the low-demand summer season to meet their obligations and the increased demand of the utilities during the winter. The gas stored is exclusively from the fields that they (Chevron and Marathon) own and operate. This will not be the situation, when and if, storage from a spur line is initiated. However, the characteristics of these facilities are probably very like those that will be developed for storage of spur line natural gas. Havelock (2006) provided a table that summarized the existing facilities and it is reproduced (*with modifications*) here to provide an overview of the current situation and to serve as an example of what the future gas storage pools may resemble.

Table 4.1. Cook Inlet Gas Storage Deliverability (MMcf/d) (Havelock 2006) (*modified to include revisions for Swanson River and Pretty Creek as provided by Chevron;[3] numbers in parenthesis are from Chevron)*

Facility	Number of Wells	Peak Delivery/Well (Average) (MMcf/d)	February 2006 Rate (MMcf/d)	Historical Average Produced Volume (MMcf)	Total Daily Peak Delivery (MMcf)	Total Daily Average Delivery (MMcf)	Working Gas (Bcf/yr)
Swanson River (Tyonek 54-5 and 77-3)	2 *(4)*	10.4 *(~15 to 16)*	9.2	3.7	20.8 *(60 to 70)*	7.4	2.2
Kenai (Sterling Pool #6)	9	6.7	3.7	–	60.3	33.3	6.0
Pretty Creek (Beluga 31-5)	1	7.3 *(10)*	–	2.4	7.3 *(10)*	2.4	0.7
TOTAL	**12 (14)**				**88.4 (~135)**	**43.1**	**8.9**

[3] Chevron – personal communication, December 2007

5 Characteristics of Potential Underground Storage Facilities in Cook Inlet

The objective is to identify and describe in detail the characteristics of depleted or soon to be depleted reservoirs that may be suitable for conversion to and use as future potential underground gas storage facilities in Cook Inlet

This task involves the identification, review, and evaluation of all gas fields or participating areas that may be depleted or otherwise abandoned by the time the spur line is built (10 years ±), to determine their suitability as base-load and/or peak-load gas storage facilities. Oil fields have been **excluded** and the effort is focused on the more conventional gas fields as potential storage facilities. The use of any of these gas fields/participating areas by a third party will likely depend on them no longer being economically viable as commercial gas fields.

In addition to the evaluation and characterization of the parameters listed under Tasks 2.1 and 2.2, the issue of ownership of the abandoned pore space and the ultimate responsibility for remediation and restoration of these fields may be factors that have to be considered in determining the viability of any site as a storage facility. These latter two components may have some bearing on the costs of operating some potential storage facilities.

5.1 Geological and Reservoir Engineering Characteristics of Potential Storage Facilities

The first step in evaluating Cook Inlet reservoirs as potential gas storage facilities was to eliminate the oil fields to avoid the issues related to duplication of facilities and the added costs of oil and water handling in these fields. As shown in Table 1.1, 30 gas fields and 57 gas pools have been discovered in the Cook Inlet Basin. The objective is to reduce this number to those that best meet the requirements and characteristics to function as a potential gas storage facility.

The elimination process began with the offshore gas fields (6 fields/6 pools), including the two large gas fields, McArthur River and North Cook Inlet fields. These were excluded because of the remoteness of the fields, difficult access, and limited space available to develop the gas handling and associated facilities. Next, those gas fields south of the Kenai gas field (4 fields and 8 pools) are considered to be too far removed from the major market/users and therefore are not included in the listing of fields that would be considered as potential future natural gas storage facilities. As a consequence of these two steps, the number of candidates was reduced to 20 fields and 43 pools. The bulk of the effort from this point onward was devoted to identification of primary candidates for base load storage.

The question of underground peak-load storage has two possible answers; either simply create larger base load facilities and add extra wells and increase the operating pressure or identify and develop smaller, high pressure high volume storage sites.

5.1.1 Potential Base Load Storage Facilities

After eliminating the oil fields, offshore gas fields and southern Kenai Peninsula gas fields, a high percentage of the remaining fields/pools are simply too small to provide adequate base load storage capacity for the winter heating and electrical generation needs of the area. Included in this category are fields like Albert Kaloa, Birch Hill, Lone Creek, and Lewis River, which have estimated ultimate recoveries (EUR) in the range of less than 1.0 Bcf to about 12.0 Bcf. To this point most of the culling of potential storage sites has not been based on geological and reservoir engineering criteria, but rather on location, type of native hydrocarbon, and size. There are a number of fields or pools that may have the requisite geological, engineering, and infrastructure characteristics to serve as future base load storage facilities for natural gas. These fields and pools will be the focus of this section of the report.

A total of six fields with 16 pools meet the initial set of requirements and are summarized in Table 5.1. This table provides information regarding the capacity to store cushion and working gas, reservoir parameters, and estimates of remaining reserves in 2020, the year reserves are expected to be depleted to the point of non-commerciality, and probability of reserves growth.

Table 5.1. Cook Inlet Gas Fields/Pools Geological and Engineering Characteristics

Field/pool (6/30 & 16/57)	Reservoir Volume(1) (Bcf)	Porosity(2) (%)	Perm.(3) (md)	Pay(n/g)(4) (Feet)	Pressure(5) (Psi)	Estimated reserves at 2020 (Bcf)(6)	Reserves(7) (Est. Yr. Depleted)	Reserves Growth(8) (high/mod/low/none)
Beaver Creek/ Sterling	140	30	2000	110 ft (0.88)	1100-2100	0	1994(9)	none
Beaver Creek/ Beluga	92	10	(25 ?) estimated	50 ft (1.00)	1943	2.0	2028	low
Beluga River/ Undefined	1,614	(S)31 (B)24	(S)50-199 (B)20-49	(S)107 ft (?) (B)106 ft (?)	(S)755 (B)942	73.6	2030(+)	high
Ivan River Undefined	97	20	1600	37 ft (0.39)	922	0	2019	low
Kenai/ Sterling #3	375	15	300-1000	88 ft (?)	175	0	2020	none
Kenai/ Sterling #4	506	15	300-1000	60 ft (?)	106	0	2016	none
Kenai/ Sterling #5.1	538	15	300-1000	113 ft (?)	310	0	1999(9)	none
Kenai/ Sterling #5.2	66	15	300-1000	53 ft (?)	1200	0	1981(9)	none
Kenai/ Sterling #6	603	4-16	400-1000	110 ft (0.64)	190	0	2019	none
Kenai/Upper Tyonek/Beluga	457	(25-29 ?) estimated	(25-250?) estimated	213 ft (?)	2311	19.9	2030(+)	mod
Kenai/ Tyonek	218	(25-29 ?) estimated	(5-500?) estimated	100' (?)	740	1.2	2027	mod
Cannery Loop/ Sterling	32	(15-20 ?) estimated	(300-1000) estimated	76' (?)	1012	0.4	2023	low
Cannery Loop/ Beluga	113	(10 ?) estimated	25	33' (0.6)	1627	3.6	2031	low
Cannery Loop/ Upper Tyonek	90	(25-29 ?) estimated	250	17' ().77)	651	0.3	2022	low
Swanson River/Sterling	39	28	200-250	10' (?)	1213	0	2019	low
Swanson River/Tyonek	28	25-29	5-500	13-40 (?)	2462	0	2006(9)	low

1. Reservoir Volume – Estimated Original Gas in Place Volume (OGIP).
2. Porosity – value either calculated or from cores; (?) indicates values estimated from equivalent producing intervals.
3. Permeability – value either calculated or from cores: (?) indicates values estimated from equivalent producing intervals.
4. Pay (n/g) – net pay in feet and (portion of sandstone-bearing interval that is net pay).
5. Pressure – current reservoir pressure.
6. Estimated reserves 2020 – reserves remaining to be recovered at assumed pipeline startup date.
7. Reserves (Estimated Year. Depleted) – year of last production from pool, now available for storage use.
8. Reserves Growth – probability that additional reserves will be attributed to the pool before 2020 and not included in estimated reserves 2020 column.
9. 10 MMcf/mon Production cutoff.

The criteria (1) through (8) in Table 5.1 will be applied to the candidate pools to determine their suitability for conversion to storage facilities. Each pool was examined in respect to the criteria listed above and will ultimately be ranked in terms of how closely it approaches the ideal characteristics described in Section 3. These comparisons are summarized below.

Reservoir Storage Volume: Adequate reservoir volume is the first and foremost criterion in choosing a storage facility. Based on the demand assumptions of Section 2.0, fields with adequate pressures to minimize the quantity of cushion gas may qualify if their capacity exceeds the 16.7 Bcf required for working gas volume, including a 50 percent safety margin. Under those standards all 16 pools would have adequate capacity to meet the base load storage needs of the region in 2020, but two, the Swanson River Tyonek and the Cannery Loop Sterling (Table 5.1), may be marginal to store the 23.5 Bcf needed in 2040.

Given that cushion gas will be required and perhaps in volumes equal to or greater than the working gas volume, then any pool with less than 25 Bcf of total gas storage capacity would probably be inadequate to meet the demand level expected in 2040. If the maximum expected volume of cushion gas required were equal to or slightly greater than the working gas, a total gas capacity of at least 50 Bcf would be needed. Two pools fail to satisfy this demand, Swanson River Tyonek and Cannery Loop Sterling and would not be adequate as stand-alone storage facilities. Thus under the foreseen demand scenario, 14 of the pools of Table 5.1 would have the necessary total gas storage capacity, if large volumes of cushion gas are required. Several of these have very large capacity and may be very costly to adequately charge if selected.

Porosity: Five of the pools lack data regarding porosity of the producing interval. Ten of the other eleven pools (Table 5.1) have porosities that are 15 percent or greater. The sole exception is the Beaver Creek Beluga pool, which averages 10 percent. There are no reliable porosity data for the reservoirs in the other five pools; which include the Cannery Loop pools and the Kenai upper Tyonek/Beluga and Beluga pools Table 5.1. By comparison with pools developed within the same interval and in relative proximity the Cannery Loop Sterling pool can be assumed to have porosity of 15 percent or more, and the Cannery Loop Beluga pool probably has porosities in the 10 percent range. Using Tyonek porosities from the Swanson River Tyonek pool it is reasonable to anticipate that the Kenai upper Tyonek/Beluga, Kenai Tyonek, and Cannery Loop upper Tyonek pools have porosities that exceed 15 percent and may range as high as 25 percent. Therefore, at least 14 of the pools have porosity of 15 percent or greater.

Permeability: The ability to produce at high rates requires the reservoir/pool have high permeability. Twelve of the pools have permeability data (Table 5.1) and four lack this information. For these four pools, the probable permeability range can be approximated by comparison with pools developed in similar units in nearby pools. Of the twelve pools with permeability data, at least ten equal or exceed 250 md (Table 5.1) and should be capable of high production rates. An additional three pools, the Kenai Tyonek Kenai upper Tyonek/Beluga, and Cannery Loop Sterling should also have permeabilities in this range. Based on the reported permeabilities or by analog with reported permeability ranges in the Beaver Creek Beluga and Kenai Beluga can be expected to have permeabilities of less than 100 md.

Pay: Net pay thickness is available for all the pools and ranges from a low of 10 ft in the Swanson River Sterling pool to more than 200 ft in the Beluga River Undefined. The net-to-gross ratio ranges from1.0 (Beaver Creek Beluga pool) to 0.39 (Ivan River Undefined), but the gross intervals are unknown for ten of the pools (Table 5.1). A high net-to-gross ratio combined with a pay thickness of 40 ft more provides for an excellent injection/withdrawal scenario. Ten of the pools have net pay in excess of 40 ft and three of those (Beaver Creek Sterling, Beaver Creek Beluga, and Kenai Sterling #6) have net-to-gross ratios in excess of 0.5. However, since there is little direct data on the nature of the interbedding of non-reservoir facies and the general lack of gross interval thicknesses, this parameter was not directly considered in the ranking of sites.

Pressure: Current pressure in the sixteen pools ranges from a high of 2,462 psi in the Swanson River Tyonek pool to a low of 100 to psi in four of the five Kenai Sterling pools (Table 5.1). Reservoir pressures near or above pipeline pressures are preferred to avoid the need for compression to get the gas into the pipeline system during periods of rapid withdrawal. Ten to twelve of the pools have pressures approaching or exceeding that goal. Pressures of this magnitude also reduce or eliminate the need for large volumes of cushion gas.

Estimated Reserves at 2020 and Estimated Year Depleted: The volume of recoverable native gas expected to remain in the reservoir at start up of the spur line potentially has a direct bearing on the availability or suitability of that pool as a potential storage facility. The estimated deletion rates suggest that only two pools, the Beluga River Undefined and the Kenai upper Tyonek/Beluga will still have significant remaining reserves in 2020; thus, essentially all of the remaining fourteen pools are storage candidates on this basis. The estimated year depleted refers to the date at which the field or pool would be no longer capable of economic production and a major impediment to development as a storage site would have been removed.

Reserves Growth: The life of these fields or pools depends not only on the existing known recoverable reserves but also on the as-yet-undiscovered or undeveloped/delineated resources within the known limits of the producing "structure." Single or two sandstone pools, such as the Kenai Sterling #6 pool are defined so that it is very difficult to "discover" additional reserves, unless a local fault block is indicated. On the other hand, fields like the Beluga River do not have defined single sandstone pools and in the fluvially dominated environment under which the sandstones were deposited, a multitude of additional channel sandstones are without question awaiting the properly placed extension or "exploration" well. The same is true of the Kenai field as a whole. While the probability of finding additional reserves in the Kenai Sterling #5.1 or #5.2 pools is essentially zero, the probability of finding gas within as yet untapped sandstones, present within the mapped outlines of the Kenai gas field is moderate to high. As an example of this Table 5.1 shows no anticipated reserves growth for the Kenai Sterling pools but indicates a moderate probability of reserve additions in the upper Tyonek/Beluga and Tyonek pools.

The effect of reserve additions would be to delay or make more difficult the transformation of a producing gas field into a storage facility. Table 5.1 indicates that six pools are considered to have no future reserve additions and should still be strong candidates for conversion to storage, six have a low probability of reserves growth and thus are good candidates for future natural gas storage; two pools have a moderate probability for reserves growth and combined with their anticipated depletion dates (Table 5.1) would be more risky choices, and one field, the Beluga River field has a high probability of significant reserves growth and on this basis presents one of the greatest challenges for conversion to storage.

These factors plus the infrastructure characteristics, location, pipeline access and other non-reservoir factors are examined and compared to the ideal facility for the purposes of ranking storage candidates in Section 6.

5.1.2 Potential Peak Storage Facilities

The need for a peaking storage facility is uncertain at this time. It is possible that a base load storage facility could be developed with the required working gas capacity, pressure regime, and spare wells for increased production during periods of high demand and thus eliminate the requirement for a smaller high rate, short term storage facility (see Table 2.7). However, it is necessary and prudent to identify possible peak load storage sites, even if they are not required at the start up of the spur pipeline. The evaluation of peak storage sites is focused on smaller pools with high pressures and the reservoir parameters necessary for high production rates.

Table 1.1 identifies five pools with storage volumes of 6.2 to 15.1 Bcf, which is sufficient to meet the anticipated peak load requirements if large volumes of cushion gas are not required. These pools are presented in Table 5.2.

Table 5.2. Cook Inlet, Potential Peak Load Gas Storage Sites

Field/Pool	Reservoir Volume (Bcf)	Porosity (%)	Permeability (md)	Pay (n/g)	Current Pressure (psi)
Beaver Crk/Tyonek undefined	6.3	(25 ?) estimated	(5-500 ?) estimated	45 ft (??)	1,124
Lewis River/Undefined	14.3	22	45	85 (0.45)	1,687
Lone Creek/Undefined	6.2	19	100	??	475
Pretty Creek/Undefined	11.0	22	~120 estimated	60 (.67)	910
Sterling/Beluga Undefined	15.1	10	0.1	100 ft (??)	3,154

Table 5.2 includes most of the same data as Table 5.1 with the exception of the various reserve categories. The criteria for a peak load facility are presented in Section 3.0 and differ from those for the base load facility in three significant ways: 1) require smaller volumes, a capacity of 5 to 10 Bcf or so; 2) require high reservoir pressures (2.0 to 2.5 times ambient pipeline pressures) to assure high production rates, and 3) access to high volume pipeline.

Reservoir Storage Volume: The reservoir storage volume presented in Table 5.2 is the total gas capacity, which must be adequate to include any required cushion gas as well as working gas. As a consequence, the Beaver Creek Tyonek Undefined and the Lone Creek Undefined pools, at 6.3 and 6.2 Bcf, may have inadequate storage, if a significant volume of cushion gas is required to achieve the necessary pressure to assure high production rates. This is especially true of the Lone Creek Undefined pool, which has a current pressure of only 475 psi. On the sole basis of capacity, the Pretty Creek Undefined, Lewis River Undefined, and the Sterling Beluga Undefined pools appear to be capable of providing the storage volumes necessary for a stand-alone peak load facility.

Porosity and Permeability: Porosity values for three of the pools (Table 5.2) is approximately 20 percent, which is good to excellent. There are no published data for the Beaver Creek Tyonek Undefined pool, but by analogy with the Swanson River Tyonek Pool an average porosity of 25-29 percent can be expected. The porosity of the Sterling Beluga Undefined is low at 10 percent and further downgrades this candidate.

Permeability is low by most Cook Inlet standards in all five pools, but exceptionally low (0.1 md) in the Sterling Beluga Undefined pool. The Lone Creek and Pretty Creek pools (Table 5.2) have permeability in the 100 to 120 md range, which suggests that high reservoir pressures may be required to boost production rates for peak load conditions. The Lewis River Undefined pool has a permeability of 45 md, which would require even higher pressures than the Lone Creek and pretty Creek pools.

Pay: Good to excellent pay thickness is known to be present in four of the pools (Table 5.2). There is no reported pay thickness for the Lone Creek Undefined pool. The pay parameter does not eliminate any of the pools from consideration.

Pressure: Since the peak load storage facilities need to be able to produce large volumes for short periods, it is advantageous for the facilities to operate at relatively high pressures, definitely above the ambient pipeline pressure. The current reservoir pressure in these five pools spans a low of 475 psi in the Lone Creek Undefined pool to a maximum of 3,154 psi in the Sterling Beluga Undefined pool. Most of these pools will probably require a volume of cushion gas to attain an operating pressure sufficient to meet peak demand flow rates. The sole exception is the Sterling Beluga Undefined pool, which has high pressure at 3,154 psi; however, the reservoir has a permeability of only 0.1 md and on this basis is suspect as a viable storage candidate.

5.1.3 Summary of Future Natural Gas Storage Options

The options for potential future natural gas storage facilities have been addressed from both the base load and peak load perspectives and the preliminary listing consists of 16 base load candidates and five peak load possibilities. Based on geological and reservoir engineering criteria these choices have been evaluated in terms of suitability and are ranked in Section 6 with respect to their approximation to the ideal facility as described in Section 3. While several of these sites may not have the capacity, as stand alone facilities, to fulfill the storage requirements, it might be advantageous to have two smaller storage sites as opposed to one large facility.

5.2 Gas Storage Reservoir Conversion Design Criteria

The potential gas storage fields in the Cook Inlet as described above are partially depleted gas production reservoirs. The conversion of the gas production reservoirs to gas storage reservoirs should are expected to consist of the following steps:

- Gathering of geological and engineering information.
- Assessing the mechanical condition of wells.
- Determining additional surveys needed.
- Determining the working storage content of the reservoir.
- Determining the number of wells needed.

In order to find the working storage content of a reservoir, the range of pressures used must be selected. The upper pressure is set based upon the information available, particularly the mechanical condition of the wells. The pressure range also has much to do with the flow capacity of the wells.

5.2.1 Mechanical Condition

The mechanical condition of the wells and facilities will impact the technical and economic viability. First, it is necessary to gather information on the field, such as:

- Initial reservoir pressure
- Gas production versus reservoir pressure
- Reservoir temperature
- Gas composition, gravity
- Wells drilled, locations, depths
- Reservoir structure
- Degree of water drive
- Well flow capacity
- Mechanical condition of wells.

All wells drilled to the producing horizon must be located, checked by cement bond log, caliper logs, casing inspection logs, and made mechanically sound. Where poor bond exists, squeeze cementing is required. When the casing is corroded, a liner may be cemented in place or other recompletion techniques with a non-corrosive completion fluid in the annulus. Even wells classed as dry holes should be reopened, re-cemented, or cased as observation wells.

5.2.2 Storage Capacity

Gas production and bottomhole pressure data were examined for each pool in the Cook Inlet area. Plots of P/Z versus cumulative production volumes were constructed for each pool resulting in estimates of original-gas-in-place (OGIP). Example data are shown in Appendix A, Figure A. and A.2. It was assumed that most pools would recover about 90% of OGIP at shut-in conditions. The two OGIP values were compared to insure a reasonable volume was estimated. The only pool for which the two values were not close was the Beaver Creek Sterling; the depletion performance indicates significant water influx occurred. The Kenai Sterling 5.2 also shows this characteristic behavior to a lesser degree but no water production was reported.

5.2.3 Field Deliverability

For most of the gas producing history of the Cook Inlet, supply exceeded demand; therefore, few, if any, wells were produced at capacity. Production history does not reflect the true deliverability of a pool. State of Alaska production records were used to determine the average production performance of each pool on a volume per day per well during the life of the pool. These data were combined on a plot of the P/Z versus cumulative recovery discussed in Section 5.2.2 (Appendix A). A best fit line was drawn to smooth the data over time and reservoir pressure. As noted above, these resulting flow rates are believed to be restricted volumetric rates. The flow rates used in this evaluation were increased by 50% to account for restricted flow rates, possible rate increases resulting from stimulation treatments, and current drilling and completion technology that will be used for any new wells. Marathon reports in a recent report (PN 2007a) that the use of their new Excape completion technology allows completion and fracture stimulation of several zones simultaneously, which will decrease costs and increase well productivity. A more complete well by well examination would be required to determine the amount of rate increase possible.

5.2.4 Design of Well Capacity

When the storage capacity has been set and the character of the market is known, a maximum flow rate for the field at a given content of gas can be estimated. From the estimated production schedule for the reservoir and peak day requirements, the amount of gas in the reservoir and hence the reservoir pressure can be determined. From the field performance curve and the reservoir pressure, the flowing well pressure can be determined for the stated flow rate. These calculations will give the suction pressure to the compressor required to send the gas to market.

5.2.5 Number and location of wells

The addition of the deliverabilities of the wells in the depleted field is likely to give a field deliverability curve that falls short of maximum flow rate. The remedy is to drill more wells or increase the deliverability of the old wells. A structure map of the field with the deliverability of the wells marked on it will provide a good tool to find locations in the reservoir that will give the higher deliverability needed. When drilling takes place, flow tests should be performed to determine the cumulative deliverability so that enough wells can be completed to match the predicted deliverability curve. When there is a high deliverability in part of the field and low in another the tendency may be to drill all new wells in the high permeability area. Care should be taken of creating a pressure sink if a common header gathering system is used. Wells from the high pressure, low permeability area will transfer the gas to low pressure area. Also to limit the surface piping gathering system, directional and horizontal wells should be considered.

5.2.6 Dehydration, Compression and Metering

Wellhead gas may pass directly to the gathering system without treatment, be heated, have alcohol injected into it or processed by a wellhead dehydration unit. Where central treating is performed, either solid absorbent or glycol absorption processes may be used. The solid adsorbents are more expensive to install, but easier to operate under overloaded, intermittent or short cycling conditions.

The compression requirement depends on the field operating pressure levels and market delivery pressure. Compression horsepower should be selected by an economic study of the number of wells, the field operating pressure level and the schedule of gas withdrawal in winter and need for injection in the summer.

Gas will be metered into and out of storage in American Gas Association standard meters to keep and accurate account of gas in the reservoir. Plant usage, gas losses while blowing of wells and even unaccounted for losses should be recorded.

5.2.7 Planned Observations

When converting a gas field to storage a long-term life is contemplated with a life cycle of over 30 years. The possibility that gas might find a way to leave the reservoir especially through mechanical imperfections should considered.

Gas analyses should be made of all natural gases in the vicinity of the depleted gas field to be converted to a storage field. These analyses may identify any gas found in water wells. A good guide or principle is that the water-filled confining zone above the caprock and in the gas zone on the edges of the field should be observed for both the absence of gas and the degree of pressure change.

6 Comparison of Ideal Storage Facility to Available Options

The criteria and characteristics identified in Section 3.0 are used to compare the variously identified potential storage facilities to the ideal Cook Inlet underground gas storage facility and rank them based on the results of this comparison. The ranking reflects how these options meet the optimum conditions required to satisfy base load and peak load needs associated with gas supply and usage in the Cook Inlet region. Table 6.1 was developed to facilitate the ranking process for the base load storage options but not all the criteria presented in Table 5.1 were used to construct Table 6.1. Some criteria will require additional study at the time of final selection, such as well integrity, water encroachment issues, and legal obstacles to use of the site for gas storage. Issues like access to a pipeline, relative proximity to customers, and tank-like characteristics are generally equivalent in all the remaining candidates and are excluded from the ranking criteria. The parameters of porosity, permeability, net pay, and net-to-gross have been replaced by a deliverability factor (Appendix A), which is the average well production rate derived from P/Z calculations times the anticipated number of producing wells. Finally, the total gas volume required to bring the reservoir to ambient pipeline pressure was added to the ranking process. Appendices A and B provide the basis for this table. Appendix A summarizes the process and values used to establish per well rates and volume of gas required to achieve ambient pipeline pressures. Appendix B shows the scaling used for the ranking criteria, where a ranking of 1 is best.

The limited number of peak load options did not require that a comparable table be constructed for that ranking.

6.1 Ranking Potential Base Load Storage Candidate Sites

The ranking of the base load storage candidate sites is shown in Table 6.1. It is an intermediate step in the final recommendation and reflects the comparison of the quantifiable criteria of the candidate sites to the ideal storage site, which is presented as standard for comparison. Pools with less than the ideal volume of 25 to 50 Bcf are included for consideration, as there may be justification for two or more storage facilities, as insurance against a disruption at the storage site or to reduce the potential need for large volumes of cushion gas at one of the larger sites.

The component values considered to constitute the Ideal Storage Facility are shown in Table 6.1. Pools 11 through 16 of Table 6.1 have very large reservoir size (capacity) and, with the sole exception of the Kenai Tyonek pool, require excessive volumes of cushion gas, 146 to 179 Bcf (Appendix A, Table A.1) to achieve pressures equivalent to the ambient pipeline pressure. As a consequence, these large Kenai Field pools and the Beluga River Undefined pool have been excluded from further consideration.

The Beluga River Undefined pool is somewhat unique. It includes numerous pay sandstones (more than 40) in the Sterling and Beluga formations. These pays are cut by an unknown number of the wells, probably ranging from 2 or 3 per pay to perhaps as many as 10 per pay interval. Individual wells may penetrate and produce from as many as 50 pays. The volume of cushion gas required is nearly 650 Bcf (Appendix A, Table A.2). The issues regarding well integrity, communication between pay zones, and depletion status of individual sandstones indicate that using any of these horizons for storage is not feasible based on current knowledge. Given that the operators continue to delineate and refine their understanding of the interrelations among pays, wells, and production, there may come a time when specific, depleted horizons are viable candidates for storage.

Table 6.1. Preliminary Comparison of Base Load Storage Options to the Ideal Storage Facility

Pool	Reservoir Size (Bcf)	Deliverability (MMcf/d)	Cushion Gas Volume (Bcf)	Depletion Date (Year)	Rank
IDEAL	**25-50**	**120-169**	**0.0**	**<2015**	
Swanson River/Sterling	1	2	1	2	**1**
Beaver Creek/Beluga	2	1	1	4	**2**
Swanson River/Tyonek	1	5	1	1	**3**
Beaver Creek/Sterling	3	4	1	1	**4**
Kenai/Sterling #5.2	2	5	1	1	**5**
Ivan River	2	4	2	2	**6**
Cannery Loop/Sterling	1	5	1	3	**7**
Cannery Loop/Upper Tyonek	2	5	1	3	**8**
Kenai/Sterling #5.1	5	1	5	1	**9**
Cannery Loop/Beluga	3	2	3	5	**10**
Kenai/Sterling #6	5	1	5	2	**11**
Kenai/Sterling #4	5	1	5	2	**12**
Kenai/Sterling #3	5	1	5	3	**13**
Kenai/Tyonek	5	3	3	4	**14**
Kenai/Upper Tyonek-Beluga	5	1	5	5	**15**
Beluga River/Undefined	5	1	5	5	**16**

Reservoir Size: All of the top ten pools have reservoir size that is equal to or greater than the ideal storage facility and meet the anticipated storage needs well into the middle of the 21st century. These are presented in Table 6.1. The two pools, the Cannery Loop Sterling and Swanson River Tyonek pools (Table 5.1 and Appendix B, Table B.1) have reservoir sizes that are at the lower end of the acceptable range and under some conditions may be too small to be stand-alone storage facilities but may provide secondary sites; however, they have the additional constraint in that they have limited deliverability (Appendix A, Table A.2). The other eight pools have sufficient reservoir size to qualify as stand-alone storage sites. Of these, the Kenai Sterling #5.1 pool has a reservoir size of nearly 500 Bcf (Table 5.1) and would require 178 Bcf of cushion gas to reach adequate reservoir pressure; thus, it is eliminated from further consideration on this basis. The results are that seven pools clearly meet the requirements for reservoir size and two additional pools may, but are definitely adequate as secondary pools.

Deliverability: The seven stand-alone and two smaller pools were examined from the aspect of deliverability. Deliverability is defined here as the calculated "adjusted" low average well rate times the number of wells expected to be producing from the storage facility (Appendix A, Table A.1). Table A.1 also shows the "adjusted" average high rate. The low rate was chosen, since it is the rate that must be sustainable as the storage facility is drawn down by production. For example, the Kenai Tyonek pool has been assigned a deliverability of 48 MMcf/d, but at high rates may deliver as much as 72 MMcf/d.

The Beaver Creek Beluga and Swanson River Sterling pools are expected to have deliverability rates of about 60 MMcf/d, and the Cannery Loop Beluga pool has the potential for over 50 MMcf/d. The Ivan River and Beaver Creek Sterling pools are expected to be capable of 30 to 40 MMcf/d, and the Kenai Sterling #5.2, and the Cannery Loop upper Tyonek are rated at 20 to

30 MMcf/d. This reflects the order in which they would be ranked on deliverability. From the deliverability perspective, none of these pools appears to have adequate rates to be stand-alone facilities.

The smaller Cannery Loop Sterling and Swanson River Tyonek pools are rated at 20 to 30 MMcf/d; further diminishing their attractiveness as prospective storage sites.

Cushion Gas Volume Required: The volume of cushion gas required to achieve ambient pipeline pressures is an important consideration. In this evaluation the remaining seven stand-alone and two secondary candidates have cushion gas requirements ranging from zero, in the case of the Kenai Sterling #5.2 pool, to 43 Bcf in the Cannery Loop Beluga pool (Appendix A, Table A.1). This provides an additional measure of the relative value of the potential site, in terms of monetary savings related to gas purchases.

Depletion Date: The remaining candidate pools were next evaluated based on the anticipated depletion date, which is an important factor in this analysis. It is necessary that the potential site be available for storage by the time the spur pipeline is operational. In this scenario, that date has been assumed to be 2020. Many advocates hope to have the pipeline in operation at an earlier date – such as 2017. The assumption was made that a pool would need to be at or near the end of its commercial life before it was converted to storage. Based on this assumption, pools like the Cannery Loop Beluga and the Beaver Creek Beluga, which are not expected to be depleted until 2031 and 2028, respectively, would drop considerably in the ranking. Four of the seven larger pools (Table 6.1) are expected to be depleted by 2020 and would be potentially available for conversion to storage. The Cannery Loop Upper Tyonek pool depletion date is estimated to be about 2022.

Among the smaller pools the Swanson River Tyonek pool is also expected to be depleted by 2020 and would be a possible storage site, while the Cannery Loop Sterling is expected to be depleted about 2023.

The summation and discussion above constitutes the basis for the final list of recommended sites to be considered as potential future base load storage facilities. This listing will deviate in some details from that of Table 6.1 due to a more objective integration of timing, deliverability, and total gas volumes required to attain pipeline pressures. The foregoing discussions of Section 6.1 establish the rational for this approach.

6.1.1 Final Ranking

The ranking of potential future base load storage sites is strongly determined by the following considerations. The other criteria of Tables 5.1 and 6.1 do not vary significantly among the principal potential storage sites and were largely discounted in this final selection process.

- Reservoir size near the ideal volume–excessive capacity may require large volumes of cushion gas in order to achieve optimum operating rates, and capacity significantly below the ideal would require high existing reservoir pressures to minimize cushion gas and maximize working gas. Excessive storage concerns may be offset by using a greater number of wells to keep withdrawal rates at required levels. Reservoir size less than the ideal volume will require multiple facilities, which may be an advantage, when taking disruptions into consideration.
- The deliverability of a reservoir is a function of the number of wells and reservoir pressure and communication. In the scenario presented in the following discussions, the number of wells in each potential storage site is taken to be two times the number of wells utilized during that pools historically high production (Appendix A, Table A.2). It may be possible to achieve greater deliverability by drilling more infill wells.

- Gas volume can be a very costly component of the storage issue. The amount of working gas is taken as a constant (20 Bcf) and the variable is the volume of cushion gas required, which is based largely on the reservoir pressure. Large low pressure reservoirs may require ten's to hundred's of Bcf's of gas to achieve the necessary pressure.
- Depletion prior to 2015 is preferred and prior to 2020 is a virtual necessity. This provides adequate time to plan and prepare the site for gas storage. Those that are depleted after 2020 would need to be deferred or some agreement with the lease holders/operators would need to be negotiated to use part of all the field/pool for storage.

Table 6.2 summarizes the rankings for the potential base load storage site candidates and compares them to the "Ideal Pool". The four criteria are listed with values extracted from Table 5.1 and Appendix A (Tables A.1 and A.2). Despite all efforts to base the decision on quantifiable, objective data, there remains an element of subjectivity in the selection process. Until detailed studies of the candidate pools are completed, the true strengths and weaknesses of these sites will be largely unknown. These ranked potential future base load storage sites are located on Figure 6.1.

Table 6.2. Ranked Candidates for Base Load Storage

Rank	Pool	Reservoir Size (Bcf)	Deliverability[1] (MMcf/d)	Cushion Gas Required (Bcf)	Depletion Date (Year)
	IDEAL POOL	**25-50**	**120-169**	**0.0**	**2010-2015**
1	Swanson River/Sterling	39	60 (160)	9.0	2019
2	Beaver Creek/Beluga	92	61 (106)	16.0	2028
3	Ivan River	97	34 (65)	8.0	2019
4	Kenai/Sterling # 5.2	66	30 (36)	0.0	1981
5	Swanson River/Tyonek	28	29 (89)	6.0	2006
6	Beaver Creek/Sterling	140	33 (51)	24.0	1994

1. The number in the column is the 'adjusted" low deliverability, which is the value used to rank the candidate sites, the number in parenthesis is the "adjusted" high deliverability and can be achieved but is not sustainable for the entire demand season (Table A.2).

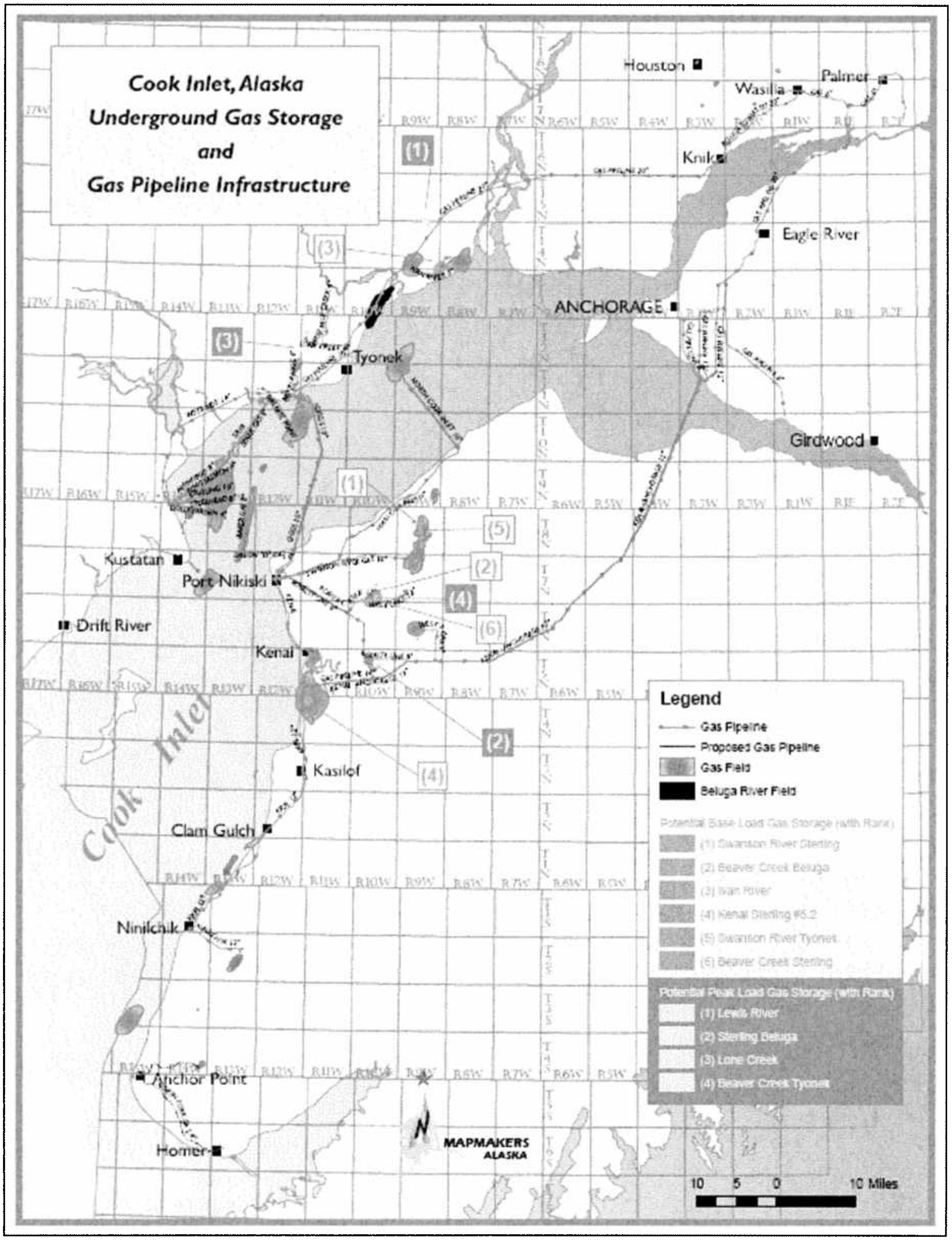
The Swanson River Sterling pool is ranked as number one primarily because it has good-to-high deliverability, is expected to be depleted by 2020 and requires moderate amounts of cushion gas. The reservoir size is adequate but falls in the mid-range of the preferred size class, and expansion of storage capacity is limited to about 10 Bcf.

The Beaver Creek Beluga site has excellent reservoir size, the highest deliverability, but requires more cushion gas and is not expected to be depleted until 2028. These latter two factors prevent it from being ranked No. 1 and could drop it below the Ivan River pool.

The Ivan River pool is rated as the third choice due to the capacity and moderate volume of cushion gas required. The expected depletion date of 2019 is an additional plus. The primary negative factor is the relatively low deliverability of only 34 MMcf/d.

The Kenai Sterling # 5.2 has been depleted since 1981 and has good-to-excellent reservoir size. The capacity is in excess of the requirements and no cushion gas is required to achieve ambient pipeline pressures. The chief problem is deliverability of only 30 MMcf/d using the one-to-one producing well scenario. There are suggestions that water encroachment has been detected, which may have the potential to reduce deliverability.

Figure 6.1. Cook Inlet Map of Storage Locations



The Swanson River Tyonek pool is the smallest of the top six candidates at 28 Bcf, which is at the low end of the preferred size range. It requires a moderate amount of cushion gas, but has a projected deliverability in the one-to-one infill well case of only 29 MMcf/d.

The Beaver Creek Sterling pool is ranked No. 6 because of the problems with water encroachment, which requires a large volume of cushion gas and also reduces the deliverability. There is a large capacity for gas storage, and an early depletion date, but unfortunately that is due largely to the fact the pool watered out. The anticipated deliverability is about 33 MMcf/d.

The results of these evaluations indicate that there are viable potential future underground natural gas storage sites in the Cook Inlet gas fields. However, among the leading candidates there are no true stand-alone reservoirs with regard to sustainable deliverability. Each of the candidate pools meets the capacity needs but under the proposed development none of them are capable of achieving the 120 to 169 MMcf/d design withdrawal rates of Table 2.6 and Section 3.1.

The large pools, Kenai field pools and the Beluga River field, that were eliminated early in the evaluation process would have the deliverability required, if cushion gas volumes well in excess of 100 Bcf were injected (Appendix A, Table A.1). In fact, to establish ambient pipeline pressure, 648 Bcf of cushion gas would need to be injected into the Beluga River field (Appendix A, Table A.2) unless a zone or zones could be successfully isolated while maintaining active production operations. But, why shelve expensive cushion gas when the same volumes could be used as working gas in two or three smaller facilities, such as the Swanson River Sterling and others of Table 6.2? The use of two or more storage facilities also provides a safety measure in the case of a disruption at the storage facility. It would also be advantageous to have a facility located in both sides of the Cook Inlet for similar reasons.

Unless future detailed studies indicate otherwise, these pools in some combination should provide adequate storage for any reasonably forecast seasonal storage needs and achieve the deliverability needs for peak season demand. Under certain conditions, multiple base load storage facilities may negate the need for separate peak load storage, at least for the initial years of the pipelines existence.

6.2 Final Ranking Potential Peak Load Storage Candidate Sites

The need for a separate peak load facility or facilities depends on the ultimate nature of the base load storage facilities. At this time the working scenario requires peak load storage for the short, very high demand periods resulting from conditions of extreme cold weather. As identified in Section 5, there are five pools that would be candidates for potential peak load storage (Table 5.2) and the total storage capacity of these pools ranges from 6.2 Bcf to 15.1 Bcf (Appendix A, Table A.3). These pools are all on the pipeline system and are within 50 to 100 miles of the major consumers. Three key factors were utilized to rank or eliminate the pools. These are same factors used to develop the final rankings for the base load storage: reservoir size, deliverability, and cushion gas requirements.

The five identified pools/fields are of such a size that they meet the requirements of the peak load demand anticipated in 2020. In increasing order of total storage capacity they are (Appendix A, Table A.3):

- Lone Creek Undefined – 6.2 Bcf (requires zero cushion gas),
- Beaver Creek Tyonek Undefined – 6.3 Bcf (0.5 Bcf cushion gas),
- Pretty Creek Undefined – 11.0 Bcf (6.0 Bcf cushion gas),
- Lewis River Undefined – 14.3 Bcf (1.6 Bcf cushion gas),

- and Sterling Beluga Undefined – 15.1 Bcf (2.0 Bcf cushion gas).

The existing Cook Inlet gas storage facilities have gas volumes of this size or smaller and average deliverability rates are about one percent of the total working gas. Based on these averages, maximum deliverability rates may range from a low of 58 MMcf/d for the Beaver Creek Tyonek undefined pool to a high of 131 MMcf/d for the Sterling Beluga Undefined pool (Appendix A, Table A.3). This assumes the reservoirs are filled to capacity and the cushion gas has been discounted.

Based on minimization of cushion gas volume (Appendix A, Table A.3) the Pretty Creek Undefined pool would be eliminated, since nearly half the volume of gas in the pool would be unavailable for withdrawal.

Using the one percent of working gas volume (original gas in place minus cushion gas equals working gas) as average daily deliverability, the only two of the remaining pools are capable of achieving the 80 MMcf/d maximum anticipated peak gas requirements in 2040. The Lone Creek Undefined and the Beaver Creek Undefined pools are fall below the margin of 70 MMcf/d in 2025 for the assumed spur pipeline rates. Both the Lewis River and Sterling Beluga undefined pools have capability to achieve the desired deliverability in 2040 with potentials of approximately 125 to 130 MMcf/d each.

The ranking for peak load storage and reasons are given below, and their location and ranking are given in Figure 6.1.

1.) Lewis River Undefined: low cushion gas requirements, near power generation facility, and maximum potential deliverability of approximately 130 MMcf/d.

2.) Sterling Beluga Undefined: low cushion gas requirements, ready access to Anchorage area gas users, and maximum potential deliverability of 125+ MMcf/d.

3.) Lone Creek Undefined: falls short of the deliverability rate with a maximum rate of about 62 MMcf/d but requires no cushion gas and could provide a secondary peak storage facility.

4.) Beaver Creek Tyonek Undefined: falls short on deliverability rate at 58 MMcf/d but requires only 0.5 Bcf cushion gas and could provide a secondary peak storage facility.

The Lone Creek and Lewis River sites are located on the west side of the Cook Inlet and could easily supply the electrical generation plant, while the Beaver Creek and Sterling Beluga sites are located on the east side and could be dedicated to the gas utilities (Figure 6.1).

6.3 Summary of Potential Underground Natural Gas Storage Candidates

The evaluation has established the existence of six potential base load storage and four peak load storage sites. All the base load storage candidates are of sufficient size, that even with the anticipated cushion gas requirements of the various pools, they retain the capacity for the requisite volume of working gas. At the calculated low, sustainable deliverabilities none of them are gauged to have rates that are sufficient to serve as the sole storage facility and multiple storage units are required. At the calculated high deliverability rates the Beaver Creek Beluga (120 MMcf/d) and the Swanson River Sterling (160 MMcf/d) can meet the demand, but not for sustained periods or for the duration of the high demand winter season.

The four peak storage sites are equally distributed between the west and east sides of Cook Inlet and the Lewis River and Sterling Beluga undefined pools have the potential to meet any anticipated peak demand needs. The Lone Creek and Beaver Creek Tyonek, as a pair could also meet that demand.

7 Costs of Potential Storage Facilities

The Federal Energy Regulatory Commission (FERC) published a report in 2004 describing the "Current State of and Issues Concerning Underground Natural Gas Storage" (FERC 2004) that describes the status and economics of underground storage in the U.S. Storage economics, storage development costs, and the value of storage as described. Storage development costs for a typical 2-cycle/yr depleted reservoir field can cost between $5 million and $6 million/Bcf of working gas capacity (FERC 2004). The costs are site-specific based on:

- the quality and variability of the geologic structure of the proposed site;
- the amount of compressive horsepower required;
- the type of surface facilities needed;
- the proximity to pipeline infrastructure; and
- permitting and environmental issues.

The FERC report (2004) reports that cost-of-service is frequently used to value services offered by regulated storage providers such as interstate pipeline companies. It allows for recovery of costs and a return on capital. The FERC review (2004) of 20 storage operator tariffs indicated a median cost-of-service of $0.64/Mcf. The economic evaluation of Cook Inlet gas storage is expected to be different, most likely higher cost, than Lower 48 gas storage because of the inability to purchase gas at low prices in the summer for storage and sell it at higher prices in the winter season and the more remote and higher cost environment in the Cook Inlet. A cost-of-service estimate is not included in the report.

Estimates for capital and operating costs associated with developing and operating potential Cook Inlet storage facilities are described below. These costs are generic and general at this stage of gas storage design and are intended as a basic guideline to identify the components and provide a reasonable estimate of the magnitude. The regulatory framework and the allowable rates of return have not been established for any regulated storage facilities in Alaska.

The factors influencing the cost of operating the storage facility includes such items as:

- Conditioning the reservoir to serve as a storage facility.
- Designing and developing the gas injection and withdrawal infrastructure including reconditioning of old wells and drilling and completing any new wells required to meet deliverability requirements.
- Construction or upgrades of a pipeline to connect the gas storage facility to the gas distribution system.
- Rentals or other fees to owner of pre-existing infrastructure.
- Costs (price/unit volume) associated with acquiring a gas storage lease and any fees associated with the injection of stored gas, docking (length of time stored), and withdrawal.
- Purchase cost of cushion gas and working gas.
- Operating and maintenance costs.

It is noted in the FERC report (2004) that the cost of purchasing cushion gas is one of the most expensive elements of a storage project. In addition, if there are remaining reserves in the field at the time of conversion, the value of those stranded reserves may need to be added to the costs or accounted for in the yearly production cycle.

The estimated cost data in Table 7.1 are for a 20 Bcf working gas storage facility requiring 20 Bcf of cushion gas, four new infill wells, and 100 MMcf/d of maximum deliverability to provide a general guideline for expected costs to construct a storage facility in the Cook Inlet. The total capital costs include the purchase of cushion gas. The costs will vary depending on the specific sites chosen. The operating costs needed for a cost-of-service calculation can be estimated as shown based on percentages of the capital cost on an annualized basis. These calculations are not included in this study.

Table 7.1. Estimated Cost of Construction of a 20 Bcf Gas Storage Facility

Expenditure item includes installation	Cost
Compressor 4000 hp	$8,000,000
Dehydration	$2,200,000
Piping and valves	$50,000
Instrumentation and controls including metering	$1,000,000
Civil, concrete etc	$1,750,000
Insulation and paint	$25,000
Electrical bulk material	$500,000
Engineering	$750,000
Make up wells @ $7MM	$28,000,000
20 Bcf cushion gas @ $6.00 Mcf	$120,000,000
Total Capital Costs	**$162,275,000**
Total Capital Costs ($millions/Bcf)	**$8.1 million/Bcf**
Operating cost	
Fixed costs: Depreciation, interest taxes, insurance, etc. –41% of annualized capital costs	
Direct costs: 3% of annualized capital costs	

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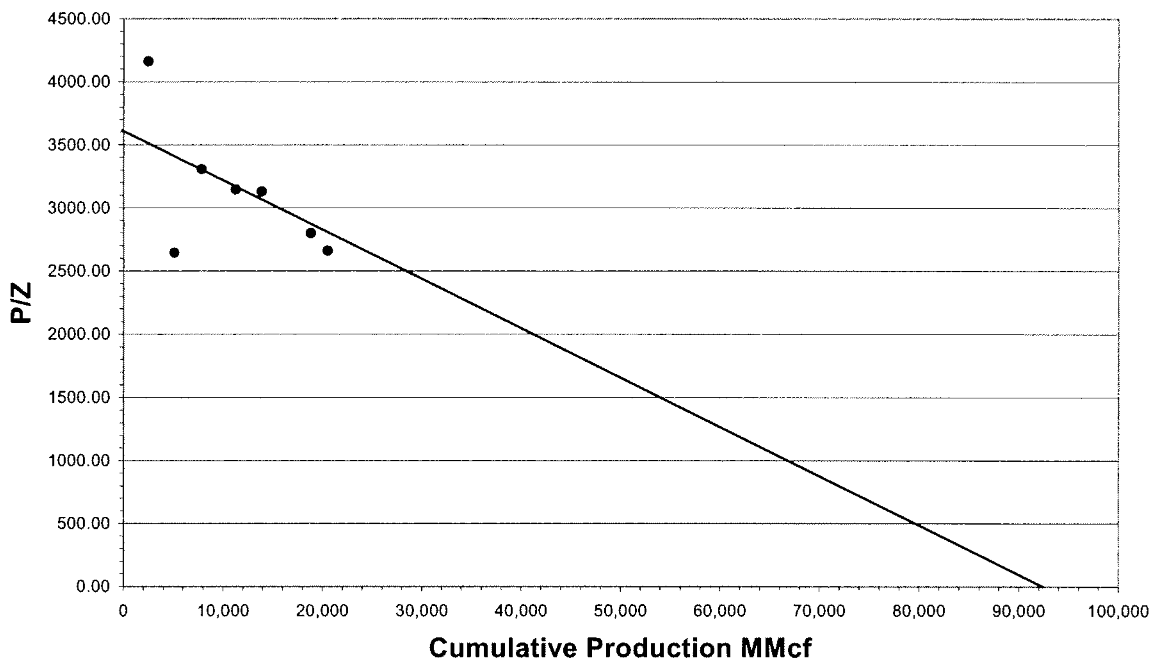
9 Attachments

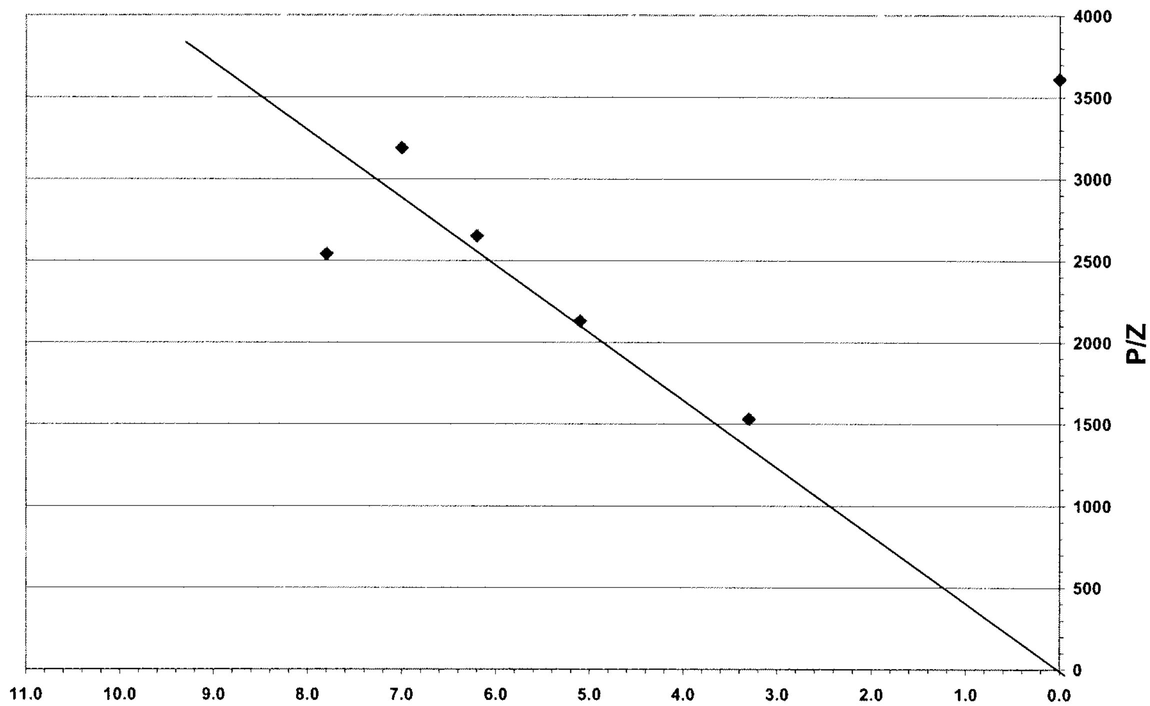
Appendix A: Gas production and bottomhole pressure data were examined for each pool in the Cook Inlet area. Plots of P/Z versus cumulative production volumes were constructed for each pool resulting in estimates of original-gas-in-place (OGIP) as shown in Figure A.1 for the Beaver Creek Beluga Pool. It was assumed that most pools would recover about 90% of OGIP at shut-in conditions. The two OGIP values were compared to insure a reasonable volume was estimated. The only pool for which the two values were not close was the Beaver Creek Sterling and the depletion performance indicates significant water influx occurred. The Kenai Sterling 5.2 also shows this characteristic behavior to a lesser degree but no water production was reported.

Figure A.1. Beaver Creek Beluga Pool, P/Z versus Cumulative Production



For most of the gas producing history of the Cook Inlet, supply exceeded demand; therefore, few if any wells were produced at capacity. Therefore, production history does not reflect the true deliverability of a pool in the Cook Inlet. State of Alaska production records were used to determine the average production performance of each pool on a volume per day per well during the life of the pool. These data were combined on a plot of the P/Z versus production rate as shown in Figure A.2. A best fit line was drawn to smooth the data over time and reservoir pressure. The flow rates on a per well basis were estimated from these curves for the as a function of pressure. The low rate is determined at a P/Z of 1000 and the high rate at the P/Z with 20 Bcf of Working Gas added to the remaining reserves at 2020. The pressures and rates are shown for each pool in Table A.1.

Figure A.2. Beaver Creek Beluga Pool P/Z versus Production Rate



The historical Cook Inlet flow rates are thought to be restricted in many cases; therefore the flow rates used in this evaluation were increased by 50% to account for restricted flow rates. Possible rate increases resulting from stimulation treatments and current drilling and completion technology used on any new wells as shown in Table A.1 (adjusted average well rates in the last two columns in the table). Marathon recently reported on the use of their Excape completion technology that allows completion and fracture stimulation of several zones simultaneously, which decrease costs and increases well productivity. A more complete well by well examination would be required to determine the amount of rate increase possible in any pool.

Table A.2 shows the Cook Inlet Pools as ranked in Section 6. The table includes the Total Gas Required to have 20 Bcf of working gas above a P/Z of 1000, the number of existing wells, and the number of wells and deliverability with 1-to-1 infill, ½–to-1 infill, and no infill.

Table A.3 contains evaluation data developed by the same methodology used for data in Table A.1 and A.2 for the potential peaking storage pools. None of these reservoirs are expected to have any remaining reserves in 2020. The maximum deliverability is taken to be 1% of the working gas volume.

Table A.1. Cook Inlet Potential Base Storage Pools: Evaluation data

Field/ Pool/ Formation	OGIP (Bcf)	2020 Status		Cushion Gas Volume(1)	P/Z with 20 Bcf Working Gas Added	Total Gas Required (Bcf)	Estimated Well Rate		Adjusted Avg. per well rate (MMcf/d)	
		P/Z	Remaining Reserves				Avg. at High P/Z (MMcf/d)	Avg. at P/Z of 1000 (MMcf/d)	High	Low
Beaver Creek										
Beluga	92.4	325	2.5	16	1800	36	4.4	2.5	6.6	3.8
Sterling	140.0	1,250	0	24(2)	1700	44	8.5	5.5	12.7	8.2
Ivan River										
Undefined	97.0	650	0	8	1,950	28	5.4	2.8	8.1	4.2
Cannery Loop										
Beluga	113.1	270	4.4	43	1,350	63	6.2	5.4	9.3	6.8
Sterling	32.0	300	0.6	9	2,520	29	15.0	6.0	22.5	9.0
Upper Tyonek	89.6	275	0.5	8	2,200	28	7.3	3.0	16.0	4.5
Kenai										
Sterling 3	375.5	225	0	146	1,120	166	5.7	5.2	8.6	7.8
Sterling 4	506.2	200	0	160	1,100	180	5.0	4.6	7.5	6.9
Sterling 5.1	538.4	250	0	178	1,080	198	4.7	4.4	7.1	6.5
Sterling 5.2	65.7	1,300	0	0	1,570	20	6.0	5.0	9.0	7.5
Sterling6	603.0	250	0	179	1,080	199	4.8	4.5	7.2	6.8
Tyonek	218.0	225	1.4	27	1,220	47	6.0	4.0	9.0	6.0
Upper Tyonek	457.4	610	22.7	60	1,210	80	1.3	1.0	2.0	1.5
Swanson River										
Sterling	39.2	330	0	9	2,580	29	13.4	5.0	20.1	7.5
Tyonek	28.0	340	0	6	3,090	25	7.4	2.4	11.1	3.6
Beluga River										
Undefined	1,614	295	83.8	628	1,020	648	12.2	12.0	18.3	18.0

1. Volume of gas required to increase P/Z to 1000 psi. Includes estimated reserves remaining at 2020.
2. This increases pressure to about 1,500 psi, which results in water-free reservoir conditions.

Table A.2. Cook Inlet Potential Base Storage Pools: Number of Wells and Estimated Deliverability Rates

Rank	Pool (Preliminary Ranking – Table 6.1)	Total Gas Required (Bcf)	Wells		Estimated Delivery Rates (MMcf/d)					
			Existing wells	Number wells with 1 to 1 infill	1 to 1 infill		½ to 1 infill		No infill	
					Max(2)	Min(2)	Max	Min	Max	Min
1	Swanson River/Sterling (1)	29	4	8	160	60	121	45	80	30
2	Beaver Creek/ Beluga (2)	36	8	16	106	61	79	46	53	30
3	Ivan River (6)	28	4	8	65	34	49	25	33	17
4	Kenai/Sterling # 5.2 (5)	20	2	4	36	30	27	23	18	15
5	Swanson River/Tyonek (3)	25	4	8	89	29	67	22	45	15
6	Beaver Creek/ Sterling (4)	44	4(1)	4	51	33	38	25	25	16
	Kenai/ Sterling # 5.1 (9)	198	14	28	199	182	149	137	100	91
	Kenai/ Sterling # 4 (12)	180	14	28	210	193	158	145	105	97
	Kenai/Tyonek (14)	47	4	8	72	48	54	36	36	24
	Cannery Loop/ Beluga (10)	63	4	8	74	54	56	41	37	27
	Cannery Loop/ Sterling (7)	29	1	2	46	18	--	--	23	9
	Cannery Loop/Upper Tyonek (8)	28	2	4	44	18	33	14	22	9
	Kenai Sterling 6 (11)	199	12	24	173	163	130	122	86	82
	Kenai Sterling 3 (13)	47	9	18	155	140	112	101	77	70
	Kenai Upper Tyonek (15)	80	23	26	92	69	69	52	46	35
	Beluga River Undefined (16)	648	17	34	622	612	467	459	311	306

1. Two wells that watered out early in field life cannot be used.
2. From Table A.1, Adjusted average per well rate.

Table A.3. Cook Inlet Potential Peaking Storage Pools: Evaluation Data

Field/Pool	OGIP (Bcf)	2020 P/Z	Cushion Gas (Bcf)	Working Gas (Bcf)	Max. Rate = 1% Working Gas ((MMcf/d)
Lewis River Undefined	14.3	650	1.6	12.7	127
Sterling Beluga Undefined	15.1	400	2	13.1	131
Lone Creek Undefined	6.2	60	0	6.2	62
Beaver Creek Tyonek Undefined	6.3	600	0.5	5.8	58
Pretty Creek Undefined	11	240	5	6.0	60

APPENDIX B: Scaling criteria utilized to rank candidate gas pools as potential future base load gas storage facilities. These factors are used in constructing the various ranking tables of Sections 5 and 6. The specific criterion is shown with a range of values and the rank of 1 to 5, **with 1 being the best**.

Table B.1. Scaling Criteria to Rank Candidate Pools

CRITERION:	RANGE	RANKING	CRITERION:	RANGE	RANKING
Reservoir size	25-50 Bcf	1	Pay	>50'	1
	50-100 Bcf	2		40-50'	2
	100-150 Bcf	3		30-40'	3
	<25 Bcf	4		20-30'	4
	>150 Bcf	5		<20'	5
Depletion	<2015	1	Net-to-gross	0.8-1.0	1
	2015-2020	2		0.6-0.8	2
	2020-2025	3		0.4-0.6	3
	2025-2030	4		0.2-0.4	4
	>2030	5		<0.2	5
Proximity	<50 miles	1	Pressure	>2,000 psi	1
	50-75 miles	2		1,000-2,000 psi	2
	75-100 miles	3		500-1,000 psi	3
	100-125 miles	4		250-500 psi	4
	>125 miles	5		<250 psi	5
Porosity	>25 %	1	Cushion Gas Required	0-25 Bcf	1
	20-25 %	2		25-30 Bcf	2
	15-20 %	3		30-40 Bcf	3
	10-15 %	4		40-50 Bcf	4
	<10 %	5		>50 Bcf	5
Permeability	>1,000 md	1	Deliverability	>60 mmcf/d	1
	500-1,000 md	2		50-60 mmcf/d	2
	250-500 md	3		40-50 mmcf/d	3
	125-250 md	4		30-40 mmcf/d	4
	<125 md	5		< 30 mmcf/d	5