North Slope of Alaska Facility Sharing Study

Prepared for
Division of Oil & Gas
Alaska Department of Natural Resources

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Executive Summary

Facility sharing is critical for the future of the oil and gas industry on the North Slope. This study was commissioned by the Alaska Department of Natural Resources, Division of Oil and Gas to address issues associated with processing facility sharing agreements for future North Slope activity. The goals are: to characterize the existing facilities, their current throughput, and their theoretical capacities; to identify the needs and desires of independent producers and North Slope facility owners and operators; to describe how facility access is managed in other oil and gas provinces; and to develop guidelines for facility access on the North Slope. Exploration and drilling activities are not addressed in this study. Only issues related to facility sharing and availability of space in pipelines are addressed in this report.

Petrotechnical Resources of Alaska (PRA) prepared this report by: compiling existing facilities data from BP Exploration (Alaska), ConocoPhillips Alaska, and ExxonMobil; identifying capacity issues; surveying independent oil companies; reviewing existing facility sharing agreements; and preparing guidelines for third-party access to facilities.

While many North Slope processing facilities have spare capacity for oil, water, or gas handling, most facilities have reached capacity for handling at least one of these components. A summary of facility constraints and excess capacities at the field level includes:

1. Alpine currently meets capacity for oil, gas, and water injection, and planned facilities expansions likely will be filled by Alpine satellite development (Fjord, Nanuk, etc).
2. Badami is in warm shutdown, and theoretically has space available up to design capacities,
3. Endicott currently has spare oil capacity, but water and gas are at capacity limits,
4. Kuparuk currently has spare oil capacity, but water, total liquid and gas are at capacity limits,
5. Milne Pt. has oil and gas capacity available through 2015, water capacity until 2011,
6. Northstar has capacity available in oil and water handling, and will reach gas capacity by 2006,
7. Lisburne Production Center is currently at or near both gas and water capacity,

8. Prudhoe Bay facilities have room for oil, but gas production is at capacity limits and water handling is at or approaching capacity limits in all facilities.
9. Pipeline capacity for Alpine is full; Kuparuk, Milne Pt, Northstar, and Lisburne/ Pt. Mac are nearly full; and Badami, Endicott, and Prudhoe Bay have pipeline capacity available.

The reference facility sharing agreement suggested herein by PRA is based largely on Ballot No. 255 for Kuparuk, which has served as the standard for several subsequent North Slope facility sharing agreements. The PRA reference agreement includes examples of potential costs associated with facility access.

Only Kuparuk River, Prudhoe Bay, Lisburne, and Endicott production facilities have existing facility sharing and services agreements addressing satellite production. The existing facility sharing agreements, while created with only unitized production in mind, are de-facto templates for recent access negotiations. The joinder agreement (Appendix D) between Winstar and the Kuparuk River Unit is an example of the use of Ballots 255, 255A, and 260 for the Kuparuk River Unit allowing for third-party satellite production.

The guiding principles from the United Kingdom (U.K.) Code of Practice and Alberta’s Jumping Pound formula have much in common with the existing North Slope facility sharing agreements. However, the U.K. and Alberta contracts provide for regulatory interdiction as needed to resolve disputes between negotiating parties, although emphasis on a cooperative approach to facility sharing has been successful in negating the need for government interdiction. Existing agreements between unit partners on the North Slope present the starting point for new third-party facility sharing agreements, and an understanding of these agreements will aid potential third-party producers in negotiating new agreements.

A survey of 15 independent oil companies currently interested in Alaska oil and gas exploration indicates that their primary concerns regarding access to existing facilities include: backout calculations, access fee methodology, timeliness of access negotiations, insurance requirements, and operatorship issues.

The report concludes that: 1. Interested parties should be able to negotiate an acceptable agreement and negotiations should be initiated as early as prospect maturity allows; 2. Development and communication of a process for facility access which is fair and transparent will help to resolve any lack of trust, and create opportunity for expanded resource development; 3. Potential third-party producers need to provide operators with a well thought-out development plan and crude characteristics to support any request for facility access; 4. Facility operators need to communicate the backout methodology and terms, and respond to requests for access costs in a timely manner; 5. It must be recognized that backout is a valid concept , representing real lost or deferred barrels to the facility owners, for which reasonable compensation is justified; 6. Agreement must be reached on a simplified backout methodology for fields without a detailed dynamic plant model; and 7. The State of Alaska has options to help defray the impact of backout fees, and this may prove to be a decisive factor in the success of North Slope facility sharing.

North Slope of Alaska
Facility Sharing Study

Introduction

The State of Alaska, the North Slope operators and the companies having or seeking to purchase leases on the North Slope all recognize the need for business cooperation and efficient use of resources to maintain a vibrant North Slope oil and gas industry. The continued and increased production of North Slope crude oil and gas is a goal of all parties. This study addresses issues associated with the processing facility sharing agreements for future North Slope activity. The study characterizes existing facilities and their processing potential, identifies the needs and desires of independent oil and gas companies and North Slope facility owners and operators, and lays the groundwork for designing a template for successful facility access on the North Slope of Alaska which benefits all parties involved.

PRA believes that there is mutual benefit to the facility owners and third-party producers in adopting reasonable terms for facility access which are equitable and understandable. In other mature basins, such as the North Sea, facility owners offer an "Indicative Tariff", or ballpark figure for facility access cost to interested producers. A survey of interested independent oil and gas explorers was undertaken to gather their issues and concerns about the future development in Alaska (Appendix A). The North Slope operators responded to facility information and data request (Appendix B). PRA compiled these various data and information in preparation for this report.

The list of deliverables provided is:

- Definition of existing facilities and design capacity for: Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, Pt Mac/Lisburne, and Prudhoe Bay Fields.
- Identification of constraints and excess capacity for: Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, Pt Mac/Lisburne, and Prudhoe Bay Fields.

- Identification of facilities currently operating at capacity and areas that may need higher capacity based on satellite exploration activity.
- Compilation and communication of the North Slope facility owners/operators perspective on facility sharing.
- Assessment of facility sharing and back-out costs including a negotiation strategy template, and a review of facility sharing agreements in other places.
- Compilation and communication of the current Independent oil companies' perspective on facility sharing.

The issue of facility sharing is critical for the future of the oil and gas industry on the North Slope. A successful facility sharing agreement must provide a solution that is mutually satisfying to all parties. The existing owners and operators, the Independent producers looking to be active on the North Slope, and the State of Alaska all have a vested interest in seeing a process that enhances the oil and gas industry.

Potential producers have the burden of exploring and bringing the crude to the surface, negotiating a facility sharing agreement for the processing of their fluids, and transporting or establishing a custody transfer agreement at the outlet of the facility. The exploration and drilling activities have their own significant challenges, which are not addressed in this study. Only facility sharing issues and transportation issues, as they relate to availability of space in pipelines and tankers, are addressed in this report.

The PRA team analyzing and reviewing this study included the following individuals:

Cathy Foerster	Reservoir Engineer
Robert Kaltenbach	Facility Specialist/Cost Analyst
Jan MacDonald	Reservoir Engineer/Commercial Analyst
Chantal Walsh	Petroleum Engineer
Tom Walsh	Project Manager/Geophysicist
Pete Stokes	Petroleum Engineer/Business Consultant
Chris Livesey	Geologist

A tremendous amount of data and support to this study was provided by the North Slope Facility Owners and Operators: BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and ExxonMobil. Additionally, the following Independent Oil companies submitted valuable insight and ideas to this evaluation: Winstar, Talisman, Alaska Venture Capital Group, Kerr McGee, and DevonCanada.

Guiding Principles for Facility Sharing Practices

Facility sharing is a key component in the future viability of the oil and gas industry on the North Slope and in order for successful sharing to take place, real mutual benefit to all parties must be demonstrated. Given the complexity of the business drivers represented by the parties, demonstration of mutual benefit is not a trivial exercise and it is helpful to define a basic set of guiding principles for facility sharing on which all parties can agree. Below is a list of guiding principles compiled from oral and written communication from a cross-section of contributors to this study, including facility owner and operator companies, potential third-party producers, and State of Alaska government officials.

The facility sharing process must:

- Be fair, equitable, and understandable to all parties
- Result in net increase in production, improve resource conservation, and reduce waste
- Not result in any new government regulation
- Preserve and promote operational integrity
- Preserve the integrity of unit rights/obligations, and tax partnerships
- Reduce financial and operational risk
- Introduce no significant adverse impact to existing production
- Provide timely access to indicative fee structure for bona fide inquirers
- Create a level playing field for all producers, where the “best” barrels are produced
- Allow for resolution of conflicts
- Compensate the facility owners for their historical capital costs and lost or deferred production
- Provide equitable sharing of ongoing costs among all users

Physical Considerations

Potential producers are faced with the burden of exploring for oil and gas, bringing it to the surface, processing their fluids either with their own facilities or negotiating a facility sharing agreement, and transporting or establishing a custody transfer agreement at the outlet of the facility. If the third party producers build their own processing facilities, the product stream will need to tie into a pipeline for transportation. The common carrier pipelines will accept the production as long as it meets their specifications.

The North Slope processing facilities have specific design capacity limits, indicating the amount of oil, water and gas which can be handled by the facility. If the handling capacity of one of these streams is reached for a given facility, it limits the overall production output from that facility. While some facilities may be producing below capacity for oil, they are often limited due to capacity constraints on total water production or gas production. In this case, additional production can be introduced into the facility by backing out existing wells, such as those with high GOR or WOR, and processing third party production of oil with lesser amounts of water and/or gas. The facility-owner's production volume that is deferred due to the introduction of third party processing is referred to as "backout" or "backout volume". Compensation for this backout volume is an item of particular interest in negotiating a facility sharing agreement. The method of calculating this backout volume is detailed later in the report.

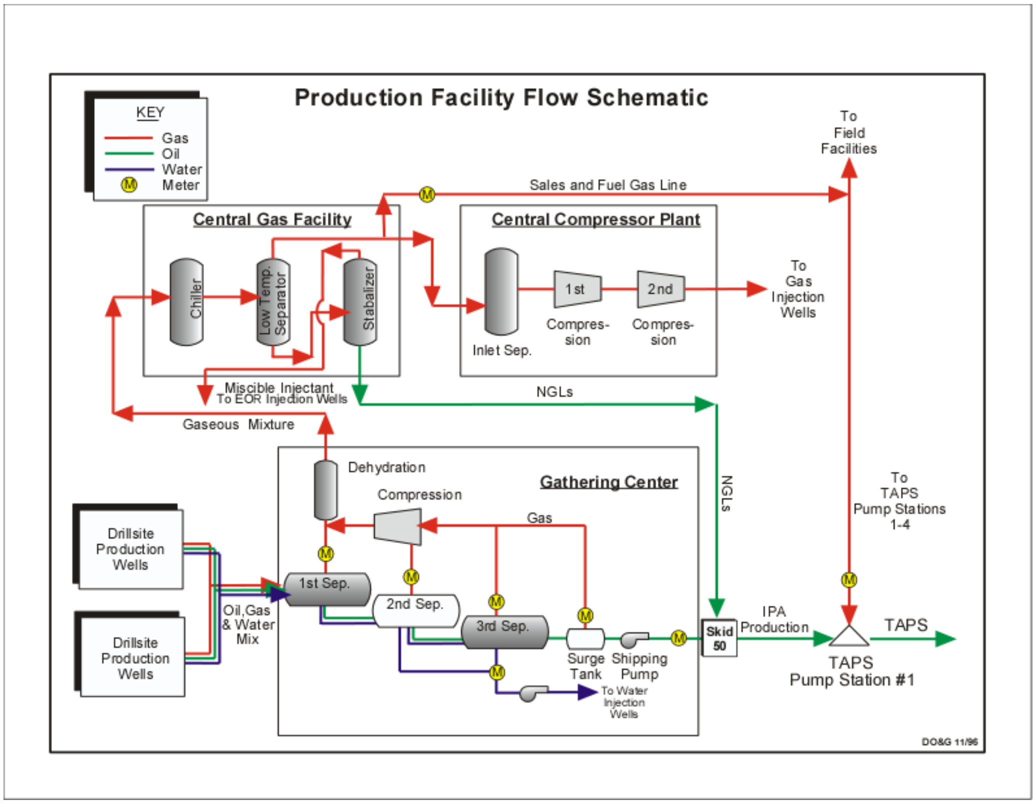
Where facilities are producing at peak oil handling capacity, backing out high GOR or WOR oil will not result in additional oil production, and backout costs for satellite producers would be prohibitive. Additionally, the pipelines necessary for transporting the produced fluids must have room for additional volume if new production is to be introduced. It is essential to remember that, even if there is available processing capacity in the facilities, there must be room for additional oil in the downstream pipeline system to accommodate satellite production. (See section on pipeline volume and forecasts.)

The first step toward understanding the North Slope facility sharing issues is to identify the processing infrastructure associated with each field and the design capacities of these facilities. The next step is to review, by processing facility, the constraints which drive the capacity limits. The North Slope processing facilities represent a complex network of systems with strong interdependencies. Facility operators are continually optimizing production parameters to maximize sales oil volume and minimize cost, managing individual well production for hundreds of wells to match plant specifications and pipeline and tanker capacities. To understand how and where third party oil can be processed, all of these factors need to be considered.

North Slope Overview

There are eight primary operating areas on the North Slope of Alaska that currently process North Slope oil and gas (See Figure 1). These eight facilities are: Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, Point McIntyre/Lisburne, and Prudhoe Bay. Northstar and Endicott are on man-made islands. Generally, the facilities consist of oil/gas/water separation, gas dehydration/compression/reinjection, water treatment/reinjection, and in some cases, NGL production. For a generic process flow diagram, see Figure 2. Individual facility process flow diagrams are shown in Figures 3 – 8. Oil is transported from each of the facilities into common carrier pipelines. The design capacities of each specific facility are shown below and compared with their current operating conditions. The forecast shows whether it is likely or unlikely that any new satellite production would incur backout costs.

Figure 2 **<u>Generic Facility Flow Diagram</u>**



Alpine

There is currently one producing pool (Alpine Participating Area) in the Colville River Unit (CRU). The major components of the basic facilities used by the CRU are: Alpine Processing Facility, Two Drillsites (CD-1 and CD-2), Alpine Pipeline, Seawater Treatment Plant (STP) pipeline, (Under a special agreement, STP supplies waterflood water to the CRU), the Alpine Main Camp, Spill Response Center, Warehouse, Airstrip, diesel supply line, roads and pipelines, and one Class 1 non-hazardous waste disposal well.

Oil processing at Alpine consists of 2 stages of 3-phase separation and a dehydrator to remove water to sales oil quality. Produced water is re-injected into injection wells at drillsite CD-1 (Colville Delta-1). Produced gas is compressed (through four stages) and flows into the gas injection header system. Gas is taken and mixed with indigenous natural gas liquids (NGLs) to form miscible injectant (MI). The MI is distributed to water-alternating-gas (WAG) injection wells at CD-1 and CD-2. Injection water consists of produced water and seawater from the Seawater Treatment Plant (STP).

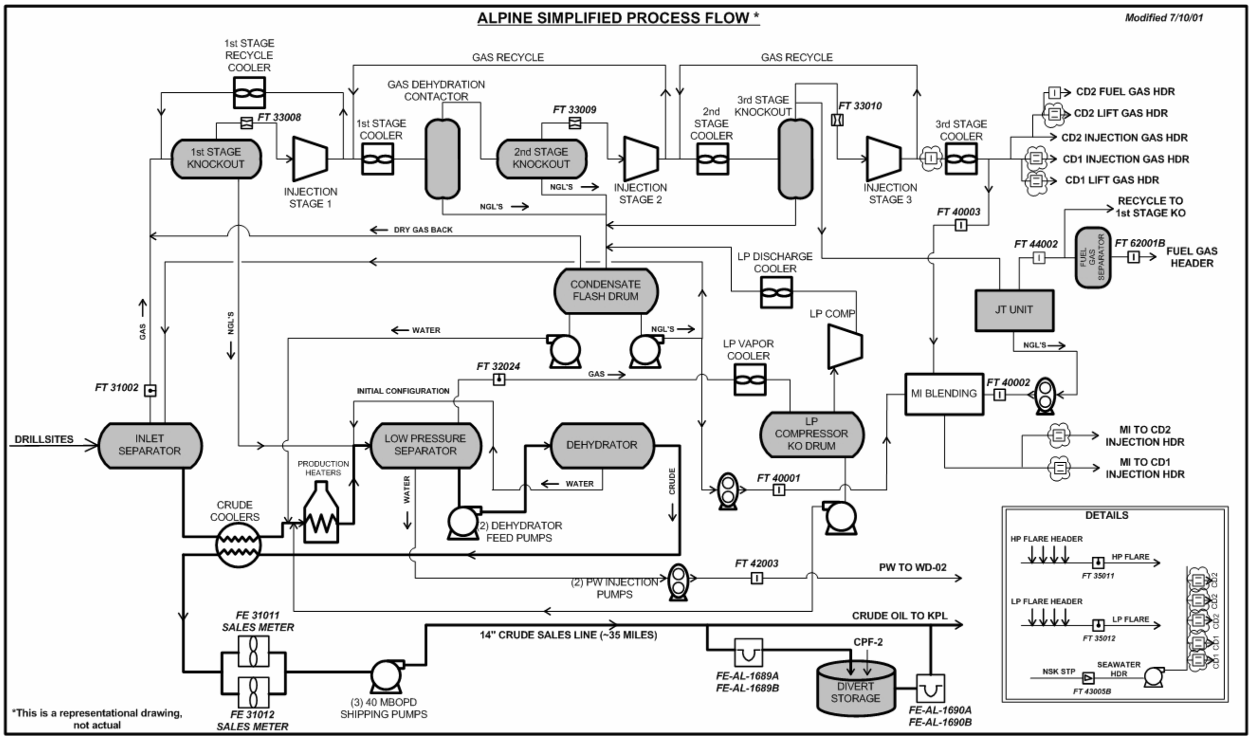
Table 1 depicts the 2003 production vs. original design capacity of the facility, along with the planned expansion capacity for late 2004 and 2005.

Table 1 **Alpine Facility Operation vs. Capacity**

Stream	**2003 Oper/design**	**ACX-1 Design Late '04**	**ACX-2 Design '05**	**Units**
Oil Production:	100,000/83,000	110,000	140,000	bopd
Gas Handling:	120/130	160	180	mmscfd
Water Handling:	4,000/10,000	100,000	100,000	bwpd
Water Injection:	80,000/80,000	140,000	140,000	bwpd

At this time, the Alpine Processing Facility has no spare capacity for new production. Alpine currently meets processing capacity for oil, gas, and water injection. Facilities expansions are planned for 2004 and 2005; however, it is likely that Alpine satellite development (Fjord, Nanuk, etc.) will offset most of the expanded capacity.

Figure 3 **Alpine Simplified Process Flow Diagram**



Badami

The Badami Field is currently in a warm shutdown. The production facilities consist of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, and oil export facilities. A WAG injection and lift gas system are also in place at Badami.

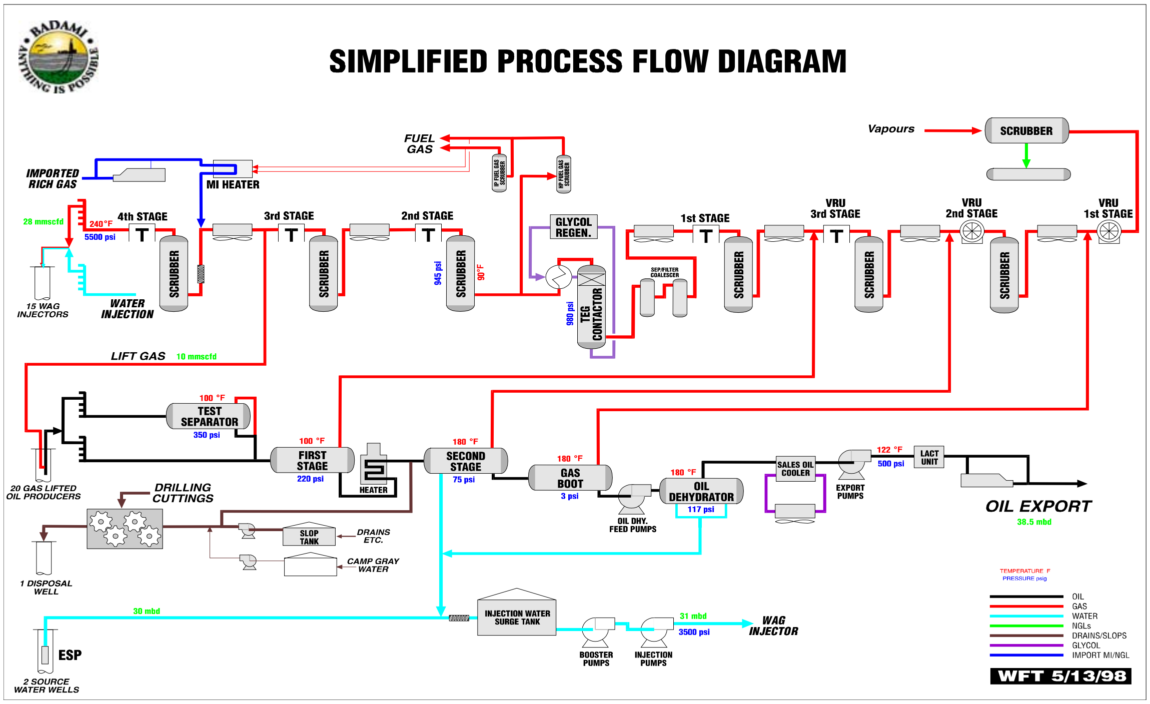
Access to the Badami facilities is by barge, ice road, rolligon, or air. Peripherals are an airstrip, a dock, a Class 1 non-hazardous waste disposal well, a grind-and-inject disposal well, and a source for electricity.

Table 2 **Badami Facility Operation vs. Capacity**

Stream	**Operation/Capacity**	**Units**
Oil Production:	0/35,000	bopd
Gas Handling:	0/25	mmscfd
Water Handling:	0/12,000	bwpd
Water Injection:	0/30,000	bwpd

Since Badami is in warm shutdown, there is theoretically space available up to the capacities shown. There may be additional costs associated with startup but there should not be any backout charges for processing here.

Figure 4 <u>Badami Simplified Process Flow Diagram</u>



Endicott

The Endicott facility consists of two man-made gravel islands located in the Beaufort Sea. Produced gas is separated from the crude oil and processed to remove NGLs. The NGL volumes are injected into the dry oil sales line subject to capacity available with existing pipeline vapor pressure specifications. NGLs not sold are blended to create a miscible injectant (MI) that is used in a water-alternating-gas enhanced oil recovery project. Any residual gas is reinjected into the reservoir to provide pressure support, used for fuel, or routed to the gas lift system to provide artificial lift. Produced water is treated before being reinjected into the reservoir. Seawater can also be treated before being injected.

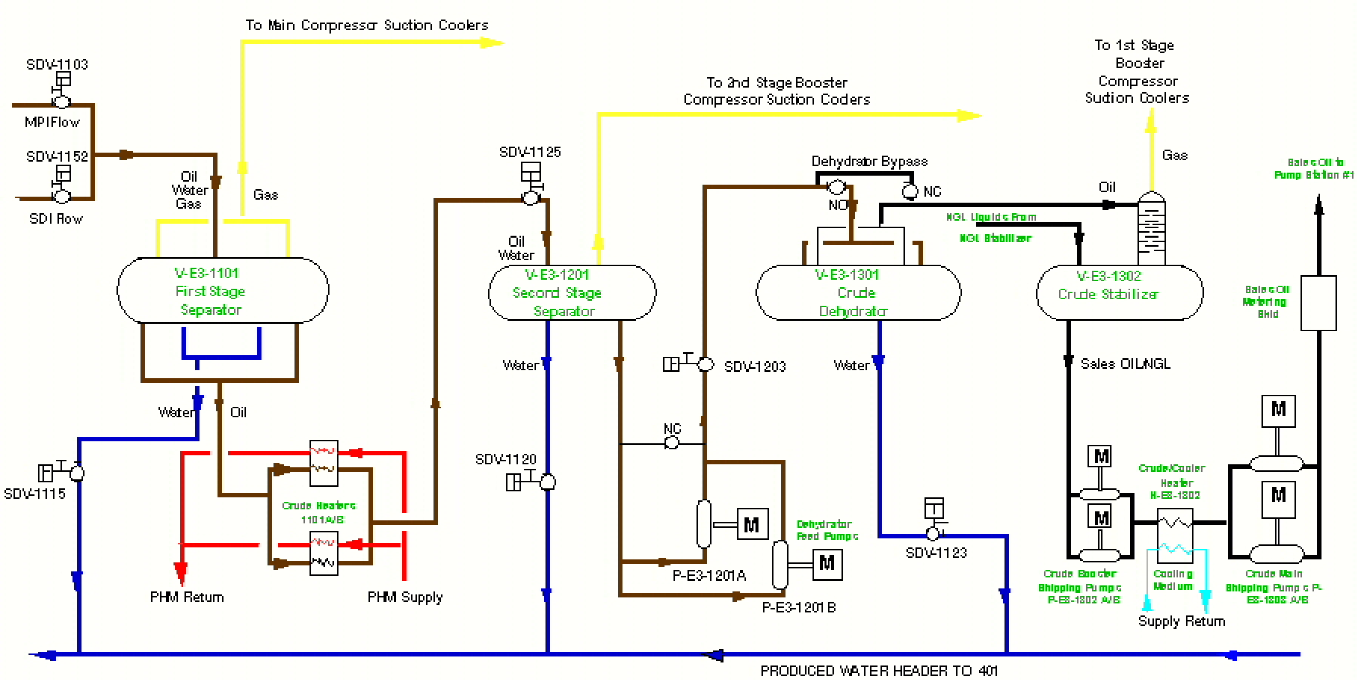
Endicott's two gravel islands are connected to each other, and linked to land by a gravel causeway.

Table3 Endicott Facility Operation vs. Capacity

Stream	Operation/Capacity	Units
Oil Production:	~25,000/115,000	bopd
Gas Handling:	~455/455	mmscfd design
Water Handling:	~210,000/225,000	bwpd design estimate.
Water Injection	~245,000/245,000	bwpd design estimate.

There currently is spare oil capacity at Endicott, but water and gas are at capacity limits. Any new production would likely result in some backout.

Figure 5 Endicott Simplified Process Flow Diagram



Kuparuk

The Kuparuk facilities consist of three Central Processing Facilities (CPF).

The production facilities consist of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, and oil export facilities. There is a seawater treatment plant designed to prepare seawater for waterflood operations.

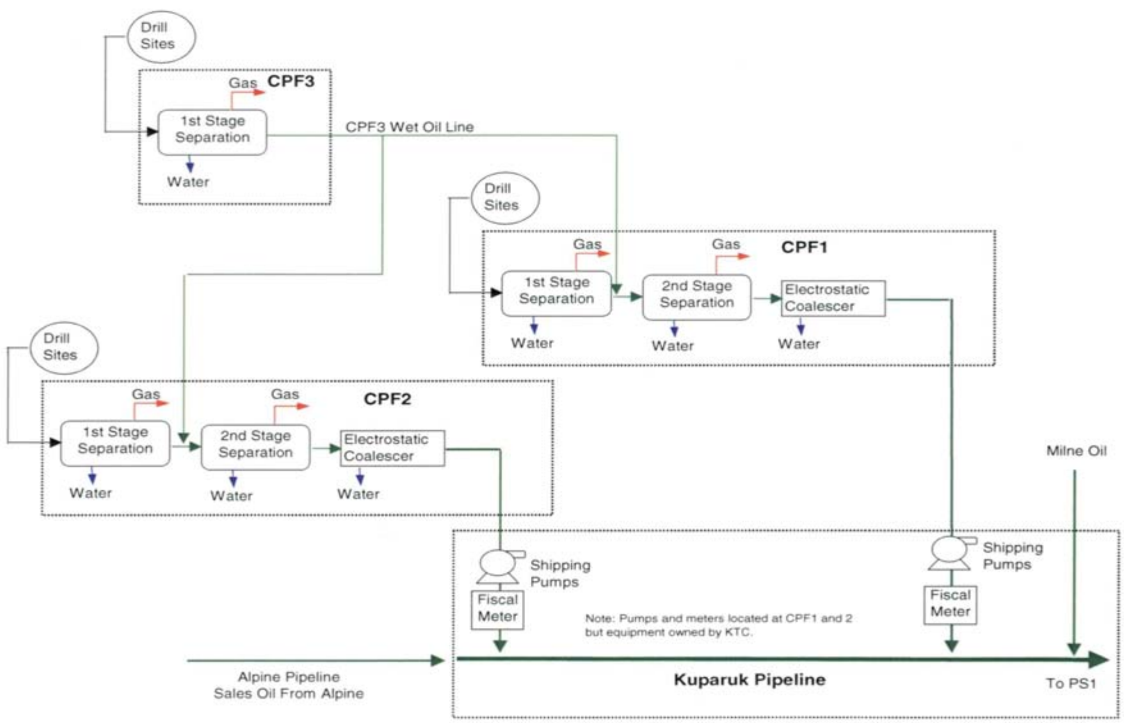
Access to Kuparuk is by a gravel spine road. Other facilities include a construction camp, spill response center, industrial center, warehouse, airstrip, topping plant and roads. There are four Class 2 non-hazardous waste disposal wells within the Kuparuk River Unit.

Table 4 **Kuparuk facilities Operation vs. Capacity**

Stream	**CPF-1**	**CPF-2**	**CPF-3**	**Units**
Oil Production	105,000/170,000	120,000/160,000	50,000/85,000	bopd
Gas Handling	200/200	260/260	150/150	mmscfd
Water Handling	250,000/250,000	250,000/250,000	100,000/125,000	bwpd
Water Injection	250,000/250,000	300,000/300,000	150,000/220,000	bwpd

There currently is spare oil capacity, but water, total liquid and gas production are at capacity limits. New production would result in backout.

Figure 6 **Kuparuk Simplified Process Flow Diagram**



Milne Point

The Milne Point Unit consists of a Central Facility Plant (CFP) and 12 producing / injecting well pads. The production facility is designed to separate oil, gas and water. After the gas is produced, it is compressed for gas injection and gas lift in the reservoir. After processing, all of the produced water is injected into the reservoir. Artificial lift at the Milne Point Field is a mix of ESPs, jet pumps and some gas lift, with ESPs being the most prevalent. Two pipelines transport liquids to and from Milne Pt. (NGL northbound, and oil southbound).

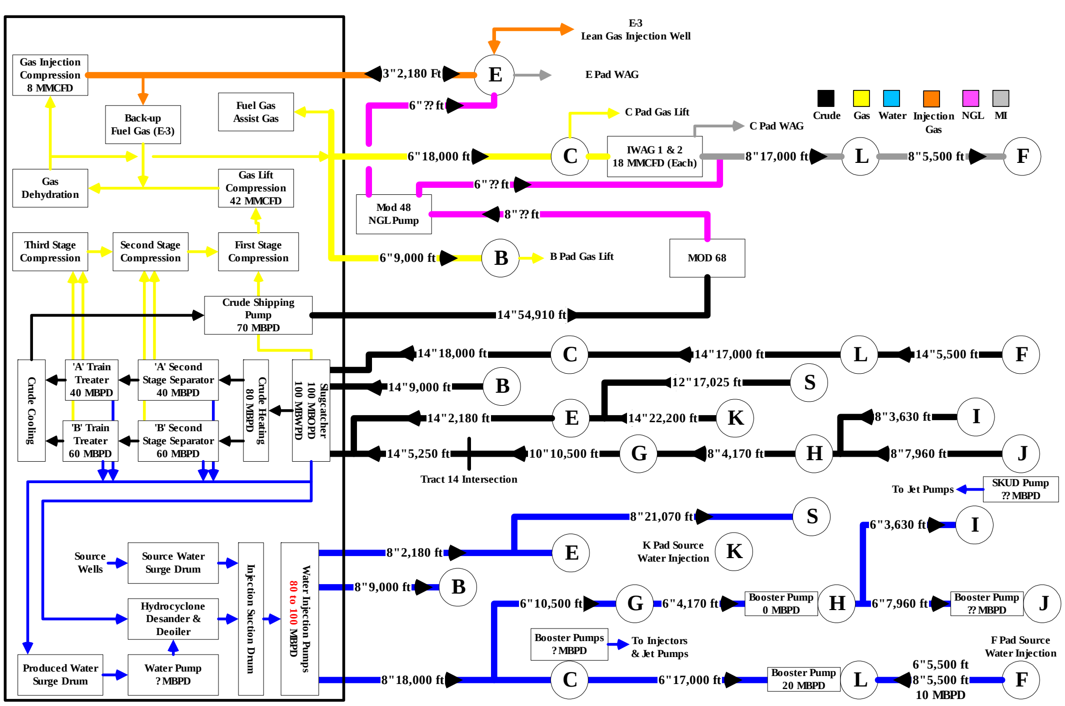
A permanent camp facility for up to 306 personnel is available. MPU currently utilizes ~40% of the space most of the time (~110 personnel). Transportation to and from Milne is by gravel road.

Table 5 **Milne Point Facility Operation vs. Capacity**

Stream	Operation/Capacity	Units
Oil Production:	~58,000/75,000	bopd
Gas Handling:	~40/42	mmscfd design estimate.
Water Handling:	~47,000/80,000	bwpd design estimate.

Milne Point has oil capacity available up to 12,000 bpd, and gas capacity available up to 2 mmscfd through 2015. In 2011, the water capacity is expected to be reached.

Figure 7 **Milne Point Simplified Process Flow Diagram**



Northstar

The Northstar facilities are on Seal Island, located 6 miles offshore of the Point Storkerson area in the Alaskan Beaufort Sea. Seal Island is a gravel island of approximately 5 acres. Two pipelines transport hydrocarbons to and from the Northstar Unit. The pipelines include one 10-inch common carrier pipeline from Seal Island to Pump Station No. 1 to transport the sales oil to TAPS. The second 10-inch pipeline is to import gas from the Central Gas Facility in the Prudhoe Bay Unit. The production facility is designed to separate oil, gas and water. Produced water is processed and disposed of into a Class 1 waste disposal well (there are two on the island). Following dehydration and NGL removal, produced gas is injected into the reservoir. Sales oil is cooled to Northstar export pipeline specification and shipped to TAPS. At the Pump Station No. 1 end of the export line, the sales oil is re-heated to TAPS specifications.

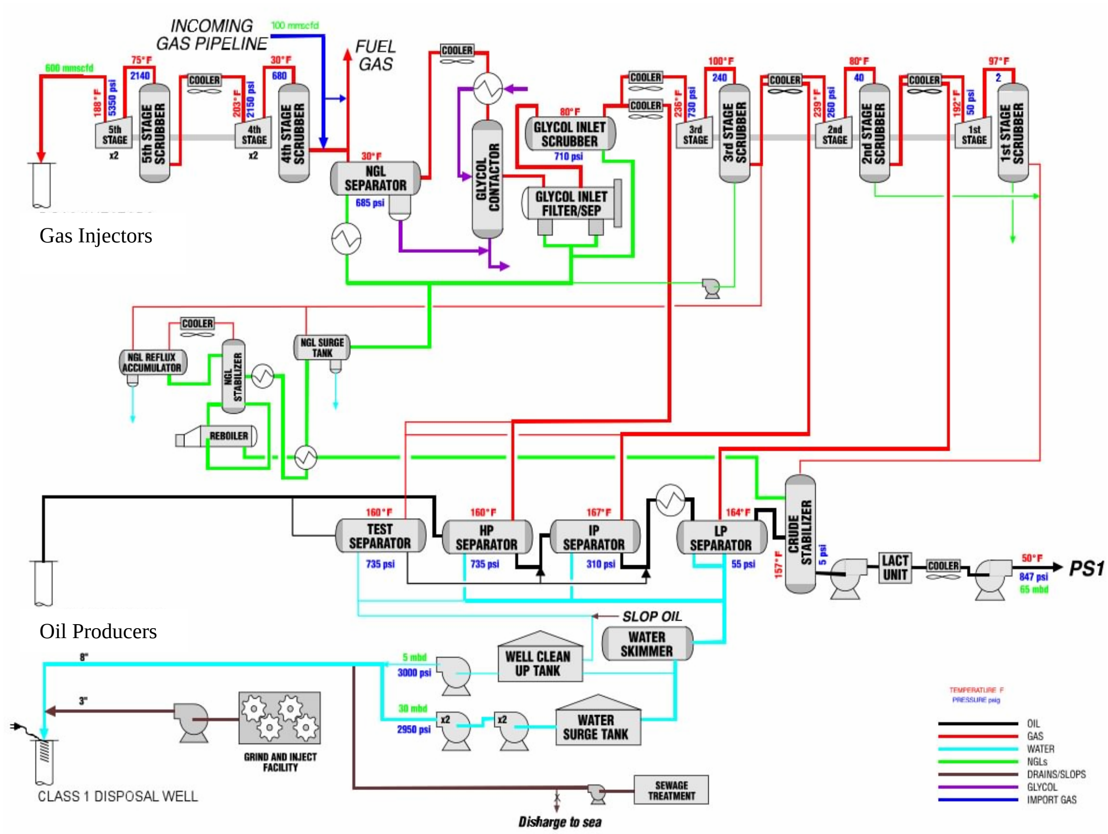
A permanent camp facility for up to 74 production and drilling personnel is also installed on the island. Multiple modes of transport are utilized depending on the season: an ice road during winter; barge, hovercraft and helicopter transport during summer; and helicopter and hovercraft transport during broken ice.

Table 6 **Northstar Facility Operation vs. Capacity**

Stream	**Operation/Capacity**	**Units**
Oil Production:	~65,000/77,000	bopd
Gas Handling:	~410/500-555	mmscfd design estimate.
Water Handling:	~7,500/30,000	bwpd design estimate.
Combined Water and Oil limit	~70,000/85,000	bfpd design estimate

Northstar will have capacity available in oil and water handling but is expected to reach gas capacity by 2006.

Figure 8 **Northstar Simplified Process Flow Diagram**



Point McIntyre/Lisburne

The Lisburne Production Center (LPC) consists of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, NGL production facilities, and oil export facilities. The LPC also generates electric power.

The Pt. Mac/Lisburne facility has no camp. It houses personnel at the nearby Prudhoe Bay Main Construction Camp. Access to and from Point McIntyre/Lisburne is by gravel roads.

Table 7 **Pt. McIntyre/Lisburne Facility Operation vs. Capacity**

Stream	Operation/Capacity	Units
Oil Production:	~60,000/205,000	bopd
Gas Handling:	~375/470	mmscfd design
Water Handling:	~140,000/160,000	bwpd design estimate

The facility is currently at or near both gas and water capacity. New production would result in some backout.

Prudhoe Bay

The Prudhoe Bay facilities, the largest on the slope, consist of six separate major production processing centers with a central power station, central gas processing facility, central compressor (injection) facility, two operating centers, a central seawater treatment plant, a topping plant, and a plant to grind and inject drill cuttings. There is one grind-and-inject well, and three Class 2 non-hazardous waste disposal wells. The production facilities consist of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, NGL production and oil export.

The main housing facilities for the Prudhoe Bay Field are the Eastern Operating Camp (EOC), the Western Operating Area Camp (BOC), and the Main Construction Camp (MCC). In addition to these, there are a number of support camps throughout the field. The PBU area can accommodate up to 963 people. (This figure does not include accommodations in Dead Horse.)

Table 8 **Prudhoe Bay Facility Operation vs. Capacity**

Stream	**Operation/Capacity**	**Units**
Oil Production:	~487,000/1,660,000	bopd
Gas Handling:	~8,700/8,700	mmscfd design estimate.
Water Handling:	~1,720,000/1,720,000	bwpd design.

There is room for oil, but gas production is at capacity limits and water handling is at or approaching capacity limits in all facilities. New production would result in some backout.

Projected Production and Pipeline Constraints/ Excesses

The following describes current and forecasted oil production for North Slope facilities. These numbers are for trend and probable outcomes and should not be taken as exact. The information was provided by the producers, with the exception of Endicott, Lisburne and Prudhoe, which were taken from the State of Alaska 2003 Revenue Source Book. Any new permits or emissions restrictions have not been addressed in this report. These rates are used for forecasting the pipeline usage. Also shown on the first row of the table are current pipeline capacities.

Table 9 North Slope Pipeline Capacities and Projected Field Production

MBPD Year	Badami Pipeline	Endicott Pipeline	Milne Pt. Pipeline	Alpine Pipeline	Kuparuk Pipeline	NorthStar Pipeline	TAPS Pipeline
Current Capacity	**35**	**100**	**65**	**100**	**400**	**65**	**1400**
2003	0	29	51	98	361	62	994
2004	0	30	52	99	359	68	997
2005	0	29	53	98	364	60	982
2006	0	27	57	103	376	50	968
2007	0	25	58	117	390	40	954
2008	0	24	59	117	379	32	923
2009	0	22	59	104	367	27	878
2010	35	56	59	86	338	20	852
2011	50	70	58	71	322	17	824
2012	48	66	57	60	300	15	775
2013	38	55	56	51	290	12	734
2014	31	47	56	44	273	10	691
2015	27	42	55	38	267	9	663

(a) Badami includes projected Liberty throughput

(b) Endicott includes Badami and Liberty throughput

(c) Kuparuk includes Alpine and Milne Pt. throughput

Before entering the oil and gas exploration and development business, a potential producer should consider the process required to transport hydrocarbons from the North Slope to market. Currently there are three market options for North Slope production: sales at the production facility, sales in Alaska, and sales on the West Coast. Sales at the production facility trigger no transportation issues for the producer, as the custody transfer is at the outlet flange of the facility. The other two options will entail the use of one or more of the Common Carrier Pipelines in Alaska. These pipelines are regulated by State and Federal Commissions. These pipelines will not discriminate between shippers, but will prorate volumes if pipeline capacity is exceeded. Crude oil product must meet certain specifications to be accepted by the pipeline.

The pipeline specifications for the oil delivery to PS1 are as follows:

- Maximum basic sediment and water (BS&W) content of 0.35%
- Minimum delivery temperature of 105^{o} F to prevent paraffin deposition
- Maximum delivery temperature of 142^{o} F
- Maximum True Vapor Pressure of 14.2 psia

The existing TAPS system can handle more than 1.4 million barrels of oil a day. Alyeska Pipeline Services Company is currently evaluating a plan to redesign TAPS to transport approximately 1 million bpd, expandable up to about 1.14 million bpd with drag reducing agent.

These are only guidelines for capacity since the addition of drag reducing agent and operational variation can change the overall capacity. If the amount of production exceeds the capacity, the pipeline operators will reduce each producer's rate on a prorated basis until capacity is met. Therefore, new production going into a pipeline that is at capacity will cause a reduction in existing production so that all producers can ship their product. This production will not increase or decrease the total quantity, just redistribute the production allocated to each producer.

Each pipeline has a group of owners that will transport fluids for a per barrel charge (tariff). Transportation must be coordinated from point of production to market and may involve several pipelines and different shippers. TAPS will transport the product to the Port of Valdez. The product must be tanker transported from Valdez to the interstate market.

Figure 9 is a map of the North Slope pipelines and TAPS. Figures 10 - 16 are timelines of the pipeline capacity and potential excess shipping space. These figures are based on production profiles as shown in the State of Alaska 2003 Revenue Book and on information provided by producers.

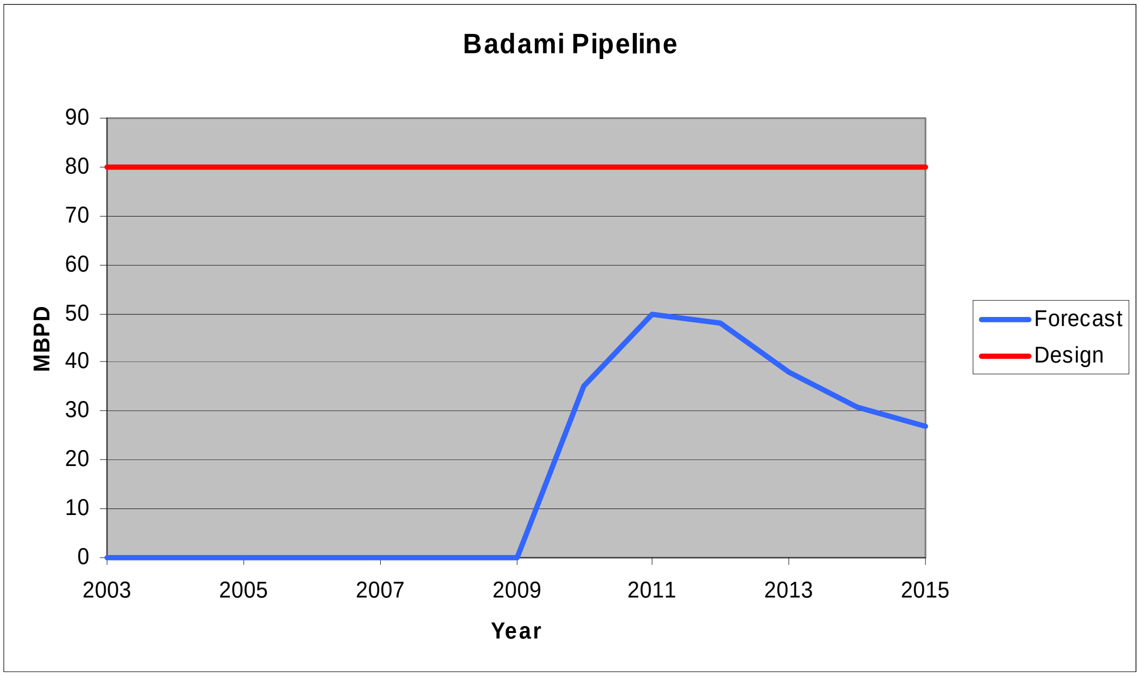


Figure 10

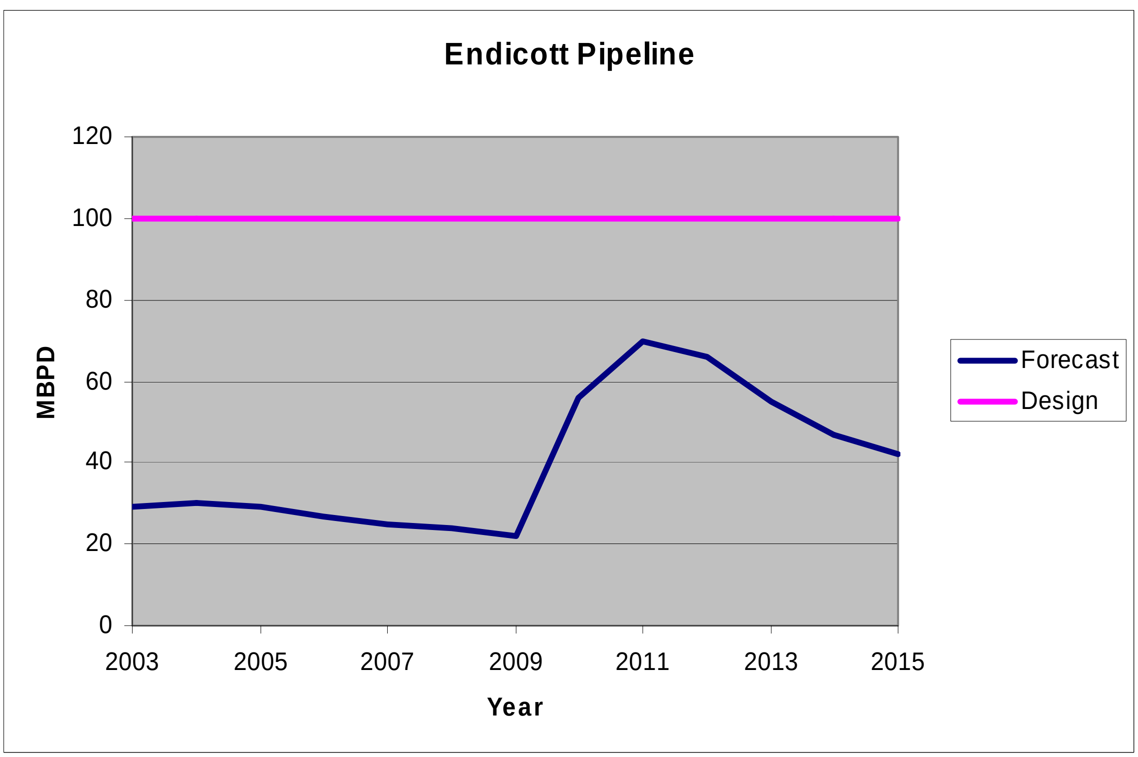


Figure 11

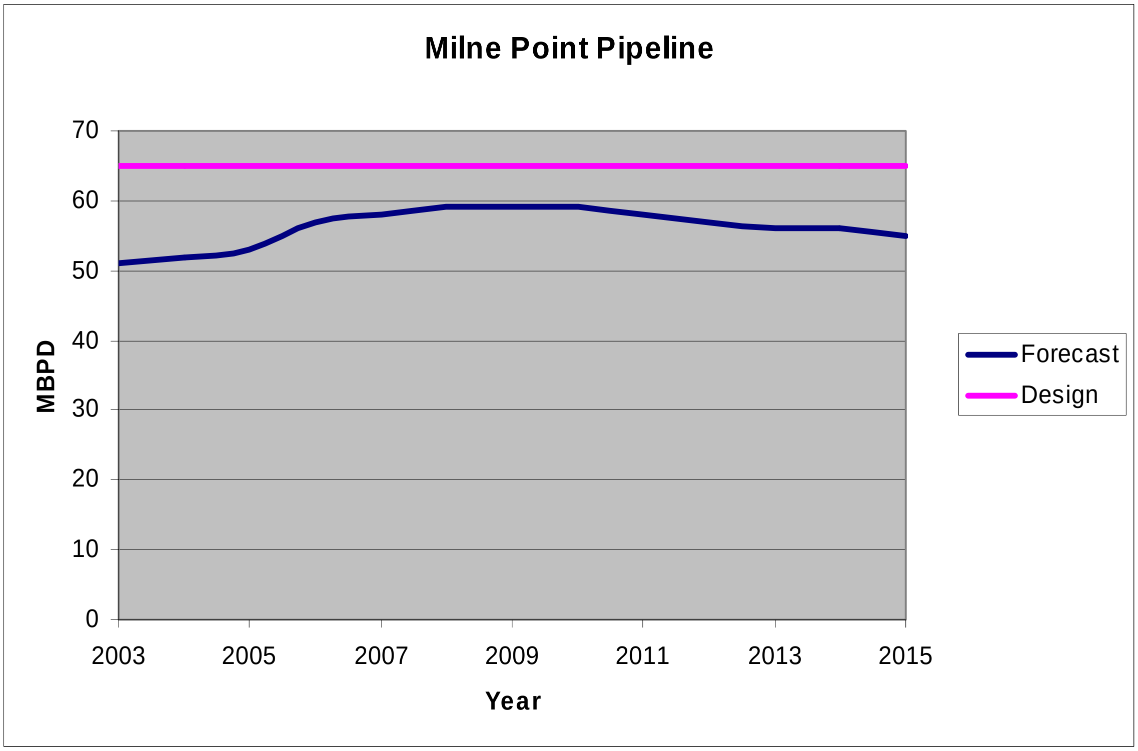


Figure 12

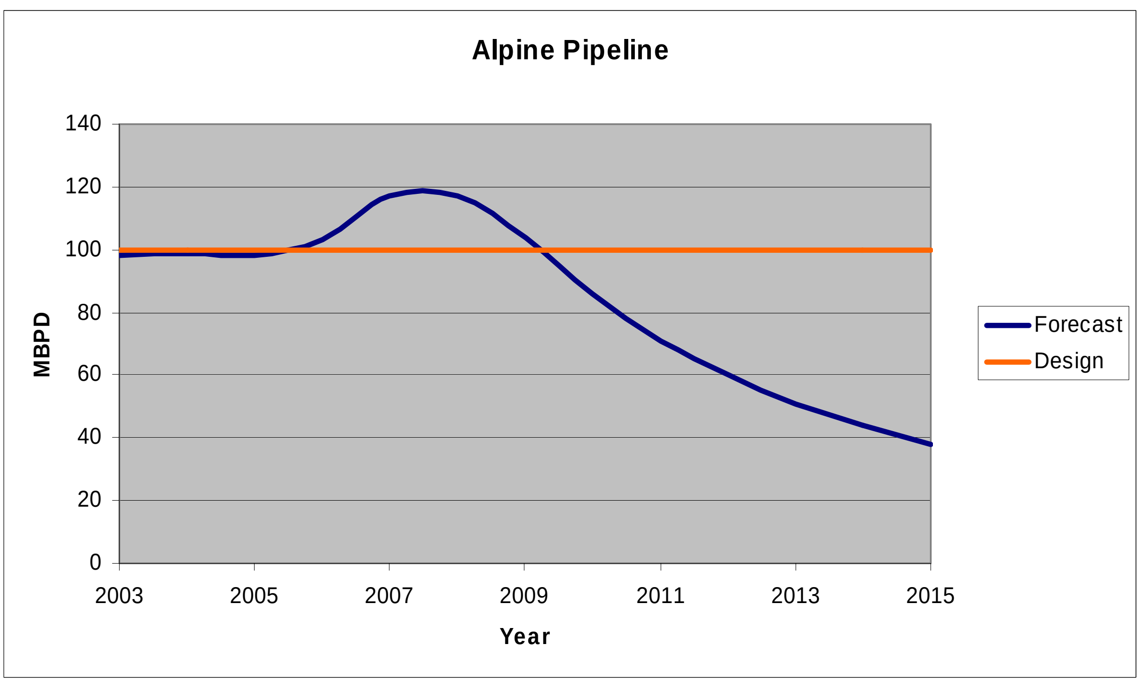


Figure 13

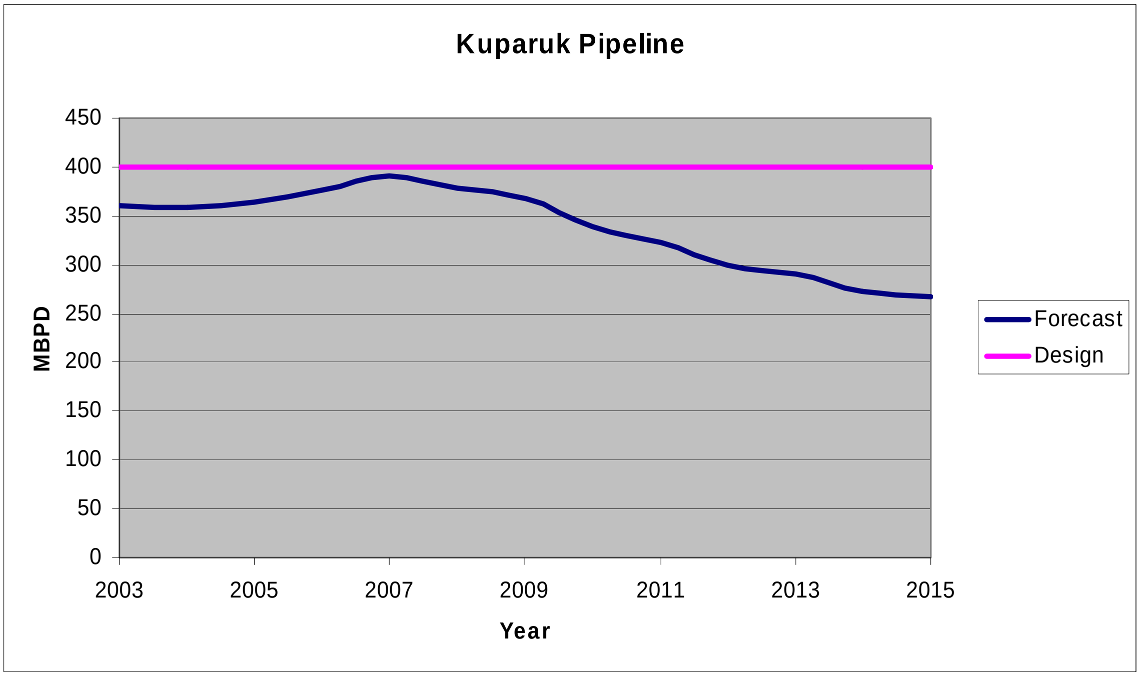


Figure 14

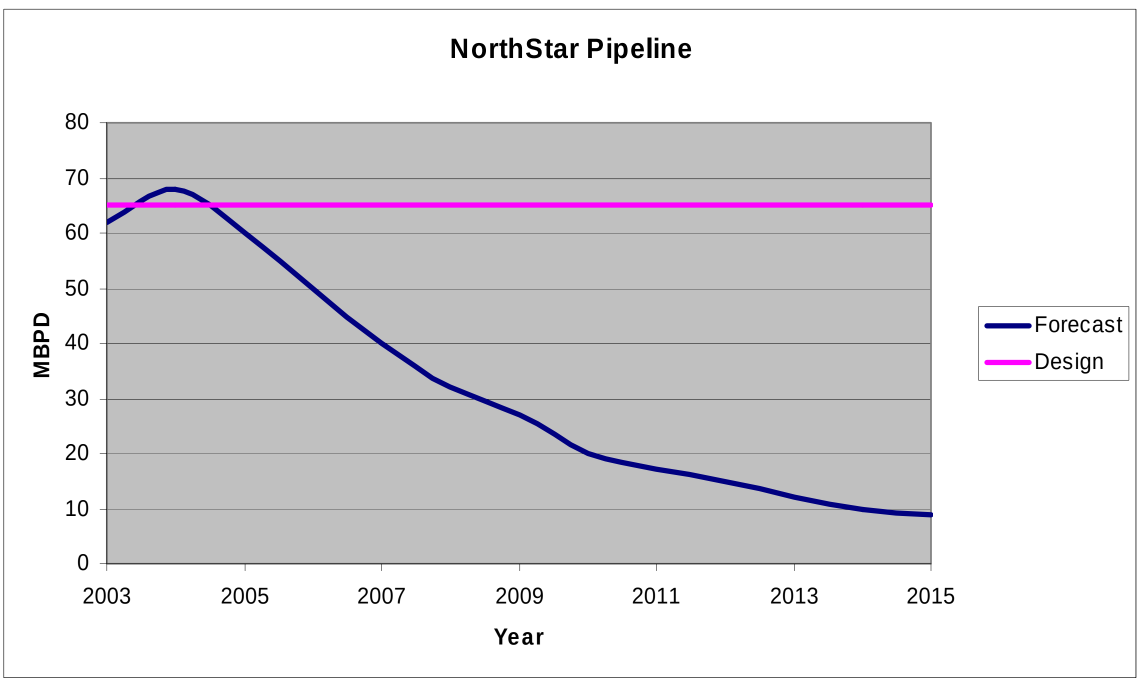


Figure 15

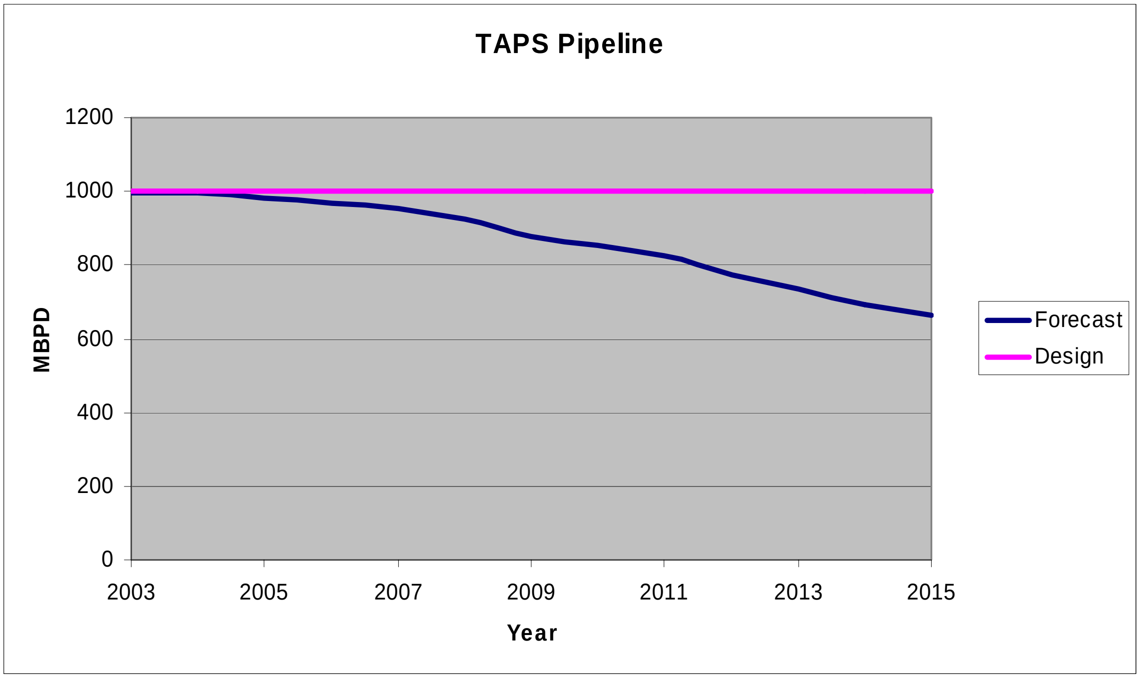


Figure 16

Table 10 illustrates the processing streams for which excess capacity is available, which streams are constrained, whether a backout calculation is likely, and status of pipeline capacity for each of the North Slope fields.

Table 10 **Facility and Pipeline Capacity/Constraint Summary**

Facility	Capacity Available for:	Constrained Stream	Backout	Pipeline
Alpine	none	oil, gas, water	likely	Full
Badami	oil, gas, water	none	not likely	Not Full
Endicott	oil	gas, water	likely	Not Full
Kuparuk	oil	gas, water	likely	Near Full
Milne Point	oil, gas, water	water 2011	maybe	*
Northstar	oil, gas, water	gas 2006	maybe	Near Full
Pt. Mac/Lis	oil, water,	gas	likely	Near Full
Prudhoe Bay	oil	gas, water	Certain	Not Full

- Feeds into Kuparuk Pipeline and dependent upon space there.

Areas of Independents' interest and activities

Figure 17 is a map of recent (2001-present) North Slope exploration activity, including recent exploration wells, unit boundaries, and recently acquired state leases. This map portrays the areas of interest expressed by North Slope explorers through their lease acquisitions and drilling activities, and indicates the areas most likely to put pressure on existing infrastructure. Some of the activities which, given successful exploration programs, will potentially impact the facility sharing landscape include:

1. Pioneer/Armstrong Oooguruk Unit evaluation
2. Kerr-McGee/Armstrong Nikaitchuq 2004 Exploration drilling
3. ConocoPhillips 2004 NPRA drilling
4. Pioneer 2004 lease acquisition
5. AVCG 2004 lease acquisition
6. Ultrastar 2004 lease acquisition

Pioneer and Armstrong partnered in 2003 to drill 3 exploration wells in the Oooguruk Unit northwest of KRU (yellow leases). They have announced a discovery in the Nuiqsut Fm., and are evaluating options for development of this discovery. This potential development could impact KRU facilities and/or the Kuparuk Pipeline.

Kerr-McGee and Armstrong drilled two wells (Nikaitchuq #1&2) northwest of MPU in 2004, and have announced a discovery in the Sag River Fm. Potential development here could impact MPU facilities, the Milne Point Pipeline, and the Kuparuk Pipeline.

ConocoPhillips has drilled a number of discovery wells to the west of CRU, all of which figure to impact the Alpine facilities, Alpine Pipeline, and Kuparuk Pipeline.

Pioneer acquired tracts in the 2003 North Slope and Beaufort Sea Areawide Lease Sales in the Hemi Springs area, as well as north of PBU, east of Northstar, and west of Kuparuk. Successful exploration programs associated with these lease acquisition could impact numerous production facilities.

AVCG added to their lease position in 2003 with acquisitions east and south of CRU, north of PBU, and west of KRU. They are considering stand-alone processing options at this time, which would limit the facility impact to common carrier pipelines.

UltraStar Exploration added new leases to their portfolio in 2003 around Badami, and north of PBU, and successful drilling of their prospects could impact Badami, Pt. McIntyre/Lisburne and/or PBU facilities.

Most of the activity shown on the map is focused around existing facilities, with the exception of SWEPI and Unocal's lease acquisitions some 50 miles south of KRU, and Total's drilling nearly 50 miles west of CRU.

A critical constraint will be available processing and pipeline capacity to the west and north of KRU. Alpine satellites, NPRA, and the Ooooguruk and Nikaitchuq discoveries will all place significant pressure on the Kuparuk and Alpine pipelines. However, with enough new production potential realized, additional pipeline capacity may be justified.

Facility Sharing Negotiation Specifics

Guideline for Negotiation Strategy Template

PRA has put together a guideline for a facility sharing agreement based largely on Ballot No. 255 for Kuparuk. This guideline deals with the technical and accounting aspects and not the legal provisions of an agreement. All parties are advised to obtain legal counsel to protect their rights and limit their liabilities.

This guideline's purpose is to illustrate the anticipated components of a possible agreement and the expected ranges of costs associated with key components. It is not intended to be all inclusive. Every actual agreement will have its own particulars and be specific to that situation. The key to an agreement is to establish fair terms for utilizing existing infrastructure that provide third party owner(s) improved economics to develop and produce from nearby fields or other commercial paying reservoirs while compensating infrastructure owners for their existing investment, risk taking and operations. The facility owners have incurred substantial risk and invested large capital in their facilities. The third party owners can benefit from avoiding construction time, permits (possibly) and risk of delays by using existing facilities. All parties can benefit by increased production and operations.

Any specific numbers in this guideline are for illustrative purposes and indicate possible ranges and are not intended to be fixed or binding on any party.

Facility Sharing Agreements Should Include the following provisions:

1. **Identification of Facility Owners**

This provision identifies the facility owners and their intentions.

2. **Identification of Third Party Owners**

This provision identifies the third party owners and their intentions.

3. **Definitions of Terms**

This provision defines terms of substance to this agreement for clarity.

4. **Definition of Facilities**

This provision defines facilities that are and are not included in this agreement.

5. **Definition of Third Party Facilities**

This provision defines facilities that are third party sole responsibility.

6. **Standards of Produced Fluids**

This provision defines fluid compatibility and physical limitations.

7. **Priorities Governing Production Processing**

This section states that the facility sharing agreement will maximize the total oil production. It sets priorities and defines impacts of operations. In order to maximize oil production, high GOR, high WOR wells will be curtailed first regardless of ownership. Wells of the facility owner could be shut-in or curtailed, thereby decreasing the facility owner's total production. The volume not produced by the facilities owners is "backed out" to make room for the third party production. To compensate the owners for this backout, the backout volume is calculated via a process described in more detail later in this report, and transferred to the facility owners from the third party owners. This backout volume is used to adjust the fee-appropriate volumes for the third. In other words, the third party owners do not pay fees on the barrels they must give up as backout compensation

8. Produced Water and Seawater

Facility owners will provide to each third party a volume of water, for water injection, that is equal to the volume of water delivered to the facilities by the third party production facilities.

9. Excess Water Volumes

To the extent that additional produced water or seawater volumes are available and desired, facility owners will provide third party facilities with water volumes in excess of their water production where needed to maximize and optimize field development. A fee may apply for this excess volume.

10. Facility Access Fees

The facility owners will be compensated for their investment and ongoing costs incurred to provide facilities and processing of the third party fluids.

Capital Access Fee

This fee compensates the facility owners on an adjusted per barrel processed basis for their past capital investment. This fee recognizes that the facility owners have invested large sums in the past for the equipment and facilities that are available to the third party. Generally this fee would have a depreciation component and a rate of return component.

Capital Access Fee Surcharge

This fee compensates the facility owners for capital costs incurred after third party processing begins. This would apply if the third party did not participate in a joint capital project but the third party benefits from the project. This fee could be a per barrel charge and apply in capital increments. For example: a capital access fee of $0.025 per barrel imposed following each $25 million increment of cumulative gross amounts expended on joint capital projects and excess routine field CAPEX.

Abandonment Fee

This fee compensates facility owners for future abandonment costs that will be incurred during the abandonment of the facilities.

Abandonment Fee Surcharge

This fee is to cover abandonment costs for capital added after third party processing begins.

11. Accounting

For purposes of determining volumes of third party oil processed through facility equipment, the volumes specified in the monthly production and injection reports filed with the Alaska Oil and Gas Conservation Commission will be used less any adjustments caused by backout. Allocation among the owners will be determined by the parties.

12. Operating and Maintenance Costs

The facility owners incur operating and maintenance costs for all of the facilities and drillsites. The costs for any facilities not benefiting the third party facilities or production shall be excluded from the calculations.

Plant Liquid Processing Fee

The per-barrel fee shall be determined by dividing the O&M costs by the volume of total liquid production (oil plus water) processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross liquid processing operations but do not include any O&M costs not benefiting the gross liquid processing operations.

Plant Gas Processing Fee

The per-mcf fee shall be determined by dividing the O&M costs by the volume of total gas production and lift gas processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross gas processing operations but not include any O&M costs not benefiting the gross gas processing operations. The fee shall be applied to the allocated volume of fuel gas, flare gas, take-in-kind, shrinkage and lost gas attributable to third party fluids.

Common Drillsite

The per barrel fee shall be determined by dividing the O&M costs by the volume of total liquid production (oil plus water) processed in the facilities. The O&M costs can include total drillsite labor, direct operating costs and allocated field support costs which are attributed to all drillsite operations but shall exclude charges for operations which do not benefit the third party production. The fee shall be applied to third party gross liquid production (oil plus water) processed through the facilities less any adjustments.

Water Fee

The per-barrel fee shall be determined by dividing the O&M costs by the total make-up water volume made available and used for injection in all reservoirs. The O&M costs can include total labor, direct operating costs and allocated field support costs which are attributed to seawater treatment plant operations and associated pipelines which carry seawater to the injection plants. This fee shall be applied to each barrel of make-up water injected into the third party reservoir.

Ad Valorem Tax Fee

The annual ad valorem taxes chargeable to the third party shall be determined by multiplying the total annual ad valorem taxes by the third party adjusted gross liquid production (oil plus water) processed in the facilities divided by the total liquid production (oil plus water) processed in the facilities.

13. Accounting

The fees for liquid and drillsite shall be applied to third party's gross liquid production (oil plus water) processed through the facilities less any adjustments.

14. Fluids Associated with Backout Oil

The adjusted backout volumes have an associated volume of water and gas. These volumes of water shall be the gross third party water production times the adjusted third party backout volume divided by the gross third party oil production. The gross third party gas production times the adjusted third party backout volume divided by the gross third party oil production is the associated gas volume.

15. Determination of Costs and Volumes

The costs shall be based on the actual booked costs and actual volumes of fluids processed. The third party volumes shall be those specified in the production and injection reports filed by the operator with the Alaska Oil and Gas Conservation Commission.

16. Routine Field Capex Share

Routine field CAPEX shall be allocated to the third party owners on third party's gross liquid production (oil plus water) processed through the facilities less any adjustments divided by the total liquid production processed through the facilities.

17. Joint Capital Projects

A joint capital project may be proposed by either the facility owners or the third party owners. The percentage voting and procedure for proposing the projects can be negotiated by the parties and set forth in this agreement. All construction and modifications shall be owned solely by the facility owners.

18. Volume Adjustments

Backout

There will be a volume adjustment to reflect a backout of production from the facility owners' production caused by the introduction of third party production. This volume would be further adjusted to account for quality, royalty, and tax. **See separate write up on Backout Methodology Guidelines.** This adjustment will transfer the processing fees to the receiving party for the backout volumes.

Quality

The differences in the characteristics of the oil production from the facilities and the oil production from the third parties will be recognized and compensated with a quality adjustment. These differences could be caused by API gravity differences, compositional differences and impurities. The compensation will be a transfer of barrels between the parties. The exact procedure and calculation would be negotiable after the determination of the Quality effect. A quality adjustment factor (QAF) will need to be established for each stream and agreed to by the parties. The QAF volume is equal to the gross oil production for the stream (adjusted for royalty and tax) times the QAF for the stream minus the QAF average divided by the QAF average. The QAF average is the total of each stream's gross oil production times its QAF divided by the sum of the gross oil production for all streams. If the resulting QAF volume is positive, the stream will receive barrels, if negative, the stream will deliver barrels. The methodology can be simple, such as based on API gravity ratios, or can be more complex, such as based on component value.

Tax and Royalty

Backout is considered a financial transaction; thus the value of the backed out oil is transferred to the receiving party while the delivering party retains the reserves for booking purposes and payment of royalties and severance taxes. To calculate the net backout share allocated to each party, the backout volume is adjusted for severance tax and royalty to keep the receiving parties whole on an after severance tax and royalty basis. The net backout volume will equal the backout volume calculated using a processing facility dynamic model, times one minus the royalty, times one minus the ELF, times the severance tax rate.

Adj.BO=BO{1-Royalty}x{1-ELF}x{SEVTAX}.

For example: If 100 barrels is the calculated backout volume, the adjusted volume would be: first, 100 times (1-.125 Royalty) equals 87.5 barrels; second, 87.5 times (1- (0.15 severance tax rate times .9 ELF)) equals 75.68 barrels. This way the delivering party pays the Royalty and Tax and the receiving party gets the barrels royalty and Tax free.

Allocation and Metering

Third party owners shall pay for all metering investments required for processing their fluids. Facility operator will prepare and maintain all information necessary for the filing of any reports required by governmental regulatory authorities relating to volume, quality, and disposition of produced fluids.

The unit operator will conduct well tests or metering as required for the allocation of production and provide information to all parties. This information will be that necessary for the third party to file any reports required by government regulatory authorities relating to volume, quality, and disposition of produced fluids.

19. Gas Supply

Each third party owner shall be obligated to supply gas to satisfy gas consumed during third party operations and utilized in the facilities for processing the third party production. Third party owners shall be responsible for fuel gas consumed by its equipment and a proportionate share of the fuel gas used in the facilities.

20. Gas Use and Reinjection

Any gas not used and consumed shall be taken in kind, reinjected into the third party reservoir or injected into the facility owners' (FO) reservoir. The gas injected into the FO reservoir will be considered indigenous to the FO reservoir and no compensation for the gas will be given.

21. Warehouse Sharing

The third party facilities will be permitted to use facility materials for a percentage each year. The exact material and costs will be negotiated.

22. Legal and Accounting Rights

The agreement would have several provisions maintaining each party's various legal rights, indemnity and auditing procedures.

Example of Potential Costs

Although each case will have its own specifics, as an example of potential costs, a third party would expect to pay fees for KRU such as those shown below:

Table 11 __**Example of potential costs**__

Fee	Typical range	Per
Capital Access	$1.00-1.80	BBL Oil
Abandonment	$0.10-0.20	BBL Oil
Plant Liquid	$0.09-0.15	BBL Liq.
Plant Gas	$0.03-0.6	MCF
Drill Site	$0.11-0.15	BBL Liq.
Excess Water	$0.04-0.07	BBL Ex.Wtr.
Ad Valorem	$0.10-0.16	BBL Liq.

Possible ranges of Backout:

Backout could range from as low as 2% to as high as 50%. The PBU satellites range from 2% to 6%. The KRU satellites range from 3% to 30% with an average of 9%.

Backout Methodology Guidelines

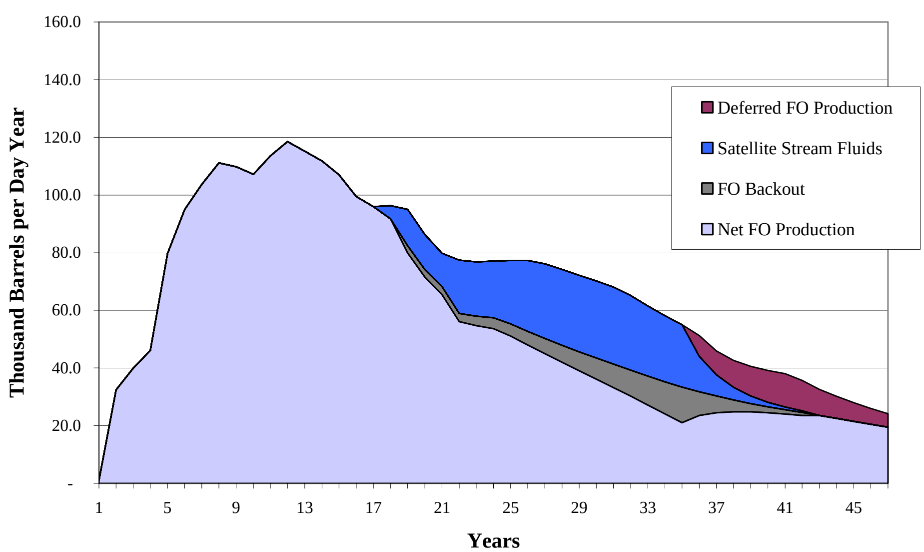
The following procedures are guidelines for a hypothetical methodology for determining the impact of backout fluids in facility sharing agreements. It is not intended to be all inclusive and areas may be subject to negotiation for a specific agreement. Kuparuk Ballot 255A is generally followed as this guideline. This methodology is detailed, complex and heavily dependent on a detailed dynamic plant model. Presently, only the KRU and PBU facilities have such a model in place. Other facilities would have to develop such a model, make use of existing less sophisticated models or negotiate a method for determination of backout volumes. See Backout Methodology Alternatives Section.

The owners of the existing processing facilities shall be designated as "FO" and the owners of the stream of fluids to be introduced into the facilities shall be designated as "SO". The term backout fluid means that volume of FO oil that will be deferred due to the limitations of the facilities if the SO fluids are processed.

The concept of backout is real, and it represents actual deferred or lost production, resulting in measurable loss of revenue to the facility owner. Backout only exists when the facilities are constrained in some manner, causing the combined streams to be larger than the capacity of the facilities. This is remedied by backing off the less efficient wells, such as those with high GOR or WOR, in lieu of production from lower GOR or WOR wells. In a simplified example, if the FO stream generates 100 mmscfd of gas and the facilities can handle 120 mmscfd, while the SO stream generates 30 mmscfd, then the gas handling is the limiting factor. For efficient operation of the facilities, the highest GOR wells would be backed out, likely from the FO wells, thus reducing the overall production for the FO but actually increasing the total sales oil production by adding the lower GOR SO oil. This reduction in FO oil is called backout, and the FO must be compensated for their lost or deferred production. This reduction volume is theoretically deferred until production in the far future. The effect of this time delay in production is financial and physical. The wells may not produce as efficiently when returned to service, the prices of oil will be different, today's value of the barrel will be discounted by the time delay of production and the facilities may be uneconomical to operate thereby not recovering all of the barrels. These situations are not easy to define, and an overall modification factor can be negotiated to account for variance in these unknowns.

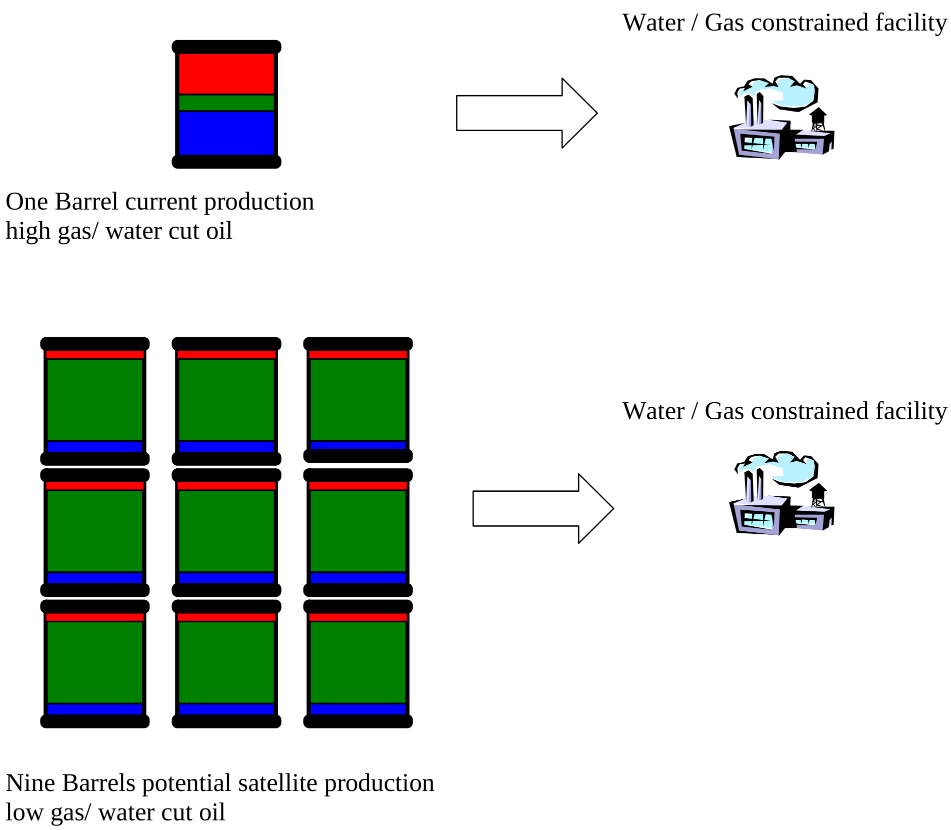
Figure 18 illustrates the impacts of backout on the production profile. Hypothetical facility owner (FO) production in thousands of barrels per day is shown in light blue. Satellite stream (SO) operator production (dark blue) begins in year 18 and is accompanied initially by modest rates of backout (grey). Over time backout increases as satellite stream fluids GOR increases, in this example to a peak of about 35% of FO gross production. Eventually satellite production ramps down and shuts in. In period 36, toward the end of field life, FO deferred production is re-established (magenta). In this illustration FO deferred production is less than cumulative backout, indicating that a portion of cumulative backout is not recovered. Thus, in addition to lost time value of money, FOs forego production due to backout.

Figure 18 **Hypothetical Backout Illustration**



Backout can be caused by limitations in any or all of the following areas: oil handling, oil transmission, gas handling, gas treating, gas re-injection, water handling, water treating, water injection, electrical generation and pipeline proration. Figure 19 portrays the basic concept of backout, whereby a high GOR and WOR barrel of oil is backed out of the production stream to allow for multiple barrels of low GOR and WOR satellite oil to be produced. The backed out barrel does have value, if produced, but it is relatively small in relation to the satellite barrels.

Figure 19 **Backout concept**



Application of General Backout Concepts:

- The backout calculations will be performed monthly.
- The basis of the calculations will be the average monthly allocated production and injection for that month (at the well level) as filed by the operator with the AOGCC.
- To the extent possible, the backout calculations will make use of logic that follows the optimization logic used in actual field operations.
- Adjustments will be made to account for any joint capital project participation by all parties.
- Changes in methodology will be made as appropriate to ensure the results reasonably reflect production adjustments.
- The operator shall be responsible for preparing the backout calculations.

Gas and Produced Water Backout:

This calculation is the first-order factor in calculating total backout, and it is based on plant gas handling and produced water capacity limits, as well as the relative GOR and WOR of the FO and SO streams. The operator uses a computer simulation program to model the day to day processing operations at the facilities. The results are compared to actual operations and calibration modifications are made to the model until the model results match actual operations to within 5%. Then the program is run with its optimization components to determine the basis for the calculations. All SO production is “turned off” in the calculations and the production potential for FO is determined. If there are more than one SO stream, a series of runs are made with one stream at a time “turned off”. The results are used to determine the backout oil and the water oil ratio (WOR) of the backed out oil.

Water Injection Backout:

The operator will have to have methodology for simulating the impacts of reduced/increased water injection rates on the reservoir and production. This information will determine the relationship of oil rate backed out as a result of reduced water injection. Additional adjustments will be made to account for compressibility effects in the reservoir and to minimize possible double counting of backed out production. The WOR is used to determine the water injection backout for each SO stream.

Electrical Power Backout Calculations:

If electrical power generation capacity becomes a constraint to production, it is likely that high water cut wells being lifted with electric submersible pumps would be shut in to free up electrical capacity. It is also likely that these wells would be FO wells. To account for this possibility, a backout amount will be calculated.

The operator will verify each month whether any electrical power related production deferrals events occurred. If not, this calculation is not necessary. If an event occurred, causing lower FO production, the electrical power-related backout volume and the amount of power necessary to avoid this backout will be estimated. The total amount of electrical power used directly by the SO will be tabulated and adjusted for any funded electrical joint capital projects. The backout volume would be allocated according to the

SO usage. If the power necessary to avoid the backout is greater than the total SO usage, then the impact of this calculation is to lower the total calculated backout.

Proration Adjustment Backout Calculations:

Production impacts caused by common carrier or marine capacity prorations are to be shared by the FO and the SOs in percentages proportional to their gross share of pipeline volume. If no proration events occurred for the month, then no calculation will be made.

If there are proration impacts, a table of the **actual** production and the **estimated** production losses (actual proration) will be constructed for each stream. The difference between the target proration and the actual proration is the theoretical adjustment. If the number is negative, the stream will receive barrels and if positive, the stream will deliver barrels. For example, if the FO production rate is 100,000 bopd, and the SO production rate is 20,000 bopd, and a proration event calls for combined rate to be reduced to 60,000 bopd, then the FO rate would be prorated to 50,000 bopd, while the SO rate would be prorated to 10,000 bopd. However, if operational considerations dictate that one or the other stream does not reduce to the prorated value, the difference between that stream's actual production, and the prorated value triggers a backout calculation.

Modification Factor:

The parties will negotiate a further backout modification factor. Each stream's net backout shall be multiplied by the modification factor.

Backout Methodology Alternatives

Several facilities may not have a detailed dynamic plant model to simulate their facility operation. In that case, each facility will have to decide to either develop such a detailed model or devise an alternative method using their existing models to calculate backout. Each of these alternatives has associated costs that would be borne by all parties. Some suggested possibilities are:

- Gather information of shut-in and curtailed wells based on GOR and WOR and determine a theoretical production if these wells were not curtailed. Prorate this number or an adjusted amount to the third parties for barrel delivery after royalty and tax.

- Hire an independent processor to simulate the field once a year and agree on a representative percentage to be applied throughout the year.
- Use a graph of the KRU or PBU satellite situation based on API, WOR and GOR to estimate the backout percentage.
- As long as the pipelines are not at capacity, the State of Alaska could consider implementing a program that takes the backout barrels from royalty barrels or a portion thereof.

Commercial Considerations

Commercial Framework

The concept and practice of facility sharing is not new to the North Slope of Alaska. Development of satellite fields within and adjacent to existing unit production has required unit operators and owners to create agreements allowing for processing of satellite production through existing or expanded facilities. Kuparuk River, Prudhoe Bay, Lisburne, and Endicott production facilities provide for access to satellite production through facility sharing and services agreements. The other North Slope units have not developed such agreements.

The existing facility sharing agreements were not created with non-unit production in mind, but they are de-facto templates for recent negotiations. The joinder agreement (Appendix D) between Winstar and the Kuparuk River Unit is an example of the use of Ballots 255, 255A, and 260 for the Kuparuk River Unit for third-party production.

Existing North Slope Facility Sharing agreements

The North Slope has a number of existing agreements in place for access to processing facilities. The fields that have not entered into infrastructure access agreements are: Alpine, Badami, Milne Point, and Northstar. There are agreements for Kuparuk (Ballots

255, 255A and 260), Endicott, and Prudhoe Bay/Pt Mac/Lisburne. These are summarized below:

Kuparuk

A series of ballots establishing facility access to the Kuparuk Participating Area (KPA) are 255, 255A and 260. These agreements provide for the processing of a third party's satellite fluids (oil, water and gas), as well as access to injection water, electricity and some common drillsite operations. The ballots offer 'modified available capacity access' and do not provide for 'firm capacity access' to the process facilities. This modified available capacity is based on the principle that the best wells will be produced to maximize facilities oil throughput, regardless of ownership. Therefore, assuming the facilities are operating at full utilization, available capacity for any party is a function of their well stream quality. Third parties pay for this facility access based on their satellite's actual utilization of the facilities.

Ballot 255 is the overriding ballot addressing the main principles of the sharing agreement, Ballot 255A is a detailed description of the methodology for the backout calculation, and Ballot 260 provides access to ancillary services. Ballots 255 and 255A are included in the appendix (E and F).

Ballot 255 Summary:

- Satellites pay a capital access fee to compensate KPA owners for investments made to put the process and related facilities in place. This fee is paid on a per-barrel- of-oil basis.
- The Satellites also pay a fee (on a per barrel-of-oil basis) to cover future process facility abandonment costs.
- Satellites pay fees to cover the satellite's proportional share of fluid processing and other common operation costs. These costs are determined yearly and based on actual costs and production from the previous year.

- Satellites compensate the KPA owners for deferred production in the event KPA production is 'backed-out' or restricted by satellite production. Backout is calculated according to the methodology described in Ballot 255A.
- An oil quality adjustment is made to account for the differences in the characteristics of KPA and satellite oil. The quality adjustment is determined monthly and paid in barrels at Pump Station 1. If satellite crude is superior to KPA crude, the satellite receives net barrels from the KPA. If satellite crude is inferior to KPA crude, then the KPA receives net barrels from the satellite.
- Satellite owners must provide sufficient and timely information regarding the Satellite plan of development and operation to enable the unit operator and KPA owners to assess the demands and impacts the satellite may have on KPA equipment, production and future operations.
- Satellite owners may install and operate their own wells and equipment. Satellite owners are responsible for any and all efforts and direct costs associated with satellite construction, permitting, maintenance, operation, taxes, royalty and abandonment.
- The unit operator is responsible for operating all KPA process facilities, pipelines and all wells on KPA drillsites as well as controlling the rate of production into the facilities. Either the unit operator or a sub-operator will be responsible for operating satellite equipment.
- Fluids must be compatible with KPA equipment. Satellite owners are responsible for any costs to bring satellite fluids into compatibility.
- In the event of competing demands for process capacity, the unit operator will strive to maximize total oil production through unit facilities. The best wells will be produced, the worst wells will be shut-in or curtailed, regardless of ownership. In the event that KPA production is deferred by this optimization of total oil production, KPA owners will be kept whole and compensated through the backout provisions.

- Satellite owners may propose KPA capacity expansions to meet their production requirements. The KPA and various satellite owners will pay for such capacity expansions in accordance to their relative benefit.

Ballot 260

Ballot 260 provides access to a wide range of services on an ad-hoc, as available, basis. Some of the key services included in the document are:

- Mobile and non-mobile equipment
- Emergency fire response
- Spill response
- Waste management
- Camp services
- Materials
- Solid oily waste management

Endicott:

Endicott has two facility sharing agreements (FSA) in place for Eider and Sag Delta North satellites and is a receiving entity under the IPA (Initial Participating Area) Ballot Agreement 98-202: Authorizing Use of IPA Equipment and IPA Services. These agreements provide for the development of the satellites using the Endicott facilities to process fluids. The general terms of the FSAs are outlined below and a summary of the IPA Ballot Agreement 98-202 is provided in the Prudhoe Bay Unit (PBU) and Pt. Mac/Lisburne section.

Endicott FSAs Summary:

- Describes scope of satellite operations and equipment needs
- Provides access to Endicott facilities for operations, gathering and treating of production

- Determines the satellite responsible for paying for any facility modifications
- Establishes fees for various services provided
- Establishes equipment access, O&M, abandonment, excess power, and make-up water fees
- Establishes fees for additional processing operations as applicable
- Sets production capacity priority based on competitive WOR/GOR if capacity limited
- Provides backout calculation for production and value adjustment for crude quality differences
- Provides fuel in-kind calculation

PBU and Pt. Mac/Lisburne:

There are three primary categories of facility sharing agreements relating to PBU facilities and services. First, there are a number of agreements that relate to operations of the Lisburne Production Center. Second, there are agreements related to processing PBU satellite production in facilities originally developed to produce the main Prudhoe reservoir ("IPA Facilities") (Ballot 97-196). Third, there is an agreement authorizing third-party sharing of certain equipment and services ("IPA Equipment and Services") (Ballot 98-202). The PBU Owners also have entered into agreements that address the use of specific equipment.

A summary of these categories of agreements follows:

1. Lisburne Production Center Agreements

The Lisburne Production Center (LPC) was developed to process production from the Lisburne Reservoir. In the early 1990s, agreements were developed to address what is called the Greater Pt. McIntyre Area ("GPMA"). These agreements allow the Pt. McIntyre, Niakuk, West Beach and North Prudhoe reservoirs ("Sharing PAs") to be processed through the LPC with Lisburne production, and for sharing between the IPA

Owners and the owners of the participating areas within the GPMA of certain support facilities, electrical power, vertical support members, source water and other facilities and services.

2. Facility Sharing Authorization Agreement (Ballot 97-196)

This agreement provides for the development of a Facility Sharing Agreement (FSA) for each satellite field under which production fluids from that satellite could be processed through the use of IPA Production Equipment. There are currently no FSAs with parties external to the Prudhoe Bay Unit.

Owners of a satellite seeking access to IPA facilities must provide specific information regarding the plans for development and operation of the satellite to enable the IPA owners to evaluate demands and impacts that regular production from the satellite will have on IPA production equipment and services, field development plans, and production levels. This information includes:

(i) The scope and timing of Satellite development, including location of Satellite well pads and facilities, projected number and timing of Satellite wells to be drilled on each well pad, and identification of specific facilities for which access, modification, use or tie-in is proposed;

(ii) Projections of satellite production to be delivered to IPA production equipment, the quantities of "returned" gas (gas lift, fuel or injection) and satellite produced water to be made available by the IPA owners to the satellite, all on a year-to-year basis;

(iii) Description of electrical power, gas, make-up water or other IPA production equipment and services for use by the satellite; and

(iv) Description of the stratigraphic horizon and areal extent for the portion of the satellite reservoir proposed for development with compositional descriptions and producing characteristics (e.g. temperatures and pressures) of the anticipated satellite production.

Based on this information, the IPA owners may enter into an FSA that will specify appropriate terms and conditions including:

i) The specific O&M fee, capital access fee, abandonment fee, backout, and volume adjustment factor (VAF) as well as fees for use of IPA area equipment and IPA services in support of subsurface satellite operations, additional processing operations and satellite drilling and construction activities, and fees for make-up water, additional electrical power or other items.

a) The O&M fee is to reimburse the IPA owners for the satellite's proportionate share of the IPA production equipment and services producing costs for base processing operations.

b) The capital access fee is to reimburse the IPA owners for investment in IPA production equipment.

c) The abandonment fee is to reimburse the IPA owners for a satellite's proportionate share of the estimated future abandonment costs for IPA production equipment accessed by that satellite.

d) Backout is the estimated volume of IPA oil that cannot be produced during a specified time period because of the processing of satellite produced fluids through IPA Production Equipment. The Satellite is responsible for keeping the IPA whole on deferred production by reimbursing the IPA for backout with a volume of satellite production.

e) VAF is a volume adjustment to a satellite's oil volume that reflects, among other things, the differences in physical quality, compositional differences and handling considerations of produced fluids from the IPA and satellites.

(ii) Incorporation of specific terms and conditions which address any issues raised by the information provided above including the commercial terms required for any satellite modification, joint equipment or additional services requested.

(iii) Scope and timing of development (including all satellite modification and joint equipment requirements), range of rates for satellite production and reservoir boundaries for which use of IPA production equipment and services will be allowed.

3. Ballot Agreement Authorizing Use of IPA Equipment and IPA Services (Ballot 98-202)

This agreement authorizes the use of certain IPA area equipment and services (not including oil and gas processing equipment) by other units/participating areas (receiving entities), establishes terms of compensation for use of IPA area equipment and services, and defines the allocation of liability between IPA owners and the receiving entities with respect to the use of IPA equipment and services.

IPA equipment and services under Ballot 98-202 are intended to be for incidental use of receiving entities. Use of IPA area equipment and services for other than incidental use would be subject to a separate agreement negotiated on a case-by-case basis. (Incidental use means use of equipment and services by a receiving entity that is in excess of the IPA owners' needs at the time of such use and that is insubstantial when compared to the IPA owners' use of such equipment or services.)

Equipment and Services include:

A) Mobile & non-mobile equipment
B) Airport shuttle bus services
C) Sewage disposal
D) Production lab
E) Wellhead services
F) Hot water plant
G) West Dock staging area
H) Drum disposal
I) Halon support services
J) Camp services
K) Projects & construction
L) Overhaul & rotating equipment
M) Scheurle trailer
N) Investment recovery
O) Flow measurement
P) Miscellaneous services
Q) Mukluk Pad
R) CTD work platform
S) Security checkpoint

4. Specific Equipment: Grind and Inject Plant Operating Agreement (IPA Ballot 97-201)

This agreement allows authorized parities to use the Grind and Inject Plant to dispose of drilling waste for a fee.

Facility Sharing Analogs

The concept of Facility Sharing is a growing consideration in mature oil and gas basins around the world. Aside from the examples mentioned above on the North Slope, publicly available information pertaining to facility sharing agreements in other countries exists. Understanding these agreements is useful when negotiating future agreements for the North Slope. In general, the guiding principles from both the United Kingdom (U.K.) Code of Practice and Alberta's Jumping Pound formula are aligned with the existing North Slope facility sharing agreements. Both Alberta and the Offshore U.K. have mature oil and gas basins where the facility sharing concept has proven beneficial for operators, third party producers, and the government. Both examples reviewed provide for regulatory interdiction as needed to resolve disputes between negotiating parties, although the UK Code of Practice has not had to rely on the government intervention process to date. Emphasis on a cooperative approach to facility sharing has been successful in negating the need for government interdiction. Both facility sharing approaches outlined below are proven starting points for successful negotiations. Existing agreements between unit partners on the North Slope present the obvious starting point for new facility sharing agreements, and the highly cooperative approach adopted in the United Kingdom sets a good example for expanding these existing agreements to meet the needs of an expanding group of potential producers.

UK Offshore Infrastructure Code of Practice

The United Kingdom's "Indicative Tariff" Code of Practice for offshore oil and gas infrastructure is a cooperative industry document on the rules and procedures governing third party access to these facilities. This document provides a framework for easy, fair and non-discriminatory access to offshore oil and gas facilities. The process is supported by the oil and gas industry. It is not mandated or enforced by a government agency, however if a dispute over access does arise, there is a government body that has the legal authority to settle the differences. The framework for third party facility access is a combination of the Offshore Infrastructure Code of Practice for conducting commercial negotiations and the legal backstop of appealing to the UK Secretary of State for Trade and Industry to settle disputes over access. The real strengths of the system are the adherence to a timeline for the negotiation and the support from all parties to have a practical means of an early understanding of the availability and the approximate costs of bringing and processing hydrocarbons in existing facilities.

The owners maintain an up-to-date database on their offshore infrastructure. When a potential user requests this data, the owner has 10 days to respond with the requested data as well as an indication of the probable tariff. If interested in proceeding, the user formally contacts the owner and provides specifics as to the kind of hydrocarbon composition and specifications, along with the development strategy. Within 30 days, or a mutually agreed-upon timetable, the owner must reply to the prospective user with a detailed technical response to the specifics of the requested facility use. If the request from the user fits with the available access from the owners, the negotiations continue with another 30 day clock. The parties may agree in the process of these final negotiations to substantially change the standard terms they started with. The UK Department of Trade and Industry (DTI) website is a valuable source of information, and the Code of Practice can be found on their website: http://www.og.dti.gov.uk/regulation

The self-maintained database of the infrastructure owners is expected to include the following data:

a. Technical description: Hydrocarbon entry specification, pressure regimes/compressor curves at entry and exit, dehydration regime, process diagrams and other operating conditions;

b. Operational capability including measures of past performance and reliability. Planned changes affecting operational capability should be indicated;

c. Services that can be provided;

d. Indicative price of services;

e. Indicative forecast of available capacity normally for 5 years ahead, but for a longer period for significant infrastructure; and

f. Pertinent general contract terms: lifting procedures, ownership, priorities, system allocation principles, substitution terms, voting rights, etc.

Although this information does not constitute an offer capable of acceptance, it provides to the user the indicative terms, which can be used as a yardstick as negotiations progress toward settlement.

The prospective third-party user is expected to provide the following specific information on the service requested:

a. Production profiles;
b. Compositions;
c. Start-up date;
d. Broad outline of development concept;
e. Hydrocarbon specification (such as H_2S, CO_2, gravity etc).

While this 1996 offshore infrastructure code of practice is a working process for facility owners and potential third party users, it is still an evolving procedure. In 1998, the Petroleum Act was instigated to provide an appeal process for the Secretary of State to settle disputes over access. Further to this, in the spring of 2001, the UK Department of Trade and Industry responded to allegations that access to infrastructure was still a commercial barrier to oil and gas development with a study on the effectiveness of the voluntary Infrastructure Code. The results of the study found that although it is not necessary to replace or update the existing code, it is imperative to continue to check on its effectiveness at least every three years. At this time, even though the code is not a perfect system, it is still supported by the industry. Clearly this voluntary arrangement, in combination with a legal backstop for the governing body to step in to provide a means to settle disputes over access, is recognized as crucial for their continued offshore oil and gas development. Currently, Work Groups formed by the DTI are preparing a proposal to amend the Infrastructure Code of Practice with the key changes being:

- Allowing for the Secretary of State to become automatically involved in an infrastructure access request if insufficient progress is being made after a certain period (to be determined) and allowing the Secretary to set a tariff.
- Allowing for the provision of more information and transparency.

It is expected that this proposal will be published in May 2004.

There are no published examples of how the Code of Practice has worked, as these negotiations for infrastructure terms are confidential. Per the Code, indicative tariff offers are reported to the DTI, which are then published.

The Secretary of State, to date, has not been asked to formally intervene to set tariffs or enforce access. Operators have preferred to work out agreements among themselves rather than taking the risk of government intervention using methodology that is not clearly defined. The Secretary's office has participated informally in cases to move negotiations along when companies complain.

Alberta's Facility Sharing Agreement, the Jumping Pound Formula

Alberta Canada also has an industry-agreed-upon voluntary guideline for calculating oil and gas processing tariff ranges. The access to infrastructure is agreed to be an open and non-discriminatory access, in facilities where capacity is available. The Jumping Pound methodology is based on an industry-derived formula. The formula was developed for a case decided by Canada's National Energy Board (NEB) for the processing tariff charged at a gas processing plant at Jumping Pound in 1990.

The Alberta Jumping Pound Formula (JP 90/ 95) was developed jointly by a number of industry organizations as a guideline for parties to use in negotiating fair and reasonable fees on an everyday basis and to assist in dispute resolution. The Alberta Energy and Utilities Board (EUB) supported the initiative but did not play a major role in the development of the actual formula. The formula was developed to determine the components which form any tariff rate for oil and gas processing at plants, e.g. rate of return, rate base and range, operating costs, plant capacity, and special fee considerations. The two documents describing the JP 90/95 formula are *Gas Processing Fee, Jumping Pound 1990 (Jp-90), January 1990*, and *Joint Industry Task Force Report On Processing Fees JP-95, April 15, 1996*, which have some general examples of cases.

The calculation for the fee establishing the calculated return on the capital investment for the Jumping Pound Formula uses the original cost of the facilities as the Capital Base, depreciated in a straight line over the life of the project (normally set at 20 years). A return on capital is established as 15% before tax rate of return on the capital, and is allocated among the owners of the facility as a capital allowance. Based on these costs, the fee for the facility access is prorated per total throughput. Additionally, there is a component of the formula that accounts for the sharing of the operating costs of the facility. This component is generally also prorated on a production basis.

Although the formula is used voluntarily by the industry as a starting place for negotiations on facility access, the key to Alberta's facility sharing practice is the regulatory board's legal power to ensure a third party gains access to infrastructure.

Where disputes on processing fees cannot be resolved on a voluntary basis, there is provision in the Alberta Oil and Gas Conservation Act (OGCA) for a party to apply to the EUB to set the fees. When the EUB has receives an application and determines that it is complete, a public hearing is scheduled to consider the application. The EUB has stated that, if application is made to the EUB to set processing fees, it will use the Jumping Pound Formula, unless there were compelling opposing reasons. The EUB gets very few applications requesting the setting of processing or transportation fees (one or two a year, typically), and has not yet set any such fees. All applications requesting fee-setting were withdrawn while the applications were being processed. The EUB encourages parties to continue negotiations or mediations in parallel with filing an application with the EUB. Typically once a EUB hearing date is set these negotiations or mediations result in resolution as the opposing party often does not want to be drawn into the regulatory arena through the public hearing process. Although the EUB has not yet set any fees, it remains prepared to do so.

The Alberta law dealing with third party access is set out in Part 9 of the OGCA. Disputes on access may result from a number of issues - volumes, delivery points, fees, drainage issues. The application requirements are set out in EUB Guide 65. (The OGCA and Guide 65 are available on the EUB web site www.eub.gov.ab.ca.) If the EUB approves an application, access is granted by means of an order which declares a party to be a common carrier (access to a pipeline), common processor (access to a gas processing plant), or common purchaser (access to market). An order can simply be a declaration; for example, Company XYZ is a common processor of gas from the Pipestone Viking F Pool. Additional direction can also be included to give effect to the order; for example, the order can allocate production among producers in a pool (a usual provision), specify the delivery point, or set out the fees. Usually an order does not deal with all of these issues; the nature of the dispute that resulted in the application being filed with the EUB determines which issues are addressed. When a party is declared to be a common carrier, processor, or purchaser the OGCA requires it to treat parties without discrimination within the limitations of the order (within a pool, typically).

The EUB has no data to know how widely JP90/95 is used as a benchmark, as the vast majority of companies who want capacity in facilities they do not own (whether processing plants or pipelines) are able to privately negotiate satisfactory voluntary arrangements, and the matter does not come before the EUB. There is no requirement to file contracts that result from these negotiations.

Independent Oil Companies' Perspectives

PRA surveyed 15 independent oil companies currently interested in Alaska oil and gas exploration to get their perspective on facility access and to identify their needs in creating a template for negotiating access. Five of the companies contacted responded to the survey, and others provided feedback through informal discussions, including open discussions during a meeting of independent oil companies hosted by Alaska Governor Frank Murkowski in Juneau in December of 2003.

The questions asked of these companies are listed in Appendix A.

The key areas identified as concerns and issues are:

- Backout calculations;
- Capital access fee methodology;
- Timing of negotiations;
- Insurance requirements;
- Operatorship;
- Trust and access to supporting information.

Summary of Independent Company Concerns:

Backout calculations

The term “backout fluid” describes the volume of oil currently going through the facility that will be deferred due to the limitations of the facilities if third party fluids are processed. Several concerns were cited regarding backout calculations, which range from companies not wanting to pay backout costs at all, to a desire to see every detail regarding the calculation of backout. The calculation is complicated, and is seen as a “black-box”, with no supporting information available. The possible range of backout costs is seen as very broad, and actual calculations are not accessible to third-party producers.

Capital access fee methodology

This fee, associated with the capital cost of building and maintaining the existing facilities is perceived again as a potential show-stopper to those seeking facility access. The various methods available for calculating this fee can result in widely varying output, and it is seen as a possible means for the facility owners to profit unfairly on third-party production.

Timing of negotiations

Third-party producers have a need to run screening economics before investing in exploration and development projects, and accessing the necessary cost information for access to existing facilities currently takes too long. The first case in which third-party access was negotiated took nearly three years to complete an agreement.

Insurance requirements

An important issue to address, regardless of facility access needs, is insurance. Current producers will require newcomers to secure insurance for any North Slope project they pursue, whether self-operated or operated by a current producer. The current producers’ motivation is to avoid any and all liability for any catastrophic loss that might occur during the operations – whether the loss involved a safety, environmental, or capital issue. This concern is reasonable provided that the required amount of insurance should is reasonable. Studies should be undertaken to determine risk levels and appropriate insurance requirements. New producers should be informed and resolve the issue of insurance early in the process to avoid unnecessarily exorbitant costs.

Operatorship issues and constraints

Another consideration prospective new producers on the North Slope face is whether to operate their own production. The current North Slope producers have expressed a willingness to entertain fee-based operatorship for new producers. Some of the prospective new producers like this option, but others have expressed a strong desire to operate their own production. These tend to be the producers with significant cold-weather experience elsewhere in the world. They feel confident that they can utilize their experience to reduce North Slope costs. Whether or not this is true is yet to be shown, but the potential to introduce cost-saving ideas to the North Slope has promise not just for the new producers but for the existing ones as well.

Trust and access to supporting documentation

Most of the parties are coming into the North Slope with no prior experience on the North Slope, therefore the expense and operations are unknown. The lack of documentation from the operators on the capital access fees and the "black box" calculations associated with backout contribute to their suspicions and mistrust. Additionally, there is a concern that the small independent companies will not receive the same access to and costs of facility sharing that major third party companies receive.

Recommendations

BP, ConocoPhillips and ExxonMobil historically have been major participants in the development of oil resources on the North Slope of Alaska. All were leaders in building the Trans Alaska Pipeline System. Today, they are three of the largest interest owners on the North Slope, and BP and ConocoPhillips are the largest operators.

The environment for finding, developing and producing oil and gas is challenging and complex, in Alaska and the world. The giant Prudhoe Bay and Kuparuk fields are in decline. World energy markets continue to experience price volatility, competition for capital and opportunities, and financial and technical challenges to discover, develop and produce new fields.

The State of Alaska is committed to maintaining and enhancing competition, diversity and balance in the exploration, development and production of North Slope resources, sustaining and growing both oil and gas production, and ensuring that the State's natural resources are developed in an environmentally and socially sensitive and responsible manner. The operators recognize that a business opportunity exists for establishing a formal agreement with fair terms for processing third party production volumes in existing infrastructure.

In the State's view, expressed in the CHARTER FOR DEVELOPMENT of the Alaskan North Slope, the Commissioner of Natural Resources possesses the statutory, regulatory and contractual authority to require working interest owners to provide other producers access to production and other facilities, on terms that are non-discriminatory, just and reasonable. Under the Charter for Development, the Commissioner may require access whenever necessary to

1. maximize the economic and physical recovery of the State's oil or gas resources,
2. maximize competition among parties seeking to explore and develop the resources,
3. minimize the adverse effects of exploration, development, production and transportation activity,
4. or otherwise to protect the best interests of the State.

Also, as stated in the CHARTER FOR DEVELOPMENT of the Alaskan North Slope, BP and ConocoPhillips take no position on the State's view. BP and ConocoPhillips commit that they will not unreasonably withhold their voting support as facilities owners for allowing nearby satellites to have access to existing unit facilities on reasonable commercial terms.

Recent history indicates that the owners and operators are willing to negotiate access.

PRA compliments the commitments stated above and makes the following recommendations:

1. Nearly all of the existing facilities have the potential for developing or a precedent for facility sharing agreements. The Independent producers should expect to be able to negotiate an acceptable agreement. The negotiations should be initiated by independent producers as early as possible.

2. The largest obstacle to successful negotiations is a lack of trust. Development and communication of a process for third-party facility access which is fair and transparent will help to resolve this lack of trust, and create opportunity for expanded resource development.

3. The Independents need to provide operators with a well thought out development plan with as many crude characteristics as possible.

4. The most critical technical issue is the calculation of the backout volumes. The operators need to communicate the backout methodology and be able to respond to requests in a timely manner.

5. The Independents need to recognize backout is a valid concept, representing real lost or deferred barrels to the facility owners.

6. Both parties need to be ready to compromise on the backout methodology to simplify the calculations for fields without a detailed dynamic plant model.

7. The State of Alaska has shown interest in investigating methods to defray the backout impacts to the Independent producers, and this should be continued.

8. Significant positive progress has been made through the compilation of this report, and further investigation and communication should be energetically pursued to assure continuation of this progress.

Appendix A

North Slope Facility Access Questionnaire

Where are you looking for access (i.e., southeast of Prudhoe Bay, northwest of Kuparuk)?

Will operatorship be an issue? In other words, how important is it that you operate – or not operate – your own exploration or production?

In addition to forecasts of capacity and cost at various facilities, what information do you need from operators?

Are you familiar with ballots 255 and 260A?
What are your impressions of these ballots as an acceptable platform for determining access to North Slope facilities?

Based on your experiences in other basins, what advice would you give Alaskan operators and regulators in determining facilities access on the North Slope?

If left to you, what would the North Slope facility access provisions look like?

If you were Conoco-Phillips or BP, what would your access provisions look like?

What experiences and insights might you offer to the State and the current North Slope operators to assist in cost management, both for developing new fields and for operating existing fields on the Slope?

What have we not asked that you think is important to tell us?

Appendix B

Information Request for BP Operated Fields:

- What are the maximum capacities, current and forecast throughput of oil, water and gas, and constraints on production facilities, from transportation pipeline to drill site level?
  - Are there any “quick wins” to increase available capacity?
- What are the opportunities and constraints associated with input oil quality?
  - What are the input specification requirements for the processing plants?
  - How leveraging is oil quality on processing costs?
- What agreements are currently in place which would impact facilities access?
  - Could you provide a summary description and/or copies of these agreements?
- If you were to design a template to offer facilities access, what would be the key components?
- How would you rank potential access opportunities for the BP operated fields?
  - Milne Pt. -- North Star
  - Badami -- Prudhoe Bay
  - Endicott -- Lisburne/Pt.McIntyre/Niakuk

Information Request for CPAI Operated Fields

- What are the maximum capacities, current and forecast throughput of oil, water and gas, and constraints on production facilities, from transportation pipeline to drill site level?
  - Are there any “quick wins” to increase available capacity?
- What are the opportunities and constraints associated with input oil quality?
  - What are the input specification requirements for the processing plants?
  - How leveraging is oil quality on processing and transportation costs?
- What agreements are currently in place which would impact facilities access?
  - Could you provide a summary description and/or copies of these agreements?
- If you were to design a template to offer facilities access, what would be the key components?
- How would you rank potential access opportunities for the ConocoPhillips operated fields?

Appendix C

Operator Facility Sharing Contacts

ConocoPhillips Alaska Inc.

Jim Ruud: 907-263-4933 Manager Land- Alaska

John Cookson: 907-265-6547. Engineering Advisor - Greater Kuparuk Area

Dan Kruse 907-265-1315 Manager - Subsurface GPA

John Whitehead: 907-265-6513 Vice President Western North Slope

Darren Jones: 907-263-4431 Vice President Greater Kuparuk Area

Meg Yeage: 907 263-3710 Vice President Greater Prudhoe Bay Area

http://www.conocophillipsalaska.com/facilityaccess/

BP Exploration (Alaska) Inc.

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Appendix D

Joinder Agreement

Appendix E

KRU Ballot 255

Appendix F

KRU Ballot 255A