2/03/12 PRESENTATION: NORTH SLOPE FACILITIES, CAPACITIES, AND EXPANSION TECHNOLOGIES

<TARGET><BILL></BILL><SUBJECT>2-03-12 PRESENTATION NORTH SLOPE FACILITIES, CAPACITIES, AND EXPANSION TECHNOLOGIES</SUBJECT><COMM>SRES27</COMM></TARGET>

library

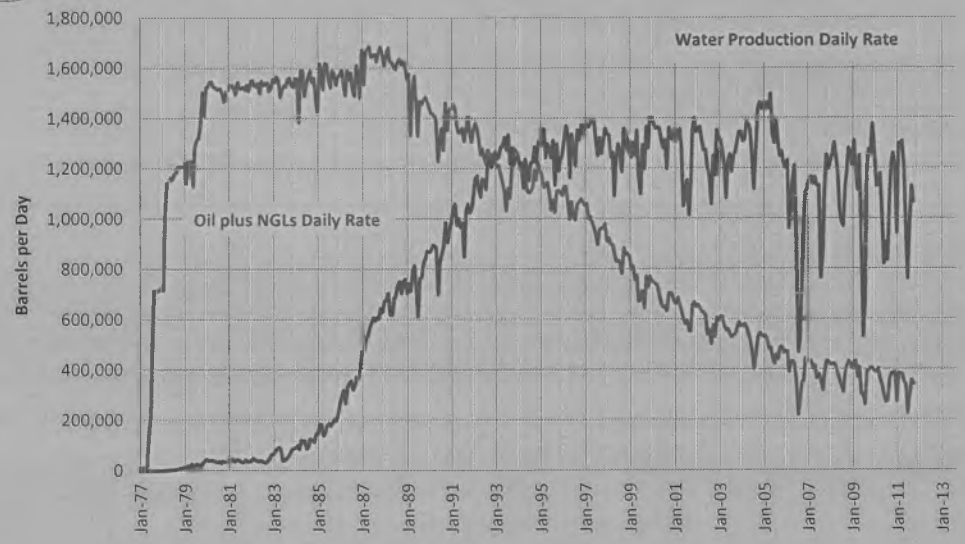
Senate Resources Committee
3 February 2012

William C. Barron
Director
Division of Oil and Gas

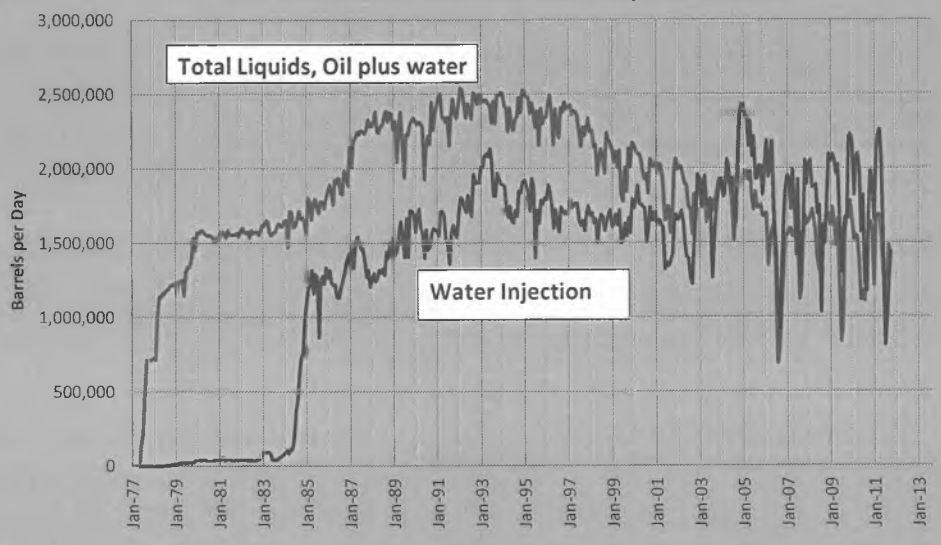
Overview

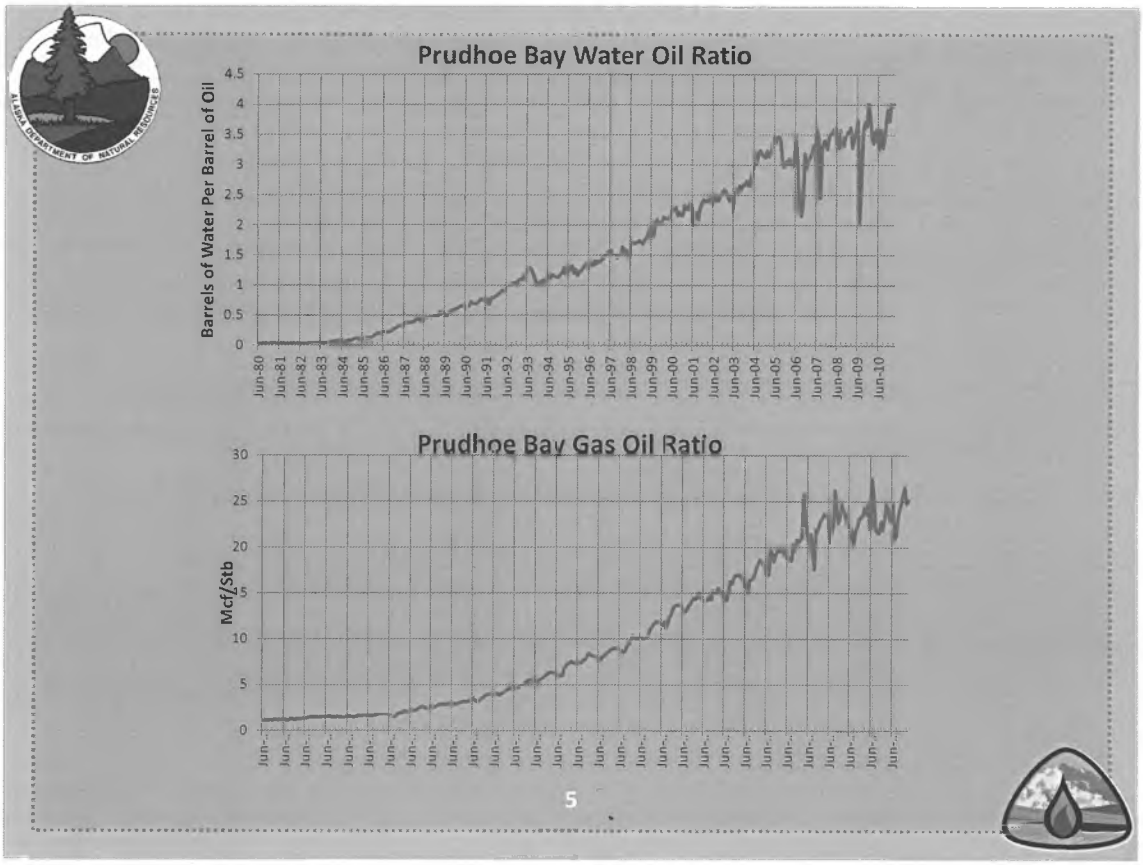
- Update North Slope Facilities Expansion
- New Technologies
- Appendix

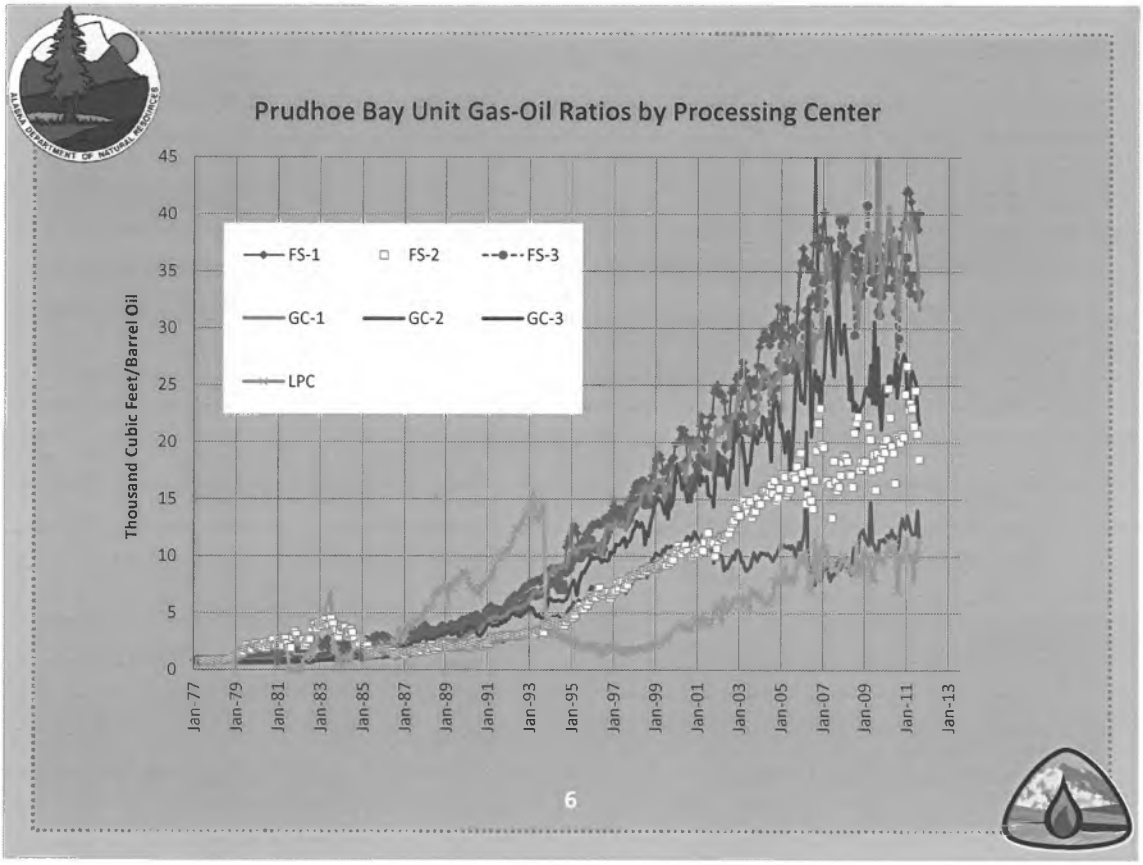
Prudhoe Bay Unit, Oil and Water Production Rates



Prudhoe Bay Unit,
Total Fluid Production and Water Injection Rates

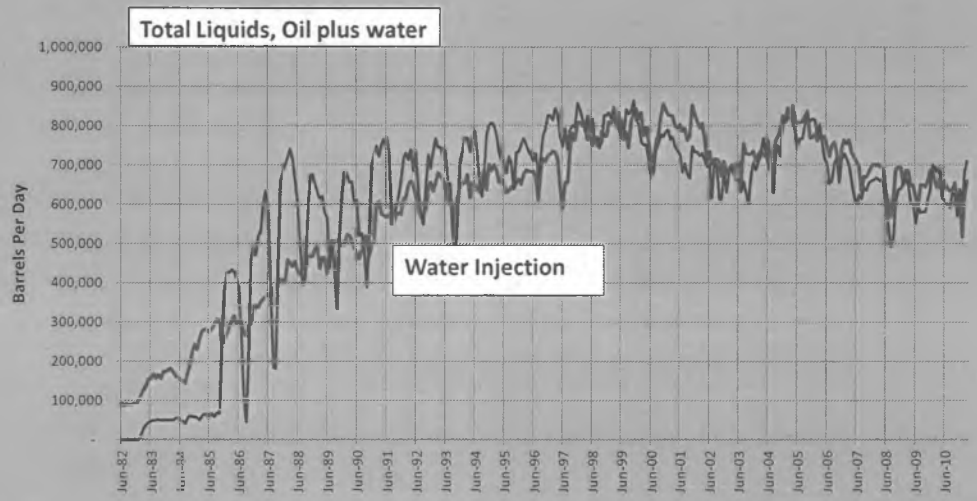



Prudhoe Bay Water Oil Ratio
Barrels of Water Per Barrel of Oil
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Jun-92
Jun-93
Jun-94
Jun-95
Jun-96
Jun-97
Jun-98
Jun-99
Jun-00
Jun-01
Jun-02
Jun-03
Jun-04
Jun-05
Jun-06
Jun-07
Jun-08
Jun-09
Jun-10
Prudhoe Bay Gas Oil Ratio
Mcf/Stb
0
5
10
15
20
25
30
5

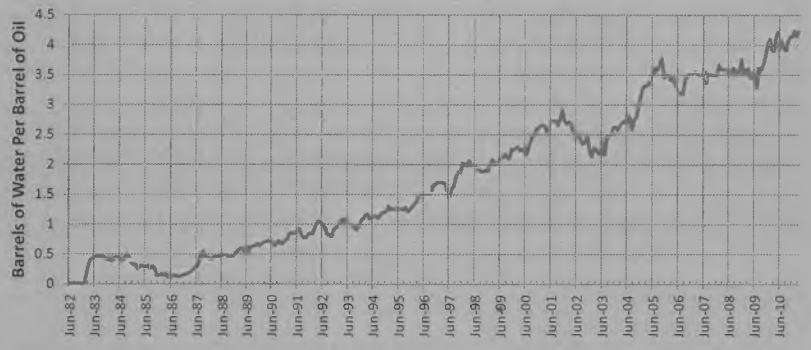

Prudhoe Bay Unit Gas-Oil Ratios by Processing Center
Thousand Cubic Feet/Barrel Oil
0
5
10
15
20
25
30
35
40
45
FS-1
FS-2
FS-3
GC-1
GC-2
GC-3
LPC
Jan-77
Jan-79
Jan-81
Jan-83
Jan-85
Jan-87
Jan-89
Jan-91
Jan-93
Jan-95
Jan-97
Jan-99
Jan-01
Jan-03
Jan-05
Jan-07
Jan-09
Jan-11
Jan-13
6

Kuparuk River, Oil and Water Production Rates

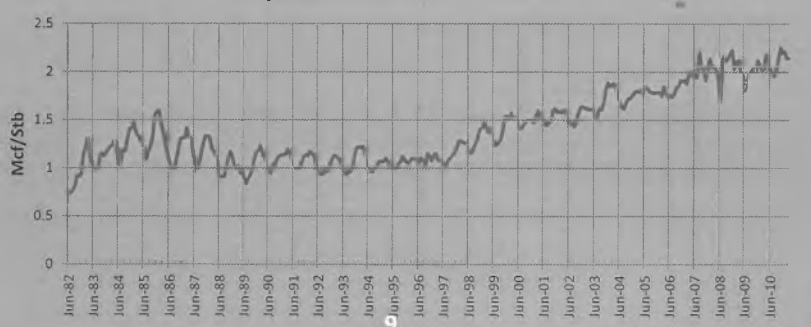
Kuparuk River,
Total Fluid Production and Water Injection Rates



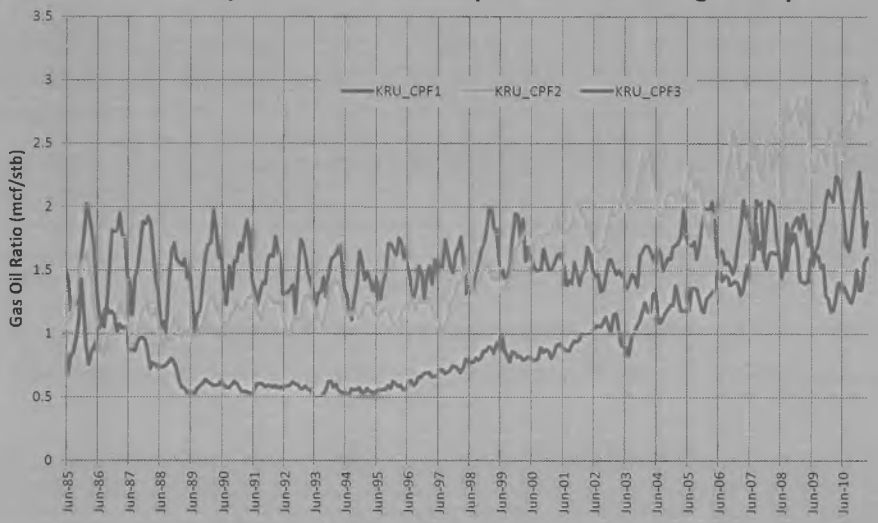
Kuparuk River Water Oil Ratio



Kuparuk River Gas Oil Ratio



Kuparuk Gas Oil Ratio by Central Processing Facility



- GOR behavior by facility indicates that CPF2 could have the largest issue with gas constraints if oil production were to increase

Capacity of North Slope Facilities

Unit	Facility startup date	Oil and NGLs, Standard barrels Per day (stb/d)	Gas, million standard cubic feet per day (mmscfd)	Water (bwpd)	Water injection (bwpd)	Handling limitations & comments
Badami	1998	35,000	25	12,000	30,000	No limits
CoMille River	2000, exp 2004,2005	140,000	180	100,000	140,000	We know of no limits
Endicott	1986	115,000	455	225,000	245,000	Limited gas & water
KU						
CPF-1	1981	170,000	200	250,000	250,000	
CPF-2	1983	160,000	260	250,000	300,000	
CPF-3	1985	85,000	150	100,000	220,000	
Milne Point	1983	75,000	42	99,000		None known for current development
Northstar	2001	77,000	555	30,000		Limited by gas handling, water production is not at limit. Uncertain whether rated capacity is current
PBU						
FS-1	1977	360,000	2,800	140,000		
FS-2	1977	360,000	1,200	650,000		
FS-2	1979	360,000	1,300	300,000		
GC-1	1977	330,000	2,600	180,000		
GC-2	1977	250,000	1,070	300,000		
GC-3	1978		1,100	275,000		
CGF	1977 , exp 1986, 1990, 1994		8,700			
CCP	6/1977, exp 1986, 1990, 1994		7,700			
LPC Greater Pt. McIntyre	12/1986	205,000	450	120,000		Limited gas, water, and total fluid. Some wells from Pt. McIntyre flow into GC1
Oooguruk	2008					Production to Kuparuk CPF-3. No known handling limits at **Oooguruk**
Nikaitchuq	2011	40,000	Unknown	120,000		No limits at this time

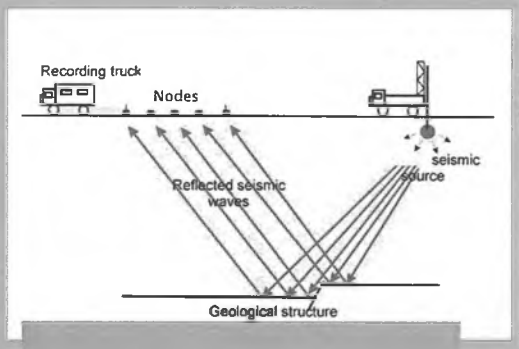
New Technologies

- Nodal technology
- Heavy Oil – CHOPS
- Gas Cap Water Injection

Nodal Technology

State of the Art Technology

- Recording Impact is Minimized:
  - Size and weight is up to 9X less
  - No cables on land minimizing impact to vegetation and wildlife = Footprint minimized
  - Time in area of operation is reduced
- Autonomous: There is no communication between any of the components.
- Cable-Free Operation: Each unit is 100 percent free of external cables/wireless.
- Reliability: The absence of any external cables provides the units with extraordinary field reliability.
- Continuous Recording: Each node begins acquiring data, recording continuously and locally storing the data onto internal FLASH memory until retrieved.
- Self Contained: Each unit contains all of the elements and technologies needed to sense, acquire, digitize, filter and store the seismic data.



Operation:
The sound waves that are generated are sent deep into the subsurface. When they reflect back to the surface, they are captured by geophones and recorded by a computer.

An image of the subsurface, called a seismic profile, is created. This profile allows geologists to predict where oil and natural gas deposits may be located. An **"Ultra-sound"** of the earth is created.

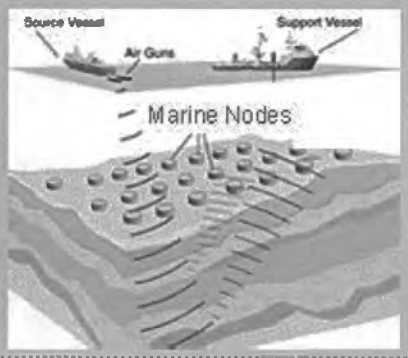
Deploying land nodes

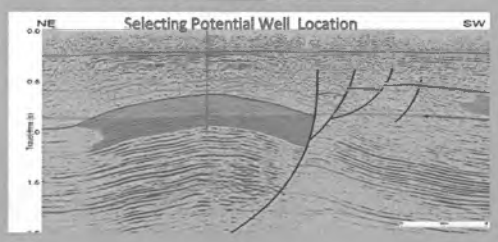
Apache Cook Inlet November 2011

- Marine (Wireless) Nodes deployed in the Cook Inlet from vessels made and rigged in Alaska....and manned by Alaskan crews.
- The nodes are tethered to each other with rope and retrieved within 15 days.
- The nodes are rated to 700 meters of water depth.
- Minimizes Tidal influence
- Nodes Rest on the Seabed providing higher quality data
- Sound waves are produced using compressed air
- Multi vessel acquisition permits a larger "acquisition area" in a shorter period of time

Deploying and Retrieving nodes (data)

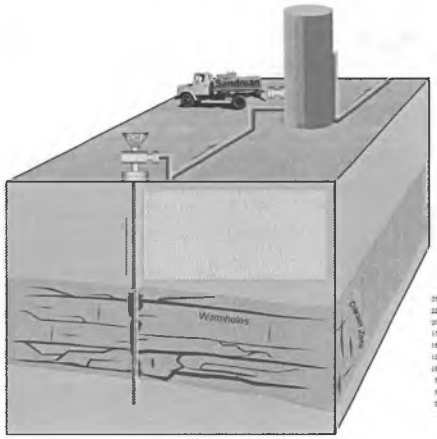
Downloading seismic information and recharging



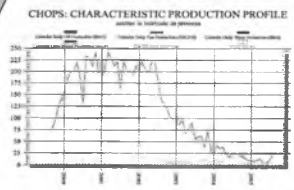


Cold Heavy Oil Production with Sand

CHOPS Elements



- Unconsolidated rocks
- PCP Pump
- Surface Drive
- Heated Separation Tank
- Sand Disposal

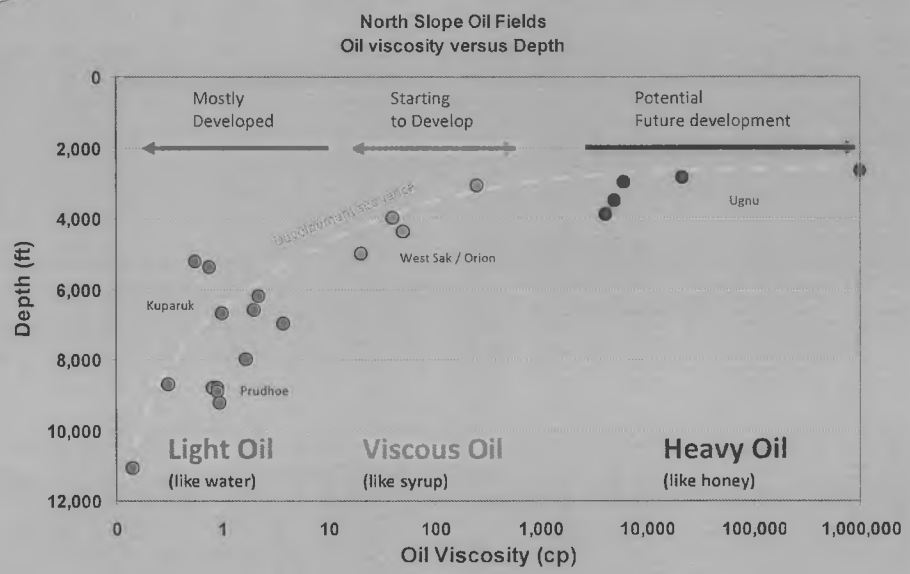


RENEWAL

Courtesy of BP

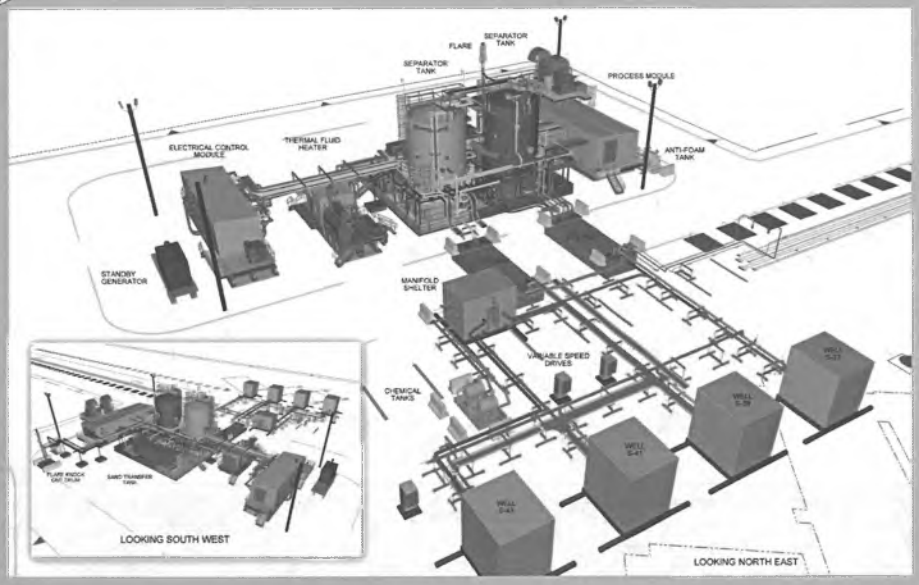
Alaska Fluid Viscosity

Alaska fluids range over a continuum of viscosities



Courtesy of BP

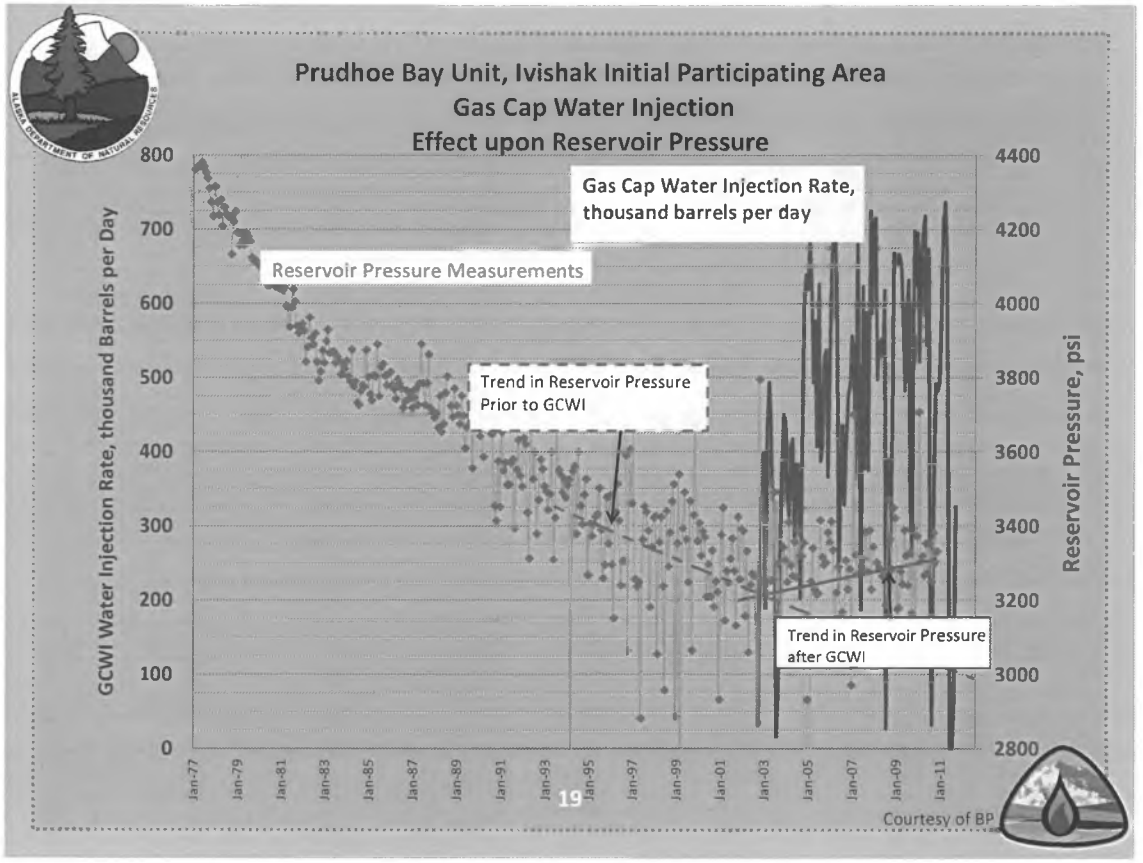
Milne Point S-Pad Heavy Oil Facility

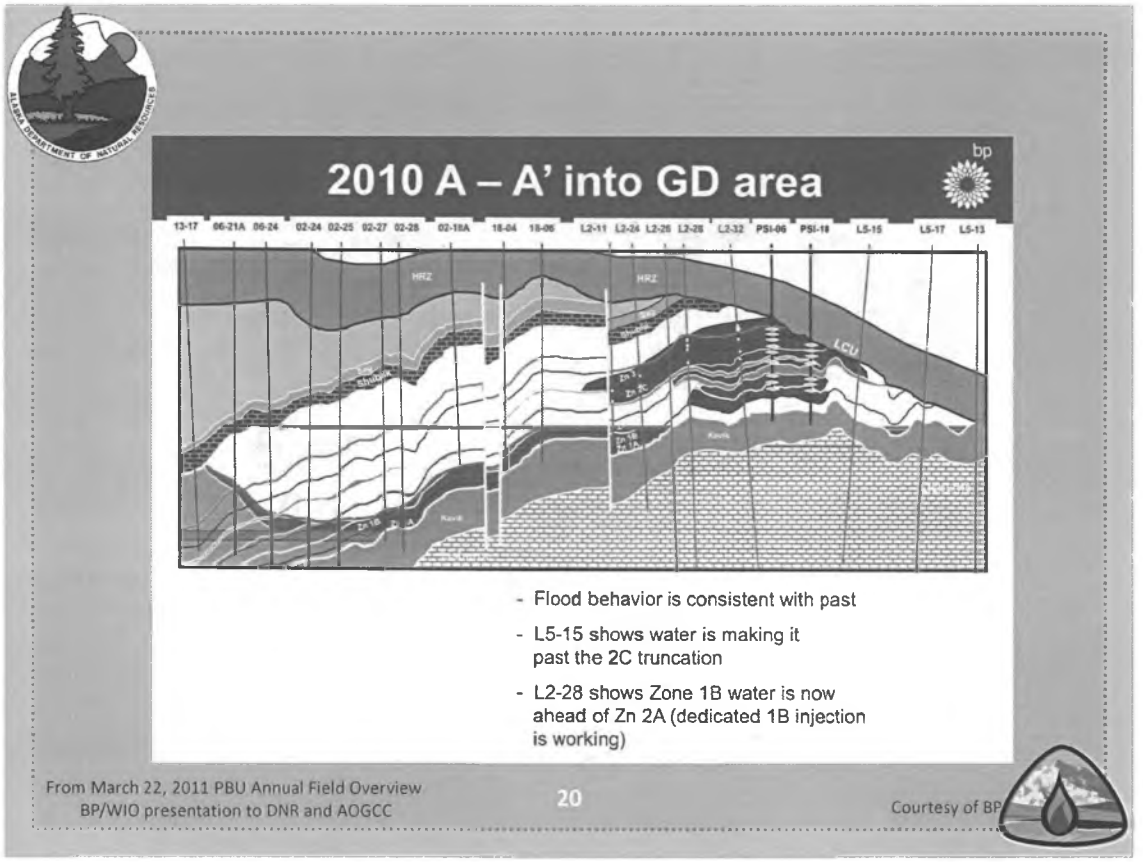


Courtesy of BP

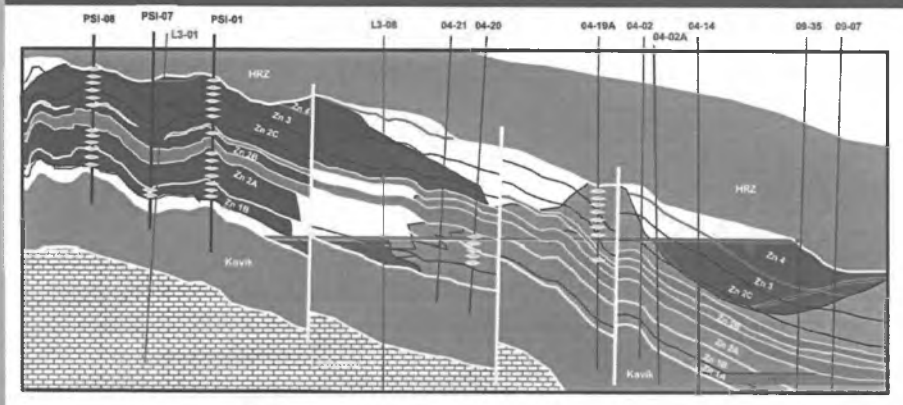
Prudhoe Bay Unit, Ivishak Reservoir Gas Cap (GCWI)

- Water Injection into the gas cap of the Ivishak reservoir was begun in late 2002 to maintain reservoir pressure and increase oil reserves.
- In 2001, the Prudhoe Bay Unit Working Interest Owners (WIO) testified to AOGCC that approximately 200 million Barrels additional recovery would result from the project.
- Average pressure decline was approximately 25-35 psi per year before GCWI.
- Since the start of GCWI, the reservoir pressure has increased by approximately 100 psi (approximate increase of 12 psi per year).


Prudhoe Bay Unit, Ivishak Initial Participating Area
Gas Cap Water Injection
Effect upon Reservoir Pressure
GCWI Water Injection Rate, thousand Barrels per Day
Reservoir Pressure, psi
Gas Cap Water Injection Rate, thousand barrels per day
Reservoir Pressure Measurements
Trend in Reservoir Pressure Prior to GCWI
Trend in Reservoir Pressure after GCWI
800
700
600
500
400
300
200
100
0
4400
4200
4000
3800
3600
3400
3200
3000
2800
Jan-77
Jan-79
Jan-81
Jan-83
Jan-85
Jan-87
Jan-89
Jan-91
Jan-93
Jan-95
Jan-97
Jan-99
Jan-01
Jan-03
Jan-05
Jan-07
Jan-09
Jan-11
19
Courtesy of BP


2010 A – A' into GD area
bp
13-17
06-21A
09-24
02-24
02-25
02-27
02-28
02-19A
18-04
18-06
L2-11
L2-24
L2-26
L2-28
L2-32
PSI-06
PSI-19
L5-15
L5-17
L5-13
HRZ
HRZ
LCU
Kavik
Kavik
- Flood behavior is consistent with past
- L5-15 shows water is making it past the 2C truncation
- L2-28 shows Zone 1B water is now ahead of Zn 2A (dedicated 1B injection is working)
From March 22, 2011 PBU Annual Field Overview
BP/WIO presentation to DNR and AOGCC
20
Courtesy of BP

2010 B – B' into FS2 area



- Flood behavior is consistent with past
- GCWI is extending to FS2 waterflood

From March 22, 2011 PBU Annual Field Overview
BP/WIO presentation to DNR and AOGCC

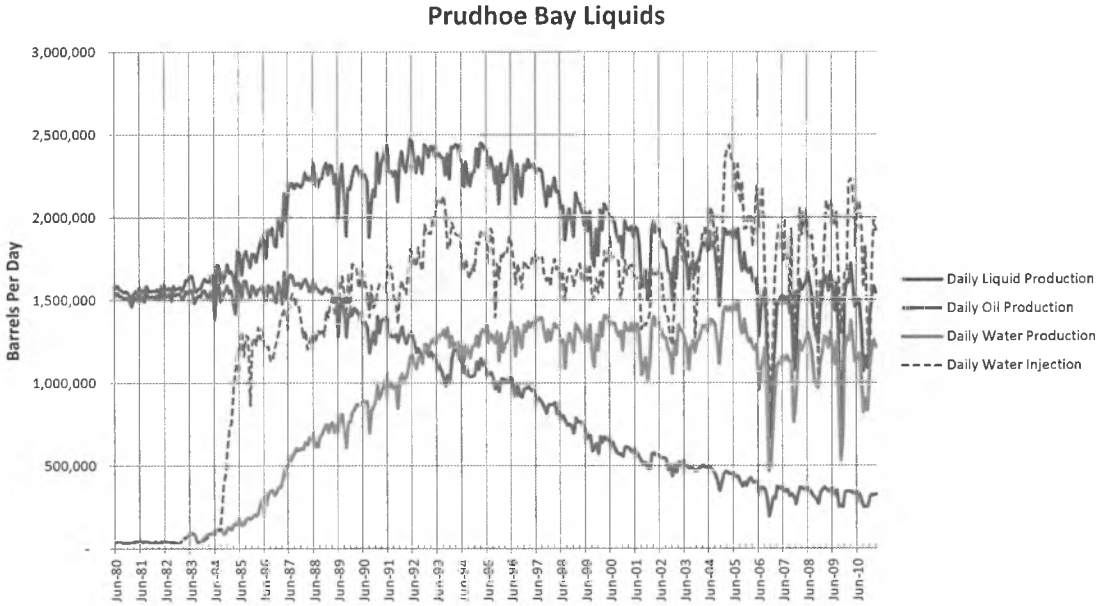
21

Courtesy of BP

Appendix

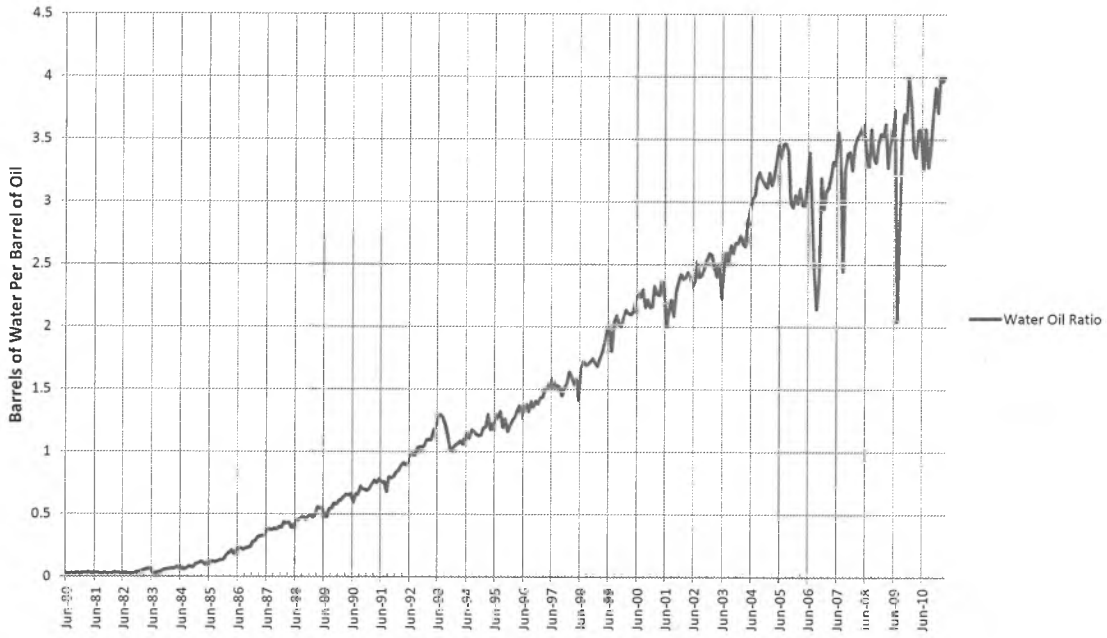
- Annotated slides of Prudhoe Bay and Kuparuk River units production history data relevant to expansion of gas processing and water handling facilities.

Prudhoe Bay Unit



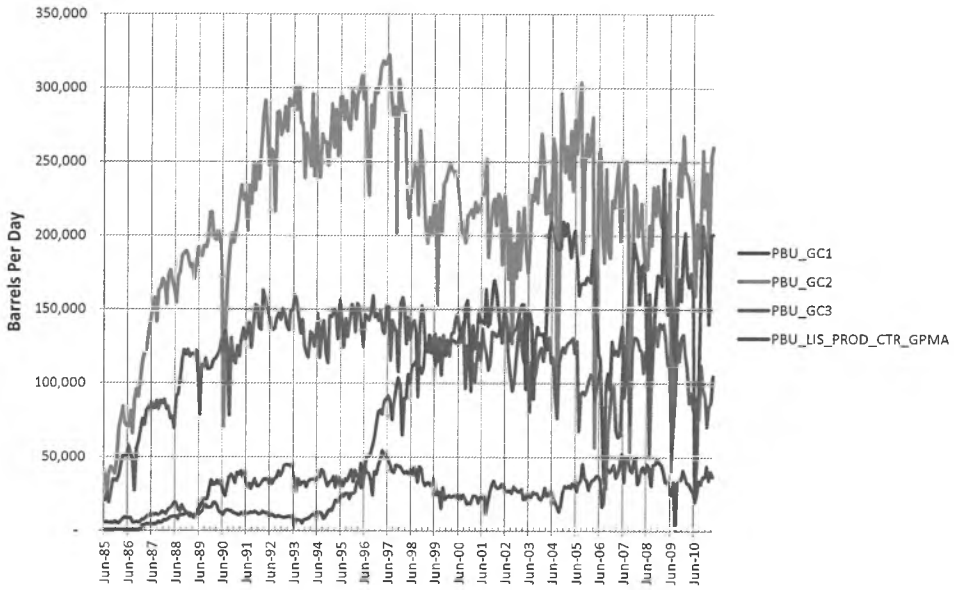
- Liquid throughput has declined considerably since the mid 90's due to oil rate decline
- Lisburne, Pt. McIntyre, Niakuk production into LPC began in 1997, increasing oil rates and water handling capacity.
- Western Satellite development after 1999 helped stem Prudhoe decline.
- Gas cap water injection began in '02, considerably increasing utilization of seawater injection capacity, and helped to stem decline with stabilized reservoir pressures

Prudhoe Bay Water Oil Ratio



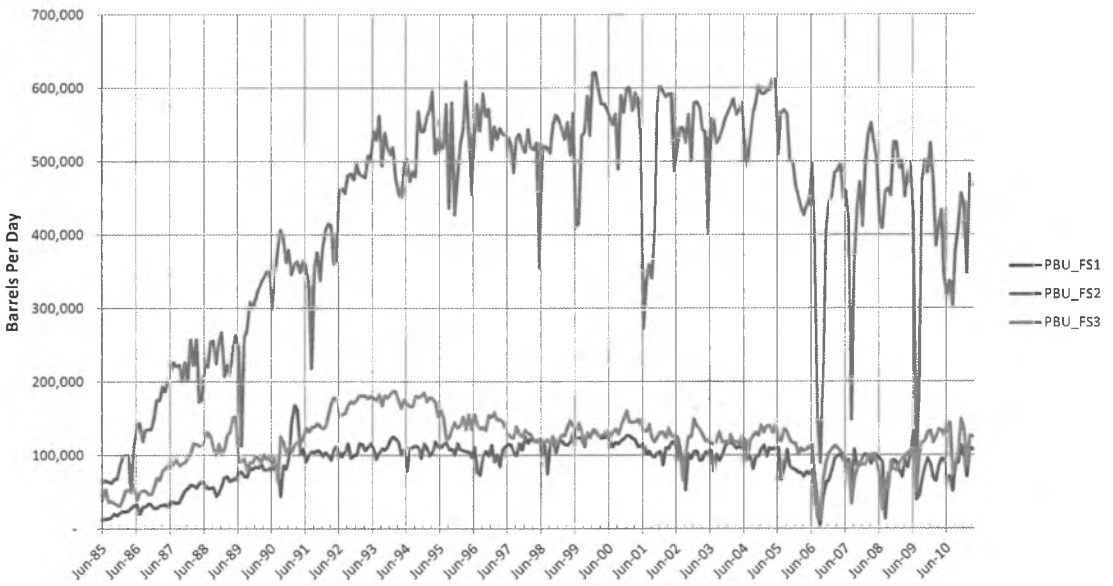
- The water oil ratio has reached 4:1 at Prudhoe with continued waterflood maturity.

Prudhoe Water Production by Gathering Center and LPC



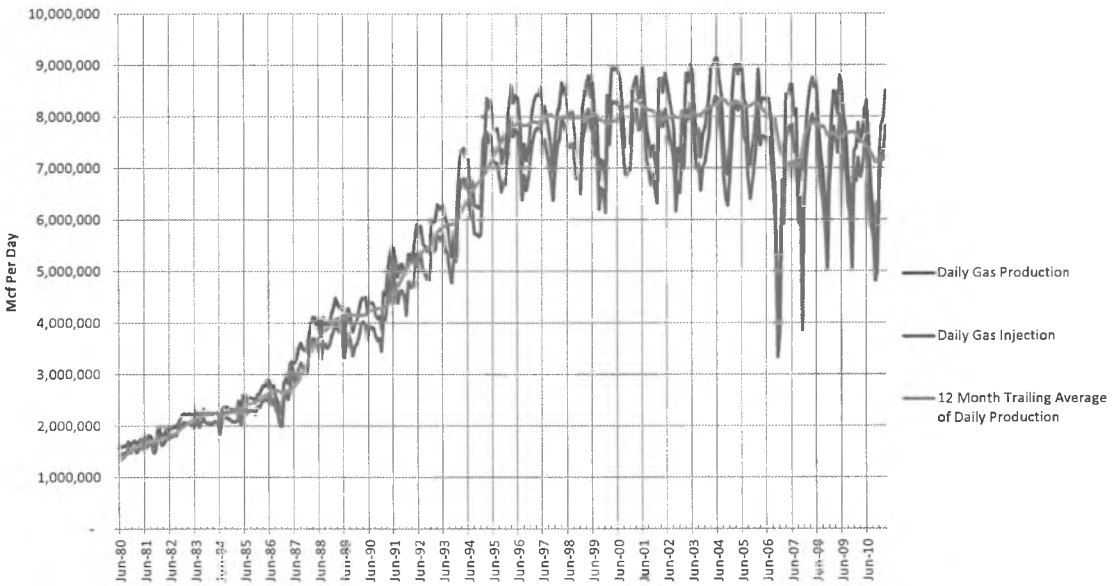
- GC1 is nearer the gas cap and has less waterflood injection, so water production is lower.
- Expansion in water injection pumping capacity at LPC in 2004.

Prudhoe Water Production by Flow Station



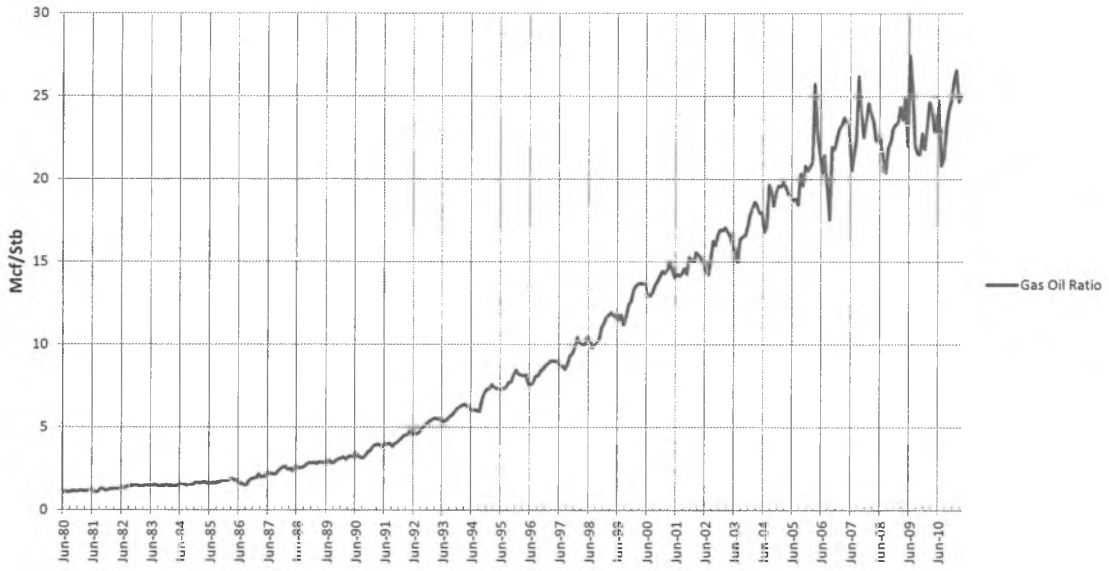
- Flow Station 2 is largely a waterflood area reflected in the higher water production rates

Prudhoe Bay Gas



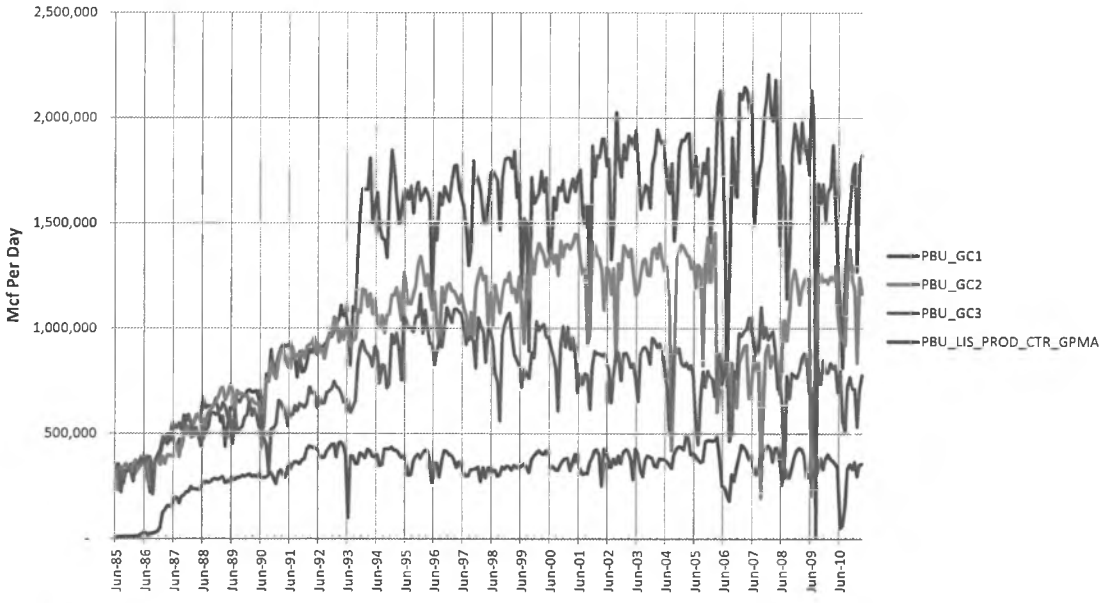
- Gas Handling Expansion – Greater Prudhoe Bay
  - CGF 1987 - Gas handling increased from +/- 4.2 BCFD from +/- 2.7 BCFD. NGL processing allows for sales into TAPS and use in miscible gas injection.
  - GHX1 1990 - gas handling increased from +/- 4.2 BCFD from +/- 5.7 BCFD
  - GHX2 1995 – gas handling increased from +/-5.7 BCFD to +/- 8.0 BCFD
- Total Prudhoe Bay gas throughput has fallen in recent years. 2006-2007 reduction due to 2006 corrosion and shutdown issues. The reductions after 2008 may be due to increased shut-downs for repair and line replacement after the 2006 shut-down.

Prudhoe Bay Gas Oil Ratio



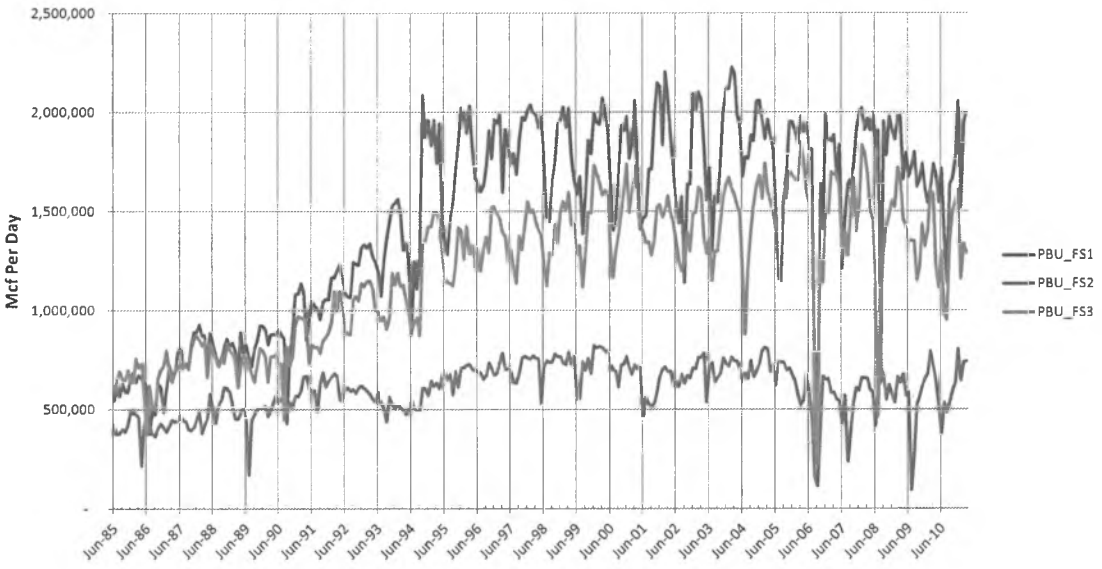
- Average GOR is approaching 25,000 cubic feet per barrel, but this ranges widely among different parts of the field, even more so among individual wells.

Prudhoe Gas Production by Gathering Center and LPC



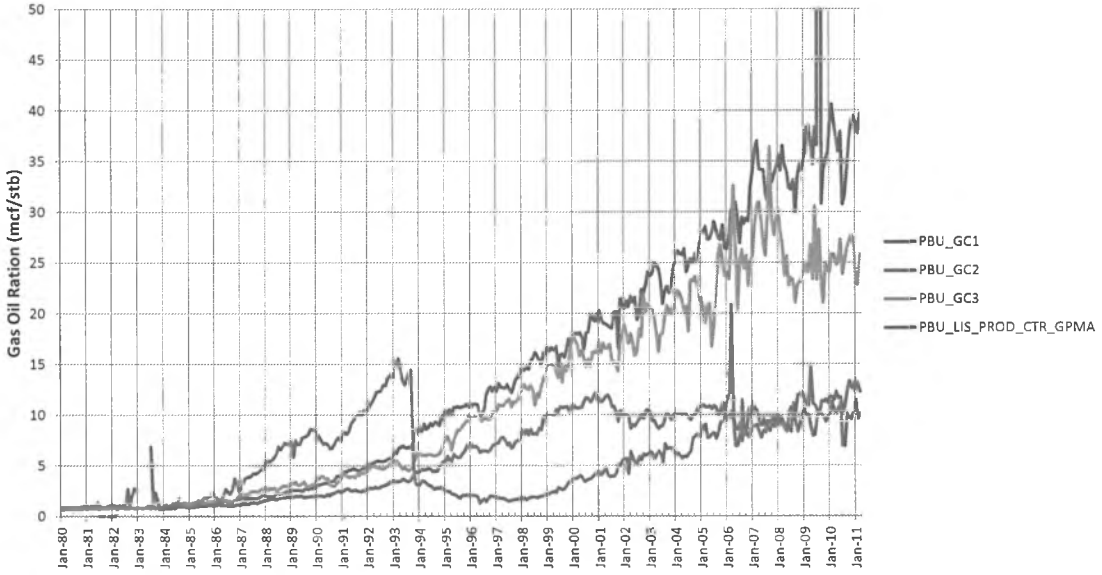
- GC2 was the main facility affected by the 2006 shutdown issues.

Prudhoe Gas Production by Flow Station



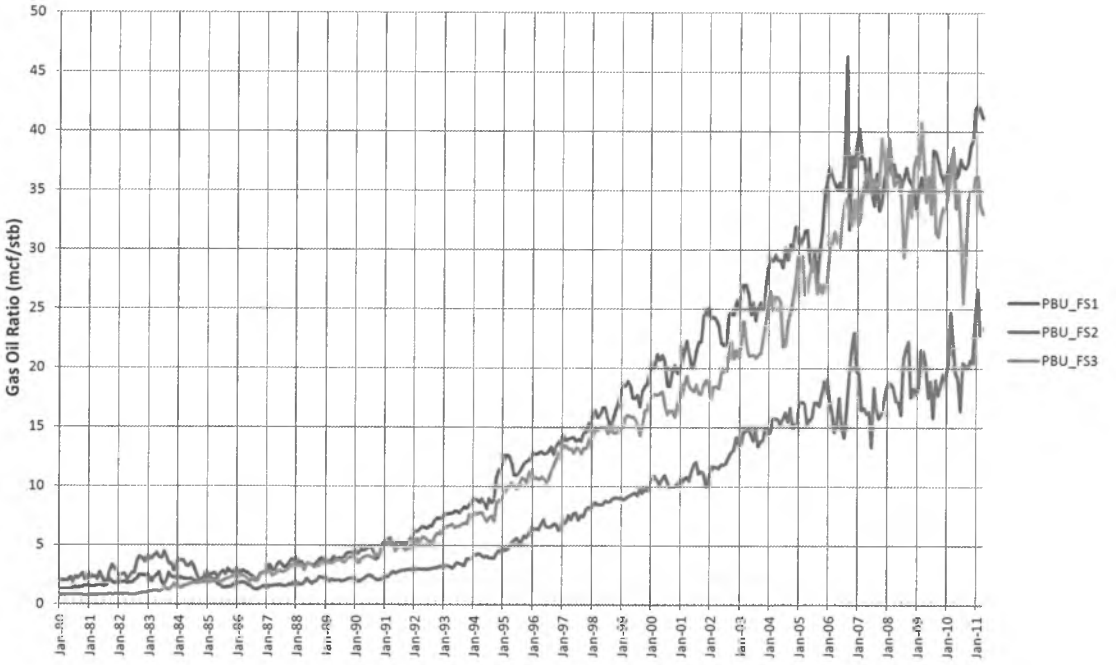
- FS3 gas production has dropped recently, indicating the possibility of spare capacity.
- FS1 and FS2 remain near their peak production

Prudhoe Bay Gas Oil Ratio by Gathering Center and LPC



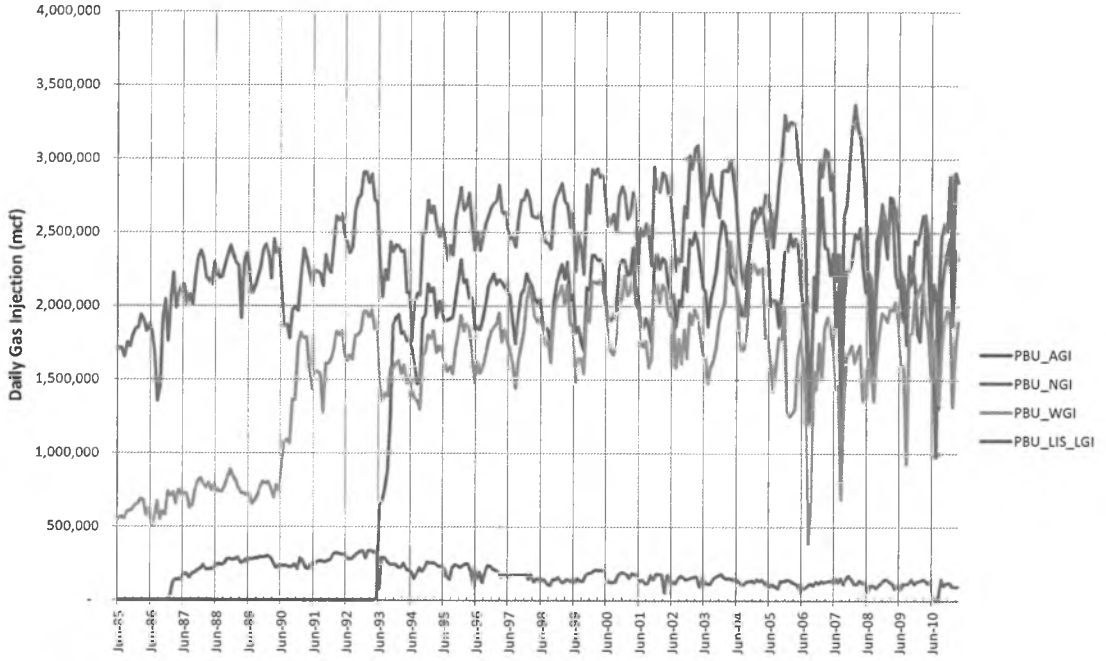
- Average GOR at GC2 and LPC is lower than other gathering centers.
- GC2 leveling of GOR starting in 1999 is a result of western satellite development.
- Gas partial processing plant being considered for GC2 may be needed for efficient continued development of the western satellites (less oil backout when new wells are brought on line)
- LPC gas handling increase may improve oil rates and allow for additional drilling and facilities sharing with developments outside of PBU

Prudhoe Bay Gas Oil Ratio by Flow Station



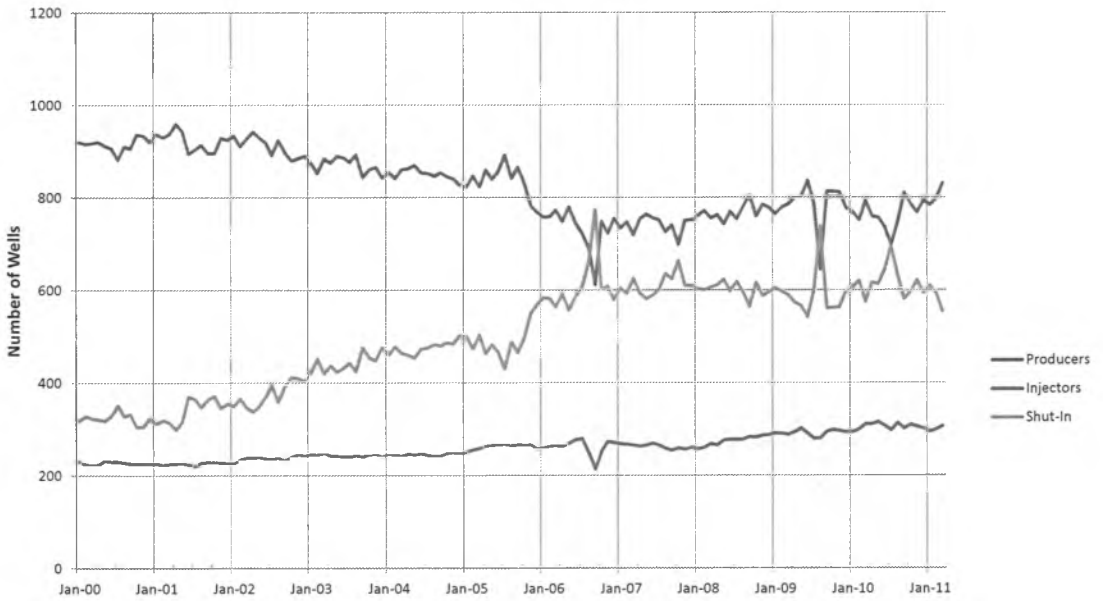
- FS2 has lower GOR as it is largely a waterflood area and further from the gas cap

Prudhoe Bay Gas Injection by Facility



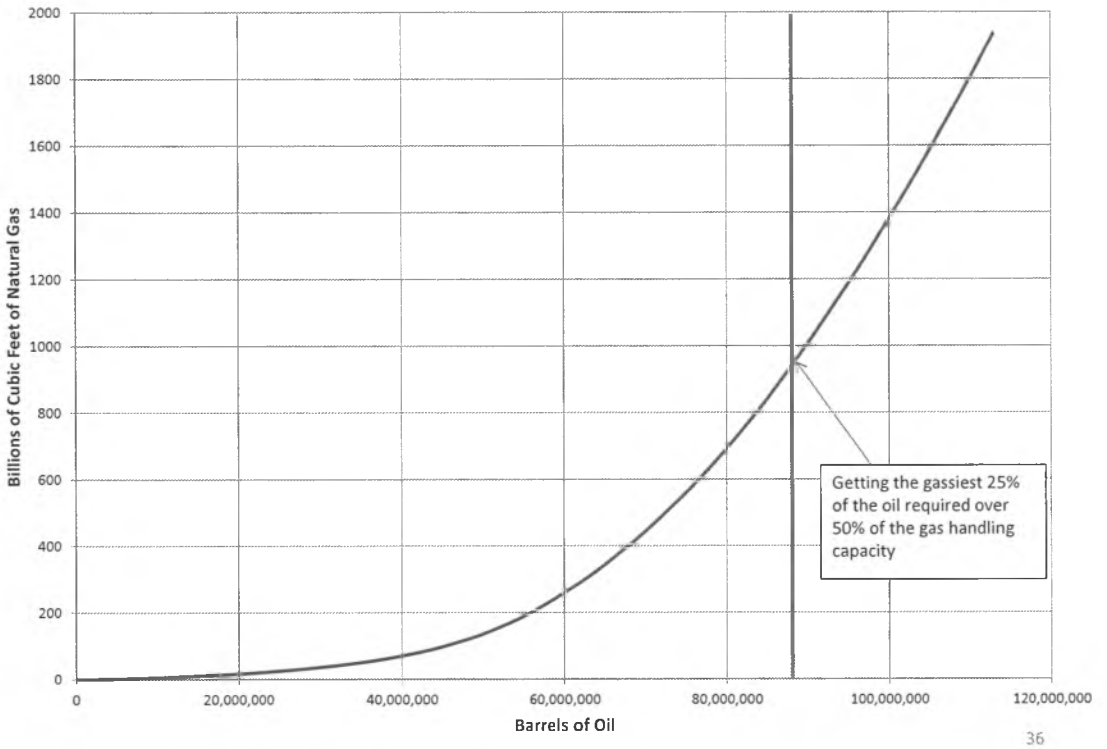
- This plot does not reflect MI injection.
- Lisburne LGI gas cap injection reduction is due to gas compression use by Pt. McIntyre. Pt. McIntyre gas injection is not shown on the graph.

Prudhoe Bay Well Count

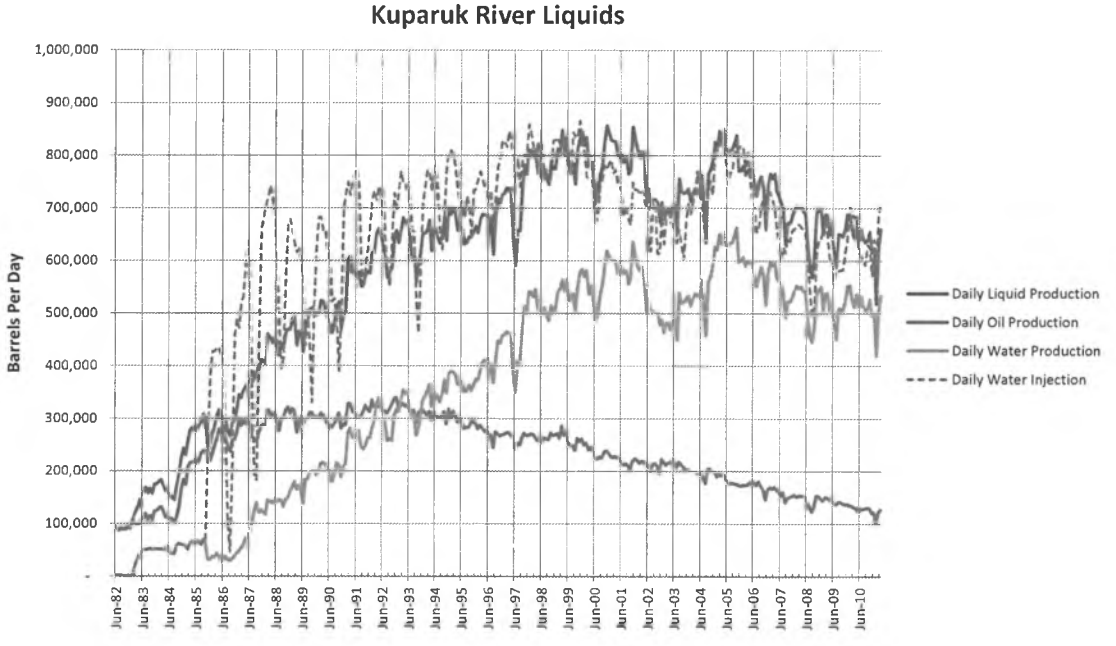


- Significant increase in shut-in wells due to mechanical integrity problems, increasing gas rates, conversion to water and MI injection, and the 2006 shut-down/corrosion problems

Cumulative Gas vs Cumulative Oil in Prudhoe Bay (2010)

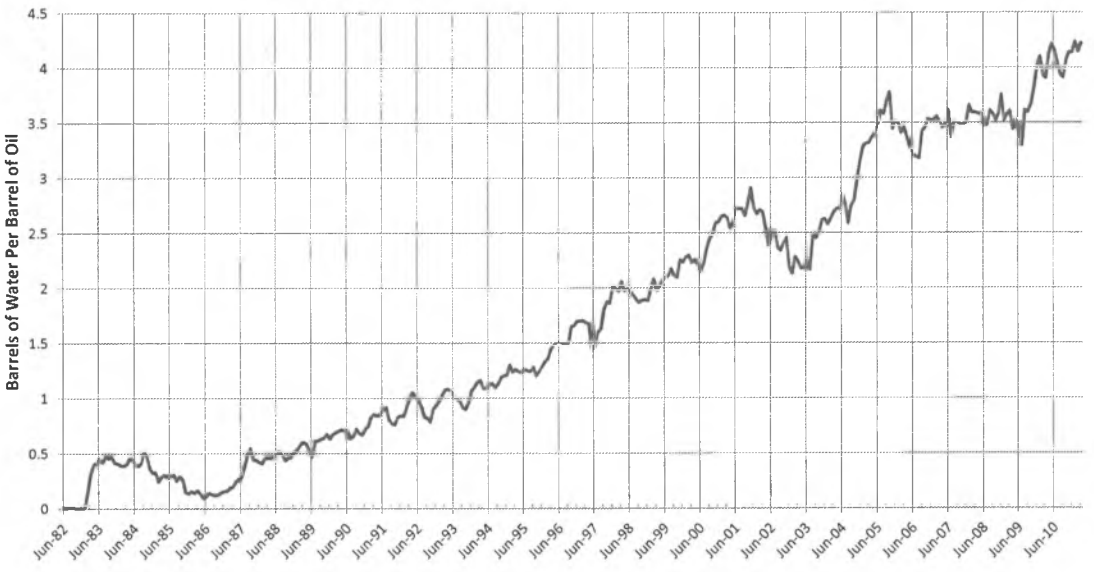


Kuparuk River Unit



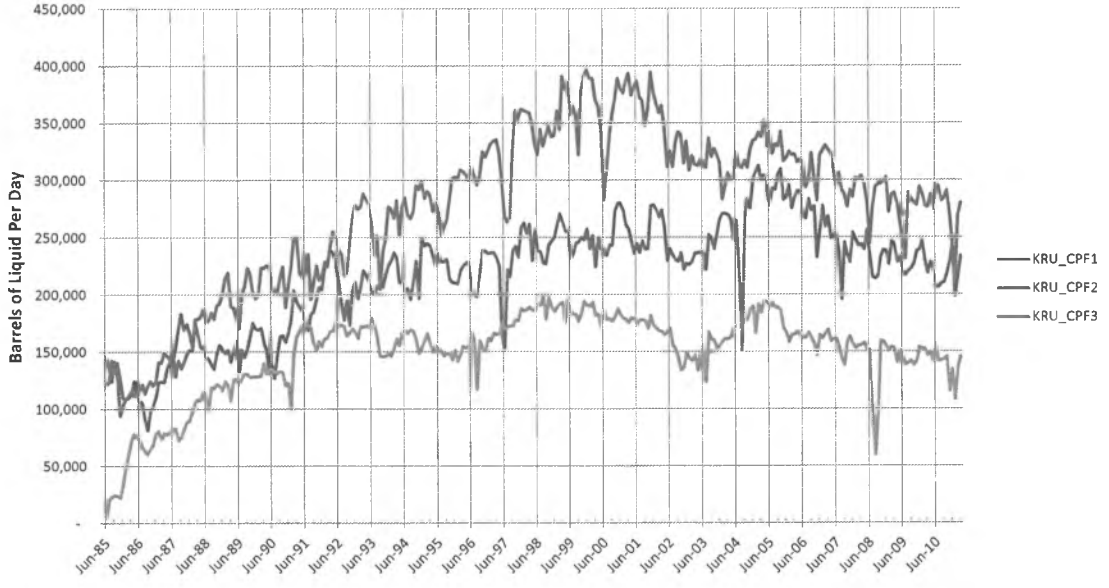
- Current field wide water production is well below former peaks which indicates spare capacity
- Water production correlates strongly to water injection as it should in a late stage waterflood
- Current facility constraints would most likely be around integrity of all steel components

Kuparuk River Water Oil Ratio



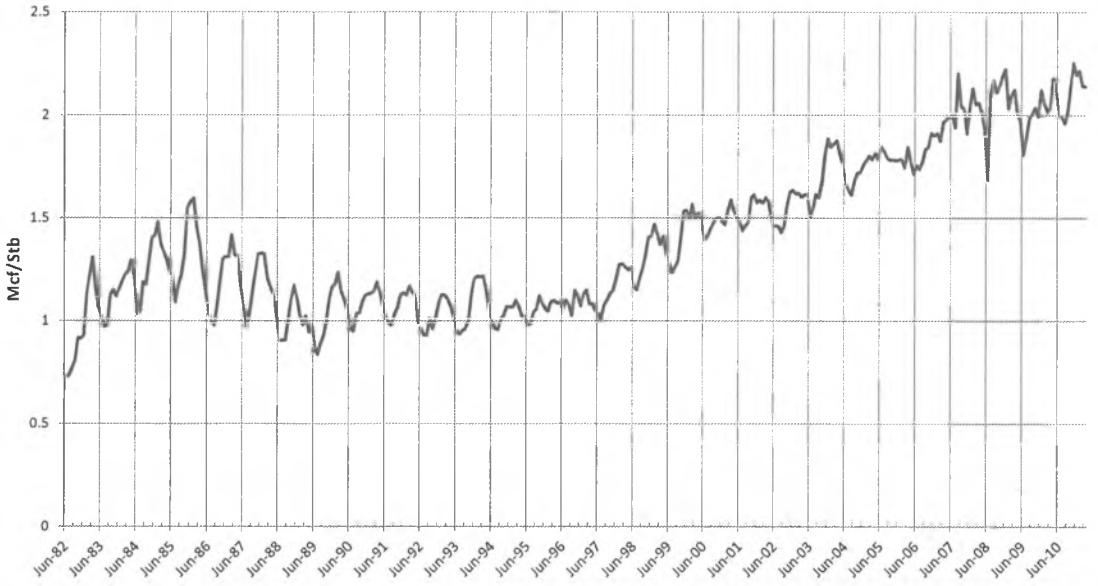
- The water oil ratio has recently exceeded 4:1 which corresponds to an 80% water cut
- It is not uncommon to see water cut for an individual well reach 95%+
- The dip seen in '02-'04 is due to a successful EOR program utilizing imported NGL from PBU

Kuparuk River Liquid Production by Cental Processing Facility



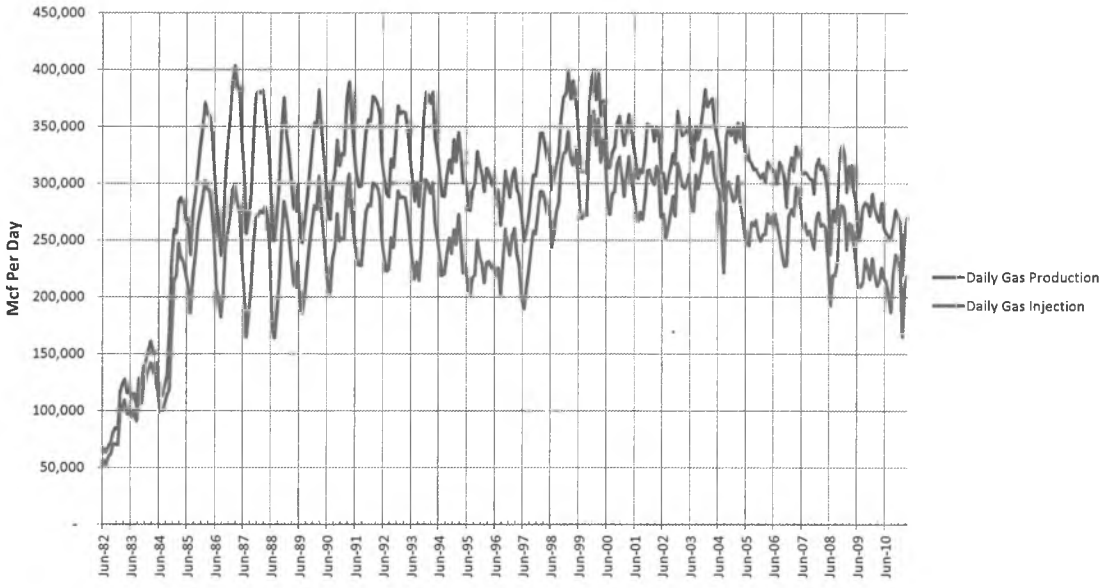
- Central Processing Facilities number one and two are likely not running at full capacity, number three may be
- If the quality of the produced oil changes in a way that it takes longer to separate from water, then it is possible that daily separation capacity could drop

Kuparuk River Gas Oil Ratio



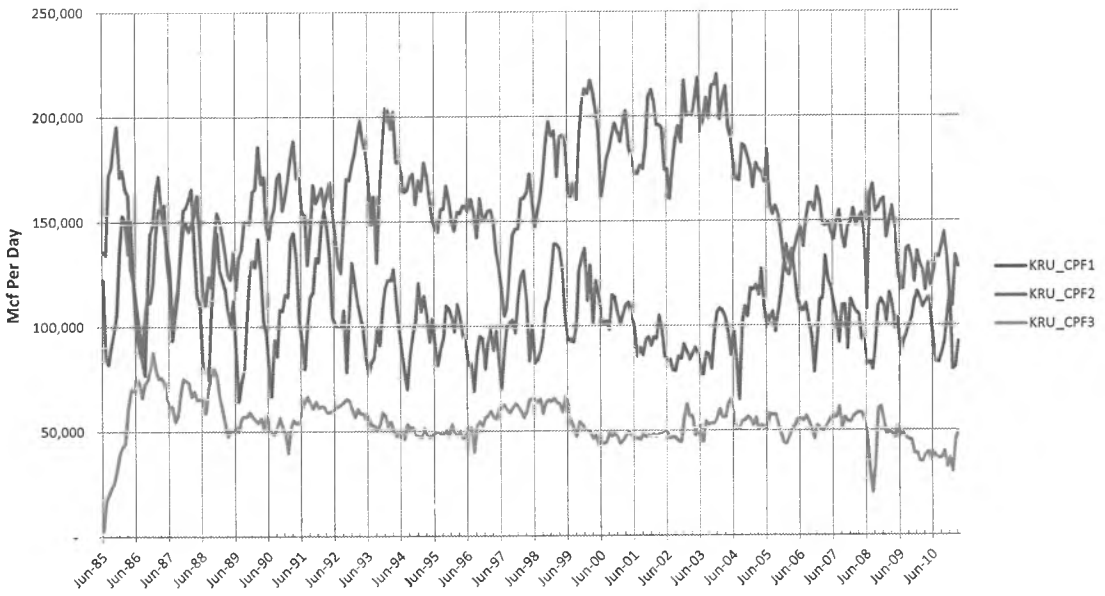
- The low gas oil ratio is what should be expected from an undersaturated reservoir such as Kuparuk
- It follows that there is no reason for GOR to increase significantly in the future unless a major secondary EOR (gas based) is pursued

Kuparuk River Gas



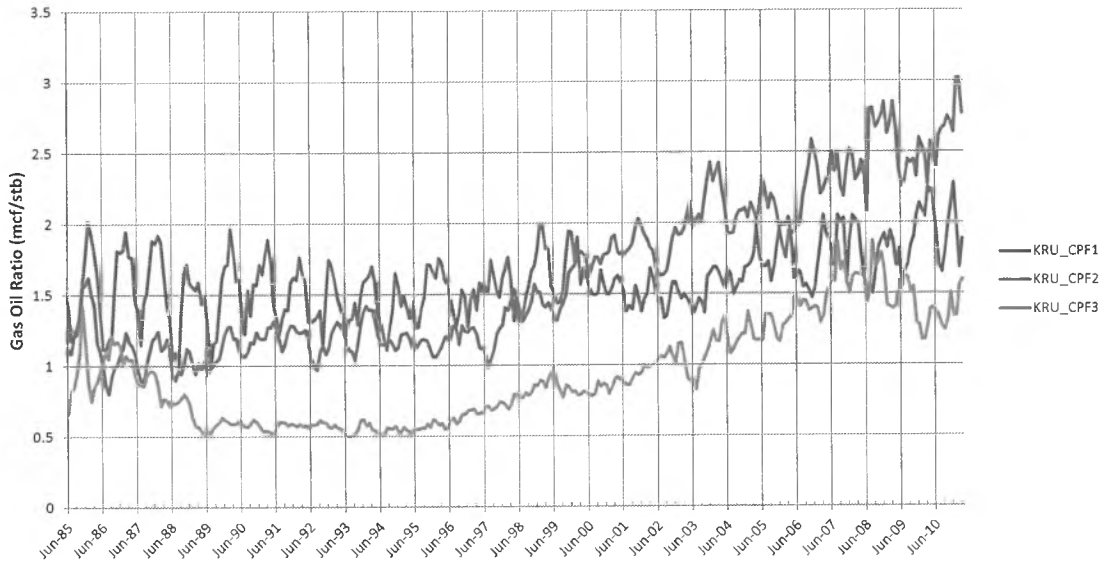
- Gas production and consequently gas injection has steadily declined over the last decade
- ConocoPhillips plans on importing gas to the field in the near future to maintain optimum producing conditions
- Field-wide there is spare capacity for gas, but there could be constraints at a specific facility

Kuparuk River Gas Production by Central Processing Facility

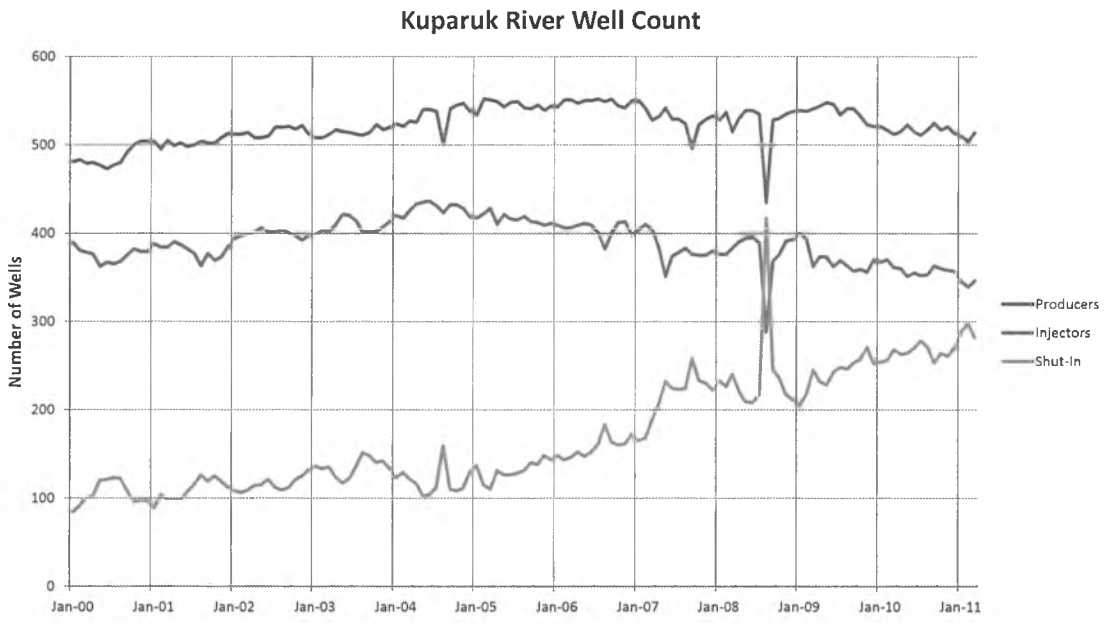


- It appears that all three facilities are not currently operating at peak capacity
- CPF2 underwent an expansion project in 2002
- The expansion project increased oil production for approximately a two year period

Kuparuk Gas Oil Ratio by Central Processing Facility



- GOR behavior by facility indicates that CPF2 could have the largest issue with gas constraints if oil production were to increase



- Shut-in wells have been climbing steadily since 2005 due to casing integrity and mature patterns
- The total well count has climbed during this time as new wells are being drilled for field expansion

Library

Date: **June 8, 2011**

To: **Senator Paskvan**

From: **DNR Division of Oil and Gas**

Re: **North Slope Facilities Expansion**

Enclosed is a document summarizing facilities expansion at Prudhoe Bay and Kuparuk, as requested by e-mail from you to Commissioner Sullivan. We have distilled most of your questions down to three basic issues addressed in this response.

1) Current and historical facilities (gas, water, and liquid handling) capacity
2) Effect upon oil production of increasing gas-oil ratios and water cut, and the impact of gas- and water-handling expansions
3) Are increases in gas- and water-handling limits required to increase North Slope oil recovery?

We are limiting this summary to major larger scale processing projects at the Prudhoe Bay Unit (emphasis upon Sadlerochit Initial Participating Area and Western Satellites) and the Kuparuk River Unit. There are also public documents which provide more thorough descriptions of capacities that may be of use to you.[1,2,3] You also requested information on horsepower and investments. It would take a bit more time to track public information down on these items.

While we do not have sufficient public information to quantify the oil production benefits of future gas and water handling capacity investments, it is our belief that additional gas and water handling capacity investments will be necessary in some cases for continuing operation of maturing fields, development and expansion of satellite reservoirs, and to allow for facilities sharing with other new developments outside of current Units. These investments are unlikely to be as massive as that for such items as the Prudhoe Gas Handling expansions and Seawater Injection and Treatment plants; rather smaller, more localized projects, debottlenecking, and upgrades are anticipated within the nearby infrastructure of the major Units.

We hope this is useful to you. If you have questions or need further information, please let us know.

---

[1] State of Alaska, Department of Natural Resources, Division of Oil and Gas and and Petrotechnical Resources of Alaska; *North Slope of Alaska Facility Sharing Study;* May 2004;
December, 2009
(http://www.dog.dnr.alaska.gov/oil/products/publications/otherreports/nsfacility/facility.share.report.pdf)

[2] ConocoPhillips Alaska; Facilities Limits; updated 1/6/2010;
http://www.conocophillipsalaska.com/facilityaccess/FacilityLimits.asp

[3] BP Alaska, Inc; *"BP in Alaska"*; 2009;
(http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_alaska_bp_in_alaska_2009.pdf)

North Slope Facilities Capacities and Expansions

The summary below addresses capacity limits for processing units within the Prudhoe Bay Unit and Kuparuk River Unit. Specifically we address the following aspects:

1) Current and historical facilities (gas, water, and liquid handling) capacity
2) Historical production volumes, the effect upon oil production of increasing gas-oil ratios and water cut, and the impact of gas and water handling expansions
3) Additional gas and water handling limits needed to increase North Slope Oil recovery

Figures illustrating historical production are provided in a separate PowerPoint file as an appendix.

Prudhoe Bay Unit

The current oil processing capacity of both the IPA facilities and the LPC is mainly limited by the amount of associated gas that can be processed and injected, however there are some limits on water handling. In other words, some of the processing capacities cannot be used because of the inability to process and inject the increasingly higher quantity of gas that is produced with the oil and water. Although efforts to shut off gas have been effective in some wells, in general higher GOR wells must be shut in with each additional new well addition. So, these new wells will "back-out" oil due to shut-in of other Prudhoe wells. The effects of this back-out vary by major processing facilities as outlined below. The following summarizes facilities capacities for the major facilities at Prudhoe Bay.

Current Prudhoe Bay capacities

The following table summarizes publicly available oil, gas, and water handling capacities for the major facilities at Prudhoe Bay. While the sum of gas production capacity at the flow stations may be as high as 10 BCF/D, the rated compression capacity at the Central Gas Facilities limits overall gas production to 8.7 BCF/D. [1]

Table 1

The capacity of each major facility is shown in the following table. However, in actual operations, the capacity of a single facility for a given component cannot be viewed in isolation and instead must be viewed in the context of the overall PBU system and other factors, such as weather and TAPS pro-rations. As such, rarely, if ever, can the capacity of more than one component (oil, water, or gas) be achieved simultaneously.

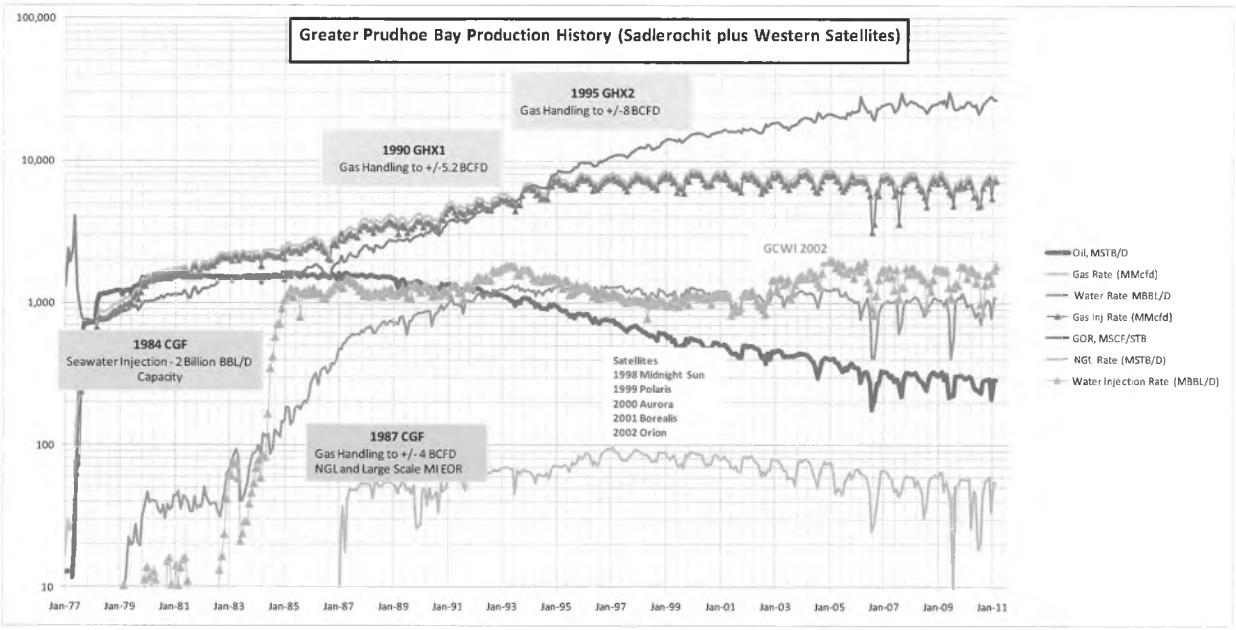
Facility	Oil Capacity MBD	Water Capacity MBD	Gas Capacity MMSCF	Gas Lift Gas Compression Capacity MMSCF
FS-1	360	130	2800	
FS-2	360	650	1150	
FS-3	360	240	1350	460
GC-1	330	150	2600	900
GC-2	250	300 *	1070	
GC-3	**	250	1100	
LPC	205	160	470	
CGF			8700	

* PW Tank currently out of service limits water to ~230 MBWPD
** GC-3 oil processing equipment was taken out of service; must consider GC-3 and FS-3 as single entity for oil processing capacity considerations

[1] ConocoPhillips Alaska Publication; *"Facilities Limits"*; initial publication 2002, updated 1/6/2010; (http://www.conocophillipsalaska.com/facilityaccess/FacilityLimits.asp)

Production and Major Facilities Expansion History

The following summarizes production history and major facilities capacity additions within the Greater Prudhoe Bay area (Sadlerochit plus Western Satellites – excludes Greater Point McIntyre). It should be noted that many smaller facilities and infrastructure expansions have occurred over time to accommodate new wells and drillsites, however major gas handling expansion has not occurred after 1995 with GHX2 addition.



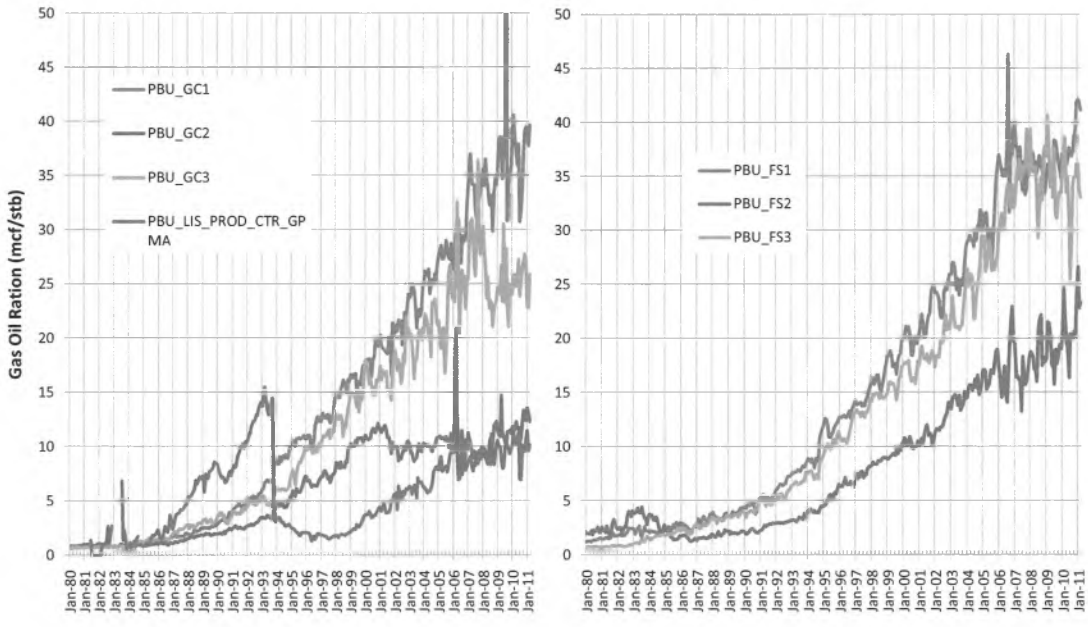
- 1983 - Major Seawater Injection Plant and Seawater Treatment Plant; 2 Billion Barrels per day injection capacity – $2 Billion
- Gas Handling Expansion – Greater Prudhoe Bay
  - CGF 1987 - Gas handling increased from +/- 2.7 BCFD to +/- 4.2 BCFD. NGL processing allows for sales into TAPS and use in miscible gas injection.
  - GHX1 1990 - gas handling increased from +/- 4.2 BCFD to +/- 5.7 BCFD
  - GHX2 1995 – gas handling increased from +/-5.7 BCFD to +/- 8.0 BCFD
- 2002 - Gas Cap Water Injection
  - Seawater is being injected into the Prudhoe Bay Ivishak gas cap to stabilize reservoir pressure.
  - Approximate incremental recovery 150-200 MMSTB (per AOGCC testimony)
- Greater Prudhoe Bay Western Satellites - (Note – Excludes GPMA)
  - Midnight Sun (1997), Polaris (production start date: 1999), Aurora (2000), Borealis (production start date: 2001), Orion (production start date: 2002), Put River (production start date: 2008).

Prudhoe Bay Future Opportunities/Needs

We do not have sufficient publicly available information to quantitatively address the oil production benefits of future gas and water handling capacity investments. However, investments in additional gas and water handling may be necessary to realize efficient and economic oil recovery: 1) for development and expansion of satellite reservoirs, 2) for facilities sharing with other new developments outside of current units, and 3) for acceleration and increased oil rates in the maturing fields. These investments are unlikely to be as massive as that for such items as the Prudhoe Gas Handling expansions and Seawater Injection and Treatment plants; rather smaller more localized projects, debottlenecking, and upgrades are anticipated within the nearby infrastructure of the Prudhoe Bay Unit.

An example of a gas expansion opportunity being considered by the Prudhoe Bay Owners includes a "Gas Partial Processing Plant" which would be placed upstream of Gathering Center 2 at a Z Pad (western portion of the Prudhoe Bay Unit). Currently, the existing GORs are low at GC2 relative to other processing facilities because the facility has not been upgraded with sufficient gas processing capability. As a result, the oil rate benefit from drilling new wells in that part of the field is significantly reduced because even moderate GOR wells have to be shut-in to accommodate the new production. The proposed gas partial processing plant would partially separate gas from incoming production Drill Pads Z, W, L, and V, then dehydrate and compress the gas for use in local gas lift. Such a plant should significantly improve the economics of new western region drilling and is a key component required for a new I Pad viscous oil development. Our very rough calculation suggests that approximately 400 MMSCF/D added gas processing could allow for about 15,000-35,000 STB/D additional oil rate (range depends upon new well and drillsite developments).

Prudhoe Bay Gas Oil Ratio Comparison by Major Processing Facility



Kuparuk River Unit

Kuparuk River facilities were built and sized for the Kuparuk Participating Area, which is the main PA in the Kuparuk River Unit. Peak liquid throughput was roughly 800,000 barrels of liquid per day. This throughput was achieved both in the late 1990s-early 2000s as well as the 2004-05 period when NGL imports were ended. Peak water production was reached during the 2004-05 liquids peak with 650,000 barrels of water per day. Water injection peaked in the late 1990s, equaling the liquid production rate at the time which was 800,000 barrels per day. Gas production peaked at 400,000 MCF per day in 2002, coinciding with the last gas handling expansion at Kuparuk. These peaks aren't necessarily hard limits, nor can we be 100% certain they can be achieved again in the future. As equipment ages it may lose some capacity so those peaks may no longer be obtainable, but they provide a good guideline for what was possible to achieve with functioning equipment.

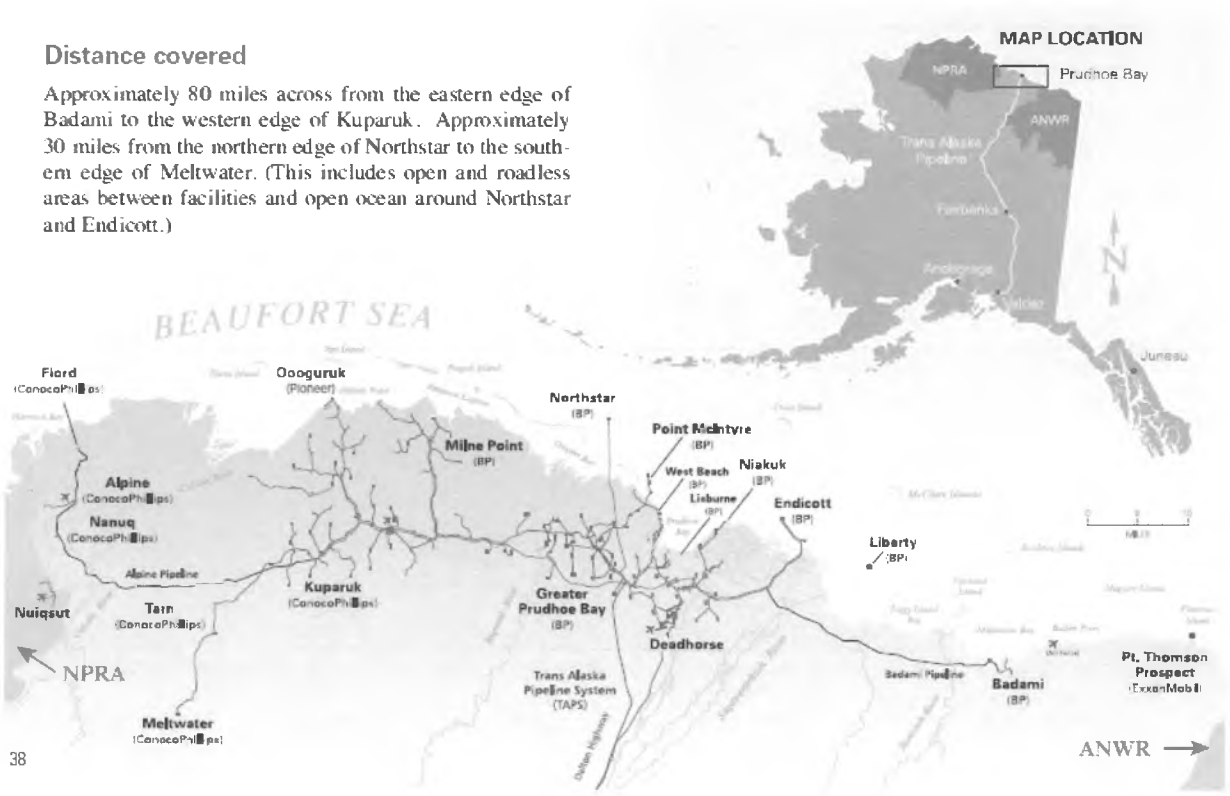
As any field matures it is likely to encounter an increased amount of gas and water per barrel of oil. If the current facilities in a field were not designed for the amount of liquid and gas being produced then wells with high GOR and high water cut may need to be shut-in, curtailing production. A facilities expansion would only increase recovery rate if there were shut-in wells to bring online or new wells that could be drilled to produce into the new facilities. In general there will be some tradeoff between how much oil can be gained by increasing facilities and how much those facilities cost. A balance must be achieved in both the initial sizing of facilities as well as any decision to expand facilities later. Kuparuk River facilities were sized in a way where it did not need to expand to deal with increasing GOR and water cut. It is possible to design facilities large enough to not have to be expanded, but that it may not always be optimal.

In some cases new facilities may be necessary to increase North Slope production. There is no question that new oil will need to be processed somewhere, the question is whether that should be somewhere in existing facilities or at a new facility. This comes down to an economic decision of whether it is cheaper to build new or pay to put production through an existing facility. At Kuparuk there is little need to expand facilities for current operations, but if any new satellites were to be brought in, or a new EOR project was undertaken then facilities would likely need to be expanded to accommodate increased volumes. Similarly, the size of a new development will have a lot to do with the decision to rent space or build new. If the development is of a size where it can easily fit into available space, that may be the cheaper option, but if that development is large enough to pay for its own facilities then it is probably optimal to build new and not deal with the expenses and logistical issues of running multiple developments through a single set of facilities.

North Slope Fields Map

Distance covered

Approximately 80 miles across from the eastern edge of Badami to the western edge of Kuparuk. Approximately 30 miles from the northern edge of Northstar to the southern edge of Meltwater. (This includes open and roadless areas between facilities and open ocean around Northstar and Endicott.)



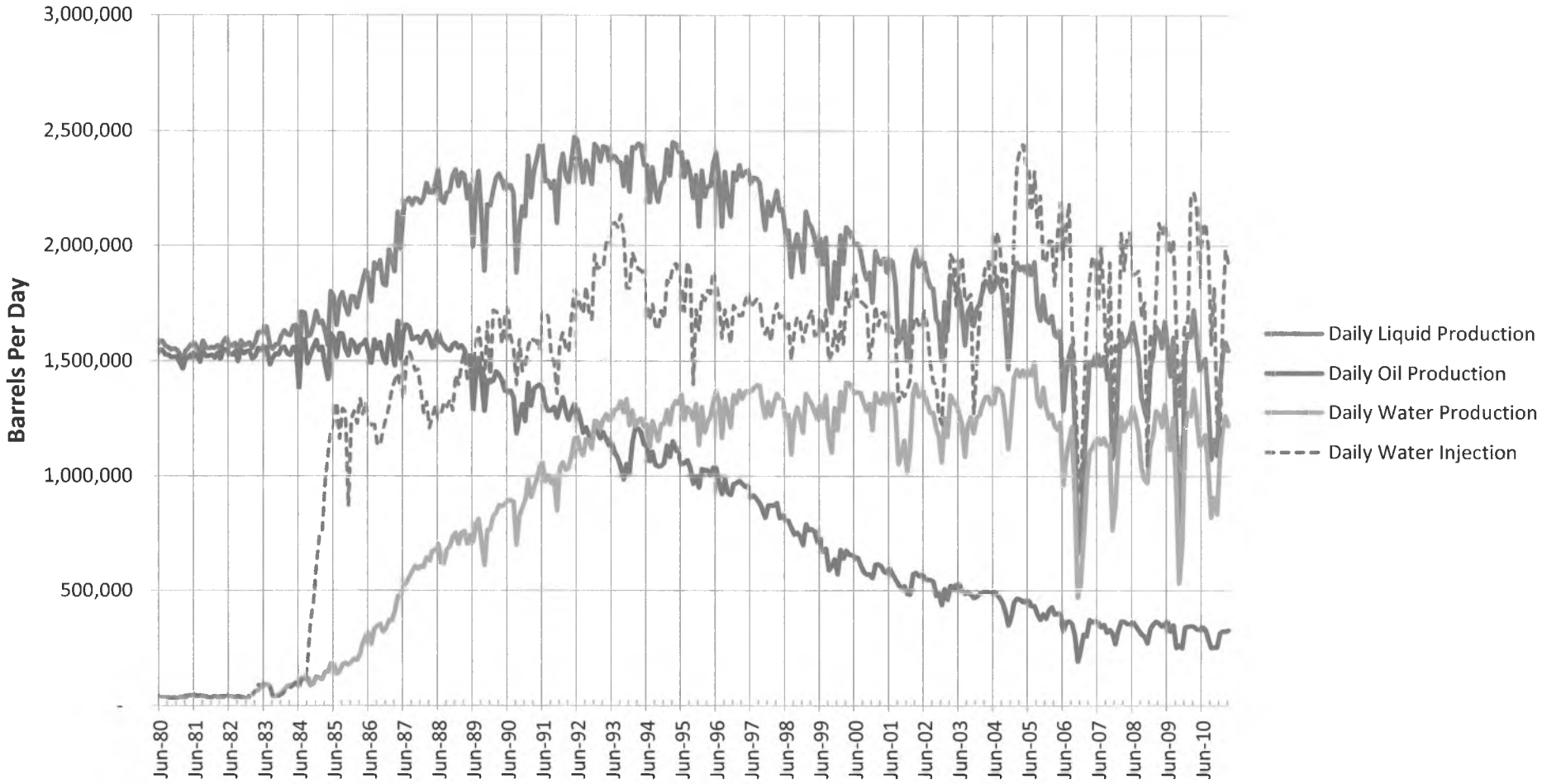
See BP Alaska, Inc; *"BP in Alaska"*; 2009; (http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_alaska_bp_in_alaska_2009.pdf)

Appendix

- Annotated slides of Prudhoe Bay and Kuparuk River units production history data relevant to expansion of gas processing and water handling facilities.

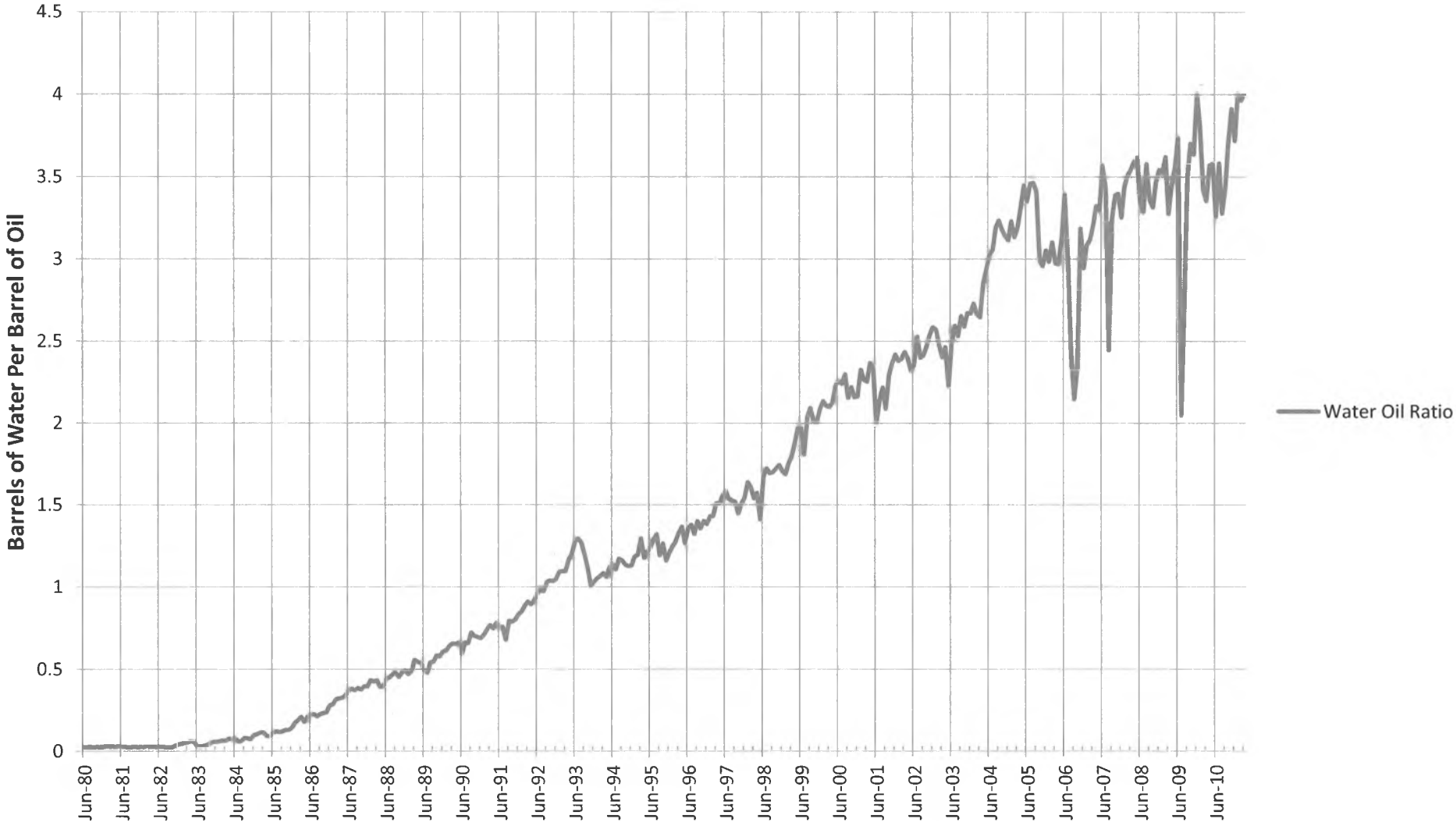
Prudhoe Bay Unit

Prudhoe Bay Liquids



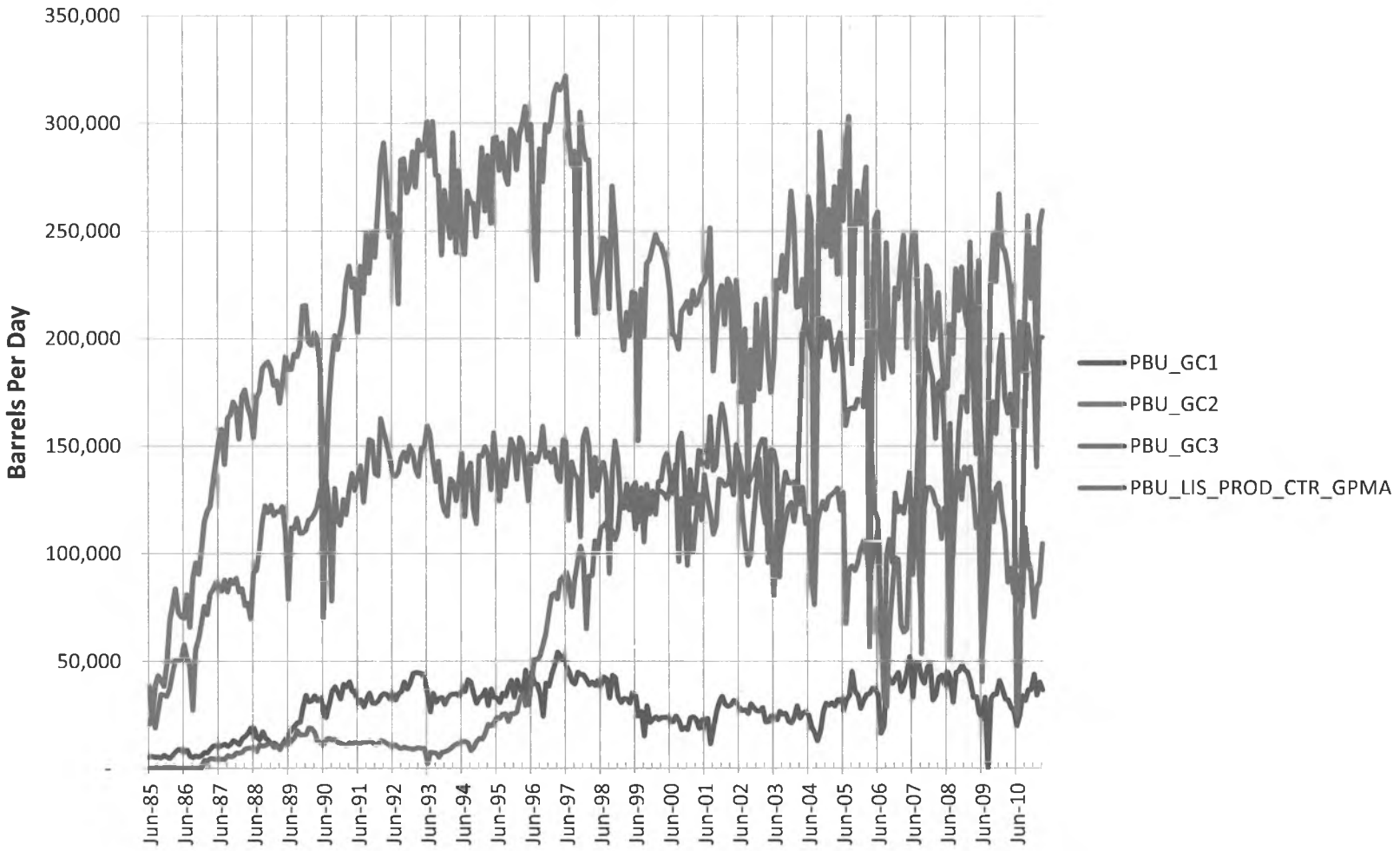
- Liquid throughput has declined considerably since the mid 90's due to oil rate decline
- Lisburne, Pt. McIntyre, Niakuk production into LPC began in 1997, increasing oil rates and water handling capacity.
- Western Satellite development after 1999 helped stem Prudhoe decline.
- Gas cap water injection began in '02, considerably increasing utilization of seawater injection capacity, and helped to stem decline with stabilized reservoir pressures

Prudhoe Bay Water Oil Ratio



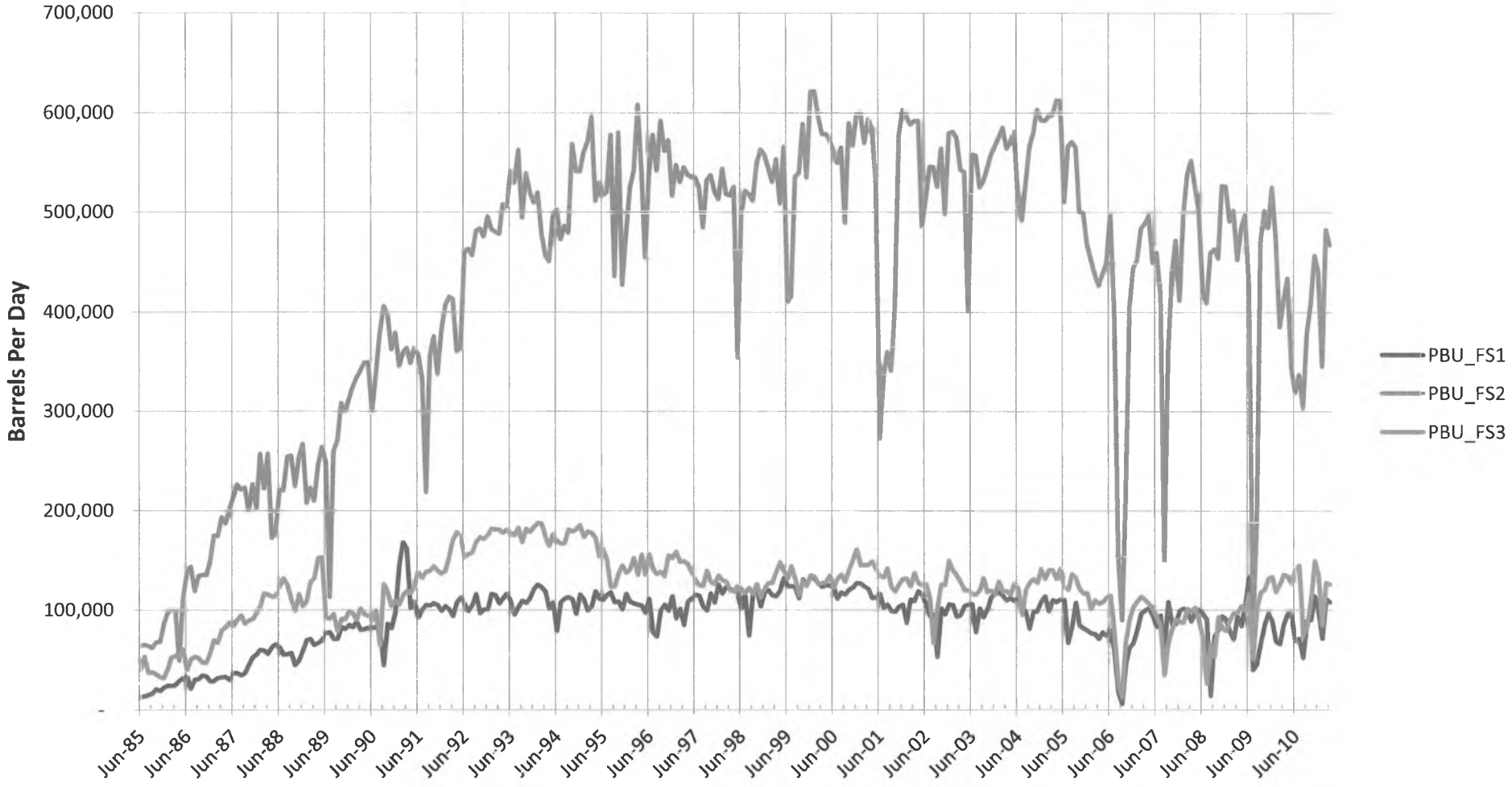
- The water oil ratio has reached 4:1 at Prudhoe with continued waterflood maturity.

Prudhoe Water Production by Gathering Center and LPC



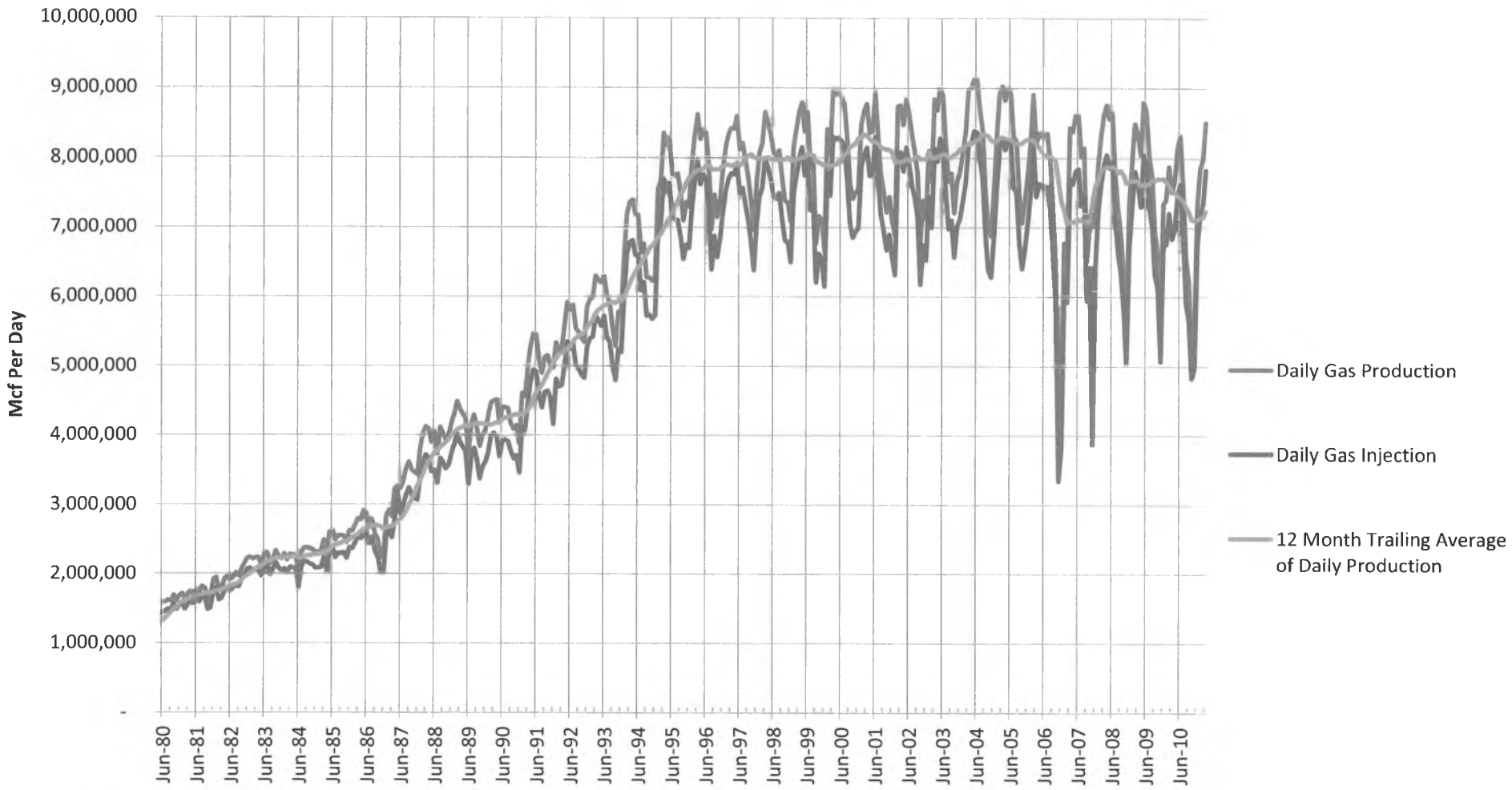
- GC1 is nearer the gas cap and has less waterflood injection, so water production is lower.
- Expansion in water injection pumping capacity at LPC in 2004.

Prudhoe Water Production by Flow Station



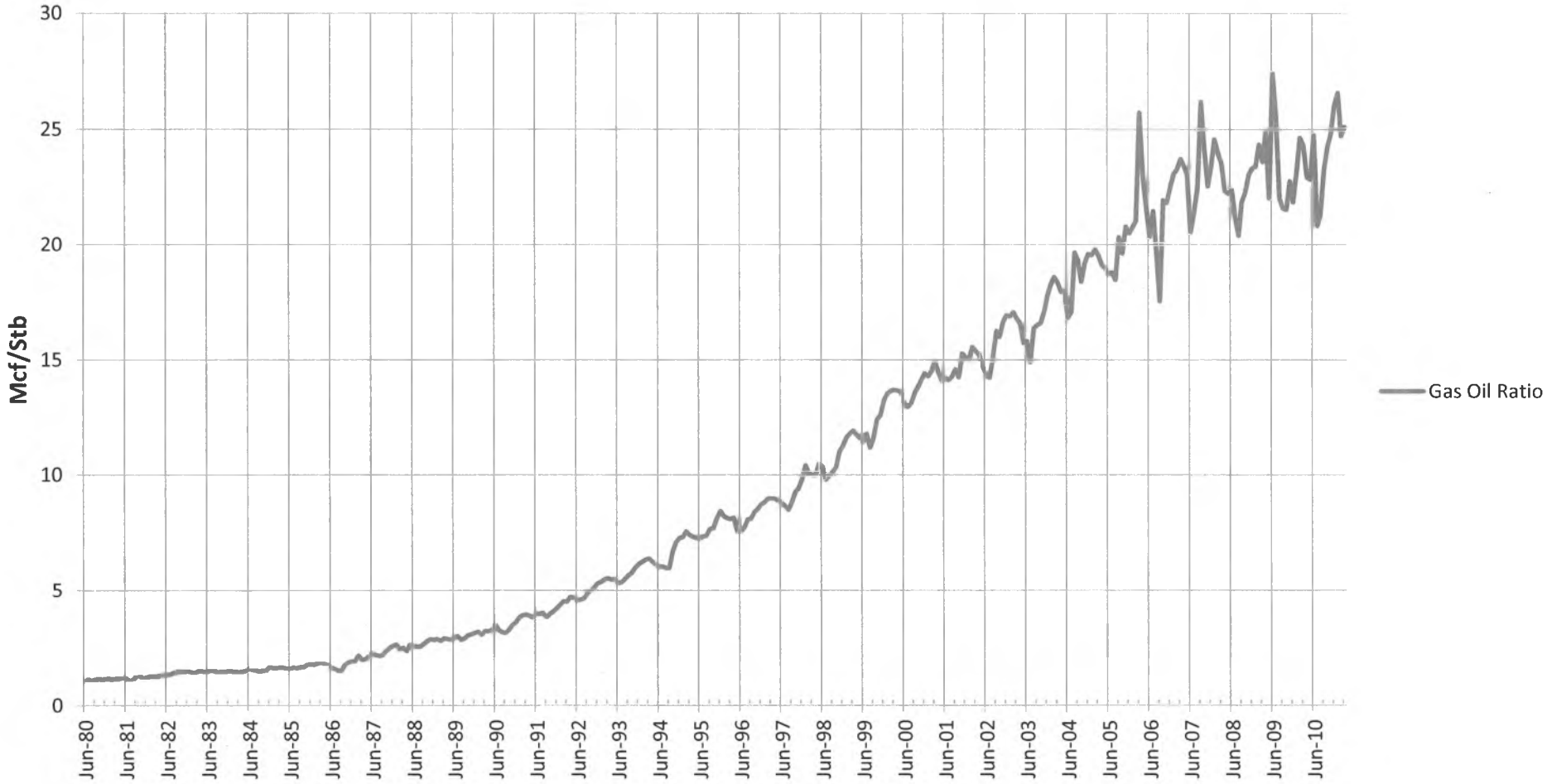
- Flow Station 2 is largely a waterflood area reflected in the higher water production rates

Prudhoe Bay Gas



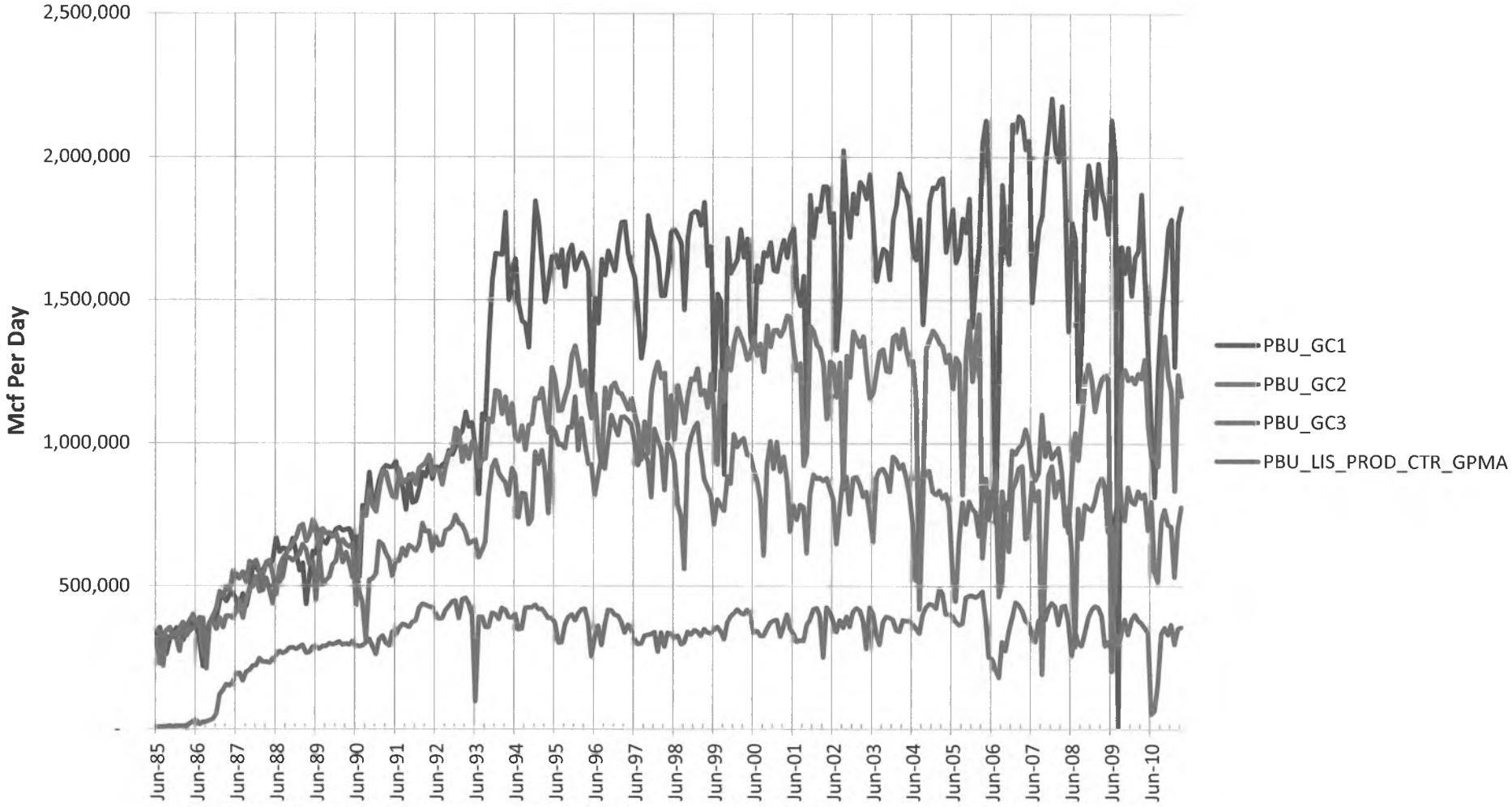
- Gas Handling Expansion – Greater Prudhoe Bay
  - CGF 1987 - Gas handling increased from +/- 4.2 BCFD from +/- 2.7 BCFD. NGL processing allows for sales into TAPS and use in miscible gas injection.
  - GHX1 1990 - gas handling increased from +/- 4.2 BCFD from +/- 5.7 BCFD
  - GHX2 1995 – gas handling increased from +/-5.7 BCFD to +/- 8.0 BCFD
- Total Prudhoe Bay gas throughput has fallen in recent years. 2006-2007 reduction due to 2006 corrosion and shutdown issues. The reductions after 2008 may be due to increased shut-downs for repair and line replacement after the 2006 shut-down.

Prudhoe Bay Gas Oil Ratio



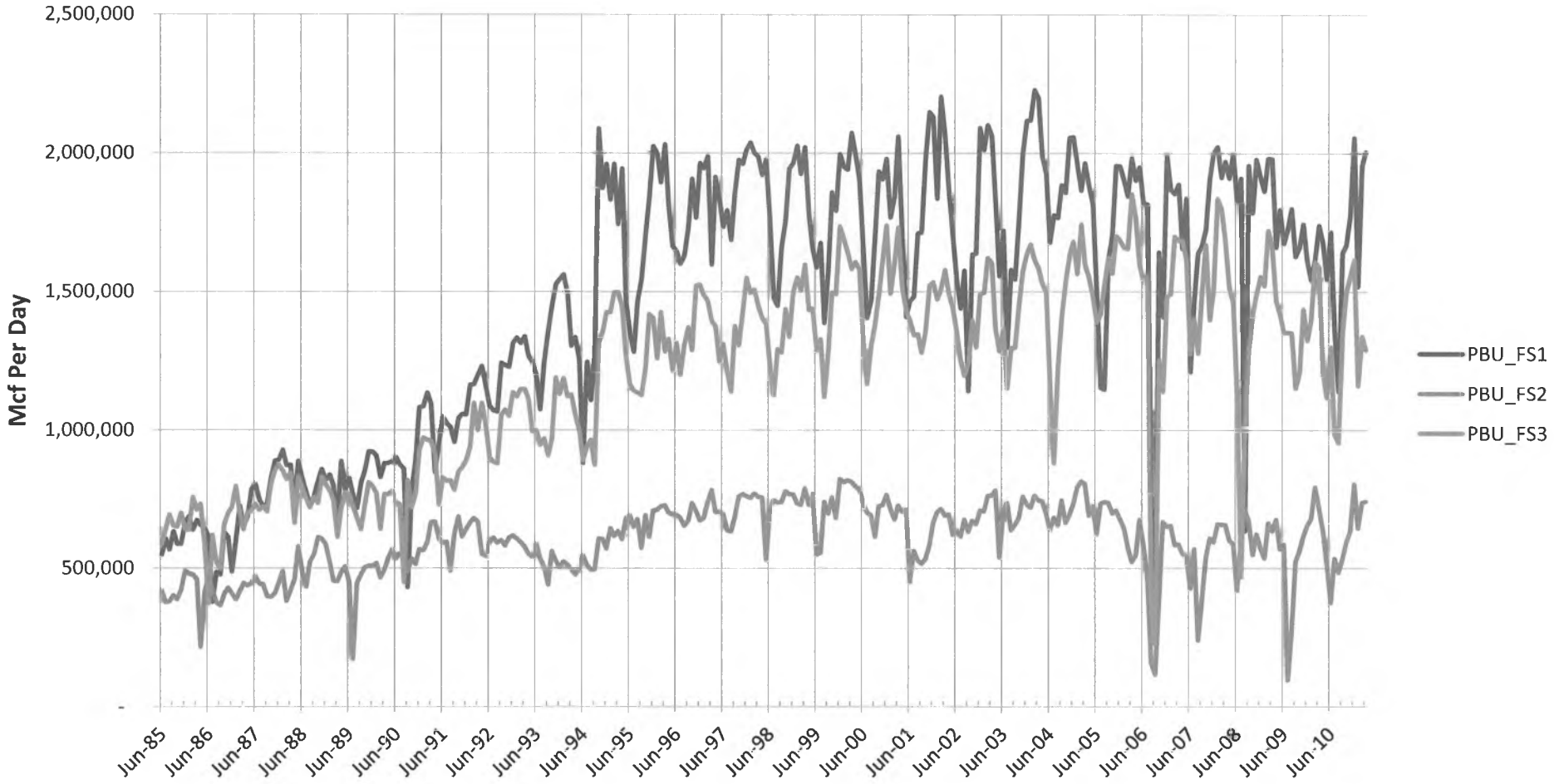
- Average GOR is approaching 25,000 cubic feet per barrel, but this ranges widely among different parts of the field, even more so among individual wells.

Prudhoe Gas Production by Gathering Center and LPC



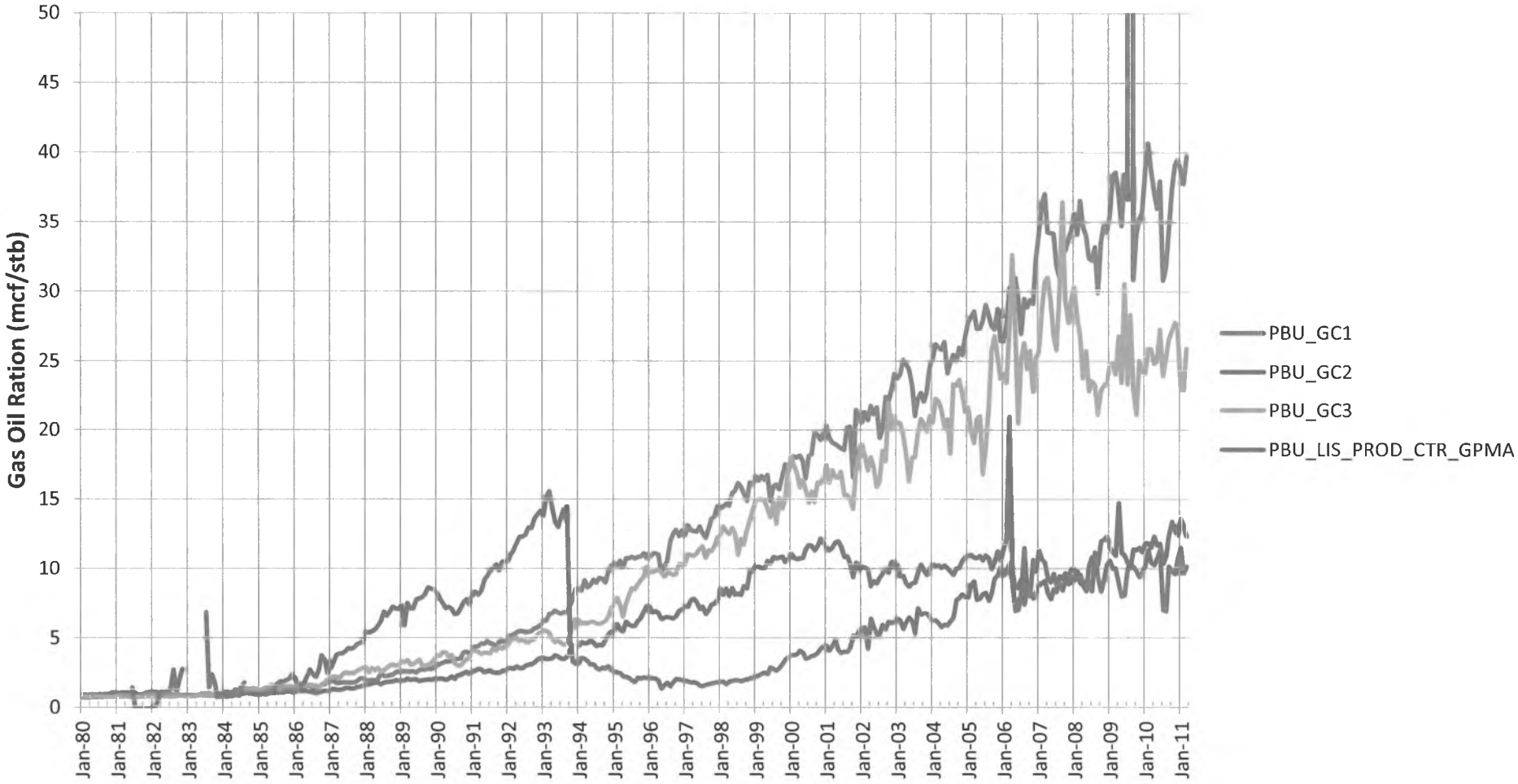
- GC2 was the main facility affected by the 2006 shutdown issues.

Prudhoe Gas Production by Flow Station



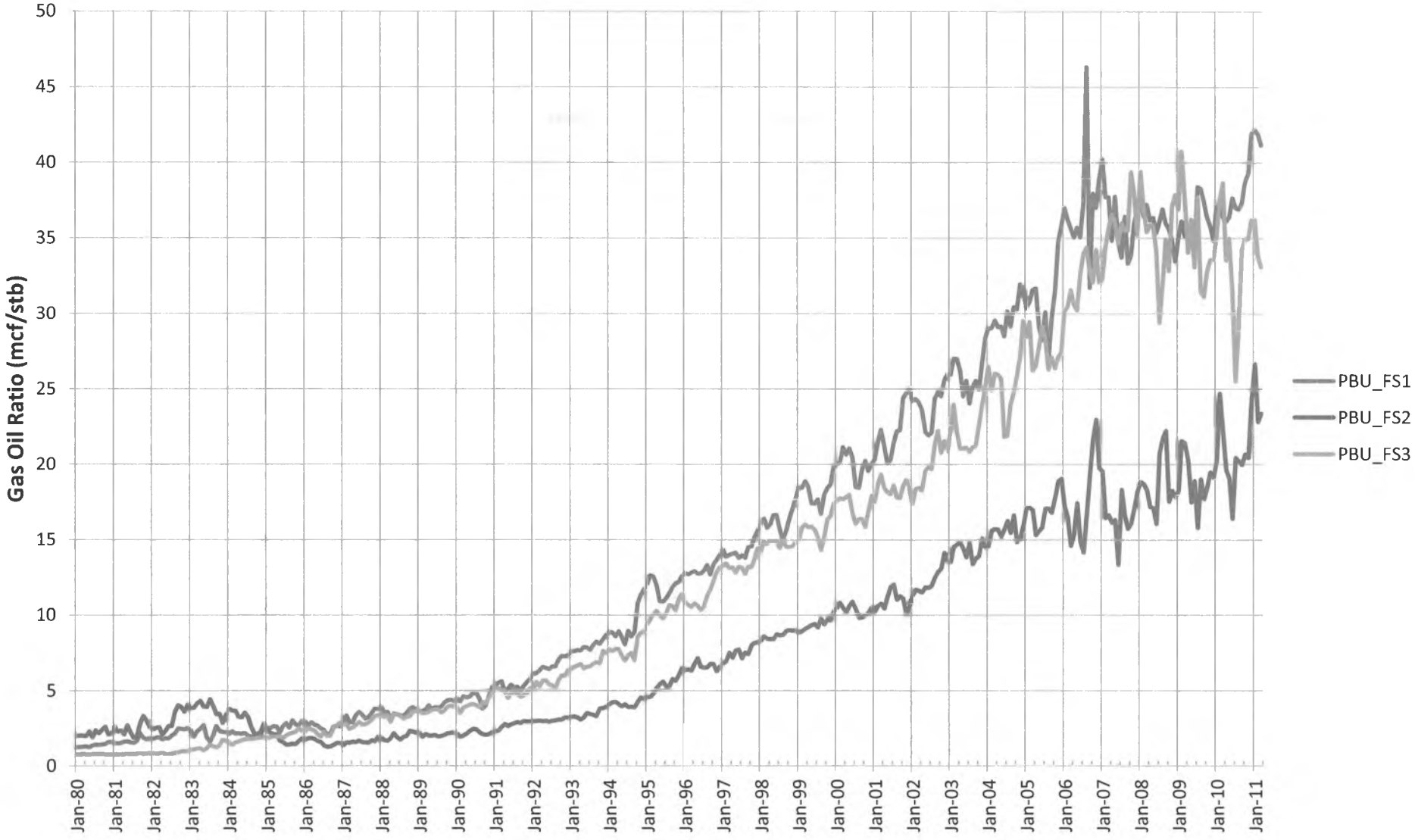
- FS3 gas production has dropped recently, indicating the possibility of spare capacity.
- FS1 and FS2 remain near their peak production

Prudhoe Bay Gas Oil Ratio by Gathering Center and LPC



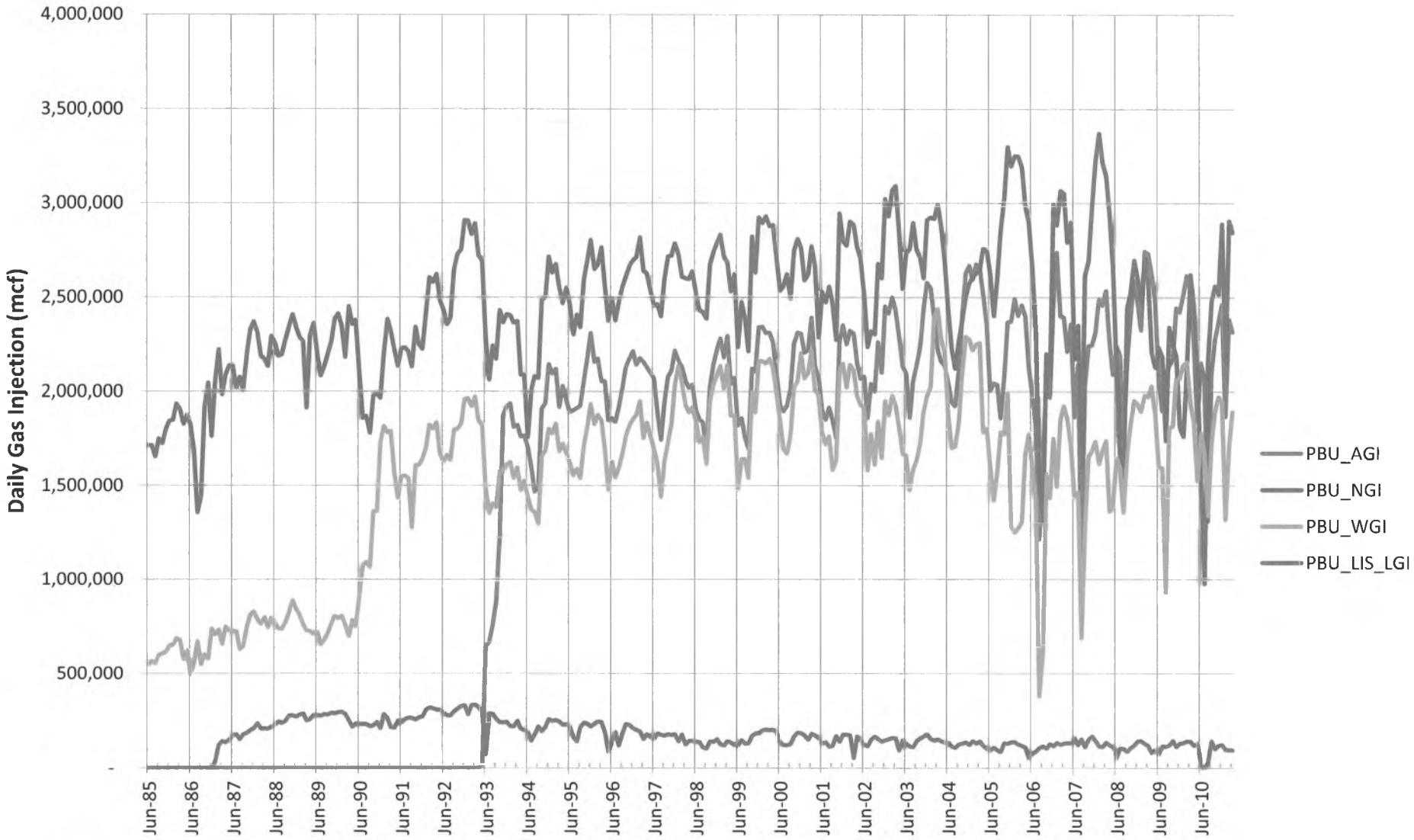
- Average GOR at GC2 and LPC is lower than other gathering centers.
- GC2 leveling of GOR starting in 1999 is a result of western satellite development.
- Gas partial processing plant being considered for GC2 may be needed for efficient continued development of the western satellites (less oil backout when new wells are brought on line)
- LPC gas handling increase may improve oil rates and allow for additional drilling and facilities sharing with developments outside of PBU

Prudhoe Bay Gas Oil Ratio by Flow Station



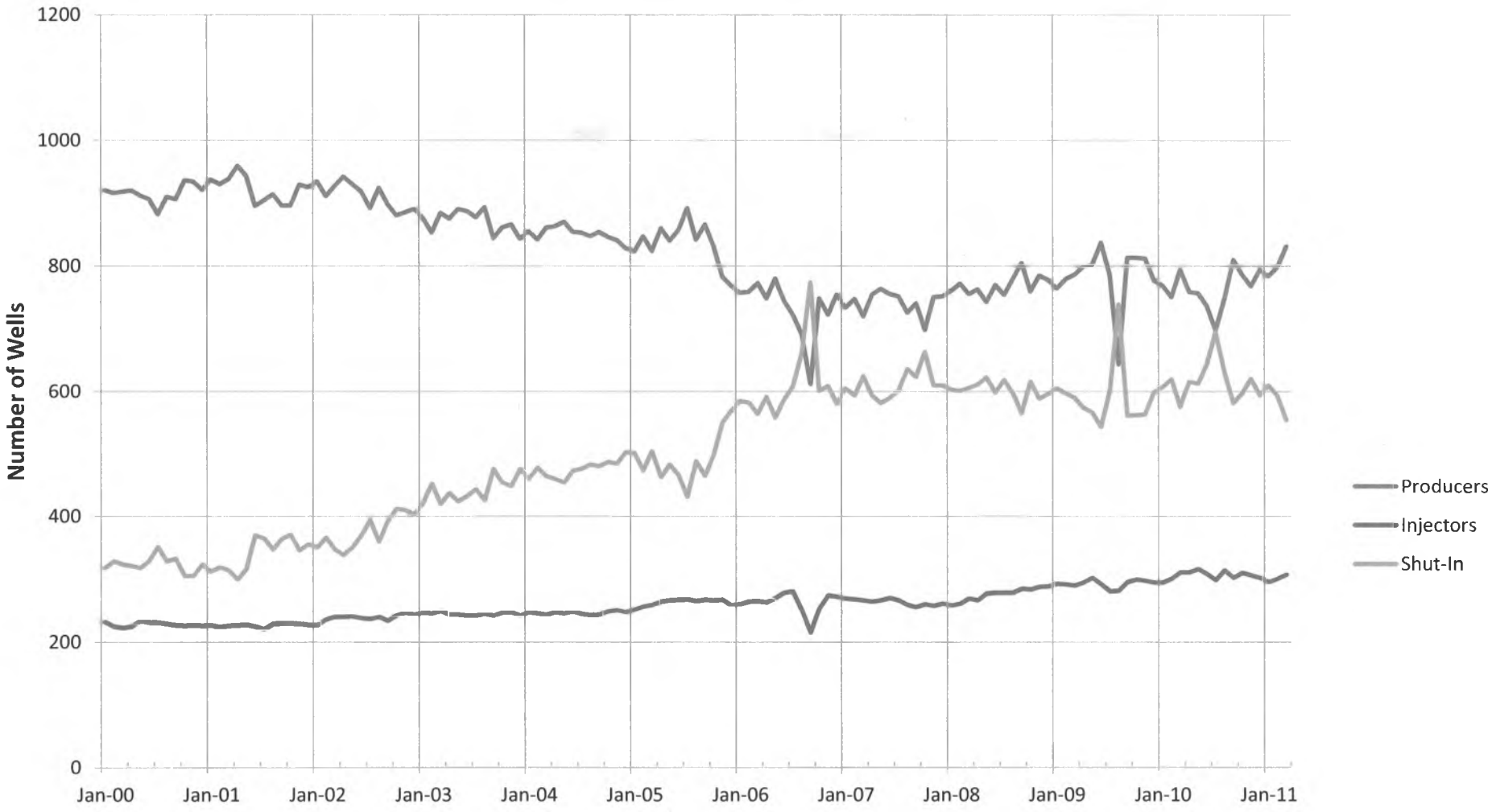
- FS2 has lower GOR as it is largely a waterflood area and further from the gas cap

Prudhoe Bay Gas Injection by Facility



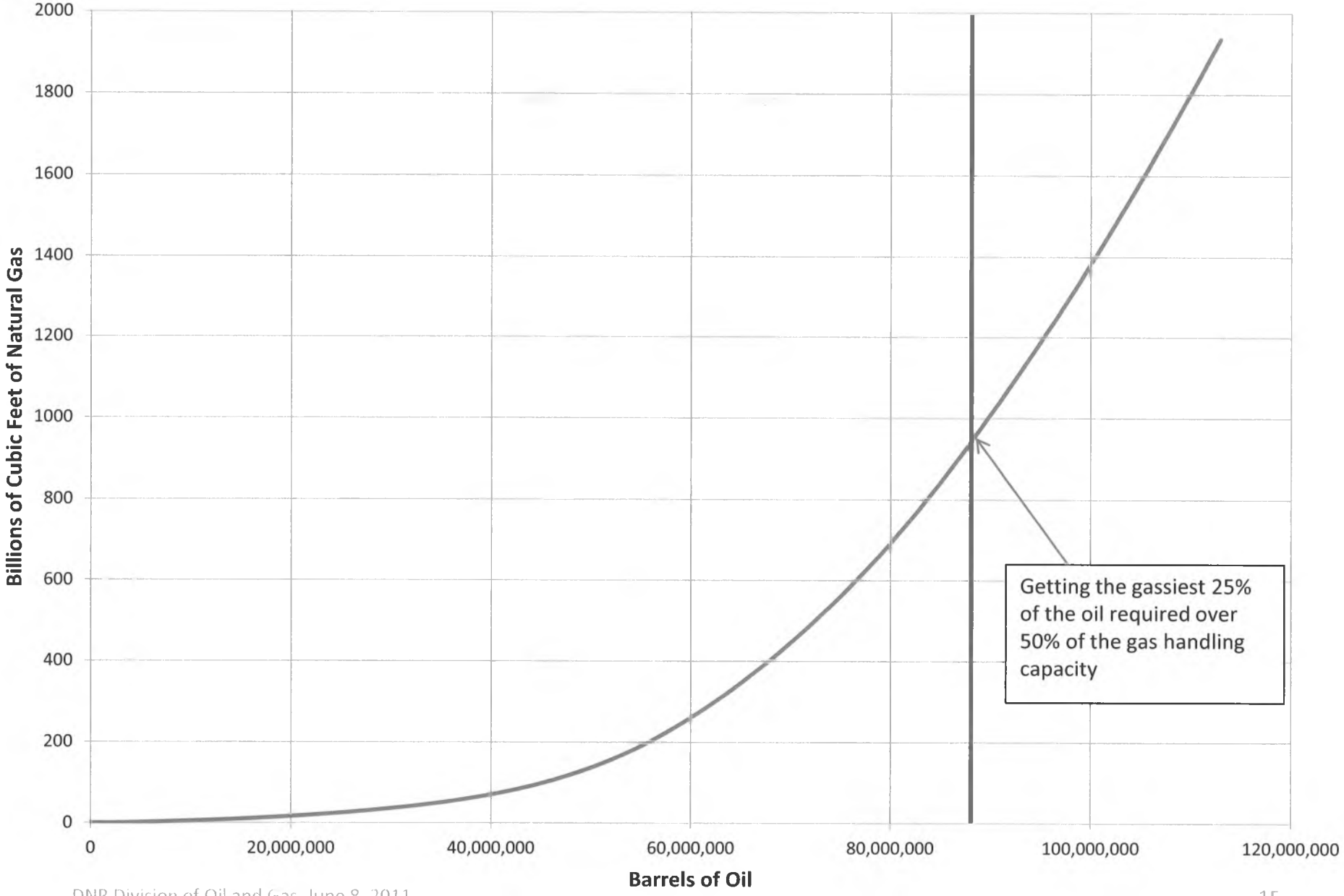
- This plot does not reflect MI injection.
- Lisburne LGI gas cap injection reduction is due to gas compression use by Pt. McIntyre. Pt. McIntyre gas injection is not shown on the graph.

Prudhoe Bay Well Count



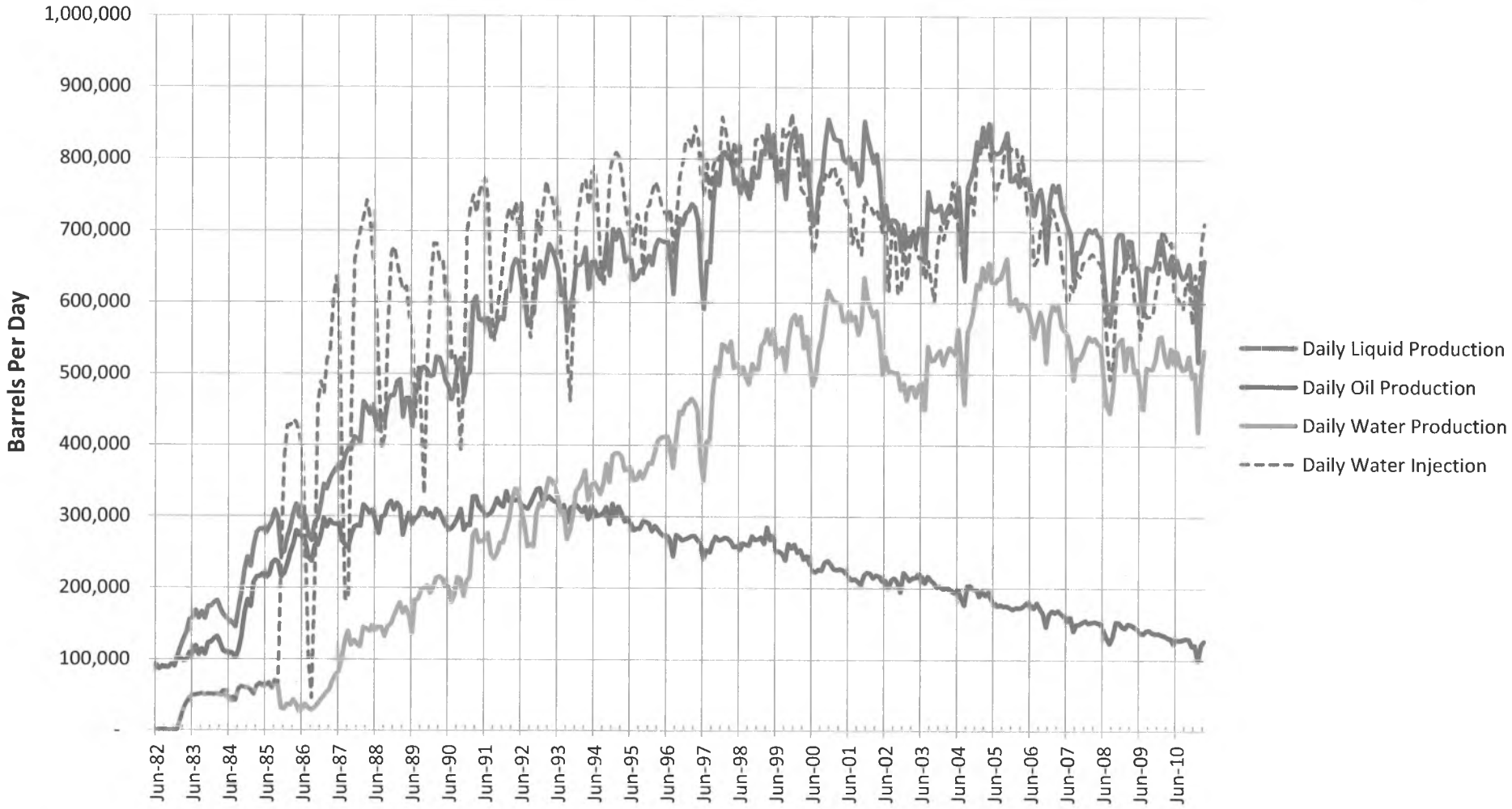
- Significant increase in shut-in wells due to mechanical integrity problems, increasing gas rates, conversion to water and MI injection, and the 2006 shut-down/corrosion problems

Cumulative Gas vs Cumulative Oil in Prudhoe Bay (2010)



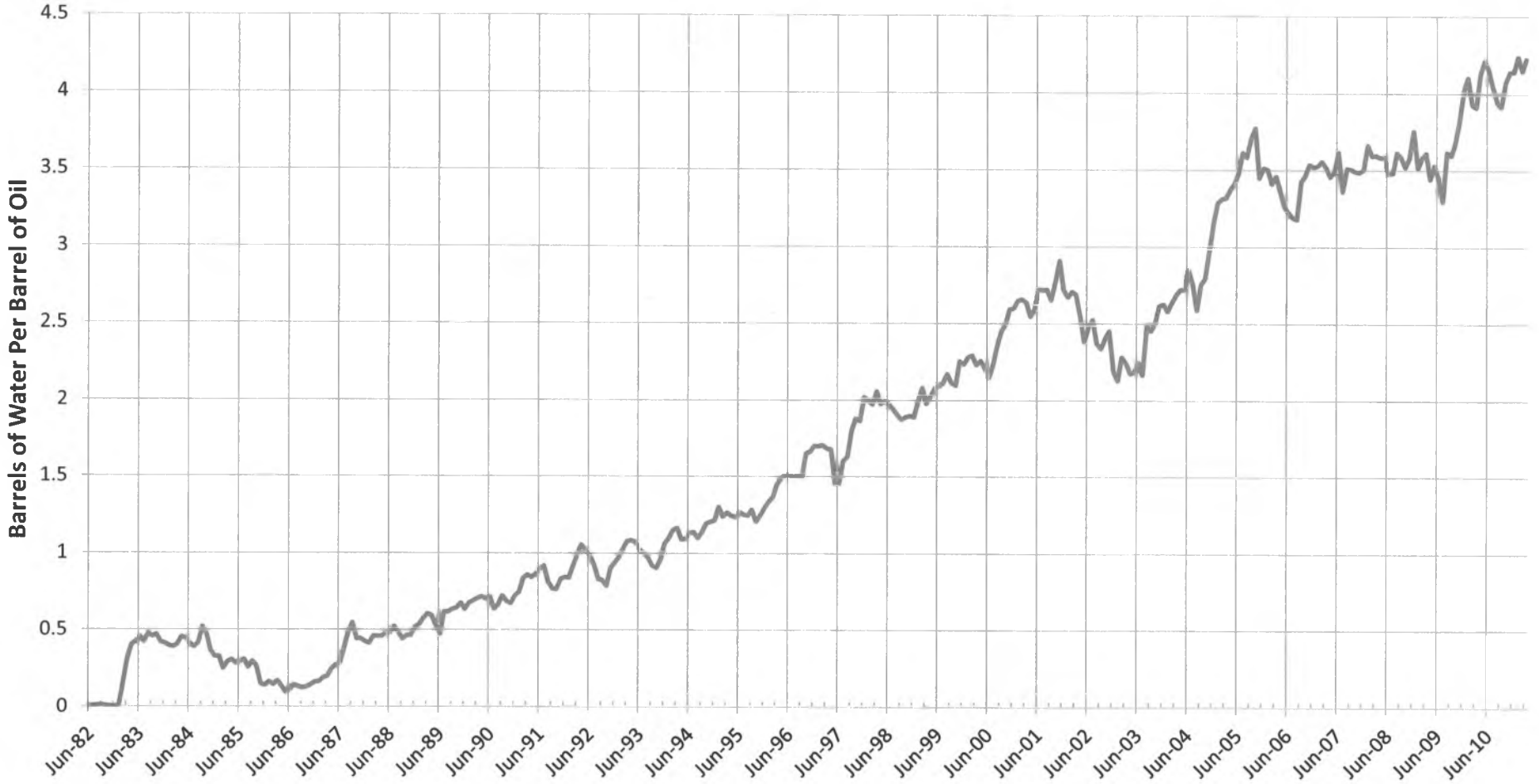
Kuparuk River Unit

Kuparuk River Liquids



- Current field wide water production is well below former peaks which indicates spare capacity
- Water production correlates strongly to water injection as it should in a late stage waterflood
- Current facility constraints would most likely be around integrity of all steel components

Kuparuk River Water Oil Ratio

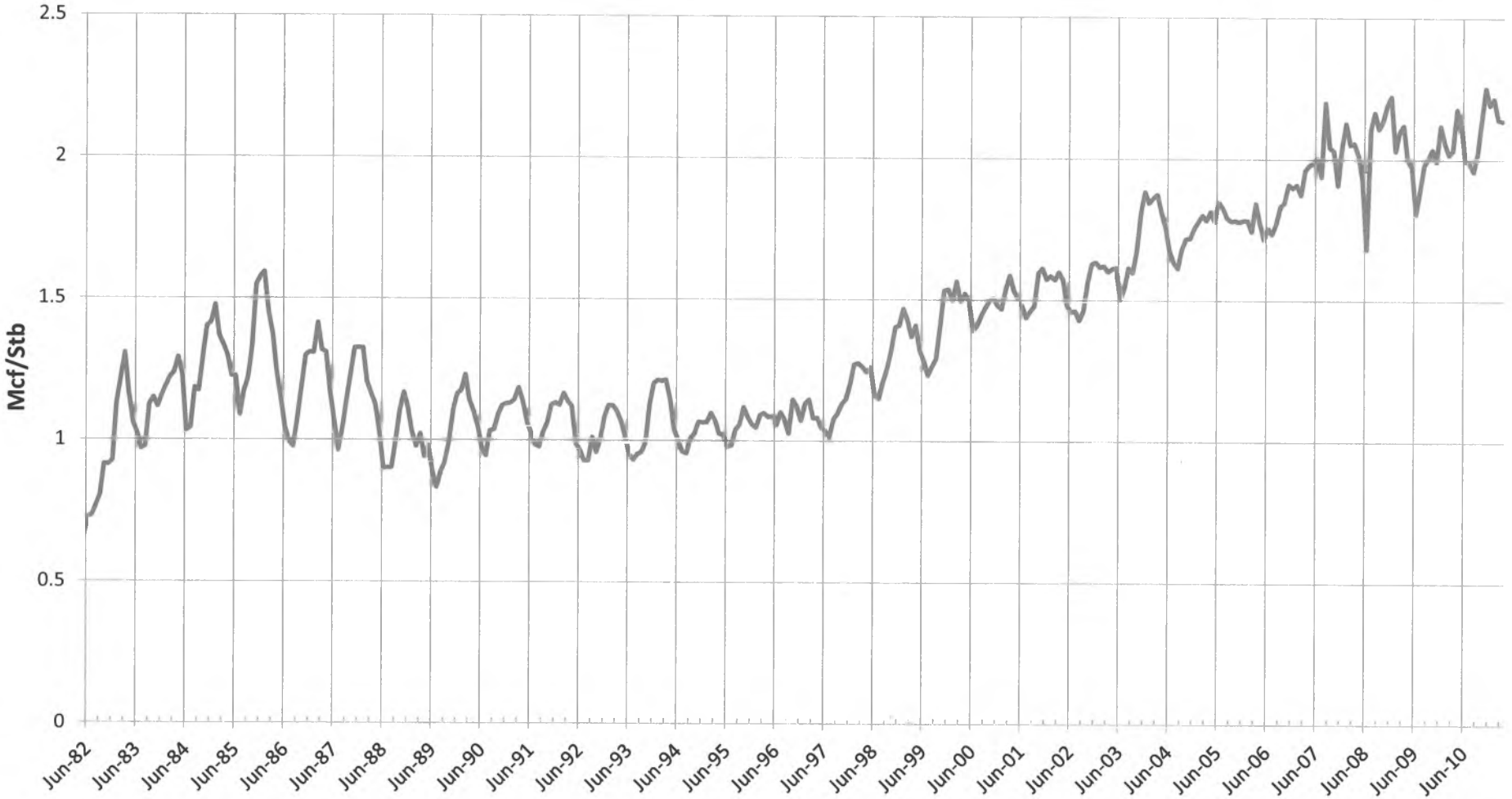


- The water oil ratio has recently exceeded 4:1 which corresponds to an 80% water cut
- It is not uncommon to see water cut for an individual well reach 95%+
- The dip seen in '02-'04 is due to a successful EOR program utilizing imported NGL from PBU

Kuparuk River Liquid Production by Cental Processing Facility

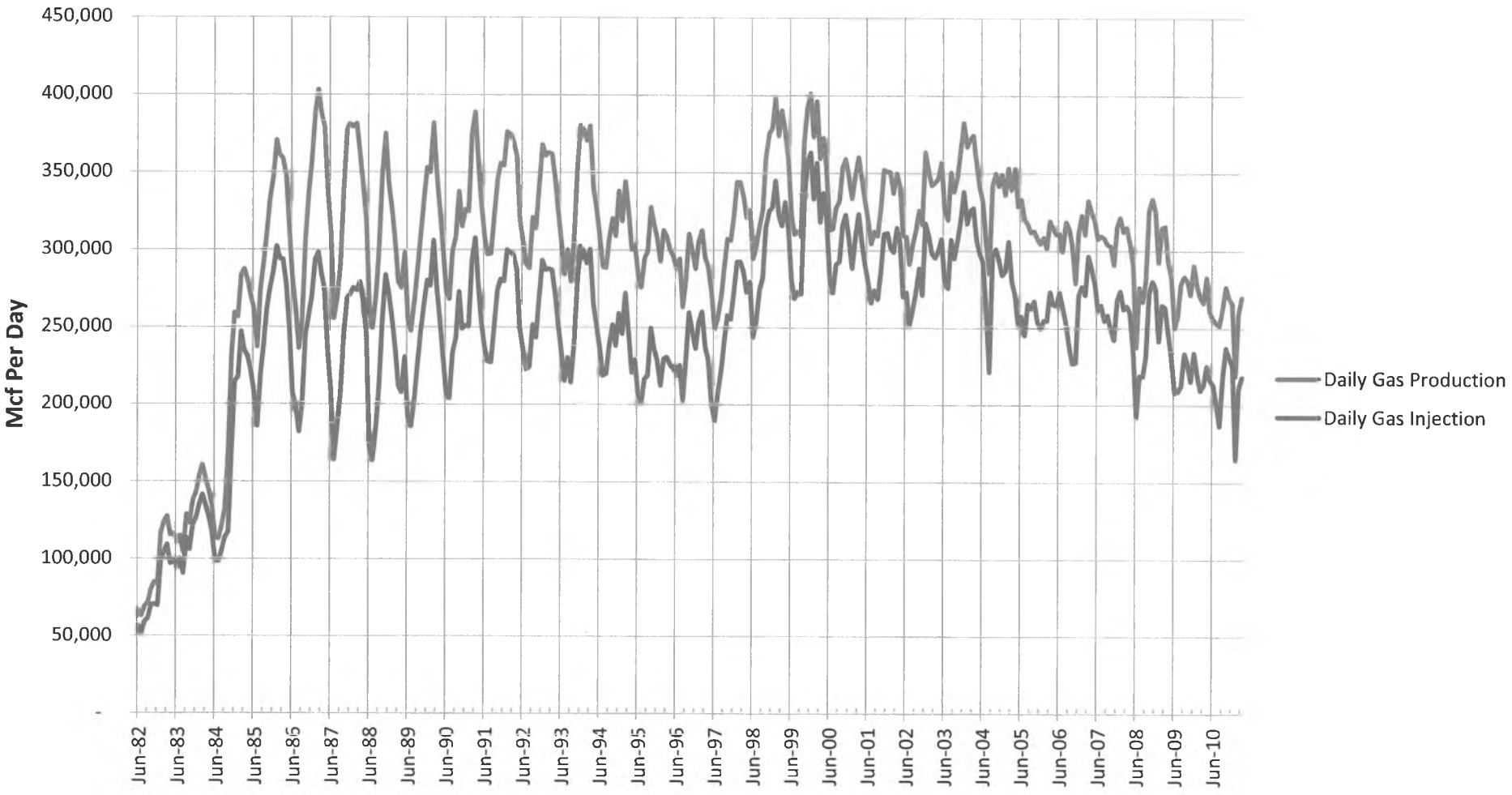
- Central Processing Facilities number one and two are likely not running at full capacity, number three may be
- If the quality of the produced oil changes in a way that it takes longer to separate from water, then it is possible that daily separation capacity could drop

Kuparuk River Gas Oil Ratio



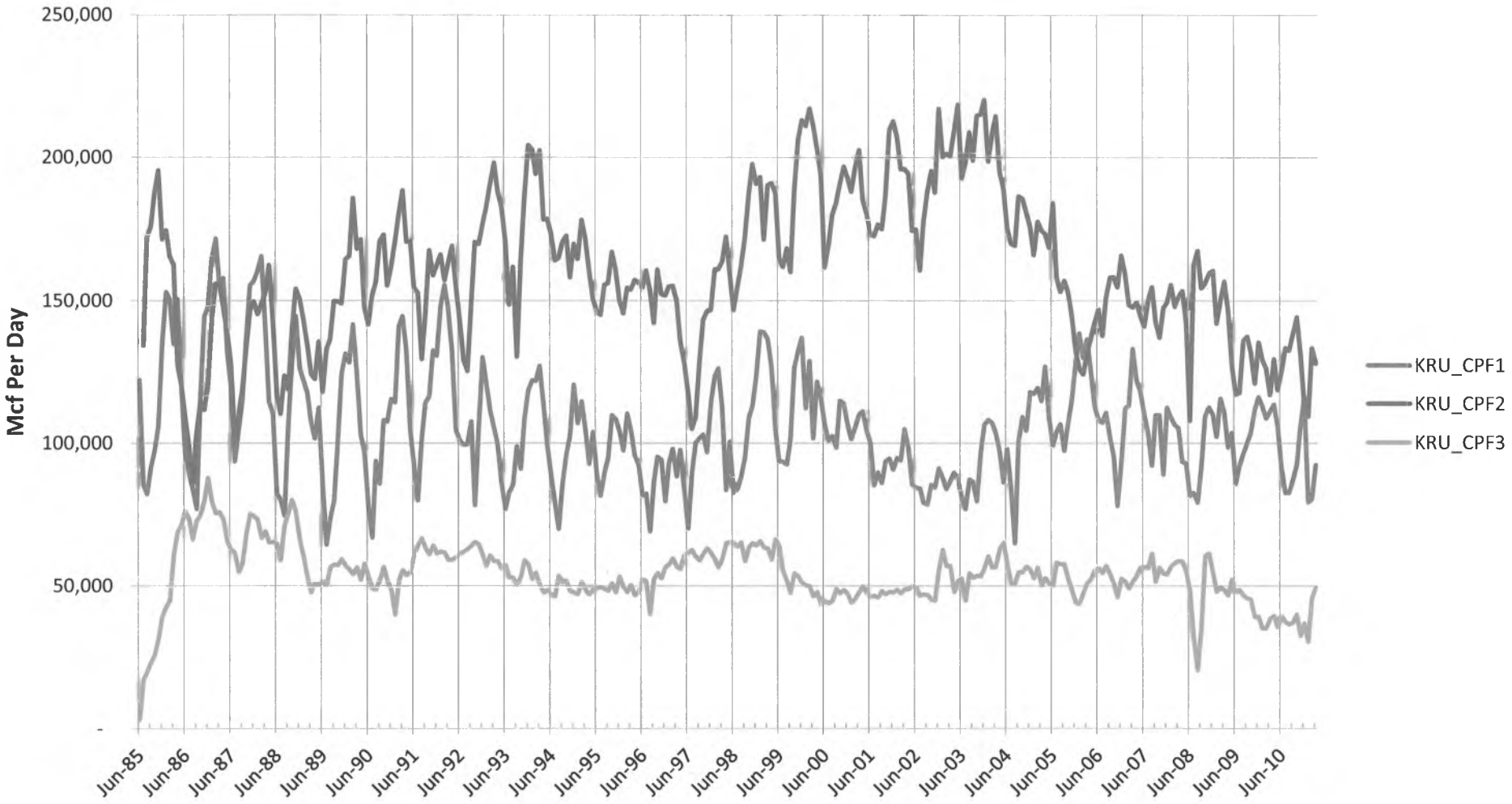
- The low gas oil ratio is what should be expected from an undersaturated reservoir such as Kuparuk
- It follows that there is no reason for GOR to increase significantly in the future unless a major secondary EOR (gas based) is pursued

Kuparuk River Gas



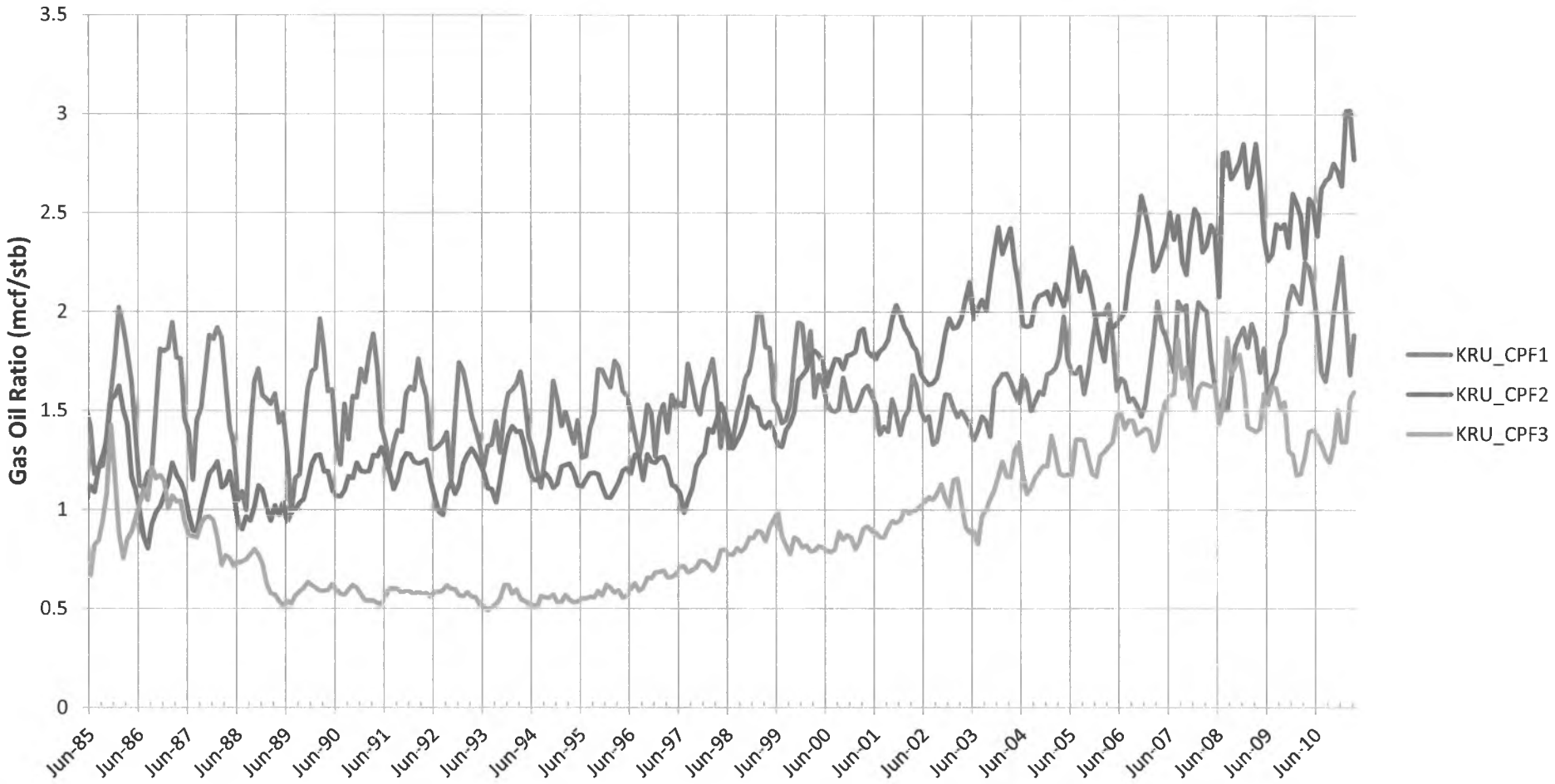
- Gas production and consequently gas injection has steadily declined over the last decade
- ConocoPhillips plans on importing gas to the field in the near future to maintain optimum producing conditions
- Field-wide there is spare capacity for gas, but there could be constraints at a specific facility

Kuparuk River Gas Production by Central Processing Facility



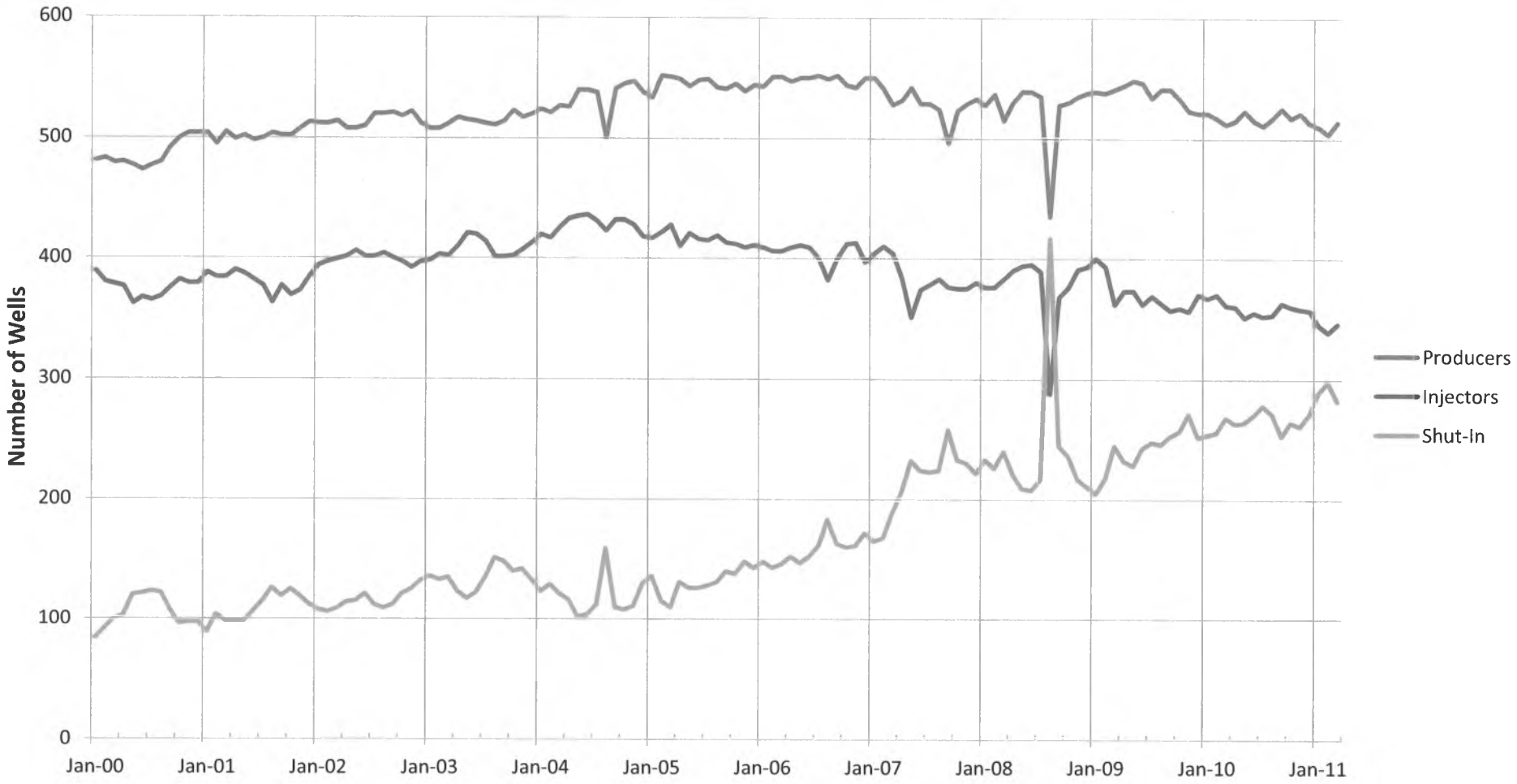
- It appears that all three facilities are not currently operating at peak capacity
- CPF2 underwent an expansion project in 2002
- The expansion project increased oil production for approximately a two year period

Kuparuk Gas Oil Ratio by Central Processing Facility



- GOR behavior by facility indicates that CPF2 could have the largest issue with gas constraints if oil production were to increase

Kuparuk River Well Count



- Shut-in wells have been climbing steadily since 2005 due to casing integrity and mature patterns
- The total well count has climbed during this time as new wells are being drilled for field expansion