THE STATE of ALASKA
GOVERNOR MIKE DUNLEAVY

Department of Natural Resources

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February 1, 2024

The Honorable Lyman Hoffman
Senate Finance Committee, Co-Chair
Alaska State Legislature
State Capitol, Room 516
Juneau, AK 99801

The Honorable Bert Stedman
Senate Finance Committee, Co-Chair
Alaska State Legislature
State Capitol, Room 518
Juneau, AK 99801

The Honorable Donald Olson
Senate Finance Committee, Co-Chair
Alaska State Legislature
State Capitol, Room 508
Juneau, AK 99801

Re: Fall 2023 Production Forecast Presentation

Dear Co-Chairs Hoffman, Olson, and Stedman,

Thank you for the opportunity to present the annual production forecast to the committee on January 17, 2024. In providing testimony, several questions needed follow-up information to better inform the committee. Those answers are below.

Did the operator of Prudhoe Bay boost marginal production in the near-term but also accelerate long-term overall decline?

As Prudhoe Bay Unit (PBU) Operator, Hilcorp has increased gas and water throughput by increasing the uptime and capacity for the facilities managing these constraints (for example, Hilcorp has achieved Central Gas Facility gas handling volumes matching the highest annual average rates since the early 2000s), which allows more production to occur today. These actions do have a short-term impact of accelerating oil production by increasing the number of wells available to flow at any given time. Over the long term, increasing the number of wells available to flow should allow Hilcorp to optimize production by creating “bench” strength. In other words, if one well goes down, other wells can be brought online to take its place because capacity is available. These optimization choices over time should enable greater ultimate recovery from the reservoir.

In addition, Hilcorp and the PBU owner group has also invested capital in the Prudhoe Bay Unit to develop resources that were not being pursued by the prior operator (*e.g.*, brought back and increased the pace of infill drilling with rotary and coiled tubing drilling rigs, and targeted untapped reserves for development in the Prudhoe Bay Western Satellites and Greater Point McIntyre Area).

Finally, a field as large as Prudhoe Bay has a huge number of inputs to its decline rate, and the long-term decline rate in Prudhoe is driven by geology and physics, and thus is expected to continue to decline over time. The Division has not observed, nor does it expect the long-term decline rate to be detrimentally increased by the aforementioned optimization efforts.

What is the subsurface ownership for the key new projects?

Please see Attachment 1, which includes an update of the table on presentation slide 7 to show ownership. Subsurface ownership determines the beneficial royalty owner. The updated slide is followed by a map showing the state's share of interest in the leases that underlie part of the Pikka and Colville River units. These lands are jointly owned by the Arctic Slope Regional Corporation and the State, so both entities receive portions of the royalties from any production according to the percentages shown in the map.

What are the capacities of different major facilities on the North Slope?

Please see Attachment 2, which is an updated table describing facility capacity status of major North Slope units. The following is an explanation of the data collection:

1) The facility throughput limitations with regards to oil, gas, and water are estimated using public information; if not available, they are estimated based on historical peak rates from AOGCC database when the historical production shows decline or flat trends.
2) Some facilities still have upward trends on water or have produced very little water up to date. Historical peak rates might not reflect the true facility capacity, so those estimates are not given and are indicated in the table by a question mark. Rather than identify inaccurate capacities for these facilities, the Department feels it would be most appropriate to identify there is not clarity from public data.
3) Production from fields with multiple facilities (such as Prudhoe Bay) are aggregated to field level due to the interconnectivity between facilities and no clear way of assigning production volumes from certain wells to a specific facility for a given period.
4) Estimation of facility capacity is based on historical peak rates and so may not reflect the real name plate capacities of the respective facilities and fields, but rather our best estimate if the facility could deliver those volumes historically. These rates may or may not be achievable under present conditions. Specifically, operators may remove equipment from service if their forecast shows historically high rates may never be achieved again, and it is not cost-effective to keep them in service.

Finally, it is important to note that gas production is influenced by ambient temperatures, so seasonality plays a large role in facility capacity.

What leases have produced gas on the North Slope in the last 5 years and have there been any changes in the companies' approaches to bring gas to tidewater?

Many leases on the North Slope produce gas that is used as fuel for field operations, treated and injected for enhanced oil recovery, or is reinjected to avoid waste. Below are tables showing the number of leases that have produced gas for sale in the last 5 years – since January 2019 – and the working interest ownership of those units.

North Slope Unit	Leases	Working Interest Ownership
Prudhoe Bay	92	ExxonMobil Alaska Production Inc. 36.40% ConocoPhillips Alaska, Inc. 36.08% **Hilcorp North Slope, LLC 26.36% (Operator)** Chevron U.S.A. Inc. 1.16%
Duck Island (Endicott)	10	**Hilcorp Alaska, LLC 50 – 100% (Operator)** Chevron U.S.A. Inc. 0 – 50%
Milne Point	22	**Hilcorp Alaska, LLC 100% (Operator)**
Kuparuk River	93	**ConocoPhillips Alaska, Inc. 52.22 – 55.40% (Operator)** ConocoPhillips Alaska II, Inc. 37.02 – 39.28% ExxonMobil Alaska Production Inc. 0.36 - 5.80% Chevron U.S.A. Inc. 4.95%
Oooguruk	12	**ENI Petroleum US LLC 100% (Operator)**
Colville River	44	**ConocoPhillips Alaska, Inc. 100% (Operator)**

The Department understands North Slope companies have been negotiating with the Alaska Gasline Development Corporation and other potential off-takers that are pursuing gas commercialization during this period.

What is the production forecast for Hilcorp, and what would the annual revenue to the State have been if those fields were not sold?

Due to the statutory confidentiality, DNR cannot provide exact royalty calculations for specific producers, and the Department of Revenue is responsible for tax-based revenue information.

However, viewing DNR's public ownership data with past DOR forecasts from the Revenue Sources Book (RSB) for the different owner groups at different times can provide a sense of how production levels at various fields have differed between BP and Hilcorp as Hilcorp assumed ownership and operation of these assets. Specifically, Hilcorp's assumption of operatorship has been associated with significant increases in expected production in the comparable forecasted period. For example, the FY 2029 production forecast in Fall 2023 for the core Prudhoe Bay area under Hilcorp's operatorship is 179,700 barrels per day, significantly greater than the Fall 2019 forecast of 139,900 barrels per day for the same FY 2029 period under BP's operatorship. While only a component of state revenue, increased royalty volumes from this additional production, especially when measured over multi-year period, are associated with significant additional revenue. Finally, for the Prudhoe Bay Unit, while Hilcorp serves as operator, it is only a minority owner, and the 73.64% majority ownership of the field continues to be held by other companies.

Hilcorp's 2024 and 2019 working interest in North Slope units is summarized in the tables below. All these working ownership interests were acquired from BP. The corresponding 2024 and 2019 working interest ownership unit maps can also be downloaded from the Department's website.

North Slope Unit	Working Interest Ownership (January 2024)
Prudhoe Bay	ExxonMobil Alaska Production Inc. 36.40% ConocoPhillips Alaska, Inc. 36.08% **Hilcorp North Slope, LLC 26.36% (Operator)** Chevron U.S.A. Inc. 1.16%
Duck Island (Endicott)	**Hilcorp Alaska, LLC 74.24% (Operator)** Chevron U.S.A. Inc. 25.76%
Milne Point	**Hilcorp Alaska, LLC 100% (Operator)**
Northstar	**Hilcorp Alaska, LLC 100% (Operator)**
Point Thomson	ExxonMobil Alaska Production 62.36% **Hilcorp Alaska, LLC 36.99% (Operator)** Other entities, collectively 0.65%
Liberty *Federal lands, no production*	**Hilcorp Alaska, LLC 50% (Operator)** **BP Exploration (Alaska) (Hilcorp North Slope LLC) 50%**

North Slope Unit	Working Interest Ownership (March 2019)
Duck Island (Endicott)	**Hilcorp Alaska, LLC 88.9% (Operator)** Chevron U.S.A. Inc. 11.1%
Milne Point	**Hilcorp Alaska, LLC 48.9160% (Operator)** BP Exploration (Alaska) 48.9160% Eni Petroleum US LLC 1.0602% Herbaly Exploration LLC 0.9970% Joyce, George Allen 0.1108%
Northstar	**Hilcorp Alaska, LLC 100% (Operator)**
Liberty *Federal lands, no production*	**Hilcorp Alaska, LLC 50% (Operator)** BP Exploration (Alaska) 40% ASRC Exploration LLC 10%

Below is the Fall 2023 RSB production forecast table with the Hilcorp ownerships annotated.

Appendix **C-2**

Annual Average Daily Crude Oil Production
By production area

			Thousand barrels per day									
		Hilcorp ownership	Forecast									
			FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033
	Alaska North Slope											
1	Prudhoe Bay	26.36%	190.4	191.8	192.3	189.6	185.0	179.7	175.1	170.8	167.1	162.8
2	PBU Satellites	26.36% (+ Milne Point 100%)	82.4	87.1	90.9	94.8	98.0	98.8	97.8	95.9	93.7	91.7
3	GPMA	26.36%	28.4	27.6	26.5	24.9	23.7	22.4	21.1	19.9	18.9	18.0
4	Kuparuk		51.4	45.7	44.1	41.6	39.2	36.7	34.4	32.4	30.5	28.3
5	Kuparuk Satellites		28.2	30.0	35.0	48.3	62.2	64.3	59.6	54.9	50.7	47.0
6	Endicott	74.24%	9.5	10.8	9.4	8.3	7.5	6.9	6.4	5.9	5.5	5.2
7	Alpine		32.3	30.7	27.4	25.1	24.1	24.6	24.5	24.3	25.6	29.4
8	Offshore	Northstar 100%	27.6	25.6	24.3	22.7	21.3	20.8	21.3	22.2	22.6	22.3
9	NPRA		17.0	11.6	16.7	16.7	11.9	9.6	23.0	63.8	108.0	130.3
10	Point Thomson	36.99%	3.0	2.8	4.1	6.1	8.1	8.5	8.2	7.9	7.7	7.4
11	Other		0.0	0.0	2.5	38.2	67.9	73.8	75.6	73.3	78.5	90.7
12	**Total Alaska North Slope**		**470.3**	**463.8**	**473.1**	**516.5**	**548.8**	**546.1**	**546.8**	**571.2**	**608.7**	**633.0**
13	**Cook Inlet**		**8.2**	**7.4**	**7.1**	**7.4**	**7.8**	**7.7**	**7.5**	**7.0**	**6.5**	**5.9**
14	**Total Alaska**		**478.5**	**471.2**	**480.2**	**523.9**	**556.6**	**553.9**	**554.3**	**578.2**	**615.2**	**638.8**

Field grouping:

1 Prudhoe Bay

2 Aurora, Borealis, Midnight Sun, Milne Point, Orion, Polaris, Sag River

3 Lisburne, Niakuk, North Prudhoe/Put River, Point McIntyre, Raven

4 Kuparuk

5 Coyote, Nuna-Torok, Tabasco, Tarn, West Sak

6 Badami, Eider, Endicott, Minke, Sag Delta

7 Alpine, Fiord West, Mustang, Nanuq, Narwhal, Qannik

8 Hooligan, Nikaitchuq, Northstar, Oooguruk

9 Greater Mooses Tooth, Willow

10 Point Thomson, Sourdough

11 Projects under development or evaluation outside previous areas that have forecast production within ten years. Includes Alkaid, Horseshoe, Pikka, Quokka, Talitha, Theta West.

Notes: FY 2018, FY 2019 and FY 2022 production figures have been revised since being originally published due to revised company submissions.

Shipments of natural gas liquids (NGLs) from Prudhoe Bay to Kuparuk for use in large-scale enhanced oil recovery are excluded from historical data. These shipments ceased in August 2021 and are not expected to occur in future. NGLs from Central Gas Facility shipped on TAPS are included in this table.

Totals may show slight differences from other sources due to rounding and aggregation differences.

Below is the Fall 2019 RSB production forecast table with the Hilcorp ownerships annotated.

Appendix C 2

Annual Average Daily Crude Oil Production

By production area *(Continued)*

	Hilcorp ownership	Thousand Barrels per Day									
		Forecast									
Fiscal Year		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Alaska North Slope											
Prudhoe Bay[2]	0%	202.2	195.4	187.3	179.6	172.0	164.6	157.8	151.5	145.6	139.9
PBU Satellites/Milne Point[3]	0%/48.9%	46.2	51.9	47.0	42.0	38.8	36.5	34.7	33.4	32.3	31.4
Greater Point McIntyre Area[4]	0%	27.0	21.4	19.2	17.5	16.1	14.9	13.9	13.0	12.2	11.5
Kuparuk		70.4	67.7	64.2	61.1	58.2	56.6	53.6	51.1	48.9	46.8
Kuparuk Satellites[5]		32.7	31.9	33.8	32.1	28.4	36.5	29.0	25.8	23.7	22.1
Endicott[6]	88.9%	8.1	7.2	6.6	6.1	5.7	5.4	5.0	4.7	4.4	4.2
Alpine[7]		54.2	56.9	50.2	44.9	43.4	42.3	39.2	34.8	30.8	28.0
Offshore[8]	Northstar 100%	34.3	36.4	32.2	28.9	26.8	26.1	26.3	26.6	26.3	25.1
NPR-A		11.5	13.4	11.3	17.8	27.9	36.9	40.2	39.3	44.7	52.6
Point Thomson		5.6	8.2	8.2	8.2	8.1	7.9	7.5	6.5	5.4	4.9
Other[9]		0.0	0.1	0.1	1.4	9.0	22.4	51.5	82.2	108.1	128.1
Total Alaska North Slope		**492.1**	**490.5**	**460.1**	**439.7**	**434.3**	**450.0**	**458.9**	**468.9**	**482.5**	**494.5**
Cook Inlet		**16.2**	**15.7**	**13.7**	**12.4**	**11.3**	**10.5**	**9.8**	**9.5**	**9.5**	**9.2**
Total Alaska		**508.3**	**506.1**	**473.8**	**452.1**	**445.7**	**460.4**	**468.7**	**478.4**	**492.0**	**503.7**

[1] FY 2018 production figures have been revised from the *Fall 2018 Revenue Sources Book* due to revised company submissions.

[2] Includes Natural Gas Liquids (NGLs) from Central Gas Facility shipped to TAPS. Fall 2019 Forecast assumes that for all years of the forecast, 10,000 barrels per day of NGLs will be shipped from Prudhoe Bay to Kuparuk for use in a large scale enhanced oil recovery project. These NGLs are excluded from production actuals and forecasts reported in this table.

[3] Aurora, Borealis, Midnight Sun, Orion, Polaris, Sag River, Schrader Bluff, Ugnu, Milne Point.

[4] Lisburne, Niakuk, Point McIntyre, Raven, West Beach, West Niakuk.

[5] Meltwater, NEWS, Tabasco, Tarn, West Sak.

[6] Endicott, Minke, Sag Delta, Eider, Badami.

[7] Alpine, Fiord, Nanuq, Qannik, Mustang, Fiord West.

[8] Northstar, Oooguruk, Nikaitchuq, Liberty, Nuna.

[9] Projects under development and under evaluation that are outside of the preceding areas. Includes Alkaid, Guitar, Narwhal, Pikka, Placer, Smith Bay.

Note: Totals may show slight differences from other sources due to rounding and aggregation differences.

Please let me know if we can be of further help in providing information to the committee.

Sincerely,

Joe Byrnes

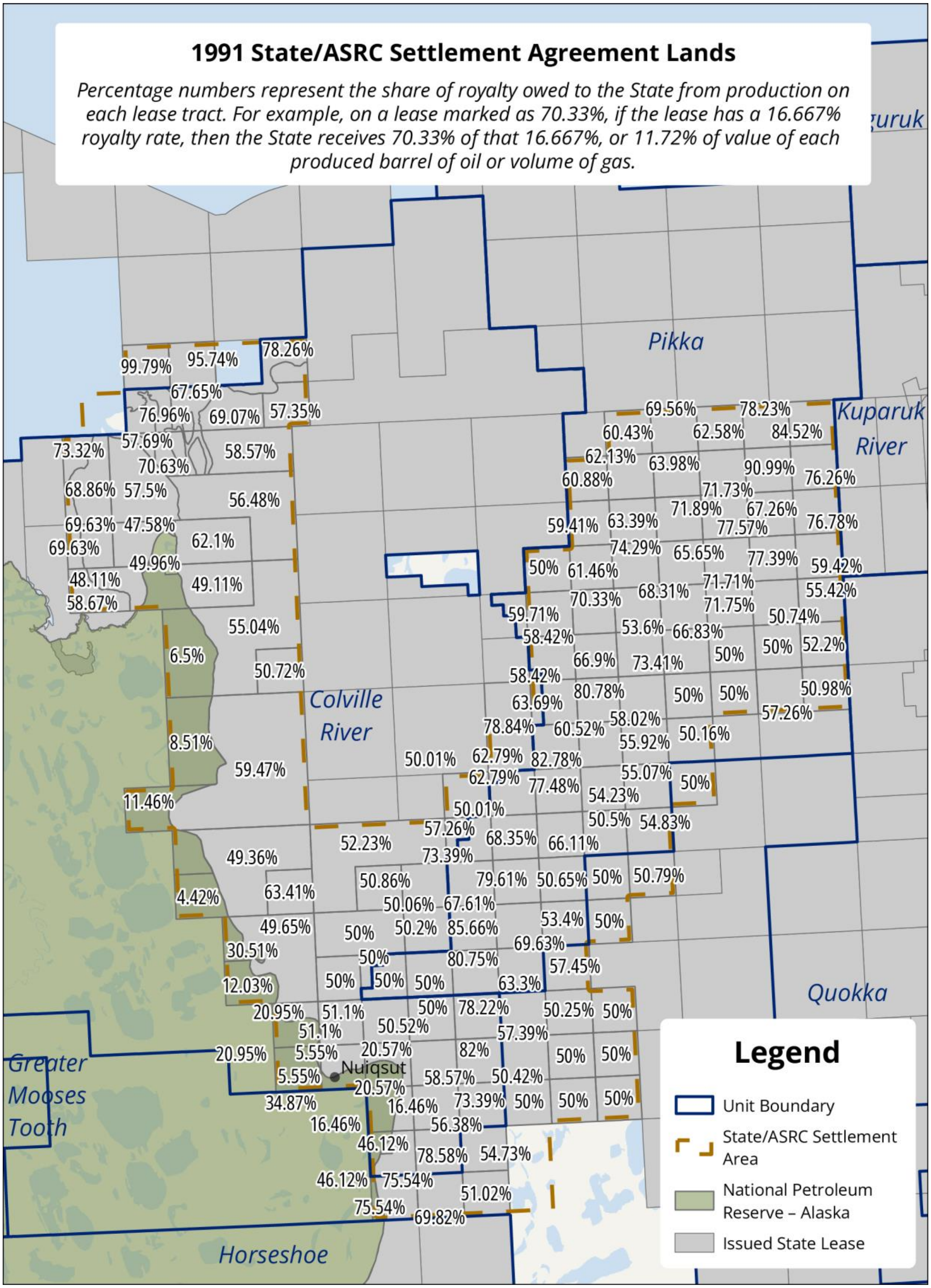
Joe Byrnes
Legislative Liaison

Cc: Laura Stidolph, Governor's Legislative Office Director

Project	Status: January 2023	Status: January 2024	Production Rate Estimates
Pikka State and ASRC land. Royalty rates: 16.67%	Project Final Investment Decision (FID) approved in August 2022 for Pikka Phase 1. Project first oil anticipated in 2026.	Project construction and drilling activities ongoing, and project first oil anticipated in Q2 of 2026.	Peak design capacity rate, Phase 1: 80,000 bopd
Willow 100% Federal Land	Awaiting BLM Record of Decision (ROD) on SEIS. FID cannot be made before the ROD is made. First oil expected 6 years after FID, if approved.	BLM ROD on SEIS issued in 2023 and Conoco started construction activities in April 2023. FID announced December 2023. First oil expected in 2029.	Peak rate: ~180,000 bopd
CRU Narwhal CD8 State, Federal, and ASRC land. Royalty rates: 16.67%.	Sustained production from CD8 could commence as early as 2028, pending stakeholder alignment, permitting, internal studies and alignment. This conceptual first oil date remains consistent with the 23rd POD submitted in 2021.	The conceptual first oil date changed to 2030 in the 25th CRU POD submitted in 2023, pending stakeholder alignment, permitting, and internal studies and alignment.	Peak DNR estimates >32,000 bopd
MPU Raven Pad 100% State Land Royalty rates: 12.5% 3 NPSLs with 30% net profit share	November 2022 Hilcorp applied for approval to construct a new drilling and production pad (R Pad) within the Milne Point Unit.	DNR approval granted for R Pad construction in February 2023 within the Milne Point Unit. Construction activities ongoing.	Peak DNR estimates ~10,000 bopd. Analogous to the 2018 M Pad development at MPU.
KRU Nuna-Torok 100% State Land Royalty rates: 12.5% and 16.67%. 3 NPSLs with 30% net profit share.	2022 KRU POD states rotary drilling is planned in Q3 of 2022 with an additional injector/producer pair for additional Torok reservoir appraisal to inform future developments.	Conoco project funding approved in 2023, and subsequently DNR approved drill site 3T expansion activities. Construction activities are ongoing, and first oil is anticipated in 2025.	Peak rate up to 20,000 bopd

Acronyms:

POD: Plan of Development	BLM: US Department of Interior Bureau of Land Management	CRU: Colville River Unit	YE: Year End
FEED: Front End Engineering Design	ROD: Record of Decision	MPU: Milne Point Unit	Q: Quarter
FID: Final Investment Decision	SEIS: Supplemental Environmental Impact Statement	KRU: Kuparuk River Unit	


1991 State/ASRC Settlement Agreement Lands
Percentage numbers represent the share of royalty owed to the State from production on each lease tract. For example, on a lease marked as 70.33%, if the lease has a 16.667% royalty rate, then the State receives 70.33% of that 16.667%, or 11.72% of value of each produced barrel of oil or volume of gas.
Pikka
Kuparuk River
Colville River
Quokka
Greater Mooses Tooth
Horseshoe
Nuiqsut
99.79% 95.74% 78.26%
67.65%
76.96% 69.07% 57.35%
73.32% 57.69% 58.57%
70.63%
68.86% 57.5% 56.48%
69.63% 47.58% 62.1%
69.63%
49.96%
48.11% 49.11%
58.67%
55.04%
6.5%
50.72%
8.51%
59.47%
11.46%
49.36%
63.41%
4.42%
49.65%
30.51%
12.03%
20.95% 51.1%
51.1%
20.95% 5.55%
5.55%
34.87%
16.46%
69.56% 78.23%
60.43% 62.58% 84.52%
62.13% 63.98%
60.88% 90.99% 76.26%
71.73%
71.89% 67.26%
59.41% 63.39% 77.57% 76.78%
74.29% 65.65% 77.39%
50% 61.46% 59.42%
71.71%
70.33% 68.31% 55.42%
71.75%
59.71% 50.74%
58.42% 53.6% 66.83%
50% 50% 52.2%
66.9% 73.41%
58.42%
80.78% 50% 50% 50.98%
63.69%
57.26%
78.84% 60.52% 58.02%
55.92% 50.16%
50.01% 62.79% 82.78%
62.79% 77.48% 55.07% 50%
54.23%
50.01%
57.26% 50.5% 54.83%
52.23% 68.35% 66.11%
73.39%
50.86% 79.61% 50.65% 50% 50.79%
50.06% 67.61%
50% 50.2% 85.66% 53.4% 50%
69.63%
50% 80.75% 57.45%
50% 50% 50% 63.3%
50% 78.22% 50.25% 50%
50.52%
57.39%
20.57% 82% 50% 50%
58.57% 50.42%
20.57%
16.46% 73.39% 50% 50% 50%
56.38%
46.12%
78.58% 54.73%
46.12% 75.54%
51.02%
75.54%
69.82%
Legend
Unit Boundary
State/ASRC Settlement Area
National Petroleum Reserve – Alaska
Issued State Lease

Unit	Facility	Oil Capacity *bopd*	Gas Capacity *mscf/d*	Water Capacity *bwpd*	Notes	Facility Limits
Prudhoe Bay	Gathering Center 1, 2 & 3 Flow Station 1, 2 & 3 Central Gas Facility (CGF) Central Compression Plant Central Power Station	?	8,500,000	1,450,000	• Unclear how much of the oil export equipment remains in service • Prudhoe Bay is too interconnected between facilities to deduce individual facility limitations based on publicly available production data • As for all estimates, the operator would be the authoritative source for the actual current capacities of facilities but is not required to disclose to DNR what may be viewed as sensitive, commercial information	Gas is the biggest constraint, though water handling at the waterflood facilities is often maxed out in conjunction with PBU field gas-handling. For example, water pumps at GC-2 could be fully utilized while gas throughput at GC-2 might have space – but there is no capacity for extra gas due to the CGF being at its gas limit.
	2023 avg. rate	*230,750*	*7,680,000*	*1,342,000*		
Greater Point McIntyre (GPMA)	Lisburne Processing Center	?	500,000	200,000	• Unclear how much of the oil export equipment remains in service • The water capacity estimate may be too high since some Pt. Macintyre production is processed at GC1 but is included in the GPMA	Same as PBU on constraints; gas is the biggest constraint though water is often maxed out.
	2023 avg. rate	*28,100*	*447,500*	*183,400*		
Milne Point	Milne Point Central Processing Facility	60,000	35,000	170,000		Predominately water constrained, but gas is also often close to maxed out.
	2023 avg. rate	*40,400*	*24,400*	*160,200*		
Kuparuk River	Kuparuk Central Production Facility 1, 2 & 3	340,000	400,000	670,000	Field level max is *not* a sum of facility max but is based on historic field performance. Facilities reached their respective highest rate at different times, so the sum is higher	Water handling capacity has often been a constraint on the oil production rate. CPAI is progressing studies aiming to forecast and balance seawater and produced water over time. Gas handling limits with the gas lift compressors will continue to constrain production from the KRU. CPAI is progressing studies that aim to forecast and balance gas across the field.
	2023 avg. rate (including Oooguruk)	*86,400*	*130,500*	*578,200*		

Unit	Facility	Oil Capacity *bopd*	Gas Capacity *mscf/d*	Water Capacity *bwpd*	Notes	Facility Limits
Point Thomson	Point Thomson Unit Initial Production System	10,700	200,000	?	• Highest rate month to-date for both gas and condensate production is December 2018. The field averaged ~200,000 mscfd gas throughput to achieve this condensate rate for that month • Gas capacity is estimated based on public Exxon materials • Field makes very little water, unclear what the real water limit could be	Well production constrained.
	2023 avg. rate	*4,500*	*80,100*	*50*		
Badami	Badami Processing Facility	38,500	20,000	?	• Oil capacity is estimated based on public media reports • Field makes very little water, unclear what the real water limit could be	No facility limits with current wellstock.
	2023 avg. rate	*760*	*470*	*16*		
Duck Island (Endicott)	Endicott Processing Facility	120,000	380,000	250,000		Facility is routinely bumping up against both gas and water handling limits.
	2023 avg. rate	*6,300*	*349,000*	*231,600*		

Unit	Facility	Oil Capacity *bopd*	Gas Capacity *mscf/d*	Water Capacity *bwpd*	Notes	Facility Limits
Nikaitchuq	Nikaitchuq Processing Facility	25,000	5,000	70,000	Water production keeps rising over years, doesn't seem to have peaked yet.	No constraints noted by operator as of date.
	2023 avg. rate	*16,100*	*2,750*	*59,200*		
Northstar	Northstar Production Facility	80,000	620,000	20,000		No constraints noted by operator as of date.
	2023 avg. rate	*7,200*	*564,000*	*14,400*		
Oooguruk	KRU's CPF 2	15,000	20,000	7,500		Gas constraints due to limited gas lift capacity and limitations with shared KRU facilities
	2023 avg. rate	*5,900*	*4,900*	*3,500*		
Colville River	Alpine Central Facility	140,000	180,000-220,000	184,000	• Oil capacity estimated based on historical peak rate, actual capacity would need to be confirmed by operator • Water and gas capacity based on public information	Gas capacity increased by 30 mmscfd since completion of Alpine Gas Expansion project in 2021. Gas handling capacity still limits production due to addition of Greater Mooses Tooth 1 & 2 projects. Operator drilled injection wells at GMT2 to improve gas handling.
	2023 avg. rate (including Greater Mooses Tooth 1 & 2)	*51,000*	*157,000*	*57,000*		