**STATE OF ALASKA**
OFFICE OF THE GOVERNOR

**MEMORANDUM**

DATE: November 12, 2024

TO: Members of the Alaska State Legislature
Members-Elect of the Alaska State Legislature

FROM: Governor Mike Dunleavy

SUBJECT: Alaska's Energy Crisis

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The looming Cook Inlet crisis is the most critical energy issue facing Alaska policymakers and I am writing to provide an important analysis requested by the legislature, which will be formally presented during a House Resources Committee hearing on November 19, 2024. During this hearing, legislators will hear from energy experts with the international energy research firm Wood Mackenzie, who will present the economic case for quickly constructing the Alaska LNG pipeline.

The Alaska Gasline Development Corporation (AGDC) is currently leading the development of Alaska LNG on behalf of the state, and at my direction AGDC created a phased construction strategy for Alaska LNG. Alaska LNG Phase 1 prioritizes construction of the pipeline to more quickly deliver North Slope natural gas to Interior and Southcentral Alaska and resolve the Cook Inlet energy crisis. Alaska LNG Phase 2 includes the infrastructure components needed to convert gas to LNG and export it.

Last spring, via intent language, the legislature requested an economic analysis of Alaska LNG Phase 1 to document the benefits of this approach, as follows:

*"It is the intent of the legislature that the Alaska Gasline Development Corporation continue to work towards meeting the critical energy needs of Alaskans by advancing a pipeline project proposal which would deliver North Slope natural gas to Alaska's utilities, businesses, and homeowners. Further, it is the intent of the legislature that the Alaska Gasline Development Corporation complete an independent third-party review of a project proposal that would commercialize North Slope gas and present that analysis to the legislature by December 20, 2024.* ***It is the further intent of the legislature that if analysis shows a positive economic value to the state, all parties would work toward Front End Engineering and Design for Phase 1 of a pipeline project****." (Emphasis added.)*

As you will see, Wood Mackenzie's independent analysis yields three key findings:

**(1) Alaska LNG Phase 1 economics are superior to or competitive with alternatives.**

- Alaska LNG Phase 1 can predictably deliver natural gas in a range between $8.97-$12.80 per million British thermal units (mmbtu). Alaska LNG Phase 1 is not subject to market volatility.
- Imported LNG is difficult to reliably price because of market volatility. Wood Mackenzie conservatively estimates a range beginning between $10.21 to $13.72/mmbtu, excluding the additional costs of required onshore infrastructure, estimated to be in the hundreds of millions of dollars, and regulatory and permitting uncertainty, which will also drive costs higher for imports.

**(2) Alaska LNG will dramatically lower long-term Alaska energy prices.**

- Alaska gas prices will drop to $2.23/mmbtu when the export components are complete and full volumes are achieved. For comparison, the current price of Cook Inlet gas is approximately $8.69/mmbtu.

**(3) Alaska LNG Phase 1 will uniquely deliver up to $16 billion in additional Alaska economic benefits that won't occur with other options.**

- These benefits include construction capital expenditures, jobs, tax and royalty state revenue, consumer savings from lower gas prices, business and economic growth, and improved Fairbanks health outcomes and investment.

Completing Alaska LNG will ensure that an affordable and reliable supply of clean energy is available to Alaskans for generations. As we approach the coming legislative session, I look forward to collaborating with you to expeditiously evaluate and act on ways we can move Alaska LNG forward and transition Alaska LNG to an industry-led project that benefits all Alaskans.

# Economic viability assessment and economic value of Alaska LNG project - Phase 1

**Final**

October 2024

# Project Background

Wood Mackenzie has worked extensively as an independent consultant on Alaska's energy issues since 2016 to provide an economic analysis of the viability of the cost of supply (CoS) for Alaska LNG (also referred to as AK LNG). Most recently in 2021/22, Alaska Gasline Development Corporation (AGDC) engaged Wood Mackenzie for an updated analysis that included calculating a new base CoS, identifying opportunities to optimize the CoS, a competitive analysis and providing our long-term projections.

Since the last study, AGDC has proposed a phased approach to developing Alaska LNG. Phase 1 involves developing the gas pipeline from the North Slope to Southcentral and Interior Alaska markets. As part of Phase 1, ADGC has engaged Wood Mackenzie for **an independent economic analysis of the proposed gas pipeline** and an **economic benefit analysis** for the state of Alaska.

The information on which this independent report is based has either come from our experience, knowledge and database or it has been supplied to us by AGDC. The opinions expressed in this report are those of Wood Mackenzie. They have been arrived at following careful consideration and enquiry, but we do not guarantee their fairness, completeness, or accuracy. The opinions, as of this date, are subject to change. Please note that for this engagement, we have adjusted our standard base case to reflect disclosed asset-specific information.

This Report is structured across 5 sections:

- Southcentral and Interior Alaska market overview
- Delivered cost of piped gas and scenario analysis
- Analysis of LNG imports as an alternative
- Economic impact of Alaska LNG Phase 1
- Final takeaways and conclusions

# Gas supply via pipeline provides over ~US$10 Bn of positive economic impact, 2 - 4x more jobs, and access to lower delivered costs vs LNG imports, though it requires higher capex

- **Cook Inlet gas supply has declined**, and despite exploration efforts by operators, **no new volumes** have been **discovered**
- Lack of reliable and affordable gas supply drove **decline in demand**, however going forward **supply** is expected to **drop faster** creating a **demand gap of ~2.3 tcf** (to 2071) projected to begin by the end of this decade
- With Cook Inlet gas production proving to be challenging, there are **two main alternatives** to address the forecasted **supply & demand gap**:

| | Natural Gas Supply via Pipeline | LNG Imports |
|---|---|---|
| | A 765 mile (Phase 1), 42-inch diameter pipeline connecting the Southcentral Alaska region with the North Slope fields | Gas imports via LNG, for which regas and further downstream infrastructure is required |
| | ▪ Cost of delivered gas in the **US$2.23 – $12.8/mmbtu** | ▪ Cost of delivered gas in the **US$10.2 – $13.7/mmbtu (plus onshore costs)** |
| | ▪ Direct, indirect and induced GVA**: ~US$ 10.3 Bn**<br>▪ **2,271 jobs**[1] created during construction and **1,138 in operations** | ▪ Lower capex & lower direct, indirect and induced GVA **~US$0.6 – 1.4 Bn**<br>▪ **568 jobs**[1] during **construction** and **250** in **operations** |
| | ▪ Time to first gas 2031[3] | ▪ 3-4 Years post FID[2], though no major permit applications have been submitted. Permitting and/or required buildout could delay first gas |
| | ▪ Provides access to **upside demand** with additional industrial and economic benefits to the state<br>▪ **Reducing emissions** and **removal from EPA's nonattainment** in **Fairbanks** via substitution of oil & wood as primary energy source | ▪ Focused supply for the Southcentral region<br>▪ No Fairbanks or additional industrial demand<br>▪ Exposure to higher price volatility for energy needs |
| | ▪ Higher **likelihood** of **full Alaska LNG Project** | |

Source: Wood Mackenzie; 1. Direct, indirect and induced jobs, average per year of each period; 2. First gas for LNG imports is dependent on receiving all required permits, and Wood Mackenzie is uncertain about the status of those. Additionally, as of March 2024, Enstar's (local gas distributor) earliest estimation of first gas is 2029. 3. The AGDC has indicated that the pipeline has all major permits in place

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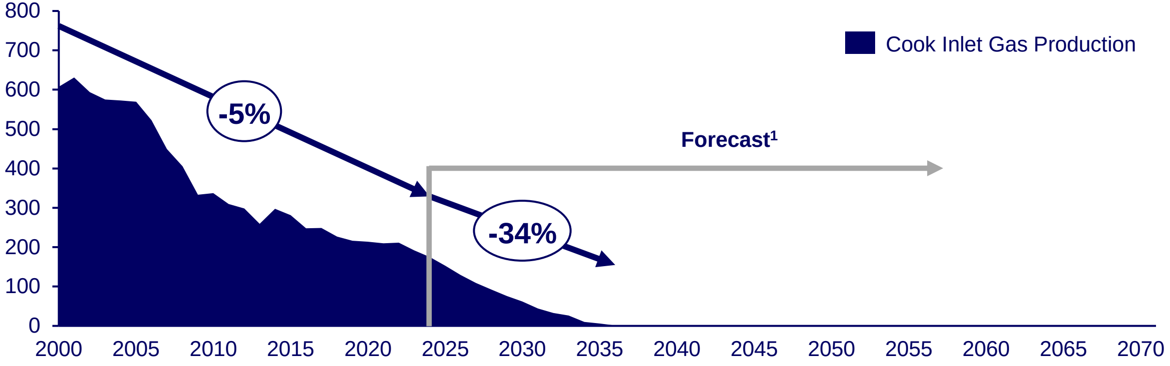
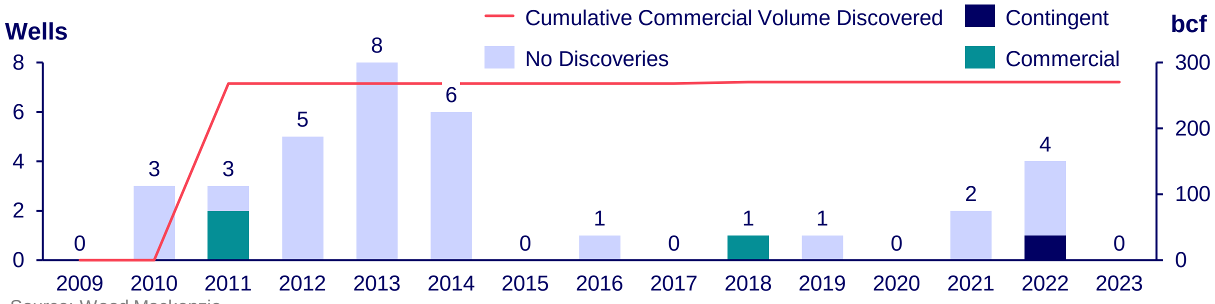
# Gas supply has been dwindling, and despite exploration efforts by operators, no new volumes have been discovered in Cook Inlet to replenish the reserves

**Cook Inlet gas production**
mmcfd




**Exploration activity in the Cook Inlet basin**




- Cook Inlet production is expected to be depleted by the mid-2030s
- Exploration success in the Cook inlet has been limited:
  - **34 exploration wells** drilled in the last 15 years
  - **9% success rate** with only three commercial discoveries
  - **270 bcf** of reserves discovered in the last 15 years

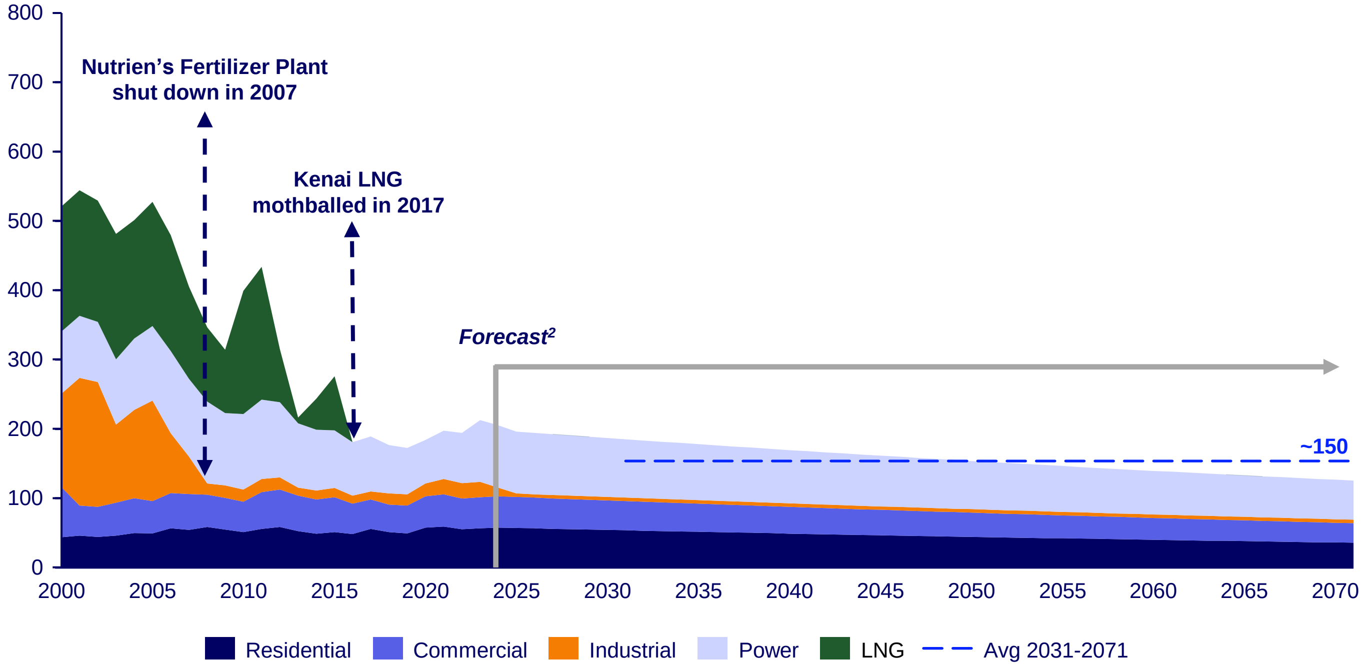
Source: Wood Mackenzie
1. Compounded Annual Decline Rate is 34% driven by production reaching 0 in 2037.

# A lack of secure, consistent, and affordable supply of gas has driven a consistent decline (5% CAGR) in gas demand for the past 20 years

Based on Wood Mackenzie's (WM) current demand outlook for Alaska (adjusted for Industrial Sector reporting), we extended the forecast to 2071 to match the operating horizon for Alaska LNG Phase 1.

Due to supply constraints, industrial activity was impacted by the Nikiski Refinery lowering its demand to 5 mmcfd.

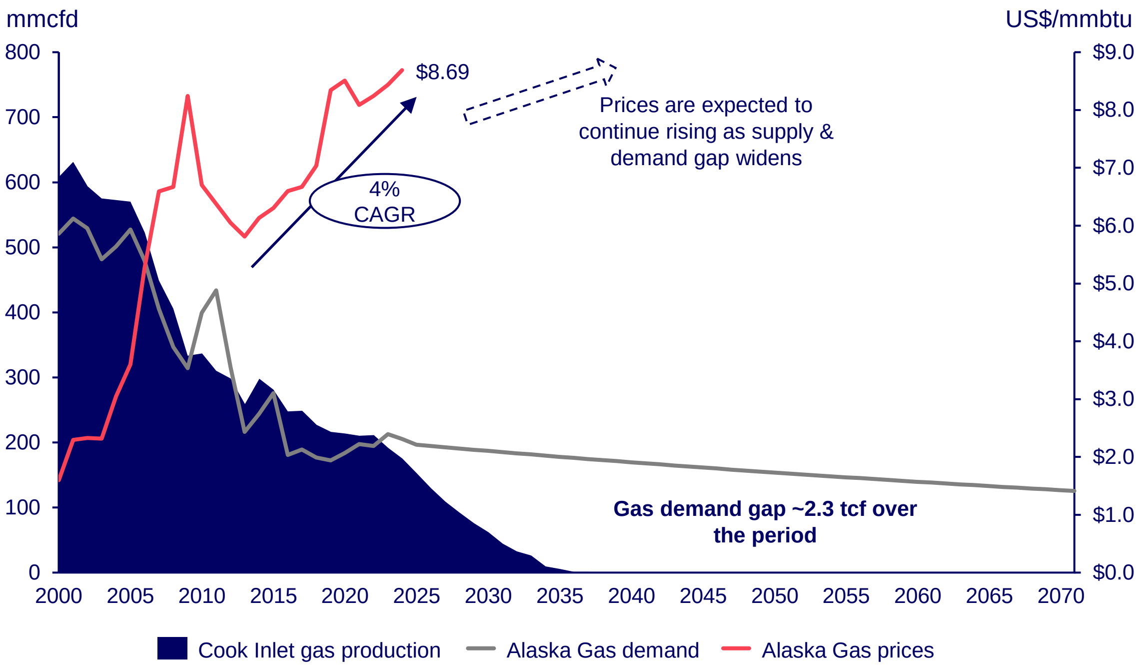
**Current State gas demand in Alaska[1] (2000–2071)**
mmcfd




Source: Wood Mackenzie
1. Excludes North Slope Region In-field gas and considers the rest of regions with gas demand (Anchorage, Mat-Su, and Kenai Peninsula). Refer to Appendix for detailed assumptions. 2. Demand forecast shows WM outlook for 2024-2050, extended to 2071 and adjusted for Industrial reporting (2021-2023).

# An estimated cumulative demand gap of ~2.3 tcf is projected which will likely continue to drive gas prices up for Alaska consumers

**Cook Inlet gas production/demand[1] and gas prices in Alaska**




- Lack of steady gas supply and increasing gas prices have affected industrial development in the region
- Prices will continue to rise as the demand gap expands and reaches an average of 192 mmcfd between 2031 and 2071
- A total of **2.3 tcf** of gas is needed to fill the identified gap from 2031 to 2071, more than 8x the discovered reserves in the last 15 years
  - For this reason, relying on additional production from Cook Inlet is not considered a viable option to meet long-term demand

Source: Wood Mackenzie, Prices from EIA

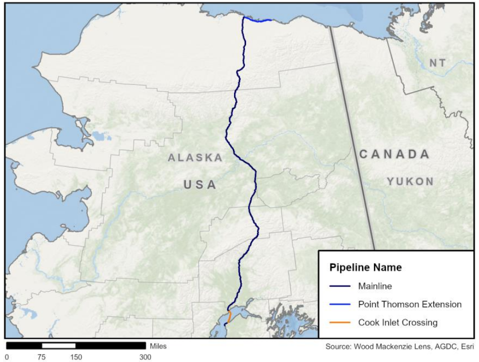
1. Demand shows WM outlook for 2024-2050, extended to 2071 and adjusted for Industrial reporting (2021-2023)

# With Cook Inlet gas production recovery proving to be a challenge, two main alternatives to addressing the forecast supply gap are a new gas pipeline and LNG imports

## Gas supply alternatives for Southcentral and Interior Alaska market

### 1. Natural gas supply via pipeline

In Phase 1, a 765-mile, 42-inch diameter mainline pipeline will connect the Southcentral Alaska region with the northern fields, providing a secure and affordable gas supply. In the beginning, the pipeline will supply local and industrial consumption, then expand to provide feed gas for export into LNG markets.

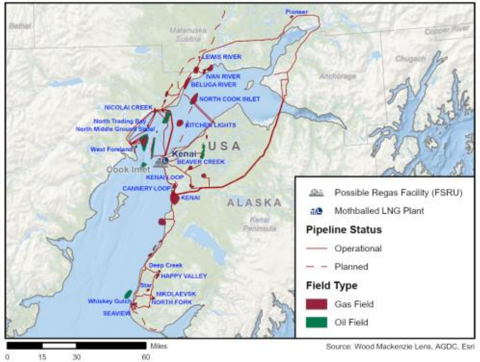



**Key stats**

- Total capex: From US$10.8 billion to US$14.9 billion for max capacity
- Time to first gas: 2031
- Capacity: 3.3 bcfd at max
- Ability to expand to cover incremental investment in subsequent LNG phases

### 2. LNG imports[1]

Gas imports via LNG require regas and further downstream infrastructure, including an FSRU dock to take the imported gas and potentially inland storage for operations optimization across yearly seasonality.




**Key stats**

- Total capex: TBD
- Time to first gas: 3 - 4 years post FID[2]
- Capacity: 400 to 450 mmcfd fit for current demand without increased industrial activity
- Expected utilization: 40 – 45%

Source: AGDC, Wood Mackenzie

1. Map location of the FSRU is illustrative since planned location is pending definition based on receiving port; 2. Excelarate Energy announced in Aug '24 a target commercial start date for LNG imports via FSRU for 2028, suggesting its plans to take FID during 2024, though location of the required dock and overall status of the project is not clear as of writing of this report

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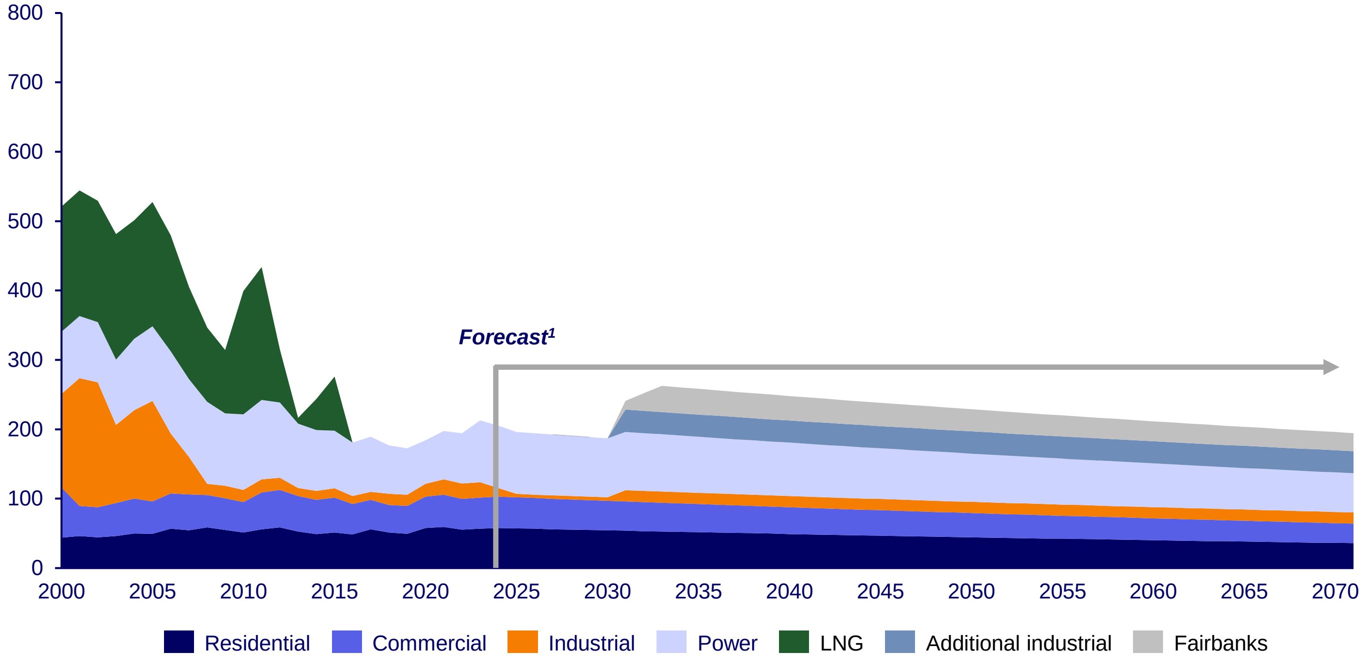
# If the Pipeline is built, additional demand will arise from 3 main sources: Fairbanks shifting to gas for energy/heat needs, Nikiski refinery demand recovering, and additional industrial applications

In addition to the Current State demand forecast, as shown in slide 5, the following are anticipated:

- Substitution of oil and wood as primary energy/heat source in Fairbanks[1].
- Industrial gas demand from the Nikiski Refinery shifts to burning propane. Gas demand reduces to 5 mmcfd, then rebounds to 16 mmcfd after the pipeline begins operations.
- New or returning industrial activity will produce an additional gas demand of 32 mmcfd with new gas supply availability[2].

**Expected gas demand in Alaska (2000 – 2071)**
mmcfd




Source: Wood Mackenzie

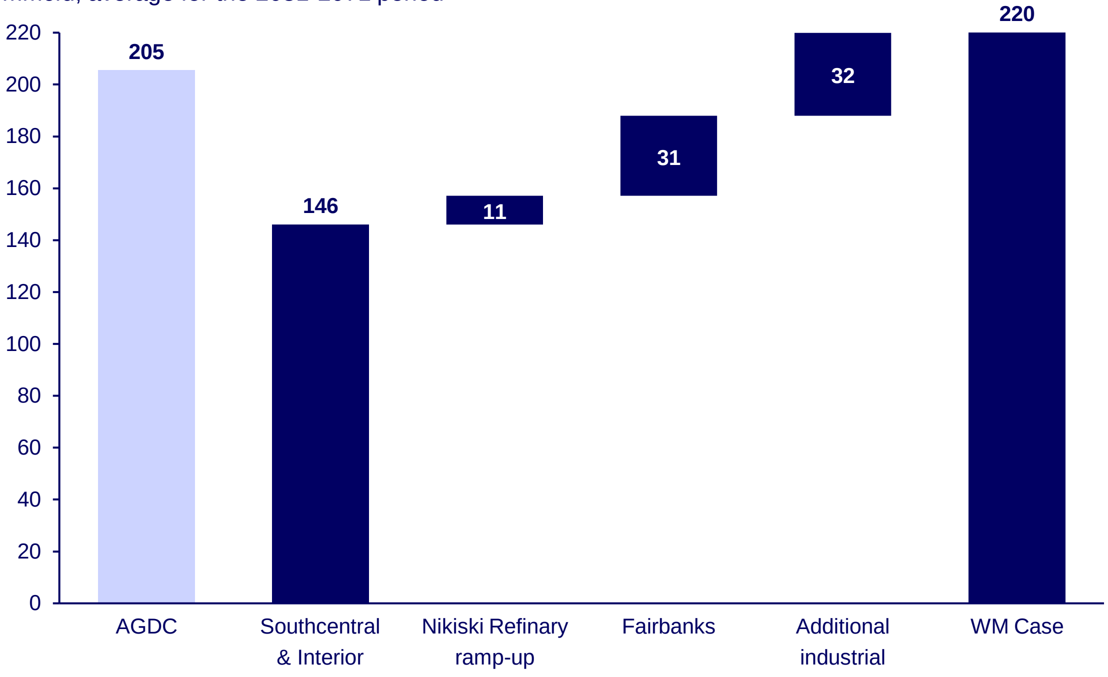
1. Fairbanks is a nonattainment area under the EPA. If Alaska LNG Pipeline is built, Fairbanks could change to gas for energy/heat needs. We assume 90% penetration with a 3-year transition (2031 – 2033)
2. In 2001, industrial demand reached 185 mmcfd with population at 632,716. Even though the population is expected to peak in 2033, WM expects enough demographic base to support increased demand back to historic levels via additional uses of natural gas, excluding the Fertilizer Plant (185 total – 137 Fertilizer – 16 Nikiski Refinery = 32).

# We have built a Wood Mackenzie (WM) case by accounting for current gas demand, adding Fairbanks and incremental industrial applications

- **AGDC input:** demand estimate based on feedback from current utilities and industrials at 75 bcf per year (~205 mmcfd)
- **Southcentral and Interior**: Includes WM forecast for Alaska gas demand with additional considerations:
  - Demand for Southcentral and Interior regions[1]
  - Possibility of storage for optimized capacity usage during seasonal peaks.
- **Nikiski Refinery,** and/or other gas-consuming operations expanding to 16 mmcfd with access to piped gas from 5 mmcfd currently
- **Fairbanks** substitution of oil/wood for gas.
- **Additional Industrial** activity
- **WM Case:** Current State, adjusted for regional demand, plus Nikiski Refinery, Fairbanks, and additional demand

**Gas demand for the Southcentral and Interior regions**

mmcfd, average for the 2031-2071 period




Source: Wood Mackenzie

1. Outside the Southcentral region, other regions have limited gas access mainly because of infrastructure constraints. 95% of gas demand is considered to come from the Southcentral region.

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# Four scenarios were developed and analyzed to account for: existing gas demand (baseload), potential new demand brought by gas availability, and the construction of a 20 mtpa LNG facility

| Scenario | Description | Components | Average gas demand (mmcfd, 2031-2071) |
|---|---|---|---|
| **Scenario 1: Baseload** | This includes the Current State demand for gas in Southcentral and Interior Alaska. Plus, additional demand from Fairbanks substitution of oil/wood as gas becomes available to avoid EPA's nonattainment area designation and finally, the ramp-up from the Nikiski Refinery | Current state (Southcentral + Interior) + Fairbanks + Nikiski Refinery | ~190 |
| **Scenario 2: WM Case** | Baseload plus additional gas demand based on historical gas demand for the industrial sector and population growth forecasts. We estimate Industrial demand will reach 48 mmcfd (32 mmcfd additional to 16 mmcfd from the Nikiski Refinery[1]). | Baseload + Additional Industrial Activity | ~220 |
| **Scenario 3: Additional Industrial demand** | This considers the maximum upside from industrial demand based on high-consuming facilities starting operations. This incremental gas demand could come from restarting a previously operating fertilizer plant, a new ammonia plant (brownfield or greenfield) or new data centers. | WM Case + High-consuming industrial plant | ~320 |
| **Scenario 4: Alaska LNG** | The 20 mtpa LNG Facility (Alaska LNG) will require an additional 2,844 mmcfd at full capacity[2]. This demand was added to the WM Case and assumed to come online in 2032 with one 6.7 mtpa train and two more in 2033 and 2034, respectively. | WM Case + Alaska LNG[3] | ~2,930 |

Source: Wood Mackenzie 1. In 2001 industrial demand reached 185 mmcfd with industrial activity and population at 632,716. Even though population is expected to peak in 2033, WM expects enough demographic base to support increased demand back to historic levels via additional uses of natural gas 2. Feedgas estimation considers 7.11% Liquefaction Loss, 1.56% Transport Loss, and 52,000,000 mmbtu/mt and 1,090 Btu/scf conversions. 3. Additional average demand is 2,705 for the 40 years due to phased kick-off of one train per year.

# The delivered cost of piped gas is calculated based on the cost of feed gas plus the pipeline tariff, which covers its capex, opex and a 10% expected return

**Delivered Cost of Gas – High Level Considerations**

The delivered cost of gas is estimated using a discounted cash flow model with a target ROE of 10% and the following considerations:

- Capex for Phase 1: US$10,769 million[1] (2024)
- One year of construction prep and four years of construction, starting in 2026
- Allowance for Funds Used During Construction (AFUDC) method for construction costs recognition
- 75% debt financing at 6.25% interest rate
- Property tax rate at 0.2%
- Feed gas is purchased at US$1.00 (2024) and escalated at 2% per year
  - Supplied by the Great Bear Pantheon Development of the Aphun and Kodiak fields
- Alaska LNG Phase 1 operating horizon from 2031-2071

Source: Wood Mackenzie, AGDC
1. Includes US$50 million of Property Taxes

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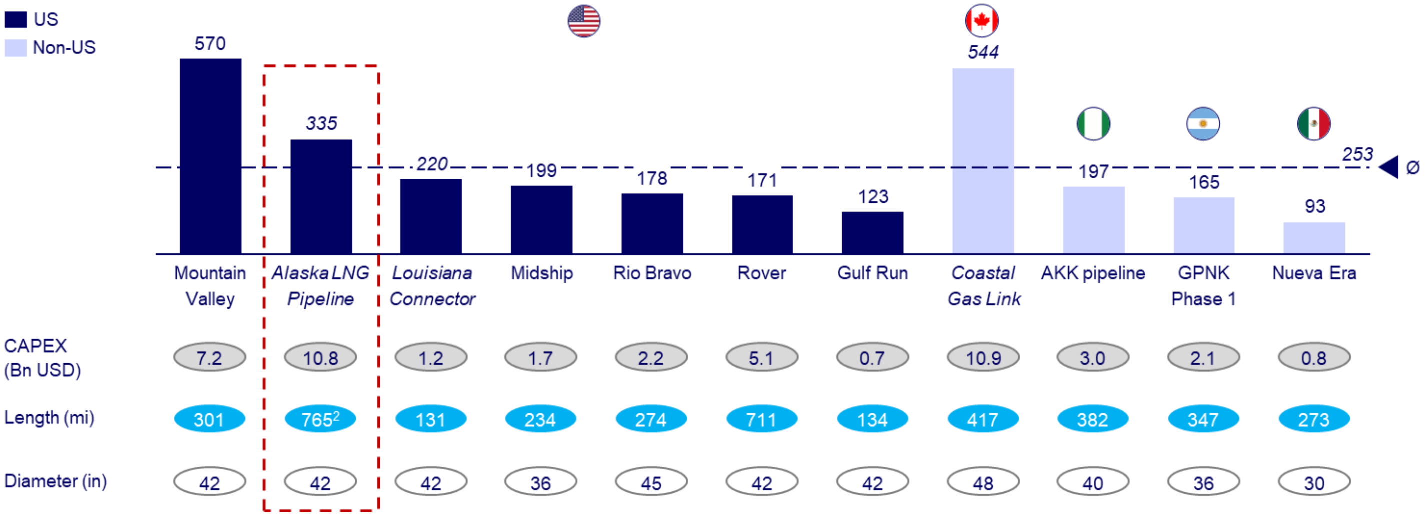
# The total estimated cost of the pipeline is US$10.8 billion for Phase 1, well within the range of recently built and proposed pipelines

## Pipeline cost benchmark

k US$/in-mi[1], real 2024




*Italic labels refer to cost estimation (pipeline not built and operating)*

- Mountain Valley and Coastal Gas Link have high costs largely due to specific regional context.
- Specific regions with regulatory challenges that have built new infrastructure, like the US NE and Canada BC, have seen longer timeframes and/or regulatory challenges delays.
- Additionally, economies of scale can be obtained for larger projects. Alaska LNG Phase 1 is two to five times bigger than peers
- However, this could lead to further contingency and/or cost overruns in the estimated cost of the Alaska LNG Phase 1 pipeline, on top of the 20% contingency currently considered

Source: Wood Mackenzie, AGDC; 1. Refers to US$ thousands divided by a composite of diameter and length; 2. Considers the announced 807 miles minus reduction due to lower scope requirement on Phase 1; Selected pipelines have been considered based on diameter, length, recency and main use

# Costs in the first three scenarios account for minimum compression capacity but with Alaska LNG, the cost for compression and a segment to cross Cook Inlet is also considered

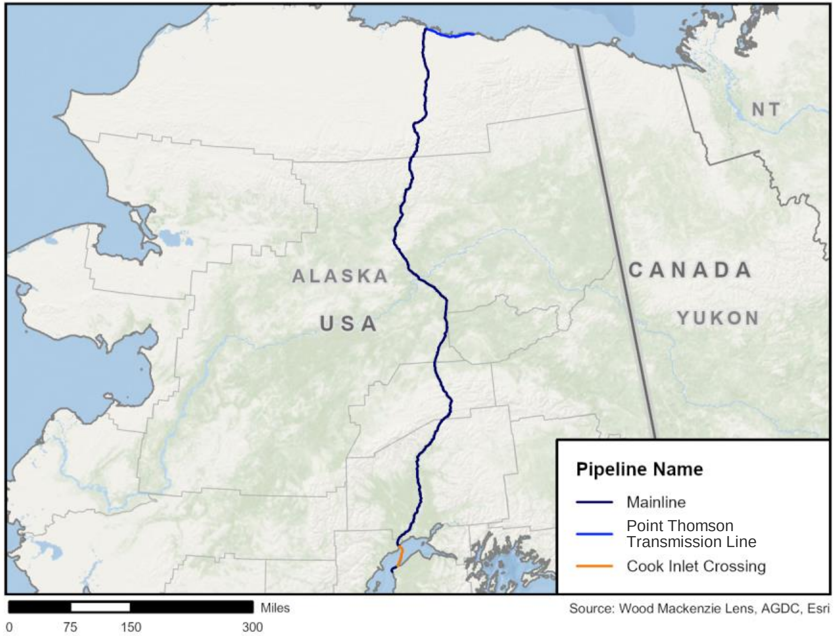
## Alaska LNG Pipeline capex by scenario

Real 2024 US$ million

| **Capex / Scenarios (2024 US$ million)** | | **Baseload** | **WM Case** | **Additional Industrial demand** | **Alaska LNG** |
|---|---|---|---|---|---|
| Phase 1 mainline[1] | $10,769 | ✓ | ✓ | ✓ | ✓ |
| Compression | $2,485 | | | | ✓ |
| Cook Inlet + Additional Section | $1,131 | | | | ✓ |
| Point Thompson Expansion | $564 | | | | N.A.[2] |
| **Total Amount** | **$14,950** | **$10,769** | **$10,769** | **$10,769** | **$14,385** |

- In-state gas demand is burden only by Phase 1 Capex
- Additional cost is considered only for LNG volumes coming online

## Alaska LNG Pipeline Scope




Source: Wood Mackenzie Lens, AGDC, Esri

Source: Wood Mackenzie with information from AGDC

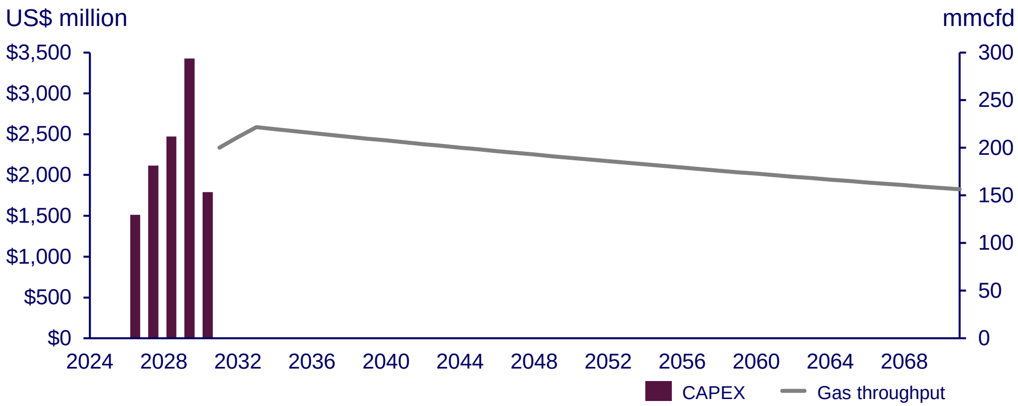
1. Considers 20% Contingency and US$50 million of Property Taxes

2. Alaska LNG Scenario does not consider the Point Thompson Expansion cost. In order not to affect the rest of the shippers it must be considered as part of the purchase gas cost for the LNG facility only.

# The delivered cost of gas in the Baseload Scenario is US$12.80/mmbtu; this accounts for current utilities and industrial demand, plus energy/heat needs from Fairbanks shifting to gas

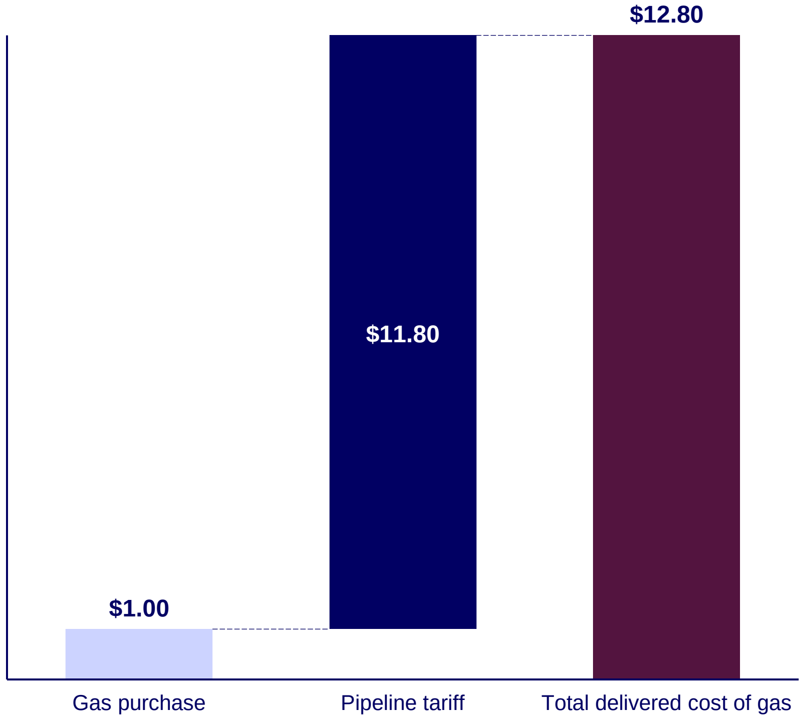
| Main assumptions | |
|---|---|
| Capex[1] | $10,769 (2024 US$ million) |
| Opex | 0.35% (Annual as % of capex) |
| Average throughput (2031 - 2071) | 188 mmcfd |
| Capital Structure | 25% Equity / 75% Debt |
| Interest Rate | 6.25% |
| Target Return on Equity (ROE) | 10% |

## Gas throughput and capex for Alaska LNG Phase 1 pipeline




## Delivered Cost of Gas

Real 2024 US$/mmbtu



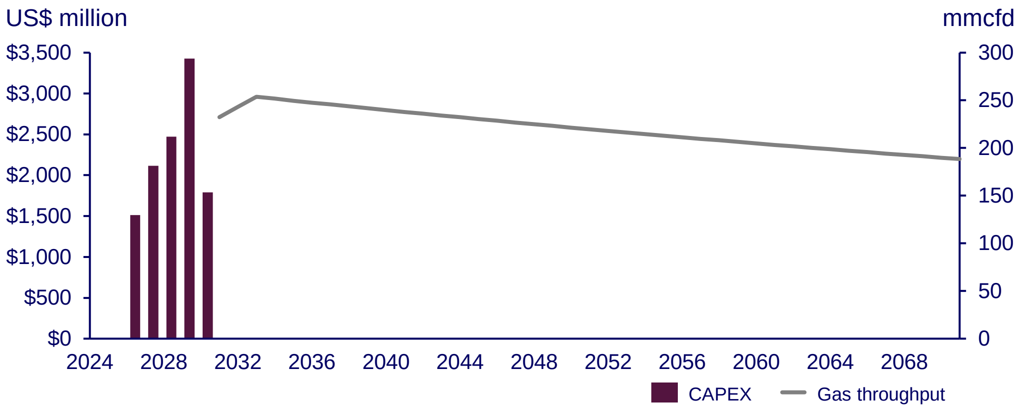

Source: Wood Mackenzie

1. US$ 10,769 million capex considers 20% contingency and is reflected in 2024 terms. Inflation during construction and Allowance for Funds Used During Construction (AFUDC) are considered in the model.

# The WM Case includes probable additional industrial demand as a result of new gas supply availability and results in a US$11.20 /mmbtu delivered cost of gas

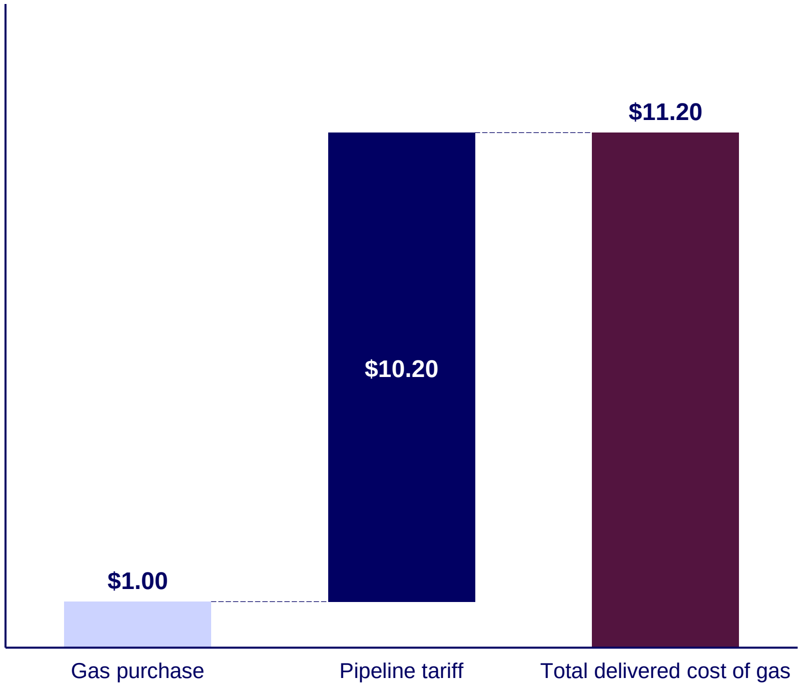
| Main assumptions | |
|---|---|
| Capex[1] | $10,769 (2024 US$ million) |
| Opex | 0.35% (Annual as % of capex) |
| Average throughput (2031 - 2071) | 220 mmcfd |
| Capital Structure | 25% Equity / 75% Debt |
| Interest Rate | 6.25% |
| Target Return on Equity (ROE) | 10% |

## Gas throughput and capex for Alaska LNG Phase 1 pipeline




## Delivered Cost of Gas

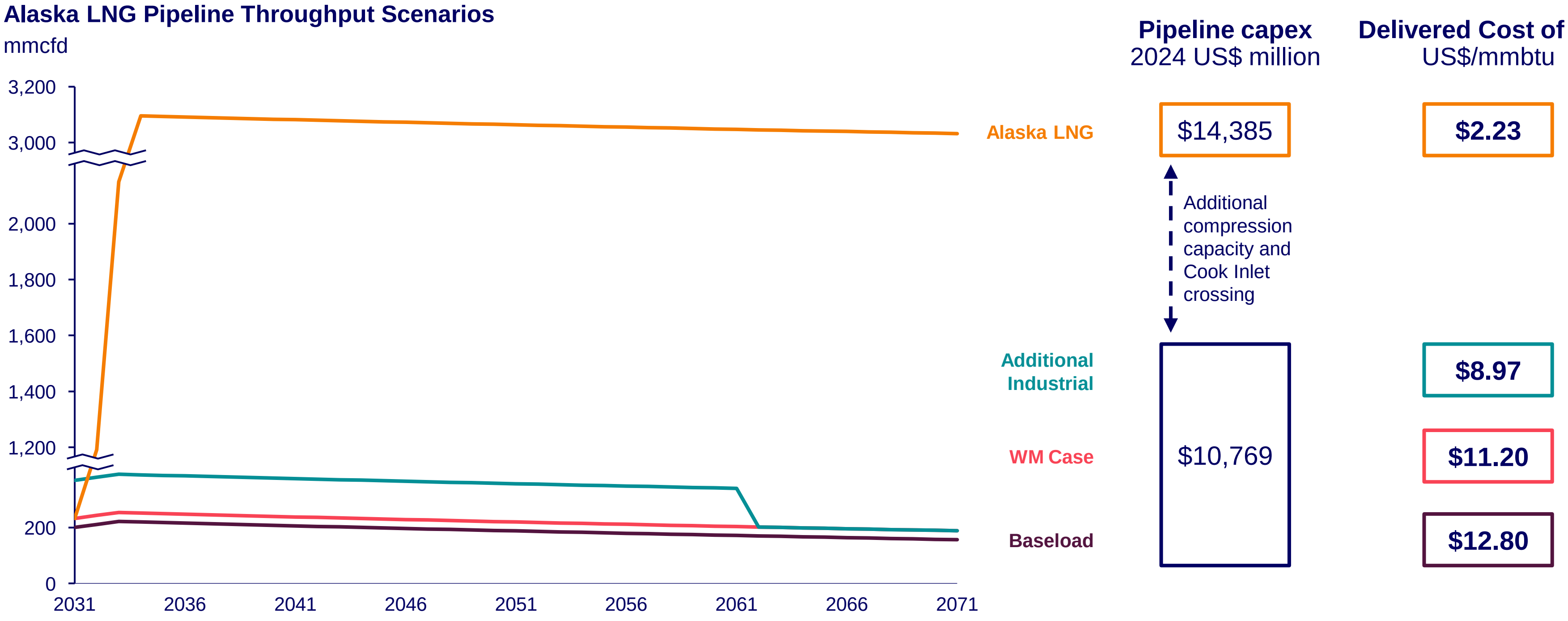
Real 2024 US$/mmbtu




Source: Wood Mackenzie

1. US$ 10,769 million capex considers 20% contingency and is reflected in 2024 US$. Inflation during construction and Allowance for Funds Used During Construction (AFUDC) are considered in the model.

# The scenario analysis shows an asymmetrical impact on the delivered cost of gas from a change in demand accruing to the consumers' benefit



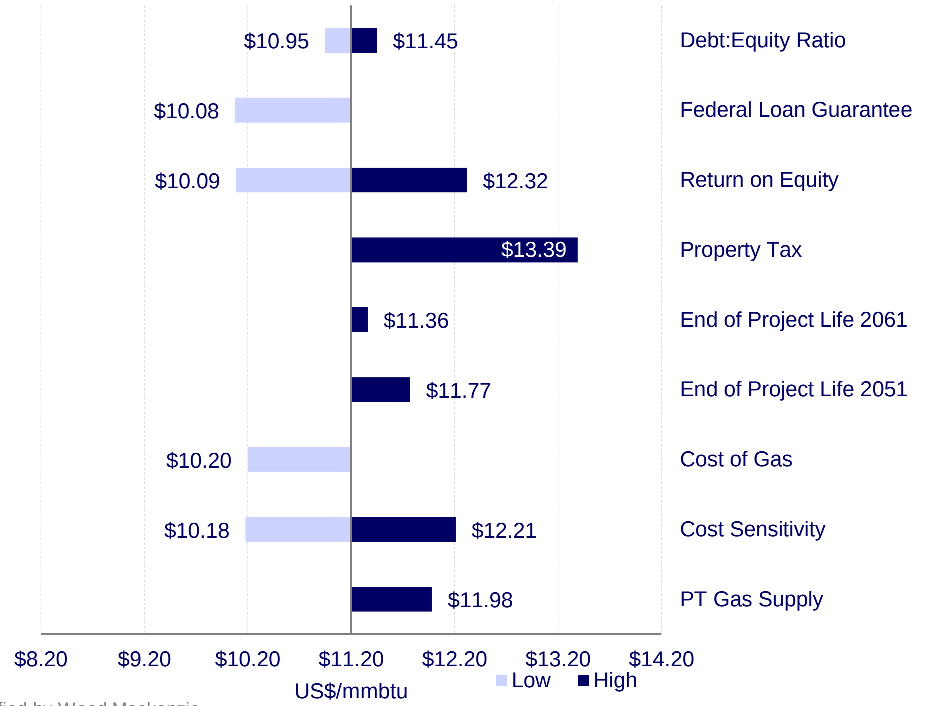

Source: Wood Mackenzie

# Additional sensitivities showed that securing a Federal Loan Guarantee and reducing Property Tax have the most impact on the cost of gas

| Assumptions | Low | Base | High |
|---|---|---|---|
| Leverage – Debt : Equity Ratio | 80:20 | 75:25 | 70:30 |
| Federal Loan Guarantee | 5.00% | 6.25% | - |
| Return on Equity | 7.5% | 10.0% | 12.5% |
| Property Tax | - | 0.2% | 2.0% |
| End of Project Life in 30 years | - | 2071 | 2061 |
| End of Project Life in 20 years | - | 2071 | 2051 |
| Cost of gas | $0/mmbtu | $1/mmbtu | |
| Capex Sensitivity | -10% | $10.8 Bn | +10% |
| Alternative supply at Point Thomson: Increased Capex and Gas Price[1] | | $10.8 Bn & $1/mmbtu | +564M & +US$ 0.25/mmbtu |

## Delivered Cost of Gas – Sensitivity analysis on the WM Case Scenario

Real 2024 US$/mmbtu




Source: Wood Mackenzie; 1. The assumed gas price of US$ 1.25/mmbtu was provided by AGDC and not verified by Wood Mackenzie

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# The LNG import cost analysis considers four main components (LNG cost, shipping, and regasification) across the value chain, each with a potential range of results

## LNG import cost components

### 1 LNG Cost

- Multiple alternatives exist for securing supply of LNG (i.e. acquiring the molecule), ranging from spot market purchases, long-term supply and purchase agreements (SPA), or taking a tolling position partnering with an LNG developer
- Each alternative provides exposure to its own set of market risks and requires different levels of investment and management

### 2 Shipping

- LNG being a global commodity provides multiple geographical alternatives that require shipping cost considerations
- Alaska's access to the Pacific means geographical focus in Pacific facing projects, ideally as close as possible (e.g. West Canada projects), though other limitations arise, such as availability of supply or possible ship sizes

### 3 Regasification

- LNG requires to be re-gasified (transformed back to natural gas) to be consumed
- Regasification costs depends upon configuration of the processing facility e.g.: Land vs. FSRU[1], overall size, storage requirements, levels of utilization, etc.

### 4 On shore gas reception

- There are potential infrastructure requirements depending on specific circumstances such as costs to access the gas network and/or requirement to have a dock that meets the needs to bring the gas in-land in the case of an FSRU

**Range of Cost estimated for LNG Imports**

Source: Wood Mackenzie; 1. Floating Storage Regasification Unit

# 1 LNG Cost: Multiple types of deals are possible, though JKM or Oil-linked based are the ones expected to be used by Alaska LNG importers

## Overview of options to purchase LNG

| Type of Deal | Description | Considerations | |
|---|---|---|---|
| Buy LNG at spot market | ▪ LNG Purchases on the spot market, without the requirement of a term contract; price determined on each transaction | ▪ Subject to supply availability, potential for higher volatility depending on price marker selected/available for purchase | **Unlikely to be used widely to import into Alaska due to risk of supply** |
| Long-term JKM[1] based price | ▪ LNG Purchases via a Sales and Purchase Agreement (SPA), for example, with exposure to a JKM net-back<br>▪ Price determined by the JKM reported marker | ▪ Most liquid and common for deals done in the last decade in Pacific facing projects, preferred by LNG marketers | **Considered for this analysis as imports via an FSRU will likely require long-term supply deals (10 to 20yr range[2])** |
| Long-term Oil-linked price | ▪ Contract purchases based on a formula typically considering a constant plus a percentage of oil price; Price determined by the specific formula and the reported oil price at agreed timeframe | ▪ Historically used, but less popular as LNG marketers prefer LNG price marker exposure<br>▪ Slightly higher management complexity as price formulas are negotiated and reviewed frequently | |
| Local gas hub-based price | ▪ Purchases based on a local gas hub (e.g. 115% of Henry Hub), or self purchase gas in the local market and lift the LNG via a tolling agreement | ▪ High degree of complexity as it requires involvement in multiple upstream operations, including the potential requirement to source the gas in a different market<br>▪ Companies that have inked favorable deals typically have equity positions in the LNG terminals | **Unlikely to be used to import into Alaska due to complexity and further upstream capabilities and capital requirements** |

Source: Wood Mackenzie; Henry Hub based deals are mostly for US Gulf Coast LNG projects, though these are not possible to supply Alaska due to Jones Act limits in shipping; 1. JKM refers to the Japan Korea Marker benchmark price 1. Shorter term deals are possible, though the majority of deals in the past 5 years have been 10yrs or longer term and to secure FSRU commitments they would require to be coupled with long-term LNG supply

Wood Mackenzie

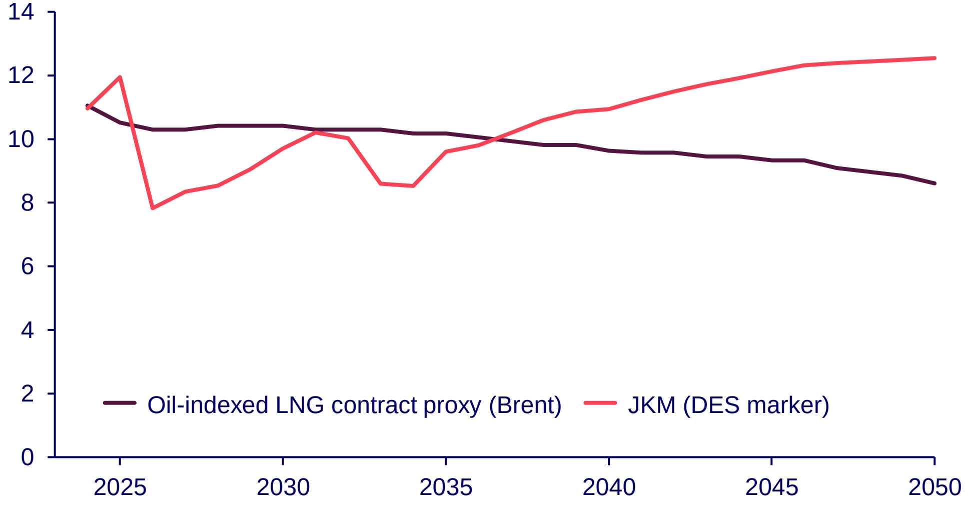
# 1 Access to LNG in the Pacific will be linked to JKM or Oil-indexed long-term pricing; sellers are likely biased towards accepting JKM netback contracts

## LNG Price – Considerations

- Oil linked prices are expected to trend lower as oil prices decline long term in real terms
- LNG supply and demand dynamics decouple with some seasonality in the short term and raise long term
- As JKM marker has matured, liquidity has risen, resulting in increased adoption for LNG deals
- LNG sellers are more likely to prefer **JKM** linked deals for **long term purchase (10 to 20yr range)** agreements, evidenced by the recent dominance of them, though the analysis will consider the two alternatives

## LNG price outlook

US$/mmbtu, real 2024



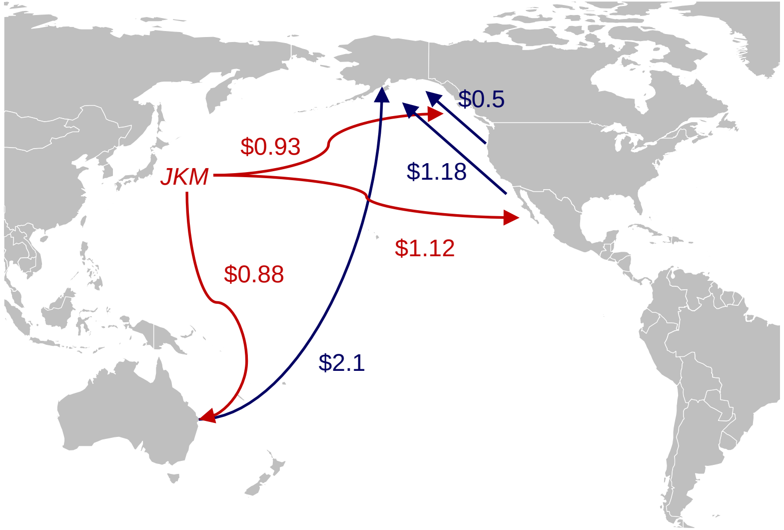

| Delivered Price | Period Average | 2031-2050 average |
|---|---|---|
| JKM (Des) | 10.61 | 11.00 |
| Oil linked (Brent) | 9.86 | 9.64 |

Source: Wood Mackenzie; Delivered into Japan

# 2 **Shipping costs** can impact delivered cost of LNG in the -0.4 to 1.2 /mmbtu range, depending on location of supply

**Shipping routes and costs**

US$/mmbtu, cost of roundtrip




- The shipping adjustment should generally be positive to Alaska LNG imports due to access to the Pacific and proximity to potential LNG supply area in West Canada
- However, availability of supply in adequate form (e.g. ship size) can prove challenging for which alternative supply sources such as Australia have been considered

**Net shipping adjustment** (US$/mmbtu)
Considers net back from JKM (subtracting cost from source to JKM) and adjustment to Alaska (adding cost from source to Alaska):

- Canada= (0.93) + 0.5 = (0.43)
- Australia = (0.88) + 2.1 = 1.22
- Mexico = (1.12) + 1.18 = 0.06

- At best JKM could be discounted considering ~(0.43) shipping adjustment. Though portfolio players would generally pocket premiums for any route optimization, giving buyers a full JKM price (without shipping adjustment) as alternative
- We consider the -0.43 to 1.22 as the shipping adjustment range

Source: Wood Mackenzie; Considers netback trips (red lines) with 174,000 m3 ship size and added costs (blue lines) with 75,000 m3 ship size

# 3 **FSRUs** generally show low levels of utilization (relative to onshore regas facilities) and regasification costs show correlation to overall size of facilities

## FSRU Cost range

mmcfd, US$/mmbtu, real 2024

| Average Send Out Capacity (Nominal mmcfd) | Regas Cost (US$/mmbtu) |
|---|---|
| 520 + | 0.4 – 0.75 |
| 500 | ~0.75 |
| 480 | ~0.80 |
| 410 | ~1.5 |
| 100 | 2.50 |

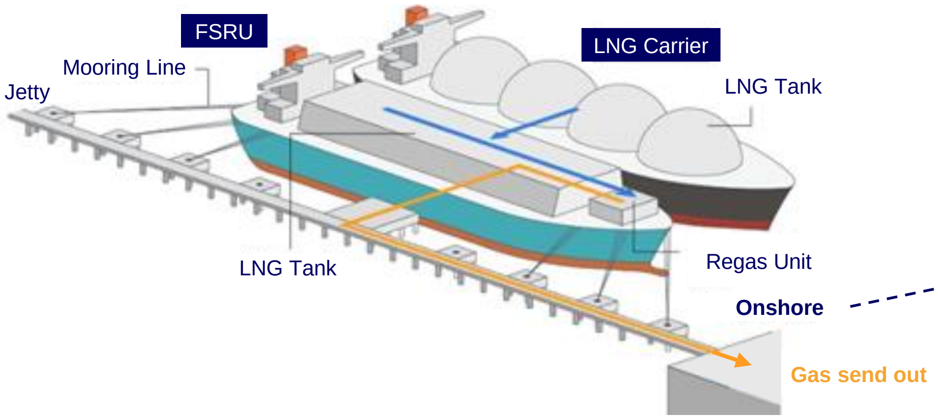
- Operating FSRUs generally show low utilization, ranging from 40 – 45%
- For a ~150 mmcfd estimated demand (South Central demand), nominal capacity would be expected in the 350 – 400 mmcfd range
- We estimate the regas cost would be in the **US$ 1.0 – 1.5 / mmbtu**, though there would be incremental costs to build or adapt receiving infrastructure and further downstream requirements (e.g. site for docking, receiving gas network costs)
- There could also be optimization opportunities, including onshore storage operations to increase utilization, resulting in a lower sized nominal capacity requirement, though there is less availability of small scale FSRUs (i.e. under 200 mmcfd capacity)

Source: Wood Mackenzie; Considers a data set of 48 FSRUs that are operational, under construction, proposed or speculative; Regas costs consider a 40 to 45% utilization

# 4 **Onshore** reception site is largely dependent on infrastructure configuration, meta-oceanic conditions and specific buildout, requiring additional investment

**Illustrative FSRU Onshore Connection**

*ILLUSTRATIVE*




Onshore connection configuration can vary due to multiple factors resulting in additional investment requirements

Additional Capex could be in the US$ 50 – 500 million range. However, as of now Wood Mackenzie is uncertain of a site and/or configuration to be used for the potential FSRU, thus costs and investment requirements are yet to be estimated

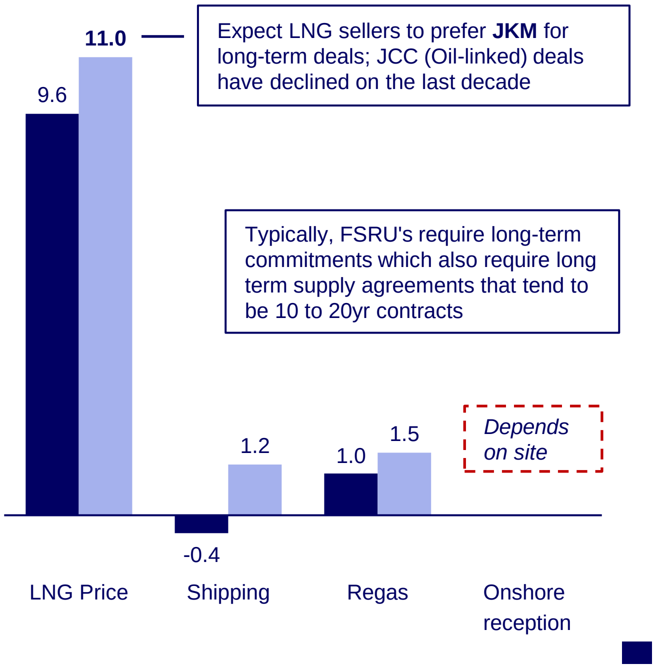
Source: Wood Mackenzie; Image from Mitsui OSK Line Blog

Wood Mackenzie

# LNG imports estimated at ~US$10.2-13.7/mmbtu plus onshore costs downstream of regas, within range of the delivered cost via pipeline

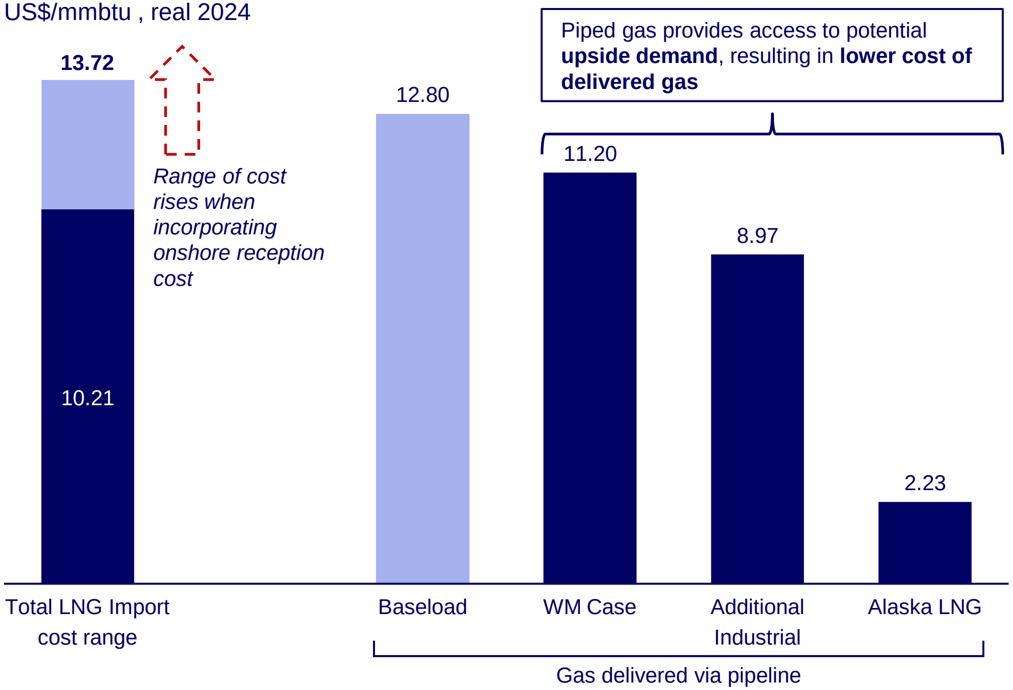
## LNG Import cost range per value chain component[1]

US$/mmbtu, real 2024




## LNG Import cost (without onshore investment) vs Gas delivered via pipeline

US$/mmbtu , real 2024




Source: Wood Mackenzie

1. Considers LNG Price average for the 2031 – 2050 Period, Shipping and Regas costs maintained constant in real terms

# Contents

# The approach to assess the socio-economics benefits of Alaska LNG Phase 1 considers four components

## Components Considered to Assess Socio-Economic Benefits

**1 Assess standalone capex by project components:**

- Total **Capital Expenditure** for **Construction**
- Analyze spend directly impacting Alaska
  - Direct impact from increased labor, land, and rights of way activity related to the project
- Additional implied benefit of access to incremental demand and higher probability of AK LNG

**2 Assess socio-economic benefits for the lifetime of the project**

- Lifetime **operational expenditure** (mostly in-state spend)
- **Government tax** for gas monetization, pipeline operations, and others
- **Direct job creation** by project components
  - Construction phase
  - Operations phase

**3 Assess Indirect and Induced benefits**

- Benchmark and select input-output **multipliers** for **indirect** and **induced** benefits
- **Quantify Indirect & Induced** impact on **Alaska Gross Value Added (GVA)[1] and jobs**

**4 Assess potential for savings with access to low-cost gas supply & other benefits**

- Identify expected total state **gas consumption**
- Compare resulting **cost of gas** under base case scenario to alternatives (LNG Imports)
- Project potential for **savings** across the target operating period (2031–2071)
- Include other benefits, such as Fairbanks gas adoption

**Alaska LNG Phase 1 development: Socio-economic benefits reflected in GVA, jobs and potential savings**

Source: Wood Mackenzie; 1.GVA refers to the lifetime impact on Alaska's GDP

Wood Mackenzie

# The construction and operations multipliers are used to calculate direct, indirect, and induced GVA from local construction capex, project lifetime expenditure, and government take

## Calculation for Alaska potential Gross Value Added (GVA) increase resulting from the pipeline's construction and operation

**Construction Phase**

- **Total capex Spent[1]** × **Alaska Construction Multipliers**

**Operations Phase**

- **Total opex Spent** × **Alaska Multipliers for Relevant Operations**
- **Total Government Revenue from Project's Corporate Tax Revenues and Project Dividends** × **Alaska Operations Multipliers* (as proxy)**
- **Total Government Upstream Fiscal Tax Revenues *(only for Great Bear Pantheon)*** × **Alaska Construction Multipliers* (as proxy)**

↓

**Total GVA increase over the lifetime of Alaska LNG Phase 1**

Source: Wood Mackenzie, the Perryman Group; 1. Total capex spent (US$ 2024) used for indirect and induced GVA, though adjusted for spend in-state impacting Alaska for the direct economic impact

# Alaska in-state direct impact from the Pipeline Capital Expenditure is estimated at ~55% of the total project's capex or ~US$6.0 billion

## Local Alaska Impact from Pipeline capex components

Assumption[1] for capex component distribution on the Pipeline:

| Component | % of capex |
|---|---|
| Raw Material: Steel Pipes, Coating, Fittings, etc. | 20% |
| Excavation, Trenching | 7% |
| Welding / Joining | 7% |
| Installation | 10% |
| Backfilling and Restoration | 5% |
| Inspection, testing, logistics, transport and other labor | 5% |
| Compression | 25% |
| Land, rights of way, access and civil work | 10% |
| FEED, PMO, Environmental, Regulatory | 5% |
| Miscellaneous & Others | 5% |

Alaska In-state spend estimation assumptions:

- Full **land**, **RoW**, **access and civil work** spend
- **~70** to **80%** of **labor** spend
- **~10%** of **raw material** spend
- Removal of Compression expenditure for Phase 1

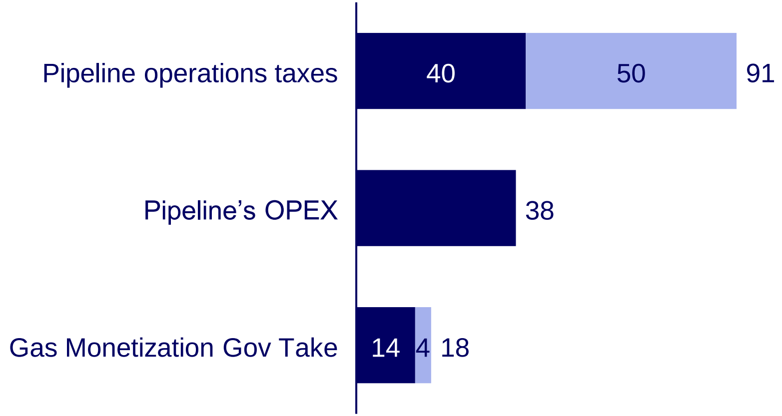
**Total capex = US$10,769 million**

| Component | Capex direct impact into Alaska (US$ million): |
|---|---|
| Raw Material: Steel Pipes, Coating, Fittings, etc. | 237 |
| Excavation, Trenching | 948 |
| Welding / Joining | 888 |
| Installation | 1,027 |
| Backfilling and Restoration | 553 |
| Inspection, testing, logistics, transport and other labor | 197 |
| Compression | N.A. |
| Land, rights of way, access and civil work | 1436 |
| FEED, PMO, Environmental, Regulatory | 359 |
| Miscellaneous & Others | - |
| **Total** | **$ 5,961 (~55% of capex)** |

Source: Wood Mackenzie Analysis; 1. Assumptions are based on Wood Mackenzie's experience and available cost data

# The Project's lifetime opex, and total Government take from the gas monetization and pipeline operations add up to ~$5.9 billion

**Average Yearly Cash Flows During AK LNG Phase 1 Operations Phase**
US$ Million




**Cumulative for the Project Lifetime** [US$ Bn]

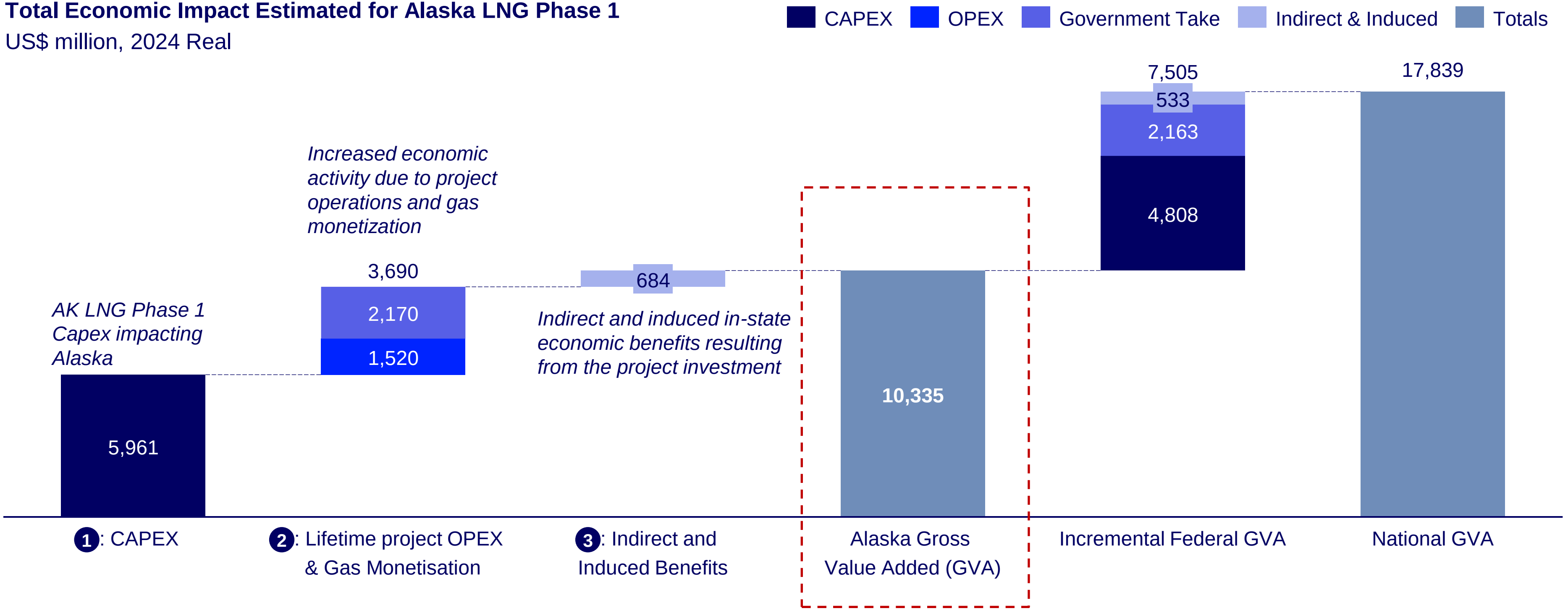
| | In-State Spend | Federal Spend |
|---|---|---|
| *Taxes generated from pipeline operations and profits* | 1.62 Bn | 2.00 Bn |
| *Operational Expenditure to run the pipeline* | 1.52 Bn | - |
| *Incremental royalties and taxes paid for monetizing the gas in the state* | 0.56 Bn | 0.15 Bn |
| | **US $3.7 Bn** | **US $2.16 Bn** |

Source: Wood Mackenzie; Pipeline operations taxes consider State, Federal and Property Taxes; Gas Monetization Government Take consider Royalties, Federal and State Taxes

Wood Mackenzie

# Gross Value Added for Alaska LNG Phase 1 is estimated at ~US$10.3 billion, with ~US$ 9.6 billion of direct economic impact from the Project's investment and operations in-state expenditure

**Total Economic Impact Estimated for Alaska LNG Phase 1**
US$ million, 2024 Real




Source: Wood Mackenzie, AGDC, the Perryman Group; 1. Considers WM Case Scenario and high-end cost of LNG imports

# Component 4: Construction of Alaska LNG Phase 1 could represent up to US$25.9 billion savings to consumers compared to importing LNG; WM Case estimation is up to ~$5.7 billion savings

| Scenario | Unit cost<br>US$/mmbtu | Total Cost for 2.3 tcf[1]<br>US$ million (2031-2071) | Total Savings<br>US$ million (2031-2071) | Annual Savings<br>US$ million | Annual Savings per Southcentral Alaska resident[1]<br>US$ per person-year |
|---|---|---|---|---|---|
| LNG Imports (Low) | $10.21 | $22,993 | - | - | - |
| LNG Imports (High) | $13.72 | $30,897 | - | - | - |
| Baseload | $12.80 | $28,826 | ($5,833)<br>$2,072 | -<br>$52 | -<br>$106 |
| WM Case | $11.20 | $25,222 | ($2,229)<br>$5,675 | -<br>$142 | -<br>$291 |
| Additional Industrial | $8.97 | $20,200 | $2,792<br>$10,697 | $70<br>$267 | $143<br>$549 |
| Alaska LNG | $2.23 | $5,022 | $17,971<br>**$25,875** | $449<br>**$647** | $923<br>**$1,329** |

LNG Import costs without onshore investment

Wide range of possible savings (from - $6Bn to $26Bn), with **~US$5.7** of direct impact, in the lower end of the range and reasonably achievable among the different scenarios

This will also have indirect and induced effects

Source: Wood Mackenzie

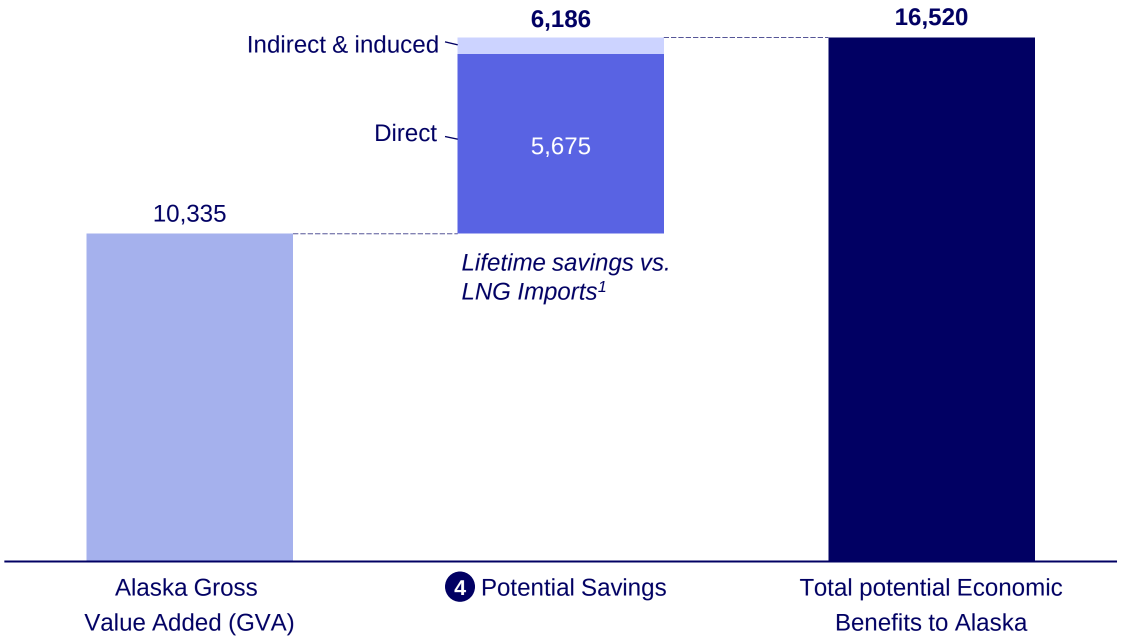
1. The demand gap of 2.3 Tcf considers Current State demand shown in slide 6 to compare the same volume base for both LNG Imports and Piped Gas alternatives 2. Based on the Alaska Department of Labor and Workforce Development, the Population in the region is estimated at 486,727 in 2023 (Anchorage/Mat-Su Region and Gulf Coast Region).

# With potential implied savings (compared to LNG imports) economic benefits to the state add up to ~US$ 16.6 Bn

- Gas via pipeline has additional economic benefits over the long term:
  - Lifetime **savings** from the **baseload** supplied via Pipeline, compared to LNG add up to **~US$ 5.7 billion**
  - Savings going back into the economy would also generate indirect and induced impact
  - The pipeline provides potential upside for gas demand and industrial activity
  - Overall potential impact to the state of Alaska is estimated at ~ **US$16.5 billion** or 2.8x in-state capex

**Total Economic Impact Estimated for Alaska LNG Phase 1**

US$ million, 2024 Real




Source: Wood Mackenzie, AGDC, the Perryman Group; 1. Considers WM Case Scenario, high-end cost of LNG imports and grossed up with the construction economic multiplier (as proxy)

# Alaska LNG Phase 1 will create an annual average of 1,066 direct jobs during the construction period and 250 permanent jobs during the 40-year operation period

**Direct jobs[1] created during construction and operation of Alaska LNG Phase 1**

Average jobs per year

| Phase | Construction[2] | Operations[3] |
|---|---|---|
| Duration | 5 years | 40 years |
| Direct Jobs (Avg per year) | 1,066 | 250 (permanent) |

- Cumulative direct jobs during construction will total 5,330[2]. Peak employment is expected to occur between 2028-2029.
- The direct jobs created during Phase 1 operations would be permanent, lasting the entire 40-year period.
- Operation and maintenance of the Phase 1 pipeline are expected to require approximately **250[3] full-time workers**, consisting of trade technicians, technical specialists, safety personnel, support staff, and management

Source: Wood Mackenzie, AGDC. 1. Information from Alaska LNG Resource Report 5, Socioeconomics adjusted to match current 2026-2031 construction schedule. 2. Total direct jobs for construction of the Mainline and Point Thompson Expansion is estimated at 7,400 in the Regulatory Filing Resource 5. This number was adjusted to reflect only Phase 1 based on capex structure, excluding compression, Cook Inlet crossing and Point Thompson expansion; 3. Similarly. total operation jobs for the full mainline were estimated at 330, adjusted for Phase 1 as it does not include compression or Point Thompson expansion.

Wood Mackenzie

# Indirect and induced jobs are estimated to represent an additional ~1,200 jobs during construction and 888 during operations.

- Local spending has a stimulus effect on the State's economy, thereby increasing the number of jobs and labor income. Construction and operation of the Project would create indirect and induced part-time and full-time jobs via this **multiplier effect**.
- These indirect and induced positions would attract a diverse workforce, including individuals without specialized skills, for lower-paying service sector jobs, like retail and food service.
- We assume a **2.13x multiplier** for Phase 1 construction and **4.55x** for operations employment.

**Total jobs created during construction and operation of Alaska LNG Phase 1**

Number of jobs

| Phase | Construction[1] | Operations[2] |
|---|---|---|
| Duration | 5 years | 40 years |
| Direct Jobs (Avg per year) | 1,066 | 250 (permanent) |
| Employment multiplier | **2.13x** | **4.55x** |
| Indirect and Induced Jobs (Avg per year) | 1,205 | 888 |
| **Total Direct, Indirect and Induced Jobs** (Avg per year) | **2,271** | **1,138** |

Source: Wood Mackenzie, University of Alaska Center for Economic Development 1. Multiplier effect from the "AMDIAP Economic Impact Analysis", a 2019 study on a controlled-access industrial road from the Dalton Highway to the Ambler Mining District in Northwest Alaska. The report estimates a 2.13x employment multiplier for 1,441 direct jobs and 3,063 total jobs (direct, indirect, and induced).3. Operations multiplier effect is larger as represents a full-time job long-term established into Alaska and is estimated based on the Alaska LNG Resource Report 5

Wood Mackenzie

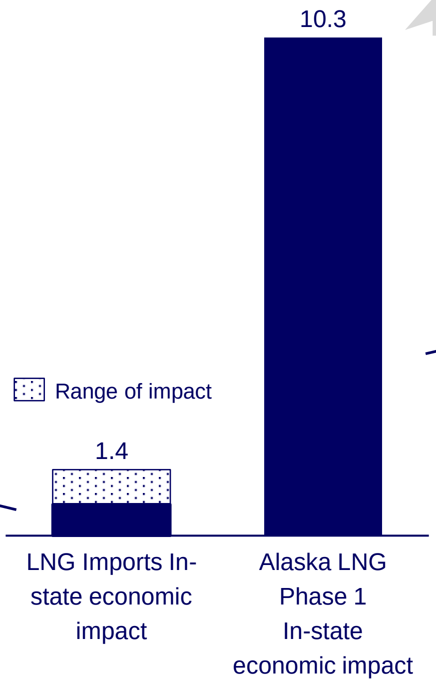
# Economic impact for Alaska LNG Phase 1 is 7x – 10x larger than the LNG imports alternative with the additional benefit of potential lower gas cost via industry expansion and upside demand

**Economic Impact Comparison – LNG Imports vs Alaska LNG Phase 1**

GVA in US$ billion, 2024 Real

**Phase 1 costs** are **offset** by roughly equivalent **economic impacts**

- Marginal FSRU capex considered as only requiring setting up – construction done elsewhere
- No upside for gas demand outside of current baseload consumption
- Impact mainly considering:
  - Dock construction
  - FSRU and dock required labor
  - Local services and materials suppliers
  - Local businesses stimulated



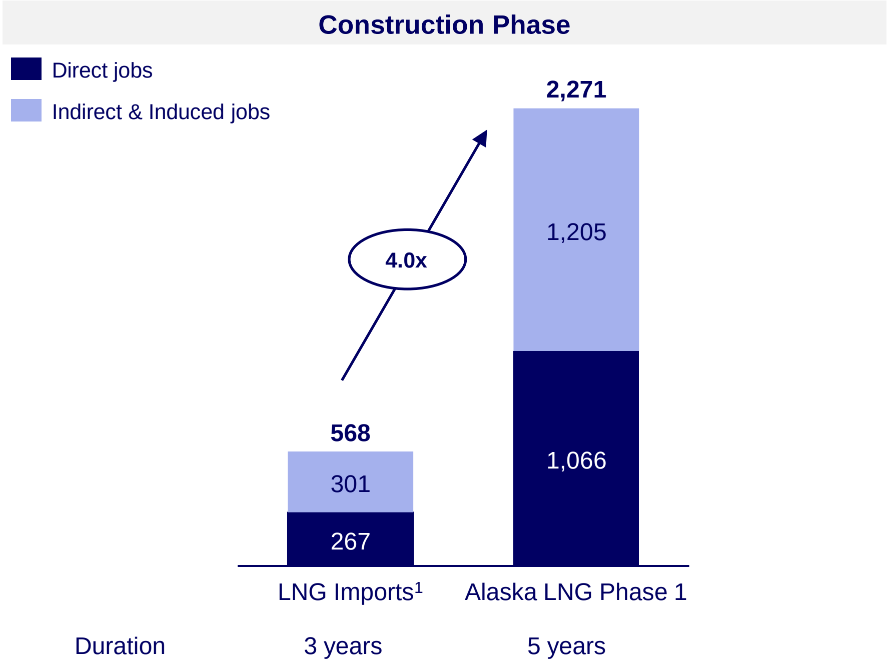

- Pipeline construction related activity and capital spend directly impacting Alaska economic activity
- Lifetime operational expenditure
- Government revenue from project’s corporate taxes
- Government take from upstream gas monetization
- Upside for gas demand (additional industrial) and Fairbanks gas switch from higher emissions fuels

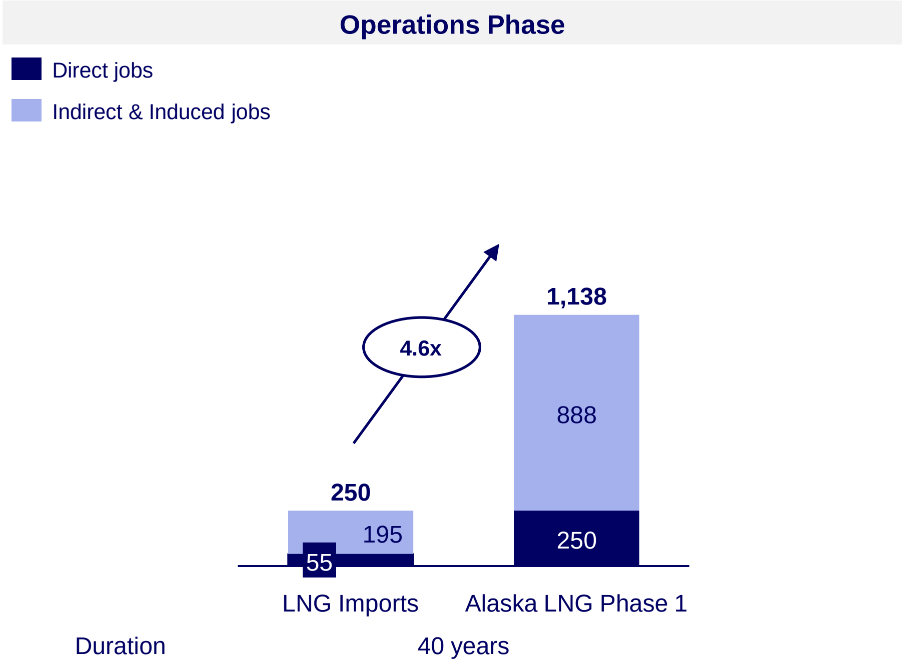
Source: Wood Mackenzie

# The impact in jobs created from Alaska LNG Phase 1 is 4x larger than the LNG imports alternative mainly due to a larger in-State construction scope

## Economic Impact Comparison – LNG Imports vs Alaska LNG Phase 1

Average jobs per year - Direct, indirect, and induced




Source: Wood Mackenzie and AGDC. 1. Refer to appendix for key assumptions

Wood Mackenzie

# The substitution of wood/oil for gas in Fairbanks for its energy needs offers a range of benefits: cleaner air, lower emissions, removal from EPA's nonattainment designation, etc.

## Cleaner air

- Local emissions from wood stoves and burning distillate oil contribute to particulate pollution
- With access to gas, a cleaner alternative becomes available to improve air quality

## EPA's nonattainment designation

- A portion of the Fairbanks North Star Borough, including the City of Fairbanks, was designated as a PM$^{2.5}$ Nonattainment Area in December 2009.
- By removing the designation, administrative expenses are reduced as the implementation plans to attain and maintain air pollutant emissions are no longer required.

## Health

- Air pollution has direct consequences in public health
- By reducing air pollution, public health expenses may also decrease

## Potential access to grants and investment

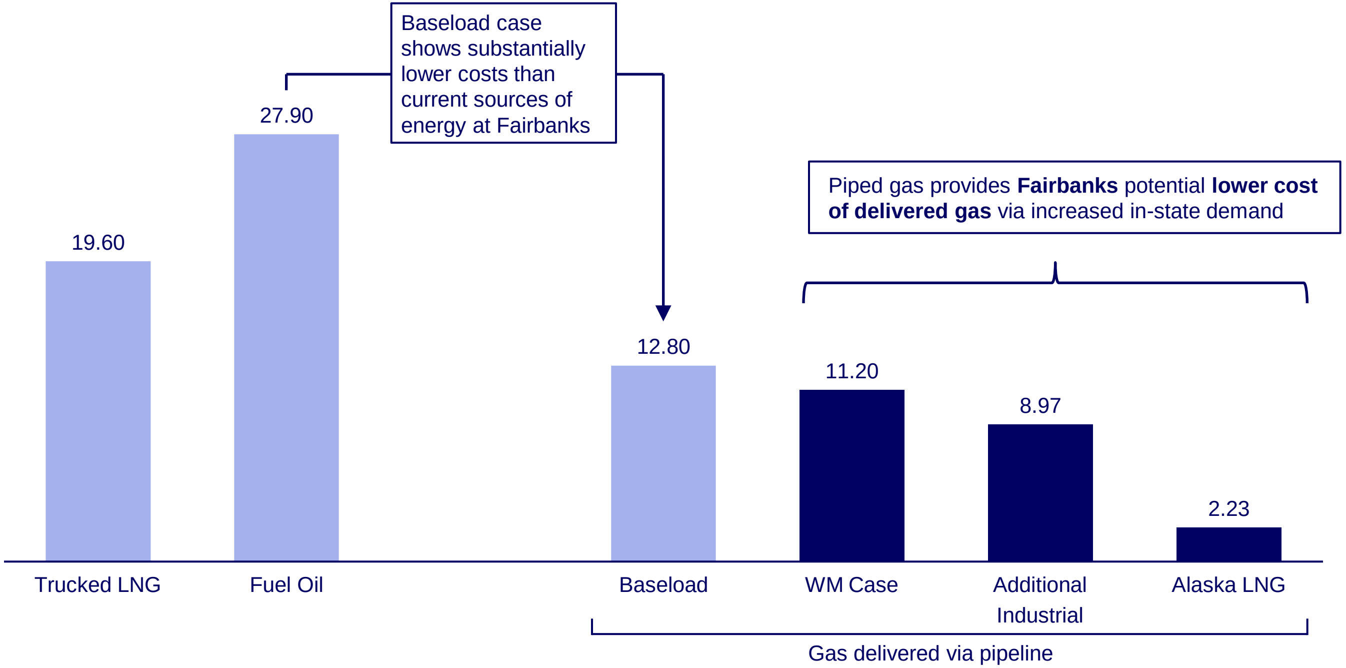
- EPA's nonattainment designation may limit private and/or public investment in the region

Source: Wood Mackenzie and Alaska Department of Environmental Conservation

# Additionally, energy costs at Fairbanks could potentially drop when switching from fuel oil and trucked LNG to natural gas via pipeline

**Fairbanks energy cost comparison – Trucked LNG and Fuel Oil vs Gas delivered via pipeline**

US$/mmbtu , real 2024




Source: Wood Mackenzie; Prices of trucked LNG and Fuel Oil at Fairbanks are lower end of cost range extracted from Interior Gas Utility (IGU) update published March 2023

Wood Mackenzie

# With the pipeline, Fairbanks estimated savings could reach ~US$3.9 to 7.7 Bn over the 2031 – 2071 period; equivalent to ~US $0.9k – $1.8k savings per resident per year

| Scenario | Unit cost<br>US$/mmbtu | Total Cost for 461 bcf[1]<br>US$ million (2031-2071) | Total Savings<br>US$ million (2031-2071) | Annual Savings<br>US$ million | Annual Savings per Fairbanks Alaska resident<br>US$ per person-year |
|---|---|---|---|---|---|
| Trucked LNG | $19.60 | $9,043 | - | - | - |
| Fuel Oil | $27.80 | $12,873 | - | - | - |
| Baseload | $12.80 | $5,906 | $3,137<br>$6,967 | $78<br>$174 | $714<br>$1,586 |
| WM Case | $11.20 | $5,168 | $3,876<br>$7,705 | $97<br>$193 | $882<br>$1,754 |
| Additional Industrial | $8.97 | $4,139 | $4,905<br>$8,734 | $123<br>$218 | $1,117<br>$1,989 |
| Alaska LNG | $2.23 | $1,029 | $8,014<br>$11,844 | $200<br>$296 | $1,825<br>$2,697 |

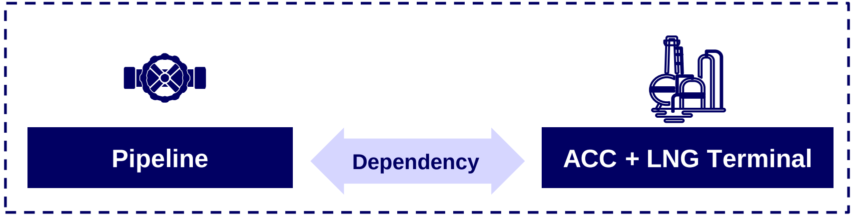
Source: Wood Mackenzie

1. The demand gap of 465 bcf considers Fairbanks demand of ~30 mmcfd for the 2031 – 2071 period

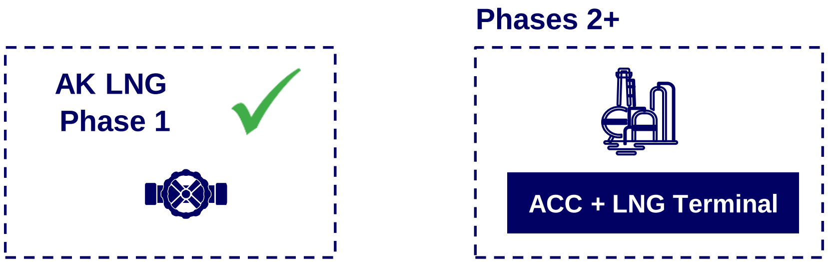
# As Phase 1 goes forward, ‘Project on Project’ risk is largely mitigated, improving success probability of the full Alaska LNG project

## A phased approach to Alaska LNG coupled with a successful Phase 1 reduces the overall project risk:

- The **inter-dependence** of the project’s components **compounds** the **risks** across (project on project risk) and has represented a key challenge to sanctioning Alaska LNG i.e.:
  - Even in a successful LNG Terminal + ACC scenario, the overall project depends on the success of the pipeline




- **Risk can be evaluated independently** with a phased approach
- One of the **largest risks is mitigated** (access to feedgas) with a successful Phase 1 allowing a focused risk evaluation into subsequent phases, and resulting in:
  - **Increased likelihood** of **full Alaska LNG** project
  - Optionality on size of LNG Terminal e.g., continue a phased approach with each LNG train




Source: Wood Mackenzie

# Contents

Wood Mackenzie

# Gas supply via pipeline provides over ~US$10 Bn of positive economic impact, 2 - 4x more jobs, and access to lower delivered costs vs LNG imports, though it requires higher capex

- **Cook Inlet gas supply has declined**, and despite exploration efforts by operators, **no new volumes** have been **discovered**
- Lack of reliable and affordable gas supply drove **decline in demand**, however going forward **supply** is expected to **drop faster** creating a **demand gap of ~2.3 tcf** (to 2071) projected to begin by the end of this decade
- With Cook Inlet gas production proving to be challenging, there are **two main alternatives** to address the forecasted **supply & demand gap**:

| | Natural Gas Supply via Pipeline | LNG Imports |
|---|---|---|
| | A 765 mile (Phase 1), 42-inch diameter pipeline connecting the Southcentral Alaska region with the North Slope fields | Gas imports via LNG, for which regas and further downstream infrastructure is required |
| | ▪ Cost of delivered gas in the **US$2.23 – $12.8/mmbtu** | ▪ Cost of delivered gas in the **US$10.2 – $13.7/mmbtu (plus onshore costs)** |
| | ▪ Direct, indirect and induced GVA**: ~US$ 10.3 Bn**<br>▪ **2,271 jobs**[1] created during construction and **1,138 in operations** | ▪ Lower capex & lower direct, indirect and induced GVA **~US$0.6 – 1.4 Bn**<br>▪ **568 jobs**[1] during **construction** and **250** in **operations** |
| | ▪ Time to first gas 2031[3] | ▪ 3-4 Years post FID[2], though no major permit applications have been submitted. Permitting and/or required buildout could delay first gas |
| | ▪ Provides access to **upside demand** with additional industrial and economic benefits to the state<br>▪ **Reducing emissions** and **removal from EPA's nonattainment** in **Fairbanks** via substitution of oil & wood as primary energy source | ▪ Focused supply for the Southcentral region<br>▪ No Fairbanks or additional industrial demand<br>▪ Exposure to higher price volatility for energy needs |
| | ▪ Higher **likelihood** of **full Alaska LNG Project** | |

Source: Wood Mackenzie; 1. Direct, indirect and induced jobs, average per year of each period; 2. First gas for LNG imports is dependent on receiving all required permits, and Wood Mackenzie is uncertain about the status of those. Additionally, as of March 2024, Enstar's (local gas distributor) earliest estimation of first gas is 2029. 3. The AGDC has indicated that the pipeline has all major permits in place

# Appendix: Methodology and Additional References

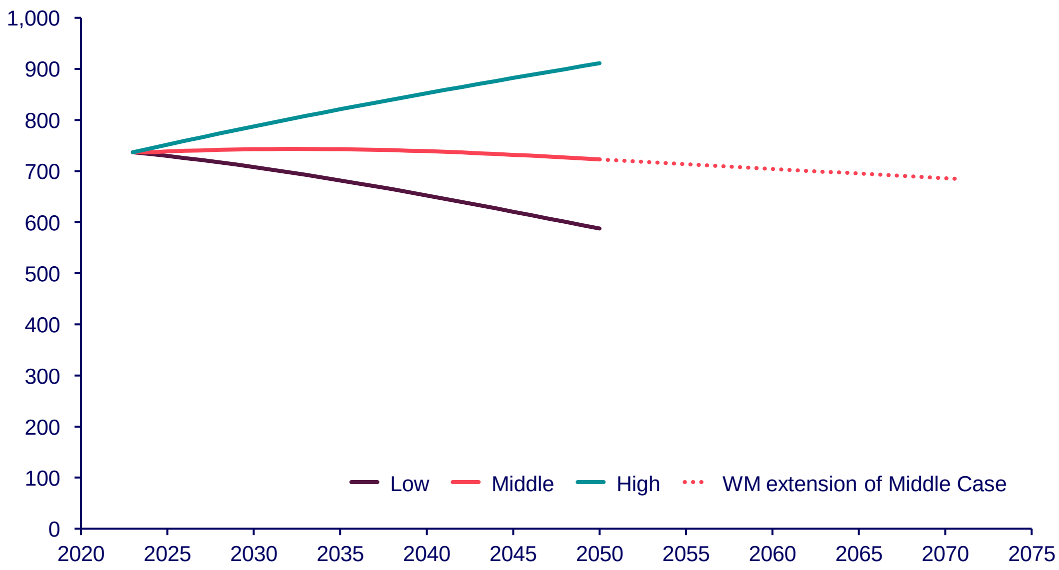
# Alaska demand forecast methodology

## Considerations to extend the gas demand forecast of the State of Alaska

- Reference: Wood Mackenzie's Strategic Planning Outlook 1H 2024 published on April 30th, 2024 adjusted for Industrial Activity reporting (2021-2023 demand increase attributed to reinjection)
- For 2071 extension:
  - Population growth forecast, Middle Case from "*Alaska Population Projections 2023 to 2050*" by the Alaska Department of Labor and Workforce Development, July 2024. WM extended the forecast to 2071 assuming the last annual change forecasted in the report.
  - Energy efficiency and electrification assumptions by Wood Mackenzie.

## Alaska Population Forecast (2023-2071)

Population ('000)

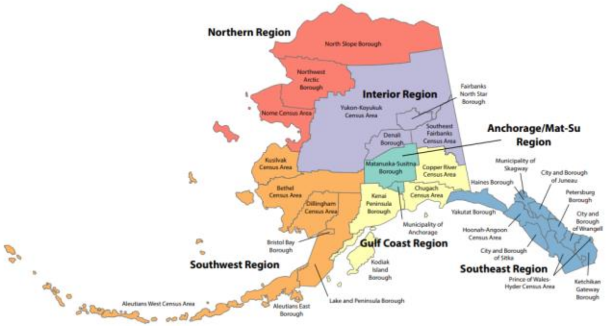



Source: Wood Mackenzie and Alaska Department of Labor and Workforce Development

# Existing gas demand forecast - Baseload Scenario

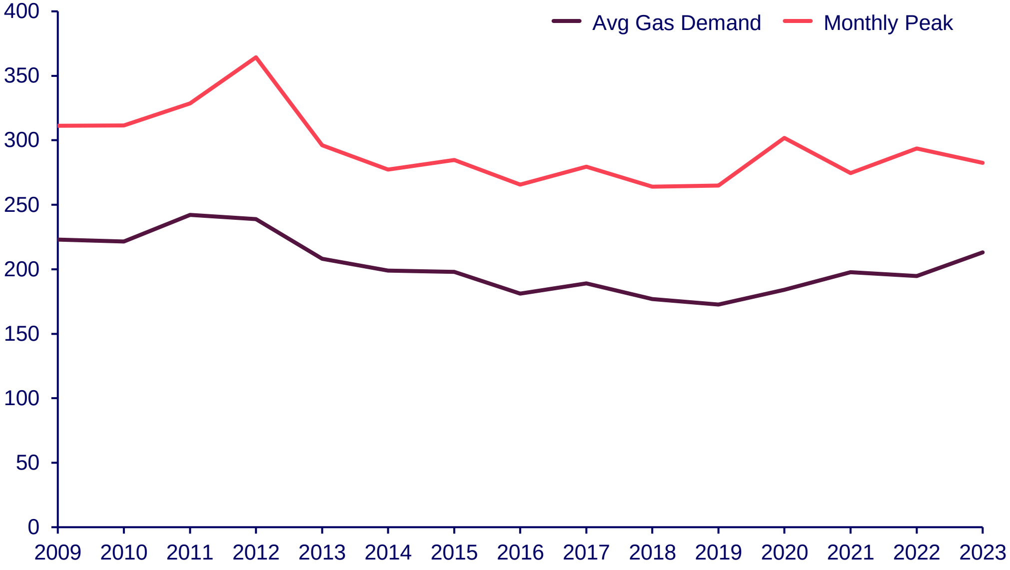
## Alaska Economic Regions

- Based on the extended Alaska demand forecast for 2031 -2071 we also considered:
  - Share of gas demand currently accounted for in Southcentral[1] and Interior Regions: 95%[2]
  - Seasonality adjustment to consider monthly peak within a year: The difference in the last 15 years is 45% but optimized via storage availability, resulting in contracted capacity equal to volume throughput.




## Alaska Gas Demand ex-LNG[3] (annual average vs monthly peak)

mmcfd




Source: Wood Mackenzie and Alaska Department of Labor and Workforce Development

1. Southcentral considers Anchorage/Mat-Su Region and Gulf Coast Region. 2. Excludes Fairbanks as its energy needs are supplied with other sources. 3. Excludes Kenai LNG to isolate its effects as it is no longer operational.

# Wood Mackenzie analyzed Pantheon's Ahpun and Kodiak developments, considering multiple scenarios to model different IP rate[1] outcomes that ultimately determine profitability

## Scenario Analysis – Consideration for Pantheon's Aphun and Kodiak

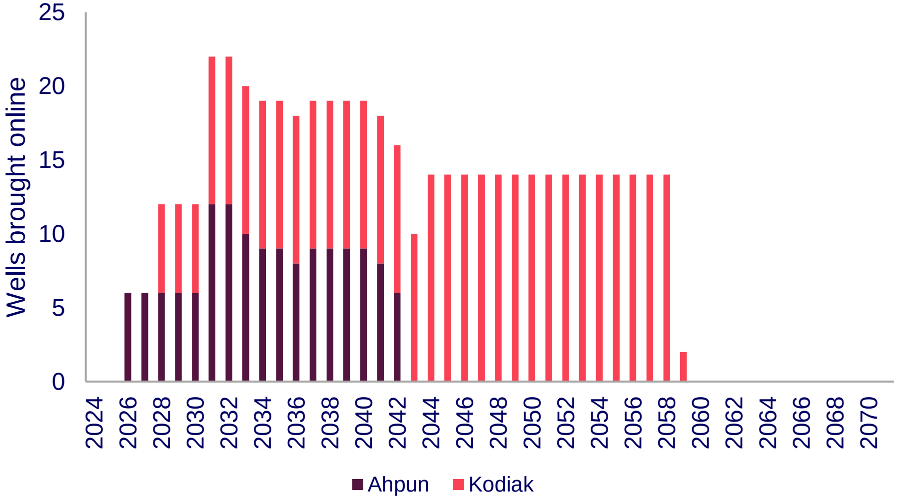
| | | Low IP Rate | Medium IP Rate | High IP Rate |
|---|---|---|---|---|
| | | *Actual test rates from Alkaid-2 declines matched to Coyote* | *Base case conservative oil rate* | *SLB model oil rate with adjusted decline to match disclosed EUR* |
| **IP 30 Rates** | Oil IP (kbd) | 0.18 | 0.50 | 0.78 |
| | NGL IP (kbd) | 0.33 | 0.85 | 1.40 |
| | Gas IP (mmcfd) | 2.50 | 6.50 | 10.76 |
| **Ultimate EUR** | Oil (mmbbl) | 0.41 | 0.72 | 1.78 |
| | NGL (mmbbl) | 0.75 | 1.21 | 3.21 |
| | Gas (bcf) | 5.74 | 9.33 | 24.73 |
| **Base Economic Assumptions** | Liquids Pricing | 10% discount to Brent –assumed US$65/bbl flat | | |
| | TAPS Tariff | TAPs tariff of US$5.78/bbl and $3.25/bbl for onward shipment | | |

Source: Wood Mackenzie; 1. Refers to Initial Production Rate for the drilled wells

# Base development assumptions provide comfort that there is enough gas to support Cook Inlet region demand; Ahpun targets FID by 2025 with first production to follow in 2026

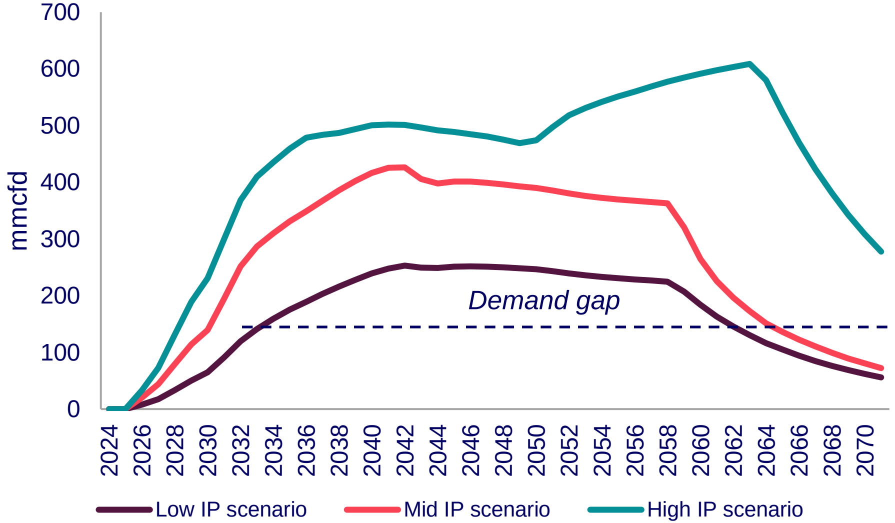
| | | | | |
|---|---|---|---|---|
| **Base Development Assumptions** | **Planned Wells** | 187 | | |
| | Producer:Injector Ratio | 3:1 | Injection Well Drilling Cost | US$M 4.85 |
| | Development Well Drilling Cost | US$M 5.32 | Injection Well Completion Cost | US$M 5.49 |
| | Development Well Completion Cost | US$M 10.94 | Abandonment Cost | US$M 1.5 |

**Producer well drilling schedule assumptions**




Source: Wood Mackenzie

**Gas production**




Source: Wood Mackenzie

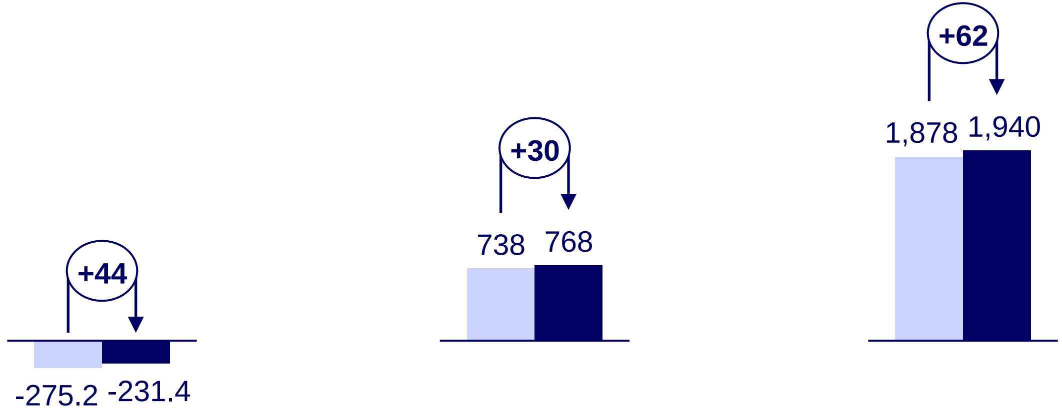
Wood Mackenzie

# Gas monetization provides ~US$30 million to post-tax present value on the medium case, but will increase Capex/boe; profitability ultimately depends on well productivity

| Low IP Rate: 180 kbd | Medium IP Rate: 500 kbd | High IP Rate: 780 kbd |
|---|---|---|
| *Actual test rates from Alkaid-2 declines matched to Coyote* | *Base case conservative oil rate* | *SLB model oil rate with adjusted decline to match disclosed EUR* |

**Remaining PV 10 post-tax ($M)**

Gas monetization provides increased Present Value to the project




**Capex / boe ($)**

Gas sales will increase capital expenditure

| | Low IP Rate: 180 kbd | | Medium IP Rate: 500 kbd | | High IP Rate: 780 kbd | |
|---|---|---|---|---|---|---|
| | No Gas Sales | Gas Monetisation | No Gas Sales | Gas Monetisation | No Gas Sales | Gas Monetisation |
| Capex / boe ($) | 5.0 | 5.3 | 3 | 3.4 | 1.9 | 2.3 |

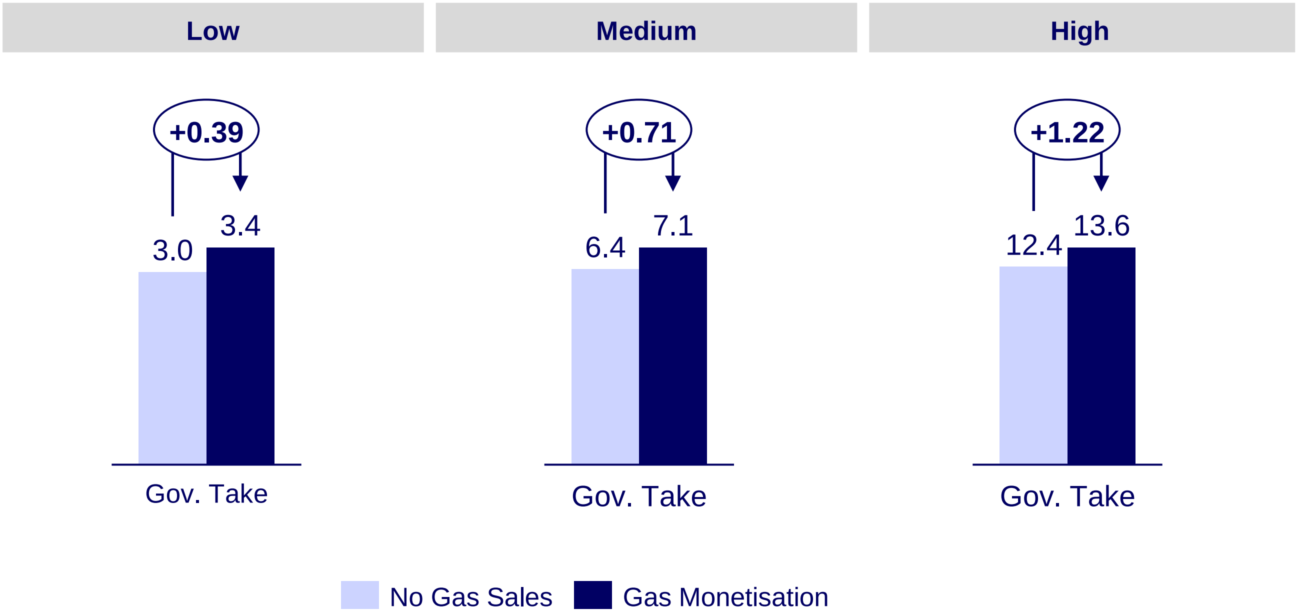
No Gas Sales  Gas Monetisation

Source: Wood Mackenzie

# Gas monetization from Pantheon's Ahpun and Kodiak also increases government take for the field development by ~US$710 million over the field lifetime in the medium IP scenario

**Lifetime Government Take[1] from Great Bear Pantheon Field Development – Gas Monetization Impact**
US$ billion, real

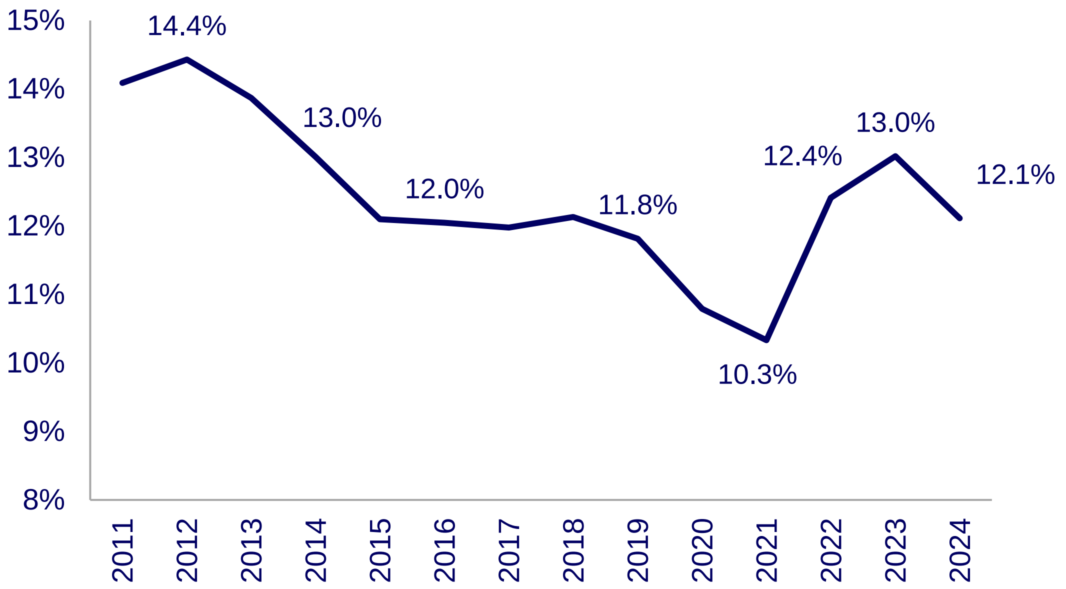
Gas monetization provides incremental government take in the range of **~US$ 0.4 – 1.2 Bn**




Source: Wood Mackenzie; 1. Government take considers Royalties, State Tax and Federal Taxes

# Oil indexation levels in Asia have trended down, though they've increased since the low historic point in 2021

## Average oil indexations in new contracts to Asia + US$0.50/mmbtu constant DES




- A historical downward trend in oil-linked prices has been driven by large LNG producers such as Qatar opting for a market share strategy; other sellers holding long uncontracted positions and Japanese legacy buyers being out of the market for long-term volumes.
- However, higher spot prices have exerted upward pricing pressure, heightened by the high LNG prices seen during 2022
- We anticipate new long-term contracts being signed within the 12% slope range

Source: Wood Mackenzie and Alaska Department of Labor and Workforce Development

# Shipping and Regasification Costs

## Shipping costs

- Costs are based on long-term charter rates. Voyage costs take no account of additional costs for ice-class shipping, though these would likely not be applicable for the analyzed routes. The main projects affected by additional ice-class shipping costs are Yamal and Arctic LNG-2, which we estimate would incur additional shipping charges of US$ 0.20 – 0.80 / mmbtu.
- Costs are based on currently available routes, now considering Panama Canal when possible.
- We assume an average fleet speed of 16 knots for all vessels and a newbuild cost assumption of US$ 235.0 million for a 174,000 $m^3$ capacity LNG carrier.
- LNG and Fuel oil prices are reflective of a 10-year average of our forecast, including the current year. For LNG, we take 10-year average (2024 – 2033) of our JKM and TTF prices. For Fuel Oil, we take the 10-year average (2024 – 2033) of Singapore and NW Europe VLSFO 0.5% S prices.

## Regas costs

- A database of 48 operating, under construction and proposed FSRUs has been used
- Regas costs for each FSRU have been estimated by either
  - A standard Capex and Opex assumption based on size and type of project
  - Building a discounted cash flow for the project economics
  - Regas tariff comes from the operator’s or government’s website which is updated and republished regularly.

Source: Wood Mackenzie

Wood Mackenzie

# Pricing indexation into the Pacific has favored JKM over JCC (Oil linked), though local gas hub and hybrid indexation have dominated the last 5 years

**ACQ of contracts by pricing indexation**
mmtpa

| Year signed | Henry Hub | JKM | JCC | AECO | Waha | Hybrid |
|---|---|---|---|---|---|---|
| 2016 | 0.80 | 0.00 | 5.52 | 0.00 | 0.00 | 3.78 |
| 2017 | 1.11 | 0.00 | 3.90 | 0.00 | 0.00 | 5.53 |
| 2018 | 8.10 | 0.76 | 0.60 | 2.80 | 0.00 | 0.00 |
| 2019 | 1.70 | 0.00 | 0.28 | 0.00 | 0.00 | 1.60 |
| 2020 | 1.00 | 1.15 | 2.40 | 0.00 | 0.00 | 2.50 |
| 2021 | 13.74 | 0.00 | 0.00 | 0.00 | 0.00 | 3.60 |
| 2022 | 24.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.60 |
| 2023 | 12.65 | 3.22 | 0.00 | 0.00 | 1.00 | 0.40 |
| 2024 (YTD) | 0.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.89 |

No JCC linked deals since 2020

Source: Wood Mackenzie, Note: TTF, NBP and Brent-oil based deals not shown as those are assumed to be largely focused on the European Market

Wood Mackenzie

# Component 1: Total capex validated with benchmarks and used for the economic model of Alaska LNG Phase 1

## Built an economic model and gas demand scenarios to estimate the delivered cost of gas

- Wood Mackenzie estimated the demand gap expected to be supplied on a "WM Case" and modelled the pipeline and gas production economics leveraging verified AGDC's costs estimation and gas purchase price assumption
- **Upstream costs** include a gas price assumption based on AGDC's input and Great Bear Pantheon development plan
  - Validated reasonability of assumption by modelling the impact in the present value of the Great Bear Pantheon development
- **Pipeline phase I costs:** Using AGDC's costs assumptions and benchmarked against a peer group selected from a database of over 100 pipelines

## Estimated direct economic benefits and impacts to the state of Alaska

- **Characterized the Pipeline total capex** into multiple categories including:
  - Raw Materials
  - Multiple categories of labour: excavation, welding & joining , installation, etc.
  - Compression
  - Land
  - Rights of Way
  - Environmental, regulatory
  - Feed and PMO
- **Incorporated assumptions of in-state impact per category:**
  - 70 – 80% of labor sourced in-state
  - Approximately 10% of raw materials
  - Removal of compression expenditure for Phase 1

Source: Wood Mackenzie

Wood Mackenzie

# Components 2 & 3: Lifetime project direct, indirect and induced impacts are assessed with a combination of top down and bottom-up approach

## Bottom-Up View:

**Interviews and support from internal industry experts**

- Upstream Supply base experts
- Gas & LNG consulting and economic benefits experts

**Economic modelling for the pipeline and other project components**

- AK LNG Ph I under the WM case
- Quantification of the Pipeline's lifetime opex and Project's Government revenues under the WM Case
- Modelling of Great Bear Pantheon increase in Government take because of gas monetization

**Direct and indirect employment assessment consolidated from previous studies**

- Direct employees, skilled, and unskilled
- Compiled total support services and their employment requirements, skilled and unskilled

## Top-Down View:

**Benchmark multiplier analysis**

- Identified AK's peers, deriving from global screening of countries' petroleum reserves and other socio-economic indicators.
- Using input-output statistical analysis approach – a standard and widely used methodology for socio-economic impact assessment
- Input-output analysis conducted for peer countries to derive a proxy for Alaska's economic impact multipliers.
- Analysis supported by experienced internal principal economists.

**Complementing Secondary research**

- Benchmark study of similar developments (Pipelines)
- In-depth study of socio-economic benefits from LNG developments leveraging previous studies completed

Source: Wood Mackenzie

Wood Mackenzie

# Component 3: Indirect and Induced economic benefits determined by applying suitable multipliers derived from benchmarks and previous studies performed

**Peer Country Screening**

- **Rank >100 countries in WM's database for hydrocarbon resources and infrastructure**
- **Filter for top half countries**
- **The US falls within top hydrocarbon endowed countries and Alaska can be comparable to some small developed countries**

**Countries with quality data available chosen for quantitative benchmark multiplier analysis**

**Alaska's multiplier ratio aligned with peers**

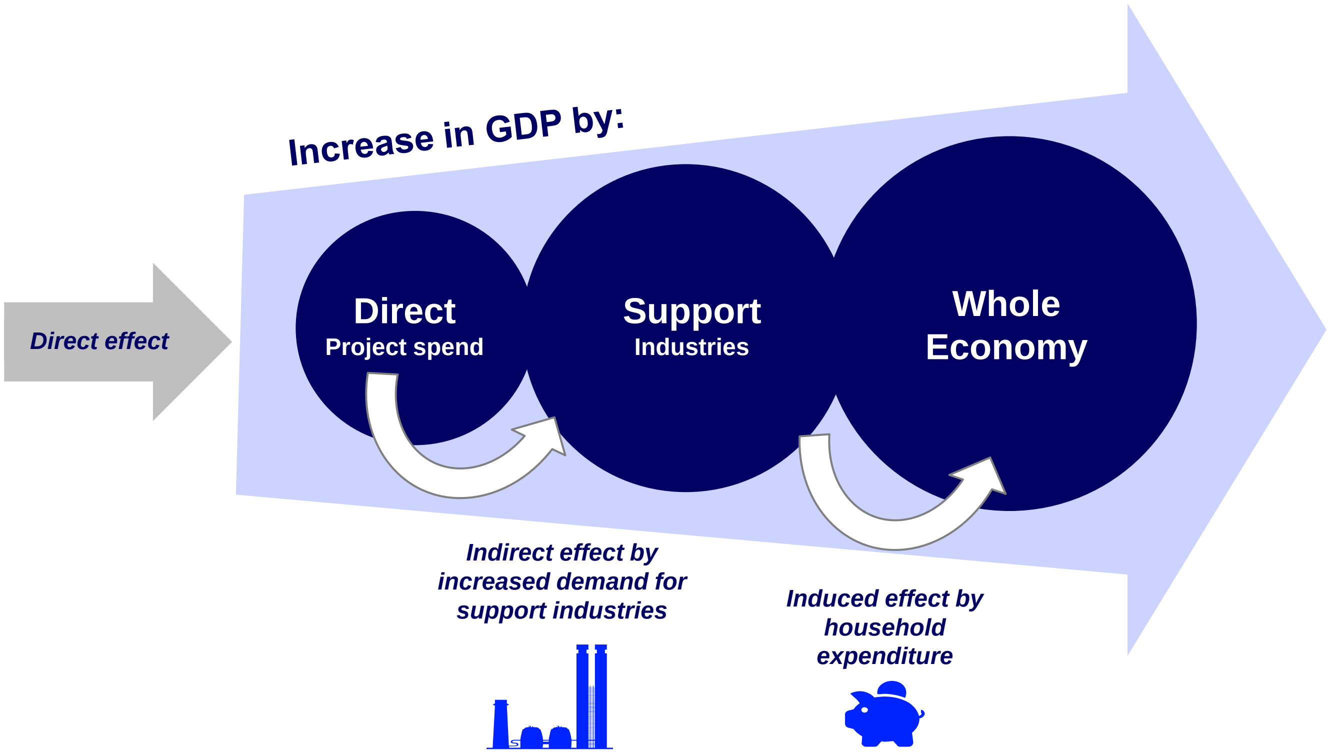
**Calculation of total Gross Value Added (GVA) and mapping of employment increase from construction and operation of Alaska LNG Phase 1**

*A benchmarking methodology is used to estimate Alaska's GDP multiplier effect as data is generally reported at a country level*

Source: Wood Mackenzie

# Multiplier effects take place as spending, taxes, and household income derived from a petroleum project cycles through the economy

**Regional spend**
- Construction
- Operations




Source: Wood Mackenzie

# Certain factors commonly drive economic multiplier effects higher or lower

## Where does Alaska sit?

| | Economy Size | Stage of Development |
|---|---|---|
| + | High GDP per Capita | Large Urban Population |
| + | Large  Population | High Literacy Rate |
| + | Large Economy | Large share of services and industry in GDP |
| – | Small Economy | Lower share of services and industry to GDP |
| – | Small Population | Low Literacy Rate |
| – | Low GDP per Capita | Large Agricultural Population |

Source: Wood Mackenzie

Wood Mackenzie

# The multiplier benchmark considers classifying countries into peer groups based on their characteristics

*Larger Size*

Economy size

### Large & Developed Economy

- Australia
- Canada
- UK
- USA

### Large & Less Developed Economy

- Brazil
- Indonesia
- Russia
- Mexico

**What is the downward/upward impact on the multiplier?**

### Small & Developed Economy

- Israel
- Netherlands
- Norway
- Saudi Arabia

**Alaska**

### Small & Less Developed Economy

- Brunei
- Malaysia
- Peru
- Tunisia

Stage of Development

*Less developed*

Source: Wood Mackenzie

Wood Mackenzie

# Economic and social indicators confirm Alaska's peer group of 'Small & Developed' Economies

**Economic Indicators – Heat Map of Benchmark Countries - 2023[1]**

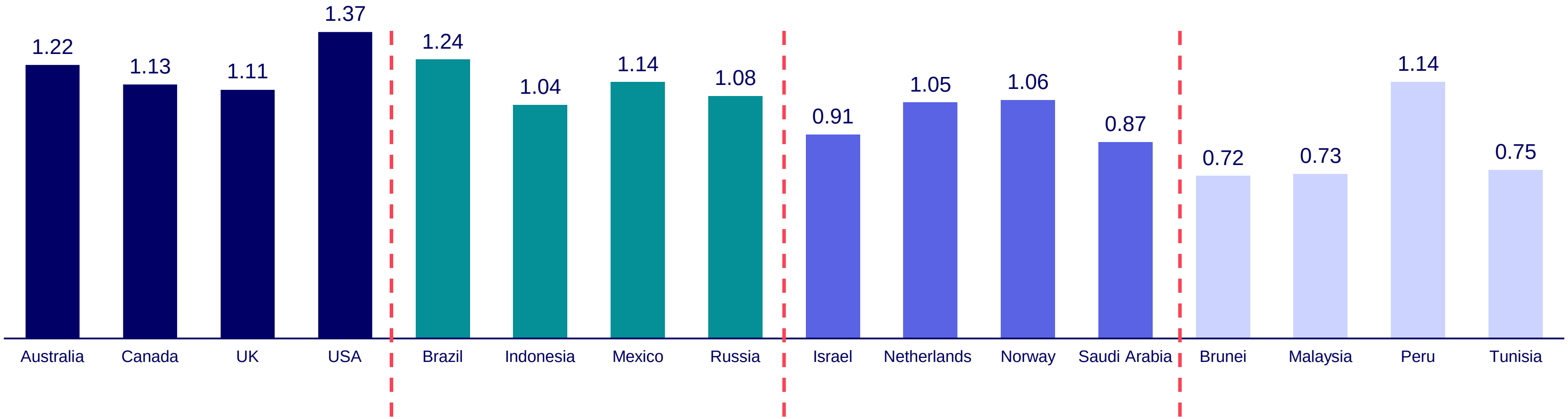
| | Indicator | USA | CAN | UK | AUS | BRA | IDN | RUS | MEX | ISR | NLD | NOR | SAU | AK | BN | MY | PE | TN |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Economy Size | GDP (US$bn) | 27,360 | 2,140 | 3,340 | 1,720 | 2,170 | 1,370 | 2,020 | 1.790 | 510 | 1,120 | 486 | 1,070 | 64 | 15 | 400 | 267 | 49 |
| Economy Size | Working Population (mn) | 216 | 26 | 43 | 17 | 151 | 189 | 95 | 86 | 6 | 11 | 4 | 26 | 0.5 | 0.4 | 24 | 22 | 8 |
| Stage of Development | GDP/ Capita ('000) | 82 | 53 | 47 | 65 | 10 | 5 | 14 | 14 | 52 | 63 | 88 | 29 | 75 | 33 | 12 | 8 | 4 |
| Stage of Development | Industry & Services/ GDP (%) | 98 | 98 | 98 | 97 | 94 | 87 | 94 | 97 | 99 | 97 | 97 | 99 | 95 | 98 | 94 | 93 | 83 |
| Stage of Development | % Urban population | 83 | 82 | 85 | 87 | 88 | 59 | 75 | 82 | 93 | 93 | 84 | 85 | 60 | 79 | 79 | 79 | 71 |
| Stage of Development | % Secondary School Completed | 92 | 99 | 98 | 93 | 82 | 79 | 93 | 81 | 99 | 93 | 96 | 95 | 90 | 83 | 72 | 89 | 93 |

**Large & Developed Economy** (USA, CAN, UK, AUS) | **Large & Less Developed Economy** (BRA, IDN, RUS, MEX) | **Small & Developed Economy** (ISR, NLD, NOR, SAU, AK) | **Small & Less Developed** (BN, MY, PE, TN)

Source: Wood Mackenzie, The World Bank, Economist Intelligence Unit, 2023 data except for Woking population and % Secondary School Completed where latest available number was included

# Results of the multiplier benchmark analysis confirm that economic size and development has an effect on a multiplier's magnitude

**Construction Multipliers – Direct + Indirect + Induced**




**Average = 1.21** | **Average = 1.13** | **Average = 0.97** | **Average = 0.84**

*AK multiplier expected higher than peers due to being part of the US*

Similar exercise performed for Operations Multipliers

Source: OECD, Wood Mackenzie Analysis, the Perryman Group

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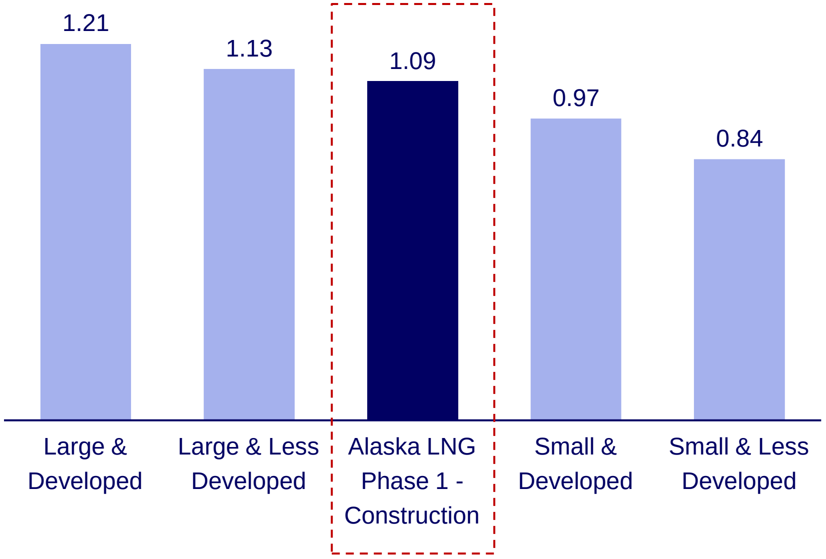
# Multipliers for Alaska are estimated higher than the average for its peer group of small and developed economies, as they consider Alaska's integrated economy with the US

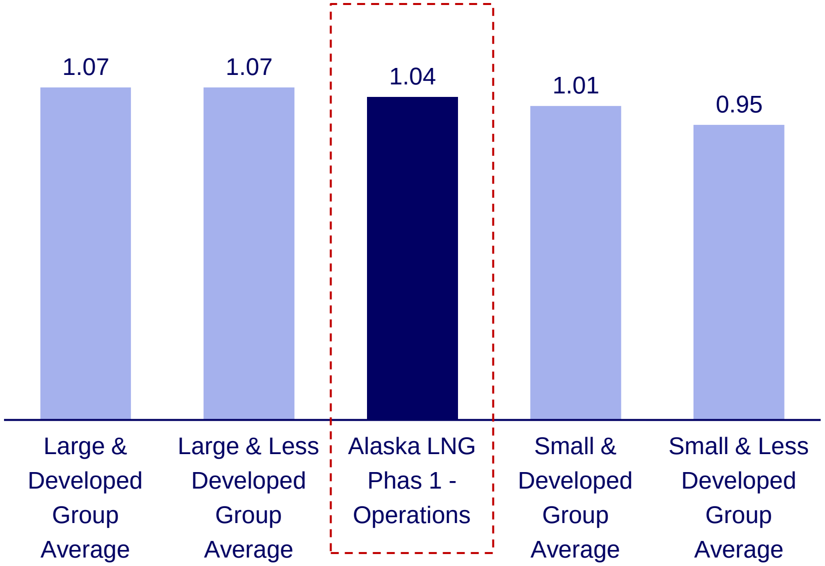
**Construction Multipliers**

Group Average and AK estimated assumption




**Operations Multipliers**

Group Average and AK estimated assumption




Source: OECD, Wood Mackenzie Analysis, the Perryman Group

# Labor impact from LNG Imports development: estimation based on dock construction, dock and FSRU operations.

| Project Scope | Phase | Direct Job Creation<br>Estimated Range | Total Direct Job Creation<br>(Considers middle of range) |
|---|---|---|---|
| Dock Construction<br><br>(Based on a US $100 to 200 million Dock investment) | Planning, engineering and design | 50 – 100 | **800** |
| | Site preparation and civil works | 150 – 250 | |
| | Dock construction | 250 – 400 | |
| | Installation of utilities and equipment | 100 – 150 | |
| | Finishing and commissioning | 50 – 100 | |
| Dock Operations | Dock management and logistics team | 10 – 15 | **20** |
| | Support staff | 5 – 10 | |
| FSRU Operations | Marine Operations Crew | 10 – 20 | **35** |
| | FSRU Regasification Plant Ops Crew | 15 – 25 | |
| | | **TOTAL** | **855** |

Source: Wood Mackenzie

# Disclaimer



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