Key Issues: Legislative and Policy Options for Alaska LNG

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Basis of Opinion

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Executive Summary

This report was requested by the Chair of the Legislative Budget and Audit Committee to inform legislators about the possible legislative implications of the planned AK LNG project. At this stage in the project, a host of key financial and economic inputs are yet to be defined, such as capital cost estimates, gas supply arrangements, degree of federal support, and other important parameters. Consequently, it is not yet possible to set out a definitive picture of what steps may be required of the legislature in the coming months, as the project continues to evolve. However, with over 170 LNG export facilities in 22 exporting countries, there is a considerable body of experience from which Alaska can draw and helps to provide guidance on what may be expected.

In essence, any exporting nation or state must balance the enablement of a successful Final Investment Decision (FID) with securing appropriate benefit for the host state and its citizens. This equation is extremely complex and involves a host of decisions from government on key areas of policy, taxation and financial support. This report starts with a description of some of the key features of the AK LNG project and sets these out against how other nations or states have achieved LNG success. The report concludes with some of the market background that will be relevant, as decisions on the AK LNG project are reached.

While the pre-requisites for FID are driven primarily by technical and commercial features, the state government's role in bringing the AK LNG project to fruition is a meaningful and likely essential ingredient for success. Without exception, major LNG investments encompass a negotiated approach to taxation and other regulatory/policy features, including some level of fiscal stability to support economic forecasting. With its substantial exposure to upfront capital, and need for dependable long-term revenues, these aspects of the AK LNG project will be even more critical than other oil and gas development projects currently being considered in Alaska. The TAPS project in the 1970s is the only comparable development in scale and capital deployed.

Significantly, the AK LNG project also encompasses an initial Phase I plan involving the gas pipeline alone, supplying gas and power to utilities and end-users in Southcentral and parts of the Interior. The business case behind this initial phase benefits from its potential to address the forecast energy shortages in Southcentral Alaska in the short to medium term.

With its primary role in energy supply to in-state users, this portion of the project would rely on various pre-requisites including:

- A gas supply agreement with one or more North Slope gas producers, with appropriate Alaska Oil and Gas Conservation Commission (AOGCC) approvals.

- Long term contracts with utility scale shippers such as gas and power utilities guaranteeing long term revenue for the pipeline owner.
- A supporting pipeline tariff, potentially set by the Regulatory Commission of Alaska (RCA), or through legislative means, to provide long term credit support through energy sales.
- An agreed commercial and ownership structure for the pipeline supported by financing arrangements relying on the features listed above.

To better inform potential investors on a final investment decision, these features, including an updated cost estimate for the pipeline, would typically need to be largely in place.

In addition to state legislative measures to enable the wider AK LNG export project to come to fruition, federal assistance, such as credit support, may also be needed and this is discussed later in the report.

The administration in Washington, D.C., is taking steps to promote US energy investment and to leverage energy exports including LNG to further trade and foreign policy goals. The Alaska LNG project has been at the forefront of these initiatives and garnered attention from a number of industrialized economies highly dependent on LNG imports, such as Japan, South Korea, Taiwan, Vietnam and Thailand, as well as other significant buyers such as China. Federal government support and links with wider trade discussions may have a positive impact and improve the chance of success of AK LNG reaching FID; however, the project will depend on commercial contracts in which governments are likely to play only a facilitating role. Formal but non-binding letters of intent (LOI) or Heads of Agreement (HoA) have been signed with CPC of Taiwan and PTT of Thailand, each of 2 MTPA[1]. Additionally, a 1 MTPA letter of intent was signed with JERA, the largest Japanese buyer of LNG, Tokyo Gas, and POSCO in Korea. POSCO, who in early December developed their LOI into a Heads of Agreement may also play a role in supply of steel. It is noteworthy that both PTT and CPC are state owned, but interest from JERA and Tokyo Gas, as examples of private companies, implies wider interest from the LNG community. Glenfarne has said that 12 MTPA of the proposed 20 MTPA nameplate capacity is subject to some form of non-binding commitment.[2]

One of the challenges faced by the majority of LNG projects is that project development timeframes are typically longer than the 4 or 5-year election cycle seen in many

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1 MTPA – Millon tonnes per annum of LNG (see glossary for full list of definitions).

2 https://www.reuters.com/sustainability/boards-policy-regulation/thailands-ptt-buy-2-mtpa-lng-glenfarnes-alaska-lng-over-20-years-2025-06 24/#:~:text=PTT%20said%20it%20was%20was, decisions%20have%20yet%20been%20made.

countries. The AK LNG project is no exception, and changes in the administration in Washington could affect the factors outlined above.

The single most significant hurdle for the project is the high capital cost and related risk of cost inflation. Although there have been multiple budget assessments over the years, these reviews have remained at a Class V[3] level of estimation. In order to derisk the cost uncertainty, better ascertain the project economics, and enable commercial negotiations to proceed, much more detailed engineering and design work is required. This is termed the FEED (front end engineering design) stage of the project and, together with sales contracts and financing is the main precursor to a final investment decision (FID). In previous iterations of the project, the FEED stage has not been reached, and therefore the prior estimates are still subject to high degrees of uncertainty and further deteriorate as time passes due to changing market conditions, including LNG cost inflation and escalation.

Preliminary economics suggest that Alaskan LNG could be delivered to Asian gas buyers at a price that would compete with LNG originating from the US Gulf Coast. However, if the FEED estimates of the capital investment needed to build the gas treatment plant, pipeline and liquefaction facility significantly exceed current budget assessments, project economics may be threatened. Conversely, US Gulf Coast projects typically rely on buying gas from the wholesale market which is priced relative to the main US gas index, Henry Hub. As a result, increases to US wholesale gas prices would lead to higher cost LNG and would erode the competitiveness of Gulf Coast LNG compared to the AK LNG project.

The AK LNG project benefits from four structural advantages when compared to competing sources of LNG, such as the US Gulf Coast:

- Shipping distances to markets in Asia, a major source of demand growth, are much shorter.
- The shipping route avoids major bottlenecks and security threats, such as the Panama Canal, Red Sea/Suez Canal and Straits of Hormuz.
- The gas resource in Alaska is substantial, well understood, and potentially very low cost, benefitting as it does from existing infrastructure and experience.
- Finally, the project benefits from years of study and development work, which has created a wealth of knowledge to underpin more advanced engineering studies and has also facilitated a series of successfully awarded permits.

[3] A Class V cost estimate is the least detailed and accurate type of project cost estimate, used in the earliest stages of a project for feasibility studies. It's based on very limited information, with an accuracy range of approximately -50% to +100%.

To capitalize on these advantages, engaging in a dialogue between all key stakeholders (state and federal government, project developers and lenders) on enabling legislation will be essential in securing a successful outcome that fully captures the long-term benefits of the project to the State and its citizens.

Although there are many features of the project that are well defined, a definitive package of enabling legislation and fiscal framework for the project cannot yet be contemplated. This requires two additional steps:

1. A detailed economic model of the project is required before the legislature can take an informed view as to the appropriate degree of government take that the project can sustain, and how this could evolve over time.
2. Given the likely involvement of federal government agencies in the evolution of the project, the degree of federal support and fiscal stimulus (if any) could also materially influence how the Alaska legislature approaches its own fiscal policy towards AK LNG.

Introduction

The AK LNG project has been in some form of conceptual design for many decades but last received significant attention to its design, permitting and engineering effort in the 2013-2016 timeframe. This followed the establishment of a legislative framework under Governor Parnell (including HB 4 in 2013 and SB 138 in 2014) and the formation of a special purpose company that included ExxonMobil, BP, ConocoPhillips and the State of Alaska. The prior legislation also included provisions for the formation and governance of the Alaska Gasline Development Corporation (AGDC), which took over 100% of the project after the energy company sponsors, Exxon, ConocoPhillips and BP decided to withdraw in August 2016.

Since 2016, AGDC has been seeking commercial support for development of the project, which culminated in AGDC transferring 75% of the project and responsibility for taking the project forward to Glenfarne, a Houston based energy infrastructure development company. This was formally agreed in March 2025.

Since the original project concept was developed under SB 138, natural gas supplies to Southcentral Alaska have come under considerable pressure due to the decline in Cook Inlet gas production, resulting in a predicted supply shortage as early as 2027. The requirement for the replacement of Cook Inlet natural gas supplies has provided an additional driver for the gas pipeline element of the project, which is now seen as both central to the LNG export concept, as well as addressing serious in-state energy shortages.

Furthermore, the change of administration in Washington, D.C., in January 2025 has resulted in a series of Executive Orders, cabinet appointments and policy changes which have prioritized the development and export of LNG from Alaska.

As a result of all these developments, the strategic rationale, geopolitical support, and commercial framework behind the project have all changed substantially. While the chances of a successful outcome have improved, a series of complex technical, economic and market related challenges remain. These have now become the primary focus of the project activity. Another key objective which will underpin project economics and feasibility is the completion of the FEED process. This will be needed in order to achieve the ambitious target for FID or final investment decision, first for the gas pipeline from the North Slope and secondly for the LNG export project itself.

However, as set out in the sections below, a successful project will likely require suitable enabling legislation from the state legislature, among other key pre-requisites. Fiscal and regulatory features of the project will need sufficient detail to reduce uncertainty for long term investors and lenders. This process, for the current project, is at the early stages and based on global experience, months or years of legislative effort may be required before being fully concluded.

Federal action could also be very beneficial. For example, federal loan guarantees would be an important enhancement to project economics in addition to other forms of possible policy support. Funding or loans through the US Department of Energy Loan Program Office (LPO) may also result in some degree of economic support.

This report is divided into three sections. The first discusses the role of the state and the scope of enabling legislation, the second provides examples of enabling legislation from the Lower 48 and internationally, and the third addresses the wider LNG market developments that may influence state policy as AK LNG is being discussed.

1 Considerations for the State Legislature

1.1 Why is State Involvement Needed?

Any major LNG project development requires significant dialogue and negotiation with its host government on a range of matters. The scale and materiality of new LNG facilities on the host nation/state economy is such that in most cases, special tax treatment, subsidies or other features apply. These are outside the typical scope for more modest energy project investments but are common for LNG projects. This is particularly the case in Alaska, since unlike projects in the Texas/Louisiana LNG corridor, the Alaska LNG project is influenced by a host of factors that are not present or are less significant for Gulf Coast developers, such as the close integration with North Slope oil production and the impending gas shortage in Southcentral Alaska.

While subsidies and tax breaks are common in LNG project enabling legislation, the principle that typically applies is that each concession in fiscal treatment is balanced against other economic benefits enjoyed by the state, often of a longer-term nature.

1.2 Gas Resource Considerations

The multiple trillions of cubic feet of gas resources on the North Slope will never contribute directly to the state economy without a route to market and would otherwise remain unproduced. Unless a mechanism can be found to monetize the gas, the value to the state, and indeed lease holders, will be severely limited. By contrast, natural gas resources in the southern US can be monetized in a variety of ways including power generation, petrochemicals, and other industrial markets. Even without LNG, the gas resources in the rest of the US have other commercialization options and thus the option of selling via LNG primarily only influences the pace and to some degree the price at which those resources can be developed.

The economic scale of the gas opportunity for Alaska is vast. With proved gas reserves of around 35 TCF and estimates of 200 TCF for gas yet to be discovered[4] the North Slope represents a world class gas resource. For example, if gas production were to reach just half this potential volume, 100 TCF, it would have a market value in the range of one to two trillion US dollars, using an end market value of $10 to $20/MMBtu.

1.3 Capital Intensity

The AK LNG project is arguably the most capital-intensive LNG project ever attempted and rivals or exceeds many of the biggest Australian projects brought to market in the

[4] https://agdc.us/alaskas-lng-project/alaskas-natural-gas-supply/

last decade or so. The more capital intensive a project is, the greater the need for risk mitigation to ensure the investment is recouped and to provide comfort to the investors, including the State of Alaska, making the investment decision. This being the case, fiscal stability, regulatory arrangements, and other features in which the state plays a major role will materially affect whether the project reaches FID.

1.4 Oil/LNG Economic Interplay

Unlike AK LNG, none of the other US LNG export projects are fully supported through the production of associated gas (gas that is produced as a byproduct from oil production). For AK LNG, a very strong link exists between the economics of gas production and the monetization of remaining oil resources. This includes secondary features such as Enhanced Oil Recovery (EOR) using re-injected CO_2 produced alongside the gas. Production of natural gas could reduce oil production in the short to medium term but may extend the life of the oil field thus generating additional oil revenues in the long term. In the context of the LNG project, new legislation that creates a tax or royalty mechanism that links oil and gas revenues, potentially changing over time, could be created to better align the commercial interests of the oil producers with the fiscal requirements of the state. This could also contribute to a lower gas price for the project, and for energy customers in the state. This is an area where the Alaska Oil and Gas Conservation Commission (AOGCC) may have a role.

1.5 Carbon Capture and Sequestration (CCS)

Many of the Gulf Coast LNG projects incorporate carbon capture and sequestration (CCS). This is done both as a means to enhance profitability through tax credits[5] as well as a way to attract LNG buyers and lenders, many of whom have emissions targets and constraints that low-carbon LNG sources can meet. The recently passed Alaska legislation on CCS (HB 50, 2024) may represent another opportunity for the state to work with the AK LNG project to improve economics. The raising of federal tax credits for Enhanced Oil Recovery (EOR) in the One Big Beautiful Bill Act (OBBBA), also designated H.R. 1 or Public Law 119-21, could also provide enhanced economics when combined with increased oil production.

As an example, if the CO_2 capture plant were to remove 2 million tonnes of CO_2 per annum, at the current rate of credit ($85/tonne of CO_2), this could generate income of $170m which equates to a saving of about 17cents/MMBtu in the cost of the LNG.

[5] 45Q tax credit is a U.S. federal performance-based tax incentive for businesses that capture and securely store or utilize carbon oxides (carbon dioxide and carbon monoxide) that would otherwise be released into the atmosphere.

1.6 State as Equity Partner

The potential for the State of Alaska to enter the project as a full equity partner is unique to Alaska, in US terms, but is a very common feature of LNG projects globally. The equity participation of host governments highlights the importance of such projects and their contribution to the economy, employment, and energy security. As an investor, the State would be able to influence major decisions from the engineering concept stage through development and operations. With its dual role as host government and project participant, equity participation also enables a range of other commercial or economic features which may help lead to a successful FID.

A major consideration in this context is how state and private investors arrive at an overall project framework that meets a reasonable return to equity investors and maintains an attractive outcome for the government. LNG developers will typically be seeking a 10-15% internal rate of return for the equity investment in an LNG project[6], with the level of equity investment required and medium-term revenues dominating their economic analysis. Governments typically have a different view of the required rate of return for capital in such projects because the State will benefit more broadly from the wide-ranging economic activity generated by such a major infrastructure project. As a result, it will likely benefit from a lower weighted average cost of capital (WACC). This feature can be helpful in balancing commercial negotiations, where shorter-term returns are less financially significant to the State, compared to project sponsors.

State investment in the project is also a direct way to ensure that the State benefits in future revenues and profits which can grow significantly in the longer term. Any tax or stability concessions offered to the project to enable FID may be weighed against these longer-term benefits, particularly considering that the economic lives of many LNG facilities globally extend beyond the 20 years typically used for design life and any investment decision. They can also experience periods of high profitability due to unanticipated changes in global market conditions during their lifetime. However, state investment may also involve sharing economic downside with other project sponsors, especially in the short to medium term.

1.7 Impact on State Economy

Another reason for the level of host government involvement in projects of this magnitude globally is their materiality within the jurisdiction's economy. A 20 MTPA LNG

[6] Target IRR may vary depending on the project structure and risk allocation along the value chain. For example, a tolling liquefaction terminal would typically attract a lower IRR hurdle.

export project generates over $10 billion per annum[7] in revenue, as the LNG leaves the US for export. While this represents less than half a percent as a proportion of Texas GDP[8], the ratio to Alaska GDP is more than 20%. This does not include the multiplier effects from jobs and other economic activity from the massive initial investment and decades of operational life. With this level of economic impact, decisions by the legislature carry a much higher burden, with implications into the very long-term for Alaskan citizens and standards of living.

1.8 Alaska's History in LNG

One helpful feature, especially in the context of LNG sales to Japan, is that the Phillips/Marathon LNG sale contract with Tokyo Electric, signed in 1967 which resulted in almost five decades of reliable supply, is perceived as one of the first major building blocks of Japan's highly successful LNG strategy. That historical LNG relationship was partly the result of The Treaty of Mutual Cooperation and Security signed in 1960, and which has some similarities with the current diplomatic efforts to build US relationships in Asia. In spite of the many years that have passed, perceptions in Japan are that Alaska was a founding, reliable long term LNG supply partner from its first days of LNG imports.

1.9 Phase 1 Pipeline Project Concept

As is well understood, in-state natural gas supplies are under considerable pressure, with the continuing decline in Cook Inlet production, the source of most of Southcentral's heating and electricity fuel.

Supplementing or replacing Cook Inlet gas can be achieved through the following steps, either alone or more likely in combination:

- Development of incremental supplies in the Cook Inlet, most likely at a higher cost than current long term natural gas contract prices.
- LNG imports, with the Chugach/Hilcorp conversion of the former LNG export facility in Nikiski, or the Enstar/Glenfarne development based on the LNG storage tanks and port infrastructure (LNG carrier jetty) for the planned AK LNG project design.
- New gas supplies to Southcentral created by expediting the permitted 42" pipeline to connect the Southcentral gas network to new supplies from the North Slope.

[7] December 2026 Asian forward price is $11.05/MMBtu at the time of writing. This price would translate into approximately $11billion per annum of annual sales revenues.

[8] Gross Domestic Product (GDP) is the total market value of all final goods and services produced in a country over a specific period, usually a quarter or a year.

- A reduction in gas demand through accelerated development of non-gas power generation facilities, potentially including coal, biomass, or other renewables.

From testimony provided and public domain reporting, it appears likely that some gas supply mitigation might be required before any new gas pipeline could be commissioned, though how this is achieved is likely to depend on the comparative economics of the aforementioned alternatives, time constraints, and risk.

The main advantages of an expedited pipeline include reducing the economic and technical risk of a full-scale LNG export project, which could enhance the likelihood of a successful FID for the export element of the project.

Other benefits include the possibility of gas supplies to parts of the Interior, such as Fairbanks and if the LNG export element of the project is implemented, Southcentral energy consumers would see substantial savings in energy costs. This scenario is also likely to generate significant in-state employment, tax revenues and resulting GDP impact from more affordable energy supplies and the establishment of businesses that rely on lower cost energy, such as data centers.

The use of in-state gas supplies rather than imports also enhances energy security for the state.

The main disadvantages include the possibility of a significant and long-term cost burden for Southcentral energy consumers if the enhanced flow from the LNG project does not occur or is significantly delayed. However, it should be noted that all the energy supply options under consideration are costly compared to current gas and power customer tariffs.

Other challenges include the need to resolve complex commercial and financing details, with participation and support from the main Southcentral energy utilities.

Setting a tariff for the pipeline also has the potential to require a large and complex filing under the Regulatory Commission of Alaska (RCA) tariff-setting responsibilities pursuant to the provisions of AS 42.08 (In-State Pipeline Contract Carrier Act) and 3 AAC 48, or new legislation to support pipeline tariff determination.

The tariff discussion will also involve complex negotiations concerning the allocation of the pipeline cost burden between the LNG export project and in-state gas users, under the broadly defined “Alaska Advantage Principles” which form part of the agreement between AGDC and Glenfarne.

1.9.1 Commercial Structure and Regulations for an In-State Pipeline

At the very core of the commercial framework for a Phase I gas pipeline from the North Slope down to Southcentral Alaska will be a secure revenue stream sufficient to support debt service/repayment and a reasonable rate of return for shareholders. This revenue support and assurance would rely on two features: first, the credit and balance sheet of each of the major utilities taking gas through the pipeline; and second, revenue from the gas and power end-users who are consuming the gas or the power generated using the gas. The key contractual vehicles for this would be ship-or-pay transportation agreements with the utilities taking the gas, and a regulated tariff setting the price that end-users (gas and electricity consumers) would be obliged to pay for their supply.

Supply pipelines to LNG liquefaction facilities fall into two broad categories:

- those with a regulated tariff and
- those with a privately negotiated tariff between the pipeline owner and the LNG project.

In Canada, the Coastal GasLink supply pipeline is governed by undisclosed negotiated arrangements between the LNG project sponsors and the owner of the pipeline. For many Gulf Coast export projects, the gas is supplied through a combination of FERC regulated or state regulated pipelines with declared tariffs and privately owned and unregulated pipelines.

If the gas being supplied from the North Slope to the AK LNG project were being solely used for liquefaction and export, no state regulation of user tariffs would be required. However, the pipeline will also be used to supply gas to in-state consumers and power generating companies, at significant cost to those entities. In fact, Phase I of the project is solely for this purpose. Without a revision to current statutes (conceivably as part of enabling legislation for the project as a whole), this would fall to the Regulatory Commission of Alaska (RCA) to regulate. Current RCA oversight rules include wide ranging powers to examine costs, financing, operations and other details of the pipeline design, construction, and operation. A very detailed economic assessment would be needed to meet RCA's statutory requirements that any tariff be in the public interest and based on just and reasonable rates, terms, and conditions for public utilities.

There are several commercial constructs for the way in which gas is sold to end-users through the pipeline. For example, one model would be based on a bundled gas supply with transportation to a delivery point in Southcentral. An alternative would involve gas purchase directly from a North Slope provider, with a separate gas transportation agreement for the pipeline. However, given that the pipeline element of the cost would be the dominant feature, any RCA regulatory process would focus on the manner in which this is passed on to Southcentral consumers regardless of the wider commercial structure governing gas sales.

The utility scale gas consumers in Southcentral will have an existing portfolio of contractual commitments from other sources, notably Cook Inlet producers, which will contain terms governing the setting of annual quantities and any termination rights. Their ability and willingness to sign transportation contracts for a new gas pipeline will depend on both these existing volume commitments and their assessment of how much gas they are able to purchase at the elevated cost that this new supply would involve. As a result, initial demand for capacity in any new pipeline will be less than eventual forecast demand. If initial gas volumes are low, this feature could lead to higher than anticipated tariffs.

To be consistent with typical FID requirements for a project of this sort, the primary contractual instruments referenced above would need to be complete, or at least largely agreed, including:

- Fully termed gas supply agreements with North Slope gas producers with detailed volume and pricing terms. This would be supported by a suitable certificate of reserves adequacy to sustain supplies at least through the debt repayment phase.
- Ship-or-pay gas transportation agreements or take-or-pay gas sales agreements with utility scale customers at an economically sustainable tariff.
- A regulated end-user tariff or gas/electricity price to support debt service and returns in the medium to long term.
- Finance arrangements including non-recourse debt (project finance) and commitments from pipeline owners/shareholders.
- A well-understood mechanism for the tariff structure that would follow FID on the LNG export element of the project.

Once these agreements are sufficiently defined to enable FID, significant uncertainty would remain as to the final cost of the pipeline, with FID-level cost estimate typically in the -10% to +30% band. For a project such as LNG Canada, with a negotiated tariff between the LNG project and the owners of the Coastal GasLink pipeline, mechanisms would exist for the allocation of any cost overrun or saving between the LNG project, the pipeline, and the EPC (Engineering Procurement and Construction) contractor tasked with building it. For Phase I of the Alaska gas pipeline, a more complex scenario exists, given the role potentially played by the RCA in determining a fair and reasonable tariff. For example, it is unlikely that a tariff would be set for Southcentral gas/power consumers which could be varied depending on final budget, so construction price inflation may have to be taken by the utility scale shippers and the pipeline owners. It would also be typical to build some protection against cost inflation into the EPC contract with the pipeline construction contractor, who would also be expected to carry some price risk.

The Alaska gas pipeline project does, however, benefit from various advantages which suggest that construction cost inflation risk is lower than a typical project of this sort. The pipeline has been extensively studied over many years, with a high degree of technical certainty, the route and staging areas are well understood, and share the TAPS pipeline corridor for over a third of the route. Detailed studies supporting FERC authorizations also remove risk. With the benefit of the budget study currently being undertaken by Glenfarne with Worley, a higher degree of confidence on construction cost may be possible.

In summary, therefore, construction price inflation is a risk that would be carried by potential shippers in the pipeline such as Southcentral utilities, shareholders in the pipeline, and the EPC contractor. Unless explicitly addressed in any end-user tariff for Southcentral customers, energy prices would not necessarily be affected by changes in pipeline cost between FID and completion of the pipeline.

1.9.2 Potentially Accelerated FID for Phase I Pipeline

As noted above, there are a number of unresolved features of the Phase I gasline project that would typically put the timeframe for FID much further out than the project developers Glenfarne have indicated. In March 2025 Glenfarne suggested that the pipeline FID could be as early as late 2025, with subsequent indications being that FID could occur in early 2026. A key step in FID is said to be completion of the cost estimate being carried out by Worley, which is due for completion in December 2025.

Glenfarne have also noted that they are in negotiations with steel suppliers and pipe mills to secure capacity for manufacture of the pipeline to commence in time for an in-service date of 2028.

The earlier a decision is taken to commit to build the pipeline, the more risk and uncertainty remains among other very material features set out above such as a secure and stable gas supply for the in-state demand, contractual arrangements for gas customers/shippers, lending/funding details, and the tariff necessary to support it.

For FID to proceed prior to these major features being fully defined, these risks would need to be borne by a credit worthy entity. A central role for the State in taking on some or all of these risks may be sought by the developers if FID is to be taken as early as 2026. This could include a guarantee to support a multi-year tariff, a backstop on construction costs, other financial support to facilitate timely execution of an EPC contract or a mix of all of these or other steps. Some of these features are what are commonly found in a “gas aggregator” role, adopted by some governments.

1.9.3 Pipeline Ownership

As long as the contractual framework governing the pipeline meets the criteria for FID, the anticipated return on the pipeline would reflect the hurdle rate for any typical infrastructure investment supported by secure long-term tariffs such as a new airport, a toll road, or port, for example. Provided tariff revenues are contractually firm, and the counterparties are highly credit-worthy, a pipeline can attract relatively low risk capital, with anticipated hurdles rates of less than 10%.

Ownership of the pipeline could, therefore, ultimately rest with a variety of institutional investors such as pension funds, infrastructure funds, or other similar entities.

1.10 What Legislative Action may be Needed?

The AK LNG project amounts to a very large upfront capital investment that relies on decades of predictable revenues to create an adequate and reliable return for shareholders. Other than commodity risk, which investors are typically familiar with, the main risks for investors are cost inflation during construction, project delays for any number of reasons and finally the level of government take that investors will encounter over the life of the project.

Government take and limiting the impact of future tax changes is likely to be among the most actively negotiated features of the legislative agenda. There are two elements to this:

- Setting a level of tax that the project will be subject to over its life (which may differ from other oil and gas projects), and
- Arriving at an understanding concerning what discretion can or cannot be exercised by the State that might create adverse tax changes affecting project economics, often linked to debt/financing and achieving a minimum level of financial return from the project. This can be accompanied by contractual obligations or an adjustment mechanism if the fiscal burden changes.

1.10.1 Setting Taxes and Fiscal Terms

Since Alaska is a mature oil and gas producing region, many of the basic structures for tax and other government take provisions already exist within the legislative and regulatory framework, for example:

- Production tax
- Royalty
- State Corporate Income Tax

- Property tax

Within SB 138 it was envisaged that these key contributors to government take would be set at a level to enable adequate project returns and enable a framework for stabilization.

While tax treatment cannot compensate for the possibility of major cost escalation, it will be a focus for project sponsors and will need to be a key element considered when approaching FID. Accelerated depreciation and other tax modifications are sometimes adopted.

Federal taxes are also likely to feature in discussions and could potentially be addressed alongside other federal measures being contemplated, but State taxes are also likely to be a major focus.

Under current tax statutes, upstream tax and royalty have the potential to generate tax revenues in the region of 25% of the feedstock cost representing about 25c-35c/MMBTU of delivered price assuming gas for the LNG is purchased at a price of between $1 and $1.40/MMBtu. This would generate between $250 and $350 million annual tax revenue based on 20 MTPA or 1 billion MMBtus/annum. One consideration for the State is the way in which lease expenditures and new investments are applied against Production Tax, and this feature may need re-examining in the context of the LNG project.

Property tax, under currently drafted statutes, has a much higher cost to the project and impact in delivered price. For example, based on a speculative $50 billion capital cost, a resulting $1 bn tax would result in the first year of operation (albeit a property tax holiday until first gas has been put in place). Even if the full 20 MTPA were achieved early in the project, this would still represent a cost of about $1/MMBTU on delivered LNG that the developers would need to recover. If the three trains are started over a period of months or years, the initial property tax payments, as a proportion of delivered LNG cost, could be still higher.

Since shareholder returns and net present value are heavily dependent on project revenues in early years, the property tax levy would represent a major downside to overall project profitability. For this reason, a focus following SB 138 was the development of a payment in lieu of tax, or PILT, and this is likely to feature in any state tax dialogue in coming months.

Currently in Alaska only companies structured as a C corporation pay corporate income tax. State corporate income tax (CIT) will be payable by the C corporation equity holders in the project once it becomes profitable, which is likely a medium to long term outcome. The current rate of 9.4% would apply, unless amended either specifically for the LNG project, or more generally. A 10% profit margin on a sales price of $10/MMBtu would correspond to $1bn per annum in profit, resulting in $94 million in tax revenues for the state.

1.10.2 Other Taxes

In general, it is becoming more common for host governments to design tax and fiscal arrangements around specific oil and gas projects, and this is particularly common where gas projects are involved. A consideration for the state, therefore, is to levy taxes specifically on the AK LNG profits, particularly if concessions are offered in other areas, such as property tax.

1.10.3 Fiscal Stability

The broadest interpretation of fiscal stability is that over the life of the project, or at least for a significant period, the overall level of government take applied to the LNG project remains at predictable levels. LNG projects have adopted various models of fiscal stability, each offering investors a different level of risk protection. However, they each contain important key attributes which are set out in more detail below.

The degree of fiscal stability sought by investors can also depend on the jurisdiction. Stability mechanisms are typically given the most emphasis in emerging economies that lack a long track record in oil and gas development and have less dependable governance and regulatory structures.

With its budget dependency on oil revenues, Alaska is likely to be seen differently from the Lower 48 but would be perceived as less risky than many LNG investments in Africa or Asia. In particular, Alaska's upgraded Fitch rating to AA- (stable) provides a good measure of financial stability, and recent federal policy support for Alaska's energy exports would also be perceived as positive by lenders and investors.

In jurisdictions where investors seek to control risk of tax changes, fiscal stability is usually achieved through one of two broad mechanisms, with some LNG projects including elements of both:

- Fixed terms, with no tax changes possible, and
- Economic stabilisation, with a mechanism of compensation for tax changes

These are set out in more detail below.

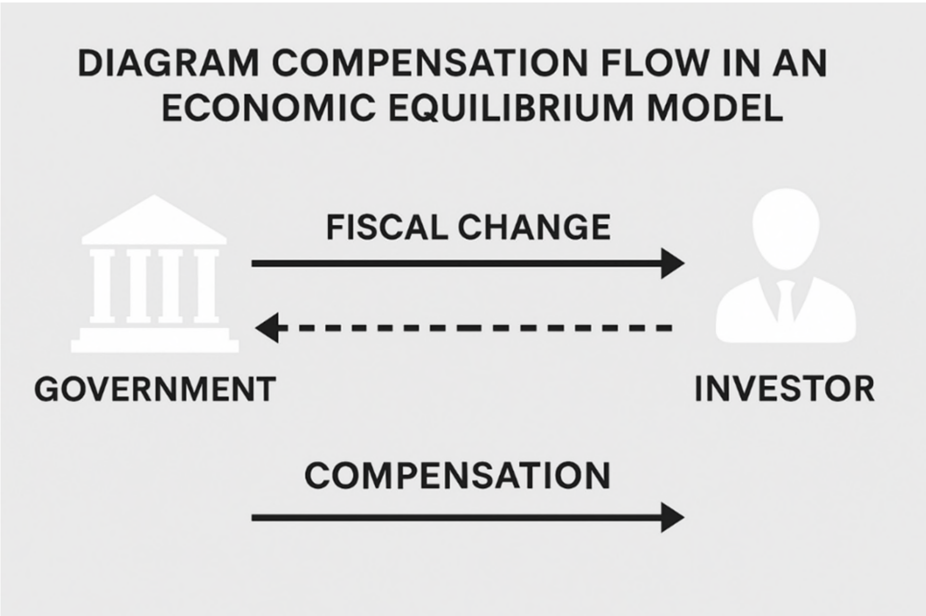
Fixed Terms

A host government will offer fixed tax rates applicable for the life of the project and often provide exemptions from smaller taxes that may be subject to changes during the project's life such as import duties, value added taxes, sales taxes, etc. Examples of this approach include Qatargas I and II, Papua New Guinea (PNG) and the Sakhalin LNG project.

Advantages include certainty for investors, but these types of clauses limit the scope for future legislation and policy changes for the host nation, as circumstances evolve. They are less common in modern LNG projects.

Economic Equilibrium Model

The principle of this approach is that if there are legislative changes to the fiscal terms governing a project, a compensating mechanism exists to ensure that the project investors experience approximately the same financial outcome, as had the original fiscal framework continued to exist. This approach is the one most often favoured in more recent LNG negotiations.



Fiscal Stability – Key Features

A stability clause negotiated between government and investors as part of a formal stability agreement would typically contain the following features:

- Triggering Events: What types of legal or fiscal changes activate the clause (e.g., tax increases, new environmental laws).
- Scope of Protection: Whether the clause covers all fiscal instruments or only specific ones (e.g., corporate tax, value added tax (where applicable), royalties).
- Remedial Mechanism:
  - Freezing: No change applies.
  - Economic Equilibrium: Compensation or renegotiation.
  - Hybrid: Mix of exemption and compensation.

Mechanism for Enactment

While the mechanism for creating fiscal stability depends on the jurisdiction, the following approaches have commonly been adopted, with various pros and cons:

- Statutory law (e.g., Nigeria NLNG Act). This has the highest certainty, enshrined in national law.
- Project-specific decree-law (e.g., Mozambique LNG). This is typically tailored to a project, ring-fenced fiscal rules, usually 25–30+ years.
- Negotiated agreements (e.g., PNG LNG, Peru LNG, LNG Canada). This is usually flexible, often ratified by MoU or law, but may be less durable.

The core question for the Alaska legislature is one of compatibility with constitutional protections, particularly those that prevent one legislature irreversibly committing a future one to a certain course of action. Given these restrictions, the nature of fiscal stability offered to LNG investors may fall short of a contractual agreement and instead rely on assurances and the building of an understanding and trust between project developers and the State.

1.11 Natural Gas Supply

The clear candidates to supply the feedstock to support LNG exports at the scale envisaged are the Prudhoe Bay (PB) oilfield and the Point Thomson (PT) gas-condensate field. In aggregate, these fields contain sufficient gas resources to supply the LNG project for at least two decades. As such, the companies most able to influence the supply side of the LNG project are Hilcorp, ConocoPhillips, and ExxonMobil. The latter two of these three companies are among the six major global LNG players who benefit from significant worldwide revenues and are leaders in the LNG sector. They were also part of the AK LNG joint venture formed in 2014 and dissolved in 2016.

The economics of supplying gas to AK LNG have as much to do with oil and condensate economics, as they do with natural gas. Prudhoe Bay is known as a “gas cap” type reservoir where gas reinjection has been carried out on a large scale (up to 8 BCFD) to maintain oil production. Gas cap reservoirs will typically reach a point known as the “blow down phase” where oil production has been optimized, gas re-injection starts to lose its effectiveness, and finding a market for the gas will become a consideration in the economics.

Point Thomson has similar complexities where the production of oil, condensate and natural gas is carefully managed to optimize reservoir economics. Part of the Alaska Oil and Gas Conservation Commission’s (AOGCC) role is to oversee and regulate this type of fluid balancing in order to achieve an optimal outcome for the state.

Managing gas production and reinjection is therefore a key task for the operators of these two fields, and the ability to monetize gas through sales and disposal will feature in any investment planning over the next decade or more. While the revenue for the producers from the gas sales themselves will be a key part in decisions around gas disposal, the secondary effect on oil and condensate production is likely to be material.

Given the wider economic benefits of being able to recognize a revenue stream from gas sales into the LNG project and optimize oil production, the major North Slope producers are likely to be incentivized to provide a gas supply for the project.

While the PB/PT gas will be the bedrock for the LNG project, other potentially lower cost solutions also exist to provide initial supplies of gas, particularly if the in-state concept is developed in advance of the main LNG exports. Great Bear/Pantheon resources are in the process of establishing a commercial development of their oil and associated gas interests, though some further definition and economic assessment will be needed before these gas resources can be firmly incorporated into the supply portfolio. However, the timeline involved with proving up and committing to develop these oil and gas fields appears compatible with the planned 2028 start date if activities were accelerated. Other North Slope gas supply options for the stand-alone pipeline concept also appear to be feasible in the timeframe.

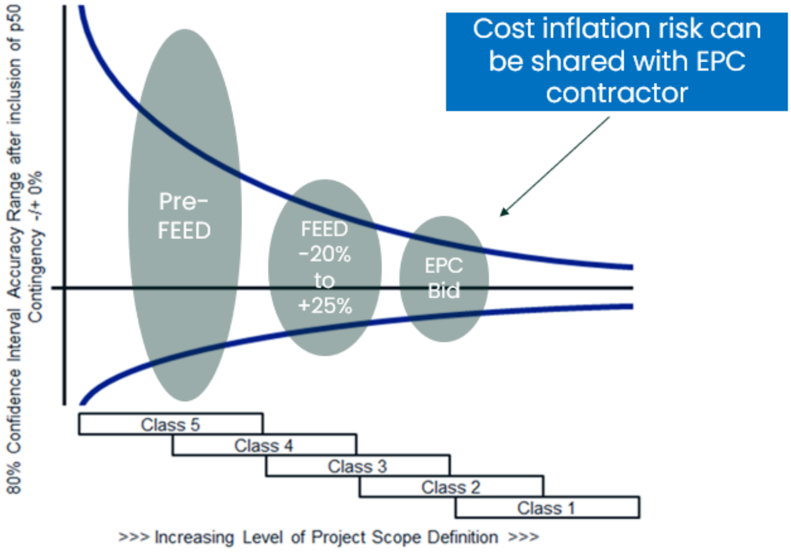
1.12 Economics

The economic viability of the AK LNG project has attracted considerable commentary over the years and has increased since the announcements in late 2024 and early 2025 making public the role of Glenfarne as the project sponsor. Much of this speculation has focused on the possible capital cost of the project, and the resulting cost of LNG supplied to Asian markets.

While the scope of this report does not include a full examination of project economics, the following considerations should be borne in mind:

- The FEED phase of the project, which Glenfarne is planning to undertake, is an essential step towards developing a more accurate estimate of capital cost. While global experience suggests that the cost may be higher than the $44 billion estimate set out by Wood Mackenzie in 2022, any increase or speculation as to the project viability cannot yet be determined.
- The company appointed to do the cost update is Worley, a global Engineering, Procurement and Construction (EPC) company with considerable LNG experience. AGDC has also noted that Worley has previous involvement with the gas pipeline, from the 2013-2014 timeframe, when TransCanada Energy was a partner.

- Even with the FEED carried out, material uncertainties are likely to remain, and one of the key tasks of the project development will be to assign cost risk to the various project stakeholders including the EPC company selected.



Source: AACE® International Professional Guidance Document No. 01

Figure 1 Cost estimate uncertainty by project phase

- As much as 84%[9] of the delivered cost of Alaskan LNG to Asia could be attributable to processing, pipeline tariffs, and liquefaction, all of which will be substantially proportional to the capital cost of these major components of the project.
- As is well understood, therefore, resolving the capital budget estimate is the most significant step in determining project economics.
- Other material features of the economics will revolve around:
  - Cost of feedstock gas delivered into the pipeline at the North Slope.
  - The potential availability of federal loan guarantees, which would lower cost of debt materially and therefore cost of delivered LNG.
  - State and federal taxes/levies/imposts and their phasing over the project life.

[9] With an assumed sales price in Asia of $11.05/MMBtu (December 2025 price), a shpping cost of 85c/MMBtu and a gas sales price at the North Slope of $1/MMBtu, the remaining sale price attributable to processing and pipeline is 84% of the $11.05 sale.

1.13 Cost of Feedstock

Discussions with key gas providers including Hilcorp, ConocoPhillips and ExxonMobil will be pivotal as the project goes through FEED and works towards FID. Similar to Qatar, Alaska's LNG cost of feedstock has the potential to be low, especially when compared to US Gulf Coast projects that are linked to the cost of wholesale gas prices in the Lower 48.

The cost of feedstock and the related CO_2 processing required to clean the gas prior to liquefaction is inextricably linked with monetization of the huge oil resources still extractable from the North Slope. Understanding the relationship between oil and gas economics is likely to be an important feature of establishing an appropriate commercial equation on which to base the price of feed gas to the LNG project.

Due to the economic rent available in the downstream trading and sale of LNG produced at the AK LNG plant, commercial terms for supply of gas to the pipeline/processing plant and rights to liquefied gas as it leaves the LNG terminal may be linked. This will be a key question for the commercial structure eventually adopted and has implications for how the state might approach any review of production tax and royalty.

1.14 Competing Projects: Vulnerability to Henry Hub

One consideration for Alaska, which could support its economic case, is that there is some risk of Henry Hub price escalation. Significant new demands will be made on gas supplies in the Lower 48. This comprises additional demand to feed LNG exports and emerging gas demand for AI-related power generation.

Current gas demand to feed US LNG exports of over 15 Bcf/d is expected to grow to 26 Bcf/d by 2030, doubling demand from 2024[10]. A further 3-5 Bcf/d may be required for new gas-fired generation. While the major gas producing basins in the Lower 48 continue to represent the primary source of gas for all these needs, there is a risk of escalation in the price paid for gas to liquefy. As the lowest cost gas resources are exhausted, higher cost gas will be developed with a potential impact on wholesale gas prices.

The figure below shows a recent Wood Mackenzie forecast[11], which notes that while many upstream focused E&P (Exploration and Production) companies are largely planning on the basis of little real change in Henry Hub, their own forecast is that prices could rise from the current ~$3.50/MMBTU to an average $5.00/MMBTU (nominal) in 2030, and to $6.00/MMBTU by 2035. Applying this to US Gulf Coast LNG pricing formulae would create a price increase of some $2.88/MMBTU on delivered LNG prices to Asia compared to current prices. Such a price rise would have a similar impact to about a 40% increase in

[10] US Dept of Energy.

[11] https://x.com/WoodMackenzie/status/1928457817494630733

capital cost for AK LNG, depending on assumptions around cost of debt and other factors.

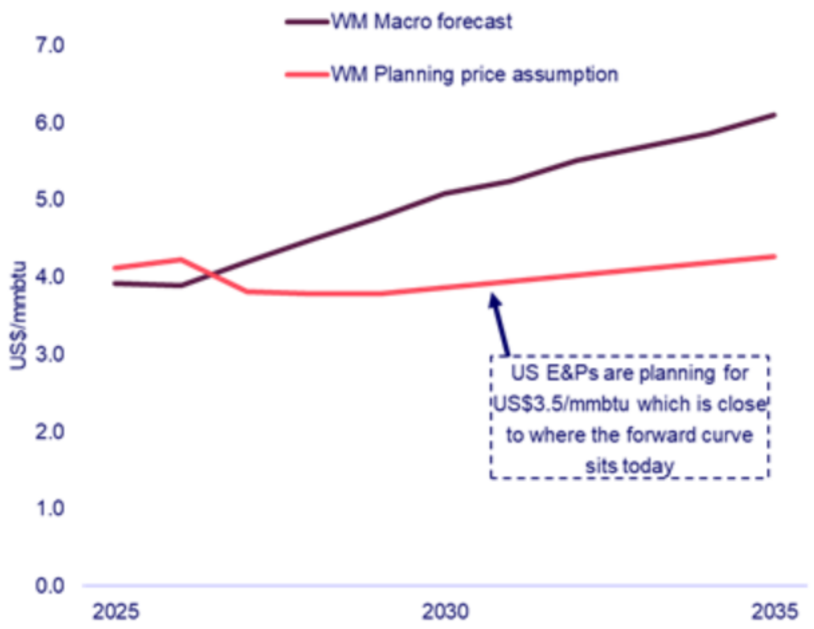


Figure 2 Wood Mackenzie comparison of Industry Planning Assumptions and Forecast HH Price

1.15 Federal Loan Guarantees

A typical LNG project commonly funds 60-70% of the development capital through project finance, sometimes referred to as non-recourse debt since lenders are taking some degree of risk with respect to debt service payments and ultimate recovery of the initial lending. Since the AK LNG project is so sensitive to the initial capital investment that would need to be supported by long term revenues, the cost of debt has a major contribution to cost of supply. A federal loan guarantee would have the effect of reducing lender risk, translating into a lower interest rate. Estimates from Wood Mackenzie suggest that the cost of debt may be reduced by 1-2%, compared to the likely interest rate without a guarantee. This would have a material benefit to the competitiveness of AK LNG compared to competing LNG sources.

The cost of financing for LNG projects continues to evolve, but historically, LNG project finance debt has been priced at a risk-free interest rate[12] + 1.5% to 3%, which translates to roughly 3.5%–6% in low-rate environments.

[12] Traditionally LIBOR was the London Interbank Offered Rate, but has now been replaced by other similar measures such as the Secured Overnight Financing Rate (SOFR).

In recent years, with higher base rates and risk premiums, all-in costs have moved closer to 5%–8% for large-scale liquefaction projects, and sometimes up to 9% for riskier jurisdictions or where exposure to commodity price fluctuations is high.

Using these guidelines, the following example helps to illustrate the potential benefit of a federal loan guarantee:

For an assumed $50 billion capital cost for the project, with 60% debt finance, $30 billion of lending is required. If we assume that an interest rate of 6.5% is applied, this will result in an annual interest charge of $1.95 billion. With debt repayment for a 20-year loan this would generate a total interest plus repayment cost of some $2.7 billion per annum. If we assume that a federal loan guarantee was to reduce interest rates by 1.5% to 5%, the initial yearly interest payments would be approximately $1.5 billion and the total loan interest plus principal repayments would average $2.4 billion. For a 20 MTPA export volume, the saving translates into a reduction of $0.32/MMBtu on the fully amortized cost. For a higher cost estimate, the savings in finance would be proportionally increased.

1.16 Project Structure

Under the structure proposed under SB 138 in 2014, the gas producers on the North Slope would have co-invested in the entire gas value chain (production, gas treatment plant/CO_2 handling, pipeline and liquefaction) and sold the LNG into the global market. Under the framework agreed, the State of Alaska would have had an option to coinvest up to a 25% share, with entitlement to market and sell the same proportion of the LNG produced. The sales and marketing of LNG could be assigned by the State to one of the other project participants, at market reflective rates.

With the increasing commoditization of the LNG market and an increasing emphasis on capital discipline within the oil and gas industry in recent years, the attractiveness of allocating significant capital to gas infrastructure has dwindled. While direct investment in LNG infrastructure by international energy companies (IECs) remains commonplace in jurisdictions with high country risk or regulatory risk, in the US a range of privately funded companies has adopted a business model focused on liquefaction only. Examples of companies predominantly running a business based on LNG liquefaction and the predicable revenues would include Venture Global and Cheniere, both of whom have invested in multiple LNG export terminals in Texas and Louisiana. Among their customers for LNG offtake or liquefaction capacity are some of the primary global LNG players, such as Shell, Total and ExxonMobil, who together with Chevron, ConocoPhillips and BP comprise the main global non-government owned LNG companies.

Although not yet owners of an operational liquefaction facility, Glenfarne appears to have adopted a similar liquefaction-based business model as the foundation of their Gulf Coast projects, Texas LNG and Magnolia LNG. However, Glenfarne, like Venture Global and Cheniere, has a revenue model based on both selling capacity in the liquefaction facility, known as tolling, and keeping back capacity to support sales of LNG directly to buyers. The tolling model, especially where well-capitalized companies are among the customer base, can be an effective way to underpin debt service, while the direct sale of LNG carries commodity risk but also the potential for higher returns.

So far, non-binding offtake agreements have been signed with CPC of Taiwan and PTT of Thailand. More recently this has been extended to JERA, POSCO[13] and Tokyo Gas. All these companies not only have significant demand for LNG, but traditionally also co-invest in the LNG plant and upstream gas resources associated with their LNG purchases. CPC and PTT are state owned, and therefore their strategic goals and investments are more closely linked to government's wider ambitions compared to other types of LNG buyer. These expressions of interest are likely to have arisen, therefore, at least in part from government-to-government dialogue, led by the White House, potentially including trade talks, and national defense matters. The interest from POSCO, Tokyo Gas and JERA, all heavily influenced by their respective government policies, is, however, likely to have a greater commercial driver.

Although the project structure and arrangements remain confidential, it is possible that some combination of making liquefaction capacity available to third parties, and direct sales of LNG could be used as the basis for revenue generation for AK LNG. With the potential for capacity over and above the nameplate design, and debottlenecking of the LNG facility in its first few years of operation, access to these additional quantities of LNG would offer very much improved economics, which are likely to accrue to the Glenfarne/AGDC joint venture, under the framework announced.

1.17 Non-Binding Letters of Intent

In the LNG industry, commercial discussions around the buying and selling of LNG often commence with a non-binding letter of intent (LOI). This is usually very general in nature but will typically refer to an annual volume and sometimes pricing principles. A second, more detailed non-binding agreement often seen in pre-FID discussions is referred to as a Heads of Agreement (HoA) and is usually much more detailed, running to several pages. The agreements made public by Glenfarne are mostly characterised as LOIs, although the arrangement with PTT is termed a "cooperation agreement." Also, the agreement with POSCO has recently moved from being described as an LOI, to the more detailed HoA framework. Although terms vary considerably depending on the counterparties and the jurisdiction, industry estimates suggest that an LOI can evolve into a fully termed agreement between 20% and 40% of the time and an HoA has a higher

[13] The arrangement with POSCO was expanded into a Heads of Agreement between POSCO and Glenfarne Alaska LLC on December 1st, 2025.

chance of success, as much as 80%. This is because Heads of Agreements have usually addressed a series of key commercial features, and so less work is required to negotiate a fully termed agreement.

1.18 GDP Impact of LNG Exports

LNG exports can materially alter the GDP outlook for host nations. The following examples provide some insights into the potential GDP growth that an AK LNG project may generate:

British Columbia

- LNG exports started in July 2025 and at the time of writing 23 vessels have loaded and departed, containing around 1.7 million tonnes with a market value delivered to Asia of about $1 billion.
- LNG projects in BC are expected to add $8 billion annually to BC's GDP, roughly 3% of provincial GDP.
- LNG investments are expected to generate $78 billion in provincial government revenues by 2064 and create 71,000 jobs boosting wages by $4.6 billion per year.
- Since the Alaskan economy is about a quarter the size of BC, the GDP impact of LNG exports for Alaska would be proportionally bigger.

Qatar

- World's largest LNG exporter (~77 MTPA, expanding to 126 MTPA by 2027).
- GDP share: At peak, oil and gas (mainly LNG) contributed over 60% of GDP and ~85% of export earnings.
- LNG wealth transformed Qatar into the world's highest GDP per capita economy (~$85,000+ in purchasing power parity (PPP) terms).

Nigeria

- Nigeria LNG (NLNG) currently accounts for ~7% of annual global LNG trade.
- Contributes around 4% of Nigeria's GDP and 9–10% of government revenues.
- NLNG is one of the largest single contributors to Nigeria's tax base, paying more than $ 20 billion in taxes/dividends since inception.

Mozambique (future impact)

- LNG investments in Mozambique represent $50–60 billion, or more.

- The International Monetary Fund (IMF) estimates that LNG could add up to $15–18 billion annually to exports once fully operational, potentially boosting GDP by more than 30% compared to pre-LNG levels.
- LNG is expected to transform Mozambique into a top 5 global LNG exporter, raising GDP growth from ~3–4% to potentially 8–10% during peak export years.

Papua New Guinea (PNG LNG)

- ExxonMobil has invested in the region of $19 billion in its PNG LNG project which was the first LNG project in the country and started production in 2014.
- In the first years of operation, the project boosted GDP by 10–15%.
- LNG is now PNG's largest export earner (over 30% of GDP contribution indirectly).

Trinidad & Tobago

- LNG exports via Atlantic LNG transformed the economy in the 2000s.
- At peak, oil and LNG exports contributed ~45% of GDP and ~80% of exports.
- LNG stabilized T&T's economy with revenues from LNG exports helping to stabilise volatile oil revenues.

2 Benchmarking – Enabling Legislation and Fiscal Stability for LNG

At this early stage in considering a legislative framework for AK LNG, it is helpful to review how other LNG projects have approached these challenges.

While the LNG investments in the Lower 48 have primarily hinged on commercial arrangements, these projects have also negotiated special treatment with state governments, and these can be a source of insight for Alaska.

Given its geographic proximity and similarities to the AK LNG project (a long dedicated gasline with exports targeted on Asia) LNG Canada may be of particular interest for the legislature. Although the Canadian government framework differs substantially from the US, the collaboration between provincial (state) and federal Government may also provide some insights. Another source of insight is the Ksi Lisims LNG export project, a 12 MTPA proposed project just 60 miles from Ketchikan, on the Alaska-British Columbia border.

Finally, given the size of the LNG investment, the reliance of the Alaska economy on oil and gas revenues, and the impact on the state's economy, there may also be lessons from further afield, such as some of the African or Asian LNG projects, where a carried[14] state interest can also be present. Given Alaska's credit rating and its ability to raise capital, a carried interest may be inappropriate, but some form of equity structuring could be helpful.

2.1 Lower 48

Since 2012, unprecedented growth in US LNG exports has arisen from the transformational economics of shale gas that created a low-cost gas feedstock that could be exported profitably. This has enabled the US to rapidly grow from negligible LNG export volumes to the biggest global exporter in 2025. These same features have also enabled LNG exports to grow in both Canada and Mexico. The table below illustrates the current operational capacity in those countries:

Table 1 North American LNG Export Terminals (operational)

Location	Name	Production MTPA	In service date
Texas	Corpus Christi Liquefaction	19.5	Q4 2018 - Q4 2025
Louisiana	Plaquemines LNG	27.2	Q4 2024 - Q2 2025
Texas	Sabine Pass LNG	27	Q1 2016 - Q4 2021

Texas	Freeport LNG	15.9	Q3 2019 - Q1 2020
BC	LNG Canada	7	Q3 2025
Louisiana	Cameron LNG	13.5	Q2 2019 - Q2 2020
Louisiana	Calcasieu Pass LNG	11.4	Q4 2021 - Q4 2022
Maryland	Cove Point LNG	5.78	Q1 2018
Mexico	Fast LNG Altamira	1.4	Q3 2024
Florida	Elba Liquefaction Project	2.5	Q4 2019 - Q3 2020
Alaska	Kenai LNG	(1.53)	Q4 1969 (Offline)

In addition to the export facilities already in operation, a further 130 MTPA of capacity is already under construction, either as a new terminal, or capacity additions to existing ones, and over 400 MTPA of prospective new capacity has been announced, including AK LNG, though many of these projects remain at a speculative stage.

Table 2 North American LNG Export Terminals (under construction)

Location	Name	MTPA Capacity	Expected in service
Texas	Corpus Christi Liquefaction	9	Q2 2025 - Q4 2028
BC	LNG Canada	7	Q1 2025 - Q4 2025
Mexico	Fast LNG Altamira	1.4	Q3 2027
Texas	Rio Grande LNG	30	Q4 2027 - Q2 2031
Texas	Port Arthur LNG	26	Q4 2027 - Q4 2031
Texas	Golden Pass LNG	18	Q1 2026 - Q1 2027
Louisiana	Woodside Louisiana LNG	16.5	Q1 2029 - Q4 2029
Louisiana	CP2	14	Q4 2027
BC	Cedar LNG	3.3	Q4 2028
Mexico	Energia Costa Azul	3.25	Q2 2026 - Q3 2026
BC	Woodfibre LNG	2.1	Q3 2027 - Q4 2027

Texas and Louisiana based LNG projects are among the many developments that have benefitted from substantial tax relief and investment subsidies. The approach has some similarities with the incentives and fiscal initiatives used in Alaska for other types of oil and gas development.

A summary table is shown below:

Table 3 Tax Incentives for US LNG Plant

Incentive Type	Program	State	How it works	investor benefit /duration	LNG example(s)
Property tax abatement	Industrial Tax Exemption Program (ITEP)	Louisiana	Exempts local property taxes for manufacturing facilities (up to 10 years).	Up to 10 years; examples in billions	Sabine Pass ($4.9B), Cameron LNG ($3.7B), Calcasieu Pass ($2.9B)
Property tax abatement	Reinvestment Zone Abatement	Texas	Local governments may abate up to 100% of property taxes for up to 10 years in designated zones.	Up to 100% for 10 years	All Texas LNG projects in scope have Ch.312 deals; Corpus Christi LNG also under Ch.313
School district value limitation	Value Limitation for Property Tax purposes	Texas	School districts capped taxable value of industrial property for 10 years.	10 years (program expired 2022)	Corpus Christi ($762M), Port Arthur ($694M), Freeport ($447M), Golden Pass ($235M)
PILT (Payment in Lieu of Taxes)	County-level PILT with Cove Point	Maryland	Negotiated annual payment instead of property tax; later tax relief period	$60M/yr (2023 to 2038); earlier PILT ~$55M/yr (2013 to 2023)	Cove Point LNG (Calvert County)
Sales & use tax exemptions	Manufacturing machinery & equipment exemptions	Louisiana	Exempts qualifying M&E and certain software; consolidated under R.S. 47:305.5	Ongoing statutory exemption	LNG terminals as manufacturers may qualify for M&E purchases
Sales & use tax exemptions	State manufacturing exemption; energy used in manufacturing	Texas	Exempts manufacturing equipment and (with predominant use study) electricity/natural gas used in manufacturing	Ongoing statutory exemption	LNG terminals classified as manufacturing may qualify
Payroll/income tax rebates	Quality Jobs (QJ) Rebate	Louisiana	Cash rebate up to 6% of annual payroll for up to 10 years plus either state sales/use tax rebate or 1.5% project facility expense rebate: sunsets 6/30/2025	Up to 10 years; also reported $492M aggregate to LNG in LA	Louisiana LNG terminals have "Quality Jobs" grants totaling ~$492M
Deal-closing cash grant	Texas Enterprise Fund (TEF)	Texas	Performance-based cash grants for projects competing with out-of-state sites; job and wage targets with clawbacks	Varies by project; paid post-performance	Available statewide; case-specific
Port tariffs/leases (case-by-case)	Port authority pricing & concession terms	TX/LA (e.g., Port of Corpus Christi)	Ports set wharfage/dockage tariffs and may structure incentives via leases or pricing strategies	Case-by-case via tariff or lease	Not project-specific; demonstrates mechanism

2.2 LNG Canada

In terms of models for AK LNG to consider, LNG Canada represents an excellent learning opportunity. The project reached FID relatively recently (2018) and has just commenced commercial deliveries. Like AK LNG, it involves a long-distance gas pipeline.

One of the key features that enabled LNG Canada to achieve FID was an extensive enabling legislation package which consolidated and clarified most aspects of provincial and federal tax and provided assurances on long term stability.

The main elements of the LNG Canada fiscal stability framework were as follows (further details are in Appendix I):

Provincial LNG Income Tax (BC LNG Income Tax Act, 2014)

BC created a special LNG income tax to capture additional revenue from LNG projects.

Rates:

- 1.5% on net operating income until project capital costs are recovered.
- Then rises to 3.5%, and eventually 5% (originally planned higher, but reduced to improve competitiveness).
- Applies in addition to federal and provincial corporate income tax.

Federal Incentives (Accelerated Capital Cost Allowance – ACCA)

- The Government of Canada provided accelerated depreciation for LNG facilities (starting 2015, extended in 2018).
- Allows companies to write off capital costs more quickly, reducing taxable income in the early years.
- Designed to improve early cash flow and project economics during the critical first phase.

BC Provincial Incentives

- Electricity Pricing: BC Hydro offered industrial electricity rates to LNG projects, helping reduce operating costs.
- Carbon Tax Adjustments: LNG projects subject to BC's carbon tax but gives allowances to ensure competitiveness with global LNG exporters.

- Infrastructure Support[15]: BC government invested in road, port, and power infrastructure upgrades to support LNG Canada.

Fiscal Stability Agreement

- One of the most important aspects, LNG Canada secured a long-term stability agreement with the BC government.
- This guarantees that tax rates, royalties, and regulations will not be arbitrarily increased in ways that undermine project economics.
- Gives investors confidence in a long-term project horizon ensuring returns on capital and an adequate debt service/repayment outlook.

Indigenous and Local Benefits

- LNG Canada and the Coastal GasLink pipeline entered into Impact Benefit Agreements (IBAs) with Indigenous communities.
- Some Indigenous nations are also pursuing equity ownership stakes (e.g., in Cedar LNG, Haisla Nation holds majority).
- These agreements include revenue-sharing, training, and employment benefits, which indirectly tie into the overall “tax and benefits” framework.

Pacific NorthWest LNG (Petronas main sponsor)

Although a rival to LNG Canada, Petronas (who ultimately switched their focus to becoming a partner in LNG Canada) negotiated a deal with the British Columbia Government in 2015.

While not enacted as standalone legislation, the agreement offered assurances on taxes, regulation, and operating terms[16].

Though the project did not proceed, the dialogue surrounding it is a good example of the type of debate that is likely to evolve around AK LNG.

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[15] BC Hydro has linked major projects like the Site C Dam (costing about C$16 billion) and the Prince George to Terrace Capacitors Project (estimated at C$582 million) to LNG electricity demands. These projects are considered enabling infrastructure for LNG terminals, especially as future facilities aim for full electrification to reduce emissions.

[16] The fiscal stability mechanisms for the Pacific NorthWest LNG project were set out in a Project Development Agreement (PDA) signed in May 2015 between the Government of British Columbia (represented by Finance Minister Michael de Jong and Premier Christy Clark) and the Pacific NorthWest LNG Limited Partnership (PNW LNG).

2.3 Ksi Lisims LNG

One of the most noteworthy features of this proposed 12 MTPA project is that its location is just a few hundred yards from the Alaskan border with BC, and only 60 miles from Ketchikan, but other features of the project are also worth examining.

The project is largely a result of efforts over the last ten years by the Nisga'a Nation to develop an LNG export terminal, and the development is said to borrow heavily from the Nisga'a Nation's commitment to stewardship of the land and its people[17]. A key participant in the project is Rockies LNG Partners, a consortium of natural gas producers in Northern BC who are focused on securing export markets for their gas, and Western LNG, a Houston-based LNG development company.

The project concept has two key features, first a very low carbon footprint, partly based on using renewable power for the liquefaction process, and secondly it is planning to use a floating LNG (FLNG) solution, built remotely and floated into position.

The project will not depend on the Coastal GasLink pipeline being used for LNG Canada but instead it relies on a different long-distance pipeline for bringing gas to the plant. The project developers have acquired the Prince Rupert Gas Transmission (PRGT) pipeline project from TransCanada, which comprises up to 780 kilometres (485 miles) of land-based pipeline and up to 120 kilometres (75 miles) of marine pipeline.

[17] Ksi Lisims LNG is being designed to have a low level of carbon emissions, which reduces the amount of offsets required to achieve net zero.

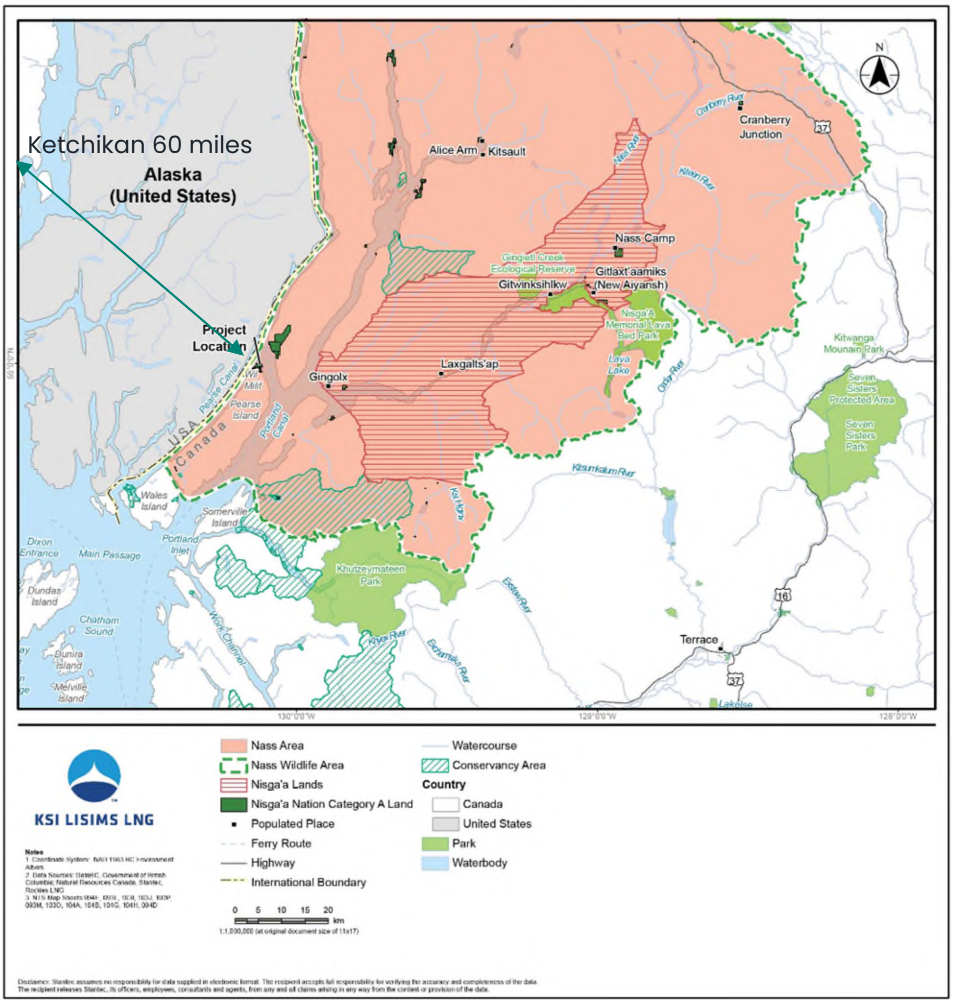

Figure 3 Location of Ksi Lisims LNG Project (source: project website)

Ksi Lisims LNG Project: Collaboration Between Provincial and Federal Governments

In terms of enabling legislation, the key feature of interest for Ksi Lisims is the degree of collaboration and coordination between provincial and federal government. This is one of the major lessons from LNG Canada which the project is able to leverage.

Below are the key features of this collaboration:

- **'One Project, One Review' Approach**

  The project was assessed under a substituted impact assessment model, where British Columbia's Environmental Assessment Office (EAO) conducted the review on behalf of both governments. This approach was enabled by the Impact Assessment Cooperation Agreement between Canada and BC, aiming to reduce duplication and increase efficiency in project reviews. While this is of interest, some of the permitting features of the AK LNG project are well advanced, and agency responsibilities are clear.

- **Federal Approval Based on Provincial Assessment**

  The federal Minister of Environment and Climate Change approved the project based on BC's substituted assessment, marking a precedent-setting use of the revised Impact Assessment Act. The federal decision included legally binding conditions to mitigate environmental and socio-economic impacts, especially those affecting Indigenous communities.

- **Indigenous Partnership and Treaty Considerations**

  The project is co-developed by the Nisg̱a'a Nation, who own the land, alongside Rockies LNG and Western LNG LLC. The assessment and approval process incorporated the Nisg̱a'a Final Agreement (Treaty), reinforcing Indigenous governance and economic participation. With land rights in Alaska being governed by the Alaska Native Claims Settlement Act (ANCSA) of 1971, no direct parallel may apply, but this feature underlines the role that Alaska Native corporations could play in the LNG project.

- **Shared Environmental and Socioeconomic Oversight**

  Both governments (provincial and federal) imposed conditions to protect wildlife, marine ecosystems, Indigenous health, and cultural heritage. The project must connect to BC Hydro's renewable energy grid, aligning with BC's net-zero emissions policy.

- **Legal Challenges and Ongoing Dialogue**

  Despite the collaborative approval, First Nations groups such as the Lax Kw'alaams Band and Metlakatla First Nation have filed judicial reviews, citing concerns over environmental impacts and Indigenous rights. This underscores the importance of continued engagement and responsiveness to Indigenous concerns throughout the project lifecycle.

- **Strategic National Interests**

  The Canadian federal government views the project as a means to diversify trade, boost economic resilience, and strengthen Canada's energy position globally, especially in light of geopolitical shifts and trade dynamics. This mirrors the pro-LNG policies being adopted by the US federal government.

2.4 Projects Outside the Americas

Enabling legislation, favorable tax treatment and fiscal stability clauses are widely used to facilitate FID on LNG projects around the world. Some examples are set out below:

Table 4 Tax and Stability Features - International

Country	Tax Concessions	Fiscal Stability Mechanism[18]
Papua New Guinea	Reduced corporate tax rates, accelerated depreciation	Formal FSAs guaranteeing no adverse changes
Nigeria	Tax holidays, duty exemptions	NLNG Act prohibits unilateral fiscal changes
Qatar	Low royalty and corporate tax rates, no export duties	Long-term PSAs and government commitments. Taxes are fixed at outset.
Mozambique	Customs and VAT exemptions	Stability clauses in contracts
Australia	Accelerated depreciation, cost deductibility	PRRT framework and policy consistency
Russia	Zero mineral tax, export duty exemptions, Arctic incentives	PSAs and tax stability clauses
Oman	Tax holidays (25–30 years), customs exemptions	Shareholder agreements and gas supply contracts
Indonesia	Tax holidays (up to 20 years), tax allowances, depreciation	PSC terms with stabilization clauses
Malaysia	Pioneer Status[19], Investment Tax Allowance, customs exemptions	PSC terms with PETRONAS provide predictability
Senegal	CIT reduction to 15%, VAT/customs exemptions	Investment Code guarantees and Special Economic Zone protections
Peru	Customs/VAT exemptions, accelerated depreciation, research & development deductions	State contracts and concession agreements
Brunei	100% income tax exemption, customs duty exemptions	Long-term agreements with Brunei LNG and government guarantees
Trinidad & Tobago	10-year tax holiday. Accelerated capital allowances, petroleum tax incentives	PSC terms and LNG-specific agreements

Each of the examples above is typically the result of years of negotiation and analysis by stakeholders and governments. Although the fiscal framework in Alaska benefits from decades of development, and legislators are familiar with the oil and gas industry,

[18] PSA/PSC: Production Sharing Agreement/Contract, a framework for hydrocarbon development that enables cost recovery; FSA: Fiscal Stability Agreement; PRRT: Petroleum Resource Rent Tax, a tax on profits considered above typical rates of return; VAT: Value Added Tax.

[19] A tax incentive designed to attract investments in sectors that are considered strategic for national development.

negotiation of specific tax and fiscal stability provisions might be expected to take many months or years.

2.5 Open Book Economic Model (OBEM)

A commonly used tool to enable efficient analysis and negotiation of tax treatment and stability clauses is an Open Book Economic Model or OBEM. This comprises a detailed economic model of the project, usually in Excel format, which is developed by the lead partner in a project and audited/agreed to by all stakeholders.

The model is populated with a set of clear assumptions known to all stakeholders, such as currently estimated capital and operating cost forecasts, technical performance, and other features. It is then used by each partner to inform the value impact of various assumptions and sensitivities as may be relevant, including such things as gas/oil price assumptions, LNG sales price, debt/financing costs and terms, required returns and so forth, which otherwise would be confidential to each stakeholder.

3 LNG Market Background Relevant to AK LNG

3.1 Industry Summary

LNG on a commercial level came into being in the early 1960s with exports from Algeria to Britain and France. The original Alaska export project in 1969 was the first example in the Pacific. During the first few decades of the industry, it was common for an export project to be dedicated to a single LNG buyer, and for the ships to go back and forth on the same route year after year. Over the last 20 years, that model has slowly evolved, and while long term sale and purchase agreements (SPAs) are still very much a feature of the industry, especially with respect to raising finance, LNG flows are far more versatile and commercially flexible.

The economics of an LNG project depend on being able to support the cost of the liquefaction plant and ships needed to move the gas. Although each project is unique, if the gas needs to be transported more than about 1,500 miles, LNG is usually a more economical solution than a pipeline, assuming ocean access is possible.

The high level of pre-production capital needed also requires low-cost gas with which to feed the liquefaction plant, commonly termed the "feed gas." That being the case, most of the value in an LNG project is not from the upstream gas production activities, but from construction and the revenues that accrue from the infrastructure. In that sense, an LNG project can look similar to other types of infrastructure, such as an airport or a toll-paying highway.

LNG projects are among the costliest infrastructure investments, regardless of industry, with the upfront capital usually of the order of tens of billions of dollars. As a result, they can take years or decades to reach commercial maturity but once in operation make a substantial contribution to the economy of the host nation or state. Furthermore, over the many decades that they can be in operation, they create significant free cashflow, which can fund new investments and contribute to state budgets, especially if the gas resource is able to sustain LNG exports beyond the 20-year typical design life.

Above all, an LNG project requires a very high level of confidence in long term cashflows at a level sufficient to cover operating costs, debt service, and required returns for the shareholders. Because of the expected rates of return that energy companies need to deploy capital, LNG projects put considerable emphasis on minimizing development costs and maximizing near-term revenues, as longer term cashflow has a much lower value to them owing to the discount rates applied. However, for governments or other types of investors with a lower cost of capital, and without the pressure of shareholder returns, longer term cashflow can have a higher value. After about ten years of operation, when the plant is largely depreciated, earnings and therefore taxes can increase significantly. A good example is Brunei, which started exporting LNG in 1969, around the same time that Alaska's Kenai project started, and continues to supply LNG today, more than 50 years later. The project is a joint venture between the government of Brunei who own 50% of the project, and Shell and Mitsubishi who own 25% each. It has proven a major contribution to Brunei's economy, and a highly profitable investment for the commercial investors.

For Alaska, one of the considerations is that given the cost of the pipeline, processing, and liquefaction, the value of the natural gas being used to feed the LNG plant could represent as little as 10-15% of the delivered LNG. For example, the cost of gas entering an LNG export facility on the Gulf Coast would be about $4.23[20]/MMBtu plus a typical 15% uplift for fuel and the cost of transporting the gas to the liquefaction plant. This creates a total gas cost of $4.86/MMBtu or 44% of the forecast delivered price to Asia for the same month ($11.05[21]/MMBtu), with the remaining 56% attributable to liquefaction and shipping and profit. For Alaska, using a gas cost assumption of $1/MMBtu, this would represent only 9% of the estimated delivered price, with the remaining 91% being attributable to removal of CO_2 from the gas produced on the North Slope, pipeline tariff from the North Slope to Kenai, shipping and profit.

Using this example, it can be seen that if the input gas price is based on a fixed or slowly escalated pricing basis, production tax and royalty, especially after accounting for lease operating expenditures, could represent limited revenues. However, higher levels of corporate income tax may arise in the later years of the project, when the plant is depreciated and taxable income increases.

3.2 Global Supply and Demand Trends

There are some structural changes occurring in the global LNG market which will influence anticipated demand in the timeframe that AK LNG would be coming on stream. This will also influence the countries and companies that are likely to engage in marketing discussions with the project today.

It should be noted that the LNG market is global, and LNG vessels can move between markets, subject to time, distance, and pricing signals. Although the Pacific and Atlantic basin markets operate somewhat independently, LNG can flow between them when market conditions dictate.

Some of the macro trends in supply and demand that will affect the market picture for Alaska are worth considering in more detail:

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20 Based on the December 2025 futures price published on 11th November 2025.

21 ICIS forward price for December 2025 assessed as of 11th November 2025.

3.3 Demand Trends

- While Alaskan LNG is unlikely to physically flow to Europe, developments in Europe will materially impact LNG global flows, and therefore will influence demand. In particular, the extent to which US Gulf Coast LNG is drawn towards Europe will influence Asian appetite for alternative US supplies in the Pacific.
- After the supply crunch following the Russia-Ukraine conflict, the falling trend in gas demand and LNG imports in Europe was evident in 2024 with LNG imports reducing by over 21 MT to an annual import quantity of 100 MT. This was due to a combination of lower gas demand, higher storage levels and continuing pipeline supplies from Norway and the North Sea. Renewable generation was also up, displacing gas fired capacity. The UK saw the highest drop in natural gas demand with a 45% decline, while France, the Netherlands and Spain were all down to a lesser extent, though imports picked up again by 8.3 MT between January and May 2025.
- In January, gas transit to Europe via Ukraine ceased, and while the impact of this had been largely priced in by the time the gas flows ceased, there was some degree of disruption and recalibration of gas flows.
- The stabilization of European gas supply and demand has also been a driving feature of EU policy to eventually eliminate Russian pipeline imports. In May, the EU set out a roadmap for the complete cessation of Russian imports by the end of 2027. Since 2021, Russian pipeline imports to the EU have already fallen from 45% to just 18% in 2024.
- Further evidence of more stable gas supplies returning to Europe was the relaxation of the 90% gas storage rule prior to each heating season (introduced as part of the emergency gas measures). Although the rules will be retained for a further two years, utilities have been given greater flexibility and modified targets, based on pricing and other factors.
- In contrast to stagnating European demand, Asia continued to see significant increases with a 7.5 MT increase in LNG demand in China for 2025, and a 4.2 MT increase in India.
- However, in the first five months of 2025, imports to China have been affected by the trade tariff dialogue between China and the US, where a 25% import tariff on LNG has resulted in a cessation of US imports in February, and those volumes being diverted to other buyers. Russian pipeline gas through the Power of Siberia pipeline is also replacing LNG demand in western and central China.
- Analysis of 2024 also showed a modest increase in demand in Japan and Korea. However, Japan is intensifying the energy transition push through a 2040 energy plan that is expected to reduce future gas demand. Therefore, Japanese LNG

buyers are increasingly adopting a strategy based on flexible contracts without destination restrictions, to enable diversion to other countries.

- Overall, global LNG demand in 2024 rose by a modest 2.4%, to just over 411 MT.

3.4 Supply Trends

- By the end of 2024, LNG supply capacity had grown by almost equal amounts (4 MT) in the Asia Pacific and North American regions, while capacity in the Middle East remained broadly the same. By the end of 2024, total global liquefaction capacity had risen to over 494 MT, suggesting an overall utilization rate of 83%.
- In 2025, ICIS, an LNG data service provider, forecasted a tight market with LNG supply and demand closely tracking one another between 430 and 435 MT and the latest forecasts are leaning towards a slight oversupply in the market.
- In terms of new capacity reaching FID, 2024 saw a marked reduction in projects moving to construction, with only 15 MTPA of capacity getting the green light, compared to nearly 60 MTPA in 2023. This is the lowest number of FID announcements since 2020.
- In terms of operational capacity, the US cemented its position as market leader reaching nearly 100 MTPA supply capacity. Australia's capacity is approaching 90 MTPA and Qatar's nearly 80 MTPA. Together, these countries supply over half the global demand for LNG and will continue to dominate in future years.
- Qatar's goal to regain market leadership received a boost with comments from the energy minister in April 2025. He stated that the North Field East expansion plans will start to add LNG capacity as soon as mid-2026 when the first train of the initial 32 MTPA plant starts operations. Qatar plans to increase LNG exports to 142 MTPA by 2030.

During the first half of 2025, the new administration in the US removed some regulatory constraints on LNG exports introduced by the previous one. Additionally, new measures were put in place to streamline permitting for LNG to accelerate project development. This has seen restrictions lifted for domestic projects such as Commonwealth LNG (Louisiana), Port Arthur Phase II (Texas) and Venture Global's CP2 (Louisiana) projects, with permit extensions approved for Golden Pass LNG (Texas). Very pro-active federal government support for LNG has been clearly evidenced. This change in policy has had the biggest impact in Alaska, with the AK LNG project receiving unprecedented support from Washington, resulting in reinvigorated discussions both at a government and commercial level.

Other developments, some of which may be a result of the increased policy support, include:

- The FID approval for Louisiana LNG (previously Driftwood LNG) under Woodside's ownership is one of the first major new investment commitments under the new administration. It is notable that the main project sponsor is a foreign company, and some trade related considerations (regarding Australia) might have been a factor in their decision to invest.
- The Woodside FID reinforced some market forecasts that predicted an LNG oversupply in the 2026 to 2036 timeframe, with ICIS, a data gathering organization, forecasting a peak oversupply of 69 MT in 2029. However, an undersupply is forecast for 2037 onwards through 2050.
- Some confidence in long-term LNG demand has returned because of changing emphasis on climate policy and net zero. Several countries and energy companies have now moderated their forecasts and are placing greater emphasis on gas and LNG, partly as a result of economic pressures.
- On the downside, some trade policies by the new US administration have created headwinds for the LNG sector, including potential measures to impose tariffs on Chinese owned or operated LNG vessels calling at US ports, and a phased requirement to use US constructed carriers (none exists today) for US LNG exports. However, after industry push back, these requirements appear to have been rolled back.

3.5 Climate Policy Risk to LNG Demand

Policy initiatives aimed at curbing carbon emissions and encouraging more sustainable fuels have been steadily gaining momentum over the last decade, particularly in Europe and parts of Asia. Many of these policies are focused on a phasing out of natural gas and other fossil fuels, with renewables and green fuels such as hydrogen taking their place. Under the COP[22] series of intergovernmental meetings, several countries have made "net zero" commitments, many of which focus on a 2050 timeframe. However, over the last year or more, many governments have had an opportunity to consider the cost and feasibility implications of these commitments. While there continues to be a strong undercurrent of carbon mitigation goals, many countries are taking a more considered view on natural gas and LNG. Demand for LNG in the developing countries of Asia appears strong and continues well beyond the 2050 timeframe.

Examples of moderation of climate policies have been evident in the last few months. For example, the Japan Gas Association has indicated that it would take a more flexible

[22] Conference of the Parties, which is the supreme decision-making body for the UN Framework Convention on Climate Change (UNFCCC).

approach in its drive to become carbon neutral by 2050, allowing greater use of natural gas in combination with carbon capture or other decarbonization measures.

European Union countries may seek to simplify the EU's methane emissions law, which has created concerns in some energy companies that it could hamper imports of US LNG and impact the planned measures to move away from Russian imports. From this year, the EU requires importers of oil and gas to monitor and report the methane emissions associated with these imports, in addition to wider carbon intensity features.

However, there is also evidence that consumers and shareholders continue to place emphasis on decarbonization and net zero goals. Shell, as an example, has been challenged at its shareholder meeting about its high forecasts for LNG demand, amid claims that this is inconsistent with the company's stated climate goals.

There has already been litigation seeking to prevent development of the AK LNG project on the grounds that climate change issues have not been taken into account, and these can be expected to continue, as they have for all the US Gulf Coast LNG export projects.

3.6 Recent Developments in US LNG

As previously referenced in the report, a series of Executive Orders was issued by the incoming US administration in January 2025, to promote domestic oil and gas investment, energy independence, and to encourage the export of US energy to friendly countries in Europe and Asia. New appointments at the Environmental Protection Agency, the Department of Energy, and the Department of the Interior have created a very pro-fossil fuel environment, which deemphasizes funding for low carbon and renewable technologies and promotes a streamlined and non-intrusive regulatory and permitting environment. In some cases, funding and grants have been withdrawn or paused for some Department of Energy sponsored projects, which has created a delay in investment for certain energy-transition projects.

From January to June 2025, 90% of new LNG FIDs were for US projects, a major contrast with 2024 where most of the sanctioned projects were in the Middle East. As mentioned above, this includes Woodside Petroleum's Louisiana LNG (formerly Driftwood LNG) with FID announcements anticipated shortly for Venture Global's CP2, Cameron Train 4, Corpus Christi Stage 4 and Texas LNG, among others.

First LNG is also anticipated for Corpus Christi Stage 3, Golden Pass Train 1; and Plaquemines LNG is already producing LNG while the plant is being commissioned.

As already noted, Japanese utility JERA signed multiple agreements to purchase US LNG in June, including a heads of agreement (HoA) for 1.5 MTPA from the second phase of the Port Arthur LNG project. This phase aims to double the plant's capacity to 26 MTPA. JERA also signed agreements for additional LNG supplies from other US projects, being cited by administration officials as strong international interest in US LNG. The deals include sales and purchase agreements (SPAs) with NextDecade Corporation and Commonwealth LNG, as well as an HoA with Sempra Infrastructure and Cheniere Marketing (all LNG exports from Texas/Louisiana). Most recently, of course, JERA signed a letter of intent for supplies from AK LNG.

However, economic hurdles and delays are also observable with some project cancellations and postponements. Venture Global has withdrawn its application for the proposed 24.4 MTPA Delta LNG export project. Instead, the company is focusing on its planned Plaquemines LNG expansion project, which is expected to produce a similar amount of LNG but on a faster timeline. The final investment decision for the Plaquemines expansion is expected to occur only after another planned export project, CP2, achieves first production in 2027 or later.

Due to a combination of higher return requirements by investors alongside higher project costs, the effective tariff for liquefaction of LNG has risen to about $2.80/MMBTU in some recently signed deals. While everything hinges on the updated capital cost estimates for Alaska, this potentially reduces the competitive position of Gulf Coast LNG which could be amplified should wholesale gas prices see a rising trend in the Lower 48.

3.7 Other Sources of Competition

While US Gulf Coast LNG exports remain the main competitive threat to a project in Alaska, there are other global activities that could put new sources of lower cost LNG onto the market in the same timeframe as Alaska. In particular, other Pacific Coast export terminals are the most relevant.

LNG Canada (BC)

The first commissioning cargo from Train 1 (7 MTPA) at LNG Canada was being loaded in June, with full operations anticipated shortly and Train 2 has just commenced operations.

With the sunk cost involved in the Coastal GasLink pipeline, the economic outcome for a second train is stronger than for the first. Train 2 is expected to reach FID in the coming months. With a robust upstream gas resource in Alberta and British Colombia from which to source additional gas, further expansion is possible.

Ksi Lisims LNG Project (BC)

While this project is still at the development phase, some aspects are more advanced than AK LNG. For a buyer seeking diversification from Pacific Northwest supply, the project is a direct competitor with similar steaming distance to Asian markets, and a large, well understood gas resource from which to draw. See section 7.2 for additional background.

Qatar

Qatar's LNG industry is based on the North Field, the largest gas field in the world. The project already involves several large LNG trains, situated at the Ras Laffan gas complex, and with the expansion of gas production from the North Field these will be significantly augmented with new liquefaction trains.

The expansion project is expected to start production by mid-2026. This expansion is a significant part of Qatar's strategy to boost its LNG production capacity. The project aims to increase production from 77 MTPA to 126 MTPA by 2027.

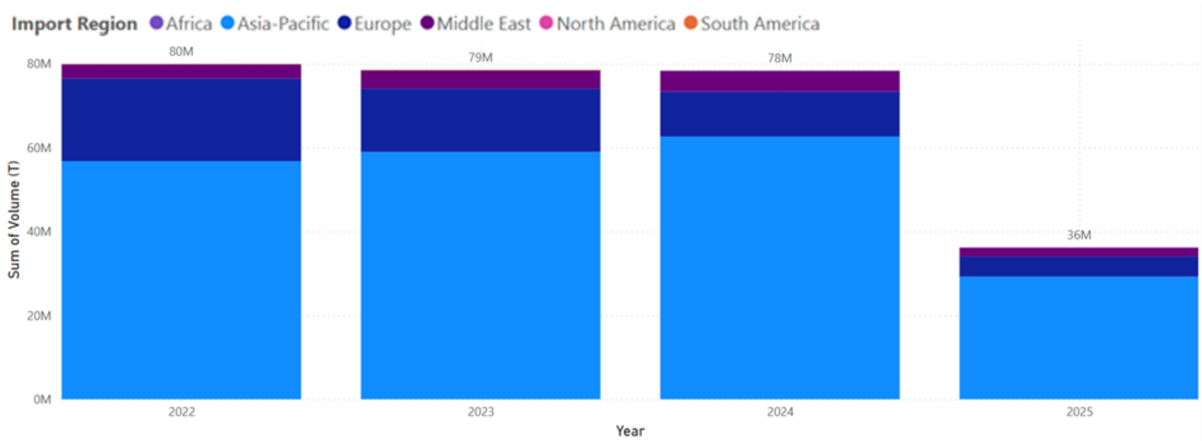
Additionally, Qatar Energy's investment in the US Golden Pass project is expected to come online by the end of this year, further enhancing Qatar's LNG production and trading capabilities.

Overall, Qatar's expansion plans are set to significantly increase its LNG output and strengthen its position in the global LNG market over the next few years.

In effect, Qatar and the US are by far the largest potential sources of LNG to fulfil growth in market demand in the coming decades.

The proportion of Qatari production exported to Asian markets in 2024 grew slightly and continues to form the largest destination in the first part of 2025.

Figure 4: Qatari LNG Destination by Year



It is noteworthy that Qatar benefits from a very low-cost gas feedstock due to prolific wells and significant condensate revenues. Given the very material revenues created by the condensate that accompanies the natural gas, Qatar can effectively produce LNG at a much lower cost and higher margin than any US project. The competition therefore revolves around the other, non-Qatari LNG supplies that will be needed to bridge the gap between global supply and demand.

When Qatar ramps up LNG production, by 2030 it could account for somewhere in the region of a quarter of the global LNG market. All of this LNG passes through the Straits of Hormuz, a vulnerable choke point. As a result of this, marine security in this area has been augmented by a significant naval presence in recent years. The US maintains a strong naval force through the US Fifth Fleet, based in Bahrain, while other Western allies also contribute warships and maritime patrol aircraft. Given recent developments, this feature creates a very different risk profile for those LNG buyers concerned about security of supply, with the short, secure marine passage from Alaska offering a much lower risk profile. Thus, at least in the medium term, low risk of LNG carrier disruption is a major benefit that Alaska can offer.

Mexico

Largely because of natural gas availability in the Permian Basin in the US and new gas pipelines across the border, Mexico is emerging as an LNG exporter, with several projects operational and under development. However, compared to some earlier forecasts, it has proven more difficult to bring projects to FID, partly because of economic headwinds, and potential regulatory and geopolitical factors that are putting the focus on US LNG sources.

Operational projects include:

- **Energia Costa Azul (ECA LNG)**: A Sempra Infrastructure project in Baja California, adding liquefaction capabilities to an existing import terminal. Although of smaller scale at 3.25 MTPA, the project is nearing completion. Commissioning is anticipated soon.
- **Altamira LNG**: New Fortress Energy's 1.4 MTPA modular facility on the Gulf Coast, exporting LNG, including to Europe, delivered its first cargo in 2024, with a second unit reaching FID in 2024 as well. The Altamira "Fast" LNG concept is focused on quick deployment and early revenues but is typically of smaller scale.

There is another major Pacific Coast project that would compete with the Alaska project in terms of volumes and approximate timeframe, but has yet to reach FID:

- **Saguaro Energía LNG**: A large-scale 15 MTPA project by Mexico Pacific in Sonora, aiming to export LNG to Asia, bypassing the Panama Canal. However, the project has not yet reached FID, and has experienced several challenges surrounding financing, regulatory constraints, and the possible negative consequences of the Administration's focus on trade imbalances.

Argentina

Argentina's national oil company (NOC), YPF[23], has been working to monetize the Vaca Muerta unconventional gas basin, which has many similarities with the Eagle Ford oil and gas basin in Texas. The project has some similarities with Alaska, but lacks many of Alaska's advantages such as a well-established and proven supply source, a range of key permits, and significant technical/engineering study:

- Similar timeframe to development.
- Requires the construction of a pipeline to take the gas to an Atlantic coastal terminal (about 400 miles). This location would incur additional shipping costs to Asian markets.
- Participation and investment by experienced LNG companies is being sought and government-to-government discussions feature in the project development.

There are a number of features that makes Argentina relevant to Alaska. The project is based on a 30 MTPA phased development plan, which is facing considerable uncertainties in terms of cost, financing, political and economic stability and lack of government regulatory framework. However, it continues to attract participation by major companies including Shell and ENI, who recently agreed to a strategic partnership agreement with YPF, signed by the President of Argentina and the Prime Minister of Italy. The level of interest and investment in Argentina demonstrates that in spite of considerable uncertainty, investment and interest in a new source of LNG, as Argentia would represent, remains strong.

[23] YPF, or Yacimientos Petrolíferos Fiscales, is a large, state-owned energy company in Argentina involved in oil and gas exploration, marketing, and operations.

4 Conclusion

The AK LNG project and associated gas pipeline is one of the most ambitious gas infrastructure projects ever attempted globally and would require resolution of a host of complex commercial, technical and logistical features to come to fruition. However, if fiscal and related terms are set appropriately, the impact on the State economy could be very material, especially in the medium to long term as profitability increases.

In any project approaching this scale, it would be a requirement for the government of the host nation or state to consider its role in both a successful FID and also securing the best outcome possible for both current and future citizens of the state. Furthermore, the scale of the project and its significance to the furtherance of a number of federal policy goals may attract federal financial support, which could help project economics and also influence state policy.

For a detailed policy framework and fiscal package to be agreed, the project economics would need to be defined. This would include such things as improved estimates of the capital cost, defining the terms under which gas would be supplied, and tax treatment. For the Phase I gas pipeline, key steps in project delivery, in addition to accurate cost estimates, would be agreement of contractually binding terms for a long-term tariff, which may also involve a rate case ruling from the RCA and credit support from Southcentral utilities.

However, given the timeframe usually associated with the negotiation of fiscal terms for a project of this sort, initial engagement by the legislature and consideration of tax levels and other mechanisms should be engaged with early, while the project developers continue to define the exact nature of the investment needed.

A particular consideration may be the early FID timeframe for the Phase I pipeline, where a host of commercial and economic details are yet to be set out. If an in-service date of 2028 is to be achieved, the State may be asked to use their power of appropriation to underwrite a host of risks yet to be defined, including gas supply, transportation services agreements with state utilities, and financial support/guarantees for lenders.

Finally, readers of this report should note that it represents only a high-level assessment. As the project develops in the coming months, a host of features will arise that may require legislative input, which may not be covered in this introductory report. Projects on this scale require collaborative, creative solutions and often involve innovative measures to achieve success.

Appendix I
Notes on LNG Canada Fiscal Outcome Parallels for AK Consideration

Notes on LNG Canada Fiscal Outcome

Parallels for AK Consideration

There are typically three features that represent material elements in the dialogue between host governments and international energy companies (IECs) who are investing in gas development and facilities including liquefaction. These are:

1. Overall government take, and impact on project and shareholder returns and investment hurdles.
2. The relationship between investor cashflow and government cashflow over the course of the project, and any relationship that governs it in times of higher or lower sales prices.
3. Fiscal stability, which will often involve an agreement by government not to materially change the overall tax outcome for a period of time.

The development of the LNG Canada project included all these factors, and there are some useful learnings for the project in Alaska. Many of the features that are present in the current stage of the Alaska negotiation continued to be subject to changes and renegotiation for LNG Canada as the project definition and overall economics became better defined, and this is likely to be the case in Alaska as well. However, early communication of the government's goals and fiscal requirement, and an agreed basis on which to proceed to the next phases of the project will streamline these future discussions and may enable FID to be achieved in the 2028 timeframe needed for first gas.

As mentioned, the upstream arrangements for the feed gas in Canada are governed by Provincial law, which has evolved over many decades of oil and gas leases and production experience. The feedstock for LNG Canada comes from gas production in both Alberta and British Columbia which both operate a tax and royalty mechanism designed to promote investment and development but allow gas to be produced at competitive levels. This economic cut off is defined by Henry Hub in the US, typically with about a $1/MMBTU discount to account for the longer distances that gas has to be transported to reach the key North American markets. The potential feedstock for AK LNG could be priced still lower, and this (and the taxes that apply) will be a key requisite for project success.

Because the feedstock for LNG Canada is purchased from an array of suppliers, LNG Canada was less able to agree to special terms for the upstream and instead focused on the economics of the liquefaction plant, and the way in which revenues from LNG sales (predominantly to Asia) were dealt with. The opportunity to bundle a tax deal that includes the major gas suppliers to the LNG project could provide more flexibility for a fiscal framework for the AK LNG project.

In the period preceding FID, when wholesale gas prices in Canada were low, and LNG sales into Asia were considerably higher, the Government of BC had introduced a Liquefied Natural Gas Tax Act that was perceived as a mechanism to share in what was thought to be a high profitability business. As the economic situation changed, this became a major constraint to investment.

Conversely, as the project´s economic outlook changed, a different act was passed, the Liquefied Natural Gas Project Agreement Act, which provided for various mitigating features funded by the BC government.

Finally, the LNG project was also subject to British Colombia's CO_2 tax, which added another burden for project investors and was seen as a barrier to investment.

In this way, as the project was approaching FID, a complex array of sometimes conflicting taxes, subsidies and regulatory features was at play, which in itself became a barrier to a final agreement.

By late 2017, the LNG export project had taken on strategic importance, not only to the Provincial BC government, but also for the federal government which was seeking to create new export routes for Canada's oil and gas. This was largely as a result of the significantly curtailed oil and gas exports to the US (owing to the high growth in US unconventional oil and gas). A concerted effort was made in March 2018 to set out a new fiscal framework which the IECs perceived as providing an adequate economic platform, and which both provincial and federal government could set off against the benefits to the economy.

The measures agreed cover a period of 20 years from the start of LNG production, and the key features of the fiscal package that emerged were:

- Amendment of the Income Tax Act to implement a natural gas tax credit for LNG development in British Columbia.
- Repeal of the Liquefied Natural Gas Income Tax Act that created barriers for investment set out above; and
- Repeal of the Liquefied Natural Gas Project Agreements Act which was perceived as leaving the Canadian taxpayer vulnerable to footing the bill for special industry tax and regulatory protections.

Furthermore, additional benefits were agreed as follows[24]:

[24] Note that the value of estimated tax benefits in this section is quoted in Canadian dollars (1 Canadian dollar is about 75 cents US).

- Discounted electricity prices: Through BC Hydro, LNG Canada's facility will pay the much lower industrial rate for electricity used in production. The value of this subsidy is between C$32 million and C$59 million per year. There are additional subsidies which would apply to upstream gas production (such as using electric drives for compression/fracking) which are not included in these estimated subsidies.
- Exemptions from increases in the BC carbon tax: Any BC carbon tax above C$30 per tonne of CO_2 will be rebated for approved facilities that meet a greenhouse gas intensity benchmark. As the tax will be C$50 per tonne by the time the facility opens, this tax break is worth C$62 million per year.
- A corporate income tax break: A natural gas credit against corporate income tax has been created with the intent of lowering tax from the regular rate of 12 percent to 9 percent. At the time, LNG prices were such that very little tax would have arisen in any event, but as and when the project reaches first gas, this could represent a very material concession to the project sponsors.
- Deferral of provincial sales tax on construction: This measure is essentially an interest-free loan that does not have to be repaid for more than two decades. On an annual basis, this was estimated to have a value of C$17–21 million. In essence, the tax that would have been payable during construction, of about C$600m, is repaid over a 20-year period, starting the year the facility goes into production and generates cashflow. Much of the repayment is scheduled for the last two years of the design life.
- Federal tax breaks that were estimated to reduce the overall tax burden on the project by around C$1 billion.

For the upstream, the position is more difficult to estimate. BC's royalty regime operates through a complex system of credits (for example, for deep wells or fracking) which mean that net royalty payments by the producers are typically significantly short of the gross estimate. Furthermore, the government has allowed LNG producers to enter into long term royalty agreements (LTRAs) with producers to stabilize forward planning on price and quantities.

Key Takeaways: are that the fiscal arrangements were one of the last pieces of the LNG Canada project to be put in place and involved a wholesale re-invention of many of the elements previously implemented.

The main drawbacks of the previous arrangement arose from a complex array of government take elements, captured under numerous pieces of legislation. Some of these pieces of legislation were developed under very high delivered price scenarios, while other elements were designed as subsidies to compensate for low price scenarios. The final package was considered resilient in a range of future outlooks.

Appendix II
Glossary of Terms
List of Standard Gas and LNG Industry Terms and Abbreviations

Glossary of Terms

List of Standard Gas and LNG Industry Terms and Abbreviations

ACQ	Annual Contract Quantity
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
BTU	British Thermal Units
CAPEX	Capital Expenditure
DCQ	Daily Contract Quantity
FDP	Field Development Plan
FEED	Front End Engineering and Design
FID	Final Investment Decision
GJ	Gigajoule
HH	Henry Hub (US gas hub price)
ICIS	International Commodity Intelligence Services
IEC	International Energy Company
JKM	Platts Japan Korea Marker (TM)
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units (approx. 1.055 GJ)
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MTPA	Million tonnes per annum
MT	Million tonnes
NBP	National Balancing Point (UK gas hub price)
OPEX	Operating costs
p.a.	Per annum
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton

SL	Straight line (for depreciation)
SPE	Society of Petroleum Engineers
ss	Subsea
T	Tonnes (1,000 kg or 2,200 lb)
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TTF	Title Transfer Facility (NL gas hub)
TOP	Take or Pay
US$ or $	United States Dollar

Appendix III
LNG Units, Conversions and Revenues

LNG Units, Conversions and Revenues

The global LNG industry typically uses millions of tonnes (MT) of LNG as its unit of measurement for exports, imports and capacity measures, but sales contracts use energy measures such as millions of British thermal units (MMBTU). To provide the reader with some sense of how these units relate to everyday energy requirements, the following examples might be helpful.

A metric tonne of LNG weighs 1,000 kg or 2,200 lb. Since the density of LNG is about 42% that of water, each tonne of LNG takes up about 2.4 cubic meters, or around 34 cubic feet of space. In gaseous form, this same amount of gas would take up over 20,000 cubic feet. Transporting gas in liquid form takes up about 1/600th of the space it would need as gas, and this is why transporting the fuel in ships is so efficient.

A typical LNG vessel might hold 180,000 cubic meters of LNG, or 76,000 tonnes. Each tonne of LNG contains roughly 50 MMBTU of energy so one vessel would contain about 3.8 million MMBTU. Roughly speaking, each MMBTU of gas represents about a thousand cubic feet of natural gas, so once vaporized the contents of one vessel would represent about 3.8 billion cubic feet of gas.

This is about half the quantity of gas that can be re-injected in the Prudhoe Bay oil field every day. It is also more than ten times the daily average gas consumption of Southcentral Alaska. Annual consumption in Alaska would therefore need around twelve LNG deliveries a year.

By contrast, LNG demand in a country such as Japan, with a forecast demand of 74 MTPA in 2040, would require almost a thousand LNG vessel deliveries a year, nearly three a day. The entire Alaska LNG output would account for about one quarter of demand, just for Japan.

In financial terms, assuming a value of $10 per MMBTU for the natural gas, the value of one ship load of LNG would be approaching $40 million.

Working at a capacity of 20 MTPA, the AK LNG project would fill one vessel about every day-and-a-half and generate revenues of the order of $10 billion annually.