ALASKA LNG

Alaska Arctic LNG Assessment

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TABLE OF CONTENTS

<u>List of Figures</u>

EXECUTIVE SUMMARY

With evidence of global warming, shrinking of the Arctic ice pack, and the advent of ice-breaking liquefied natural gas carriers (“LNGCs”), some are speculating if an LNG terminal should be located on or offshore of Alaska’s North Slope. The Alaska Gasline Development Corporation (“AGDC”) conducted an analysis to determine if there is sufficient commercial and technical viability to pursue a further in-depth study of a North Slope LNG alternative; and concluded that a North Slope LNG terminal is not commercially viable. This paper summarizes the analysis, and compares an Arctic option to the current design basis already well underway for the Alaska LNG Project (“Project”).

The expected capital cost of the Project is about $2,150 per tonne, when the cost of the 807-mile Trans-Alaska Gasline and the North Slope Gas Treatment Plant are included. The Project has a design capacity of 20 million tonnes of LNG per annum (“MTPA”). The cost estimate was developed during an extensive pre-front end engineering and design (“pre-FEED”) study, and includes a gas treatment plant (“GTP”) located on the North Slope of Alaska, an 807-mile pipeline routed through a utility corridor, and an LNG plant and marine terminal located near Nikiski. Although primarily an LNG export project, Alaska LNG will also provide gas to Alaskan citizens and industries. The Project’s Natural Gas Act Section 3 filing was submitted to the Federal Energy Regulatory Commission (“FERC”) () in April 2017, thereby beginning the National Environmental Policy Act (“NEPA”) process to obtain an affirmative FERC order and authorization to construct. Commercial activities are gaining momentum, and the Project appears economic under consensus LNG pricing forecasts and a tolling/merchant business model that seeks a utility rate of return.

There are four primary models that an Alaska Arctic LNG Project could follow:

1. Onshore, North Slope
2. Onshore, Barrier Island
3. Offshore, Bottom-Founded
4. Offshore, Floating

To AGDC’s knowledge, none of the Arctic LNG concepts have been engineered or costed for the Alaskan environment to a pre-FEED level; extrapolations of conceptual studies are the only way to compare to the more mature Alaska LNG Project. All have a combination of technical challenges, environmental flaws, and commercial questions. AGDC concludes that none of the above options are commercially viable; with costs in excess of $3,000 per tonne and little likelihood of being permitted. Further, when combined with winter shipping limitations, the required market price for LNG in Asia would need to be in excess of $15 per million British thermal units (“MMBTU”). Therefore, there is insufficient reason to study further.

Following is a review of the four Alaska Arctic LNG Project models, along with a review of issues that are common to all or most of the models.

1. ALASKA ARCTIC LNG: ONSHORE NORTH SLOPE

There are extensive oil and gas production and processing facilities on the Alaska North Slope, including some on man-made islands and causeways in shallow near-shore waters. The Alaska LNG Project's GTP will be located within the surface boundaries of the Prudhoe Bay Unit ("PBU"), on state land near existing PBU gas processing facilities. Learnings from the Alaska LNG pre-FEED study for the GTP provide insights on why an onshore North Slope LNG plant and marine terminal are fatally flawed.

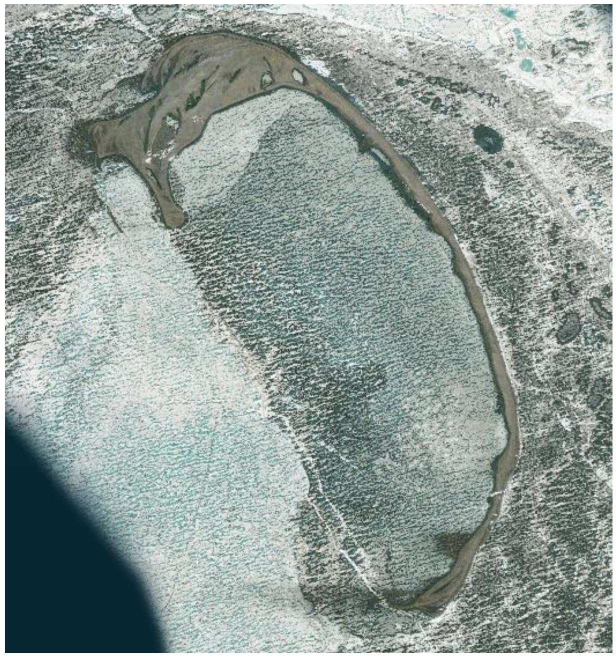
LNGCs of the size that Alaska LNG is designed for (135,000 to 216,000 cubic meters) have laden drafts of 11 to 12 meters (about 40 feet). To this one must add sufficient under-keel clearance of approximately 10 feet to accommodate vessel-seabed hydraulic interaction and to avoid resedimentation, etc. Given the shallowness and gentle sloping of the seabed near Prudhoe Bay, a channel with depth of 50 feet, width of 600 feet, and length in excess of 12 miles (plus a turning basin) would need to be dredged and maintained. A learning from the Alaska LNG pre-FEED field studies, where several dredge test trenches in Prudhoe Bay were excavated in winter and monitored thereafter, is that the resedimentation rate is significant. Therefore, from a capital cost and operating expense perspective, an onshore LNG plant and associated marine terminal in the vicinity of Prudhoe Bay is a nonstarter.

If the above problem is not enough to disqualify an onshore Alaskan LNG plant, then one must also consider the schedule implications of bringing the LNG plant modules to a similar location as the GTP modules. There is a narrow open-water window where Bering Sea ice, Chukchi Sea ice, Beaufort Sea ice, and subsistence-whaling activities are avoided. The logistical challenges were overcome during the module sealifts for existing oil and gas facilities. The Alaska LNG GTP requires four sealifts to have sufficient facilities for first production, and the LNG plant would require two more; so a North Slope onshore LNG project would be delayed by at least two years compared to the Alaska LNG Project.

2. ALASKA ARCTIC LNG: ONSHORE BARRIER ISLAND

There are numerous barrier islands located within approximately 20 miles of the Alaska Beaufort Sea coast and some of have sufficient water depth nearby such that a marine terminal for LNG export is a theoretical possibility. However, these locations have a number of technical challenges and environmental permitting uncertainties such that it is difficult to envisage an outcome that is competitive with the current Alaska LNG Project.

Figure 1. Cross Island, Beaufort Sea

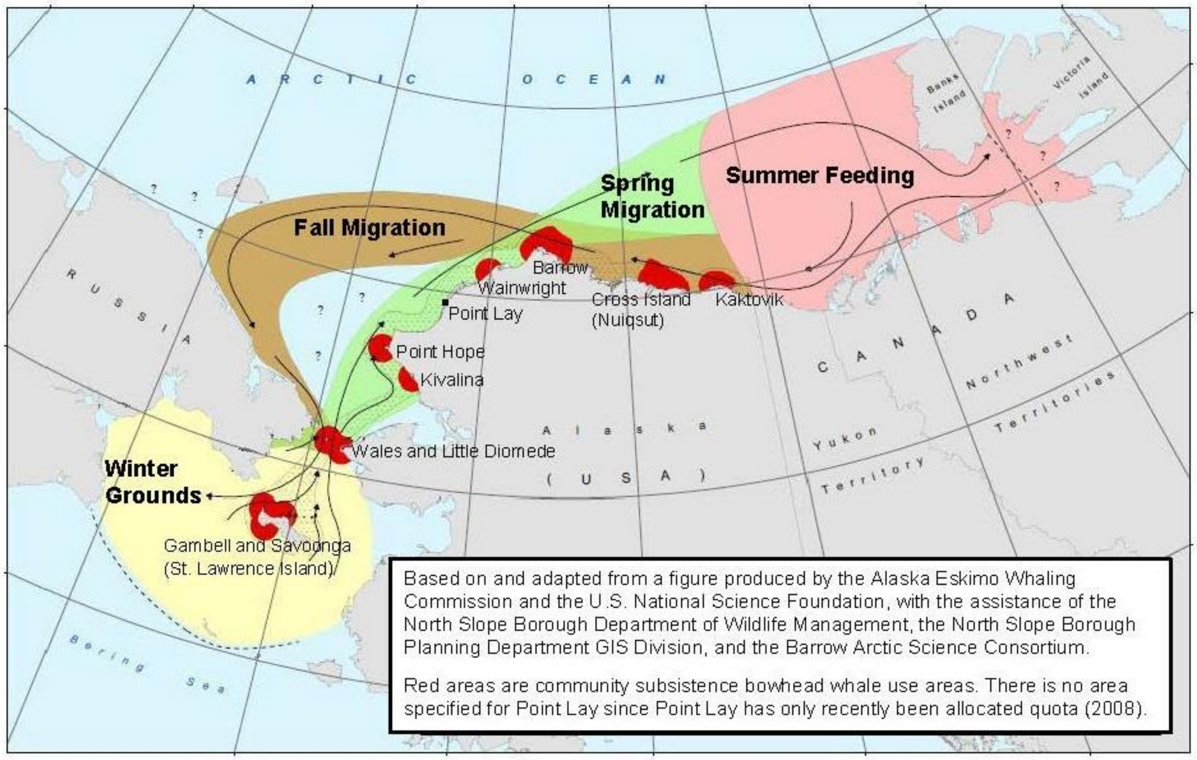


(Image Source: Bing Maps Aerial Imagery)

The first technical challenge concerns getting LNG to the marine terminal. Consider Cross Island (Figure 1), which is about 17 miles from the PBU gas processing facilities. If the GTP and LNG plant were located onshore and nearby the PBU gas facilities, there is currently no technology that would allow pumping of LNG at LNGC loading rates for 17 miles. Which means that the LNG plant would have to be located on the barrier island, along with the marine terminal, and that a gas pipeline would run from the onshore GTP to the barrier island. The gas line would need to be buried sufficiently deep to avoid damage from ice gouging. AGDC's estimate for the Alaska LNG onshore pipeline is about $10,000,000 per mile and for the offshore Cook Inlet crossing about $23,000,000 per mile; but the mobilization and supply costs to lay a line in the Alaska Beaufort Sea would be higher.

There would be significant ancillary facilities for the island-located LNG plant that would make it more costly than the Alaska LNG plant in Nikiski; such as development and manning of an onshore base for staging personnel and supplies for the island facility. LNG plant operating costs would be considerably higher than the Nikiski option, because personnel and supplies must first be sent to the North Slope, and then transported to the barrier island by helicopter and supply vessel. The scheduling delay of two years as described for the onshore LNG plant would be added to by at least three more years to redesign the facility for a barrier island installation and to acquire sufficient site data for the design and subsequent permitting. Finally, it is difficult to imagine the construction and operation of a large project on a barrier island is consistent with historical subsistence activities (Figure 2), and therefore the Alaska LNG Project would most likely be deemed as the environmentally preferable alternative by the regulatory authorities.

Figure 2. Bowhead Whale Map - Generalized Bowhead Western Arctic Stock Migration Route and Location of Alaskan Subsistence Whaling Communities



(Image Source: BOEM OCS Study 2013-218, Monitoring Cross Island Whaling Activities, Beaufort Sea, Alaska)

3. ALASKA ARCTIC LNG: OFFSHORE BOTTOM-FOUNDED

Gravity-Based Structures ("GBS") that rest on the seabed have been used for year-round exploration drilling in Arctic waters, and are used for offshore production in the North Atlantic and North Sea. However, the areal footprint of a commercially-viable (10 MTPA or more) liquefaction facility would require a large GBS with significantly increased cost compared to the Alaska LNG facility in Nikiski. Although the GBS could be located anywhere with sufficient water depth for LNGC loading, there is still the additional cost of a gas supply pipeline running for 12 or more miles and buried sufficiently for protection from ice gouging. As with the barrier island case, there is the additional cost of a shore base and associated staging of personnel and supplies, and the increased operating expense. Frequent transfer of LNG from the GBS to LNGCs under moving-ice conditions seems daunting, and the possibility would need to be validated through studies and simulations. The nearby Canadian Beaufort Sea offers an analogy, where numerous discovered oil fields remain undeveloped even in high oil-price scenarios, due to gaps in and the cost of enabling technology.

Of greater concern is the disposal of the heat removed from the natural gas as it is refrigerated and condensed from pipeline conditions to -260°F. On land, the heat is typically removed with air coolers; that is, the process gas or refrigerant passes through large radiators while fans blow air across the radiators and the heat is rejected to the atmosphere. However, a commercially viable offshore liquefaction facility would not have room for air coolers, and would instead use more compact seawater cooling. Seawater cooling requires the addition of biocide to the seawater stream to prevent fouling within the cooling system. Although warm discharged seawater is used at the Yamal LNG project in Russia to reduce ice in the harbor, it is difficult to imagine that a regulatory authority would agree to such practice in Alaskan waters; once again, the Alaska LNG Project would be deemed as the environmentally preferable alternative by the regulatory authorities.

A variation of a monolithic GBS facility is to surround the LNG plant and marine terminal with bottom-founded caissons, with the caissons shielding the LNG loading operations from ice. The scale of bringing in and setting the caissons in the brief non-ice season(s) would add to the cost of the bottom-founded model, while the environmental concerns would remain.

4. ALASKA ARCTIC LNG: OFFSHORE FLOATING

Floating LNG production and offloading from ship-shaped vessels is being developed for temperate climates, but there are technical, economic, and environmental concerns that would prohibit replication in the Alaska Beaufort Sea. Consider first the Shell Prelude Project (Figure 3), which is designed for Australian waters, has capacity of 3.6 MTPA, is the largest man-made floating structure, and has a reported cost of $7 billion. Winterization and hull-hardening for the Alaska Beaufort Sea would add significantly to the cost, and it is not obvious how capacity could be increased to attain economic viability. Or consider the floating LNG vessels in the 1 to 2 MTPA range such as the Petronas Satu (Figure 4). Again, this is a massive and expensive vessel that would require additional cost for the Alaskan Beaufort Sea while not producing enough LNG to be economically viable. Any floating LNG system would require a mooring system that keeps the vessel in position and connects to the gas supply pipeline. Although such systems exist for oil export in less challenging ice conditions (e.g., Varandey, Russia), it is not evident these can be replicated in the more severe Alaskan Beaufort Sea environment.

Figure 3. Shell Prelude FLNG

(Image Source: http://www.shell.com.au/media/prelude-flng-media-library.html)

Figure 4. Petronas Satu FLNG

(Image Source: lngworldnews.com)

Indeed, in 2008 the U.S Minerals Management Service (now the Bureau of Ocean Energy Management) commissioned a report on proposed Arctic offshore development options. In the report, IMV Project Atlantic made the following statements:

> *"While a floating structure, moored in place under tension, might operate year-round in conditions of first-year ice more typical of the Bering Sea, it would still need to be able to disconnect to move away in the event of high ice loads. Floating production systems for the Beaufort Sea, Chukchi Sea and North Bering Sea are not considered to be technically feasible, even with continuous ice management. No floating production structures could be economically designed to stay on station with multi-year ice loads in the Beaufort and Chukchi Seas, and possibly northern Bering Sea, depending on ice conditions."*[4]

It should also be noted that no floating drilling vessels were used for year-round exploration drilling in the Canadian Beaufort Sea; only bottom-founded units drilled during the winter.

Like the barrier-island and bottom-founded options, a floating model carries the additional capital cost and operating expense of the shore base, and the cost of the gas supply pipeline. Frequent transfer of LNG from the floating facility to LNGCs under moving-ice conditions seems daunting, and the possibility would need to be validated. As with the monolithic GBS, it might be possible to shield a floating LNG plant and marine terminal with bottom-founded caissons; but this would add to the cost and scale of the project, while still offering LNG sales that are less than commercially-viable.

Finally, the environmental issue of discharging heated and biocide-treated seawater from the LNG process to the Alaskan Beaufort Sea seems unlikely to receive regulatory approval.

5. COMMON ISSUES WITH ALL ALASKA ARCTIC LNG MODELS

All of the aforementioned Alaskan Arctic LNG models require treatment of the gas for acid gas removal (carbon dioxide and hydrogen sulfide) before the liquefaction process within the LNG plant. The minimum cost solution is onshore, so any Arctic LNG option must include a gas processing cost scaled from the Alaska LNG GTP. The three-train version capable of serving 20 MTPA of LNG plus in-state gas is estimated to cost $6.3 billion), so this number would need to be scaled to match the minimum output of an economically viable Arctic LNG plant.

All of the Arctic LNG options have a common flaw in that they do not provide gas to Alaskan citizens and industries. This means that Fairbanks would not have a pipeline solution to improving air quality, South Central Alaska would not have insurance against Cook Inlet gas supply decline, and mines would not have access to pipeline-supplied natural gas. That limitation exposes another flaw; the Alaska LNG Project has the possibility to spur additional exploration in the "middle Earth" between the North Slope and the Cook Inlet. To equalize, any Alaska Arctic LNG option would need to include a component such as AGDC's Alaska Stand-Alone Pipeline ("ASAP") project, of which the pipeline was costed (to FEED level) at $7 billion in 2014.

All of the Arctic LNG options, with the exception of the onshore North Slope version, which has a fatal flaw (insurmountable dredging), require the additional cost of an offshore gas supply line, buried deep enough to avoid ice scour damage. The cost of the line will depend on its length; but due to the high cost of mobilizing and supplying a lay barge in the Alaskan Beaufort Sea, the cost will be in excess of Alaska LNG's Cook Inlet crossing (estimated at $23 million per mile).

All of the Arctic LNG options have increased ongoing operating expenses compared to an LNG plant located in Nikiski, due the additional cost of getting personnel and supplies to Alaska's North Slope. The three offshore options must carry the additional capital cost of establishing a shore base, and then have significantly increased operating expenses as personnel and supplies are transported by helicopter and supply vessel from the shore base to the offshore facility.

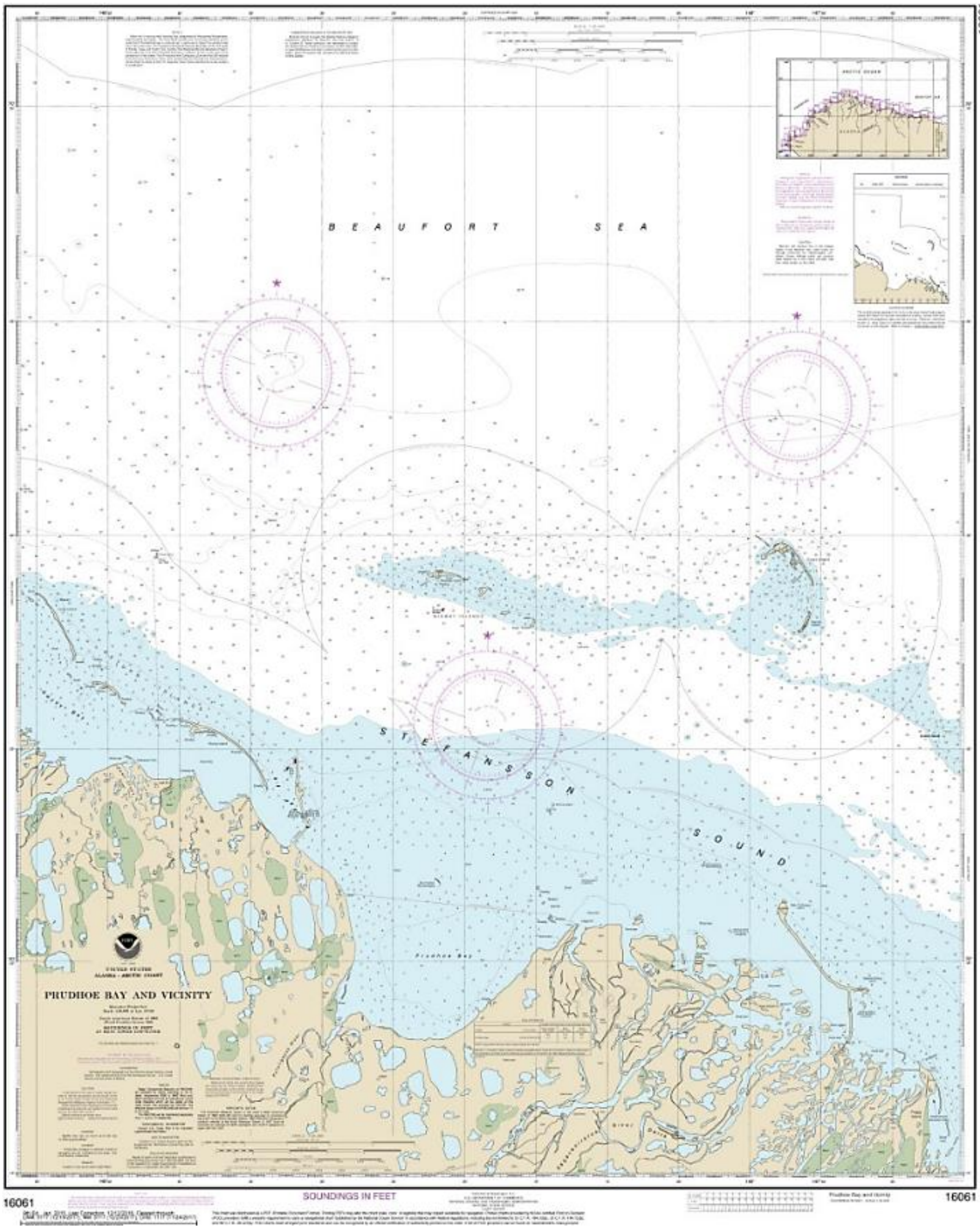
All of the Alaska Arctic LNG options have significant risk and additional cost associated with LNG loading and shipping. The icebreaking tankers that serve the Yamal LNG project receive their cargoes in a port and not in the open ocean; and they do not attempt to cross the Arctic Ocean to reach their Asian buyers in the winter months (instead, they will discharge their winter cargoes in Europe). The feasibility of winter LNGC loading and transit operations in the Alaskan Beaufort would need to be studied and simulated, and this could only be done once the necessary ice data is gathered. Vessels that are able to operate in heavy ice are not efficient in open water, so the LNG would need to be transferred at some point to conventional LNGCs. If the transfer point were in Alaska waters (near Dutch Harbor or Adak), then Jones Act implications would require resolution. The LNGCs that are capable of true Arctic operations are significantly more expensive compared to those that would serve Nikiski, which only require modest reinforcement for Cook Inlet ice and North Pacific transit. In total, LNG shipping costs would be in excess of the current Alaska LNG Project estimate of $0.80 /MMBTU and potentially $1.80/MMBTU or more.

6. SHALLOW SEAFLOOR BATHYMETRY

While the Beaufort Sea continental shelf is not particularly wide, it slopes gently giving rise to shallow seas tens of miles from shore (Figure 5).[6] In the Prudhoe Bay area, it is approximately 3 miles to 15-foot water depths and 20 miles before reaching water depths suitable for berthing and loading LNG tankers (50 to 60 feet). However, in order to accommodate most offshore loading schemes even deeper water, upward of 200 feet, is preferred allowing for flex to adjust to wave and tidal motions. This means either a LNG loading facility would have to be located 20 to 50 miles offshore, or extensive dredging would be required to build a deep-water berth on the coast with a 12 to 20-mile channel across the shelf to deeper water. This amount of dredging would give rise to significant sediment plumes and a buildup of spoils of sand, silt, and clay-sized material in the near shore areas causing potentially negative impacts on marine mammals, fish, and substance whaling. Because of the dynamic nature of sediment transfer and loading along the shallow Beaufort Sea coastline, annual dredging would also be required to keep the port and channel operable, so spoils management would be an ongoing operational and environmental issue.

During the winter season, constant maintenance would be required to keep the channel and port areas free of ice. While this may sound simple, it is not because the winter sea ice is constantly drifting. Significant ice breaking capability would be required to handle any ice pack that might move over the ship channel or into the harbor. Because of these possible environmental consequences, permitting by federal and state agencies would be difficult and prolonged. Even if successful, mitigations would be expensive and prone to causing operational disruptions. It would be hard to envisage the possibility of permitting dredging and maintaining a large port and 12 to 20-mile channel across such a protected environment as Alaska's Beaufort Sea.

Figure 5. Beaufort Sea Bathymetry Offshore of Prudhoe Bay



(Image Source: http://www.charts.noaa.gov/PDFs/16061.pdf)

7. HAZARDS OF SEA ICE

In regard to the hazards from sea ice on shipping, marine terminals, and other offshore operations, the Beaufort Sea is the most problematic of all of Alaska's marine water bodies and coastlines. The Beaufort Sea is under ice almost year-round; only in August and September does the ice break up, and then only near the coasts. In the coastal regions, surface water ranges in temperature from 29.5°F (-1.4°C) in late summer to 28.8°F (-1.8°C) in winter.[7] It only takes a short time once seawater temperatures fall below 28.8°F for ice to start forming.

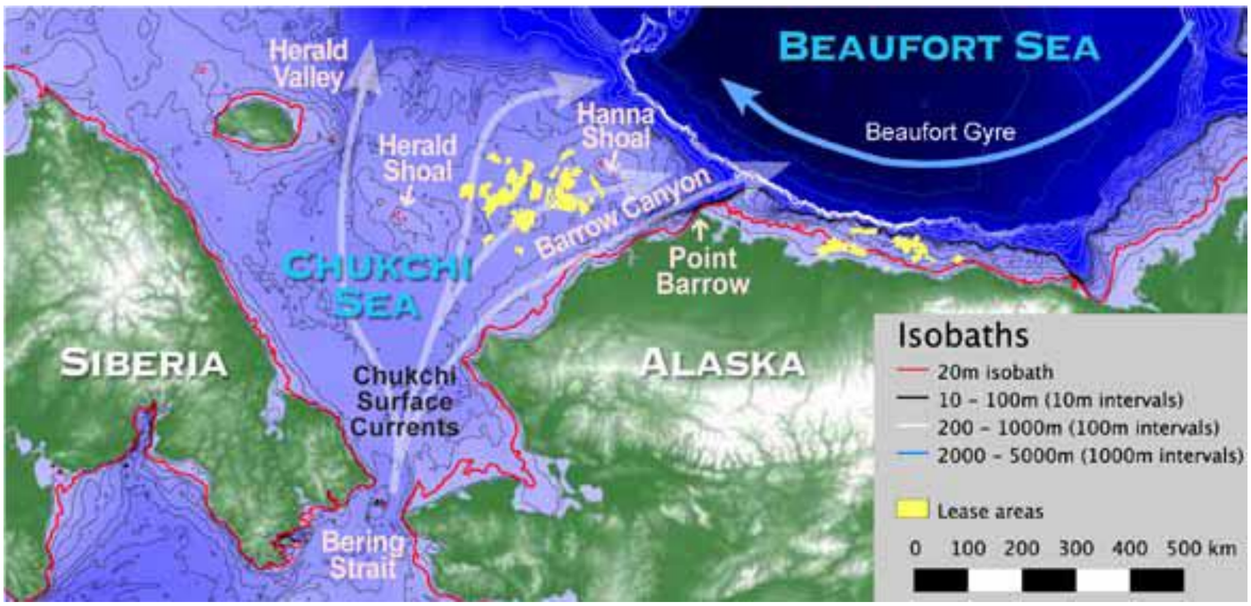
The clockwise motion of a regional ocean current known as the Beaufort Gyre (Figure 6) dominates surficial, as well as deep-water, circulation in the Beaufort Sea.[8] One effect of this current is that it transports into the Alaskan Beaufort Sea some of the oldest and thickest ice in the Arctic from the region north of the Canadian Archipelago. Because of the early and extended presence of sea ice, along with large amounts of older, thicker ice brought in from Canada, the Beaufort contains significant concentrations of multi-year (MY) ice in contrast to other areas like the Chukchi and Russian offshore that are dominated by one-year or first-year (FY) ice. MY ice is generally thicker and stronger than FY ice (Figure 7).[9]

Both glacial calving and floating sea ice constitute large ice masses in polar oceans. Many icebergs derived from glaciers are commonly in excess of several hundred meters across and of equal thickness. Sea ice however, is much thinner, but extensive ice keels form beneath multiyear, pressure-ridged sea ice, often protrude more than 30 meters (98 feet) below the sea ice base. The impacts of sea ice loads have been studied for years. Perhaps the most famous research program of all was the Hans Island Multi-Year Impact Experiments conducted in the early 1980's on a natural rock outcrop in the Kennedy Channel between Greenland and Ellesmere Island. The largest ice load recorded was measured in the summer of 1983 when a 20-feet (6-meter) thick MY ice floe, several miles in diameter, moving at 4 feet per second collided with the vertical base of the small rock island.

> *"Several methods were used to estimate the ice crushing force. The simplest, and most accurate, was to determine how the mass slowed down and then, by the use of Newton's law, the global force imparted to the island. This force proved to be about 49,500 tons (45,000 tonnes) over a contact length of about 1000 feet (305 meters). Prorating this 49,500 ton load to a 65-foot (20-meters) thick ice floe (an extreme Beaufort Sea ice feature) on a 230-foot (70-meters) wide production structure would yield an ice load of 33,000 to 44,000 tons (30,000 to 40,000 tonnes)."*[10]

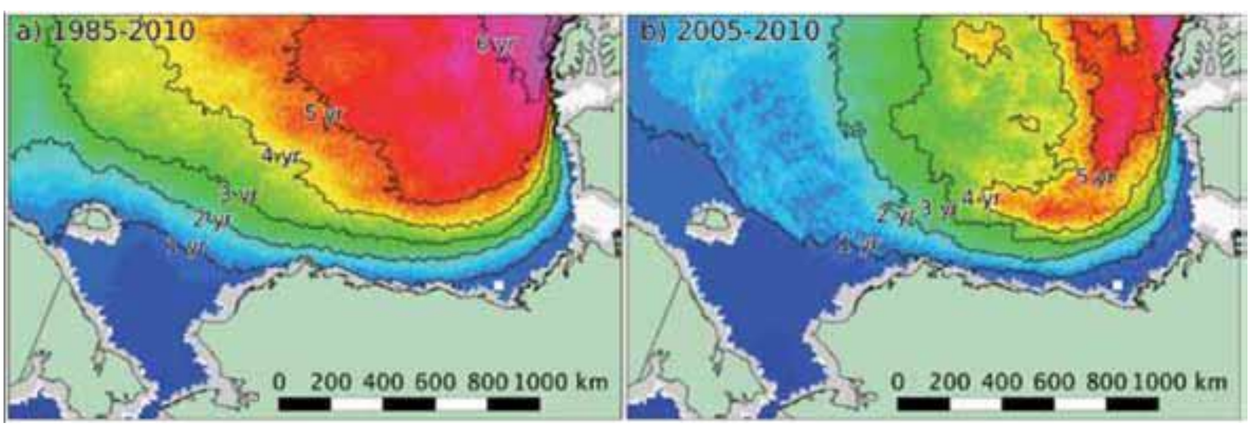
Ice gouging is another sea ice hazard, particularly for subsea equipment like pipelines. In the Beaufort Sea of Northern Canada, a 30-miles (50-kilometers) long gouge was measured, with a maximum gouge depth of 28 feet (8.5 meters). This event is estimated to be about 2000 years old and its recurrence is probably unlikely, nonetheless similar sized gouges further offshore are possible. Ice gouging of a lesser extent is a well-documented phenomena on the Beaufort seafloor and requires burying pipelines from 6.5 to 30 feet (2 to 9 meters) deep to avoid ice gouges across the pipe. Originally, it was thought that the pipe simply needed to be below the maximum ice gouge depth for that area. However, with continued Beaufort Sea development in the 1990's, greater understanding of this phenomenon recognized that soil movements and pressures are transmitted through the soil to the pipe, so even deeper trenching is required. The older, MY sea ice and icebergs generated to the east in the Canadian Arctic represents a greater obstacle and hazard to Beaufort Sea operations than is common in other coastal areas of Alaska and Russia. Even if the ice-free season were to increase in the future, the Project design would still have to address the existing ice regime.

Figure 6. Chukchi and Beaufort Seas Bathymetry and Prevalent Ocean Currents



The red contour approximates the 20-meter isobaths. Arrows indicate predominant current directions. (Image Source: Weingartner, 2005)

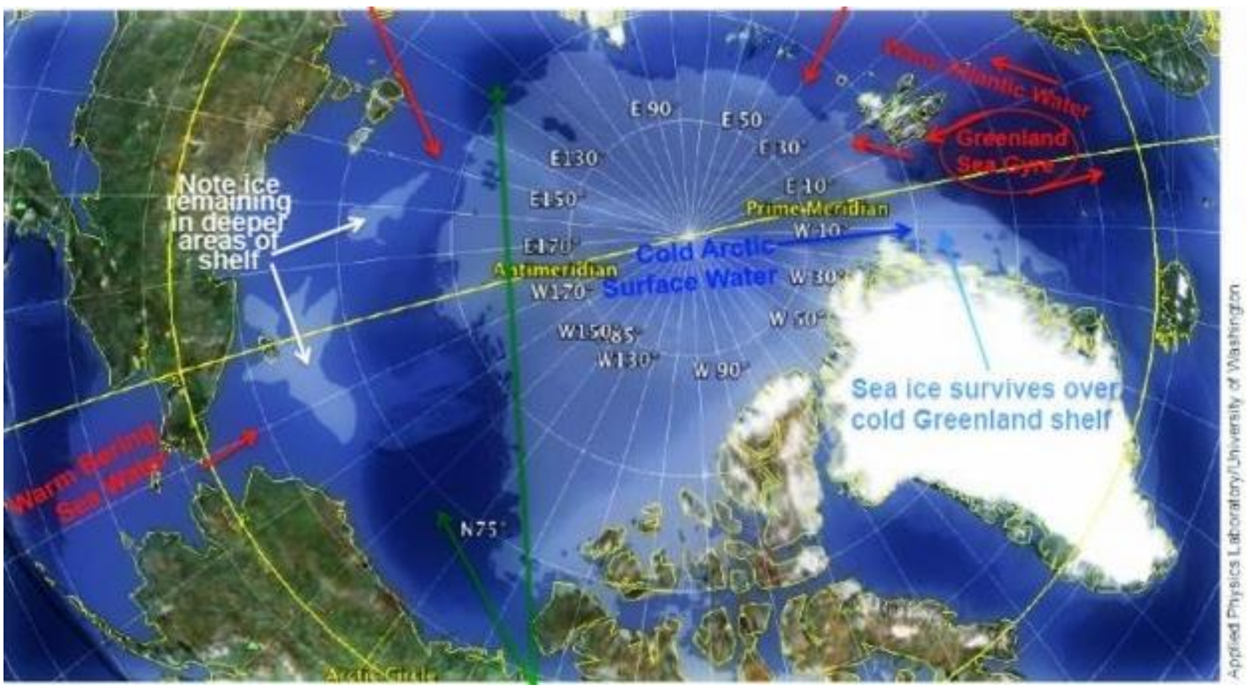
Figure 7. Sea Ice in the Alaskan and Russian Arctic



Mean sea ice age in the Chukchi/Russia and Beaufort Seas, calculated for the periods (a) 1985-2010 and (b) 2005-2010. First-year ice shown in dark and light blue. Multi-year ice depicted in green, yellow, read, and purple. (Image Source: J. Maslanik, 2012)

Furthermore, in terms of MY sea ice, the Beaufort Sea is part of the Arctic heavily influenced by the Arctic Oscillation, a global scale weather variability known to be the major controlling force on the Arctic ice pack. The name itself denotes regular variability, but under normal conditions, the Arctic Oscillation generates ocean currents and wind patterns that drive the Arctic sea ice to be more heavily packed against the shores of North America and less so against the Eurasian continent (Figure 4). Because of this, sea ice forms later, opens up earlier, and is generally thinner against most parts of western Russia, and heavier and more persistent against Greenland, Canada, and eastern Alaska. As the Arctic ice pack continues to shrink away from other areas, Greenland, Canada, and Alaska will likely be the last shorelines to experience increased open ice conditions.

Figure 8. Dominance of Arctic Ice Pack against Greenland, Canada, and Alaska

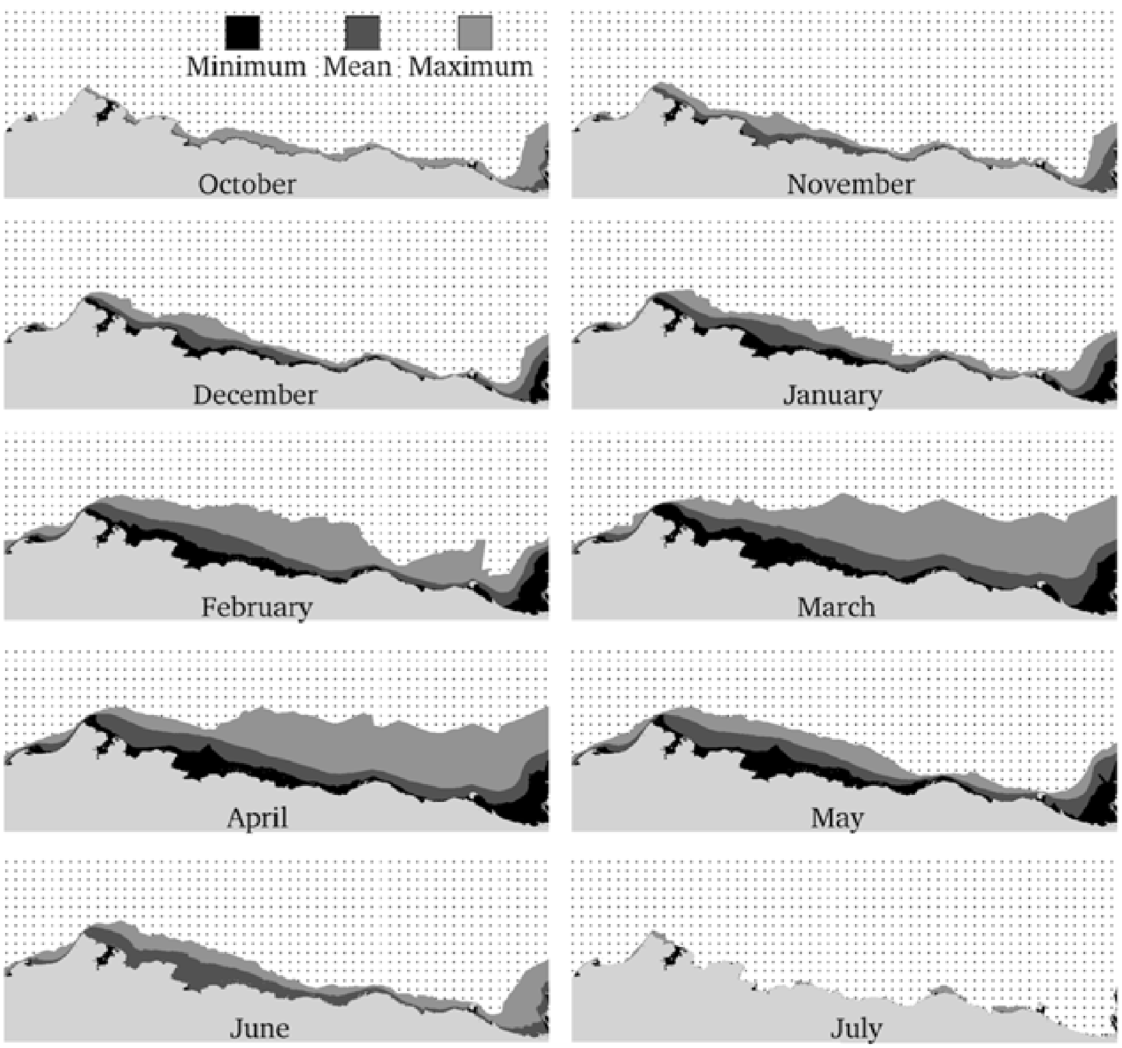


Sea ice disappears first over shallow Russian shelves dominated by warm ocean and riverine inflows and traded radiative heating. The NASA Scientific Visualization Studio published, Weekly Animation of Arctic Sea Ice Age with Graph of Ice Age by Area 1984-2016, (https://svs.gsfc.nasa.gov/4510 October 28, 2016). There are download options in the bottom right of each animation. These animations show the Arctic Ice Pack extent and sea ice age (FY versus MY) between 1984 and 2016.

8. IMPORTANCE OF LANDFAST ICE

Landfast ice is the stationary apron of sea ice that remains attached to the coast. Its seaward edge is sometimes marked by open water. However, there is often no water between landfast ice and drifting pack ice, as is the case in much of the Beaufort Sea. Because of its shallow waters, landfast ice forms sooner and lasts longer in the Beaufort Sea than other areas like the Chukchi and Russian Arctic (Figure 9). Landfast sea ice is a critical habitat for ringed seals and polar bears for denning and access to prey. Landfast ice is also used as a hunting and traveling platform by Arctic coastal communities, while also helping to mitigate coastal erosion by protecting shorelines from winter storms. Dredging a shipping channel that would have to be kept open year-round across the Beaufort shelf, thereby disrupting landfast sea ice, would most likely not be permitted by regulatory agencies.

Figure 9. Landfast Ice Minimums, Means, and Maximums Throughout the Year Along Alaska's Beaufort Sea Coast.



(Image Source: J. Mahoney et al., 2007)

9. POTENTIAL PROJECT SCHEDULE AND COST IMPACTS

To make a major engineering change at this stage in the Alaska LNG Project from the current design base to an Alaska Arctic LNG solution would require substantial time and incur considerable cost. First, a feasibility study would have to be completed to ascertain if there are any unforeseen hindrances that could stall or stop the Project. This study, including the complex marine transportation aspects, would take a year to complete and probably cost $50 million. With numerous serial one aspects of this new approach, such as a 12 to 20-mile, large diameter, high pressure, Arctic subsea gas pipeline, a positive outcome of this study is at best fifty-fifty, meaning the conclusion may be that it is not feasible. However, assuming the study results are positive, then pre-FEED would have to be completed at an estimated cost of $300 million, taking two additional years minimum, just to place this new concept on the same engineering footing as the current Alaska LNG Project. Typically, federal agencies require detailed engineering as part of the Resource Report submittals, which is difficult to complete in a two-year period. Following pre-FEED, an additional round of permitting, at an estimated cost of $100 million would also be required, as the Beaufort Sea option would entail a change in the FERC Environmental Impact Statement ("EIS") process. Optimistically, refiling would only take an additional year or two to return to the current position of anticipating a FERC Notice of Schedule for the Environmental Review of Alaska LNG. Therefore, just from a preliminary engineering and permitting standpoint, a switch at this stage will likely delay the Project by a minimum of four years and maybe as much as five years at an additional cost of $450 to $550 million.

Regarding project execution, given the limited number of modules that could be offloaded in any given year, construction of the liquefaction facility at the same North Slope location as the GTP would require additional years of sealifts for all the modules to be delivered to both sites (likely eight or more years). An alternative would be the construction of an additional dock near Prudhoe Bay's existing West Dock to allow both facilities to offload modules in the same season. However, additional haul roads would be required from the new dock to facilitate transportation to both sites simultaneously. In addition to these permitting challenges, the financial impacts would be significantly greater because of the unique designs (requiring testing prior to operations), longer construction times, as well as the higher costs of building facilities, even with modularization, on Alaska's North Slope due to slower production rates. Optimistically, a combined LNG/GTP construction on Alaska's North Slope would add a minimum of two years to the Project construction schedule for an onshore North Slope model.

10. OPERATIONAL IMPACTS

Exactly what design would be best suited for locating a liquefaction plant, storage tanks, and marine terminal on the North Slope is not at all clear. Forgoing the option of dredging a channel to deep-water, it would be least expensive to locate as much of the facilities onshore as possible rather than offshore. This means the GTP would be in the location consistent with the current design, but the liquefaction plant, storage tanks, and marine terminal would have to be located 20 to 50 miles offshore. At this point it is technically infeasible to transport cryogenic fluid through 20 to 50 miles of subsea pipeline. This is one of many concerns that would have to be addressed in the feasibility study. Pumping LNG across this distance to carriers would increase energy input with a resultant increase in heat transfer and production of boil-off gas ("BOG") volumes, greatly increasing BOG recovery requirements and associated offshore infrastructure requirements. This approach, as well as perhaps other new engineering solutions, up to now not even applied onshore, would have to be used for the first time in the Arctic offshore in order to deliver this design. If LNG cannot be transported this far through a pipeline, then the liquefaction and storage facilities would also have to be placed 20 to 50 miles offshore at significant cost.

Moving the liquefaction facility to the North Slope has another unintended consequence, which is sure to catch the attention of regulators and project opponents. Liquefaction is a complex and energy intensive process. The base case design, which already has been optimized to reduce costs and emissions, still require installing and running well over 1-million horsepower of gas turbine generators and refrigeration compressors. All of the exhaust heat would have to be vented to the atmosphere. Moving all of this equipment into the Arctic, when it could be placed in far less sensitive areas, would be sure to draw further criticism from opponents. Furthermore, chilling and condensing natural gas requires disposition of a tremendous amount of heat into the sea if the LNG plant is located offshore, and into the air if located onshore or on a barrier island raising yet more environmental scrutiny.

11. CONCLUSION

However attractive it might appear to build a project similar to Russia's Yamal LNG on Alaska's Beaufort Sea coast, on closer inspection AGDC believes this approach is not viable from cost, schedule, technical, environmental, and permitting standpoints. Serial one and untested technological solutions needed for siting on the Beaufort Sea would escalate the risk profile of Alaska LNG and diminish its commercial viability. Combined schedule impacts of four to six years are likely, and costs could increase by $500 million. A more tortuous permitting path could add a year or more, and that is without considering the threat of inevitable legal challenges from non-governmental organizations and other project opponents. Feasibility studies and additional engineering design work could likely add two more years to the project schedule. It remains to be seen if the permitting process and feasibility study/pre-FEED engineering could run concurrently, but this is unlikely. Federal agencies typically expect detailed level engineering as input to even begin the EIS process. A more complicated and higher risk North Slope sealift schedule and construction plan would very likely increase the timeline by an additional two or more years as well. Another significant drawback to the Beaufort Sea case is that it does not include an onshore gas pipeline to deliver gas to Alaskans, so this additional cost would have to be considered. Few, if any, outside investors would assume this cost.

To build this project on the coast and across the shelf of the Beaufort Sea would require first-ever engineering solutions that have not been tested. Some of the hurdles mentioned above have potential solutions, but other challenges are unknown and may require completely new technological answers. The risk of the unknown is what often drives project costs to exceed even the most pessimistic forecasts. New, first-of-a-kind technologies along with unknown permitting and project execution challenges could cause pressures that will make cost estimating highly uncertain, thereby potentially limiting the number of investors that might be willing to participate in the project. On the other hand, while Alaska LNG is burdened with the cost of a large-diameter pipeline, this technology has already been proven over the last 40-years to be the right platform for Alaska. The cost and economics of foreign government-sponsored projects are rarely transparent, so the true success of Yamal LNG may never be known. It would be imprudent to assume the Yamal LNG blueprint is best for Alaska LNG when we have decades of experience with known technologies whose costs and schedule requirements are well understood.

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