CHUGACH
POWERING ALASKA'S FUTURE

ELECTRONICALLY FILED WITH RCA

August 11, 2023

Regulatory Commission of Alaska
701 W. 8th Avenue, Suite 300
Anchorage, Alaska 99501

Subject: Informational Filing- Chugach Electric Association, Inc. Future Natural Gas Supply

Commissioners:

The Alaska Department of Natural Resources (ADNR) issued its Cook Inlet Gas Forecast[1] earlier this year which identified projected shortfalls in Cook Inlet natural gas production beginning in 2027, with supply and demand imbalances increasing each year thereafter throughout the planning horizon. Chugach Electric Association, Inc. (Chugach), with the most efficient natural gas generation in the state, currently utilizes natural gas to meet 80% of its generation requirements. Approximately 60% of Chugach's natural gas needs are met through its two-thirds working interest ownership in the Beluga River Unit (BRU) gas field and the remaining 40% are met through a long-term contract with Hilcorp Alaska, LLC (Hilcorp). Because of our business strategy of investing in the upstream, Chugach is the second largest gas producer in Cook Inlet and to date has saved over $80 million for its members since 2016 through that working interest ownership.

Chugach's gas requirements are fully met through first quarter 2028 with a small supply surplus expected over the next several years. Chugach is taking a multifaceted approach in its evaluation of alternative options to ensure long-term generation requirements are met, factoring for additional demand resulting from advancements in beneficial electrification. While natural gas will remain essential to Chugach's operations, the Chugach Board of Directors established decarbonization goals in 2022 to reduce carbon by at least 35% by 2030 and by at least 50% by 2040, provided no material negative impact on electric rates. With this filing, Chugach is providing an update to the Regulatory Commission of Alaska (Commission) on our efforts to ensure long-term gas requirements are met following the expiration of the gas contract with Hilcorp. The purpose of this report is limited to Chugach's efforts to secure natural gas with the recognition that long-term gas supply requirements can be reduced through the advancement of clean generation options as well.

In a parallel path, Chugach is working collaboratively with other Railbelt utilities as part of the Berkeley Research Group (BRG) work efforts to explore gas supply alternatives that could provide system-wide benefits to the residents and businesses of the Alaska Railbelt. Chugach supports the findings of the recent study by BRG and also concur that new clean energy supplies will not come

---

[1] https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/Cook_Inlet_Gas_Forecast_Report_2022.pdf

Chugach Electric Association, Inc.
5601 Electron Drive, P.O. Box 196300 Anchorage, Alaska 99519-6300 • (907) 563-7494 Fax (907) 562-0027 • (800) 478-7494
www.chugachelectric.com • info@chugachelectric.com

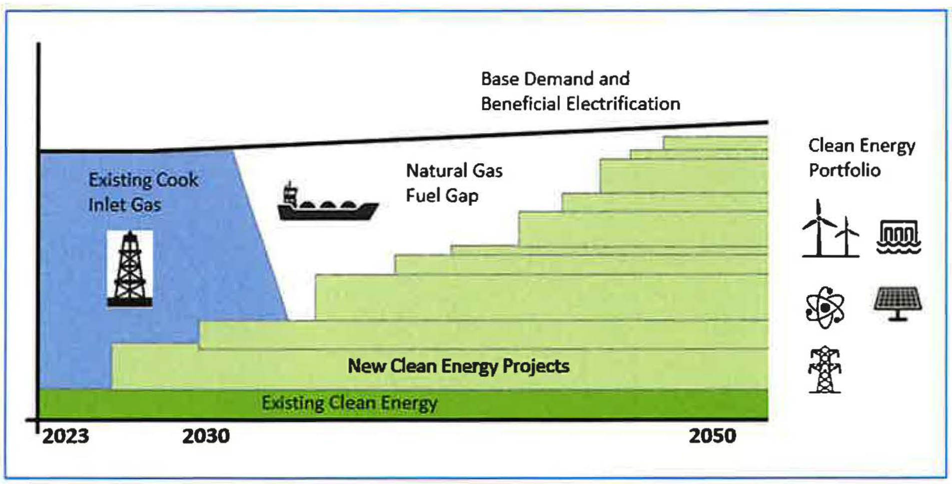
online as fast as native supplies of natural gas decline. To the extent these studies align, gas supply strategies and actions may provide additional consumer benefits.

Phase 1 Black & Veatch Study Results

Chugach has retained Black & Veatch (BV) to work with its strategic planners to perform an integrated study of its system gas supply requirements. Phase 1 of that study, entitled "Gas Supply Option and Market Assessment" reviews gas supply and demand under various forecast scenarios. It then characterizes the resulting fuel gas supply gap and identifies a range of solutions. A copy of the study is attached.

The study finds unmet gas needs will begin to develop for Chugach by early 2028 as Cook Inlet supplies decline. Eventually, the gap will close as more clean energy is developed to displace natural gas generation. Chugach estimates the gap to range between 32 and 144 Bcf total by 2040 depending on electric demand, performance of the BRU, and adoption of clean generation resources. The shape of the gap as it develops is influenced by these assumptions. Figure 1 below is an illustration of Chugach's integrated energy system and the dynamic influences surrounding the natural gas fuel gap.

Figure 1. Chugach Integrated Energy System over Time Illustration



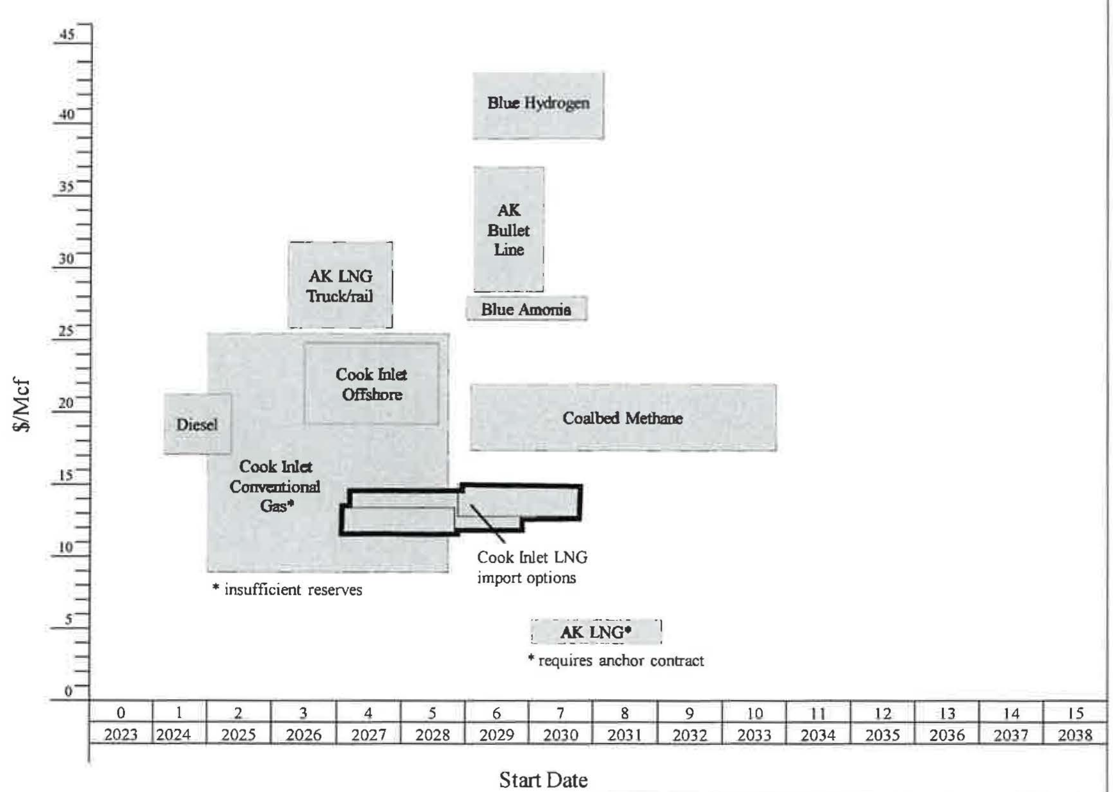
Multiple options to fill the natural gas fuel gap were investigated ranging from additional Cook Inlet supplies, new supplies from the North Slope, emerging technologies to create hydrogen and ammonia fuels, and global liquified natural gas (LNG) imports as shown in Table 1 below. These options were characterized by cost and timing, as summarized in Figure 2 below.

Chugach agrees with the Railbelt utilities working group that new Cook Inlet supplies will be in smaller volumes and at higher prices, and that LNG imports, at this time, are likely the most feasible means to meet gas demand requirements.

Table 1. Chugach Natural Gas Supply Options

Options				
Remaining Cook Inlet Natural Gas (beyond current contract volumes)	A	Proved	1	Onshore Conventional Developed and Undeveloped
		Probable	2	Offshore Conventional Undeveloped
			3	Onshore Conventional Undeveloped
		Prospective	4	Onshore and Offshore Conventional Undeveloped
		Other	5	Coalbed Methane
Other Thermal Fuels	B	Gas	6	Blue Hydrogen (natural gas feed stock)
			8	Compressed Natural Gas (CNG)
		Liquid	10	Blue Ammonia (natural gas feed stock)
			11	Diesel
		Solid	12	Coal
North Slope Gas	C	AK LNG Project	13	42' North Slope to Nikiski
			14	Pipeline Acceleration Variant
			15	Terminal Acceleration Variant
		AK Bullet Line	16	36" Size variant
			17	24" Size variant
		Other	18	Arctic Fox 12" pipeline to Fairbanks
			19	Arctic LNG (Qilak)
			20	LNG Trucking or Truck/Rail
Cook Inlet LNG Imports	D	Land Based LNG Facilities	21	Grass Roots Terminal, Storage, and Regas
			22	Retrofit existing Nikiski facilities for Import
		Floating Storage and Regas Units (FSRU)	23	Chartered FSRU
			24	Retrofit FSRU
			25	New Build FSRU

Figure 2: Gas Supply Options Dashboard



Phase 2 Plan

Chugach's Phase 2 BV study is focused on smaller LNG imports with a chartered Floating Storage and Regasification Unit (FSRU) solution ranging to 15 Bcf per year. Utilizing existing marine docking facilities in Cook Inlet or a moored swivel buoy, a chartered FSRU could deliver, vaporize, and inject gas to underground storage with each trip. This option is attractive to Chugach because of the smaller capital cost, lowest complexity of onshore retrofits, and earliest availability. It is also the most scalable, providing flexibility in a changing business environment, including the transition towards clean generation resources through time.

Chugach's emphasis in BV Phase 2 is to discover if there are financial, fleet, facility, permitting, or other barriers to chartered FSRU imports before deciding on a way forward. We anticipate completing this work in the fourth quarter 2023 and will share findings with the Railbelt utilities working group and the Commission in early 2024.

Phase 2 of the BV study is underway and will provide a detailed look at the best option for Chugach. Once this phase is complete, expected in late 2023, the study will inform decisions on solutions to ensure uninterrupted gas supplies for Chugach's generating units that provide reliable electric service to our members at the lowest possible cost.

Fuel Costs and Customer Impacts

Cook Inlet natural gas prices have not been static, rising 5% on average per year for the past decade and are now approximately $8 per Mcf.[2] Assuming LNG imports could be developed in five years at $12 to $13 per Mcf per both the BV and BRG studies, this increase is within the range of future costs of native Cook Inlet gas estimated by the ADNR. Chugach's fuel costs represent approximately one-third of an average retail member's monthly electric bill.

Conclusion

While Chugach's reliance on natural gas is expected to decline as new clean energy resources are added to its generation portfolio, natural gas will remain an integral part of its power supply. In this context, Chugach is simultaneously optimizing legacy natural gas supplies, assessing additional gas storage capabilities, and planning to bridge the projected gap between gas supply and demand while advancing a variety of new clean generation projects and system integration upgrades. Chugach will remain focused on maintaining reliability and minimizing costs for members.

Chugach is committed to prudent planning, contingency development, and transparency with stakeholders. The electric industry will be a central enabler in this transformational shift towards a lower carbon future. While the transition is complex, there is an opportunity for utility industry

[2] http://www.tax.alaska.gov/programs/oil/prevailing/cook.aspx

leadership and a unique chance to support the economy with new projects and jobs. The electric utility industry is undergoing transformational change and Chugach is transitioning towards a cleaner energy future while assuring reliability and affordability for our members.

Chugach respectfully submits the attached BV Phase 1 Gas Supply Option and Market Assessment to share information with the Commission and other interested parties about options under consideration to source natural gas in the face of projected production declines in the Cook Inlet. We will provide a summary of Phase 2 study results when it is complete.

Sincerely,

CHUGACH ELECTRIC ASSOCIATION, INC.

Arthur W. Miller

Arthur W. Miller
Chief Executive Officer
P.O. Box 196300
Anchorage, Alaska 99519-6300
Telephone: 907-762-4758
Facsimile: 907-762-4191
arthur_Miller@chugachelectric.com

Attachments

cc: John Burns, President and CEO, Golden Valley Electric Association, Inc. (Electronically)
Tony Izzo, CEO, Matanuska Electric Association, Inc. (Electronically)
Brad Janorschke, General Manager, Homer Electric Association, Inc. (Electronically)
Rob Montgomery, General Manager, Seward Electric (Electronically)
John Sims, President, ENSTAR Natural Gas Company (Electronically)
Dan Britton, General Manager, Interior Gas Utility (Electronically)

Chugach Gas Supply Option and Market Assessment

Prepared for

Chugach Electric Association, Inc.

June 2023

Contents

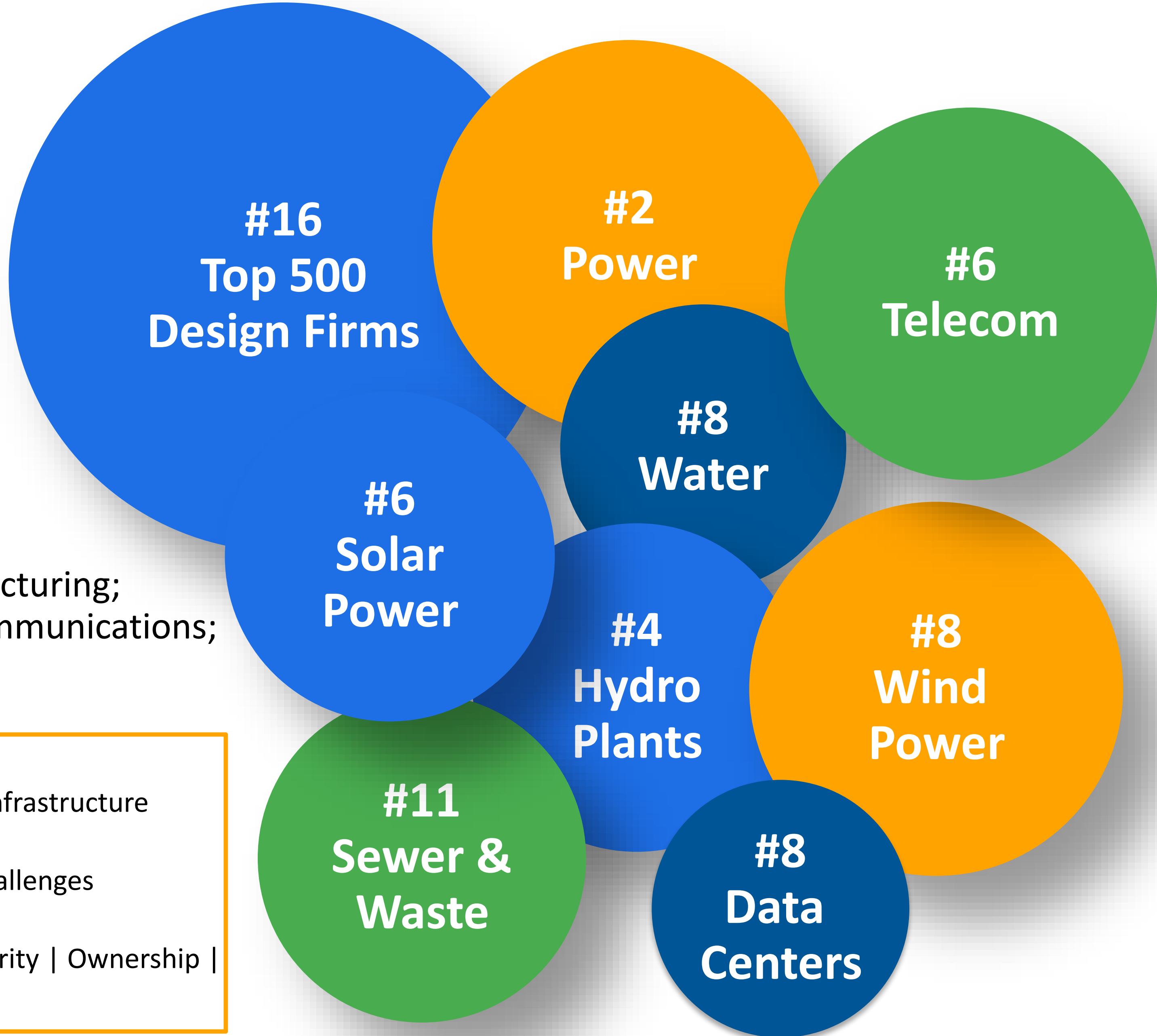
Black & Veatch Today

- **9,200+ professionals in 120+ offices**
- **Headquarters in Overland Park, Kansas, USA**
- **Employee Stock Ownership Plan structure**
- **Projects in 100+ countries on six continents**
- **$4.0+ billion in 2022 revenue**
- **Sectors**
  - Commercial; Governments; Industrial & Manufacturing; Mining; Gas, Fuels, & Chemicals; Power; Telecommunications; Transportation; Water

Mission: *Why we exist*
Building a world of difference through innovation in sustainable infrastructure

Vision: *What future we aspire to achieve*
We work relentlessly to solve humanity's critical infrastructure challenges

Values: *What we believe and how we behave*
Safety | Accountability | Collaboration | Entrepreneurship | Integrity | Ownership | Respect



Current Engineering News-Record rankings.

Strategic Advisory

Key Business Areas and Primary Solution Offerings

Strategy & Planning

- Decarbonization Strategic Planning
- Integrated Resource Planning
- Clean Power Procurement
- Transmission Strategy and Planning
- LNG and Other Fuels Strategic Planning
- Hydrogen Fuels Strategic Planning
- Transportation Electrification Strategic Planning
- Grid Mod, DER Integration Strategic Planning
- Program Management (PMO)

Rates & Regulatory

- Financial modeling and rate design for public power entities
- FERC and State Regulatory Support
- Performance-Based and Infrastructure Ratemaking
- Alternative Regulation Services
- Financial Planning, Cost of Service, and Bond Feasibility Studies
- Stormwater Utility Development and Implementation Support
- Business Operations Reviews

Transaction Services

- Independent Engineering / Technical Due Diligence
- Restructuring Advisory Support
- Construction and Operations Monitoring
- Project Development and Valuations
- Electricity and Fuel Price Forecasting

Black & Veatch's Team Experience in Alaska & LNG Markets

Alaska Experience

- North Slope Gas Monetization Strategy
- Evaluation of Chugach's Acquisition of ML&P
- Alaska Gasline Inducement Act
- Alaska Gasline Development Corporation – AK LNG
- Alaska Gas Pipeline Project
- Golden Valley Electric (GVEA) IR

LNG Market and Commercial Assessment

- Technical and Financial Review of Lower 48 and Canadian LNG Export Terminals
- Global LNG Market Report for Lower 48 LNG Export Terminals
- FERC Market Impact Study for Lower 48/Canadian LNG Export Terminals
- Commercial Advisor to LNG Import/Export capacity holders at Cameron, Freeport, Sabine Pass and Corpus Christi LNG
- Utility consulting and supply analysis for various natural gas and electric utilities

Scope of Work – Phase 1

Black & Veatch was retained by Chugach Electric Association, Inc. (Chugach) to conduct a study to identify available incremental gas supply options that can meet the projected shortfall, compare the projected cost, benefits and risks associated with each option and recommend appropriate option(s) for Chugach to consider.

To conduct this study, Black & Veatch provided the following services:

- Review of Chugach's projected natural gas supply portfolio
- Validate and quantify the projected gas supply shortfall/gap
- High level review of available options for incremental gas supply
- Global LNG market review and assessment of the LNG import options
- High level technical and engineering analysis of the LNG options

1| Executive Summary

Black & Veatch Approach and Methodology Summary

Review

Chugach projected demand and load growth profile

- ❑ Review Chugach projections

Develop

Chugach's renewable strategy;

Chugach's natural gas supply portfolio

- ❑ Supply shortfall/gap analysis for base case and three additional scenarios
- ❑ Seasonal supply and reliability requirement analysis

Structure

Alternatives to energy transition gap;

Costs and benefits of the alternatives

- ❑ Technology assessment
- ❑ Capital cost estimate
- ❑ Cost of supply evaluation
- ❑ Construction timeline estimate
- ❑ Risk assessment

Assess

Alternative(s) best meet objectives

- ❑ Market assessment
- ❑ Technical characteristics

Phase 2

Next steps to develop incremental supply alternatives

- ❑ Define detail scope, schedule and commercial availability
- ❑ Risks associated with least cost, earliest available option

Key Observations and Conclusions – Part 1

- Black & Veatch evaluated four demand and supply scenarios:
  - Scenario 1 (Base Case): no load growth, goal of 50% reductions of emissions by 2040
  - Scenario 2 (Medium Gap): moderate load growth and high renewable penetration
  - Scenario 3 (Large Gap): aggressive load growth, low renewable penetration
  - Scenario 4 (Small Gap): no load growth, high renewable penetration
- The earliest gas supply gap start date is between 2029 and 2034 including storage options. Without storage options, the gap starts 2027.
- Alternative to fulfill gas supply gap is required by November 2027 (two years ahead of earliest gas supply gap with storage) in order to coordinate with existing fuel supply portfolio over annual demand to ensure system fuel supply redundancy.

Key Observations and Conclusions – Part 2

Options		Project Cost (15.3 BCF/Year)	Cost of Supply	Schedule to Place into Service	Risks	Status	Recommended for next steps?
Additional Regional Natural Gas Supply	Cook Inlet Onshore Conv Gas	$10's million	Cook Inlet parity	1 to 3 years	Resource constraint; Outside of Chugach control	Active	
	Cook Inlet Offshore Conv Gas	$100Ms	Cook Inlet parity	3 to 5 years			
	Lower Cook Inlet Offshore Conv Gas	$1Bs	Not specified	5 to 10 years	Lack of investors; offshore permitting issue	Seeking investors	
	Coal Bed Methane	$10's million	Diesel parity	5 to 10 years	No proven economic production in Alaska	Inactive	
North Slope Natural Gas	Alaska LNG Project (42'' pipeline from North Slope to Nikiski)	$39 billion [1][2]	$6.7/Mcf [1]	8 to 10 years	Uncertainties in project development; Outside of Chugach control; additional processing required from higher BTU content	Seeking anchor customers	
	Alaska LNG Project (Terminal Accelerated)	$1.5 to $2.0 billion [2]	Not specified	5 to 6 years	Outside of Chugach control	Seeking investors	
	Alaska in-state Pipeline (Bullet line, 24'' to 36'' pipeline)	$13 billion [2][3]	$11.5 to $14.5/Mcf [4]	8 years	Outside of Chugach control	Inactive	
	Arctic Fox Pipeline, 12'' pipeline from North Slope to Fairbanks	$716 to 1,002 million [2]	$9.7/Mcf	2 to 3 years	Insufficient market	Inactive	
	LNG Trucking or Truck/Rail/Pipe	$55 million	$25 to 30/Mcf	2 to 5 years	Transportation logistics	Inactive	

Recommended for next steps - Most affordable alternatives with reasonable schedule

Recommended for next steps – Low Priority

Not recommended for next steps

Notes: (1) source: Alaska LNG Project Update dated October 27, 2022 (Alaska Gasline Development Corp.) (2) Assuming project developed by third parties. Costs represent total project costs. (3) Additional subsidies are needed to achieve the cost of supply for 24'' to 36'' pipeline. (4) source: AK Journal of Commerce 1/28/2015

Key Observations and Conclusions – Part 2

Options			Project Cost (15.3 BCF/Year)	Cost of Supply	Schedule to Place into Service	Risks	Status	Recommended for next step?
Global LNG Import Facilities(1)	Land-based LNG	Grass Roots New Land-based Import Facility	\$350 million to \$450 million	\$12 to \$13/Mcf	5 to 7 years	High initial investment; potential delay in permitting; processing is required for higher btu content of supply.	Commercially available (5)	
		Nikiski LNG Export Facility Retrofit to Import Facility (2) (3)	\$150 million	\$12/Mcf	4 to 6 years	Commercial arrangement with existing terminal owner is required; processing is required for higher btu content of supply.	Commercially available (5)	
	Floating Storage Regasification Unit (FSRU) Wheeling Option	Chartered/Leased FSRU (4)	\$60 million to \$80 million; \$36 million annual chartered fee; \$0.1/Mcf wheeling fee	\$12.6 to \$13.7/Mcf	3 to 5 years	Commercial arrangement with existing terminal owner is required; processing is required for higher btu content of supply.	Commercially available (5)	
		Retrofit FSRU	\$260 million to \$280 million	\$11.3 to \$11.4/Mcf	3 to 5 years	Relatively high upfront capex; Potential delay in permitting; processing is required for higher btu content of supply.	Commercially available (5)	
		New Built FSRU	\$345 million to \$365 million	\$12 to \$15/Mcf	4 to 6 years	Relatively high upfront capex; potential delay in permitting; processing is required for higher btu content of supply.	Commercially available (5)	

Recommended for next steps - Most affordable alternatives with reasonable schedule

Recommended for next steps – Low Priority

Not recommended for next steps

Notes: (1) Assuming LNG sourced from Western Canada
(2) Inclusive of onshore regasification and storage expansion cost, and a leased floating storage unit; costs are based on a regasification capacity of 50 MMscfd
(3) Schedule to placed-in-service assumes certain modification to existing FERC permit is required
(4) Assuming using existing Nikiski terminal after retrofit. (5) Configurations commercially available outside of Alaska

Key Observations and Conclusions – Part 2

Options		Project Cost (15.3 BCF/Year)	Cost of Supply	Schedule to Place into Service	Risks	Status	Recommended for next step?
Other Alternatives	Blue Hydrogen [1]	$1,150 million	$39 to $62/Mcf	5-7 years	High initial investment; Requires pipeline transportation	Limited commercial deployment; Research undergoing on project economics	
	Blue Ammonia [1]	$1,400 million	$26/Mcf	5-7 years	High initial investment; Relatively high cost for production and transportation		
	Compressed Natural gas (CNG)	$150 to $200 Million	$7/Mcf +	18 to 24 months	Difficult to scale	Commercially available	
	Diesel [2]	Not applicable	$17 to $20/Mcf	Not applicable	For peaking only; environmental risk	Commercially available	

Recommended for next steps - Most affordable alternatives with reasonable schedule

Recommended for next steps – Low Priority

Not recommended for next steps

Notes: (1) Project cost is based on assumed project size to meet annual demand of 15.3 Bcf/year
(2) Assuming shipping from Lower 48.

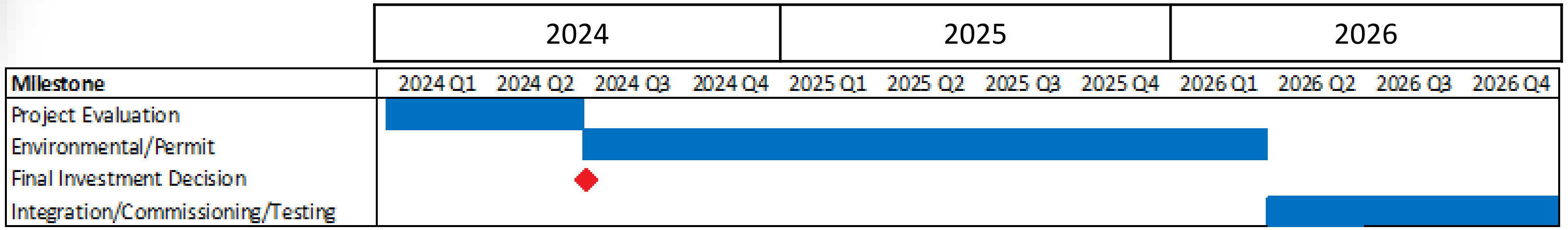
Key Observations and Conclusions – Part 3

- With the initial potential shortfall starting from July 2027 without storage option, and from November 2029 the earliest with storage option for all scenarios evaluated, a sufficient number of LNG export terminals in North America will be online to provide a competitive supply alternative to Cook Inlet and North Slope supplies at $12 to $13/ Mcf which is competitive with Cook Inlet supply at $10 to $15/ Mcf over the respective timeframe.
- Mid-term to Long-term US/Canadian LNG netbacks to Asian/European markets expected to come down as the global demand and supply balance comes back to equilibrium
- The recent run up in global LNG prices continues to support US/Canadian LNG export terminal development, where up to 15 terminals can be operational by 2034
- Western Canadian LNG export terminals may be able to provide the lowest cost LNG imports due to the shorter shipping distance
- Average LNG carrier has a shipping capacity of 3 to 4 Bcf/ship, with 4 to 5 cargoes a year for a total capacity up to 16 Bcf. Initially due to the fuel gap shape and ramp up, less cargos would be required. These solutions assume summer, ice-free delivery.
- If the existing Kenai export terminal and associated pipelines can be used under certain commercial arrangement, deploying an FSRU via a chartered agreement is expected to have least upfront capital cost. The earliest in-service time is two years after final decision is made.

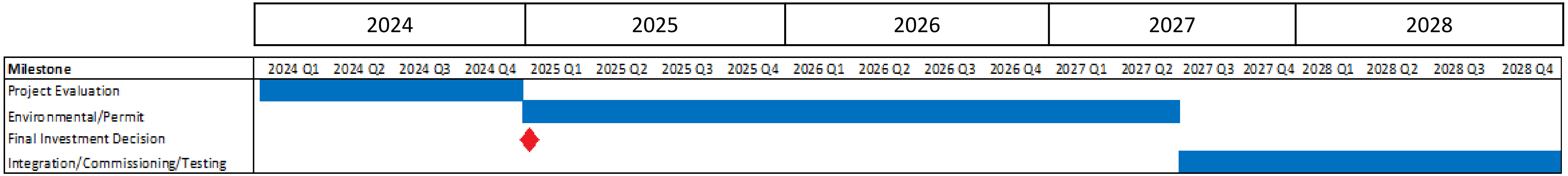
Indicative Implementation Schedule

Chartered/Leased FSRU using converted Nikiski terminal: in-service by Q1 2027 the earliest (3 to 5 years)

Earliest



Delayed



Next Steps to Develop Incremental Supply Alternatives

Phase 2 (Next 6 Months)

- Evaluate the most feasible supply option to meet the projected combined shortfall
- Mitigate potential red flags

Project Phase (6 Months – 2 years)

- Develop conceptual design and pre-feasibility analysis
- Analysis of different commercial structures to execute contracts, and operate the asset
- Estimate a Class 3 cost estimate (10% to 40% maturity level of project definition deliverables)
- Develop estimate of cost of service, cost of project, and decision timing.

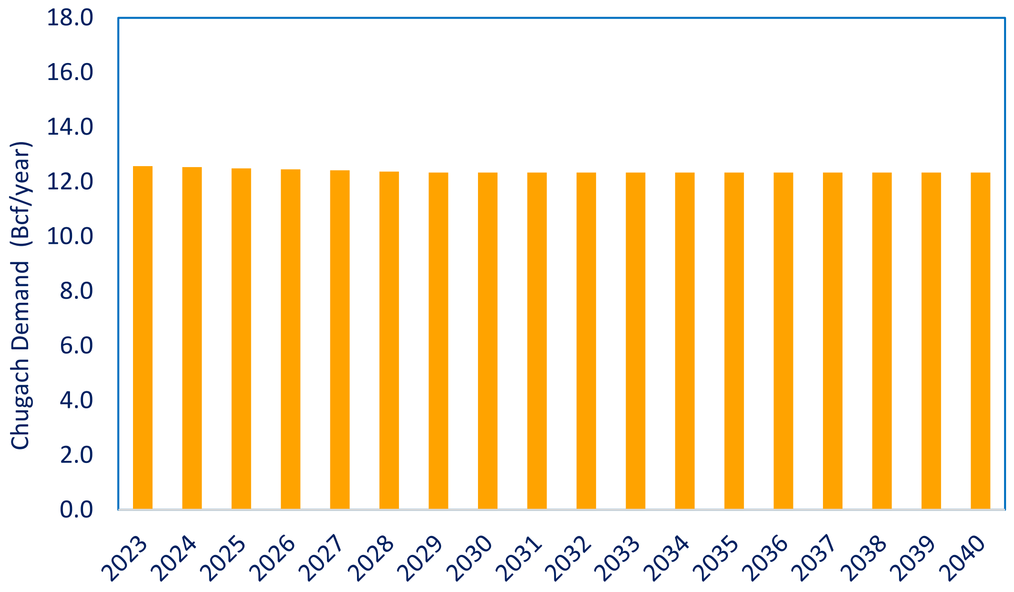
2| Gas Supply Gap Analysis

Scenario 1 (Base Case) : no load growth, 50% emissions reductions by 2040
Scenario 2 (Medium Gap): moderate load growth and high renewable penetration
Scenario 3 (Large Gap): aggressive load growth, low renewable penetration
Scenario 4 (Small Gap): no load growth, high renewable penetration

Chugach Demand and Supply – Scenario 1 (Base Case)

Demand [1]

- Chugach base gas demand from historical demand
- No load growth from heat pumps or electrical vehicles



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract[2]	March 2032

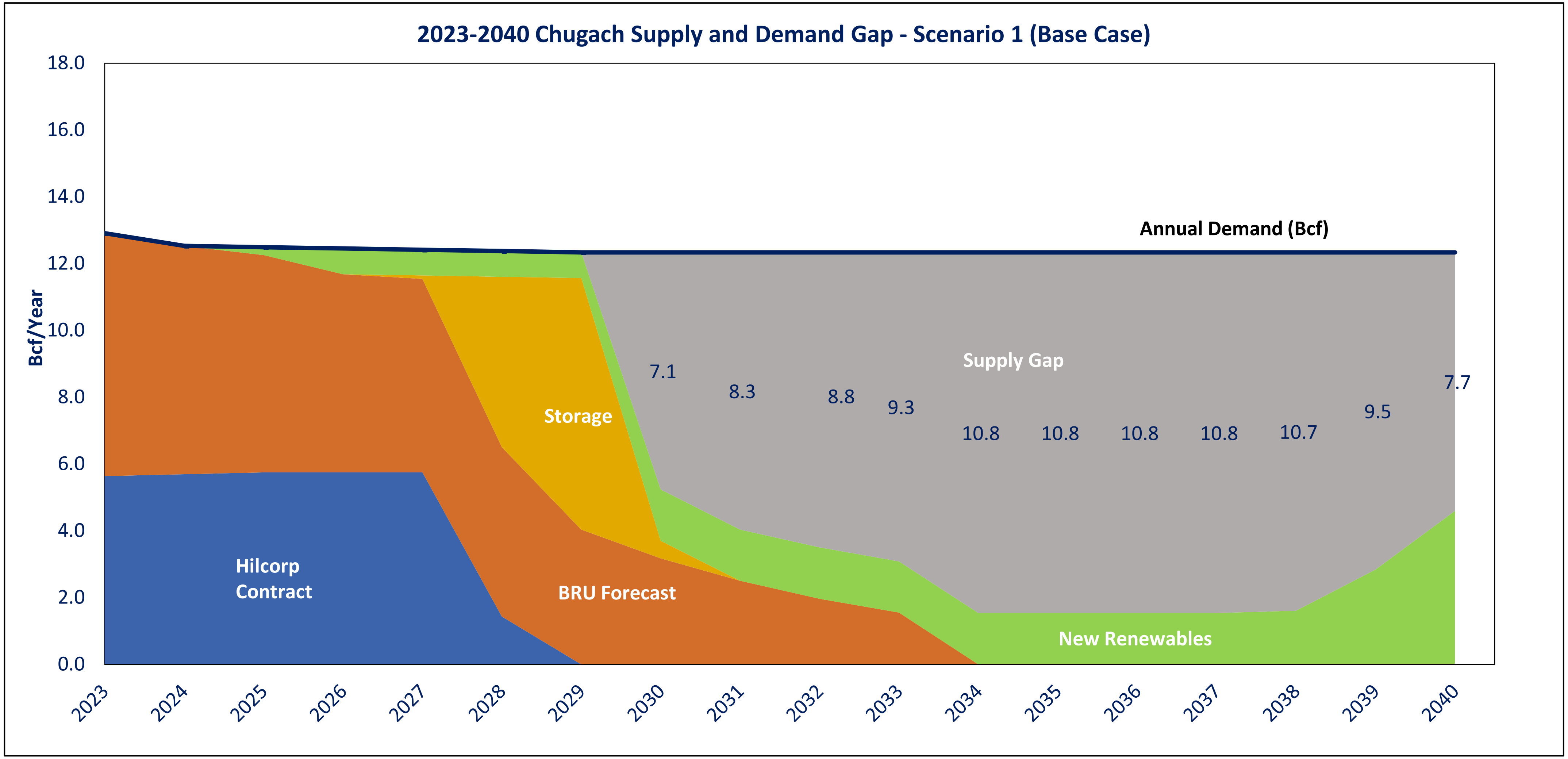
- New Renewables from 2025

100,000 MWh Board Goal	2025	100,000 MWh
200,000 MWh Total	2030	200,000 MWh
Battle Creek	2038	9,350 MWh
50% Emissions Reduction Goal	2040	588,161 MWh

  - Total by 2040: 588,161 MWh (approx. 4.6 Bcf/year equivalent[3])

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion

Gas Supply Gap Annual Profile – Scenario 1 (Base Case)



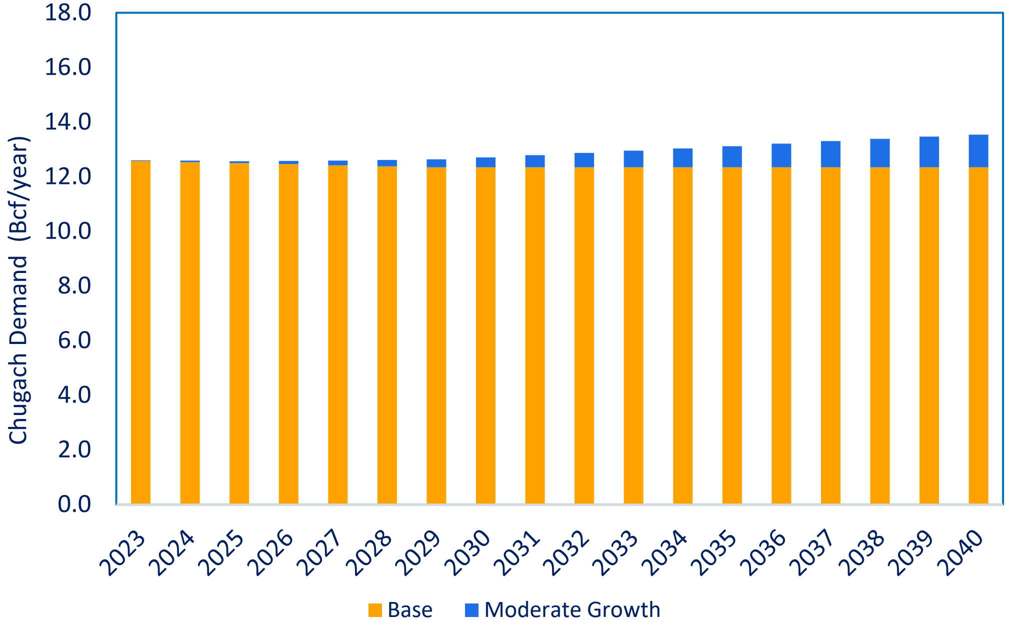
*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

Scenario 1: Gas supply gap initially starts from July 2027, which is expected to be offset by strategic planning of storage for excess BRU production through January 2030. Gas supply gap from January 2030 (after new renewables addition) is approximately 7.1 Bcf/year in 2030, increasing to 10.8 Bcf/year in 2034 due to cease of BRU supply and decreasing to 7.7 Bcf/year in 2040 due to increasing renewable penetration.

Chugach Demand and Supply – Scenario 2 (Medium Gap)

Demand (1)

- Chugach base gas demand from historical demand
- Moderate load growth compared to Base Case due to increasing consumption for electrical vehicles and heat pumps. This would be an estimated additional 42k EV and 3.3% buildings with heat pumps.



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract(2)	March 2032

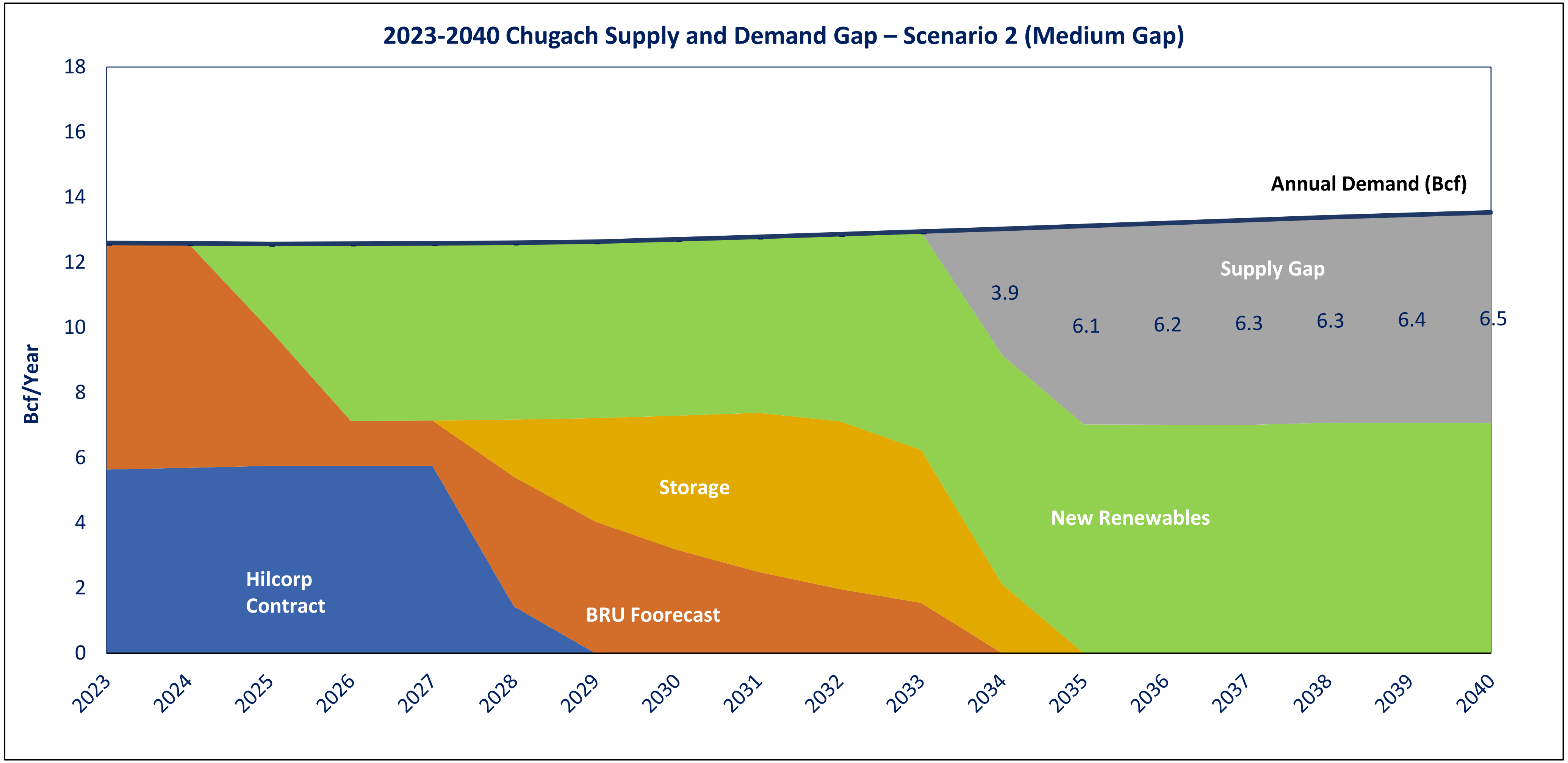
- New Renewables from 2025

Little Mt. Susitna Wind	2025	415,000 MWh(4)
Great Lands Solar	2025	194,000 MWh(4)
Godwin Creek	2032	125,000 MWh
Dixon Creek	2032	89,600 MWh
Battle Creek	2038	9,350 MWh

- Total by 2040: 832,950 MWh (approx. 6.4 Bcf/year equivalent(3))

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion
(4) Subject to power regulation limitations

Gas Supply Gap Annual Profile – Scenario 2 (Medium Gap)



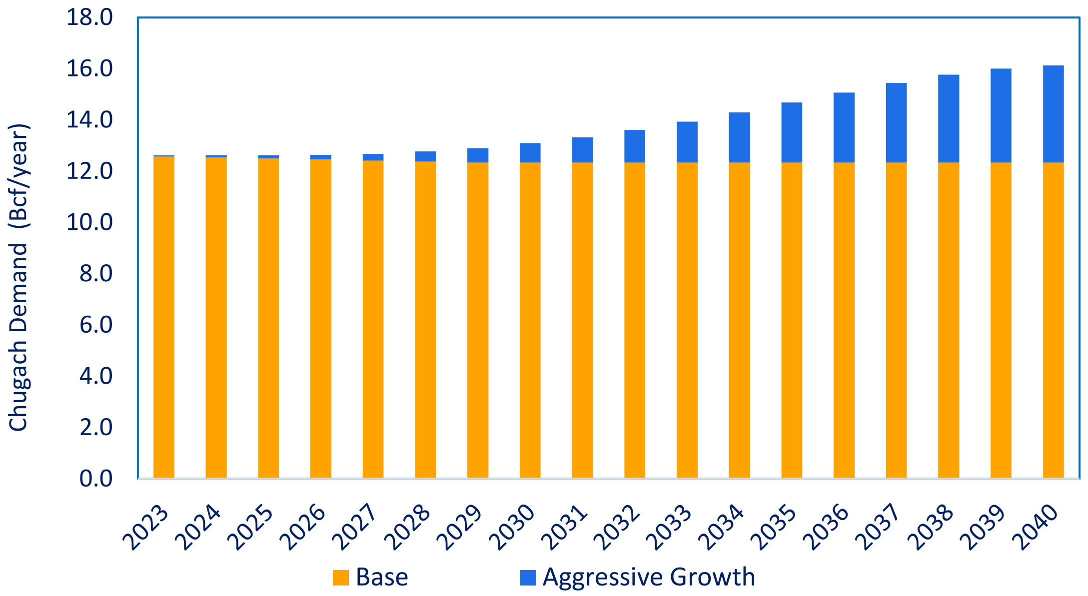
*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

Scenario 2: Gas supply gap initially starts from April 2028, which is expected to be offset by strategic planning of storage for excess BRU production through 2034. Gas supply gap from April 2034 (after new renewables addition) is approximately 3.9 Bcf/year in 2034, increasing to 6.5 Bcf/year in 2040.

Chugach Demand and Supply – Scenario 3 (Large Gap)

Demand [1]

- Chugach base gas demand from historical demand
- Aggressive load growth compared to Base Case due to increasing consumption for electrical vehicles and heat pumps. This would be an estimated additional 125k EV and 12.0% buildings with heat pumps.



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract[2]	March 2032

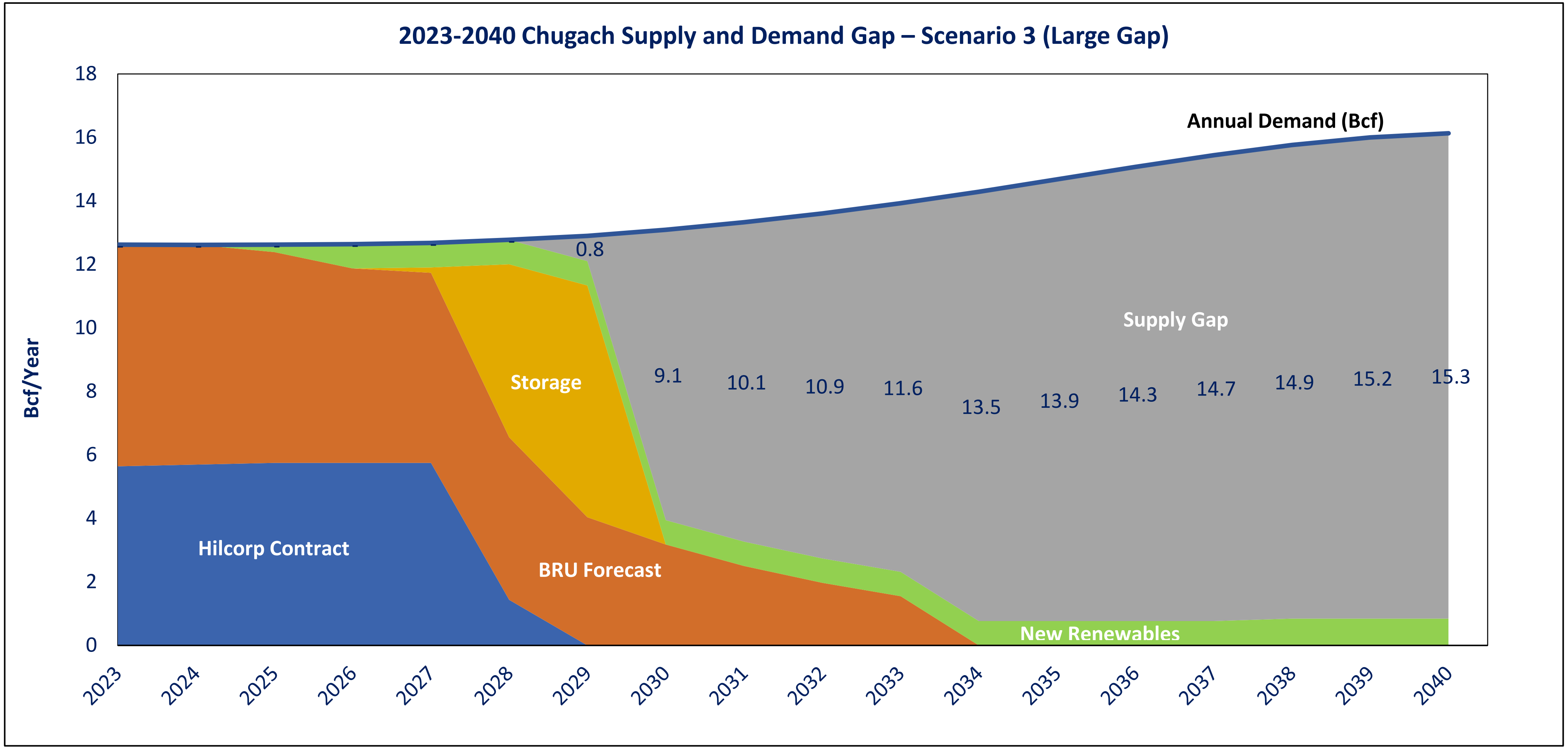
- New Renewables from 2025

100,000 MWh Board Goal	2025	100,000 MWh
Battle Creek	2038	9,350 MWh

- Total by 2040: 109,350 MWh/year (approx. 0.8 Bcf/year equivalent[3])

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion

Gas Supply Gap Annual Profile – Scenario 3 (Large Gap)



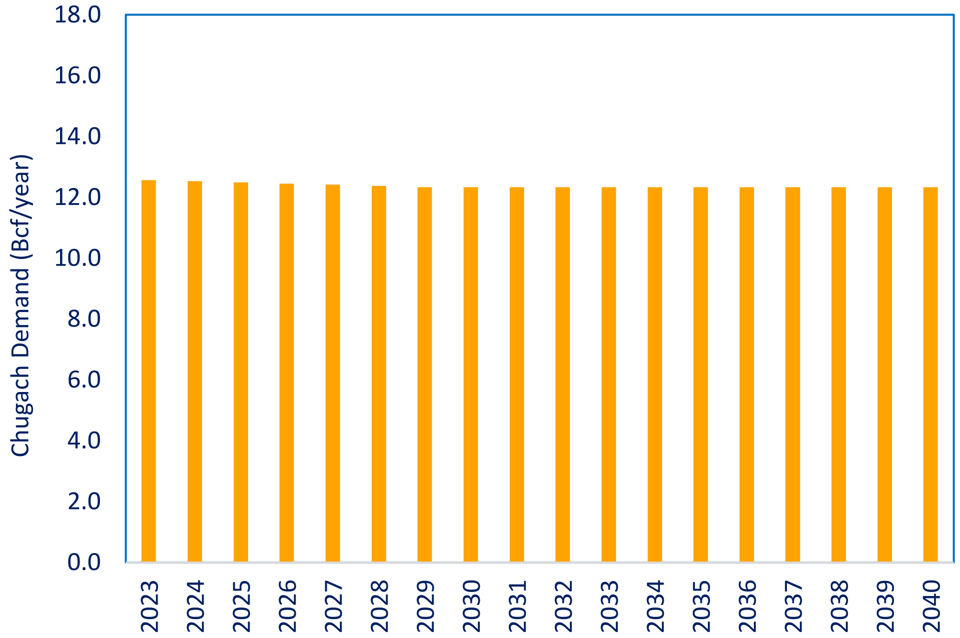
*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

Scenario 3: Gas supply gap initially starts from July 2027, which is expected to be offset by strategic planning of storage for excess BRU production through November 2029. The gas supply gap from November 2029 (after new renewables addition) is approximately 0.8 Bcf in 2029, increasing to 15.3 Bcf/year in 2040 due to load growth.

Chugach Demand and Supply – Scenario 4 (Small Gap)

Demand (1)

- Chugach base gas demand from historical demand
- No load growth from heat pumps or electrical vehicles



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract(2)	March 2032

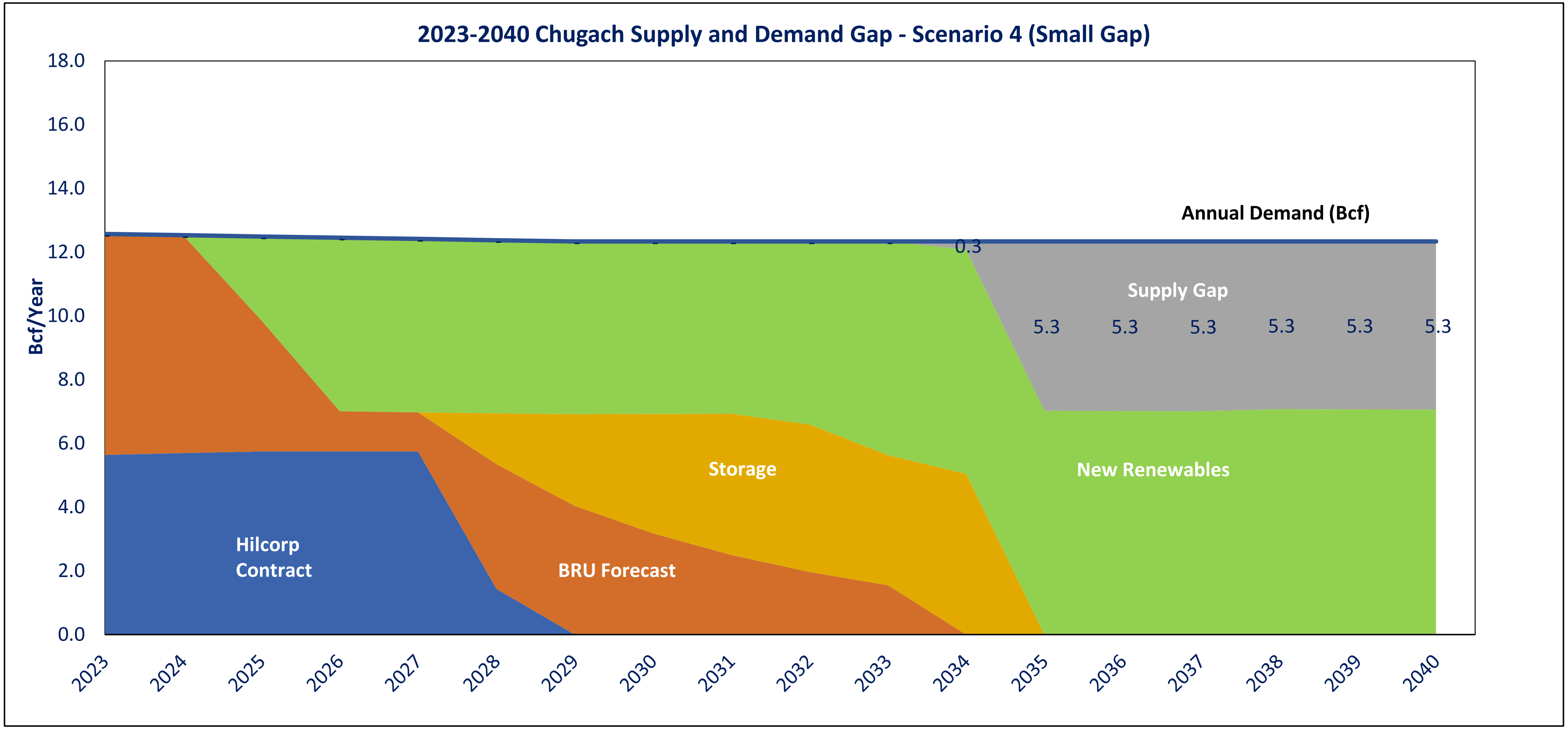
- New Renewables from 2025

Little Susitna	2025	415,000 MWh(4)
Great Land Solar	2025	194,000 MWh(4)
Godwin Creek	2032	125,000 MWh
Dixon Creek	2032	89,600 MWh
Battle Creek	2038	9,350 MWh

- Total by 2040: 832,950 MWh (approx. 6.4 Bcf/year equivalent(3))

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion
(4) Subject to power regulation limitations

Gas Supply Gap Annual Profile – Scenario 4 (Small Gap)



*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

Scenario 4: Gas supply gap initially starts from April 2028, which is expected to be offset by strategic planning of storage for excess BRU production through December 2034. The gas supply gap (after new renewables addition) is approximately 0.3 Bcf/year in 2034, increasing to approximately 5.3 Bcf/year in 2035.

Summary

Scenario	Start of Gas Supply Gap with Storage	Aggregate Supply Gap by 2040	Highest Annual Winter Seasonal Supply Gap (1)	Peak Daily Supply Gap (2)
Scenario 1 (Base Case)	January 2030	104.7 Bcf	4.4 Bcf/year	32.4 MMcf/d
Scenario 2 (Medium Gap)	April 2034	41.6 Bcf	2.5 Bcf/year	22.4 MMcf/d
Scenario 3 (Large Gap)	November 2029	144.2 Bcf	6.4 Bcf/year	44.5 MMcf/d
Scenario 4 (Small Gap)	December 2034	32.0 Bcf	2.0 Bcf/year	19.3 MMcf/d

(1) Highest annual winter seasonal supply gap: the highest of aggregate gaps for the months of January, February, March, November and December of a year from 2023 through 2040.

(2) Peak daily supply gap: the maximum of average daily supply gaps based on monthly demand profiles from 2023 through 2040.

- Alternative to fulfill gas supply gap is required by November 2027 (2 years ahead of earliest gas supply gap with storage) in order to ensure system fuel supply redundancy.

3| Gas Supply Option Assessment

Gas Supply Options

Cook Inlet Gas Production

- Cook Inlet onshore conv gas
- Cook Inlet offshore conv gas
- Lower cook Inlet offshore conv gas
- Coal Bed Methane

North Slope Gas

- Alaska LNG (42'' pipeline from North Slope to Nikiski)
- AK LNG (terminal accelerated)
- Alaska in-state Pipeline (Bullet line, 24'' to 36'' pipeline)
- Arctic Fox pipeline, 12'' pipeline from North Slope to Fairbank
- LNG Trucking or Truck/Rail/Pipe

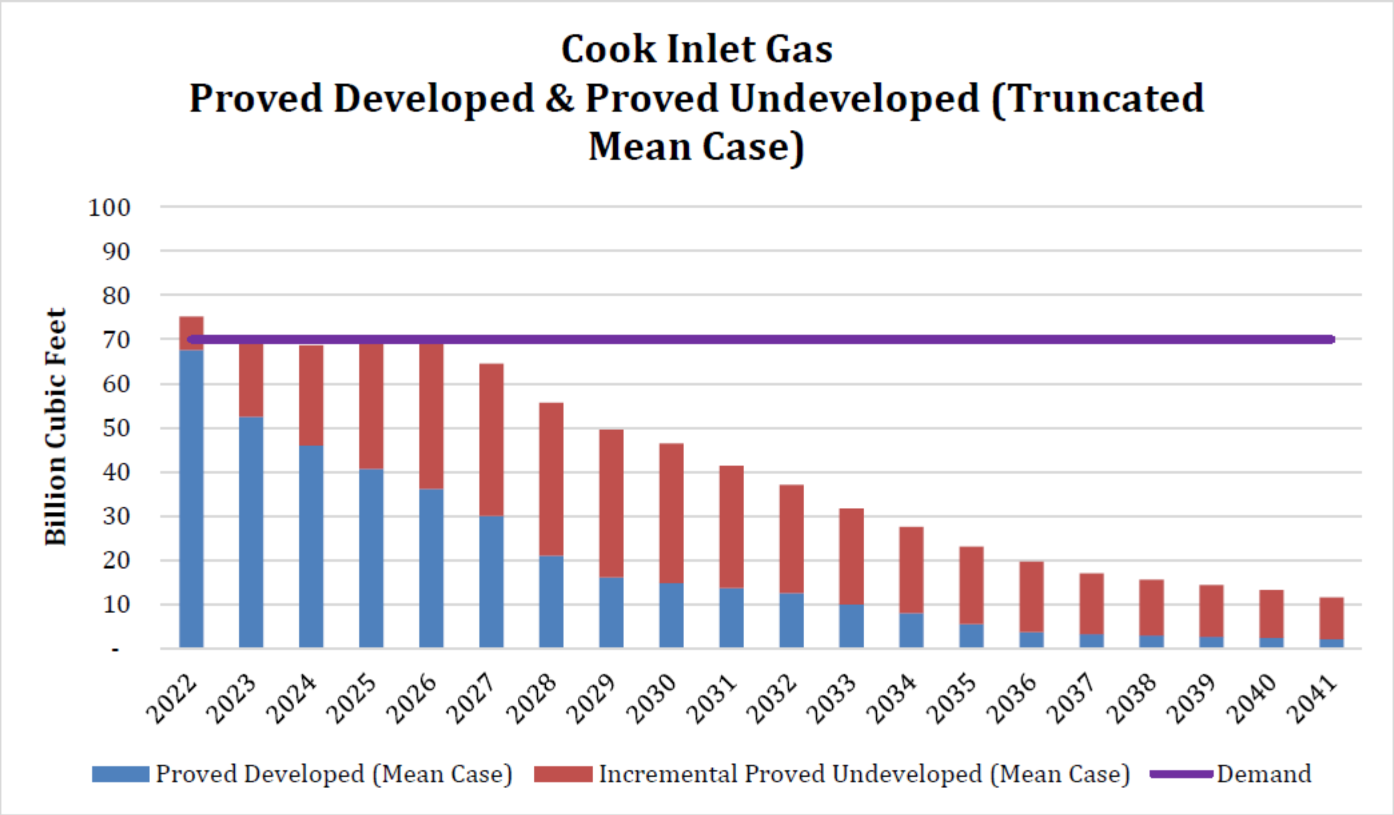
Global LNG Imports

- Grass Roots New Land-based Import Facility
- Nikiski LNG Export Facility Retrofit to Import Facility
- Chartered/Leased FSRU
- Retrofit FSRU
- New Built FSRU

Other Thermal Fuel Options

- Blue Hydrogen
- Blue Ammonia
- CNG
- Diesel

Cook Inlet Gas Production



Source: 2022 Cook Inlet Gas Forecast Report (Department of Natural Resources, January 2023)

- Cook Inlet gas production: The aggregate of proved developed and proved undeveloped Cook Inlet gas may potentially fail to meet the assumed demand profile from 2027 after the use of economic limitations.
- Unproved and potential reserves will likely be more expensive, limited volume, and take time to develop
- Coal bed methane resource: lack of economic production in Alaska
- Risks: Declining Cook Inlet gas production; Development constraints due to permits, leases or funding

North Slope Gas

	AK LNG	AK LNG (Terminal Accelerated)	Alaska in-state Pipeline	Arctic Fox Pipeline	LNG Trucking or Truck/Rail/Pipe
Assumptions	• 42'' pipeline from North Slope to Nikiski; • Developed and owned by third party	• Gas supply from global markets; • Developed and owned by third party	• 24'' to 36'' pipeline; • Gas supply from North Slope; • Developed and owned by third party	• 12'' pipeline from North Slope to Fairbank • Developed and owned by third party	• Gas supply from North Slope; • Liquefaction facility developed by Chugach • 11,000-13,000 gallons of LNG per Truck (1 Mcf)
Timeframe to Place into Service	8 to 10 years	5 to 6 years	8 years	2 to 3 years	2 to 3 years
Capital Cost	$39 billion (1) (2)	$1.5 to $2.0 billion (2)	$13 billion (2)	$716 to $1,002 million (2)	$55 million for 120,000-gallon facility
Annual Operating Cost (Non-fuel) (3)	Not appliable	Not appliable	Not appliable	Not appliable	$4.0 million
Cost of Supply	$6.5/Mcf (1)	Not specified	$11.5 to $14.5/Mcf (4)	$9.7/Mcf	$25 to 30/Mcf
Comments	Uncertainties in project development; Outside of Chugach control	Outside of Chugach control	Outside of Chugach control	Insufficient market	Frequent trucking (>50/day) is required to meet peak daily supply gap

Notes: (1) source: Alaska LNG Project Update dated October 27, 2022 (Alaska Gasline Development Corp.) (2) Assuming project developed by third parties. Costs represent total project costs. (3) not applicable for costs not directly borne by Chugach (4) source: AK Journal of Commerce 1/28/2015; would require subsidy to achieve such cost of supply.

Global LNG Import Facilities (15.3 BCF/Year Equivalent)

	Grass Roots New Land-based Import Facility	Nikiski LNG Export Facility Retrofit to Import Facility	Chartered/Leased FSRU	Retrofit FSRU	New Built FSRU
Assumptions	• New-built land-based LNG import terminal, one storage tank, and onshore regasification facility • Regasification capacity: Up to 500 MMscfd • Storage Capacity 4.0 Bcf	• Using existing Nikiski terminal • Onshore regasification expansion and floating storage • Regasification capacity: Up to 500 MMscfd • Storage Capacity 4.0 Bcf	• Using existing Nikiski terminal; • Chartered/Leased FSRU • Regasification capacity: Up to 500 MMscfd • Storage Capacity: 3.3-3.7 Bcf	• Converted FSRU and non-Nikiski terminal • Regasification capacity: Up to 500 MMscfd • Storage Capacity: 3.3-3.7 Bcf	• New built FSRU and non-Nikiski terminal • Regasification capacity: Up to 500 MMscfd • Storage Capacity: 3.3-3.7 Bcf
Timeframe to Place into Service	5 to 7 years	4 to 6 years	3 to 5 years	3 to 5 years	4 to 6 years
Capital Cost	$350 million to $450 million for regasification rate of 50 MMscfd	$150 million for regasification rate of 50 MMscfd	$60 million to $80 million; Annual chartered fee: $36 million Wheeling cost: $0.1/Mcf	$260 million to $280 million for regasification rate of 50 MMscfd	$345 million to $365 million for regasification rate of 50 MMscfd
Annual Operating Cost (Non-fuel)	$9 million	$9 million	$9 million	$9 million	$9 million
Cost of Supply	$12/Mcf to $13/Mcf	$12/Mcf	$12.6 to $12.7/Mcf	$11.3 to $11.4/Mcf	$12/Mcf
Comments	High initial investment; long planning and construction period; additional processing required from higher BTU content	Commercial arrangement with existing terminal owner is required; additional processing required from higher BTU content	Commercial arrangement with existing terminal owner is required; additional processing required from higher BTU content	Potential delay in permitting; additional processing required from higher BTU content	Relatively high upfront capex; potential delay in permitting; additional processing required from higher BTU content

Other Alternatives (15.3 BCF/Year Equivalent)

	Blue Hydrogen [1]	Blue Ammonia [1]	CNG	Diesel
Assumptions	• Steam methane reforming (SMR) technology + carbon capture utilization and storage (CCUS) • Export via pipeline • Natural gas feedstock: North Slope gas • H_2 production capacity: ~500 tons/day • Capacity factor: 70%	• SMR technology + CCUS for H2 production • Export via truck/railway • Natural gas feedstock: North Slope gas • NH_3 production capacity: ~3,000 tons/day • Capacity factor : 70%	• Compression, Chill Fill and Refrigeration • Loading to CNG Containers • Capacity: 800 MMscfd or 6 MTPA	• Sourced from west coast, lower 48; • Indexed cost; • Shipped to Anchorage
Timeframe to Place into Service	5-7 years	5-7 years	18 -24 Months	Not applicable
Capital Cost	$1,150 million	$1,400 million	$150 to $200 million	Not applicable
Annual Operating Cost (Non-Fuel)	$62 million	$69 million	$20-$30 million	Not applicable
Cost of Supply	$5 to $8/kg of H_2 ($39 to $62/Mcf equivalent)	$610/ton of NH_3 ($26/Mcf equivalent)	$7/Mcf +	$17 to $20/Mcf
Comments	High initial investment; Requires pipeline for hydrogen transportation	High initial investment; Relatively high cost for production and transportation	Difficult to scale	For peaking only; environmental risk

Note: (1) Capital and operating cost are based on assumed project size to meet annual demand of 15.3 Bcf/year

4| Global LNG Market Review

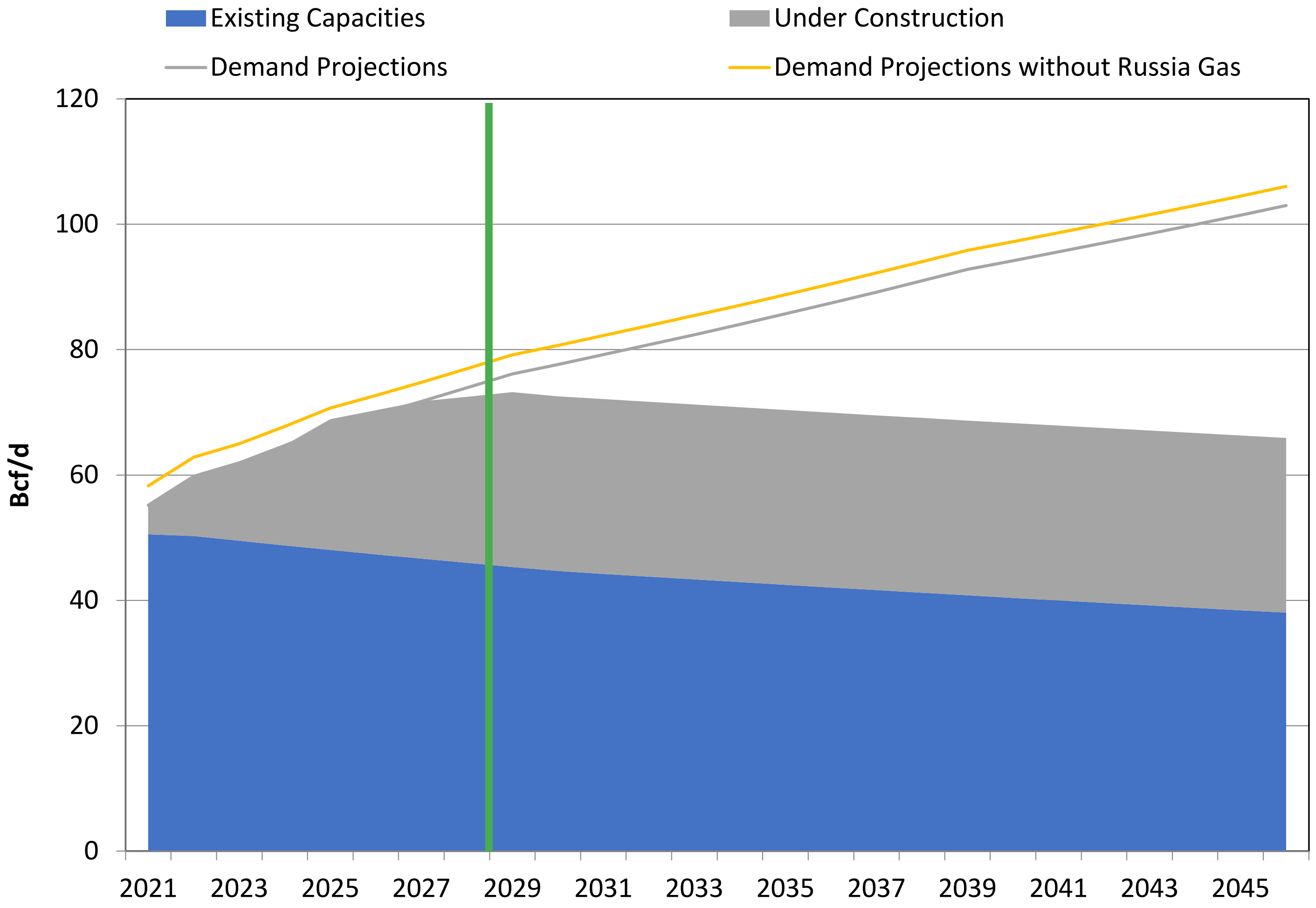
Observations – Global LNG Demand

- The near-term Russia/Ukraine conflict has impacted pipeline gas imports to Western Europe and created a near-term spike in LNG import demand
  - ~40% of EU gas consumption was from Russian supplies prior to the start of the conflict
  - Heavy reliance on LNG to replace Russian supplies, due to spare regasification capacity
  - Could make up 50% of the shortfall with LNG imports, and additional gas storage inventory
  - Other resources like renewables, nuclear, and biogas needed
  - No future gas supply contracts with Russian sources could signal a permanent shift in global gas demand
- Mid-term and Long-term growth in LNG demand expected as markets continue to decarbonize
  - Rate of decarbonization in Asia will be key. India and China have ambitious emissions targets and will need natural gas imports to replace coal generation
    - China plans to reduce coal generation from 66% of total generation in 2021 to 44% by 2030, and to 8% by 2060.
    - India plan to reduce coal generation from 75% of total generation to 32% by 2030.

Observations – Global LNG Prices/Economics

- Projected US/Canadian LNG Free-on-Board (FOB) Netback is expected to widen over the next 2-3 years due to the continued global shortfall of oil & gas production
  - Russia Ukraine conflict causing JKM to be priced at sustained discount to European Prices, while OPEC production cuts will further drive-up Brent Crude prices
  - European spot prices expected to remain above Asian LNG prices through 2023 due to decreasing domestic gas production in Europe and depleted gas storage inventory levels
- Mid-term to Long-term US/Canadian LNG netbacks expected to come down as the global demand and supply balance comes back to equilibrium
  - Average FOB Netback to Asian Markets: 2025-2030: $6.80/MMBtu, Asian LNG Price $13.21/MMBtu
  - Average FOB Netback to Asian Markets: 2031-2040: $3.44/MMBtu , Asian LNG Price $9.73/MMBtu
- US/Canadian LNG Netbacks supporting continued LNG liquefaction capacity development
  - Black & Veatch's EMP includes 13 US Gulf Coast LNG Terminal and 4 West Coast Canadian Terminals

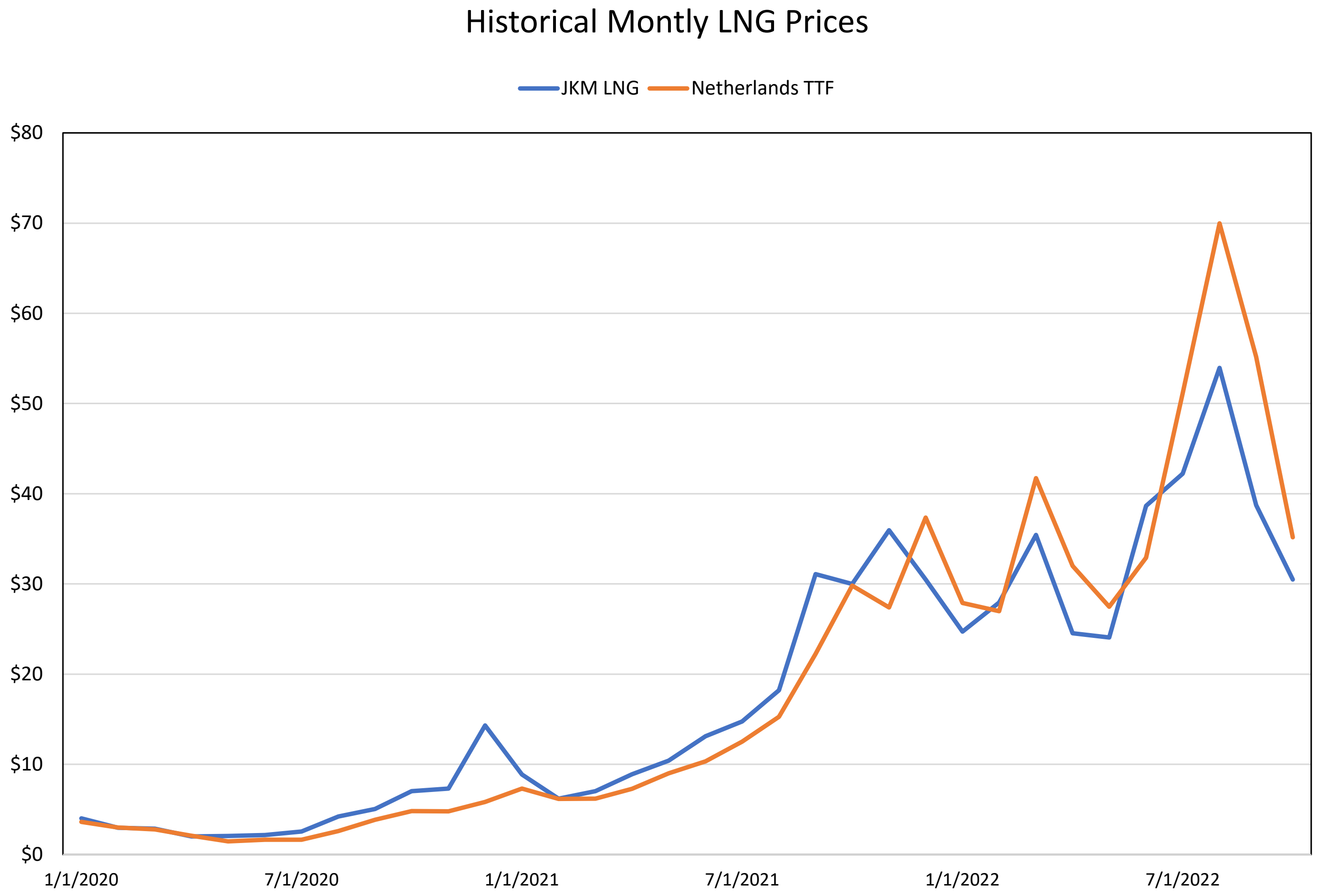
Projected Global LNG Demand/Supply Balance



- While net zero commitments and EU goals are important, Black & Veatch has not yet observed a slow down in contracting for long-term LNG supplies given the current market environment
- In 2021 approximately 78 Mtpa of LNG contracts were signed. The continued use of Henry Hub indexation was still commonplace.
- LNG terminal operators with spare/excess capacity have been able to monetize it at higher spot prices
- Potential Chugach LNG supplies may not have reached FID yet

Source: Black & Veatch EMP

Historical Monthly LNG Prices



- The SPA contract durations varied with some volumes (<8 MTPA at 5 years or less), and (25+ MTPA) for 15 years or longer
- More recent Gulf Coast LNG contracts are SPA deals indexed to Henry Hub plus fixed liquefaction charge
  - Departure from previous tolling structure
  - Recent gas customers are less interested in establishing gas trading operations/midstream companies to capture additional value
- Continued fall in Asian LNG prices in early 2023 back to sub $15/MMBtu

Key Observations – North American Gas Market Fundamental Trends

- Sufficient North American gas supplies exist to serve growing LNG export demand
    - Regional break-even costs have risen recently due to higher labor costs and upstream material shortages, however sufficient long-term supplies exist at $3.00-$4.00/MMBtu Henry Hub prices
    - Another 8-10 Bcf/d has reached FID and is under construction and will be placed into service over the next 3-4 years. By 2025, the US Gulf Coast will be close to ~33% of the global LNG market. In one decade (2016-2025), the US LNG export market has grown to providing one-third of the global LNG supply.
- On-going North American transition from natural gas will reduce traditional residential, commercial and power generation demand and allow for lower cost supplies to reach LNG export terminals
    - Over 10 Bcf/d of electrification will reduce winter and summer peak day loads
    - Seasonal gas seasonal gas price spreads are expected to narrow

BV Panorama Perspective of the North American Natural Gas Market

- Black & Veatch track and follow the major shale plays trends in drilling efficiency, well completion and cost
- Production projections by type – such as shale, coal bed methane, conventional and tight sands by basin

Upstream Gas Supply

- Black & Veatch follows all proposed infrastructure and permitting trends
- Analysis incorporates existing interstate, intrastate, and offshore gathering pipelines
- Includes natural gas storage fields with injection/withdrawal ratchets

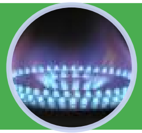
Midstream Infrastructure

- Black & Veatch examines the global LNG market to determine the competitiveness of North American LNG exports
- Mexican pipeline exports will pull gas supplies from U.S. markets to serve power generation loads

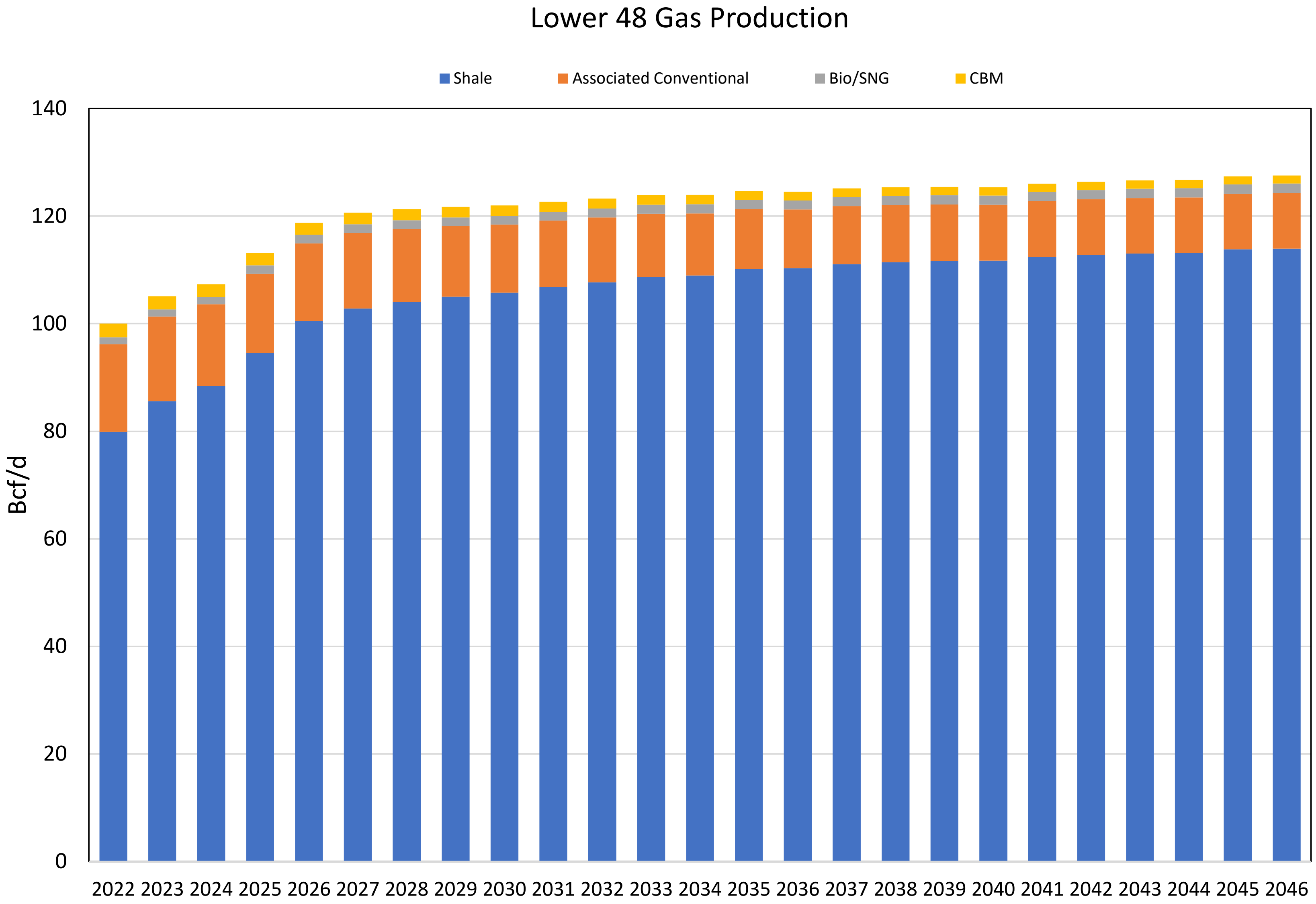
LNG & Pipeline Exports

- Black & Veatch projections gas demand by sector and by demand area – at the state and sub-state level
- Growth is tracked at state and gas utility level on a peak and design day conditions

Gas Demand



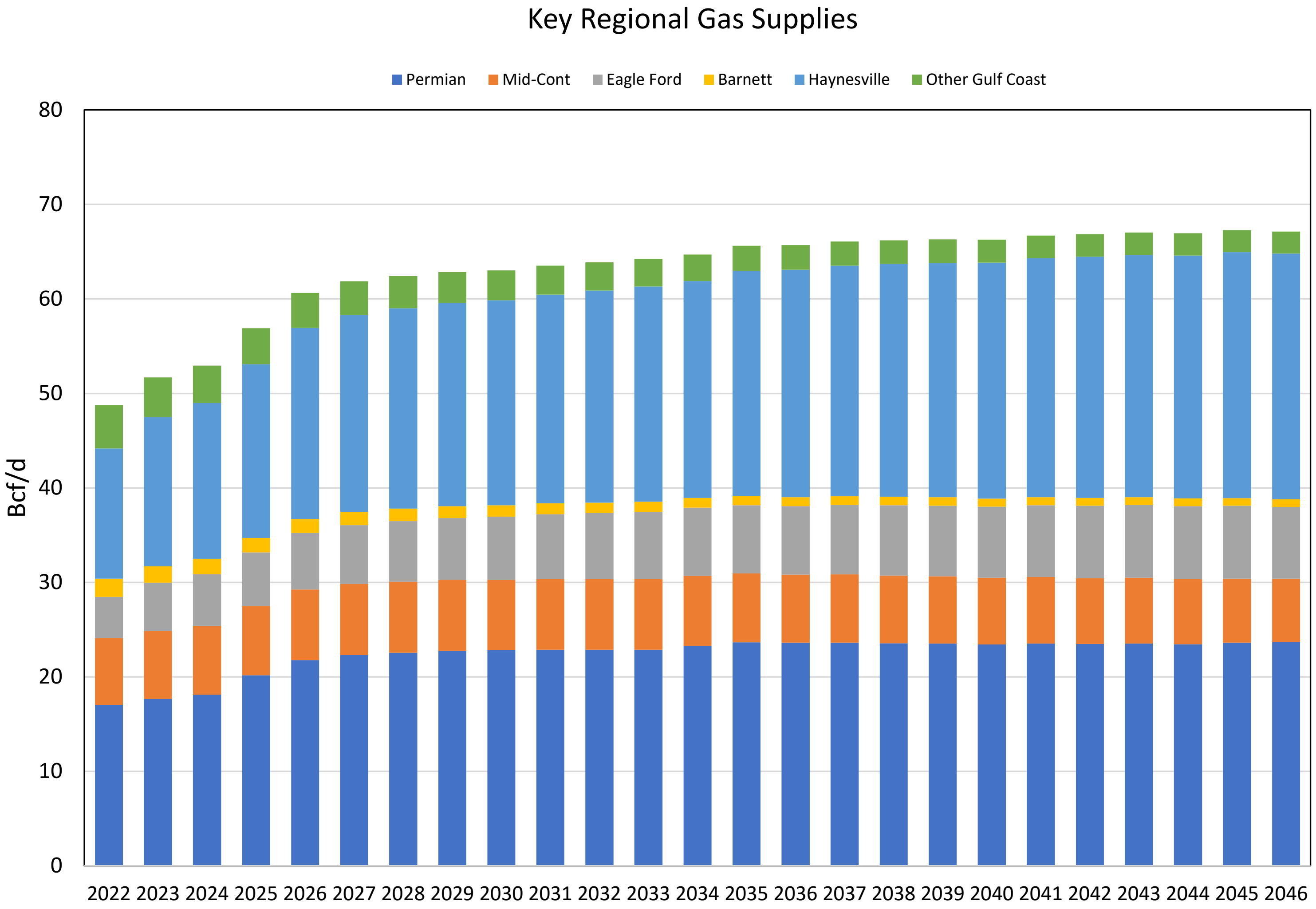
Lower 48 Production Expected to Reach 120 Bcf/d



- Black & Veatch remains bullish on Permian, Eagle Ford, Haynesville Basins in our near-term and long-term outlook
- Long-term challenges in long-haul pipeline build out may hinder the development of the Marcellus/Utica basin

Source: Black & Veatch EMP

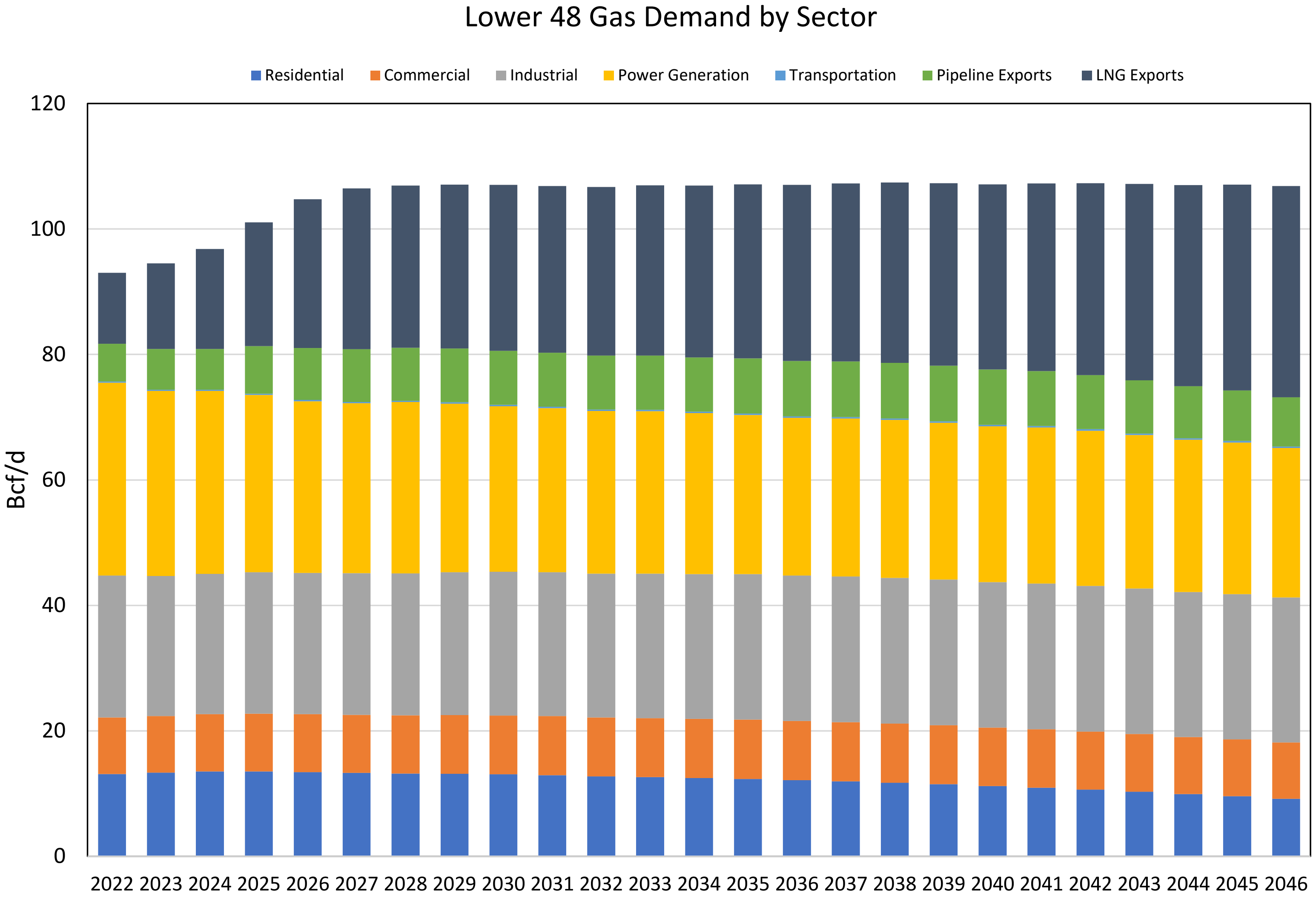
Gulf Coast Gas Production Supports Robust LNG Terminal Development



- Close to ~20+ Bcf/d of growth expected in the Gulf Coast (1.7% CAGR)
- Several Gulf Coast LNG terminals will have access to growth from the Permian, which will account for 35% of Gulf Coast supplies by 2046

Source: Black & Veatch EMP

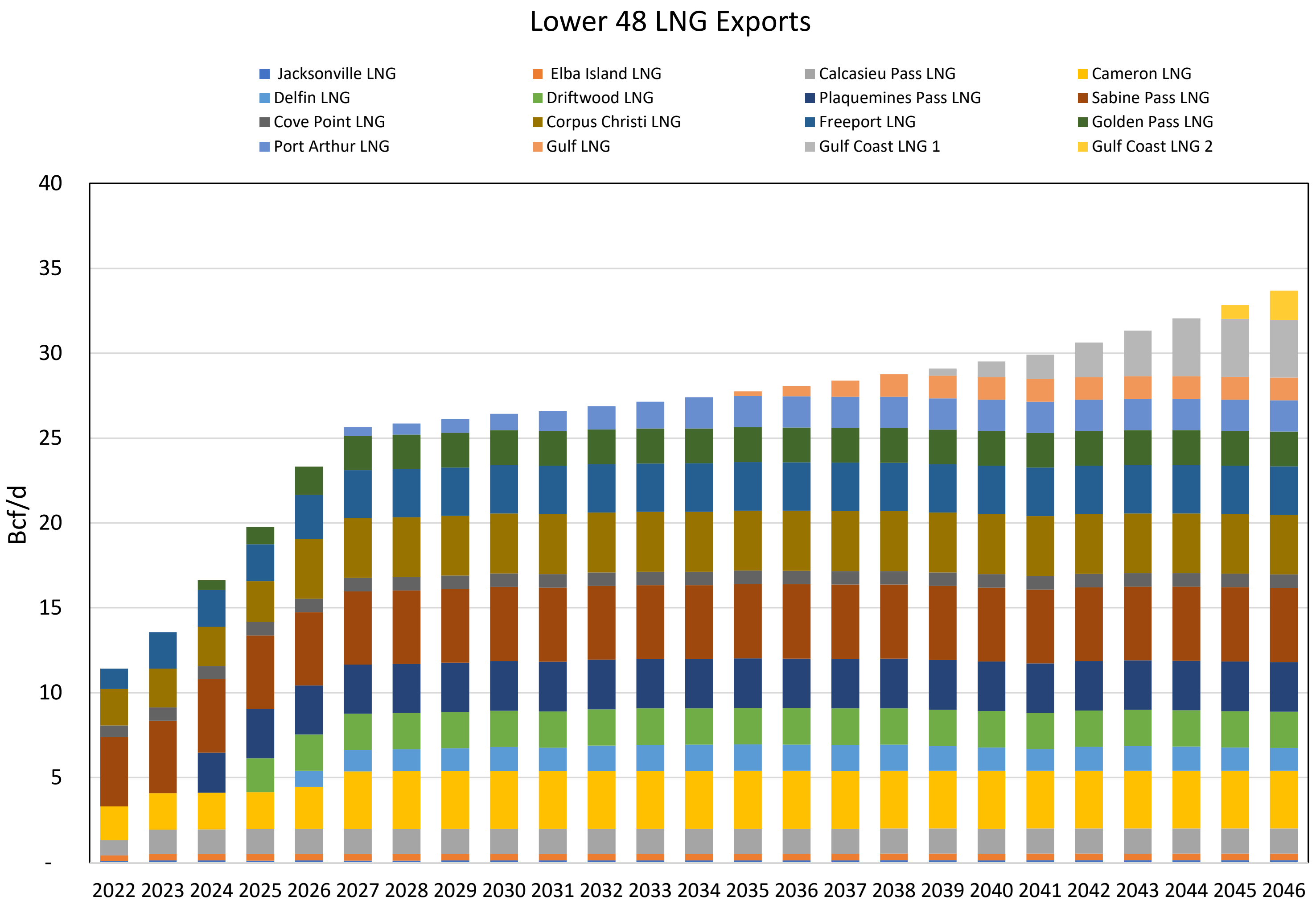
Lower 48 Gas Demand Projections By Sector



- Limited electric load growth and rising RPS targets will dampen near term demand projections in the power sector
- Traditional residential and commercial sector demand expected to decline with state decarbonization goals
- Near-term growth supported by LNG, pipeline exports and industrial demand

Source: Black & Veatch EMP

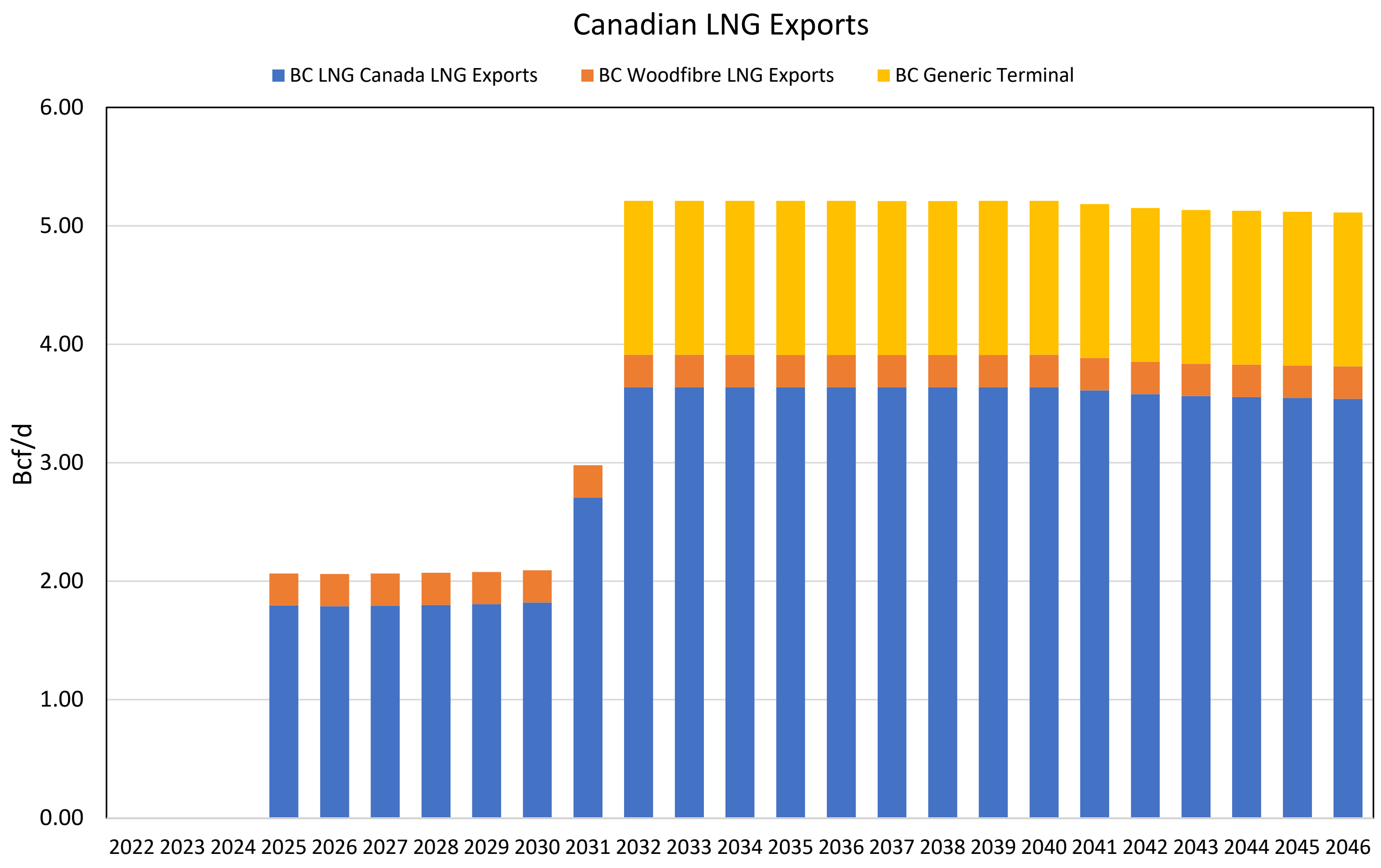
Lower 48 LNG Exports Reach 33 Bcf/d by 2046



- Black & Veatch projects 13 Gulf Coast LNG export terminal in operation by 2040
- Last 4 terminals projected have not reached FID (Generic Gulf Coast LNG)
- By 2025, the US Gulf Coast will be close to ~20% of the global LNG market

Source: Black & Veatch EMP

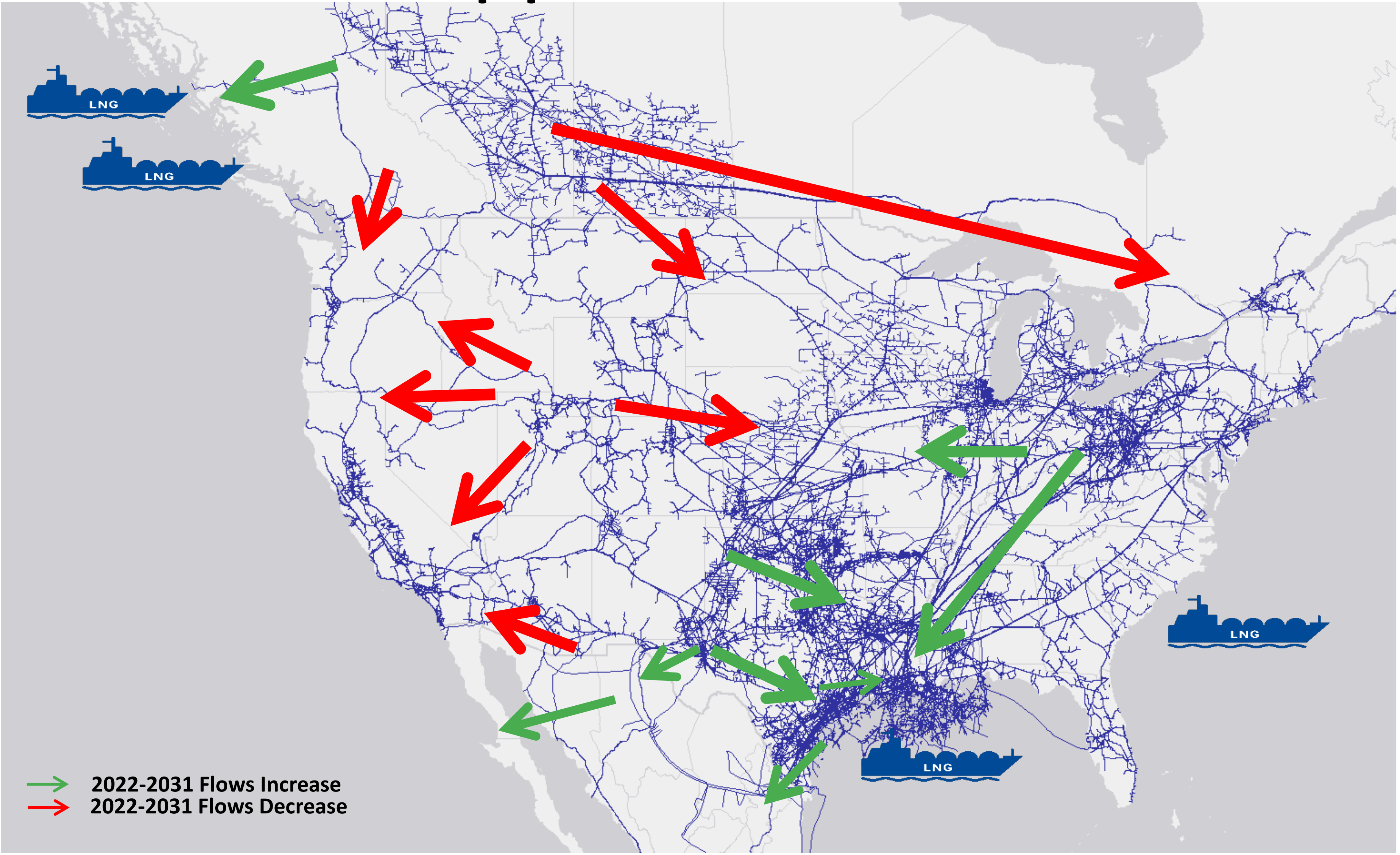
Canadian LNG Exports Reach 5 Bcf/d by 2032



- Black & Veatch projects 3 BC LNG export terminals in operation by 2032
- Sufficient WCSB production exits to provide up to 6-10 Bcf/d of feed gas

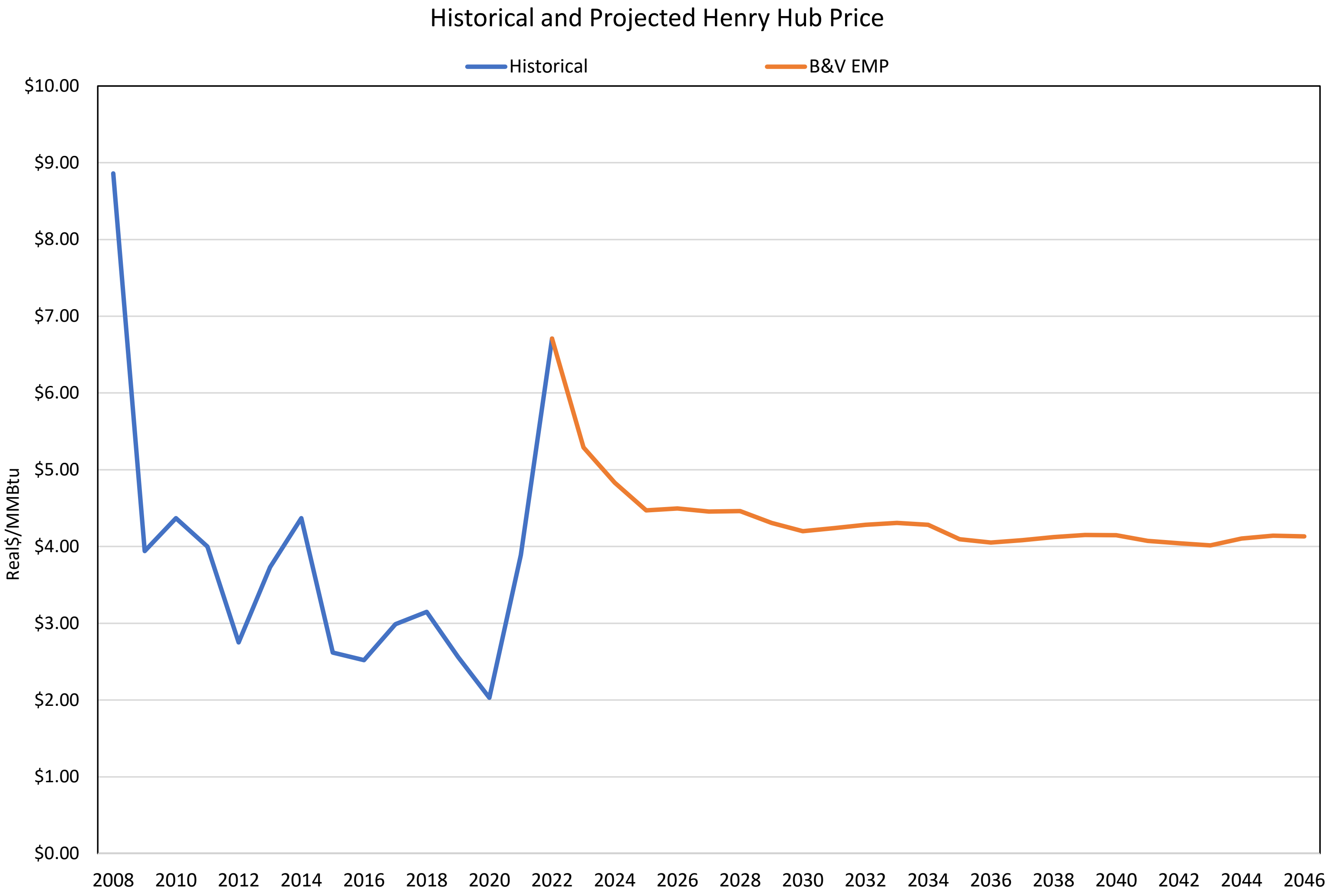
Source: Black & Veatch EMP

Gas demand growth drives pipeline flow directions and investment decisions for pipelines



Source: Black & Veatch EMP

Projected Henry Hub Price

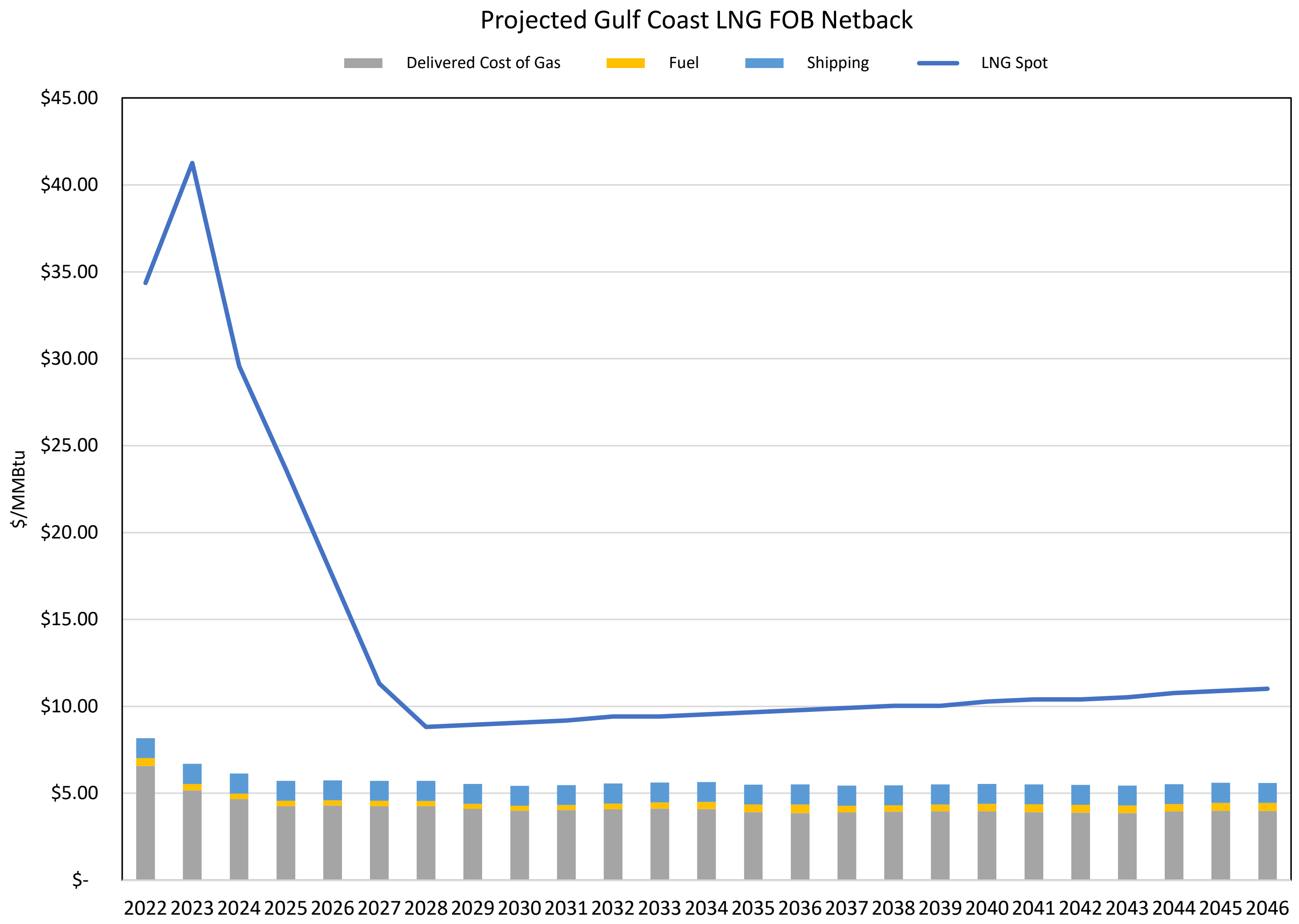


- Near-term Henry Hub price expected to remain elevated due to limited production growth and low storage inventory levels

- Mid-term prices expected to remain at $4.00/MMBtu levels due to higher labor and materials costs associated with production

Source: Black & Veatch EMP

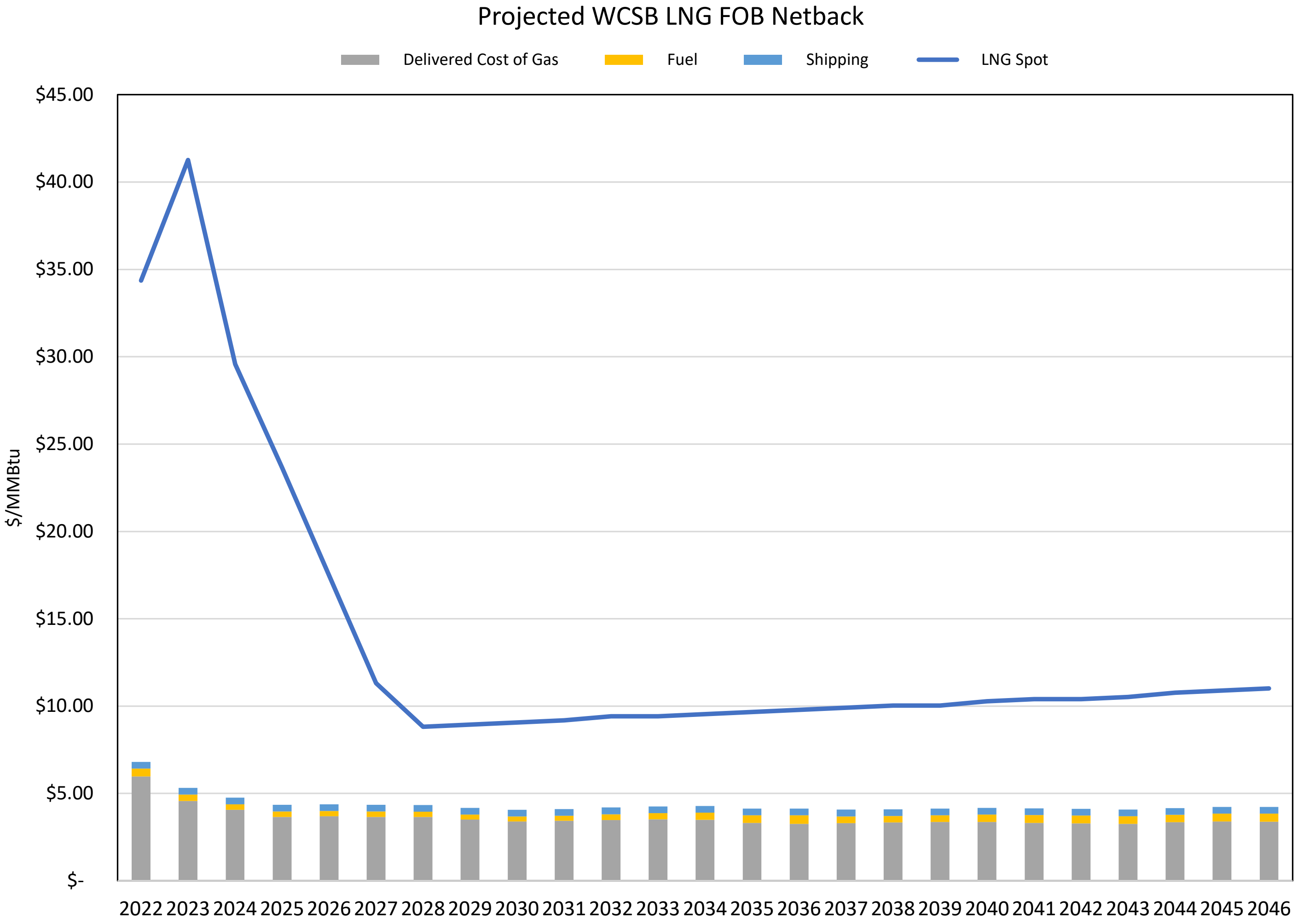
Gulf Coast LNG FOB Netback Price Projection



- LNG Spot price is based on near-term forwards over the next 4 years
- Mid-term and Long-term LNG spot prices and Delivered Cost of Gas prices based on Black & Veatch's Energy Market Perspective
- Delivered LNG Costs from Gulf Coast in 2030 is ~$9.00/MMBtu

Source: Black & Veatch EMP

WCSB LNG FOB Netback Price Projection



- WCSB delivered LNG supplies can be a lower cost alternative due to lower shipping costs
- Delivered LNG Costs from WCSB in 2030 is ~$8.00/MMBtu

5| High Level Technical Characteristics of the LNG Facility

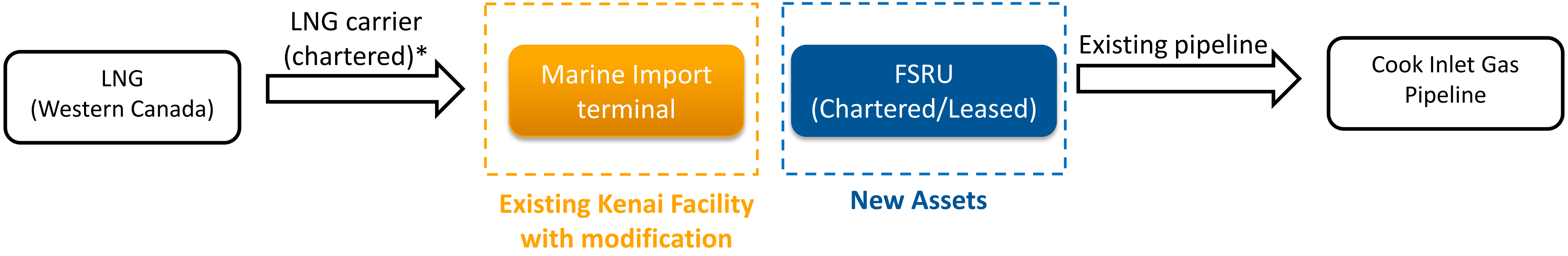
Option 1: Nikiski Retrofit and Chartered/Leased FSRU

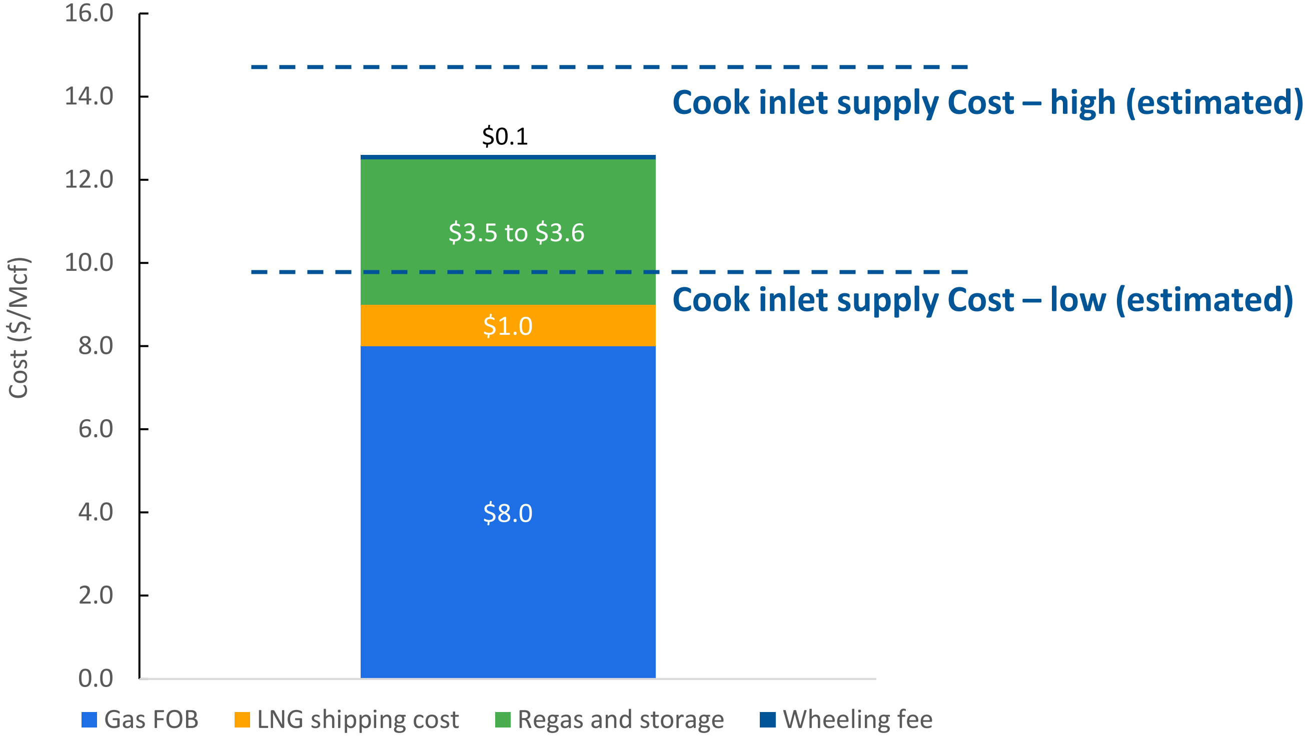
- **Assumptions:**
  - Gas supply: imported LNG from Western Canada
  - LNG transport via a typical size LNG carrier (3.5 Bcf to 4 Bcf/trip)
  - LNG import terminal: existing Kenai terminal and associated upgrades.
  - Regasification and storage with permanently moored FSRU: charted FSRU with a regasification capacity up to 400 MMscf and a storage capacity of 3.5 Bcf.

Cost estimates are an order of magnitude estimate based on Black & Veatch's project experience.

FSRU size in the image: LNG storage capacity of 150,900 m^3 (appx.3.4 Bcf); length of 291 m and a design draft of 11m

Nikiski Retrofit and Chartered/Leased FSRU - Cost of Supply





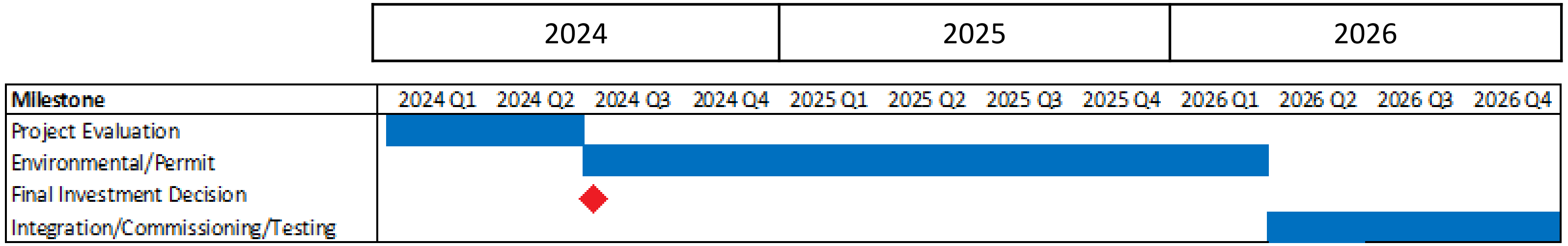
- Estimated cost of supply for LNG sourced from Western Canada to Cook Inlet gas pipeline is approximately $13/Mcf, competitive to Cook Inlet Supply

*see Appendix C for LNG carrier size

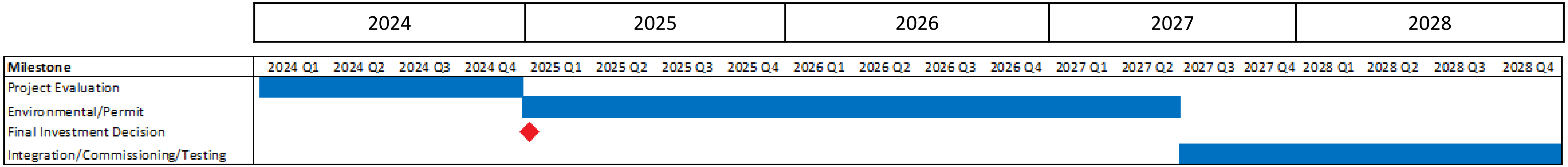
Nikiski Retrofit and Chartered/Leased FSRU - Indicative Implementation Schedule

In-service by Q1 2027 the earliest (3 to 5 years)

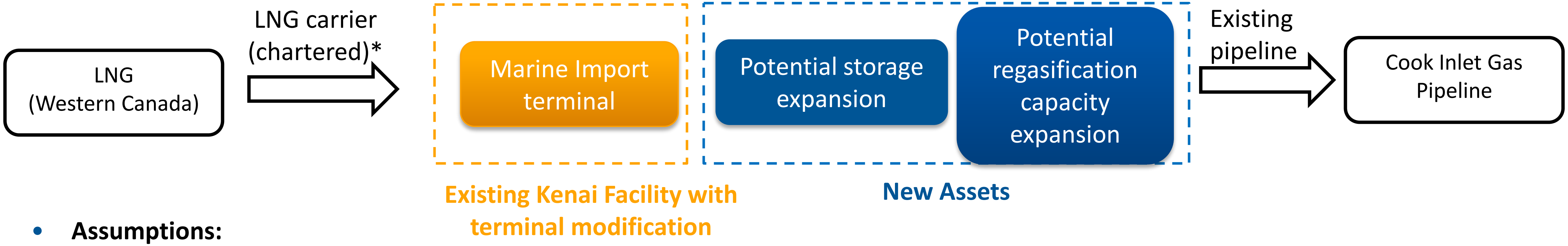
Earliest



Delayed



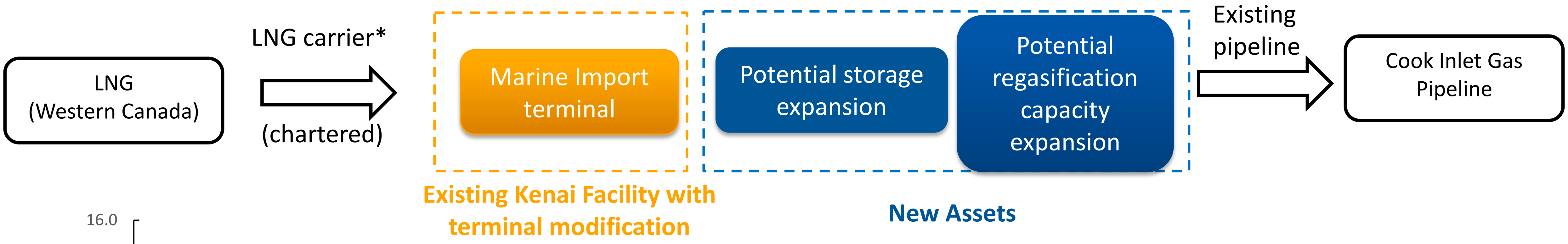
Nikiski Retrofit and Onshore Expansion – Cost Estimate

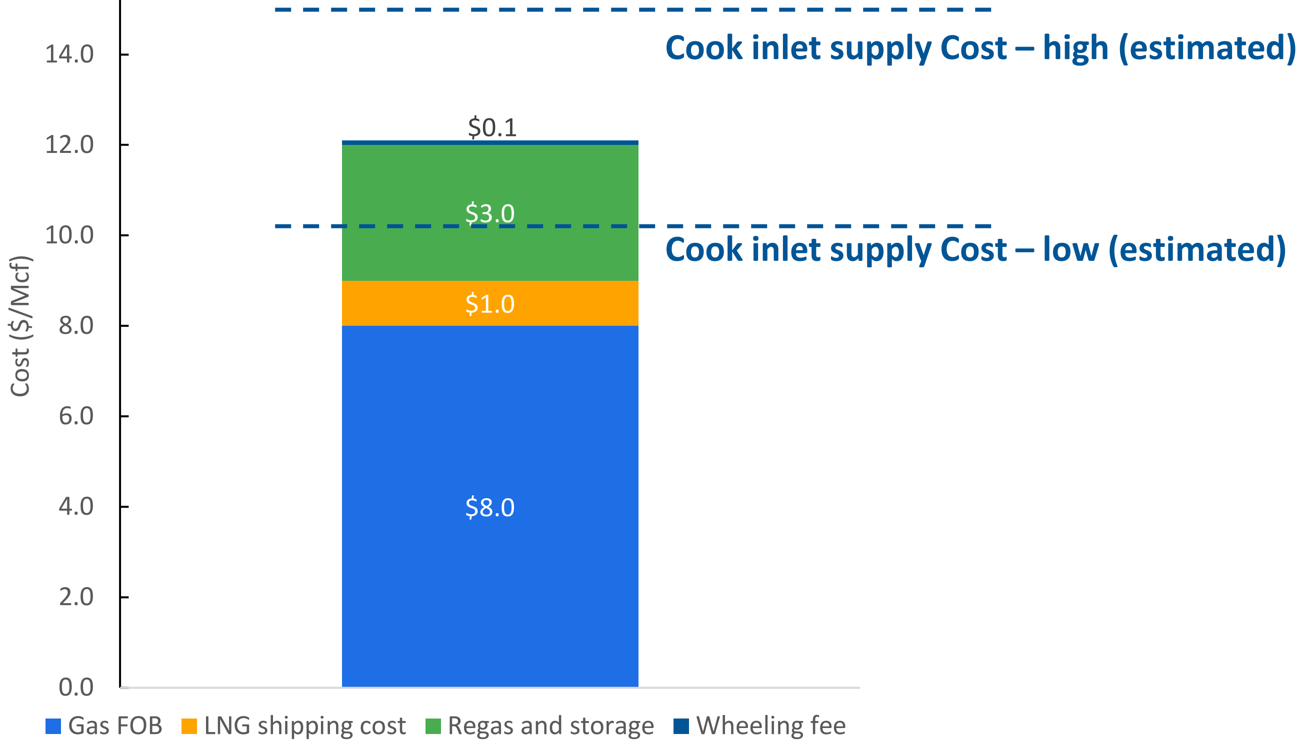


- **Assumptions:**
  - Regasification facility: peak sendout of 50 MMscf/d
  - Storage: lease floating storage unit (FSU), capacity of 4.5 Bcf
  - Conventional LNG carrier (174,000m^3 or 3.8 Bcf): up to 5 cargos/year for the maximum supply gap of 15.3 Bcf
  - Small-scale LNG carrier (20,000 m^3 or 0.4 Bcf): up to 42 cargos/year for the maximum supply gap of 15.3 Bcf
- **Capital cost:**
  - $150 million assuming a leased FSU (rental fee as part of operating costs) is required;
  - Assuming that the existing Kenai terminal can be converted into an LNG import terminal. Cost estimate includes boil-off gas (BOG) compression, vaporizers, related equipment (pumps, utilities, etc.), mechanical/E&I bulks, all construction, and owner's cost. Contingency was not included. Cost estimates are an order of magnitude estimate based on Black & Veatch's project experience.

*see Appendix C for LNG carrier size

Option 2: Nikiski Retrofit and Onshore Expansion – Cost of Supply





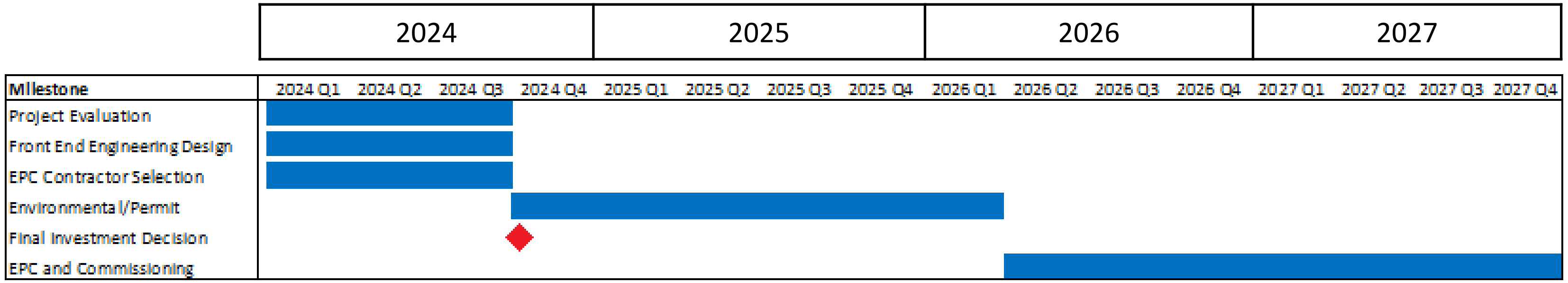
- Estimated cost of supply for LNG sourced from Western Canada to Cook Inlet gas pipeline is approximately $12/Mcf, competitive to Cook Inlet Supply

*see Appendix C for LNG carrier size

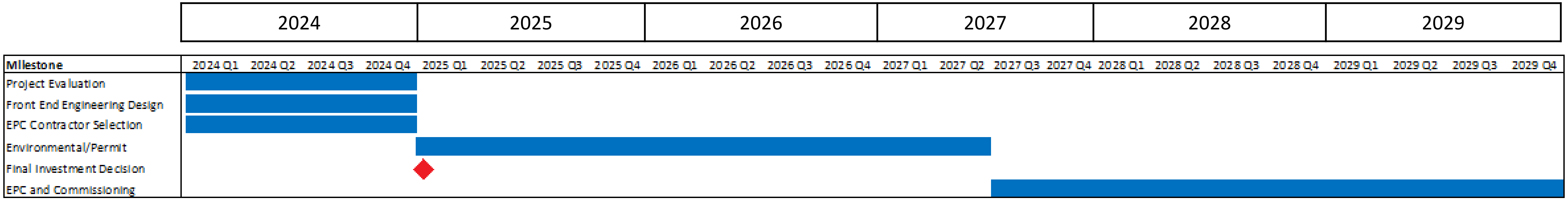
Nikiski Retrofit – Indicative Implementation Schedule

In-service by Q1 2028 the earliest (4 to 6 years)

Earliest



Delayed

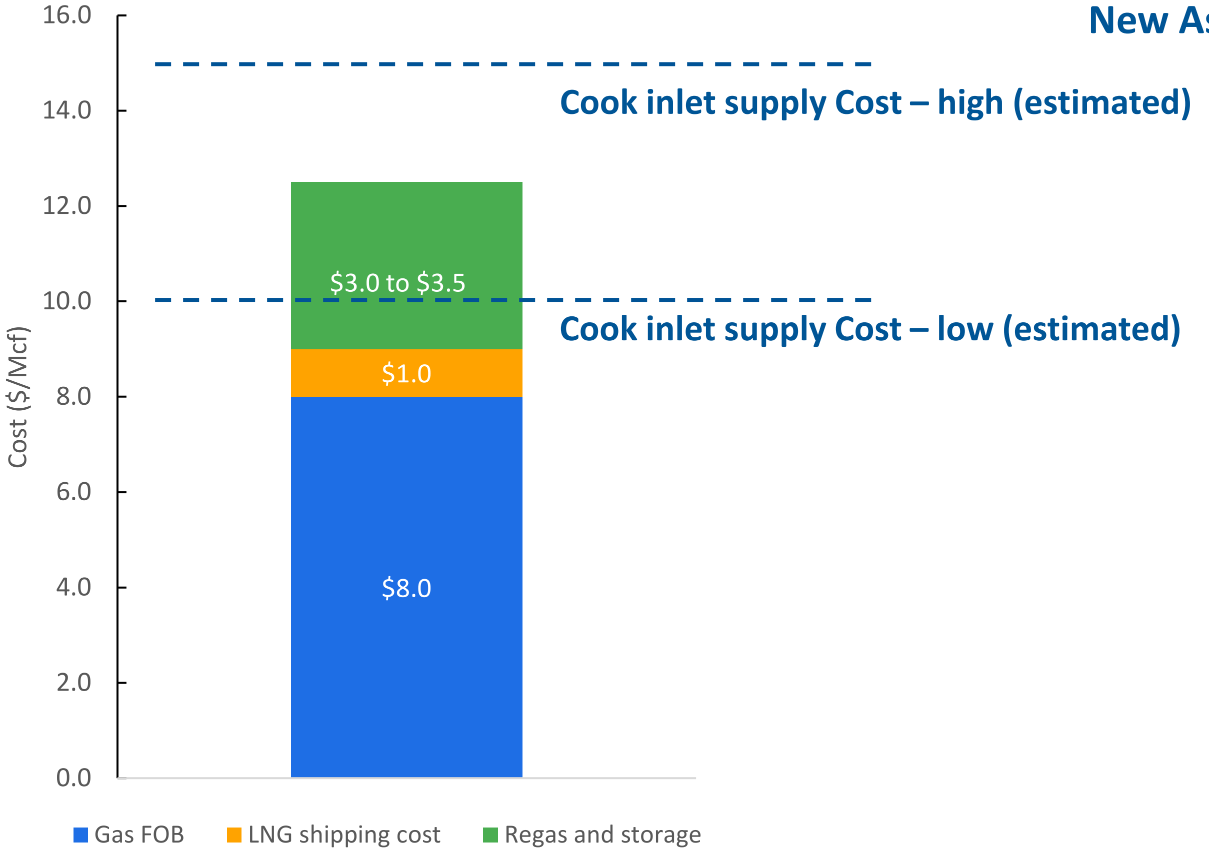


Option 3: New Built LNG Import Terminal – Cost Estimate

- **Assumptions:**
  - Regasification facility: peak sendout of 50 MMscf/d
  - Storage: one full containment tank (smaller footprint) or one single containment tank (larger footprint)
  - Conventional LNG carrier (174,000m^3 or 3.8 Bcf): up to 5 cargos/year for the maximum supply gap of 15.3 Bcf
- **Capital cost:**
  - \$350 million (using single containment tank) to \$450 million (using full containment tank)
  - Cost estimate for LNG import facility includes boil-off gas (BOG) compression, vaporizers, related equipment (pumps, utilities, etc.), mechanical/E&I bulks, short jetty and in-water work (no dredging), all construction, and owner's cost. Contingency was not included. Cost estimates are an order of magnitude estimate based on Black & Veatch's project experience.

*see Appendix C for LNG carrier size

New Built LNG Import Terminal – Cost of Supply



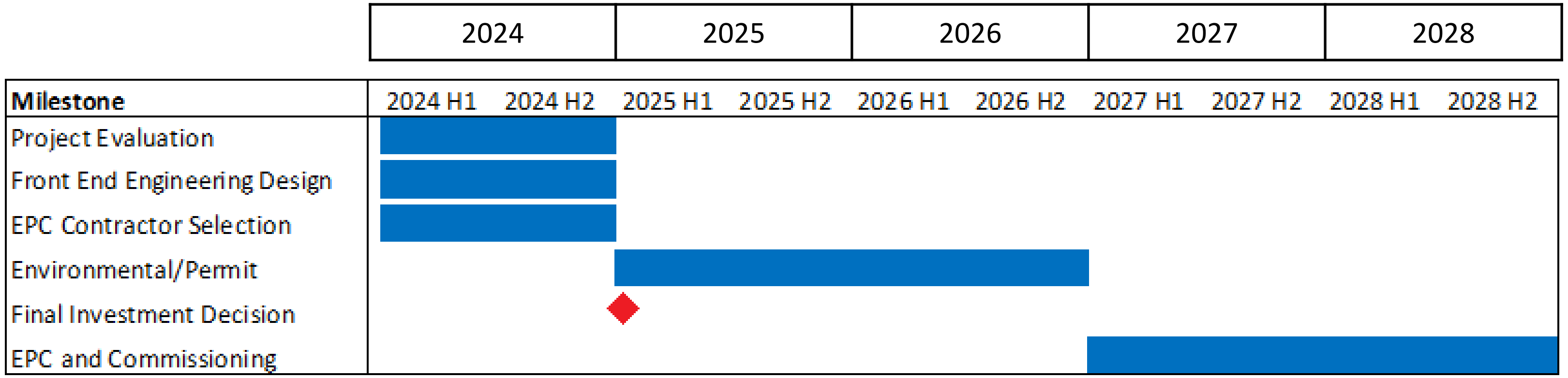
- Estimated cost of supply for LNG sourced from Western Canada to Cook Inlet gas pipeline is approximately $12 to $13/Mcf, competitive to Cook Inlet Supply

*see Appendix C for LNG carrier size

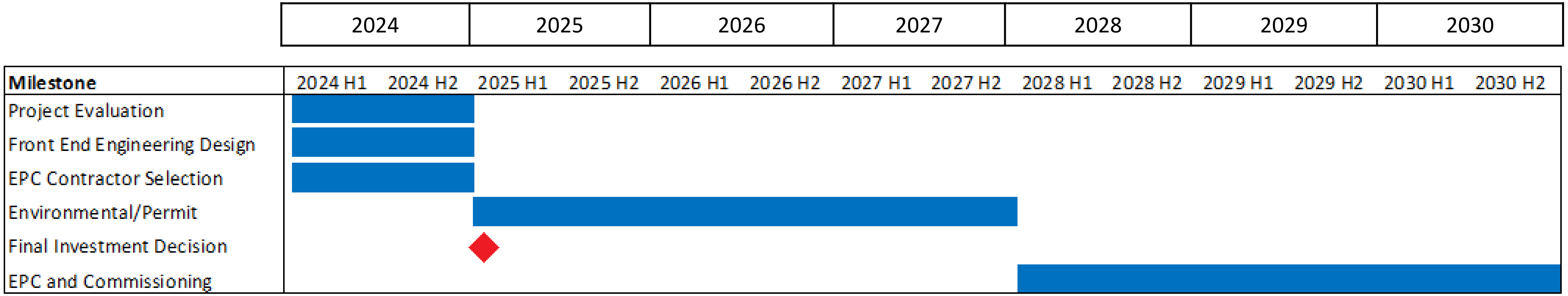
New Built LNG Import Terminal– Indicative Implementation Schedule

Operation by half year 2029 the earliest (5 to 7 years)

Earliest



Delayed



Next Steps

Next Steps BV

Phase 2:

- Research on FSRU charters
- LNG supply review
- LNG gas storage review
- FSRU Cook Inlet docking facilities review
- FSRU piping and processing requirements
- Other FSRU docking options
- Chartered/leased FSRU gas cost estimate
- Chartered/leased FSRU project schedule
- Project Stakeholders and risk assessment

Project Phase: Best option execution

Appendix

Appendix A – Option Assessment

Blue Hydrogen Option - Assumptions

- North Slope conversion
  - Steam methane reforming (SMR) technology + carbon capture utilization and storage (CCUS)
  - Export via pipeline for blue hydrogen: 800 miles from North Slope
- Facility technical characteristics
  - H2 production capacity: ~460 tons/day (for demand of 15.3 Bcf/year at 70% capacity factor)
  - Capacity factor: 70% for H2 production
  - SMR on-line: 2031
- Fuel cost: $3.0/mmbtu
- Alaska cost adder: 25% for project capital cost
- Levelized hydrogen pipeline cost: assuming 18’’ pipeline, $3.5 to $6.0/kg of H2

Blue Ammonia Option - Assumptions

- North Slope conversion
  - SMR technology + CCUS
  - Export via railway/trucking for blue ammonia: 800 miles from North Slope
- Facility technical characteristics
  - Ammonia production capacity: 2,857 tons per day (for demand of 15.3 Bcf/year at 70% capacity factor for H2 production and 97% for ammonia facility)
  - SMR on-line: 2031
- Fuel cost: $3.0/mmbtu
- Alaska cost adder: 25% for project capital cost
- Transportation:
  - Trucking miles: $0.5/mile-short ton
  - Rail miles: $0.2/mile-short ton

Coal - Assumptions

- Remaining coal fired power plants in Alaska are interior based locations served by a single coal producer and are either scheduled to retired or being investigated to be retired and replaced with natural gas and/or imported electricity from the Railbelt grid.
- Permitting for new coal fired power plants and regulations for siting, emissions, and ash disposal has become more time consuming and uncertain.
- Clean Coal (emissions scrubbing and carbon sequestration) has proven technically difficult and expensive.
- There is currently only one major producer of coal in Alaska so little competition on fuel price, permitting and funding for new Alaskan coal mines would be time consuming and uncertain.
- As of September 2021, developers have not reported plans to install any new utility-scale coal-fired power plants in the United States. Source: U.S. Energy Information Administration December 15, 2021
- Not competitive with other energy options for Cook Inlet.

Arctic LNG (Qilak) - Assumptions

- Arctic offshore liquified natural gas export terminal with ice breaking LNG tankers
- To compete with PAO Novatek Yamal facility in Russia for Asian demand
- Developer is Dubai based Lloyds Energy
- Heads of Agreement signed 2019 with ExxonMobil affiliate for Pt. Thomson supply
- 250 Bcf/yr project capacity increments
- $25/mscf capital expenditures
- $5Bn (2023) CAPEX phase 1
- Source: NaturalGasIntel March 22, 2023
- Cook Inlet not targeted market, not competitive with other global sources of LNG available to Cook Inlet.

Appendix B – LNG Market Assessment

Existing LNG Projects in Canada and Gulf of Mexico

Project Name	Location	Capacity (Bcfd)	Terminal
Freeport LNG	Freeport, TX	2.38 (Export), 1.5 (Import)	Export, Import
Southern LNG	Elba Island, GA	0.35 (Export), 1.6 (Import)	Export, Import
Cameron LNG	Hackberry, LA	2.15 (Export), 1.8 (Import)	Export, Import
Calcasieu Pass	Cameron Parish, LA	1.11 (Export), 1.31 (Import)	Export, Import
Sabine Pass LNG	Sabine Pass, LA	4.55	Export
Corpus Christi LNG	Corpus Christi, TX	2.4	Export
Kenai LNG	Kenai, AK	0.2	Export
Golden Pass LNG (Phases 1 & 2)	Sabine, Tx	4	Import
Lake Charles LNG	Lake Charles, LA	2.1	Import
Gulf LNG Energy	Pascagoula, MS	1.5	Import
Canaport LNG	Saint John, NB (CA)	1	Import
Energia Costa Azul	Baja California, MX	1	Import
Altamira LNG	Altamira, Tamulipas (MX)	0.7	Import
KMS GNL De Manzanillo	Manzanillo, MX	0.5	Import

Proposed LNG Projects in Canada and Gulf of Mexico

Project Name	Location	Capacity (Bcfd)	Expected COD	Status	Terminal
Calcasieu Pass*	Cameron Parish, LA	0.55	Q3 2023	Under Construction	Export
Plaquemines LNG	Plaquemines Parish, LA	3.4	2024	Under Construction	Export
Golden Pass LNG Phase 3*	Sabine, TX	2.57	2024	Under Construction	Export
Corpus Christi LNG Stage 3	Corpus Christi Bay, TX	1.58	2024	Under Construction	Export
LNG Canada	Kitimat, BC (Canada)	1.70	Phase 1: 2025	Under Construction	Export
Texas LNG	Brownsville, TX	0.55	2025	Proposed	Export
CP2 LNG	Cameron Parish, LA	3.96	2025	Proposed	Export
Driftwood LNG	Calcasieu Parish, LA	3.81	2026	Under Construction	Export
Rio Grande LNG	Brownsville, TX	3.6	2026	Proposed	Export
Delfin LNG	Cameron Parish, LA	1.8	2026	Proposed	Export
Magnolia LNG	Lake Charles, LA	1.19	2026 – Operational	Proposed	Export
Cameron LNG	Hackberry, LA	1.86	2023 – FID 2026 – Operational	Proposed	Export
Eagle LNG	Jacksonville, FL	0.13	2026 - Operational	Proposed	Export
Gulf LNG Energy*	Pascagoula, MS	1.5	[TBD]	Proposed	Export
Commonwealth LNG	Cameron Parish, LA	1.21	2027	Proposed	Export
Lake Charles LNG*	Lake Charles, LA	2.27	2023 – FID 2028 – Operational	Proposed	Export
Freeport LNG*	Freeport, TX	0.74	2028 – Operational	Proposed	Export
Woodfibre LNG	Squamish, BC (Canada)	0.28	2027	Proposed	Import

Note: “FID” Final Investment Decision; “Operational” is the year the facility must be operating as assigned by the regulators.
*Proposed Project is an expansion or modification of an existing facility

Appendix C – High Level Technical Characteristics of the LNG Facility

LNG Carrier Size Illustration

Small-scale LNG Carrier

525 feet

Capacity: 20,000 m^3 (0.4 Bcf)

Conventional LNG Carrier

975feet

Capacity: 174,000 m^3 (3.8 Bcf)

Q-max

1,132 feet

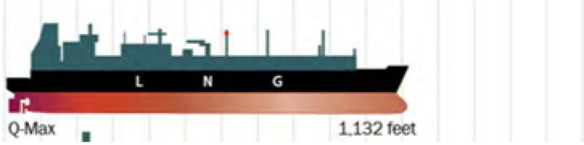
Capacity: 266,000 m^3 (5.8 Bcf)

LNG Shipping Options

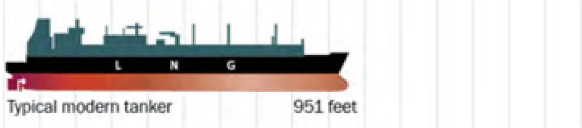
LNG Liquid Tankers

Conventional LNG Tankers

Ship Capacity



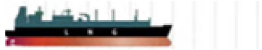
5.5 bcf



3.5 bcf

Cook Inlet Class

2.5 bcf



Small-scale LNG carrier 525 ft

0.4 bcf

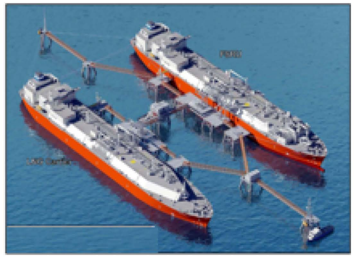
LNG Bunker Barge up to 416 feet
smaller vessels are barges towed by tugs

0.2 bcf
0.02 bcf

FSRU Options

Large FSRU-LNG Carrier

Ship Capacity



3.4 bcf

small scale FSRU

1.0 bcf
0.1 bcf

Floating storage plus onboard regasification
smaller vessels are barges towed by tugs

Cook Inlet LNG Import Options

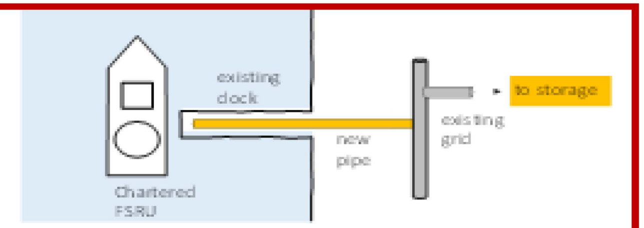
Configurations and indicative metrics

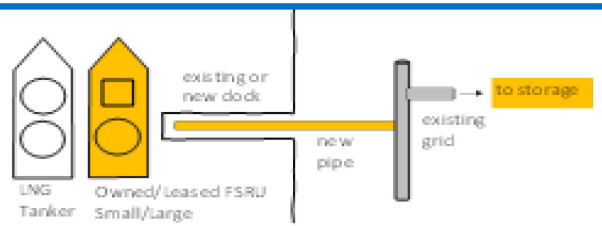
BRG size 55 Bcf/y
BV size 15.3 Bcf/y

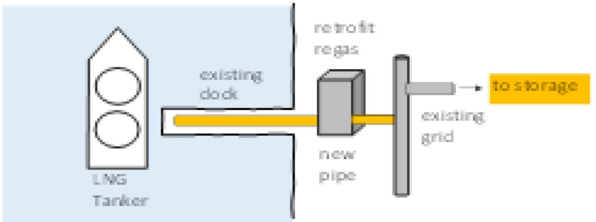
Phase 2 Scope
BRG
BV

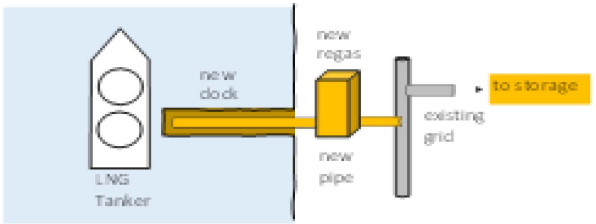
New kit required

	Size Bcf/y	Capital $MM	Years	Cost of Gas $/mcf Feedstock	Cost of Gas $/mcf Midstream	Cost of Gas $/mcf Total
Chartered FSRU	55	201	4 - 6	8.6 - 8.9	3.6 - 5.0	12.2 - 13.9
	15.3	60 - 80	3 - 5	8.0	4.6 - 4.7	12.6 - 12.7
Owned FSRU	55	607	4 - 6	8.6 - 8.9	3.6 - 5.0	12.2 - 13.9
	15.3	345 - 365	4 - 6	8.0	4.0	12.0
Kenai Retrofit	55	768	4 - 5	8.6 - 8.9	3.4 - 4.7	12.0 - 13.6
	15.3	150	4-6	8.0	4.0	12.0
Kenai Grassroots	55	876	6 - 7	8.6 - 8.9	4.0 - 5.3	12.6 - 14.2
	15.3	350 - 450	5 - 7	8.0	4.0 - 5.0	12.0 - 13.0









Special Notice

Acceptance of this Presentation, or use of any information contained in this Presentation, by any party receiving this Presentation (each a "Recipient") shall constitute an acknowledgement and acceptance by such Recipient of, and agreement by such Recipient to be bound by, the following:

(1) This Presentation was prepared for Chugach Electric Association, Inc. (Client) by Black & Veatch Management Consulting, LLC (Black & Veatch) and is based on information not within the control of Black & Veatch. In preparing this Presentation, B&V has assumed that the information, both verbal and written, provided by others is complete and correct. Black & Veatch does not guarantee the accuracy of the information, data or opinions contained in this Presentation and does not represent or warrant that the information contained in this Presentation is sufficient or appropriate for any purpose.

(2) This Presentation should not be construed as an invitation or inducement to any Recipient or other party to engage or otherwise participate in the proposed or any other transaction, to provide any financing, or to make any investment. Recipient acknowledges and agrees that it is not reasonably feasible for Black & Veatch to conduct a comprehensive investigation and make definitive determinations for the compensation provided and without thorough verification of the information upon which the Services were performed, and therefore Black & Veatch can offer no guarantee or assurances that any facts, observations, analysis, projections, opinions, or other matters contained in the Presentation will be more accurate, either at the time the Presentation is issued or at any other time.

(3) Recipient is not entitled to make any copies of any portion of this Presentation, use extracts therefrom or transmit any part thereof to any other party in any form, including without limitation electronic or printed media of any kind.

(4) TO THE FULLEST EXTENT PERMITTED BY LAW, BLACK & VEATCH'S TOTAL LIABILITY, ON A CUMULATIVE AND AGGREGATE BASIS, TO CLIENT AND ALL RECIPIENTS AND OTHER PARTIES, RESULTING FROM BLACK & VEATCH'S ACTIONS IN RELATION TO THE CREATION AND DISSEMINATION OF THIS Presentation, WILL BE LIMITED TO THE AMOUNT OF COMPENSATION (EXCLUSIVE OF THE REIMBURSEMENT OF COSTS AND EXPENSES) ACTUALLY RECEIVED BY BLACK & VEATCH FROM CLIENT FOR THE CREATION OF THIS Presentation UNDER THE PROFESSIONAL SERVICES AGREEMENT. Recipient hereby waives any right to seek or collect damages in excess thereof and releases Black & Veatch from any and all damages or losses which, if required to be paid to Recipient, would result in Black & Veatch paying total damages to any and all parties, including Client and all Recipients, in an amount that would exceed the limit set forth in the previous sentence.

The exclusive venue for any claim, cause of action, legal proceeding, or lawsuit relating to this Presentation shall be the United States District Court for the Southern District of New York and any New York State courts sitting in New York City. ALL RIGHT TO TRIAL BY JURY WITH RESPECT TO ANY CLAIM OR PROCEEDING RELATED TO OR ARISING OUT OF THE Presentation, IS HEREBY WAIVED BY EACH PARTY HERETO. Recipient and any other party irrevocably waive each argument, objection, defense, assertion, or claim that venue is improper for any reason in United States District Court for the Southern District of New York and any New York State courts sitting in New York City for any claim, cause of action, legal proceeding, or lawsuit brought in said courts or that such claims have been brought in an inconvenient forum.

The above terms and conditions are governed by and shall be governed by and construed in accordance with the laws of the State of New York, without giving effect to the conflicts of laws principles thereof other than Sections 5-1401 and 5-1402 of the General Obligations Law of the State of New York.

IF ANY RECIPIENT IS NOT WILLING TO ACKNOWLEDGE AND ACCEPT, OR AGREE TO, THE TERMS SET FORTH ABOVE, IT MUST RETURN THIS PRESENTATION TO BLACK & VEATCH IMMEDIATELY WITHOUT MAKING ANY COPIES THEREOF, EXTRACTS THEREFROM OR USE (INCLUDING DISCLOSURE) THEREOF. A RECIPIENT'S FAILURE SO TO RETURN THIS PRESENTATION SHALL CONSTITUTE ITS ACKNOWLEDGEMENT AND ACCEPTANCE OF AND AGREEMENT TO THE TERMS SET FORTH ABOVE

Assumptions

- Black & Veatch used and relied on certain information provided by the Client. Black & Veatch assumes the information provided is reasonable for the purposes of the Presentation. Black & Veatch has not been requested to make an independent analysis, to verify the information provided, or to render an independent judgment of the validity of the information provided by others. Because of this, Black & Veatch cannot, and does not, guarantee the accuracy thereof to the extent that such information, data, or opinions were based on information provided by others.
- In preparing the Presentation and the opinions presented herein, Black & Veatch has made certain assumptions with respect to conditions that may exist, or events that may occur in the future. Black & Veatch assumes that the use of this information and assumptions is reasonable for purposes of the Presentation. However, some events may occur, or circumstances change that cannot be foreseen or controlled by Black & Veatch and that may render these assumptions incorrect. To the extent the actual future conditions differ from those assumed herein or provided to Black & Veatch by others, the actual results will differ from those that have been forecast in the Presentation.
- Throughout this Presentation, Black & Veatch has stated assumptions and reported information provided by others, all of which were relied upon in the development of the opinions of this Presentation.

Building
a World of
Difference.®