FE Docket No. 12-32-LNG

LIST OF EXHIBITS

EXHIBIT A	Landowner Protest to FERC (10-3-17)
EXHIBIT B	*Oil and Natural Gas Resources and Technology*, U.S. Dept. of Energy (3/18)
EXHIBIT C	*Calculating the Economic Benefits of U.S. LNG Exports*, ICF (4/17/18)
EXHIBIT D	Landowner [Corrected] Motion for Leave to Answer and Answer (w/exhibits) (4/26/16)
EXHIBIT D-1	*The Role of Natural Gas Liquids (NGLs) in the American Petrochemical Boom*, Kinder Morgan (3/18)
EXHIBIT E	*The Future of LNG*, Bloomberg New Energy Finance (5/4/18)
EXHIBIT F	*Pembina Pipeline's (PBA) CEO Michael Dilger on Q3 2017 Results – Earnings Call Transcript* (11/3/17)
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EXHIBIT G	*Pacific Connector Gas Pipeline, LP Open Season Notice* (7/8/17)
EXHIBIT H	*CORRECTED Petronas' Canadian Unit to Look at Other LNG Opportunities* (10/11/17)
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EXHIBIT J	*Mexico Pacific Secures Funds for Sonora LNG Project* (10/23/17)
EXHIBIT K	Jordan Cove Facility Proposal Opinion Survey Toplines - Jan.-Feb. 2018 (2/14/18)
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EXHIBIT L	*Jordan Cove LNG and Pacific Connector Pipeline Greenhouse Gas Emissions Briefing*, Oil Change International (1/18)
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EXHIBIT N-1	LNG - Existing - as of April 23, 2018
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EXHIBIT O	Landowner Testimony (4/16)
EXHIBIT P	Jackson County Board of Commissions Letter to FERC (3/17/16)

EXHIBIT Q	*Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets*, U.S. Dept. of Energy (10/14)
EXHIBIT R	*The Macroeconomic Impact of Increasing U.S. LNG Exports*, Oxford Economics (10/29/15)
EXHIBIT S	*Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States*, U.S. Dept. of Energy (5/29/14)
EXHIBIT T	List of additional homeowners
EXHIBIT U	*With Montney Assets Buy, Veresen Eyes Building First West Coast LNG Facility in Oregon* (12/23/14)

Exhibits
A - H

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October 3, 2017

EFILED 10/3/2017

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, D.C. 20426

**Re: Pacific Connector Gas Pipeline L.P.
Docket No. CP17-494-000
Jordan Cove Energy Project L.P.
Docket No. CP17-495-000**

Dear Ms. Bose:

I am writing on behalf of landowners that will be directly impacted and harmed by the proposed Pacific Connector Gas Pipeline, including Robert Barker, Oregon Women's Land Trust, Evans Schaaf Family LLC, Ronald Schaaf, Deborah Evans, Stacey and Craig McLaughin, Bill Gow, Landowners United, Clarence Adams (President of Landowners United), Pamela Brown Ordway, and Barbara Brown. All of the affected landowners respectfully ask FERC to refuse acceptance of the applications from Pacific Connector Gas Pipeline L.P. (PCGP) and Jordan Cove Energy Project L.P. (JCEP) (Dkts. CP17-494-000 and CP17-495-000, respectively) for the following reasons.

LNG Export markets remain highly competitive and there is still no evidence of firm market commitments for Jordan Cove LNG which FERC says is needed to refile.

In FERC's March 11, 2016 denial order, the commissioners denied the certificate of Public Convenience and Necessity on the grounds that the public benefits did not outweigh the adverse effects. They additionally stated, "Our actions here are without prejudice to Jordan Cove and/or Pacific Connector submitting a new application to construct and/or operate LNG export facilities or natural gas transportation facilities **should the companies show a market need for these services in the future**."[1] (emphasis added).

In the Abbreviated Application of Pacific Connector Gas Pipeline, LP for a Certificate of Public Convenience and Necessity[2], PCGP has produced no evidence of non-affiliate firm

[1] Jordan Cove/Pacific Connector denial order (March 11, 2016, p. 21, § 48) **(Exhibit 1)**

[2] Abbreviated Application of Pacific Connector Gas Pipeline, LP for a Certificate of Public Convenience and Necessity filed September 21, 2017 **(Exhibit 2, without exhibits)**

market commitment — the primary objective indicator of market need — and yet it is asking once again to be given permission to build a speculative project on the backs of landowners and communities who oppose the project and who will be threatened with the exercise of eminent domain if it is allowed to move forward.

In the Abbreviated Application, the company reports that it held "a binding open season from July 18, 2017 through August 17, 2017, to determine the level of market demand for firm transportation service provided through the Pipeline."[3] The results garnered zero qualifying outside bids. Instead, Jordan Cove Energy Project, an affiliate, signed two Precedent Agreements for 95.8% of the pipeline capacity itself. PCGP claims that other terminals have engaged in similar bookings of pipelines to indicate market need. The Precedent Agreements should be looked at closely to determine if they are binding or non-binding. We suspect they may be non-binding and, if so, they should be disregarded. In addition, the LNG terminals that PCGP cites as having booked capacity on pipelines — Golden Pass Products LLC; Magnolia LNG, LLC; Corpus Christi Liquefaction; LLC, Sabine Pass Liquefaction Expansion, LLC — each received FERC approval orders **only** with the stipulation that they be confined to **U.S. domestically-sourced natural gas**. That is not true of the PCGP/ JCEP Application where it is evident that Canadian gas is likely to be transported.

PCGP's Canadian-sourced gas competes directly with US Gulf Coast domestically-sourced gas projects

The applicant claims that natural gas could be sourced from either the U.S. or Canadian Rocky mountain shale, but there are no guarantees it will not be 100% Canadian natural gas as Exhibit H – Gas Supply --has been conspicuously omitted from the PCGP Abbreviated Application. Veresen, Inc, parent of 100% owned Jordan Cove Energy Project and Pacific Connector Gas Pipeline, is itself a mid-stream Canadian-based company with the majority of its assets in Canada's Montney shale formation. Veresen has already received approval to ship 1.55 bcfd + 15% natural gas from Canada into the United States, making it highly likely that the natural gas in this proposal will be Canadian gas that would be transported through, and then exported from, the United States. As such, this Application, if accepted, translates into a blatant misuse of eminent domain and further threatens FERC's previously approved LNG export projects on the Gulf Coast by directly

(continued)
https://elibrary.ferc.gov/idmws/common/downloadOpen.asp?downloadfile=20170921%2D5139%2832409921%29%2Epdf&folder=9804562&fileid=14687464&trial=1

[3] *Id.*, p. 5.

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competing for market share of domestically-produced U.S. natural gas. In fact, the PCGP/JCEP Application can be only properly understood and evaluated by considering it in the context of the rapidly changing LNG global dynamics where LNG commodity trading is reshaping global competitiveness. Coupled with eroding destination clauses, this phenomenon gives great power to large buying entities like Japan's JERA Co., Inc.(JERA) to influence the competitive balance of existing and proposed LNG facilities.

Billions of dollars of invested capital in Gulf Coast Projects are at risk if FERC accepts this application. Aggregators/Traders are now leveraging down contract prices on Gulf Coast and elsewhere using Jordan Cove.

According to this recent Oil and Money article *Who's Ahead in Surfing Second US LNG Wave?*[4] based on a World Gas Intelligence report, seven of the ten potential next wave U.S LNG Export terminals have been fully approved but are waiting on binding offtake contracts before making their Final Investment Decisions (FID).

Top 10 Second Wave US LNG Projects			
Ranking	Project	Regulatory Status	Expected FID
1	Corpus Christi Train 3	Fully Approved	Unknown
2	Magnolia LNG	Fully Approved	Unknown
3	Sabine Pass Train 6	Fully Approved	Unknown
4	Golden Pass	Fully Approved	2018
5	Rio Grande	Filed with Ferc	2018
6	Driftwood	Filed with Ferc	2018
7	Cameron Train 4-5	Fully Approved	Unknown
8	Jordan Cove	Refiled with Ferc	Unknown
9	Delfin FLNG	Fully Approved	2018
10	Lake Charles	Fully Approved	Unknown
Source: World Gas Intelligence			

For example, Magnolia LNG "has approvals from both the Federal Energy Regulatory Commission and the Department of Energy, and its primary construction contract in place. **All it's waiting on is buyers for the offtake** before making final investment decision."[5] [emphasis added] Magnolia LNG's COO John Baguley said, "[H]e's 'a little puzzled' by the

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[4] *Who's Ahead in Surfing Second US LNG Wave?* http://oilandmoney.net/2017/08/17/whos-ahead-in-surfing-second-us-lng-wave/ **(Exhibit 3)**

[5] *Report lists planned area LNG projects as likely to come through* (September 24, 2017) **(Exhibit 4)** http://www.americanpress.com/news/local/report-lists-planned-area-lng-projects-as-likely-to-come/article_697daaf2-a150-11e7-816d-73406a613860.html

lack of urgency among buyers.... I really don't understand what everybody's waiting for. The buyer's market just doesn't seem to go forward. It's a curious situation."[6]

On the other hand, JERA, the Japanese company that expressed interest in Jordan Cove a year ago, with plenty of U.S. LNG supply to choose from, still has not firmed up its commitment to buy from Jordan Cove. This is entirely symptomatic of recent changes in the market dynamics for LNG. Asian buyers, like JERA, are now aggregators who can trade LNG worldwide and they are using their leverage to keep prices low.[7] This gives them the power to leverage one project in order to influence an outcome for another project. This results in FERC being asked again, to approve a project with no bottom line commitment while JERA pushes on others to negotiate or renegotiate flexibility and a lower price for previously binding LNG export contracts. According to JERA's president Yuji Kakimi:

> The price of LNG has to be reasonable and there needs to be flexibility. If the market lacks these things the golden-age will never come.... Compared to coal, as a fuel source for electricity, it is about 1.5 times more expensive," he said, even at $6 per mBtu.[8]

FERC's Certificate Policy Statement says that if a new pipeline competes for the same market, the adverse effects must be considered. With aggregation and no destination clauses, Jordan Cove and Canadian-sourced gas will almost certainly take away from markets that could otherwise turn to the Gulf Coast.

Greenfield is expensive versus brownfield. Is Jordan Cove undercutting Gulf Coast brownfield LNG by asking for special waivers and preferential treatment?

LNG leaders on the Gulf Coast concur with us that greenfield projects, despite the hype and money used to influence decision makers, are likely to incur far more costs. Cheniere Chief Commercial Officer Anatol Feygin said, "[C]ustomers have been confused on who to believe." There has been "a lot of rhetoric from US greenfield projects about how

[6] *Id.*

[7] *Japan outlaws restrictions on resale of LNG cargoes* (June 28, 2017) **(Exhibit 5)** http://www.forexrepository.com/news/japan-outlaws-restrictions-on-resale-of-lng-cargoes.htm

[8] *Jera's Kakimi warns over 'golden age' for LNG in Asia – Liquefied natural gas buyer says suppliers need to be more competitive* (September 26, 2017) https://www.ft.com/content/49d56400-a264-11e7-9e4f-7f5e6a7c98a2 **(Exhibit 6)**

cheaply they can do it," but Feygin believes the cost estimates are "unachievable." The CEO of Freeport LNG, Michael Smith, similarly expects greenfield projects to face rough seas. [9]

The Application here illustrates that point well: PCGP and JCEP say that they are seeking to "construct a natural gas liquefaction and deep-water export terminal capable of receiving and loading ocean-going LNG carriers, in order to export natural gas from a point of origin near the intersections of GTN and Ruby."[10] Coos Bay, Oregon is not a deep-water port and cannot accommodate the larger, more efficient LNG carriers. This negates the benefits of Jordan Cove's proximity to Asia. The remedy to compete requires significant dredging of a much deeper, wider channel than presently exists and the continuing costs associated with maintaining it. Moreover, any effort to widen and deepen the existing ship channel will be controversial and have to compete with many similar projects nationwide. Permitting a project is itself an expensive and time-consuming undertaking.

Can the Jordan Cove project truly compete with brownfield Gulf Coast projects or even other greenfield projects when all of the risks, uncertainties and costs associated with its development in Coos Bay are added in? Or will they need to be granted their additional requests for non-conforming provisions and waivers for no segmentation to be viable?

Jordan Cove asserts that the primary public benefit of their project is job creation. More accurately, this non-U.S. sourced gas greenfield project, even if successful, is likely to be competing with and taking away American jobs elsewhere.

In recent months, several far deeper pocketed projects have folded in Canada and elsewhere due to unfavorable market conditions.[11] [12]

[9] *Who's Ahead in Surfing Second US LNG Wave?* http://oilandmoney.net/2017/08/17/whos-ahead-in-surfing-second-us-lng-wave/ **(Exhibit 3)**

[10] Abbreviated Application of Pacific Connector Gas Pipeline, LP for a Certificate of Public Convenience and Necessity filed September 21, 2017, p. 14 **(Exhibit 2)** https://elibrary.ferc.gov/idmws/common/downloadOpen.asp?downloadfile=20170921%2D5139%283240 9921%29%2Epdf&folder=9804562&fileid=14687464&trial=1

[11] *Chevron Calls End of LNG Mega Project After $88 Billion Spree* (March 20, 2017) https://www.bloomberg.com/news/articles/2017-03-21/chevron-calls-end-of-lng-mega-project-after-88-billion-spree **(Exhibit 7)**

[12] *Petronas pulls the plug on Pacific NorthWest LNG project - After investing billions in Canada, Malaysian oil and gas company is cancelling its Prince Rupert LNG project.* https://www.biv.com/article/2017/7/petronas-pulls-plug-pacific-northwest-lng-project/ **(Exhibit 8)**

> The decision to cancel the development boiled down to simple economics — a world market awash in liquefied natural gas, which has driven down prices, making Pacific NorthWest LNG no longer financially viable, said Anuar Taib, CEO of Petronas's oil and gas production division.[13]
>
> * * * *
>
> It's also a hard reminder to Alaskans that no matter how much we want to sell our oil and gas, if the market doesn't want it, doesn't need it or isn't willing to pay a price to make it profitable — we can't sell our oil and gas...Prices have tumbled from $15-$18 per million btu, to just over $5.... You can't buy gas out of Cook Inlet, pay to liquify it, burn up some of it while you're liquefying it, put it in a tanker and deliver it for $5.50 per million btu and make money. It is a[n] inhospitable market and will be for the near future.[14]

Applicant has not followed FERC Certificate Policy Statement to get voluntary easements prior to filing an application and has not revealed full landowner easements, instead speculating it will get voluntary easements before construction begins.

FERC's Certificate Policy Statement from 1999 says:

> Under this policy, if project sponsors, proposing a new pipeline company, are able to acquire all, or substantially all, of the necessary right-of-way by negotiation prior to filing the application, and the proposal is to serve a new, previously unserved market, it would not adversely affect any of the three interests.[15]

[13] *Pacific NorthWest LNG megaproject cancelled* (July 25, 2017) https://www.thestar.com/news/canada/2017/07/25/petronas-backed-pacific-northwest-lng-megaproject-in-bc-not-going-ahead.html **(Exhibit 9)**

[14] *Facing global gas glut, ConocoPhillips to mothball Kenai LNG plant* (July 13, 2017) **(Exhibit 10)** http://www.alaskapublic.org/2017/07/13/facing-global-gas-glut-conocophillips-to-mothball-kenai-lng-plant/

[15] FERC Statement of Policy issued September 15, 1999, Dkt. No. PL99-3-000. The three interests that could be adversely affected by the route of a new pipeline are: 1) existing customers of the expanding pipeline; 2) existing pipelines in the market and their captive customers and; 3) the economic interests of landowners and communities **(Exhibit 11)**.

PCGP states that, "[T]hese timber companies (referring to some of the outstanding landowners) are sophisticated entities that are familiar with utility easements and with whom PCGP expects to be able to reach mutually acceptable agreements in all or virtually all cases." It additionally asserts that it has 39% of private landowner easements. Nowhere does PCGP give the total number of temporary construction easement parcels needed or permanent Right of Way easement parcels needed. Nor does it give an accounting of how many of these parcels it has secured voluntarily before applying. The FERC policy statement asks that pipeline companies do their due diligence and try and negotiate and secure easements before filing. PCGP has negotiated with landowners, but it has not secured a very high number of takers. The burden a pipeline places on landowners is significant and landowners request that we not go back down this path with little to no certainty that any of the "public benefits" the company claims are true, will actually materialize. It amounts to a Field of Dreams wish of "If you build it, they will come." FERC has a responsibility to ensure that the "benefits" outweigh any adverse effects to landowners and communities. That hinges entirely on the economic benefits test of weighing benefits tied to firm markets versus adverse effects of landowners being subjected to eminent domain.

Betsey Spomer, CEO of Jordan Cove, in July 2017 presented a power point[16] in Portland, Oregon describing the proposed project. In it she shared the following:

> From a FERC perspective, the key will be to have:
>
> –75%+ of binding transportation service agreements on the pipeline
>
> –65% to 75% of private landowner voluntary right of way (ROW) agreements
>
> Since the FERC denial, PCGP has secured 110 voluntary ROW agreements from a total of 259 private fee owners or > 40%; progress is being made daily

Nowhere in this presentation or in the Application before FERC, does the company acknowledge how many total parcels they have secured including temporary construction and permanent Right of Way easements needed. Before accepting this application, and launching into the environmental impacts through NEPA, FERC should weigh whether the applicant has raised the bar high enough with their application to meet the following FERC Certificate Policy Statement:

[16] Betsy Spomer Presentation – Portland (July 25, 2017) **(Exhibit 12)**.

> If residual adverse effects on the three interests are identified, after efforts have been made to minimize them, then the Commission will proceed to evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered.[17]

PCGP has been trying to secure the easements it needs from the landowners, but the majority of landowners -- including all of those identified in the first paragraph of this letter -- after years of having their properties held hostage and being subjected to the mistreatment and failed attempts of this company and project, are not interested and do not want to be dragged through this process for a third time. We respectfully ask that you take our concerns into consideration and ask for the necessary data to determine upfront whether the adverse effects outweigh any public benefit with the information you have been given—BEFORE deciding whether to accept the application or proceeding ahead with a NEPA analysis.

Sincerely,

Thane W. Tienson

/jz
Attachments Exhibits 1-12
cc: Clients

[17] FERC Certificate Policy Statement issued September 15, 1999, Dkt. No. PL99-3-000

EXHIBIT LIST

Exhibit 1	Jordan Cove/Pacific Connector FERC denial order (March `11, 2016)
Exhibit 2	Abbreviated Application of Pacific Connector Gas Pipeline, LP for a Certificate of Public Convenience and Necessity – Executive Summary, September 21, 2017
Exhibit 3	*Who's Ahead in Surfing Second US LNG Wave*? (August 8, 2017)
Exhibit 4	*Report lists planned area LNG projects as likely to come through* (September 24, 2017)
Exhibit 5	*Japan outlaws restrictions on resale of LNG cargoes* (June 28, 2017)
Exhibit 6	*Jera's Kakimi warns over 'golden age' for LNG in Asia – Liquefied natural gas buyer says suppliers need to be more competitive* (September 26, 2017)
Exhibit 7	*Chevron Calls End of LNG Mega Project After $88 Billion Spree* (March 20, 2017)
Exhibit 8	*Petronas pulls the plug on Pacific NorthWest LNG project - After investing billions in Canada, Malaysian oil and gas company is cancelling its Prince Rupert LNG project* (July 25, 2017)
Exhibit 9	*Pacific NorthWest LNG megaproject cancelled* (July 25, 2017)
Exhibit 10	*Facing global gas glut, ConocoPhillips to mothball Kenai LNG plant* (July 13, 2017)
Exhibit 11	FERC Certificate Policy Statement (Dkt. No. PL99-3-000, September 15, 1999)
Exhibit 12	Betsy Spomer Presentation – Portland (July 25, 2017)

Exhibit 1

154 FERC ¶ 61,190
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Jordan Cove Energy Project, L.P.	Docket No. CP13-483-000
Pacific Connector Gas Pipeline, LP	Docket No. CP13-492-000

ORDER DENYING APPLICATIONS FOR CERTIFICATE AND SECTION 3 AUTHORIZATION

(Issued March 11, 2016)

1. On May 21, 2013, in Docket No. CP13-483-000, Jordan Cove Energy Project, L.P. (Jordan Cove) filed an application under section 3 of the Natural Gas Act (NGA) and Parts 153 and 380 of the Commission's regulations to site, construct, and operate a liquefied natural gas (LNG) export terminal and associated facilities (Jordan Cove LNG Terminal or LNG Terminal) on the North Spit of Coos Bay in Coos County, Oregon.

2. On June 6, 2013, in Docket No. CP13-492-000, Pacific Connector Gas Pipeline, LP (Pacific Connector) filed an application under NGA section 7(c) and Part 157 of the Commission's regulations for a certificate of public convenience and necessity to construct and operate an approximately 232-mile-long, 36-inch-diameter interstate natural gas pipeline originating near Malin, in Klamath County, Oregon, and terminating at the Jordan Cove LNG Terminal (Pacific Connector Pipeline). The Pacific Connector Pipeline will transport natural gas to the Jordan Cove LNG Terminal for processing, liquefaction, and export. Pacific Connector also requests a blanket certificate under subpart F of Part 157 of the Commission's regulations to perform certain routine construction, operation, and abandonment activities, as well as a blanket certificate under subpart G of Part 284 of the Commission's regulations to provide open-access transportation services.

3. As discussed below, the Commission denies Pacific Connector's and Jordan Cove's proposals.

I. Background

4. Jordan Cove and Pacific Connector are Delaware limited partnerships. Jordan Cove is authorized to do business in the State of Oregon, and has one general partner, the Jordan Cove Energy Project, L.L.C., and one limited partner, Jordan Cove LNG L.P. (a Delaware limited partnership that owns 100 percent of Jordan Cove and Jordan Cove Energy Project, L.L.C.).[1] Pacific Connector is authorized to do business in the states of Oregon, California, and Utah. Pacific Connector has one general partner, Pacific Connector Gas Pipeline, LLC (who owns a one percent interest)[2] and two limited partners, Williams Gas Pipeline Company, LLC[3] and Jordan Cove LNG L.P. (who each own a 49.5 percent interest).

5. Jordan Cove and Pacific Connector are new companies. Upon construction and operation of their proposed facilities, Jordan Cove and Pacific Connector would be subject to the Commission's jurisdiction under the NGA.

II. Proposals

6. The applicants designed the Jordan Cove LNG Terminal and the Pacific Connector Pipeline Projects (referred to collectively as "the projects") to enable the production of up to 6.8 million metric tons per annum (MMTPA) of LNG, using a feed of approximately 1.04 billion standard cubic feet per day (Bcf/d) of natural gas, for export to international or domestic markets in the non-contiguous United States.[4]

[1] Jordan Cove LNG L.P. is wholly owned and controlled by Veresen Inc., an Alberta, Canada Corporation. *See* Jordan Cove's October 8, 2015 filing at 6 and Exhibit B.

[2] Pacific Connector Gas Pipeline, LLC is a Delaware limited liability company equally owned by Williams Gas Pipeline Company, LLC and Jordan Cove LNG L.P. *See* Jordan Cove's April 23, 2014 filing stating that Fort Chicago LNG II U.S. L.P. (listed in Pacific Connector's application as a part owner of the Pacific Connector Gas Pipeline, LLC) changed its name to Jordan Cove LNG L.P.

[3] Williams Pacific Gas Pipeline Company, LLC is a wholly-owned subsidiary of The Williams Companies, Inc.

[4] We note that while Jordan Cove asserted in its application that there is a need for its project to serve current and future *domestic* needs, stating "the Project will be able to provide access to LNG to meet the demand of isolated markets in Hawaii . . . and the Cook Inlet region of Alaska," Jordan Cove has not filed an application for a certificate of

7. The Pacific Connector Pipeline would carry natural gas to the Jordan Cove LNG Terminal, where the natural gas will be liquefied, stored in cryogenic tanks, and loaded onto ocean-going vessels. The applicants state that the projects will enable natural gas produced in western Canada and the United States' Rocky Mountains to serve markets in Asia, southern Oregon, and, potentially, Hawaii and Alaska.[5]

A. <u>The Jordan Cove LNG Terminal Proposal in Docket No. CP13-483-000</u>

8. Jordan Cove seeks authorization under NGA section 3 to site, construct, and operate an LNG export terminal that would consist of:

- a natural gas conditioning facility with a combined natural gas throughput of approximately 1 Bcf/d;
- four natural gas liquefaction trains that would each process approximately 1.5 MMTPA of LNG;
- a refrigerant storage and resupply system;
- an aerial cooling system;
- two full-containment LNG storage tanks, each with a capacity of 160,000 cubic meters (m^3) (or 1,006,000 barrels), and each equipped with three fully submerged LNG in-tank pumps sized for approximately 11,600 gallons per minute;
- an LNG transfer line consisting of one 2,300-foot-long, 36-inch-diameter line that would connect the shore-based storage system with the LNG loading system;
- an LNG carrier cargo loading system consisting of three 16-inch loading arms and one 16-inch vapor return arm;
- a LNG carrier loading berth capable of accommodating LNG carriers with capacities from 148,000 m^3 to 217,000 m^3;

public convenience and necessity authorizing it to transport or sell for resale gas in *interstate* commerce. The section 3 authorization it has requested extends only to operations in *foreign* commerce.

[5] *See id.* Jordan Cove would need to apply for and receive authorization under section 7(c) of the NGA prior to processing any gas for transportation in interstate commerce.

- a utility corridor to serve as the primary roadway and utility interconnection between the LNG terminal and the South Dunes Power Plant;
- a boil off gas recovery system;
- electrical, nitrogen, fuel gas, lighting, instrument/plant air and water facility systems;
- an LNG spill containment system, fire water system and other hazard detection, control and prevention systems; and
- utilities, buildings, and support facilities.

9. The Jordan Cove LNG Terminal will be located within about 400 acres of open and industrial land across two contiguous parcels (an eastern and western parcel).[6] The parcels are located on the bay side of the North Spit of Coos Bay in unincorporated Coos County, Oregon, north of the towns of North Bend and Coos Bay.

B. Pacific Connector Gas Pipeline

1. Facilities

10. Pacific Connector requests authorization under NGA section 7(c) to construct and operate a new 232-mile-long interstate natural gas transmission system designed to deliver up to 1.06 Bcf/d of natural gas from interconnects with Ruby Pipeline LLC (Ruby) and Gas Transmission Northwest LLC (GTN) near Malin, Oregon, to the Jordan Cove LNG Terminal. In addition to delivering natural gas to the LNG terminal, Pacific Connector states its pipeline would provide deliveries in southern Oregon through an interconnection with Northwest Pipeline GP's (Northwest) Grants Pass Lateral.[7] The proposed Pacific Connector Pipeline would consist of the following facilities:

- approximately 232 miles of 36-inch-diameter pipeline and appurtenant facilities[8] traversing Klamath, Jackson, Douglas, and Coos counties, Oregon;

[6] The two parcels are owned by Jordan Cove.

[7] Northwest's Grants Pass Lateral is a 131-mile-long pipeline system extending from Eugene to Grants Pass, Oregon.

[8] Appurtenant facilities include five pig launchers and receivers and 17 block valves spaced along the pipeline route in compliance with U.S. Department of Transportation regulations.

- a natural gas compressor station (Klamath Compressor Station), located on a 31-acre site in Klamath County, Oregon, containing three 20,500 horsepower (HP) compressor units[9] for a total of 41,000 HP of compression;

- appurtenant facilities, including a compressor building, suction/discharge piping, and final discharge coolers, a mainline block valve, and a pig launcher assembly;[10]

- the Jordan Cove Delivery Meter Station, that would have a capacity of approximately 1.020 Bcf/d of natural gas at 850 psig, located at the terminus of the Pacific Connector Pipeline at milepost (MP) 1.47, consisting of multiple large ultrasonic gas flow meters, a gas chromatograph, two gas filter/separators, flow control, electronic flow measurement, communications equipment, a building to house the equipment, a mainline block valve, and a pig receiver;[11]

- the Clarks Branch Delivery Meter Station, with a maximum design capacity of approximately 40 million cubic feet per day (MMcf/d) at 900 psig located at an interconnect with Northwest's existing Grant's Pass Lateral at MP 71.46 in Douglas County, Oregon, consisting of an 8-inch ultrasonic gas flow meter, a gas chromatograph, gas separator, flow control, overpressure protection, electronic flow measurement, communications equipment, a building to house the equipment, a mainline block valve, a pig launcher assembly, and a pig receiver assembly;

- the Klamath-Beaver Receipt Meter Station, with a maximum design capacity of approximately 1.06 Bcf/d at 900 psig located at an interconnect with GTN's mainline in Klamath County, Oregon, within the Klamath Compressor Station site, consisting of multiple large-diameter ultrasonic gas flow meters, gas piping and valves, gas chromatograph, flow control, electronic flow measurement, communications for voice and data transfer, and a building to house the equipment;

[9] The third 20,500 HP compressor unit is proposed for standby purposes; only two units will operate at any given time.

[10] A pig is a tool for cleaning and inspecting the inside of a pipeline.

[11] Pacific Connector states that it would enter into an operational balancing agreement with Jordan Cove prior to the in-service date of these facilities.

- the Klamath-Eagle Receipt Meter Station, with a maximum design capacity of approximately 1.06 Bcf/d at 900 psig located at an interconnect with Ruby's mainline in Klamath County, Oregon, on the Klamath Compressor Station site, consisting of multiple large-diameter ultrasonic gas flow meters, gas piping and valves, gas chromatograph, flow control, electronic flow measurement, communications for voice and data transfer, and a building to house the equipment;[12] and

- communications towers installed at each meter station and at the Klamath Compressor Station to connect Pacific Connector's system to Northwest's existing backbone microwave system, which provides communications with Northwest's gas control center. Additionally, Pacific Connector would utilize Northwest's existing Harness Mountain communications site in Douglas, County, Oregon and would lease space on seven other existing communication towers in Coos, Douglas, Jackson, and Klamath counties, Oregon.

11. Pacific Connector states that the initial firm design capacity of its proposed pipeline system is 1.06 Bcf/d and the maximum allowable operating pressure (MAOP) for the pipeline would be 1,480 psig. Pacific Connector explains that the design assumes 40 MMcf/d would be reserved for the Clark's Branch Delivery Meter Station and 1.02 Bcf/d would be reserved for the Jordan Cove Delivery Meter Station at the terminus of the Pacific Connector Pipeline. Pacific Connector estimates that the cost of the Pacific Connector Pipeline is approximately $1.74 billion.[13]

2. Request for Blanket Certificates

12. Pacific Connector requests a blanket certificate under subpart F of Part 157 to perform routine construction, maintenance, and operational activities related to its proposals. Pacific Connector also requests a blanket certificate under subpart G of Part 284 to provide open-access firm and interruptible transportation services for its customers.

[12] Pacific Connector states that it would provide contributions-in-aid-of-construction for Northwest's, GTN's, and Ruby's construction of the interconnect facilities and would enter into an operational balancing agreement with each company prior to the in-service date of the respective facilities.

[13] The cost estimate is in "as spent" dollars based on a November 1, 2017 in-service date.

3. Markets and Services

13. Pacific Connector states that it proposes the Pacific Connector Pipeline, which it has characterized as an integral component of the Jordan Cove LNG Terminal,[14] in response to rising international demand for United States' and Canadian natural gas supplies. Pacific Connector explains that its pipeline will provide market outlets to transport western Canadian and United States' Rocky Mountain natural gas supplies for export through the Jordan Cove LNG Terminal. Pacific Connector states that the pipeline also will be capable of delivering gas to markets in southern Oregon through an interconnection with Northwest's Grants Pass Lateral, but that these markets alone are not sufficient to drive the investment in the pipeline.[15] Therefore, Pacific Connector states that if the pipeline's capacity is not substantially subscribed and if the Jordan Cove LNG Terminal is not contracted, it will not build the pipeline.[16]

14. Pacific Connector has not conducted an open season for its proposed transportation capacity, and has not submitted any precedent agreements or contracts with, or subsequent to, the filing of its application. In its application, Pacific Connector stated that it would keep the Commission apprised of its plans to conduct an open season and enter into precedent agreements for the pipeline's capacity.

15. On May 7, 2014, Commission staff sent Pacific Connector a data request asking it to provide the current status of: (1) Jordan Cove's negotiations for liquefaction contracts for the Jordan Cove LNG Terminal; and (2) Pacific Connector's actions to conduct an open season and enter into precedent agreements for pipeline capacity. On May 15, 2014, Pacific Connector responded and stated that Jordan Cove had entered into non-binding Heads of Agreements with various Asian companies for liquefaction and transportation capacity. Pacific Connector stated that the Heads of Agreements generally provided for pipeline precedent agreements to be executed by October 2014, upon which it would conduct an open season (in October/November 2014).

16. On December 5, 2014, Commission staff sent Pacific Connector another data request asking Pacific Connector to update the Commission on the results of its October/November 2014 open season. On December 10, 2014, Pacific Connector responded, stating that Jordan Cove was still negotiating under the non-binding Heads of Agreements, the terms of which had been extended into early 2015. Pacific Connector

[14] Pacific Connector's June 1, 2015 Data Response at 2.

[15] Pacific Connector's Application at 7.

[16] *Id.* at 9. *See also* Pacific Connector's June 1, 2015 Data Response at 2.

explained that the extended Heads of Agreements generally provided for pipeline precedent agreements to be executed by those shippers choosing to make binding commitments by the first or second quarter of 2015, and that it anticipated holding an open season upon execution of those agreements, in the second quarter of 2015.

17. On May 20, 2015, Commission staff sent Pacific Connector a third data request, explaining that the Commission's Certificate Policy Statement requires the Commission to balance the public benefits of a pipeline proposal against its potential adverse impacts, and that Pacific Connector must show that the public benefits of its proposal outweigh the project's adverse impacts. The data request further explained that while the Commission no longer requires an applicant to present contracts for any specific percentage of proposed new capacity, contracts or precedent agreements always serve as important evidence of project demand. Commission staff then asked Pacific Connector to identify the date it held or will hold an open season and, in the event it does not enter into agreements for service prior to the time the Commission has completed its review of the applications, what evidence in the record Pacific Connector is relying on to show that the benefits of the project outweigh the potential adverse impacts. On June 1, 2015, Pacific Connector responded, stating that would not hold an open season in the second quarter of 2015, but would do so upon the execution of pipeline precedent agreements for at least 90 percent of the pipeline's design capacity, which it anticipated would happen by the end of 2015. Further, Pacific Connector stated that if Jordan Cove does not execute liquefaction agreements for the LNG terminal's capacity, transportation service agreements for service on Pacific Connector will not be executed and it will not build the pipeline. Finally, Pacific Connector stated that the U.S. Department of Energy (DOE) had authorized Jordan Cove's export of LNG to free trade agreement and non-free trade agreement nations, consistent with the public interest. Thus, because the Pacific Connector Pipeline is an integral component of the Jordan Cove LNG Terminal, the pipeline's "public benefits encompass all the public benefits of the Jordan Cove [T]erminal."[17]

18. Finally, on October 14, 2015, Commission staff sent Pacific Connector a fourth data request asking Pacific Connector to discuss: (1) the negotiations between Jordan Cove, Pacific Connector, and any potential liquefaction and transportation customers; (2) whether Pacific Connector entered into any commitments for firm service on the pipeline; and (3) if Pacific Connector entered into precedent agreements, when did or when will it conduct an open season. On November 4, 2015, Pacific Connector replied stating that negotiations between Jordan Cove, Pacific Connector, and prospective customers are "active and ongoing." Pacific Connector stated it "remains confident that

[17] Pacific Connector's June 1, 2015 Data Response at 2.

these customers will enter into binding long-term [agreements]" with both Jordan Cove and Pacific Connector. Pacific Connector again emphasized that given "the significant capital costs associated with this project, Pacific Connector and Jordan Cove must have committed customers with executed agreements in place before making the ultimate decision to move forward on construction of the project" and pledged that it "will adhere to the [C]ommission's standard ... condition that service agreements for the pipeline be executed prior to the commencement of construction."[18] Pacific Connector did not provide an estimated date that agreements would be finalized. Pacific Connector also provided information indicating that it had obtained easements for only 5 percent and 3 percent, respectively, of its necessary permanent and construction right of way.

III. Procedural Matters

A. Notice, Interventions, Comments, and Protests

19. Notice of Jordan Cove's application was published in the *Federal Register* on June 6, 2013 (78 Fed. Reg. 34,089), establishing June 20, 2013, as the due date for filing motions to intervene and protests. The parties listed in Appendix A filed timely, unopposed motions to intervene in Docket No. CP13-483-000.[19] Timely notices of intervention in Docket No. CP13-483-000 were filed by the National Marine Fisheries Service (NMFS) and jointly by the Oregon Department of Environmental Quality (Oregon DEQ) and the Oregon Department of Fish and Wildlife (Oregon DFW).[20]

[18] Pacific Connector's November 4, 2015 Data Response at 1.

[19] Timely, unopposed motions to intervene are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure. *See* 18 C.F.R. § 385.214 (2015).

[20] The timely notices of intervention filed by NMFS and Oregon DEQ and Oregon DFW are granted by operation of Rule 214(a)(2) of the Commission's Rules of Practice and Procedure and are listed as parties in Appendix A. 18 C.F.R. § 385.214(a)(2) (2015). On June 20, 2013, Landowners United and Clarence Adams, jointly, filed a pleading titled "Notice of Intervention" in Docket No. CP13-483-000. Notices of Intervention may only be filed by a State Commission; the Advisory Council on Historic Preservation; the U.S. Departments of Agriculture, Commerce, and the Interior; any state fish and wildlife, water quality certification, or water rights agency; or Indian tribe with authority to issue a water quality certification. 18 C.F.R. § 385.214(a)(2) (2015). However, Landowners United's and Clarence Adams' pleading was timely filed and satisfied all of Rule 214's requirements for filing a motion to intervene. Accordingly, we grant Landowners United and Clarence Adams party status.

20. Notice of Pacific Connector's application was published in the *Federal Register* on June 26, 2013 (78 Fed. Reg. 38,306), establishing July 10, 2013, as the due date for filing motions to intervene and protests. The parties listed in Appendix B filed timely, unopposed motions to intervene in Docket No. CP13-492-000.[21] NMFS and Oregon DEQ and Oregon DFW (jointly) also filed timely notices of intervention in Docket No. CP13-492-000.[22]

21. Late motions to intervene were filed by nine parties in Docket No. CP13-483-000 and by eight parties in Docket No. CP13-492-000.[23] We grant the late motions to intervene.[24]

22. Sierra Club filed a protest in Docket Nos. CP13-483-000 and CP13-492-000. On July 3, 2013, Jordan Cove filed an answer to Sierra Club's protest. The Commission's Rules of Practice and Procedure do not permit answers to protests and we deny Jordan Cove's answer.[25]

[21] Timely, unopposed motions to intervene are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure. *See* 18 C.F.R. § 385.214 (2015).

[22] The timely notices of intervention filed by NMFS and the Oregon DEQ and the Oregon DFW are granted by operation of Rule 214(a)(2) of the Commission's Rules of Practice and Procedure and are listed as parties in Appendix B. 18 C.F.R. § 385.214(a)(2) (2015).

[23] In Docket No. CP13-483-000, late motions to intervene were filed by: Clam Diggers Association of Oregon; Clausen Oysters and Lilli Clausen (as an individual); Coos Bay Oyster Company and Jack Hempell (as an individual); Dennis and Karen Henderson (as individuals and as trustees of the Henderson Revocable Intervivos Trust); Evans Shaaf Family LLC and Deborah Evans and Ronald Schaaf (as individuals); Jerry S. Palmer; John M. Roberts, Jr.; Sierra Club; and Waterkeeper Alliance. In Docket No. CP13-492-000, late motions to intervene were filed by: Clam Diggers Association of Oregon; Clausen Oysters and Lilli Clausen (as an individual); Coos Bay Oyster Company and Jack Hempell (as an individual); Dennis and Karen Henderson (as individuals and as trustees of the Henderson Revocable Intervivos Trust); Evans Shaaf Family LLC and Deborah Evans and Ronald Schaaf (as individuals); John F. Caughell and Tammy S. Bray; Stacey and Craig McLaughlin (as individuals); and Waterkeeper Alliance.

[24] 18 C.F.R. § 385.214(d) (2015).

[25] 18 C.F.R. § 385.213(a)(2) (2015).

23. Specifically, Sierra Club argues that the Jordan Cove LNG Terminal is not consistent with the public interest. Contrary to Jordan Cove's economic arguments in support of its proposal, Sierra Club states that LNG export will have adverse and wide-ranging effects on the domestic economy and will not result in job creation. Sierra Club states that the Commission should consider how Jordan Cove's proposal, in addition to all other LNG export proposals, will affect the price of natural gas for domestic customers, as well as how these price increases will harm United States' workers and the economy. In addition, Sierra Club asserts that the projects will induce additional natural gas production in the United States from traditional and non-traditional sources, causing impacts to air and water quality and wildlife habitats. Finally, Sierra Club requests that the Commission evaluate the cumulative impacts of all proposed LNG export terminals in a Programmatic Environmental Impact Statement.

24. Jean Stalcup also filed a protest in Docket No. CP13-492-000. Ms. Stalcup protests Pacific Connector's pipeline application because, as a landowner, she is concerned that the pipeline right-of-way will cause erosion and environmental damage, harm drainage systems and water supplies, and create a safety risk. Additionally, many commenters raise similar concerns regarding potential property devaluation resulting from construction damage and maintenance in the permanent pipeline right-of-way. They also contend that construction and operation of the pipeline will interfere with the use of the lands for farming and timber harvesting operations and the use of waters for oyster farming.

25. Additionally, on December 10, 2015, Thane W. Tienson filed a letter on behalf of six intervening landowners who will be directly impacted by the Pacific Connector Pipeline (Landowner Letter).[26] The Landowner Letter argues that the Commission should deny authorization for the pipeline project given the company's admission "that it does not have a single confirmed customer and has only obtained 4.7 [percent] of the right-of-way easement acreage and 2.8 [percent] of the construction easement acreage." The Landowner Letter states that if the Commission were to authorize the project, Pacific Connector could use the power of eminent domain over approximately 630 landowners; the letter requests that the Commission weigh these impacts against Pacific Connector's failure to execute a single contract for transportation capacity.

[26] Bob Barker, John Clarke, Oregon Women's Land Trust, Evans Schaaf Family LLC, Stacey McLaughlin, and Craig McLaughlin.

B. Request for Formal Hearing

26. Friends of Living Oregon Waters and Columbia Riverkeeper request that the Commission establish a full evidentiary hearing to determine if: (1) the proposed project is in the public interest or required for public convenience and necessity; (2) construction and operation of the project would result in significant impacts to water quality; (3) the project would degrade property values; and (4) the applicants provided adequate information regarding the project's impacts.

IV. Discussion

A. Pacific Connector's Proposed Pacific Connector Gas Pipeline

27. Since Pacific Connector's proposed pipeline facilities will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of NGA sections 7(c) and (e).[27]

1. Certificate Policy Statement

28. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new construction.[28] The Certificate Policy Statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new pipeline facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

29. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the

[27] 15 U.S.C. §§ 717f(c) and 717f(e) (2012).

[28] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis where other interests are considered.

a. Threshold Requirement – No Subsidization

30. As noted above, the threshold requirement is that the applicant must be prepared to financially support the project without relying on subsidization from existing customers. Pacific Connector is a new natural gas company and does not have existing customers. Therefore, there will be no subsidization. The Commission finds that Pacific Connector satisfies the threshold requirement of the Certificate Policy Statement.

b. Impact on Existing Customers and Pipelines

31. Once an applicant has satisfied the threshold requirement that its project is financially viable without subsidies, the Commission will consider the effects of the project on three major interests identified in the Certificate Policy Statement as having the potential to be adversely affected by approval of a major certificate project: the interests of the applicant's existing customers, the interests of competing existing facilities and their captive customers, and the interests of landowners and surrounding communities.[29] As stated above, Pacific Connector is a new company proposing to construct and operate a new pipeline; thus, it has no existing customers or services that would be impacted by its current proposal. Additionally, the proposal will not replace firm transportation service on any other pipelines in the market. Therefore, we find that Pacific Connector will not adversely impact existing pipelines in the market or their captive customers.

c. Impact on Landowners and Communities

32. Pacific Connector has made efforts to minimize the adverse effects its project might have on landowners and communities by proposing to locate approximately 95 of the total 232 miles (41 percent) of proposed pipeline adjacent to existing powerlines, roads, and other pipelines. The remaining 59 percent of the route would be constructed

[29] Certificate Policy Statement, 88 FERC at 61,747.

within newly created right-of-way on land that is primarily forest, with agricultural and rangeland being the next two most predominant land uses. Approximately 32.1 percent of the pipeline (or 74.5 miles) would cross federal and state lands, while the remaining 67.9 percent of the pipeline (or 157.3 miles) would cross private lands.[30]

33. Many intervenors and commenters express concern regarding the Pacific Connector Pipeline's potential to adversely impact land valuation, tax revenue, and business operations in the area. In the Landowner Letter, several intervenors request that the Commission balance Pacific Connector's failure to provide evidence of market demand for the proposed pipeline and its failure to acquire easements along the proposed right-of-way[31] against the impacts to landowners who would face eminent domain actions if the Commission issues a certificate for the pipeline.

34. The Commission will approve an application for a certificate of public convenience and necessity only if the public benefits from a proposed project outweigh any adverse effects.[32] The focus of the Commission's analysis under the Certificate Policy Statement is on the impact of a proposed project on the relevant interests balanced against the benefits to be gained from the project. This is a proportional approach, where the amount of evidence required to establish need will depend on the potential adverse effects of the proposed project.[33] The more interests adversely affected, or the more adverse impact a project would have on a particular interest, the greater the showing of need and public benefits required to balance the adverse impact.[34]

35. The Certificate Policy Statement describes a situation where sponsors of a new company proposing to serve a new, previously unserved market "are able to acquire all, or substantially all, of the necessary right-of-way by negotiation prior to filing the application" and explains that "[s]uch a project would not need any additional indicators

[30] *See* Final Environmental Impact Statement at 2-32 and 4-12.

[31] Pacific Connector has not submitted evidence that it has obtained any easement or right-of-way agreements for the necessary use of private lands.

[32] Certificate Policy Statement, 90 FERC at 61,389, 61,396.

[33] *Arlington Storage Co., LLC*, 128 FERC ¶ 61,261, at P 7 (2009); *Transcontinental Gas Pipe Line Corp.*, 120 FERC ¶ 61,181, at P 90 (2007); *Midwestern Gas Transmission Co.*, 116 FERC ¶ 61,182, at P 37 (2006).

[34] Certificate Policy Statement, 88 FERC at 61,749.

of need . . . [since] landowners would not be subject to eminent domain proceedings."[35] The Certificate Policy Statement goes on to recognize that it may not be possible for a sponsor to acquire all the necessary right-of-way by negotiation, stating that:

> [T]he company might minimize the effect of the project on landowners by acquiring as much right-of-way as possible. In that case, the applicant may be called upon to present some evidence of market demand, but under this sliding scale approach the benefits needed to be shown would be less than in a case where no land rights had been previously acquired by negotiation.[[36]]

36. The Certificate Policy Statement allows an applicant to rely on a variety of relevant factors to demonstrate need, rather than requiring evidence that a specific percentage of the proposed capacity is subscribed under long-term precedent or service agreements.[37] These other factors might include, but are not limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[38] The Commission stated that it will consider all such evidence submitted by the applicant reflecting on the need for the project. Nonetheless, the Certificate Policy Statement made clear that, although submittal of precedent agreements is no longer required, they are still significant evidence of need or demand for a project.[39]

37. In *Turtle Bayou Gas Storage Company, LLC* (*Turtle Bayou*),[40] the Commission denied Turtle Bayou's application to construct and operate a natural gas storage facility, finding that it failed to meet the criteria of the Certificate Policy Statement. As a new company with no existing customers, Turtle Bayou met the threshold requirement of no subsidization. However, as evidence of public benefits, Turtle Bayou presented only general assertions of a need for natural gas storage at the regional and national level. There was no evidence that any of the proposed capacity had been subscribed under

[35] *Id.* at 61,748.

[36] *Id.* at 61,749.

[37] *Id.* at 61,747.

[38] *Id.*

[39] *Id.*

[40] 135 FERC ¶ 61,233 (2011).

precedent agreements. At the same time, the record showed that Turtle Bayou owned virtually none of the property rights which would be necessary to develop its project. Having been unable to acquire those rights through negotiation with the single landowner, it appeared that Turtle Bayou would have to obtain them through exercise of the right of eminent domain provided by a Commission certificate. Given these circumstances, the Commission found that "[t]he generalized showing [of project need] made by Turtle Bayou does not outweigh the impact on the landowner that holds the majority of property rights needed to develop the proposed project ... Therefore, we cannot find that Turtle Bayou's proposed project is required by the public convenience and necessity, and we deny its request for certificate authority to construct and operate its project."[41]

38. In this case, the Pacific Connector Pipeline will impact 157.3 miles of privately-owned lands, held by approximately 630 landowners (54 of which have intervened). As stated above, the landowners contend that the pipeline will have negative economic impacts, such as land devaluation, loss of tax revenue, and economic harm to business operations (e.g., oyster and timber harvesting and farming). While we cannot predict the outcome of the eventual negotiations, it currently appears that at least some portion of the necessary property rights will need to be obtained through the exercise of eminent domain.[42] The Certificate Policy Statement makes clear that holdout landowners cannot veto a project that the Commission finds is required by the public convenience and necessity after balancing all relevant factors and considerations.[43] However, "the strength of the benefit showing will need to be proportional to the applicant's proposed exercise of eminent domain procedures."[44]

39. Here, Pacific Connector has presented little or no evidence of need for the Pacific Connector Pipeline. Pacific Connector has neither entered into any precedent agreements for its project, nor conducted an open season, which might (or might not) have resulted in "expressions of interest" the company could have claimed as indicia of demand. As it stands, Pacific Connector states that the pipeline will benefit the public by delivering gas supply from the Rocky Mountains and Canada to the Jordan Cove LNG Terminal and by providing an additional source of gas supply to communities in southern Oregon (though,

[41] *Id.* at 34.

[42] Pacific Connector has not filed any negotiated agreements to access private property along the pipeline's route.

[43] Certificate Policy Statement, 88 FERC at 61,749.

[44] *Id.*

again, it has presented no evidence of demand for such service). Pacific Connector also contends that construction of the pipeline and LNG terminal will create temporary construction jobs and full-time operation jobs and millions of dollars in property, sales, and use taxes to state and local governments. Finally, Pacific Connector contends that the Commission has previously found that the benefits provided by pipelines that deliver feed gas to export terminals outweigh the minimal adverse impacts and such projects are required by the public convenience and necessity.[45]

40. Pacific Connector is essentially asking the Commission to rely on DOE's finding that authorization of the commodity export is consistent with the public interest as sufficient to support a finding by the Commission that the Pacific Connector pipeline is required by the public convenience and necessity, as there is no other proposed way for gas to be delivered to the Jordan Cove LNG Terminal for export. Additionally, Pacific Connector emphasizes that neither the pipeline nor the terminal will be constructed unless and until customers ultimately subscribe to a significant portion of the capacity of the facilities. The Commission has not previously found a proposed pipeline to be required by the public convenience and necessity under NGA section 7 on the basis of a DOE finding under NGA section 3 that the importation or exportation of the commodity natural gas by an entity proposing to use the services of an associated LNG facility is consistent with the public interest.[46] Nor has the Commission relied solely on the fact

[45] Pacific Connector's statement is misleading because the facts presented in its cited cases differ greatly from the facts here. In *Dominion Cove Point LNG, LP*, 148 FERC ¶ 61,244 (2014), *reh'g denied*, 151 FERC ¶ 61,095 (2015), the proposed pipeline was fully contracted and would be constructed entirely on Dominion-owned land and/or right-of-ways. *Dominion Cove Point LNG, LP*, 148 FERC ¶ 61,244 at P 58. Similarly, in *Cheniere Creole Trail Pipeline, L.P.*, 142 FERC ¶ 61,137 (2013), the proposed pipeline was fully subscribed and did not need new right-of-way or easements for construction. *Id.* at PP 13 and 31.

[46] DOE's order did not purport to consider any issues related to the Pacific Connector Pipeline. While the regulatory functions of section 3 of the NGA (relating to the import and export of natural gas) were transferred to the Secretary of Energy (Secretary) in 1977 pursuant to section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b) (2006), the regulatory functions of section 7 (relating to the sale for resale and transportation of natural gas in interstate commerce) were transferred to and vested in the Commission pursuant to section 402(a)(1)(D) of that Act. 42 U.S.C. § 7172(a)(1)(D) (2006). Further, while the Secretary retained authority to authorize imports and exports of the commodity natural gas under section 3, the Secretary subsequently delegated to the Commission the authority to approve or disapprove the construction and operation of particular facilities, the site at which facilities shall be

that a company is not likely to proceed with construction of facilities in the absence of a market for a project's services – particularly in the face of significant opposition from directly-impacted landowners. Further, while the Commission could ensure avoidance of unnecessary environmental impacts by including a certificate condition providing that authorization for the commencement of construction would not be granted until Pacific Connector has successfully executed contracts for a certain level of service, the right to eminent domain is inherent in a certificate issued under NGA section 7. Thus, the Commission's issuance of a certificate would allow Pacific Connector to proceed with eminent domain proceedings in what we find to be the absence of a demonstrated need for the pipeline.

41. We find the generalized allegations of need proffered by Pacific Connector do not outweigh the potential for adverse impact on landowners and communities.

d. Certificate Policy Statement Conclusion

42. Because the record does not support a finding that the public benefits of the Pacific Connector Pipeline outweigh the adverse effects on landowners, we deny Pacific Connector's request for certificate authority to construct and operate its project, as well as the related blanket construction and transportation certificate applications.

B. Jordan Cove's Proposed LNG Terminal

43. The Jordan Cove LNG Terminal and the Pacific Connector Pipeline, though requiring authorization under different sections of the NGA, have been proposed as two segments of a single, integrated project. As described above, Pacific Connector has stated that although its pipeline will be capable of delivering gas to markets in southern Oregon through an interconnection with Northwest's Grant Pass Lateral, it will not build the project unless the Jordan Cove LNG Terminal Project goes forward.[47] Similarly, without a source of natural gas, proposed here to be delivered by the Pacific Connector Pipeline, it will be impossible for Jordan Cove's liquefaction facility to function.

located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports. The Secretary's current delegation of authority to the Commission relating to import and export facilities was renewed by the Secretary's DOE Delegation Order No. 00-044.00A, effective May 16, 2006.

[47] *See* Pacific Connector's Application at 7 and 9, and Pacific Connector's June 1, 2015 Data Response at 2.

44. As discussed above, in determining whether a proposed project will serve the public interest under the Certificate Policy Statement, the Commission balances the public benefits of a proposed project against the potential adverse consequences. While the Certificate Policy Statement does not specifically apply to facilities authorized under NGA section 3, the Commission is still required to conclude that authorization of such facilities will not be inconsistent with the public interest.[48] We find that without a pipeline connecting it to a source of gas to be liquefied and exported, the proposed Jordan Cove LNG Terminal can provide no benefit to the public to counterbalance any of the impacts which would be associated with its construction.

45. The Commission has not previously authorized LNG export terminal facilities without a known transportation source of natural gas.[49] Here, the Pacific Connector

[48] *See AES Sparrows Point LNG, LLC,* 126 FERC ¶ 61,019, at n.21 (2009), where the Commission noted that the rationale of balancing benefits against burdens to determine the public interest is the same in both types of proceedings.

[49] *Corpus Christi Liquefaction, LLC and Cheniere Corpus Christi Pipeline, L.P.*, 149 FERC ¶ 61,283 (2014), *reh'g denied*, 151 FERC ¶ 61,098 (2015) (order granting authorization under NGA section 3 to construct and operate import and export facilities located in San Patricio and Nueces Counties, Texas, and issuing a certificate to construct and operate a 23-mile-long pipeline in San Patricio County, Texas to transport natural gas bi-directionally between the liquefaction project and existing interstate and intrastate natural gas pipeline systems); *Dominion Cove Point LNG, LP*, 148 FERC ¶ 61,244 (2014), *reh'g denied*, 151 FERC ¶ 61,095 (2015) (order granting authorization under NGA section 3 to construct and operate liquefaction facilities at the company's existing LNG terminal in Calvert County, Maryland, to export domestically-produced natural gas supplied by the company's pipeline facilities); *Freeport LNG Development, L.P., FLNG Liquefaction, LLC, FLNG Liquefaction 2, LLC, and FLNG Liquefaction 3, LLC*, 148 FERC ¶ 61,076 (2014), *reh'g and clarification denied*, 149 FERC ¶ 61,119 (2014) (order granting authorization under NGA section 3 to construct and operate natural gas pretreatment facilities and several interconnecting pipelines to support liquefaction and export operations at the company's existing LNG terminal in Freeport, Texas); *Cameron LNG, LLC and Cameron Interstate Pipeline, LLC*, 147 FERC ¶ 61,230 (2014), *reh'g rejected*, 148 FERC ¶ 61,073 (2014), *reh'g denied*, 148 FERC ¶ 61,237 (2014) (order granting authorization under NGA section 3 to construct and operate export facilities at the company's existing LNG import terminal in Cameron, Louisiana, and issuing a certificate to construct and operate a pipeline and compression facilities to transport domestically-produced gas to the LNG terminal for liquefaction and export); *Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P.*, 139 FERC ¶ 61,039 (2012) (order granting NGA section 3 authorization to construct and operate liquefaction facilities to

Pipeline is the only proposed transportation path for natural gas to reach the Jordan Cove LNG Terminal.

46. Because the record does not support a finding that the Jordan Cove LNG Terminal can operate to liquefy and export LNG absent the Pacific Connector Pipeline, we find that authorizing its construction would be inconsistent with the public interest. Therefore, we also deny Jordan Cove's request for authorization to site, construct and operate the Jordan Cove LNG Terminal.[50]

V. Conclusion

47. Given this action, we dismiss as moot the environmental concerns raised by Sierra Club in its protest.[51] Likewise, Friends of Living Oregon Waters' and Columbia Riverkeeper's requests for a formal hearing on the application are moot.

export domestically-produced natural gas received from two interstate pipeline interconnected with the company's existing LNG terminal); and *Sabine Pass LNG, L.P.*, 127 FERC ¶ 61,200 (2012), *reh'g denied*, 140 FERC ¶ 61,076 (2012) (order amending authorization under NGA section 3 to allow Sabine Pass LNG, L.P. to export LNG that had been previously imported and stored in its liquid form at its existing Sabine Pass Liquefied Natural Gas Terminal located in Cameron Parish, Louisiana).

[50] We acknowledge that pursuant to its authority under NGA section 3, DOE's Office of Fossil Energy (DOE/FE) issued Jordan Cove authorization to export 15 MPTA, or 2.0 Bcf/d, of domestically produced natural gas by vessel to all free trade agreement (FTA) and non-FTA nations, finding that the potential export of such volumes to not be inconsistent with the public interest. *See* DOE/FE Order No. 3041 (December 7, 2011) (authorizing Jordan Cove to export 9 MMTA or 1.2 Bcf/d of natural gas to FTA nations for a 30-year term) and DOE/FE Order No. 3413 (March 24, 2014) (conditionally authorizing Jordan Cove to export 6 MMTA or 0.8 Bcf/d of natural gas to non-FTA nations for a 20-year term). In granting Jordan Cove long-term authorization to export LNG, DOE/FE found that there was substantial evidence of economic and other public benefits such that the authorization was not inconsistent with the public interest. However, as stated, we view the Jordan Cove Project as an integrated project, comprising both the terminal and the pipeline. Accordingly, since we are denying authorization for the Pacific Connector Pipeline as proposed, we are also denying our authorization for the Jordan Cove LNG Terminal.

[51] Additionally, we dismiss as moot the Confederated Tribes of Coos, Lower Umpqua, and Siuslaw Indians' February 22, 2016 request for an additional 30 days to comment on the Pacific Connector Pipeline Project Cultural Resources Survey.

48. Our actions here are without prejudice to Jordan Cove and/or Pacific Connector submitting a new application to construct and/or operate LNG export facilities or natural gas transportation facilities should the companies show a market need for these services in the future.

49. The Commission, on its own motion, received and made part of the record in these proceedings all evidence, including the applications and exhibits thereto, submitted in support of the authorizations sought herein, and upon consideration of the record,

The Commission orders:

(A) In Docket No. CP13-492-000, Pacific Connector's request for a certificate of public convenience and necessity under section 7(c) of the NGA to construct and operate an approximately 232-mile-long, 36-inch-diameter pipeline is denied.

(B) In Docket No. CP13-483-000, Jordan Cove's request for authorization under section 3 of the NGA to site, construct, and operate its LNG terminal in Coos Bay County, Oregon is denied.

(C) The untimely motions to intervene are granted as discussed herein.

(D) Jordan Cove's July 3, 2013 answer is denied.

(E) The Friends of Living Oregon Waters' and Columbia River Clean Energy Coalition's requests for an evidentiary hearing are dismissed as moot.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

Interventions in Docket No. CP13-483-000
*out of time

Blue Ridge Alternate Route 2013
Bob Barker
C-2 Cattle Company
Cascadia Wildlands and Oregon Wild
Center for Biological Diversity
Citizens Against LNG, Inc; Citizens Against LNG; & Jody McCaffree (as an individual)
Clam Diggers Association of Oregon*
Clausen Oysters and Lilli Clausen (as an individual)*
Columbia Riverkeeper
Confederated Tribes of the Coos, Lower Umpqua, and Siuslaw Indians
Coos Bay Oyster Company and Jack Hempell (as an individual)*
Coos County Sheep Company and Dustin A Clarke (as an individual)
David McGriff
Dennis and Karen Henderson (as individuals and as trustees of the Henderson Revocable Intervivos Trust)*
Evans Schaaf Family LLC and Deborah Evans and Ronald Schaaf (as individuals)*
Food & Water Watch
Fred Messerle & Sons, Inc.
Friends of Living Oregon Waters
Holly Hall Stamper
James R. Davenport
Jean Stalcup
Jerry S. Palmer*
Jonathan M. Hanson
John M. Roberts, Jr.*
Klamath-Siskiyou Wildlands Center
Landowners United and Clarence Adams (as an individual)
LNG Development Company, LLC (d/b/a/ Oregon LNG) and Oregon Pipeline Company, LLC
Marcella and Alan Laudani
Mark Sheldon
National Marine Fisheries Service
Northwest Industrial Gas Users
Nova Lovell
Oregon Coast Alliance
Oregon Department of Energy
Oregon Department of Environmental Quality and the Oregon Department of Fish and

Wildlife (jointly)
Oregon Department of Land Conservation and Development
Oregon Shores Conservation Coalition
Oregon Women's Land Trust
Pacific Coast Federation of Fisherman's Associations and the Institute for Fisheries
Resources (jointly)
Richard F. Knablin
Rogue Riverkeeper
Sherry M Church
Sierra Club*
State of Wyoming
Waterkeeper Alliance*
Western Environmental Law Center
Wyoming Pipeline Authority

Appendix B

Interventions in Docket No. CP13-492-000

*out of time

Bill Gow
Blue Ridge Alternate Route 2013
Bob Barker
C-2 Cattle Company
Cascadia Wildlands and Oregon Wild
Center for Biological Diversity
Citizens Against LNG, Inc.; Citizens Against LNG; and Jody McCaffree (as an individual)
Clam Diggers Association of Oregon*
Clausen Oysters and Lilli Clausen (as an individual)*
Columbia Riverkeeper
Confederated Tribes of the Coos, Lower Umpqua, and Siuslaw Indians
Coos Bay Oyster Company and Jack Hempell (as an individual)*
Coos County Sheep Company and Dustin A Clarke (as an individual)
Curtis Pallin
Daniel Fox
David McGriff
David Messerle
Dee Willis
Dennis and Karen Henderson (as individuals and as trustees of the Henderson Revocable Intervivos Trust)*
Evans Schaaf Family LLC and Deborah Evans and Ronald Schaaf (as individuals)*
Food & Water Watch
Fred Messerle & Sons, Inc.
Friends of Living Oregon Waters
Gary Gunnell
Gas Transmission Northwest LLC
Jake Robinson
James R. Davenport
Jason Messerle
Jean Stalcup
Jeff Messerle
Jennifer LM Barrows and Richard A Barrows
John Caughell
John Clarke
John F. Caughell and Tammy S Bray*
John M. Roberts, Jr.

John Muenchrath
John Szymik
Jonathan M. Hanson
Joseph P Quinn
Karen Solomon
Klamath-Siskiyou Wildlands Center
Landowners United and Clarence Adams (as an individual)
LNG Development Company, LLC (d/b/a Oregon LNG)
Marcella and Alan Laudani
Mark Sheldon
National Marine Fisheries Service
Northwest Industrial Gas Users
Nova Lovell
Oregon Coast Alliance
Oregon Department of Energy
Oregon Department of Environmental Quality and the Oregon Department of Fish and Wildlife (jointly)
Oregon Department of Land Conservation and Development
Oregon Shores Conservation Coalition
Oregon Women's Land Trust
Pacific Coast Federation of Fisherman's Associations and the Institute for Fisheries Resources (jointly)
Paul M Washburn
Process Gas Consumers Group
Rogue Riverkeeper
Ronald L Foord
Ruby Pipeline
Seneca Jones Timber Company, LLC
Shane Johnson
Sierra Club
Stacey and Craig McLaughlin (as individuals)*
State of Wyoming
Southwest Gas Corporation
Victor Elam
Waterkeeper Alliance*
Western Environmental Law Center
Will Wright
Wyoming Pipeline Authority

Exhibit 2

Jordan Cove
Energy Project, L.P.

Pacific Connector
GAS PIPELINE

September 21, 2017

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Pacific Connector Gas Pipeline, LP
Docket No. CP17-___000
Abbreviated Application for Certificate of Public Convenience and Necessity and Related Authorizations

Dear Ms. Bose:

Pacific Connector Gas Pipeline, LP ("PCGP") hereby submits for filing with the Federal Energy Regulatory Commission ("Commission" or "FERC") an Abbreviated Application for a Certificate of Public Convenience and Necessity and for Related Authorizations ("Application") to construct, install, own, and operate a new, approximately 229-mile-long, 36-inch-diameter natural gas transmission pipeline ("Pipeline") capable of transporting approximately 1,200,000 dekatherms per day of natural gas from interconnections with two existing interstate natural gas pipelines near Malin, Oregon, to the proposed Jordan Cove Liquefied Natural Gas export facility being developed by Jordan Cove Energy Project L.P.

Included herewith are four volumes. Volume I contains public information and comprises the Application and its public exhibits, except Exhibit F-I. Volume II contains the public version of Exhibit F-I and response trackers that indicate the location of each response to comments provided by FERC staff and other cooperating agencies on the draft resource reports. Volume III contains privileged and confidential information and comprises Appendices D.1 (landowner and stakeholder lists), B.4 (cultural resource survey reports), B.6 (paleontology assessment), and D.4 (cultural resources survey results) of Exhibit F-1, certain portions of Exhibit I (confidential market information), a version of the alignment sheets with landowner information, and proprietary hydraulic flow models. Volume IV contains Critical Energy Infrastructure Information ("CEII") and comprises Exhibits G, G-I, and G-II. The proprietary hydraulic flow models contain CEII as well.

Pursuant to the Commission's guidelines for eFiling,[1] PCGP is hereby eFiling the Application and will provide two complete copies of the Application to OEP Room 62-46 and one complete copy to OGC-EP Room 101-66. Pursuant to Section 388.112 of the Commission's regulations,[2] PCGP requests that the information filed in Volume III be treated as privileged and confidential and that it not be released to the public. This volume is marked "**CONTAINS**

[1] Federal Energy Regulatory Commission Filing Guide/Qualified Documents List (Feb. 14, 2017), *available at* http://www.ferc.gov/docs-filing/efiling/filing.pdf.

[2] 18 C.F.R. § 388.112 (2017).

PRIVILEGED INFORMATION—DO NOT RELEASE (CUI//PRIV)" and contains information that is customarily treated as privileged and confidential. Pursuant to Section 388.113 of the Commission's regulations,[3] PCGP requests that the information filed in Volume IV be treated as CEII and that it not be released to the public. This volume is marked "**CONTAINS CRITICAL ENERGY INFRASTRUCTURE INFORMATION—DO NOT RELEASE (CUI//CEII)**" and PCGP is submitting this information as CEII because it contains information about the location of critical infrastructure that could be useful to a person planning an attack on aboveground facilities. PCGP requests that the CEII label apply for a period of five years, unless redesignated by the CEII Coordinator.

Questions pertaining to CEII and privileged and confidential information may be submitted to:

Natalie Eades
Senior Counsel
Jordan Cove Energy Project L.P.
5615 Kirby, Suite 500
Houston, Texas 77005
Phone: 713-400-2841
Email: natalie.eades@vereseninc.com

Should you have any questions, please contact me at espomer@vereseninc.com or (866) 227-9249.

Sincerely,

/s/ Elizabeth Spomer
Elizabeth Spomer
President and CEO
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP

Attachments

cc: John Peconom (FERC)
J. Rich McGuire (FERC) (letter and application text only)
James A. Martin (FERC) (letter and application text only)
Paul D. Friedman (FERC) (letter and application text only)

[3] *Id.* at § 388.113.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Pacific Connector Gas Pipeline, LP	)	Docket No. CP17-___-000
	)	
	)	

ABBREVIATED APPLICATION OF PACIFIC CONNECTOR GAS PIPELINE, LP FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Filed: September 21, 2017

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Connector Gas Pipeline, LP	))))	Docket No. CP17-___-000

ABBREVIATED APPLICATION OF PACIFIC CONNECTOR GAS PIPELINE, LP FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Pursuant to Section 7(c) of the Natural Gas Act ("NGA"), as amended,[1] and Parts 157 and 284 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") regulations,[2] Pacific Connector Gas Pipeline, LP ("PCGP") hereby files this application ("Application") requesting the following:

1. a certificate of public convenience and necessity pursuant to Part 157, Subpart A of the Commission's regulations authorizing PCGP to construct, install, own, and operate a new natural gas pipeline system, including pipeline facilities, a compressor station, metering and regulating stations, and appurtenant facilities in southwestern Oregon;
2. a blanket certificate pursuant to Part 157, Subpart F of the Commission's regulations, authorizing PCGP to construct, operate, acquire, and abandon certain facilities as described in Part 157, Subpart F;
3. a blanket certificate pursuant to Part 284, Subpart G of the Commission's regulations authorizing PCGP to provide open-access firm and

[1] 15 U.S.C. § 717f(c) (2012).

[2] 18 C.F.R. Pts. 157, 284 (2017).

interruptible interstate natural gas transportation services on a self-implementing basis with pregranted abandonment for such services;

4. approval of the *pro forma* FERC Gas Tariff ("Tariff"), which includes the authority to enter into negotiated rate agreements, attached to this Application as part of Exhibit P;

5. approval of PCGP's initial recourse rates and the non-conforming provisions in the service agreements with the anchor shipper; and

6. a waiver of the Commission's regulation requiring segmentation and such other authorizations and waivers as may be necessary from the Commission to allow PCGP to undertake the activities described in this Application.

PCGP respectfully requests that the Commission issue a Final Environmental Impact Statement ("EIS") by August 2018 and the authorizations and waivers requested herein by November 2018, so that PCGP will be able to commence construction on a timely basis and place its facilities into service by the fourth quarter of 2022. Since the liquefaction and liquefied natural gas ("LNG") export facilities being developed by Jordan Cove Energy Project L.P. ("JCEP") in Coos County ("LNG Terminal") require gas supply from the Pipeline to undertake commissioning and testing, PCGP is proposing to place the Pipeline into service prior to the in-service date for the LNG Terminal in the first half of 2024.

In support of its request, PCGP states as follows:

I.
EXECUTIVE SUMMARY

The Pipeline is a new interstate pipeline system designed primarily to meet the natural gas transportation needs of the proposed LNG Terminal. The Pipeline and the LNG Terminal are referred to, collectively, as the "Project." JCEP is contemporaneously seeking authorization from the Commission under Section 3 of the NGA to site, construct, and operate the LNG Terminal, located on the bay side of the North Spit of Coos Bay, Oregon. JCEP will design the LNG Terminal to receive a maximum of 1,200,000 dekatherms per day ("Dth/d") of natural gas and produce a maximum of 7.8 million metric tons per annum ("mtpa") of LNG for export. The target in-service date for the Pipeline is scheduled for the fourth quarter of 2022, and the target in-service date for the LNG Terminal is scheduled for the first half of 2024.

The Pipeline will be an approximately 229-mile-long, 36-inch-diameter natural gas transmission pipeline capable of transporting 1,200,000 Dth/d of natural gas from a point of origin near the intersection of two existing interstate natural gas pipelines (Ruby Pipeline LLC ("Ruby") and Gas Transmission Northwest LLC ("GTN")), to the proposed LNG Terminal. The Pipeline will include a new compressor station, three new meter stations, five new pig launcher/receiver units, 17 new mainline block valves, and new communications towers and equipment buildings. During its routing analysis of the Pipeline, PCGP worked diligently to ensure that its preferred route minimizes environmental impacts and reviewed more than 1,000 miles of alternative alignments for the proposed route.[3] Under the preferred route, the Pipeline will be co-located with or adjacent to existing powerlines, roads, and pipelines for approximately 42.7 percent of its

[3] The proposed route includes modifications to the route that was previously analyzed in Docket No. CP13-492, resulting in a net reduction in environmental impacts of 33.4 acres.

length; the remaining 57.3 percent of the alignment will be cross-country construction. Additionally, PCGP has incorporated into its proposed route 54 route modifications resulting from landowner requests and design enhancements, 13 of which accommodated landowner requests, minimized parcel encumbrances, or avoided structures or facilities. Additionally, four of the minor route modifications have resulted in avoidance of seven landowner parcels. Through this process, PCGP has minimized any adverse effects the Pipeline may have on landowners and the surrounding community.

The Project will result in $9.8 billion of construction spending in Oregon, and of the $9.8 billion spent constructing the Project, $2.88 billion will be spent directly at Oregon businesses. Through the Project's annual purchases of goods and services from Oregon businesses and household spending by employees, the Project will support approximately $96 million in additional labor income and approximately $236 million in additional output for Oregon businesses. Construction of the Project will result in 6,147 peak monthly jobs (1,996 for the LNG Terminal and 4,131 for the Pipeline) and operation of the Project will directly employ 215 workers (200 for the LNG Terminal and 15 for the Pipeline). The benefits of the Pipeline also include potential future deliveries to communities along the Pipeline that have previously not had access to clean-burning natural gas and facilitation of the re-building of the industrial and property tax base of the Project area, including payment of $20 million per year of operations by PCGP for school districts and other local districts.

PCGP and JCEP executed two Transportation Services Precedent Agreements ("Precedent Agreements") in July 2017 that provide for JCEP, as an anchor shipper, to contract for 95.8 percent of the firm capacity available on the Pipeline. PCGP conducted a binding open season from July 18, 2017 through August 17, 2017, to determine the level of market demand for firm transportation service provided through the Pipeline. The JCEP Precedent Agreements are sufficient to demonstrate the need for the Pipeline, as proposed in this Application.

PCGP has not provided service in interstate commerce. Therefore, in this proceeding, PCGP requests an open-access blanket certificate under Part 284, Subpart G of the Commission's regulations. In addition, PCGP requests a blanket construction certificate under Part 157, Subpart F of the Commission's regulations.

PCGP is also seeking approval of its *pro forma* FERC Gas Tariff ("Tariff"), including the authority to enter into negotiated rate agreements, which is attached as part of Exhibit P hereto. PCGP is proposing initial recourse rates that include a two-part rate for firm transportation service and a one-part rate for interruptible transportation service that is equal to the 100 percent load factor derivative of the Rate Schedule FT-1 reservation and usage rates.

A detailed explanation of the Pipeline facilities is included in Resource Report 1 to the Environmental Report, included herewith as Exhibit F-1. The Environmental Report fully demonstrates that the Pipeline has been sited first to avoid, and then mitigate, environmental impacts. The Environmental Report also demonstrates that the Pipeline has been designed using all necessary equipment to satisfy applicable safety and security requirements.

PCGP submits that the Pipeline is required by the public convenience and necessity, and meets the criteria set forth in the Commission's Certificate Policy Statement addressing new facilities.[4]

II.
INFORMATION REGARDING THE APPLICANT

The exact legal name of PCGP is Pacific Connector Gas Pipeline, LP. PCGP is a Delaware limited partnership with its primary place of business located at 5615 Kirby Drive, Suite 500, Houston, Texas, 77005. Upon acceptance of the certificate of public convenience and necessity sought in this Application and completion of the construction authorized thereunder, PCGP will be subject to the Commission's jurisdiction under the NGA as a natural gas company.

PCGP is a subsidiary of Veresen Inc., a Canadian corporation, which is also the sole owner of JCEP. Veresen Inc., or its predecessor, has been involved in energy infrastructure projects since 1997. On May 1, 2017, Veresen Inc. announced that it would be acquired by Pembina Pipeline Corp., a Canadian corporation. The closing is scheduled for the third or fourth quarter of 2017. If the acquisition is completed as planned, PCGP will continue to be owned by a Canadian corporation and will supplement this Application accordingly.

III.
COMMUNICATIONS

The persons to whom correspondence and communications concerning this Application should be directed and upon whom service is to be made are as follows:[5]

---

[4] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999); *Order Clarifying Statement of Policy*, 90 FERC ¶ 61,128 (2000) ("Certificate Policy Statement").

[5] PCGP respectfully requests that the Commission waive Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), in order to allow each of the designated representatives to be included on the official service list.

* Elizabeth Spomer
President and CEO
Jordan Cove Energy Project L.P.
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: (866) 227-9249
Email: espomer@vereseninc.com

* Rose Haddon
Director, Regulatory Affairs
Jordan Cove Energy Project L.P.
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: (866) 227-9249
Email: rose.haddon@jordancovelng.com

* Anita R. Wilson
* Christopher J. Terhune
Victoria R. Galvez
Vinson & Elkins L.L.P.
2200 Pennsylvania Avenue NW
Suite 500 West
Washington, D.C. 20037
Phone: (202) 639-6500
Facsimile: (202) 879-8976
Email: awilson@velaw.com
cterhune@velaw.com

IV. DESCRIPTION OF FACILITIES

The Pipeline proposed in this Application is a new, approximately 229-mile, 36-inch diameter pipeline between a point of origin near the intersection of Ruby and GTN and the LNG Terminal, crossing portions of Klamath, Jackson, Douglas, and Coos Counties, Oregon. The western terminus of the Pipeline route is at the Jordan Cove Meter Station located on the LNG Terminal site in Coos County, Oregon.

Aboveground facilities for the Pipeline include one new compressor station, three new meter stations, five new pig launcher/receiver units, 17 mainline block valves, and new communications towers and equipment buildings. The Pipeline will provide the LNG Terminal with natural gas via the Jordan Cove Meter Station located in Coos County, Oregon. To meet pressure and flow requirements at the Jordan Cove Meter Station, PCGP will install two turbine-driven centrifugal compressor units, each providing 31,100 ISO horsepower of compression (for a total installed operating capacity of 62,200 ISO horsepower), and will install one spare unit of 31,100 ISO horsepower (which is redundant and for reliability purposes only) at the Klamath Compressor Station in Klamath County, Oregon, approximately 1.75 miles northeast of Malin, Oregon.

The Pipeline will receive all of its gas supply from interconnections with GTN and Ruby. The meter stations for these interconnections will be co-located within the Klamath Compressor Station and each will be capable of receiving up to 100 percent of the Pipeline design capacity of 1,200,000 Dth/d. The meter stations and compressor station will require a communications link with the gas control monitoring system. Multiple radio towers will be required between the Jordan Cove Meter Station and the compressor station.

Mainline block valves will be located along the Pipeline's permanent easement and will be equipped with actuators and control equipment as necessary to allow remote operations. Pig launcher/receiver equipment will be located at each end of the Pipeline, the Jordan Cove Meter Station, and the Klamath Compressor Station and at three intermediate locations along the Pipeline.

The Pipeline will require new right-of-way for construction and operation. The alignment will be co-located with or adjacent to existing powerlines, roads, and pipelines for approximately 97.74 miles or 42.7 percent of its length; the remaining 57.3 percent of the alignment will be cross-country construction. Construction of the Pipeline will require acquisition of temporary construction rights-of-way, temporary extra work areas ("TEWAs"), and permanent easements. PCGP proposes to utilize a standard 95-foot wide temporary construction right-of-way with a 50-foot permanent easement except where otherwise required by local conditions. In addition to the construction right-of-way, site-specific characteristics of the right-of-way make it necessary to obtain TEWAs.

After construction, PCGP will retain the permanent easement for long-term operations and maintenance of the Pipeline. The dimensions of the permanent easement on all federally-managed and private lands will be 50 feet, except as noted below, and will be centered over the pipe as installed.[6]

V. CERTIFICATE POLICY STATEMENT AND PUBLIC CONVENIENCE AND NECESSITY

In determining whether a proposed pipeline is required by the public convenience and necessity, the Commission considers whether the proposal meets the criteria set forth in its Certificate Policy Statement addressing new facilities.[7] The Certificate Policy Statement requires an applicant to demonstrate that a new project: (i) will not rely on subsidization from existing customers, (ii) has eliminated or minimized any adverse effects the project may have on existing customers, competing pipelines, and its captive customers. and (iii) has eliminated or minimized any adverse effects the project may have on the interests of landowners and surrounding communities. Under the standards established in the Certificate Policy Statement, the Commission must evaluate a proposed project by balancing the likely public benefit against the adverse impacts associated with the project.[8]

[6] This does not include easements required for the compressor station and communication towers. Additionally, the permanent easement for several HDD water crossings is 10 feet.

[7] *See* Certificate Policy Statement, *supra* note 4.

[8] *Id.* at p. 61,746.

As demonstrated in this Application and in the Resource Reports included herewith, the Pipeline meets the criteria of the Certificate Policy Statement, and approval of the Pipeline is required by the public convenience and necessity.

A. Threshold No-Subsidy Requirement

The Certificate Policy Statement contains a threshold requirement for existing pipelines proposing new construction stating that the pipeline must be prepared to financially support the project without relying on subsidization from existing customers.[9] PCGP is a new pipeline company with no existing customers. As such, the threshold requirement of no subsidization is inapplicable to PCGP.[10]

B. No Adverse Effects on Existing Customers, or on Existing Pipelines and Their Captive Customers

Under the Certificate Policy Statement, an analysis must be conducted to (i) identify potential adverse impacts on existing customers, competing pipelines and their captive customers, or landowners and communities affected by the construction and (ii) determine whether the applicant has made efforts to eliminate or minimize such adverse effects.[11] If residual adverse effects are identified after efforts have been made to minimize them, the Commission will "evaluate the project by balancing the evidence of public benefits to be achieved against residual adverse effects."[12]

---

[9] *Id.*

[10] *See, e.g., ETC Tiger Pipeline, LLC*, 131 FERC ¶ 61,010 at P 18 (2010) ("ETC Tiger") (finding that ETC Tiger, as a newly formed entity, had no risk of subsidization by existing customers); *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224 at P 19 (2009) ("Ruby") (holding that, as a new interstate pipeline, Ruby satisfied the threshold requirement that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers); *Fayetteville Express Pipeline LLC*, 129 FERC ¶ 61,235 at P 18 (2009) ("Fayetteville Express") (concluding that, as a new natural gas pipeline with no existing customers, Fayetteville Express's project met the threshold test that its existing customers not subsidize the project).

[11] Certificate Policy Statement, *supra* note 4, at p. 61,745.

[12] *Id.*

The Pipeline will not result in any adverse impact on competing pipelines and their captive customers since the Pipeline will be an open-access pipeline providing nondiscriminatory service in a competitive market. Further, PCGP is proposing a new pipeline to supply new demand and to increase flow, rather than to compete with existing demand. Construction and operation of the Pipeline will serve to further enhance competition in the market by providing additional competitive service options.

C. Minimal Potential for Adverse Impacts to Landowners and Communities Affected by the Pipeline

Throughout the pre-filing review process in Docket No. PF17-4-000, PCGP and JCEP conducted a public and stakeholder outreach program.[13] Consistent with the Commission's desire for early involvement by potential stakeholders, PCGP and JCEP held four open houses near the LNG Terminal and along the Pipeline route in March 2017 and attended three scoping meetings held by the Commission in June 2017. PCGP and JCEP also participated in bi-weekly calls with FERC Staff and other interested agencies and stakeholders to discuss the background and development of the Project and resolve issues as they arose during the pre-filing review process. PCGP submitted draft resource reports in Docket No. PF17-4-000, and FERC Staff and interested stakeholders reviewed and provided comments on such drafts. Through the substantial work and stakeholder outreach completed to date, PCGP has identified and addressed many potential issues prior to the filing of this Application.

A detailed description of the agencies and other stakeholders with whom PCGP has consulted is contained in Appendix D.1 of Resource Report No. 1. Additionally, a

[13] PCGP had previously conducted extensive public outreach on a substantially similar pipeline route in Docket Nos. CP07-441-000 and CP13-492-000 (import and export projects, respectively).

list of applicable permits and approvals, responsible agencies, and the filing status and schedule of each authorization is provided in Exhibit J.

PCGP submits that its proposed route is environmentally preferable to other potential construction alternatives. The potential environmental impacts associated with the Pipeline and the mitigation measures proposed regarding such impacts are discussed more fully in the Environmental Impact section in Article VII, of this Application and in the accompanying Resource Reports attached hereto as Exhibit F-1. PCGP has worked diligently to achieve the most satisfactory location for its facilities, to the extent practicable, for the affected stakeholders. As shown in Resource Report 10, the Pipeline's location and design were selected to minimize impacts to the environment and to landowners to the greatest extent possible or practical from a pipeline safety and constructability perspective.

During pre-filing and through its work in earlier proceedings, PCGP has refined its route to minimize impacts. Specifically, PCGP has made 54 route modifications in response to requests by landowners and other stakeholders. As a result of these efforts throughout pre-filing and in the prior certificate dockets, only three tenths of one mile is residential out of approximately 229 miles of land crossed by the pipeline. In the 229 miles of right of way there are just eight residences within 50 feet of the construction right of way or TEWAs. PCGP has achieved this limited impact by utilizing public lands, co-locating with other communication and utility corridors, and routing through agricultural, commercial timber, and range lands where the existing land uses can resume after pipeline construction is complete.

Approximately 81 miles of the total right-of-way required are on public land. Of the 148 miles of right-of-way that are privately owned, approximately 62 miles are held by timber companies. These timber companies are sophisticated entities that are familiar with utility easements and with whom PCGP expects to be able to reach mutually acceptable agreements in all or virtually all cases. Of the remaining 38 percent of the right-of-way mileage, PCGP has already obtained easements from 39 percent of these private, non-timber company owners of land on which the right of way will be located.[14] PCGP expects to obtain most of the easements necessary for the Pipeline through negotiation. Since the construction period for a pipeline is considerably less than the construction period for liquefaction facilities, PCGP will have ample time to complete these negotiations before construction commences.

PCGP certifies that the facilities proposed herein will be designed, constructed, installed, inspected, tested, operated, replaced, and maintained in accordance with the Natural Gas Pipeline Safety Act of 1968, as amended and recodified,[15] and pursuant to the implementing regulations of the Department of Transportation[16] and any other applicable safety standards. PCGP certifies that it will incorporate all environmental information and compliance with the National Environmental Policy Act's ("NEPA") requirements into contract bid documents and, as needed, give appropriate instruction and training to contractors and inspectors in carrying out the Commission's guidelines. Consistent with the Commission's landowner notification requirements, and as described

[14] With the route modifications described above, PCGP has reduced the number of affected private, non-timber landowners to 227 and, to date, has acquired the necessary easements from 88 (or 39%) of these owners of land on which the right of way will be located.

[15] 49 U.S.C. §§ 60101-60128.

[16] 49 C.F.R. Part 192.

in Article VIII, PCGP will send out notices to all affected landowners of record (as reflected on the landowner list included in Appendix D.1 of Resource Report 1). In addition to its adoption of all applicable environmental guidelines and its extensive pre-filing consultations, PCGP will continue to be in contact with appropriate authorities regarding measures to mitigate any adverse environmental impacts along its route to the extent practicable.

D. Benefits Associated with the Project Outweigh the Adverse Effects

The Commission balances the public benefits to be achieved by the project against the residual adverse impacts of the proposed project when evaluating whether a proposed project is needed and will serve the public interest. The overall purpose of the Project is to construct a natural gas liquefaction and deep-water export terminal capable of receiving and loading ocean-going LNG carriers, in order to export natural gas from a point of origin near the intersections of GTN and Ruby. An increase in natural gas production in the U.S. has increased the demand for LNG exports, and the U.S. stands to be a net exporter of natural gas by 2020 via LNG.[17] The Pipeline receipt point, near the intersections of the two under-utilized GTN and Ruby pipeline systems, is strategically located to give customers of the LNG Terminal access to abundant supplies of natural gas from two burgeoning natural gas supply basins – one in the U.S. Rocky Mountains (through the existing Ruby pipeline) and a second in western Canada (through the existing GTN pipeline).

The benefits of the Pipeline include significant investment in Oregon, modernization of the Port of Coos Bay, potential future deliveries to communities along

[17] U.S. Energy Information Administration, *Annual Energy Outlook with Projections to 2050* at 66 (Jan. 5, 2017), *available at* http://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf.

the Pipeline that have previously not had access to clean-burning natural gas, and facilitation of the re-building of the industrial and property tax base of the County of Coos and the towns of Coos Bay and North Bend. The overall Project will result in an investment of $9.8 billion of construction spending for the Project. During construction, the Pipeline will create 4,131 peak monthly jobs and, statewide, due to the direct, indirect, and induced impacts, an additional 43,233 full-year equivalent jobs will be supported by construction of the Project. PCGP will directly employ 15 workers in Oregon and spend $3.1 million on compensation costs during operation. Property taxes for the Pipeline are anticipated to average $20 million per year of operations for school districts and other local districts to be shared among Coos, Douglas, Jackson, and Klamath counties.

PCGP designed the Pipeline to provide firm natural gas transportation capacity to meet the requirements of the LNG Terminal. PCGP executed two Precedent Agreements in July 2017 that provide for JCEP, as an anchor shipper, to contract for 95.8 percent of the capacity available on the Pipeline.[18] The Commission views agreements for long-term firm capacity as important evidence of market demand.[19] These agreements are

[18] PCGP is submitting copies of the Precedent Agreements with this Application. The Commission has accepted such agreements between the terminal sponsor and pipeline as evidence of market support for the supply pipeline in multiple LNG export terminal proceedings. *See Golden Pass Products LLC, et al.*, 157 FERC ¶ 61,222 at P 45 (2016) (precedent agreement between affiliate of the terminal sponsor and pipeline); *Magnolia LNG, LLC, et al.*, 155 FERC ¶ 61,033 at P 11 (2016) (precedent agreement between terminal sponsor and pipeline); *Corpus Christi Liquefaction, LLC, et al.*, 149 FERC ¶ 61,283 at P 30 (2014), *reh'g denied*, 151 FERC ¶ 61,098 (2015) (sole agreement between terminal sponsor and affiliated pipeline); *Sabine Pass Liquefaction Expansion, LLC, et al.*, 151 FERC ¶ 61,012 at P 16 (2015), *reh'g denied*, 151 FERC ¶ 61,253 (2015) (terminal intended to be only customer of pipeline). As discussed in detail in JCEP's related Section 3 application, JCEP also will have agreements in place for liquefaction tolling services at the LNG Terminal. Since the Commission does not economically regulate LNG terminals the Commission does not review contracts for liquefaction tolling services. *See, Hackberry LNG Terminal, L.L.C.*, 101 FERC ¶ 61,294 at P 22 (2002), *order on reh'g*, 104 FERC 61,269 (2003).

[19] Certificate Policy Statement, *supra* note 4, at p. 61,744. The Commission considers contracts with affiliates as evidence of market demand. *See, e.g., Constitution Pipeline Company, LLC, et al.*, 149 FERC

consistent with Commission precedent and sufficient to support approval of the Project.[20] JCEP will use the capacity it has subscribed to support its own sales of LNG and will serve as an aggregator and gas supplier to liquefaction service customers. The Pipeline offers cost-effective and reliable transportation service to meet this demand.

The benefits associated with the Pipeline far outweigh the Pipeline's potential adverse effects, which have been or will be significantly mitigated through PCGP's efforts, as described in this Application and the accompanying Resource Reports attached hereto as Exhibit F-1. For the reasons discussed above and consistent with the criteria set forth in the Certificate Policy Statement, authorization of the Pipeline as proposed herein is consistent with, and required by, the public convenience and necessity.

VI.
OPEN SEASON

PCGP has executed two Precedent Agreements with JCEP, as an anchor shipper, for 95.8 percent of the Pipeline's capacity. One Precedent Agreement relates to service

¶ 61,199 at P 28 (2014) (finding contracts with affiliates to be evidence of market demand where there is no evidence of self-dealing, the pipeline will be required to execute firm contracts for capacity levels and terms of service representing in the precedent agreement prior to construction, and the pipeline's recourse rates are calculated based on the designed capacity of the pipeline); *see also Transcon. Gas Pipe Line Co., LLC*, 141 FERC ¶ 61,091 at P 21 (2012) ("Absent evidence of affiliate abuse, we see no reason not to view marketing affiliates like any other shipper for purposes of assessing the demand for capacity . . . ."); *Millennium Pipeline Co., L.P., et al.*, 100 FERC ¶ 61,277 at P 57 (2002) ("[A]s long as the precedent agreements are long-term and binding, we do not distinguish between pipelines' precedent agreements with affiliates or independent marketers in establishing the market need for a proposed project. The fact that the marketers are affiliated with the project sponsor does not lessen the marketer's need for the new capacity or their obligation to pay for it under the terms of their contracts. In addition, in a competitive environment, the marketer still must offer its commodity at competitive prices to attract customers. Also, affiliated marketers are potentially subject to greater regulatory oversight than non-affiliates. For example, pipeline affiliates are subject to the standards of conduct concerning marketing affiliates in Part 161 of the regulations."); *E. Tennessee Natural Gas Co.*, 98 FERC ¶ 61,331, p. 62,398 (2002) ("[T]he Commission does not distinguish between contracts with affiliates and non-affiliates, as long as the contracts are binding. The fact that the two power plants are affiliates of the project sponsor does not lessen their need for the new capacity or their obligation to pay for it."); *Texas Eastern Transmission Corp.*, 84 FERC ¶ 61,044, p. 61,191 (1998) ("It is not the Commission's policy to disregard contracts between affiliates in establishing need for projects.").

[20] In the absence of any precedent agreements for the Pipeline capacity, the Commission found that the prior proposal presented "little or no evidence of need." *Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,190, at P 39 (2016).

during commissioning of the LNG Terminal and the second Precedent Agreement relates to service once the LNG Terminal has achieved commercial operation. In compliance with the Commission's policy and precedent, PCGP conducted an open season in an open, transparent, and non-discriminatory manner from July 18, 2017 to August 17, 2017, seeking bids from potential customers wishing to contract for Pipeline transportation capacity that would result from construction and operation of the Pipeline. In addition to notices placed in industry publications, PCGP posted an Open Season Notice (included herewith in Exhibit Z-2) on the Project website on July 18, 2017, notifying shippers of the procedures for submitting a bid for firm transportation service entitlements on the Pipeline and how such entitlements will be allocated.[21] PCGP did not receive any qualifying bids during the open season beyond the Precedent Agreements with JCEP, and JCEP was accordingly awarded a full allocation of 1,150,000 Dth/day of capacity entitlements.[22]

VII.
ENVIRONMENTAL IMPACT

On January 23, 2017, JCEP and PCGP requested approval to participate in the Commission's pre-filing review process to engage federal and state agencies, Tribes, landowners, and other stakeholders to identify and resolve issues at the earliest stages of project development. FERC granted this request on February 10, 2017, and assigned the Project to Docket No. PF17-4-000. On June 9, 2017, the Commission issued its Notice of Intent to Prepare an Environmental Impact Statement.[23] Notably, a substantially

[21] PCGP's open season materials are included in Exhibit Z-2.

[22] PCGP received two bids from an entity that did not meet the creditworthiness requirement in the Open Season Notice.

[23] Notice of Intent to Prepare an Environmental Impact Statement, Docket No. PF17-4-000 (issued June 9, 2017) ("NOI").

similar route to the proposed Pipeline route has been reviewed in two prior FERC proceedings.[24] JCEP and PCGP reviewed comments filed in the docket during the pre-filing review process and responded to such comments on July 24, 2017.[25] Throughout the NEPA review process, PCGP has been working with Commission Staff and other interested agencies to identify all of the potential environmental impacts and associated proposed mitigation measures for the Pipeline.

The Resource Reports, included herewith as Exhibit F-1, provide sufficient information for the Commission to conduct its environmental analysis of the Pipeline, as required by NEPA.[26] The Resource Reports were prepared pursuant to Part 380 of the Commission's regulations[27] and FERC's *Guidance Manual for Environmental Report Preparation*[28] and developed through the preparation of draft resource reports filed in Docket No. PF17-4-000. Throughout the pre-filing review process, Commission Staff and interested stakeholders reviewed the draft Resource Reports and provided comments in the docket. PCGP endeavored to incorporate these comments into the Pipeline's plans and the final Resource Reports, and is including herewith response trackers that indicate the location of each response to comments provided by FERC staff and other cooperating agencies on the draft resource reports.[29]

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[24] The Commission previously issued EISs that evaluated the Pipeline route in Docket Nos. CP07-441-000 and CP13-492-000.

[25] Response to Scoping Comments of Jordan Cove Energy Project L.P. and Pacific Connector Gas Pipeline, LP, Docket No. PF17-4-000 (submitted July 24, 2017).

[26] 42 U.S.C. §§ 4321-4370d.

[27] 18 C.F.R. § 380.12.

[28] FERC, *Guidance Manual for Environmental Report Preparation* (Feb. 2017), *available at* https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf.

[29] Agency comments submitted subsequent to, and independently of, the FERC-issued comments will be reviewed and addressed in future submissions as appropriate.

As reflected in the Resource Reports, PCGP can adequately mitigate the environmental impacts associated with construction of the Pipeline. PCGP will construct and reclaim all disturbed areas in accordance with FERC's *Upland Erosion Control, Revegetation, and Maintenance Plan* ("Upland Plan") and *Wetland and Waterbody Construction Procedures* ("Wetland and Waterbody Procedures"). PCGP has made every effort to comply with FERC's Upland Plan and Wetland and Waterbody Procedures over the majority of the route; however, there are several locations where modifications are necessary. Where exceptions to FERC's Wetland and Waterbody Procedures and Upland Plan have been identified, proposed modifications have been requested in Table A.1-1 in Appendix A.1 to Resource Report 1. In addition, PCGP will incorporate appropriate environmental mitigation measures into its compensatory mitigation plan.[30]

The Pipeline will be constructed in accordance with all applicable environmental permits, approvals, and regulations. Construction of the Pipeline will require a standard 95-foot wide temporary construction right-of-way with a 50-foot permanent easement and TEWAs. Table 1.2-1 in Resource Report 1 summarizes the current land requirements for construction and operation of the Pipeline. PCGP is committed to minimizing the environmental impact of the Pipeline and to reclaiming all disturbed areas to a consistently high standard, regardless of ownership. The construction activities are

[30] One mitigation effort included within the combined JCEP and PCGP efforts to mitigate potential construction and operation impacts is the creation of more than 100 acres of critical wild Coho salmon overwinter and rearing habitat through implementation of the Kentuck Project. This project, which reflects a collaborative effort on conceptual design with the Oregon Department of Fish and Wildlife and the National Oceanic and Atmospheric Administration and is supported by current salmon science, will reconnect two spawning streams to the former Kentuck golf course and return natural tidal function the property, thereby helping to support the de-listing from the endangered species list of the Coho salmon in southwest Oregon.

not anticipated to have any significant adverse effects on residents or industrial areas and the impacts to public, recreational, or scenic areas, as well as vegetation, wildlife, and cultural resources can be adequately mitigated. PCGP will employ environmental inspectors during construction to ensure that all operations are in compliance with applicable environmental permits and regulations as well as any conditions included in the Commission's certificate order.

In accordance with the Commission's regulations, PCGP has evaluated ambient and Pipeline noise levels associated with the Pipeline facilities, assessed impacts, and proposed mitigation measures that can be implemented, if necessary, to ensure that noise levels comply with FERC noise standards and any applicable state noise standards. Construction and operation emissions associated with the new compressor station will comply with all applicable air quality regulations. In this regard, air quality impacts from operation of the proposed compressor station will be minimized by the use of equipment, emissions controls and best operating practices.

The Resource Reports demonstrate that (i) any adverse impacts associated with the Pipeline can be adequately mitigated or avoided, (ii) the proposed action is the best alternative, and (iii) significant resources will not be irreversibly or irretrievably lost due to construction activities.

VIII.
LANDOWNER NOTIFICATION AND OUTREACH

PCGP has communicated with landowners and stakeholders throughout the pre-filing review process. PCGP identified all owners of properties that (i) are directly affected by the proposed construction activities (centerline landowners), (ii) are abutters to the proposed construction areas, (iii) are located on access roads that will be used for construction activities, (iv) have residences within 50 feet of the proposed construction areas, (v) are located within 1/2 mile of the proposed compressor station, and (vi) may be directly affected by the proposed construction activities, in accordance with Section 157.6(d) of the Commission's regulations.[31] Landowners along the centerline of, or abutters to, alternative routes have also been identified. Within three days of the Commission's issuance of a notice of this Application, PCGP will notify these landowners in writing of the location of the Pipeline and provide additional information about the overall Project. Names and addresses of all affected landowners (filed under seal), towns, communities, and local, state, and federal governments and agencies involved with the Project are included in Appendix D.1 of Resource Report 1.

PCGP representatives have been in communication with stakeholders about the Pipeline, or similar proposals, since the import proposal in 2007. Prior to initiating the pre-filing review process, in December 2016, PCGP provided a notice of filing to stakeholders. Using FERC's *Suggested Best Practices for Industry Outreach Programs to Stakeholders* as guidance, PCGP developed a stakeholder engagement plan, which includes:

- maintenance of a physical PCGP office in Medford, Jackson County, Oregon;
- maintenance of a project website with information regarding the overall Project and providing all FERC filings;
- hosting four open houses for landowners, elected officials, and other stakeholders; and

[31] 18 C.F.R. § 157.6(d).

- producing and distributing informational materials.

A. Public Officials

In December 2016, PCGP representatives contacted state, county, municipal, and other local officials, state legislators, and congressional delegation members and/or their staffs to inform them about the Project prior to the pre-filing review process. PCGP solicited input from these interested stakeholders and utilized that feedback as the design process evolved. These briefings allowed officials and staff to be informed in anticipation of possible phone calls or emails from constituents.

B. State and Federal Regulatory Agencies

PCGP representatives have reached out to federal and state regulatory officials and agencies from the outset of the Project development. Various federal and state regulatory officials and agencies have been involved with the Project since the original import proposal, and JCEP and PCGP began communications regarding the current proposal in December 2016. Prior to and throughout the pre-filing review process, the PCGP team has worked with FERC Staff to schedule bi-weekly federal and state interagency meetings, including an agency meeting held in Salem, Oregon in January 2017 to present Project updates to a group of approximately thirty representatives from various agencies. Feedback received from federal and state agencies has been used to inform PCGP on agency concerns and to develop the Project.

C. Affected Landowner Outreach

After the pre-filing review process was initiated, PCGP sent notification packets to all affected landowners. Each letter contained a cover letter and fact book regarding the Project, which included maps of the proposed Pipeline route. A second letter was mailed to private, non-commercial landowners, with whom PCGP has not yet secured easement agreements, formally requesting survey permission for the right-of-way. Communication with affected landowners is ongoing and documented as the route is finalized.

D. Stakeholder Communications

Periodic communications are provided to public officials and other interested parties. These communications include in-person individual and group meetings and events, email correspondence, phone conversations, and advertisements in the main newspapers in each of the four counties. Information provided to interested stakeholders has included maps, fact sheets, presentations, and open house notifications. Updates will be provided or made available to landowners and stakeholders throughout development of the Pipeline, consistent with Commission policy.

PCGP, along with JCEP, has maintained a Project website to inform stakeholders and interested parties about recent Project facts and updates. The website contains an overview of the Project, proposed route information, information about permitting and siting, an overview of the regulatory review process, PCGP's filings in Docket No. PF17-4-000, and answers to frequently asked questions. The website also provides a toll-free number at which stakeholders can contact PCGP and JCEP to voice comments or concerns about the Project.

During previous iterations of the Project, JCEP and PCGP met and corresponded with representatives from the appropriate Tribes who are generally familiar with the LNG Terminal site and proposed Pipeline route, as well as any potential effects to cultural resources. As part of the pre-filing review process for the current proposal, JCEP and PCGP significantly increased the commitment of resources to the management of impacts on cultural resources and Tribal relations, including establishing systematic communications with the appropriate Tribes by dedicated Project Tribal relations staff, thereby ensuring that concerns of the Tribes continue to be heard and carefully considered as the formal FERC review process progresses. JCEP and PCGP are providing a Project activity update with rolling 60-day, three-month, and 12-month projections of upcoming survey work and investigations on the LNG Terminal site and proposed Pipeline route. JCEP and PCGP have also instituted a Tribal communication protocol where, to the greatest extent practicable, notification of work to be conducted on the LNG Terminal site or within the proposed Pipeline route is provided 30 days in advance to the appropriate Tribes. Applicable agencies are also included on the notifications where the work may involve permits and processes pertinent to these agencies.

E. Open Houses

PCGP held four open houses near the LNG Terminal and along the Pipeline route between March 21 and March 24, 2017. Notices of open houses were sent to affected landowners, posted on the Project website, and advertised in local newspapers. Each open house had stations with JCEP and PCGP representatives covering a variety of topics, including the FERC review process, LNG carrier transit, safety, community benefits, terminal engineering and construction, pipeline construction and engineering, landowners and land rights, and environmental and cultural resources. JCEP and PCGP received various comments at the open houses, which were recorded and considered throughout development of the Pipeline.

F. FERC Site Visits and Scoping Meetings

In early August 2017, JCEP and PCGP hosted members of FERC Staff for site visits of the LNG Terminal and Pipeline. JCEP and PCGP attended three scoping meetings held by the Commission in Coos Bay, Roseburg, and Klamath Falls in June 2017.[32] JCEP and PCGP reviewed comments filed during the scoping period and submitted a response on July 24, 2017.

IX. SUPPLY

PCGP proposes only to provide open-access transportation service on the Pipeline and, accordingly, PCGP's shippers are responsible for obtaining supplies to be transported on the capacity created by the Project.

X. RATES

A. Recourse Rates

PCGP is proposing to charge an initial recourse rate under Rate Schedule FT-1 for firm service on the Pipeline commencing on the in-service date of the Project. These rates and the support for the derivation of these rates are set forth in Exhibit P to this Application.

As reflected on the *pro forma* tariff records attached hereto as part of Exhibit P, the initial recourse reservation rate is $1.3536 per day per Dth of capacity subscribed. PCGP proposes that the usage rate for service under Rate Schedule IT-1 will be the 100% load factor derivative of the FT-1 service rate. PCGP's proposed maximum usage rate for Rate Schedule IT-1 is $1.3536 per Dth delivered. Consistent with Commission policy, PCGP's rates were developed using a straight fixed variable rate design.

PCGP has not allocated any of its cost of service to its interruptible service. Consistent with Commission policy, PCGP proposes to share interruptible revenues with

[32] Certain of the comments received during the scoping meetings related to possible revisions to the Pipeline route. These route modifications were considered by PCGP and a modification to the route was incorporated into this Application. Any additional revisions to the route will be reflected in a supplemental filing.

both its maximum recourse rate shippers and with its firm negotiated rate shippers, as applicable. Annual interruptible revenues will be credited according to Section 26 of the General Terms and Conditions of PCGP's FERC Gas Tariff to eligible shippers.

In addition to the rates for the firm and interruptible services provided, applicable charges and surcharges include in-kind fuel retainage, referred to as the Fuel Reimbursement Percentage, for fuel and lost and unaccounted-for gas ("L&U"), as described below. The initial Fuel Reimbursement Percentage for the Project facilities is 0.8 percent.

B. Cost of Service and Rate Design

PCGP's cost of service is based on total capital costs for the proposed Pipeline of $3.184 billion, as presented in Exhibit K to this Application. PCGP then calculates its proposed recourse rates based on this cost of service and on billing determinants that reflect the total mainline design capacity of the Pipeline and imputed interruptible determinants. As described in Exhibit P, the initial recourse rates reflect a depreciation rate of 2.75 percent, assuming a 40-year life and a negative net salvage rate of 0.25 percent. The initial recourse rates also reflect a 35 percent federal income tax rate and a 7.6 percent state corporate income tax rate. The rate derivation reflects a proposed overall rate of return of 10 percent, based on an expected 50 percent debt and 50 percent equity capital structure with a debt cost of 6 percent and a return on equity of 14 percent.

C. Fuel Rates

PCGP is proposing an in-kind system fuel retainage percentage with a tracking mechanism which is imbedded in the Tariff and designed to recover fuel use and L&U on a system-wide basis, as a percentage of scheduled receipts. PCGP's proposed initial Fuel Reimbursement Percentage is 0.8 percent, which consists of 0.719 percent for fuel use and 0.081 percent for L&U.[33] PCGP will make a semi-annual fuel tracker filing pursuant to Section 4 of the NGA to adjust the Fuel Reimbursement Percentage and will annually true-up any differences between the fuel retained from shippers and the actual fuel consumed and L&U.

D. AFUDC Representation

PCGP hereby provides its statement representing that the Allowance for Funds Used During Construction ("AFUDC") accruals included in the cost of the Pipeline, reflected in Exhibit K hereto, are in compliance with the Commission's policy on AFUDC accruals as set forth in the Docket No. AD10-3-000 proceeding.[34] PCGP will begin accruing AFUDC for the Project on the date it makes a final investment decision to go forward with construction, and in accordance with the Commission's AFUDC policy, PCGP hereby affirms that it will have begun to incur capital expenditures for the Project on that date and that activities necessary to develop the Project for its intended use will be in progress at that time.

XI. TARIFF

Exhibit P to this Application contains PCGP's *pro forma* Tariff. After Commission approval of the authorizations requested herein is granted, PCGP will file to make its *pro forma* Tariff effective upon the in-service date of the Pipeline. In its Tariff, PCGP is offering firm and interruptible transportation service. PCGP also included provisions in the Tariff permitting it to provide service at negotiated rates.

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[33] *See* Exhibits G and G-1.

[34] *Southern Natural Gas Co., et al.*, 130 FERC ¶ 61,193 (2010); *see also Texas Eastern Transmission, LP*, 131 FERC ¶ 61,164 (2010).

PCGP developed its Tariff to meet the needs of the market, while also complying with the Commission's regulations and policies. In that regard, PCGP's Tariff follows the Commission's requirements and policies established by Order Nos. 636, *et seq.*[35] and 637, *et seq.*[36] The Pipeline is a transportation-only pipeline and will provide its transportation services on an unbundled, open access basis under nondiscriminatory terms and conditions. PCGP's Tariff complies with all of the currently applicable North American Energy Standards Board ("NAESB") standards. Any changes to NAESB standards prior to the in-service date of the Pipeline will be incorporated into the Tariff when PCGP files to make its Tariff effective.

PCGP is not proposing to offer segmentation rights on its system because segmentation is not operationally feasible on a pipeline structured like the Pipeline.[37] Therefore, PCGP requests a waiver from Section 284.7(d) of the Commission's regulations.[38] The Pipeline receives gas from adjacent, receipt-only interconnections with upstream pipelines and transports the gas to a single delivery point at the LNG Terminal. There are no intermediate points capable of segmentation. Thus, it is not operationally feasible to offer segmentation on the system. Commission precedent justifies not offering segmentation on a system where such activity is not operationally feasible.[39] Further, JCEP, as the sole anchor shipper, has not requested segmentation.

[35] 59 FERC ¶ 61,030 (1992).

[36] 90 FERC ¶ 61,109 (2000).

[37] To the extent the Pipeline becomes capable of providing segmentation in the future and a party requests segmentation, PCGP will consider such request.

[38] 18 C.F.R. § 284.7(d).

[39] *See, e.g., Sierrita Gas Pipeline, LLC*, 147 FERC ¶ 61,192 at P 56 (2014).

A. Precedent Agreements

As discussed above in Article VI, PCGP executed two Precedent Agreements with JCEP as an anchor shipper. The Precedent Agreements require JCEP to execute corresponding Firm Transportation Agreements and Negotiated Rate Agreements, as attached to the Precedent Agreements. These agreements differ in certain aspects from the *pro forma* Rate Schedule FT-1 transportation service agreement ("Pro Forma Agreement") in the Tariff. In Exhibit I hereto, PCGP has provided a copy of Exhibit B to the Firm Transportation Agreements, which sets forth the non-conforming provisions. As demonstrated in Exhibit I, the non-conforming provisions in the Firm Transportation Agreements provide for the following:

- The Firm Transportation Agreements contain creditworthiness provisions included in the Precedent Agreements.
- One of the Firm Transportation Agreements contains a provision allowing JCEP to extend the term of the agreement for two additional ten-year periods.
- One of the Firm Transportation Agreements provides that PCGP and JCEP agree that an evergreen provision applies to the agreement and that the applicable rollover period will be one month.
- The Firm Transportation Agreements provide that JCEP's aggregate firm daily quantity at primary receipt points may exceed JCEP's contract demand.

None of these provisions are unduly discriminatory.[40] Under the Commission's existing policy, project sponsors are permitted to provide rate incentives to anchor shippers on a number of grounds, including volumes to be transported, without constituting undue discrimination.[41] None of the provisions in the JCEP service agreements present a significant potential for undue discrimination. The Commission regularly approves separate credit provisions applicable to anchor shippers, consistent with those PCGP has agreed to here, because of the financial commitment involved in construction of new facilities.[42] The Commission also has approved non-conforming provisions giving extension and rollover rights to anchor customers, again in recognition of their early commitment that enables new projects to move forward.[43] Similarly, the Commission should approve the non-conforming provision related to aggregate primary receipt point rights that exceed a shipper's contract demand because pipelines regularly allow such excess receipt point rights.

Since no shipper is similarly situated to JCEP, there is no risk of undue discrimination. For these reasons, PCGP does not believe that the provisions contained in JCEP's Firm Transportation Agreement are unduly discriminatory.

Consistent with current Commission policy, PCGP intends to file the executed Firm Transportation Agreement identifying any material deviations or non-conforming

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[40] *CenterPoint Energy Gas Transmission Co.*, 104 FERC ¶ 61,280, at P 7 (2003) (citing *Tennessee Gas Pipeline Co.*, 97 FERC ¶ 61,225, at 62,029 (2001)); *ANR Pipeline Co.*, 97 FERC ¶ 61,223, at 62,017 (2001).

[41] *Revisions to the Blanket Certificates Regulations and Clarification Regarding Rates*, FERC Stats and Regs ¶ 32,606, at PP 93-107 (2006), as confirmed in the final rule, 117 FERC ¶ 61,074, at P 68 (2006).

[42] *See, e.g., Rover Pipeline LLC, et al.*, 158 FERC ¶ 61,109 at P 103 (2017) ("*Rover*") (citing *Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, FERC Stats. & Regs. ¶ 31,191, at P 7 (2005)); *Natural Gas Pipeline Company of America LLC*, 154 FERC ¶ 61,220 at PP 30-31 (2016).

[43] *See, e.g., Rover,* at P 101; Ruby, *supra* note 10, at P 78 (2009).

provisions, at the time specified in the Commission's regulations or in a Commission order in this proceeding. As part of this application, though, PCGP has provided the following for Commission review: (1) the executed Precedent Agreements, which include the Firm Transportation Agreement and the Negotiated Rate Agreement, and (2) Exhibit B to each of the unexecuted Firm Transportation Agreements with JCEP, which sets forth the non-conforming provisions in the service agreement. PCGP is providing this information now so the Commission will be able to review and approve these provisions in the certificate order issued in this proceeding.

B. Gas Quality

Consistent with the requirements set forth in FERC's *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs*, PCGP has included as Exhibit Z-3 hereto, a chart showing "relevant information about the gas quality and interchangeability specifications of interconnecting pipelines and of the competing pipelines serving customers to be served directly by" the Pipeline.[44] Specifically, the chart shows the gas quality provisions of PCGP in comparison to the gas quality specifications of the LNG Terminal, Ruby pipeline, and GTN pipeline.

PCGP is proposing a safe harbor mechanism for total aromatics and oxygen as part of the gas quality standards in its tariff. Because PCGP is being constructed to serve an LNG export facility that has specific gas quality requirements, PCGP must deliver gas that meets those requirements. The historic gas flow on Ruby and GTN meets the requirements of the LNG Terminal, but the specific gas quality standards of those

[44] *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs*, 115 FERC ¶ 61,325 at P 45 (2006).

pipelines are much less restrictive. PCGP's proposed safe harbor mechanism will allow PCGP, through an internet posting, to set less restrictive standards for total aromatics or oxygen while reserving the ability to tighten those standards, up to the safe harbor levels in the tariff, when the co-mingled gas stream would not meet the needs of the LNG Terminal.

The safe harbor mechanism will provide flexibility to PCGP's customers to meet the LNG Terminal's gas supply needs in the least restrictive manner possible while maximizing receipts from upstream interconnections. The Commission has recently approved similar provisions for pipeline facilities supplying an LNG terminal.[45] PCGP will only limit receipts to the safe harbor levels, as set forth in the Tariff, when it determines that there is an actual or anticipated operational or engineering problem in an effort to ensure the safe operation of the Pipeline or to ensure that gas will be accepted for delivery by the LNG Terminal. In no case could PCGP post a limit more restrictive than the safe harbor limits set forth in the Tariff, without issuing an Operational Flow Order.

XII.
RELATED APPLICATIONS

PCGP has no other related applications or filings pending before the Commission. As described in this Application, JCEP is contemporaneously seeking authorization from the Commission under Section 3 of the NGA to site, construct, and operate the LNG Terminal, located on the bay side of the North Spit of Coos Bay, Oregon. That

[45] *Gulf South Pipeline Co., LP*, 155 FERC ¶ 61,287 (2016) (accepting Gulf South's proposed safe harbor provisions for the Coastal Bend Header Project).

application is directly related to this Application, and the Commission has indicated its intent to prepare a single EIS for both the Pipeline and LNG Terminal.[46]

PCGP will also require other federal, state, and local authorizations or permits for the proposed Pipeline. A description of the permits and approvals required (to the extent such permits or approvals do not conflict with the Commission's certificate and associated conditions) is provided in Exhibit J and Table 1.6-1 of Resource Report 1. All of the required federal authorizations are set forth in Exhibit J to this Application.

XIII.
REQUESTS FOR WAIVERS

PCGP submits that this Application may be granted based upon this submission and without a trial-type evidentiary hearing. In accordance with Rule 801 of the Rules of Practice and Procedure,[47] PCGP waives oral hearing in these proceedings.

PCGP further requests that the Commission grant any additional waivers, including a waiver of Section 284.7(d) of the Commission's regulations requiring segmentation, that it may deem necessary to grant the relief and issue the certificates and approvals requested herein.

XIV.
FORM OF NOTICE

In accordance with Section 157.6(b)(7) of the Commission's regulations, PCGP has included herewith a Form of Notice of this Application suitable for publication in the *Federal Register*.

[46] *See* NOI at 1.

[47] 18 C.F.R. § 385.801.

XV.
LIST OF EXHIBITS

Pursuant to Section 157.6(b)(6) of the Commission's regulations, set forth below is the listing of exhibits which are included, unless stated otherwise, in this Application.

Exhibit A § 157.14(a)(1)	The certificate of limited partnership of PCGP is included.
Exhibit B § 157.14(2)	Oregon and Delaware state authorizations are included.
Exhibit C § 157.14(3)	A list of company officials is included.
Exhibit D § 157.14(4)	An explanation of corporate relationships is included.
Exhibit E § 157.14(5)	There are no other related applications other than those described in Article XII of this Application
Exhibit F § 157.14(a)(6)	A map showing the location is included.
Exhibit F-I § 157.14(a)(6-a)	Environmental Report. Filed separately herein as Exhibit F-I.
Exhibits G/G-I § 157.14(a)(7) and (a)(8)	Flow diagram showing daily design capacity and reflecting operating conditions on the proposed facilities is provided separately under seal and marked "Contains Critical Energy Infrastructure Information – Do Not Release (CUI//CEII)."
Exhibit G-II § 157.14(a)(9)	Statement of engineering design data that explains the flow diagram is provided separately under seal and marked "Contains Critical Energy Infrastructure Information – Do Not Release (CUI//CEII)."
Exhibit H §157.14(a)(10)	Omitted. Not applicable – PCGP will provide only open-access transportation-related services.
Exhibit I § 157.14(a)(11)	Two precedent agreements are provided separately under seal and marked "Contains Privileged Information – Do Not Release (CUI//PRIV)". The non-conforming provisions from the two firm transportation agreements are provided separately.
Exhibit J § 157.14(a)(12)	List of federal authorizations is included.
Exhibit K § 157.14(a)(13)	Detailed estimate of the Pipeline's total cost is included.

Exhibit L § 157.14(a)(14)	A plan for financing the Pipeline is included.
Exhibit M § 157.14(a)(15)	A description of construction, operation, and management is included.
Exhibit N § 157.14(a)(16)	Estimate of projected system-wide revenues, expenses and income for the Pipeline's first three years of operation is included.
Exhibit O § 157.14(a)(17)	Depreciation and depletion rates are included.
Exhibit P § 157.14(a)(18)	*Pro Forma* Tariff is included.
Exhibit Z-1	Form of Protective Agreement is included.
Exhibit Z-2	Open Season Notice is included.
Exhibit Z-3	Gas quality and interchangeability chart is included.

Exhibits G through G-II are found in Volume IV and contain Critical Energy Infrastructure Information regarding system pressure and flow. Pursuant to Section 388.112 of the Commission's regulations, PCGP hereby requests privileged treatment of these exhibits, which are marked as "**CONTAINS CRITICAL ENERGY INFRASTRUCTURE INFORMATION—DO NOT RELEASE (CUI//CEII)**." In addition, PCGP is marking Volume III as privileged because it contains cultural resource location information and landowner information from Exhibit F-I, two precedent agreements representing market data in Exhibit I, and confidential hydraulic models supporting Exhibits G through G-II.[48] PCGP requests privileged treatment for this volume and has marked it "**CONTAINS PRIVILEGED INFORMATION—DO NOT RELEASE (CUI//PRIV)**."

XVI.
SUMMARY OF AUTHORIZATIONS REQUESTED

[48] The hydraulic models supporting Exhibits G through G-II are available only in electronic form in WFP format. The hydraulic flow models also contain CEII.

In summary, PCGP requests that the Commission grant the following authorizations and waivers by November 2018:

1. a certificate of public convenience and necessity under Section 7(c) of the NGA and 18 C.F.R. Part 157, Subpart A, authorizing PCGP to construct, install, own, and operate a new natural gas pipeline system; as specifically described in this Application;
2. a blanket certificate of public convenience and necessity under 18 C.F.R. Part 157, Subpart F, authorizing PCGP to construct, operate, acquire and abandon certain facilities following construction of the Pipeline;
3. a blanket certificate of public convenience and necessity under 18 C.F.R. Part 284, Subpart G, authorizing PCGP to transport natural gas on behalf of others, on an open-access and self-implementing basis, consistent with the Commission's regulations and PCGP's Tariff;
4. approval of PCGP's initial rates, *pro forma* Tariff, and non-conforming provisions; and
5. a waiver of the Commission's regulations requiring segmentation and such other waivers of the Commission's regulations and policies as set forth herein or as deemed necessary by the Commission to grant the relief and issue the certificates and approvals requested.

XVII. CONCLUSION

WHEREFORE, for the reasons set forth above, PCGP respectfully requests that the Commission issue a certificate of public convenience and necessity and blanket certificates, approve PCGP's *pro forma* FERC Gas Tariff, and issue any other authorizations the Commission deems necessary, including applicable waivers, so that PCGP can construct, install, own, and operate the proposed pipeline system, as discussed herein.

Respectfully submitted,

<u>/s/ Elizabeth Spomer</u>
Elizabeth Spomer
President and CEO
Pacific Connector Gas Pipeline, LP

September 21, 2017

VERIFICATION

THE STATE OF TEXAS)
)
COUNTY OF HARRIS)

Elizabeth Spomer, being first duly sworn, states that she is the President and CEO for Pacific Connector Gas Pipeline, LP; that she is authorized to execute this Verification; that she has read the foregoing application and is familiar with the contents thereof; and that all allegations of fact therein contained are true and correct to the best of her knowledge and belief.

Pacific Connector Gas Pipeline, LP

Elizabeth Spomer
President and CEO

Subscribed and sworn to before me this 20th day of September, 2017.

LATANYA HAMILTON
Notary ID # 130784481
My Commission Expires
August 18, 2020

NOTARY PUBLIC
STATE OF TEXAS

Notary Public,
State of Texas

My Commission Expires:

08/18/20

Exhibit 3

http://oilandmoney.net/2017/08/17/whos-ahead-in-surfing-second-us-lng-wave/

Who's Ahead in Surfing Second US LNG Wave?

Posted on *August 17, 2017* by *awieloch*

The first wave of US LNG projects effectively ended in July 2015, when Cheniere Energy took a final investment decision on Train 5 at Sabine Pass in Louisiana, hiking the volume of LNG expected to be on line by 2020 to 65 million tons per year. The proposed second wave consists of dozens of projects-in-waiting, eyeing the moment next decade when new supply will be needed as the mounting global surplus starts to work itself off.

But the LNG world will look rather different then. Buyers won't be seeking large volumes over 20 or 25 years. Instead, gradually and somewhat unpredictably, smaller wedges of demand will emerge for shorter tenures, fueled in part by the spread of floating storage and regasification units (FSRUs). Moreover, competition for buyers is set to become more intense, with Qatar's unexpected announcement that it plans to boost capacity to 100 million tons per year by 2024 likely to leave higher cost projects elsewhere at risk of death or delay, including some in the US (WGI Aug.9'17)

Given the constraints, which of the scores of proposed US second wave projects look best-placed to succeed? *World Gas Intelligence* has compiled a list of the top 10 developments it expects to take FID first. These have a combined capacity of nearly 130 million tons/yr, which would hoist overall US capacity to around 196 million tons/yr — almost double what Qatar intends to be producing.

No. 1: Corpus Christi Train 3 (Brownfield. 4.5 million tons/yr). "There is one thing on the whiteboard in my office: final investment decision Corpus Christi Train 3," Cheniere President and CEO Jack Fusco said on the company's second-quarter earnings call last week. Officials at project developer Cheniere argue that brownfield expansions like the Corpus Christi third train will be more competitive than the slew of greenfield projects proposed on the US Gulf Coast. "Customers have been confused on who to believe," Cheniere Chief Commercial Officer Anatol Feygin said. There has been "a lot of rhetoric from US greenfield projects about how cheaply they can do it," but

Feygin believes the cost estimates are "unachievable." The CEO of Freeport LNG, Michael Smith, similarly expects greenfield projects to face rough seas. As if to underscore the brownfield potential, Freeport has prefiled with the US Federal Energy Regulatory Commission (Ferc) to add a fourth train to the three under construction at Freeport, while Cheniere has prefiled for Corpus Christi Trains 4 and 5. But these three trains may not win Department of Energy (DOE) approval in time to join the second wave starting line.

No. 2: Magnolia LNG (Greenfield. 8 million tons/yr). The project, backed by Australia's LNG Ltd., has both Ferc and DOE approvals. It is prepared to open up 2 million tons/yr of capacity at a time, making it easier to accommodate smaller demand wedges. Magnolia recently lined up a $1.5 billion financing commitment from Stonepeak Infrastructure Partners and extended an engineering, procurement and construction contract through the end of the year. But it still needs to finalize offtake agreements.

No. 3: Sabine Pass Train 6 (Brownfield. 4.5 million tons/yr). This has been fully approved and marketed by Cheniere. Like Corpus Christi Train 3, it requires offtake agreements covering about 3.5 million tons/yr before FID.

No. 4: Golden Pass (Brownfield. 15.6 million tons/yr). Owned by Qatar Petroleum and Exxon Mobil. An Exxon spokesperson said recently that the two are focused on "bringing together all the remaining elements" to position the project for FID, which some observers say could occur next year. The project is fully approved and has the financial and technical backing of two top industry players.

No. 5: Rio Grande LNG (Greenfield. 27 million tons/yr). The project in Brownsville, Texas, is led by Kathleen Eisbrenner, who has previously worked for Royal Dutch Shell's LNG business and for floating regasification specialist Excelerate. Rio Grande signed up a technology provider in April and financial advisers in May, and in July signed a memorandum of understanding with the Port of Cork in Ireland on deployment of an FSRU. The project does not yet have Ferc approval, but does have the experienced leadership and downstream contacts to move quickly.

No. 6: Driftwood LNG (Greenfield. 26 million tons/yr). Another project led by industry veterans, in this case Cheniere Energy founder Charif Souki and former BG executive Martin Houston. They hope to take FID by mid-2018.

No. 7: Cameron LNG Trains 4 and 5 (Brownfield. 4.5 million tons/yr each). The trains have full approval, but will be affected by the six-month delay building the first three Cameron trains announced by project developer Sempra Energy earlier this month.

No. 8: Jordan Cove LNG (Greenfield. 6 million tons/yr). The project, in Oregon, has encountered significant local opposition, but has had the staying power to be rejected by Ferc and refile. Unlike most "second wave" projects, it has also secured preliminary offtake agreements with two major Japanese buyers, Jera and Itochu, for half its proposed capacity. It is headed by LNG veteran Betsy Spomer and could benefit from Western Canadian gas cascading south after most proposed Canadian projects stall or founder.

No. 9: Delfin (Floating. 13 million tons/yr). The project has the virtue of being relatively inexpensive, as its capacity will be spread across four separate floating liquefaction vessels, allowing incremental startup. The project is fully permitted and plans to take FID in 2018, with first LNG delivered in 2021 or 2022.

No. 10. Lake Charles LNG (Brownfield. 15 million tons/yr). This will likely be the last US brownfield project. It is backed by Shell and Energy Transfer Partners, and South Korea's Kogas recently expressed interest in participating. Shell already has significant exposure to US LNG and appears wary about adding more, with commitments to use liquefaction capacity at Sabine Pass and Elba Island. But Lake Charles can't be ruled out due to its fully-approved regulatory status and major backers.

Michael Sultan, Washington

Top 10 Second Wave US LNG Projects

Ranking	Project	Regulatory Status	Expected FID
1	Corpus Christi Train 3	Fully Approved	Unknown
2	Magnolia LNG	Fully Approved	Unknown
3	Sabine Pass Train 6	Fully Approved	Unknown
4	Golden Pass	Fully Approved	2018
5	Rio Grande	Filed with Ferc	2018
6	Driftwood	Filed with Ferc	2018
7	Cameron Train 4-5	Fully Approved	Unknown
8	Jordan Cove	Refiled with Ferc	Unknown
9	Delfin FLNG	Fully Approved	2018
10	Lake Charles	Fully Approved	Unknown

Source World Gas Intelligence

Exhibit 4

http://www.americanpress.com/news/local/report-lists-planned-area-lng-projects-as-likely-to-come/article_697daaf2-a150-11e7-816d-73406a613860.html

Report lists planned area LNG projects as likely to come through

- Emily Fontenot
- Sep 24, 2017

Southwest Louisiana LNG Projects

Source: Southwest Louisiana Economic Development Alliance

Donna Price / American Press

(Donna Price/American Press)

Six local liquefied natural gas projects were recently ranked among the top 10 most likely to become a reality out of dozens being planned nationwide.

The report, published by Oil & Money, names local project Magnolia LNG second most likely to reach final investment decision. The other Southwest Louisiana projects that made the cut were Cheniere Energy's Sabine Pass expansion project, Tellurian's Driftwood LNG, Cameron LNG's expansion project, Delfin, and Lake Charles LNG.

The planned facilities are part of a second wave of export terminals expected to meet the growing global demand for natural gas over the next decade. The first wave ended in 2015, after a handful of U.S. projects reached final investment decision.

"There really is a distinct separation between those first five projects and the rest of the projects that are planned," said Magnolia COO John Baguley.

Exhibit 4
Page 1 of 4

While the first wave created a temporary oversupply in the market, delaying many new projects, demand is expected to outpace supply in the 2020s, Baguley said. A recent study by Shell predicted that demand would grow 4 percent to 5 percent each year between 2015 and 2030.

Magnolia LNG

Magnolia was Oil & Money's No. 2 pick because of how advanced it is in the development process, according to the report.

The project, backed by Australia's LNG Ltd., has approvals from both the Federal Energy Regulatory Commission and the Department of Energy, and its primary construction contract in place. All it's waiting on is buyers for the offtake before making final investment decision.

"We were very happy to be listed as number two," Baguley said. "I was a little surprised we weren't listed as number one."

The report says Magnolia's unique design will allow it to produce LNG in smaller wedges. The facility will produce up to 8 million tons per year using four liquefaction trains, each with an annual capacity of 2 mtpa — a smaller train size than most.

"Nobody in the world today wants to buy large volumes of LNG all at once," Baguley said. "Today the buyers are looking at 1 to 2 million tons at a time, and so they like the fact that our train size aligns with their purchasing aspirations."

Baguley said he's "a little puzzled" by the lack of urgency among buyers. Now would be the ideal time to make commitments, he said, since commodity prices are low and demand is expected to increase by the time construction would wrap up on a new project.

"I really don't understand what everybody's waiting for," he said. "The buyer's market just doesn't seem to go forward. It's a curious situation."

He expects that once the first buyers make commitments, the rest will follow.

Cheniere

Third on the list is Cheniere's Sabine Pass facility's sixth and final train — the industry term for units where natural gas is cooled to a liquid for transport.

Cheniere, the only LNG terminal operating in the contiguous U.S., is developing an export facility next to its existing import facility in Sabine Pass. Its first three trains are operational, with a fourth expected to be completed this year and a fifth in 2019. Each can produce up to 4.5 mtpa.

Like Magnolia, the sixth train is fully approved and marketed; it just needs buyers.

Existing projects such as Cheniere have an advantage over brand-new projects because all the infrastructure is already in place, reducing costs and time, said company spokesman Eben Burnham-Snyder.

Because Cheniere began operating in February 2016 on time and on budget, he said, it can also bring confidence to new customers.

Cheniere was also ranked No. 1 on the list for its expansion project at the company's Corpus Christi, Texas, location, where construction is already underway.

Driftwood

Sixth on the list is Tellurian's Driftwood LNG. It's the youngest of the 10 LNG facilities being developed in Southwest Louisiana, having announced plans to build in the region in 2016.

The report notes that the project is led by "industry veterans" Charif Souki, former Cheniere Energy CEO, and Martin Houston, former BG executive. Company spokesman Joi Lezcnar said Driftwood leaders have been involved in constructing 20 percent of the liquefaction capacity worldwide.

"This experience and partnership has allowed us to move very quickly, seamlessly, and with confidence that we know what we're doing and can deliver on our promises to the market and the community," Lezcnar said.

The project is awaiting federal approval, expected by the middle of next year. It intends to sign a construction contract with Bechtel this fall and reach final investment decision in 2018.

Designed for 26 million tons per year, Driftwood is over three times as large as Magnolia. The company is open to unconventional ways of selling LNG, such as allowing shorter contracts.

"We are listening to what the customers want: smaller amounts of LNG and shorter contracts. However, we are open to all types of scenarios," Lezcnar said. "Our model anticipates change in the LNG industry, and the winners will be those companies who are operationally low-cost and commercially flexible."

Cameron LNG

Seventh on the list is Cameron LNG's Trains 4 and 5, set to follow its first three trains under construction in Hackberry.

At 4.5 mtpa each, the trains have full approval but will be affected by a six-month delay in construction until 2019 announced earlier this month by developer Sempra Energy, according to the report.

The company declined to comment.

Delfin

Delfin, a floating LNG terminal with a 13 mtpa capacity, will consist of four liquefaction vessels instead of trains. It's planned for about 50 miles off the coast of Cameron Parish.

The project "has the virtue of being relatively inexpensive," and its floating design allows for "incremental startup," the report says.

Bill Daughdrill, health and safety director at Delfin, said the liquefaction vessels can be fully constructed at a dedicated yard and shipped in later, cutting down construction time.

Delfin will also save money by not having to dredge and build complex mooring facilities, he said. And when exports begin, ships won't have to travel up the shipping canal.

"Taken together, Delfin believes all of these project features provide significant competitive advantages for our project," Daughdrill said.

Delfin has acquired the major permits needed to begin construction, including key approvals from the Maritime Administration and the Energy Department. Daughdrill said it's "actively evaluating shipyards to construct the floating LNG liquefaction vessels."

He said he expects the company to select the construction facility and make final investment decision in 2018.

Lake Charles LNG

Tenth on the list is Shell's Lake Charles LNG, with a 15 mtpa capacity. Shell delayed final investment on the project in August 2016, although it has gotten approval from both FERC and the DOE.

The report notes that Shell already has "significant exposure to U.S. LNG and appears wary about adding more." A review of the project is underway by Shell and other industry specialists.

Shell was unable to comment because its offices were damaged in Hurricane Harvey.

Exhibit 5

Japan outlaws restrictions on resale of LNG cargoes

http://www.forexrepository.com/news/japan-outlaws-restrictions-on-resale-of-lng-cargoes.htm

June 28, 2017

Japan has outlawed restrictions stopping prospects from reselling cargoes of liquefied pure fuel, in its newest transfer to liberalise a market the place Japanese utilities have lengthy been the largest consumers.

The Japan Fair Trade Commission, concluding an investigation into the sector, mentioned it was banning clauses limiting resale of LNG and known as on corporations to alter their enterprise practices for current contracts.

The ruling is more likely to imply extra lively commerce in LNG cargoes by Japanese consumers at a time when rising provides of super-cooled gas from the US, Australia and Africa are anticipated to push down costs.

"Japanese users predict excess supply of LNG," mentioned the JFTC. "They are concerned that destination restrictions will prevent them from reselling excess LNG inside or outside Japan in the future."

Historically, LNG consumers wanted to agree inflexible long-term contracts to get entry to the gas, usually with strict resale restrictions and limits on value fluctuations.

But a rising provide glut has put extra energy within the palms of consumers over producers reminiscent of Qatar, the world's largest LNG provider.

Analysts see the LNG market bearing a better resemblance to grease within the coming years, the place cargoes can change palms a number of occasions earlier than reaching their vacation spot, with extra trades accomplished within the spot market.

The ruling might push different fuel consumers in Asia to mount the same problem to main producers.

Japan's Jera, a three way partnership between utilities Chubu Electric and Tokyo Electric that's the world's single largest LNG purchaser, is seen more likely to push Qatar to renegotiate long-term contracts on extra beneficial phrases.

The JFTC choice is much like a 2005 ruling in Europe, placing down contractual clauses that prohibited German fuel corporations from reselling Russian fuel outdoors of Germany.

The JFTC mentioned it had discovered a collection of practices that had been "likely" or "highly likely" to violate Japan's anti-monopoly legislation, particularly when cargoes are offered "Free On Board", which implies the customer owns the fuel as quickly as it's loaded at an export terminal.

“This will provide political support to Japanese buyers in contract negotiations,” mentioned one fuel dealer in Tokyo.

“However, they may have overlooked the fact that more and more Japanese buyers are becoming sellers too.” Many of Japan’s largest fuel corporations have invested in abroad LNG tasks.

Japan’s largest suppliers of LNG are Australia, Qatar and Malaysia, adopted by Indonesia, Russia, Brunei and the United Arab Emirates.

Contracts with vacation spot clauses might impose a selected port or listing of ports the place the cargo will be unloaded.

The JFTC discovered that, in 48 per cent of long-term FOB fuel contracts, the customer wanted the vendor’s consent to divert the cargo outdoors Japan.

Twenty-two per cent had express restrictions on resale.

There has been a pattern in the direction of rest of vacation spot clauses in recent times however the JFTC discovered they’ve usually been changed by profit-share clauses, requiring consumers to share half of the revenue on any resale with the vendor.

“Providing profit share clauses is highly likely to be in violation of the Antimonopoly Act [for FOB contracts],” mentioned the JFTC.

Take-or-pay clauses, which oblige prospects to pay for the contracted quantity even when they don’t obtain all of it, don’t pose a contest drawback in themselves, mentioned the fee.

However, they may grow to be violations “when a seller’s bargaining position is superior” they usually impose the clause “without sufficient negotiation”.

The JFTC known as on fuel corporations to go the advantages of competitors on to customers.

“When active competition in the fixed-term contract market and the spot contract market leads to reduction of the LNG procurement cost, LNG buyers are expected to reflect properly such reduction on electricity rates or city gas rates,” it mentioned.

Exhibit 6

Natural Gas

Jera's Kakimi warns over 'golden age' for LNG in Asia

Liquefied natural gas buyer says suppliers need to be more competitive

Yuji Kakimi, the chief executive of Jera, the world's largest LNG buyer © FT montage

SEPTEMBER 26, 2017 by Emiko Terazono

The head of the world's biggest buyer of liquefied natural gas has warned producers that they need to become more competitive on price and allow for more flexible contracts if they want to usher in a "golden age" of gas in Asia.

Yuji Kakimi, the head of Japan's Jera — the joint venture launched in 2015 between Chubu Electric Power and Tokyo Electric Power to procure fuel supplies — told the Financial Times that LNG producers needed to adapt quickly to a market where rising supplies were giving more power to buyers.

"The price of LNG has to be reasonable and there needs to be flexibility," Mr Kakimi said at his offices in Tokyo. "If the market lacks these things the golden age will never come."

The Jera chief is known in the industry for bringing innovative practices into the utilities business. In 2008, he led Chubu's efforts to forge a coal buying joint venture with France's EDF.

His comments come as fast-growing supplies of LNG have led large buyers, such as Japan, to push for the end of so-called "destination clauses" and other restrictions that have for decades affected supplies of the super-cooled fuel, which allows natural gas to be shipped around the world on tankers.

Sources: Companies; Platts Analytics

Lacking domestic energy sources, Japan has become the world's biggest importer of LNG, accounting for a third of the world's 260m tonne export market. Jera brings in just under half of the country's purchases, giving the company significant clout in the market.

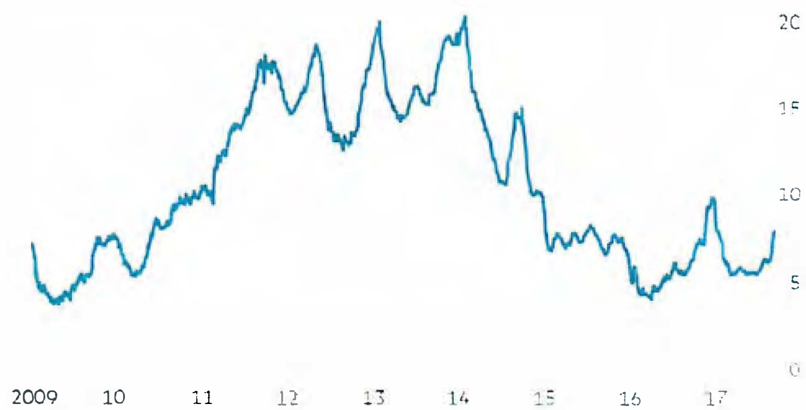
The operators who build LNG export facilities — from ExxonMobil and Royal Dutch Shell to states such as Qatar — have been dependent on signing up long-term customers to deals linked to oil prices to finance the construction of their multibillion-dollar terminals.

"Buyers now want the freedom to trade with whom they want rather than locking in security [of supply]," said Bernadette Cullinane, head of Australian oil and gas at Deloitte.

Mr Kakimi said the US shale industry had dramatically transformed LNG, smoothing its boom and bust cycle and creating a global gas market by connecting previously fragmented regions, meaning prices no longer deviated markedly between Europe and Asia.

Asian LNG price

Platts Japan Korea marker ($ per million Btu)



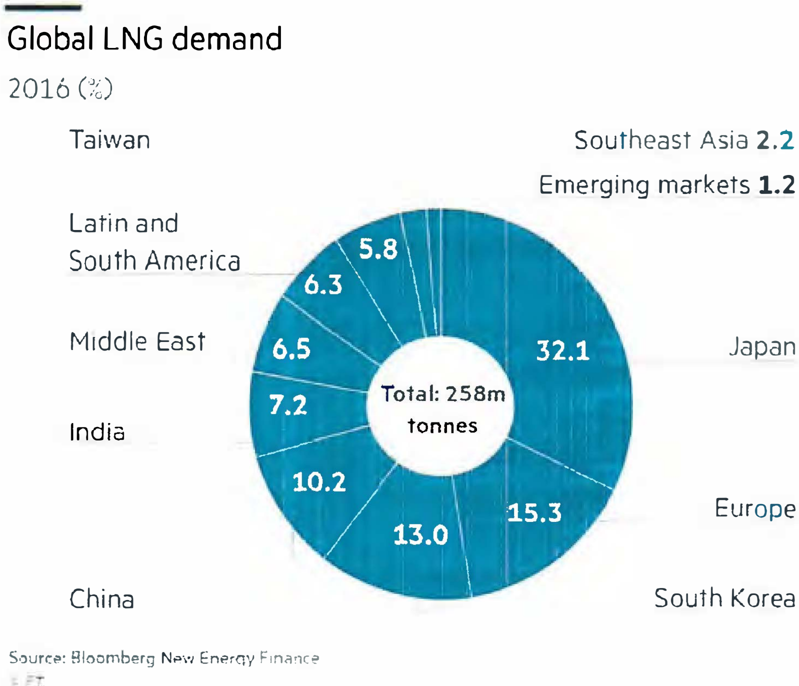
Source: S&P Global Platts

"I highly value LNG from the US. Before [US exports] and after — the market has completely changed," he said.

The construction of US liquefaction plants, which chill and condense shale gas so it can be shipped on tankers for export, has turned the old LNG business model on its head.

In the past, large oil and gas companies invested huge amounts of capital in an integrated supply chain of upstream gas production, pipelines and liquefaction plants. But the new LNG companies, such as Cheniere, do not need to dig for gas and can use existing US pipeline infrastructure to transport shale gas from producers to their terminals.

The largest LNG export projects had previously taken 10-20 years to complete but the new US projects can start bringing the commodity to the market in about five years from inception.



The surge in US shale supplies is also giving buyers a stronger negotiating position.

"If we don't like the terms [of a certain project] we can say, fine we'll ask America to make us some," said Mr Kakimi.

Alongside rising LNG exports from Australia, US flows have helped push prices lower. Asian prices have fallen from record highs of $20.20 per million British thermal units in 2014 thanks to the global supply glut. New projects coming online over the next few years mean there will be growth in LNG exports until 2020, with analysts forecasting spot LNG prices will stay at about $6 per mBtu until 2023-25.

Mr Kakimi said that US exports had bridged the gap between the previously disconnected gas markets around the world. While Asia, led by Japanese buyers, has traditionally relied on LNG mainly from Australia, Qatar, and Malaysia, Europe and the US have had their gas supplied mainly through regional pipelines.

LNG from Cheniere, which started exporting from the US in 2016, is now reaching 25 countries, with shippers not bound by destination clauses.

Under Mr Kakimi, Jera has positioned to become a more active trader in commodities, moving from being a simple price taker to playing a greater role in markets.

Last year he bought out EDF Trading's coal and freight business, wrapping it into Singapore-based Jera Trading, and entered into agreements to deliver LNG to European terminals. Mr Kakimi said the company was learning more about trading after the takeover.

Some market watchers caution that LNG prices might not stay low for long, especially if projects are not commissioned at a time when demand is rising.

Lower LNG prices have led to a rise in imports by China, Pakistan and Bangladesh, markets that are forecast to grow as they try to become less reliant on coal for environmental reasons. Mr Kakimi cautioned exporters, however, that they were still competing with other energy sources.

"Compared to coal, as a fuel source for electricity, it is about 1.5 times more expensive," he said, even at $6 per mBtu. "Can emerging markets, which are looking to grow, really push for an environment over economics? At $10 or $15, it isn't economically competitive at all."

The year which Cheniere started exporting has been amended.

Exhibit 7

https://www.bloomberg.com/news/articles/2017-03-21/chevron-calls-end-of-lng-mega-project-after-88-billion-spree

Chevron Calls End of LNG Mega Project After $88 Billion Spree

By
Perry Williams
and
Rebecca Keenan
March 20, 2017, 9:37 PM PDT

- Greenfield gas export facilities in Western Australia unlikely
- Gorgon, Wheatstone expansions off table amid focus on returns

Chevron Corp. has signaled the end of major new LNG projects in Western Australia and is unlikely to sanction an expansion of its Gorgon and Wheatstone export developments as it focuses on boosting returns from $88 billion of investment.

The climate for developing large greenfield LNG projects has shifted to smaller developments given a slump in the price of oil to under $50 a barrel, according to Nigel Hearne, a managing director with the company's Australia unit.

Nigel Hearne
Photographer: Dale Watson/Energy Images

"The mega projects of the past decade are giving way to smaller, more targeted investments with quicker economic returns," Hearne said in a speech in Perth on

Tuesday. "As it stands there is unlikely to be another large greenfield LNG development" in Western Australia.

Chevron's two major Australian LNG facilities have suffered from cost blowouts, delays and poor timing. Oil's worst slump in a generation and an LNG supply glut reduced revenue from projects across the industry.

While the third LNG train from the $54 billion Gorgon project is in the process of starting up, further expansions are unlikely in the current climate with Chevron focusing future investments on "shorter-term" returns.

"I can't see in the near-term us investing in a fourth train at Gorgon or a third train at Wheatstone," Hearne said in Perth. Chevron is focused on generating returns on its existing investments and paying a "dividend back for the money" already spent.

The first train from the $34 billion Wheatstone project remains on schedule for mid-2017, he said.

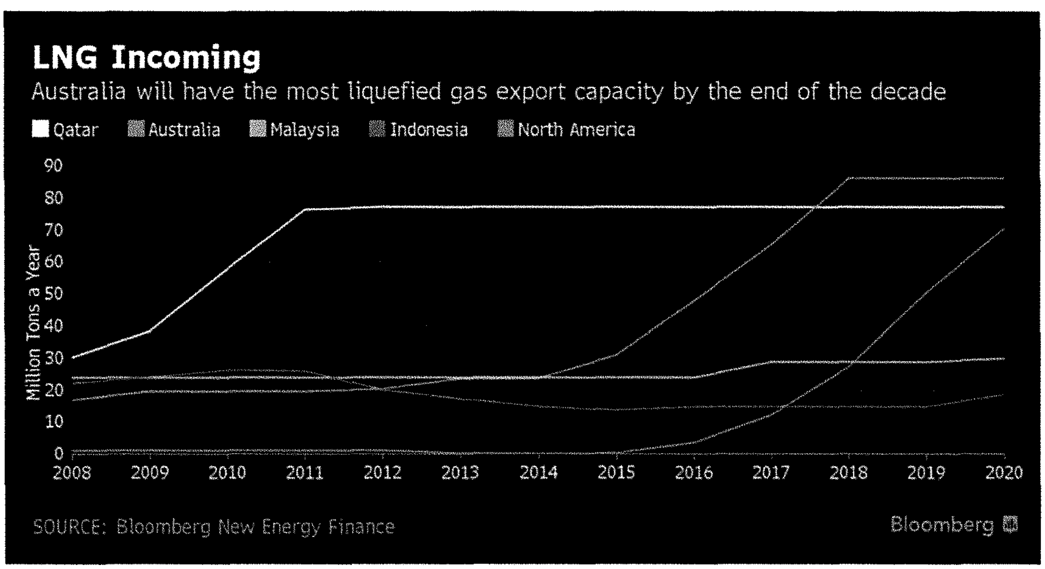


Exhibit 7
Page 2 of 3

About A$118 billion ($91 billion) of LNG developments in the nation are scheduled to be completed in 2017 including Gorgon, Inpex Corp.'s Ichthys and Royal Dutch Shell Plc'sfloating Prelude vessel, according to a December report from Deloitte Access Economics.

A growing supply glut will likely deter significant investment in new Australian LNG projects beyond 2017 with doubts growing over the feasibility of planned floating facilities, according to the report. Planned FLNG projects in Australia including Woodside Ltd.'s Browse and Sunrise facilities and Exxon Mobil Corp.'s Scarborough may not proceed due to a more competitive operating environment, Deloitte said.

— With assistance by Dan Murtaugh

Exhibit 8

https://www.biv.com/article/2017/7/petronas-pulls-plug-pacific-northwest-lng-project/

Petronas pulls the plug on Pacific NorthWest LNG project

After investing billions in Canada, Malaysian oil and gas company is cancelling its Prince Rupert LNG project

By Nelson Bennett | July 25, 2017, 10:47 a.m.

The PNW LNG plant in Prince Rupert would have cost $11 billion to build; total investment, including pipeline and gas assets, was $36 billion.

Petronas has officially pulled the plug on its $36 billion Pacific NorthWest LNG project in Prince Rupert.

"We are disappointed that the extremely challenging environment brought about by the prolonged depressed prices and shifts in the energy industry have led us to this decision," Anuar Taib, chairman of the PNW LNG board of directors, said in a July 25 press release.

"Petronas and its North Montney Joint Venture partners remain committed to developing their significant natural gas assets in Canada and will continue to explore all options as part of its long-term investment strategy."

The significant gas assets Taib referred to are its holdings in the Montney of northeastern B.C., which were acquired when Petronas acquired Alberta's Progress Energy.

While it was in opposition, the NDP officially opposed the PNW LNG project.

At a press conference this morning, one reporter asked Michelle Mungall, the new Energy, Mines and Petroleum Resources minister, what kind of message it sends to the international investment community for the NDP to lose a $36 billion project in its eighth day in office. Mungall said the cancellation was a decision based solely on market conditions.

"The company was very clear," she said. "This was a decision they are making because of the economic challenges in the global energy marketplace. The Pacific NorthWest LNG project, as proposed in its current state, was uneconomical to move forward.

"Our government is committed to working with the LNG industry to ensure that we are competitive," Mungall said.

She reiterated the NDP's demands, however, for supporting the industry: that it guarantees jobs and training for British Columbians, First Nations are made partners, that it is done in an environmentally responsible way and that "the province receive a fair rate of return for our resources."

Green Party Leader Andrew Weaver seized on the cancellation of the project as an "I-told-you-so" moment. Weaver has long derided the Liberal government's attempts to foster an LNG industry as futile.

"Since the beginning it has been clear that the global marketplace does not support the LNG industry that the BC Liberals promised in their 2013 election campaign," Weaver said.

"B.C.'s future does not lie in chasing yesterday's fossil fuel economy; it lies in taking advantage of opportunities in the emerging economy in order to create economic prosperity in B.C."

Pointing to the Aurora LNG project, also proposed for Prince Rupert, Mungall said there are still would-be LNG developers in B.C. Mungall said the NDP is committed to working with other LNG developers, like Nexen.

But as BIV points out in today's story on that project, the developer, Nexen, may have been hoping that Petronas would blaze the path for a new natural gas pipeline. The Aurora LNG project description does not mention a pipeline, and there is currently no natural gas pipeline running from northeast B.C. to Prince Rupert that could supply a large LNG project.

Despite Taib's insistence that his company's decision was strictly one based on markets and economics, Jihad Traya, manager of natural gas consulting for Solomon Associates, said he believes a new Green-backed minority NDP government coming to power has a lot to do with the timing of Petronas' announcement.

"What's happening now is very clear that there is somewhat of a non-confidence vote in British Columbia – period," he said. "There will be a need for global LNG, but the investment's saying 'Hey, we can go elsewhere and not have to deal with this headache."

nbennett@biv.com

Exhibit 9

https://www.thestar.com/news/canada/2017/07/25/petronas-backed-pacific-northwest-lng-megaproject-in-bc-not-going-ahead.html

Pacific NorthWest LNG megaproject cancelled

Malaysian national energy giant Petronas and its partners pull the plug on $36 billion project.

A liquefied natural gas export facility on Lelu Island was part of the Pacific Northwest LNG project, which had been cancelled. (ROBIN ROWLAND / THE CANADIAN PRESS FILE PHOTO)

By **IAN BICKIS**The Canadian Press
ALEKSANDRA SAGAN The Canadian Press
Tues., July 25, 2017

Malaysian national energy giant Petronas and its partners scrapped the Pacific NorthWest LNG megaproject Tuesday, ending months of anticipation on the fate of what would have been one of Canada's largest private infrastructure investments.

The decision to cancel the development boiled down to simple economics — a world market awash in liquefied natural gas, which has driven down prices, making Pacific NorthWest LNG no longer financially viable, said Anuar Taib, CEO of Petronas's oil and gas production division.

"Unfortunately for us, we don't believe we have that mix of where the sweet spot can be hit," Taib said.

While Pacific NorthWest LNG worked its way through regulatory channels over the last several years, numerous LNG projects have come online around the world.

The overall project would have cost $36 billion in total, including a 900-kilometre pipeline proposed by TransCanada to a natural gas export terminal on the province's Lelu Island, as well as the production of gas to supply it.

TransCanada later said it was reviewing its options on the $5-billion Prince Rupert Gas Transmission project, which was dealt its own setback last week after the Federal Court of Appeal ruled that the National Energy Board will need to reconsider whether it requires federal approval.

The export facility, with an estimated cost of $11.4 billion, would have compressed the natural gas into liquid form before it would be shipped to markets in Asia.

The announcement Tuesday came a couple of hours after Prime Minister Justin Trudeau met with British Columbia Premier John Horgan in Ottawa. The federal government gave its conditional approval to the project last September. Horgan voiced opposition to it, though late last month he said his position may be swayed if the concerns of First Nations were taken into consideration.

Both the federal and provincial governments emphasized that the decision was a private sector one.

"The company was very clear: this was a decision they are making because of the economic challenges in the global energy market place," B.C. Energy Minister Michelle Mungall said.

"The Pacific NorthWest LNG project as proposed in its current state was uneconomical to move forward."

Mungall said the government would work to make B.C. competitive in the global LNG industry as other proposed West Coast LNG projects sit in various stages of development.

The B.C. Liberal caucus was quick to lay blame on what it called a "closed for business" agenda of the newly sworn-in B.C. NDP government.

But when asked whether the election of the NDP played any role in the decision, Taib gave an unequivocal no. He said Petronas is still committed to working on developing the natural gas assets in northeastern B.C. it bought in part to supply the LNG terminal.

"We actually look forward to working with John Horgan and his government as we develop our vast assets in the Montney joint venture area," he said.

B.C. Green Leader Andrew Weaver, who is helping prop up the NDP government in a coalition, said the singular pursuit of the LNG industry by the former B.C. Liberal government was a mistake.

"B.C.'s future does not lie in chasing yesterday's fossil fuel economy," Weaver said in a statement. "It lies in taking advantage of opportunities in the emerging economy in order to create economic prosperity in B.C."

Environmentalists and some First Nations welcomed news of Pacific NorthWest LNG's demise, saying it would have resulted in a spike in greenhouse gas emissions and threatened salmon habitat.

"We're absolutely thrilled that the Malaysian backers of this liquefied natural gas terminal have backed down from their reckless plan to jeopardize B.C.'s second largest salmon run and blow our provincial climate targets," Peter McCartney, climate campaigner for the Wilderness Committee, said in a statement.

Exhibit 10

http://www.alaskapublic.org/2017/07/13/facing-global-gas-glut-conocophillips-to-mothball-kenai-lng-plant/

Facing global gas glut, ConocoPhillips to mothball Kenai LNG plant

By Rashah McChesney, Alaska's Energy Desk - Juneau -

July 13, 2017

The Feb. 2, 2008 file photo shows the ConocoPhillips LNG facility in Nikiski. The company plans to mothball the facility in the fall of 2017. (Photo courtesy of the Peninsula Clarion)

Last year, ConocoPhillips announced that it wanted to sell its liquefied natural gas plant on the Kenai Peninsula. The company hasn't yet found a buyer. Now, a company spokesperson said it's going to save expenses by mothballing the facility this fall.

It's the last piece of infrastructure that ConocoPhillips owns in Cook Inlet. And they're getting closer to shutting it down.

The Kenai LNG facility is up against a world market that's awash in natural gas.

"Most people are fairly aware of the fact that worldwide the price of oil and gas has been low," ConocoPhillips Senior Communications Specialist Amy Burnett said.

Generally, ConocoPhillips is doing well in the oil business in Alaska. The company announced earlier this year a new discovery that could yield up to 100,000 barrels a day in Prudhoe Bay.

But it has struggled to make money in the LNG export market.

"Over the last few years, more facilities have come online to export LNG," Burnett said. "So there are more sources available for the product which makes competition more difficult."

And the plant has been on hold for awhile.

"Our last export was actually...in the fall of 2015 and since that time the plant has been in a cold shutdown mode," Burnett said.

That cold shutdown mode means the plant isn't exporting any LNG, but could restart shipments relatively quickly. But keeping the tanks cold costs money, because they have to buy the gas they need to keep them full.

The plan is to let those tanks warm up by leaving them empty. And that means ConocoPhillips will save some money. But it also means that it will take longer — and cost more — to bring the plant back online.

And some people may lose their jobs.

"It's too soon to say actually what that's going to look like. There are about 18 ConocoPhillips employees who may be impacted by the change," Burnett said.

That's just over half of the employees currently working at the facility.

Larry Persily, Chief of Staff for the Kenai Peninsula Borough, said if the company does scale back its operations it will have an impact beyond the potential loss of 18 jobs in the Peninsula communities.

"It's also a hard reminder to Alaskans that no matter how much we want to sell our oil and gas, if the market doesn't want it, doesn't need it or isn't willing to pay a price to make it profitable — we can't sell our oil and gas," Persily said.

Prices have tumbled from $15-$18 per million btu, to just over $5.

"You can't buy gas out of Cook Inlet, pay to liquify it, burn up some of it while you're liquefying it, put it in a tanker and deliver it for $5.50 per million btu and make money," Persily said. "It is a[n] inhospitable market and will be for the near future."

The glut in the global LNG market is a roadblock in the state's efforts to market and build a pipeline to get Prudhoe Bay's enormous reserves to market.

And the financial future of that project — the Alaska LNG project — has been in question for awhile.

The legislature briefly considered cutting $50 million in funding from the state corporation tasked with developing that project.

Rep. Mike Chenault, R-Nikiski, said lawmakers ultimately decided to leave the funding in the budget in part because the glut won't last forever.

"I don't know if [Alaska LNG would] ever be viable in the current market. But markets change. And sometimes they change drastically as we well know with the price of a barrel of oil or the price of a cubic foot of gas," Chenault said.

Burnett said the company is still negotiating with potential buyers. But, she wouldn't say who those buyers were or how those negotiations were going- she said they're confidential.

In January, the state's gasline corporation disclosed that it was considering the purchase.

But any new buyer would need to get a federal export license if it wanted to sell gas to foreign markets — the company's current license expires in February of 2018.

Exhibit 11

UNITED STATES OF AMERICA88 FERC ¶ 61,227
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

Certification of New Interstate Natural Gas Pipeline Facilities — Docket No. PL99-3-000

STATEMENT OF POLICY

(Issued September 15, 1999)

In the Notice of Proposed Rulemaking (NOPR) in Docket No. RM98-10-000[1] and the Notice of Inquiry (NOI) in Docket No. RM98-12-000,[2] the Commission has been exploring issues related to the current policies on certification and pricing of new construction projects in view of the changes that have taken place in the natural gas industry in recent years.

In addition, on June 7, 1999, the Commission held a public conference in Docket No. PL99-2-000 on the issue of anticipated natural gas demand in the northeastern United States over the next two decades, the timing and the type of growth, and the effect projected growth will have on existing pipeline capacity. All segments of the industry presented their views at the conference and subsequently filed comments on those issues.

[1]Notice of Proposed Rulemaking, Regulation of Short-term Natural Gas Transportation Services, 63 Fed. Reg. 42982, 84 FERC ¶ 61,087 (1998).

[2]Notice of Inquiry, Regulation of Interstate Natural Gas Transportation Services, 63 Fed. Reg. 42974, 84 FERC ¶ 61,087 (July 29, 1998).

Information received in these proceedings as well as recent experience evaluating proposals for new pipeline construction persuade us that it is time for the Commission to revisit its policy for certificating new construction not covered by the optional or blanket certificate authorizations.[3] In particular the Commission's policy for determining whether there is a need for a specific project and whether, on balance, the project will serve the public interest. Many urge that there is a need for the Commission to authorize new pipeline capacity to meet the growing demand for natural gas. At the same time, others already worried about the potential for capacity turnback, have urged the Commission to be cautious because of concerns about the potential for creating a surplus of capacity that could adversely affect existing pipelines and their captive customers.

Accordingly, the Commission is issuing this policy statement to provide the industry with guidance as to how the Commission will evaluate proposals for certificating new construction. This should provide more certainty about how the Commission will evaluate new construction projects that are proposed to meet growth in the demand for natural gas at the same time that some existing pipelines are concerned about the potential for capacity turnback. In considering the impact of new construction projects on existing pipelines, the Commission's goal is to appropriately consider the enhancement of competitive transportation alternatives, the possibility of overbuilding, the avoidance of unnecessary disruption of the environment, and the unneeded exercise of eminent domain. Of course, this policy statement is not a rule. In stating the evaluation criteria, it is the Commission's intent to evaluate specific proposals based on the facts and circumstances relevant to the application and to apply the criteria on a case-by-case basis.

I. Comments Received on the NOPR

In the NOPR the Commission explained that it wants to assure that its policies strike the proper balance between the enhancement of competitive alternatives and the possibility of over building. The Commission asked for comments on whether proposed projects that will establish a new right-of-way in order to compete for existing market share should be subject to the same considerations as projects that will cut a new right-of-way in order to extend gas service to a frontier market area. Also, in reassessing project need, the Commission said that it was considering how best to balance demonstrated

[3]This policy statement does not apply to construction authorized under 18 CFR Part 157, Subparts E and F.

market demand against potential adverse environmental impacts and private property rights in weighing whether a project is required by the public convenience and necessity.

The Commission asked commenters to offer views on three options: One option would be for the Commission to authorize all applications that at a minimum meet the regulatory requirements, then let the market pick winners and losers. Another would be for the Commission to select a single project to serve a given market and exclude all other competitors. Another possible option would be for the Commission to approve an environmentally acceptable right-of-way and let potential builders compete for a certificate.

In addition, the Commission asked commenters to consider the following questions: (1) Should the Commission look behind the precedent agreement or contracts presented as evidence of market demand to assess independently the market's need for additional gas service? (2) Should the Commission apply a different standard to precedent agreements or contracts with affiliates than with non-affiliates? For example, should a proposal supported by affiliate agreements have to show a higher percentage of contracted-for capacity than a proposal supported by non-affiliate agreements, or, should all proposed projects be required to show a minimum percent of non-affiliate support? (3) Are precedent agreements primarily with affiliates sufficient to meet the statutory requirement that construction must be required by the public convenience and necessity, and, if so, (4) Should the Commission permit rolled-in rate treatment for facilities built to serve a pipeline affiliate? (5) Should the Commission, in an effort to check overbuilding and capacity turnback, take a harder look at proposals that are designed to compete for existing market share rather than bring service to a new customer base, and what particular criteria should be applied in looking at competitive applications versus new market applications? (6) Should the Commission encourage pre-filing resolution of landowner issues by subjecting proposed projects to a diminished degree of scrutiny where the project sponsor is able to demonstrate it has obtained all necessary right-of-way authority? (7) Should a different standard be applied to project sponsors who do not plan to use either federal or state-granted rights of eminent domain to acquire right-of-way?

A. Reliance on Market Forces to Determine Optimal Sizing and Route for New Facilities

PG&E, Process Gas Consumers (PGC), Tejas Gas, Washington Gas, Columbia, Market Hub Partners, and Ohio PUC agree that the Commission should continue to let the market decide which projects to pursue. PG&E states that the Commission should authorize all projects that meet minimum regulatory requirements, looking at whether the project will serve new or existing markets, the firmness of commitments and environmental and property right issues. PGC urges the Commission to refrain from second guessing customers' decisions. Tejas suggests that the Commission rely on the market to the maximum extent; regulatory changes that affect risk/reward allocation will increase regulatory risk and deter new investment. Washington Gas suggests letting the market decide on new construction with market based rates subject only to environmental review and landowner concerns. Columbia comments that it would not be economically efficient to protect competitors from the competition created by new capacity. Market Hub Partners specifies that, when there is no eminent domain involved, the focus should be on competition, not protecting individual competitors from overbuilding. Ohio PUC supports authorizing all applications for new capacity certification which meet the minimum regulatory requirements. Ohio PUC does not support approving a single pipeline's application while excluding all others.

The Regulatory Studies Program of the Mercatus Center, George Mason University suggests allowing projects to be proposed with no certification requirements, but allowing competitors to challenge the need. Investors would be at risk for all investments. Tejas proposes holding pipelines at risk for reduced throughput, thereby avoiding shifting the risk to customers.

On the issue of overbuilding, Millennium, Enron, PGC, Columbia, and Wisconsin PSC disagree with the presumption that overbuilding must be avoided. Millennium asserts that all competitive markets have excess capacity. Enron urges the Commission to be receptive to overbuilding in areas of rapid growth, difficult construction, and environmental sensitivity. PGC agrees that some capacity in excess of initial demand may make environmental and economic sense in that it will reduce the need for future construction, but argues that the pipelines be at risk for those facilities. Columbia alleges that the concern about overbuilding is misguided. Wisconsin PSC contends that concerns of overbuilding should not operate to limit the availability of competitive alternatives to customers currently without choices of pipeline provider. Wisconsin PSC believes the elimination of the discount adjustment mechanism and the imposition of reasonable at risk provisions for new construction will deter pipelines from overbuilding.

On the other hand, UGI recommends that overbuilding be minimized. UGI states that the Commission should ensure a reasonable fit between supply and demand. The Commission should limit certification of new projects to ones which demonstrate unmet demand or demand growth over 1-3 years.

Coastal stresses that competition should not be the only or primary factor in deciding the public convenience and necessity.

Amoco contends that, if the Commission chooses the right-of-way, it will in many cases have chosen the parties that will ultimately build the pipeline. Amoco urges the

Commission not substitute its judgement for that of the marketplace unless there are overwhelming environmental concerns. Tejas also objects to the option of the Commission approving an environmentally acceptable right-of-way and letting potential builders compete for a certificate because it believes it would be difficult for the Commission to implement.

Colorado Springs supports the concept of having the Commission select a single project in a given corridor rather than letting the market pick winners and losers.

PGC and Ohio PUC recommend that the Commission authorize all construction applications meeting certain threshold requirements, leaving the market to decide winners and losers. PGC urge the Commission to facilitate construction of new pipelines that will increase the potential for gas flows. Under no circumstances should the Commission deny a certificate based on a complaint by an LDC or a competing pipeline that new construction will hurt their market position or ability to recover costs. The Commission should not afford protection to traditional suppliers or transporters by constraining the development of new pipeline capacity.

PGC believes that only in unusual situations, where insuperable environmental barriers cannot be resolved through normal mitigation measures, should the Commission select an acceptable right-of-way. Ohio PUC does not support approving a single pipeline's application while excluding all others. Ohio PUC recommends having market forces guide construction projects unless or until obvious shortcomings begin to emerge. In such instances, the option of designating a single right-of-way with competition for the certificate could be used to spur needed construction.

B. Reliance on Contracts to Demonstrate Demand

A number of parties comment that there is no reason to change the current policy regarding certificate need (AlliedSignal, Millennium, Southern Natural, Tejas, Williston, Columbia). National Fuel Gas Supply believes the Commission should keep shipper commitment as the test because it is more accurate than market studies. National Fuel Gas Supply further believes the Commission's present reliance on market forces to establish need, and its environmental review process, form the best approach to reviewing certificate applications. Foothills agrees, but states that a new, flexible regulatory structure for existing pipelines is needed. Indicated Shippers also wants to keep the current policy, but stresses that expedition in processing is needed to lower entry barriers.

Amoco, Consolidated Natural, and Columbia urged the Commission to continue requiring sufficient binding long-term contracts for firm capacity. Millennium and Tejas stated that there is no need to develop different tests for different markets. Columbia also argued that there is no need to look behind contracts. Williams argues that the Commission should not second guess contracts or make an independent market analysis. Williston alleges that reviewing the firmness of private contracts is ineffectual and futile. Market Hub Partners cautions the Commission not to substitute its judgement for that of the marketplace.

PGC argues that there should be no change to current policy where construction affects landowners. Eminent domain is a necessary tool to delivering clean burning natural gas to growing markets; no individual landowners should be given a veto over pipeline construction. PGC adds that the absence of prefiling right-of-way agreements does not mean that a project is less good or necessary or should be treated more harshly. Southern Natural, Millennium, and National Fuel Gas Supply agree that no market preference should be given for projects that do not use eminent domain. National Fuel Gas Supply agrees that such a preference would tilt the power balance to landowners. Millennium argues that the Commission should not establish certificate preferences for pipelines that do not require eminent domain; such preferences are not needed because a pipeline that does not want to use eminent domain can already build projects under Section 311.

On the other hand, Amoco, El Paso/Tennessee, ConEd, and Wisconsin PSC recommend modifying the current policy. El Paso/Tennessee recommend that the Commission look behind all precedent agreements to see if real markets exist. ConEd suggests considering forecasts for market growth; if there is a disparity with the proposal, the Commission should look at all circumstances. Wisconsin PSC urges the Commission to consider market saturation and growth prospects by looking at market power (HHIs) and the degree of rate discounting in a market. Amoco suggests that the Commission analyze all relevant data. Peco Energy believes the current Commission policy, which provides for minimal market justification for authorizing construction of incremental facilities, coupled with its presumption in favor of rolled-in rate treatment, has contributed to discouraging existing firm shippers from embracing longer term capacity contracts.

Consolidated Natural recommends creating a settlement forum for market demand and reverse open season issues. Washington Gas urges the Commission to adopt an open entry, "let the market decide" policy. IPAA supports a need analysis focusing on the ability of existing capacity to handle projected demand. IPAA alleges that the overall infrastructure is already in place to supply current demand projections.

Some commenters support a sliding scale approach to determine need. ConEd states that the Commission should determine need on a case-by-case basis, using different standards for large or small projects. Enron advocates use of a sliding scale, requiring more market support for projects with more landowner and/or environmental impact. Enron supports requiring no market showing for projects using existing easements or mutually agreed upon easements. Enron also suggests, in addition to requiring that at least 25% of the precedent agreements supporting a project be with non-affiliates, that the Commission relax its market analysis if 75% or more of those agreements are with non-affiliates. Enron would require more market data for an affiliate-backed project. American Forest & Paper would allow negotiation of risk if there is no subsidy by existing customers. Sempra and UGI urge the Commission to look at whether projects serve identifiable, new or growing markets. NARUC states that each state is unique and that the Commission should consider those differences. Market Hub Partners believes that a project which is at risk, requires little or no eminent domain authority, and has potential to bring competition to a market that is already being served by pipelines and storage operators with market power should be expedited.

The development in recent years of certificate applicants' use of contracts with affiliates to demonstrate market support for projects has generated opposition from affected landowners and competitor pipelines who question whether the contracts represent real market demand. ConEd, Ohio PUC, and Enron believe that a different standard should be applied to affiliates. ConEd argues that the at risk condition is inadequate when a pipeline serves a market served by an affiliate; risk is shifted. Ohio PUC states that pipelines should shoulder the increased risk and that the Commission should look behind contracts with affiliates. Enron would require more market data for affiliate-backed projects and would require that all projects be supported by precedent agreements at least 25% of which are with non-affiliates.

Nevertheless, most of the commenters support applying the same standard to contracts for new capacity with affiliates as non-affiliates. Amoco, Coastal, Millennium, National Fuel, Southern Natural, Tejas, Texas Eastern, Columbia, Market Hub Partners, El Paso/Tennessee, and PGC all support applying the same standard to affiliates as non-affiliates. Market Hub argues that a contract is a contract; treating affiliates differently would be in the interest of incumbent monopolists. El Paso/Tennessee agree that affiliate precedent agreements are sufficient as long as they are supported by market demand. PGC agrees that the same standard should apply as long as the proposed capacity is offered on a non-discriminatory basis to all in an open season. Amoco makes an exception for marketing affiliates, arguing that they do not represent new demand. Columbia also makes an exception for affiliates that are created just to show market for a project.

Other parties also offered comments on affiliate issues. PGC recommends addressing affiliate issues on a case-by-case basis. Exxon supports offering comparable deals to non-affiliates. If there is insufficient capacity, it should be prorated. AGA supports prohibiting discount adjustments connected with new construction by pipelines or affiliates. National Fuel Gas Supply and Tejas support permitting rolled-in rates for facilities to serve affiliates. PGC argues that there should be no presumption of rolled in rates for affiliates.

The commenters also express concern with the current policy's effect on existing pipelines and their captive customers when the Commission approves pipeline projects proposed to serve the same market. In those cases, they believe that need should be measured differently by, for example, assessing the impact on existing capacity or requiring a strong incremental market showing and more scrutiny of the net benefits. They urge the Commission to balance all the relevant factors before issuing a certificate. A number of parties argued that need should be measured differently when a project is proposed to serve an existing market. UGI urges requiring a strong market showing for such projects. Coastal proposes that the Commission fully integrate the standards announced by the courts [4] with its certificate construction policies, balancing all the relevant factors including the ability of the existing provider to provide the service. El Paso/Tennessee would require more scrutiny of the net benefit. Sempra would require that, prior to construction, all shippers be given the opportunity to turn back capacity. Similarly, Texas Eastern would require the pipeline to use unsubscribed capacity before construction (e.g., a reverse auction).

Other commenters oppose a policy requiring a harder look at projects proposed to serve existing markets. They maintain that market demand for service in order to escape dependence on a dominant pipeline supplier should be accorded the same weight as demand by new incremental load growth. They contend that the benefits of competition and potentially lower gas prices for consumers should control over claims that an existing pipeline needs to be insulated from competition because its revenues may decrease. National Fuel Gas Supply, PGC, Florida Cities, Market Hub Partners, and Southern Natural in particular object to having different policies for new or existing pipelines.

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[4] Citing FPC v. Transcontinental Gas Pipeline Corp., 365 U.S. 1, 23 (1961) and Scenic Hudson Preservation Conference v. FERC, 354 F.2d. 608, 620 (2nd Cir. 1965)

National Fuel Gas Supply contends that generally the policies on new construction and existing pipelines should match. PGC opposes any policy that protects incumbents by requiring a harder look at projects proposed to serve existing markets rather than new demand. Many existing markets have unmet demand. Likewise, Florida Cities is concerned that the NOPR is intended to elicit a new policy where the import and influence of competition is downplayed to minimize or eliminate the risk of unsubscribed capacity on existing pipelines. Florida Cities supports pipeline-on-pipeline competition as a primary factor in determining which new capacity projects receive certificate authority and are constructed. Florida Cities believes that additional pipeline competition would benefit customers and any generic policy that would decrease or inhibit pipeline competition would not be in the best interest of the consumers the Commission is obliged to protect. Market Hub Partners urges the Commission to attempt to limit market incumbents' ability to forestall competition by defeating the efforts of new market entrants to build or operate new capacity. Market Hub Partners contend that incumbents protest on the basis of project safety and environmental concerns when they are primarily concerned with their own welfare and market share. Southern Natural contends the NGA does not permit a rule disfavoring projects that enhance competitive alternatives. Taking a harder look at competitive proposals would effect a preference for monopoly, clearly not endorsed by the NGA or the Courts of Appeal.

Wisconsin Distributor Group believes that meaningful pipe-on-pipe competition can only exist where there are choices among or between pipelines and unsubscribed firm capacity exists. Wisconsin Distributor Group argues the Commission should view favorably new pipeline projects that propose to create competition by introducing an alternative pipeline to markets where no choices exist. Wisconsin Distributor Group contends the Commission's policy should not be driven by self-protective arguments but by the need for competitive alternatives. Wisconsin Distributor Group supports the Commission's analysis in Alliance and Southern because it considers the benefits of competition and potentially lower gas prices for consumers as controlling over claims that an existing pipeline needs to be insulated from competition because its revenues may decrease. Market demand for service in order to escape dependence on a dominant pipeline supplier should be accorded the same weight as demand by new incremental load growth.

UGI, Sempra, and El Paso/Tennessee would require assessing the impact on existing capacity. Sempra states that if existing rates are below the maximum rate, new capacity may not be needed. Sempra adds that the Commission should look at whether expansion capacity can stand on its own without rolled-in treatment. Texas Eastern believes the Commission must consider how best to use existing unsubscribed capacity and capacity that has been turned back to pipelines.

C. The Pricing of New Facilities

A number of commenters submit that the existing presumption in favor of rolled-in rates for pipeline expansions sends the wrong price signals with regard to pricing new construction. They urge the Commission to adopt policies such as incremental pricing for pipeline projects or placing pipelines at risk for recovery of the costs of construction. They submit that such a policy would reveal the true value of existing capacity and properly allocate costs and risks. A number of parties also raised issues concerning rate design in general, but the Commission is deferring for now consideration of those kinds of issues which also affect the Commission's policies for existing pipelines in order to focus on issues concerning the certification of new pipeline construction.

AGA, ConEd, and Michigan Consolidated stress the importance of ensuring the right price signals. AGA urges the Commission to adopt policies that reveal the true value of existing capacity. ConEd states that rate policies should send proper price signals by properly allocating costs and risks.

AGA contends that the Commission's certification policies should protect recourse shippers. AGA and BG&E recommend that the Commission ensure that pipelines are not able to impose the costs of new capacity or the costs of consequent unsubscribed existing capacity on recourse shippers. Amoco asserts pipelines should be at risk for unsubscribed capacity. Similarly, AGA and Philadelphia Gas Works urge the Commission to ensure that pipelines are at risk for unsubscribed capacity relating to construction projects by the pipeline or its affiliate. However, Tejas believes that treatment of any under recovery must address the unique circumstances of deepwater pipelines.

APGA argues that, if the Commission allows initial rates based on the life of the contract rather than the useful life of facilities, the Commission must at least require a uniform contract with the same terms and conditions for all customers involved in the expansion.

The Williams Companies recommend that all new capacity be subject to market-based rates. The Williams Companies argue that, for new capacity priced on an incremental basis rather than a rolled-in basis, competitive circumstances in the industry support the use of market-based rates and terms of service.

AlliedSignal contends depreciation should be based on the life of the facilities not the life of a contract. If the Commission were to promulgate a general rule, it should state that depreciation rates for pipeline facilities in rate and certificate cases should be set at 25 years unless factors are brought to the Commission's attention justifying a lesser or longer time period. NGSA believes that the Commission's current depreciation methodology is appropriate. NGSA also urges that the appropriate asset life of new facilities be determined when the facilities are constructed and adhered to for the life of the asset. On the other hand, the Williams Companies point out that market-based rates would negate the need for the Commission to approve depreciation rates.

Coastal believes pipelines should have the flexibility to address new facility costs in certificate applications and in rate cases. The Commission should not establish hard and fast rules as to how a facility should be treated in a pipeline's rates over its entire life. Rather, costs should be dealt with in accordance with Commission policies from time to time in pipeline rate cases.

Enron Pipelines contend that the rate treatment for capacity additions should continue to be determined on a case-by-case basis using the system benefits test.

Louisville contends that the Commission should address the question of whether its pricing policies for new capacity provide appropriate incentives at the same time as it considers auctions and negotiated rates and services and that all of these issues should be the subject of a new NOPR.

PGC suggest that initial rates be based on a presumed level of contract commitment (e.g., 80-90%) so the pipeline bears the risks of uncommitted capacity but reaps a reward if it sells at undiscounted rates. Another option would be for the Commission to put at risk only that portion of the proposed facilities for which the pipeline has not obtained firm contracts of a minimum duration. Where an existing pipeline constructs new facilities, PGC support the Commission's current policy favoring rolled-in rates if certain conditions are met.

Williston Basin argues that fixed rates for long-term contracts would create a relatively risk-free contract for shippers while creating a total-risk contract for pipelines.

Arkansas, IPAA, Indicated Shippers, National Fuel Gas Supply, NGSA, Peoples Energy, PGC, and the Williams Companies support the Commission's current policy with its presumption in favor of rolled-in pricing for new capacity only when the impact of new capacity is not more than a 5% increase to existing rates and results in system-wide benefits. AGA, Amoco, IPAA, Philadelphia Gas Works, PGC, and UGI recommend that the Commission more rigidly apply its pricing policy and more closely review claims pertaining to the 5% threshold test and/or system benefits. Nicor urges that pipelines should not be allowed to segment construction with the goal of falling below the 5% pricing policy threshold.

APGA and Consolidated Edison recommend that the Commission adopt a presumption of incremental pricing for pipeline certificate projects. APGA would allow limited exceptions such as when the project would lower rates to existing customers or when the benefits of the project would fully offset the costs of the roll-in. Koch Gateway and Pennsylvania Consumer Advocate also recommend incremental pricing for new capacity.

Arkansas and Brooklyn Union contend that pipelines should be at risk for the recovery of the costs of incremental facilities. Brooklyn Union urges the Commission to eliminate the presumption in favor of rolled-in pricing for new capacity and require pipelines to show the benefits of each new project are proportionate to the total rate increase sought.

El Paso/Tennessee recommend that only fully subscribed projects with revenues equaling or exceeding project costs and supported by demonstrated market need should be eligible for rolled-in rates. El Paso/Tennessee believe that projects intended to compete for existing market should not be eligible for rolled-in rates.

New York questions the 5% presumption for rolled-in pricing and argues that a move away from rolled-in pricing would create competitive markets for new pipeline construction.

AlliedSignal believes pipelines should be at risk for costs relative to new services prior to filing a new rate case. In the new rate case, the burden should be on the pipeline to justify the proper allocation of costs.

Amoco suggests that the pipeline and customer be allowed to enter into any agreement that does not violate existing regulations or statutory requirements, but they must explicitly apportion any risk between themselves.

The Illinois Commerce Commission believes this issue needs more research and should not be addressed until state regulators are consulted further.

Market Hub Partners and PGC contend that rolled-in rate treatment should not be granted for facilities solely or principally being constructed on the basis of affiliate precedent agreements. On the other hand, Millennium asserts that affiliates and non-affiliates should be treated alike with respect to rate design. Also, Southern Natural argues that the fact that an affiliate subscribed for capacity on new facilities cannot alone preclude rolled-in pricing for those facilities; the Commission must leave to individual cases the issue of whether to price facilities on a rolled-in or incremental basis.

Nicor argues that the Commission cannot, in a competitive marketplace, evaluate the enhancements claimed by the pipeline to determine whether new construction should be incrementally priced or receive rolled-in rate treatment. Instead of imposing rolled-in rate treatment on the entire system, the Commission should allow individual "old" shippers to decide whether the supposed benefits are worth the costs.

Pipeline Transportation Customer Coalition contends the existing regulatory process does not reflect a reasonable risk-reward balance between industry segments, asserting that pipeline rates are too high given their relatively low risk exposure.

II. Certificate Policy Goals and Objectives

The comments present a variety of perspectives and no clear consensus on a path the Commission should follow. Nevertheless, the starting point for the Commission's reassessment of its certificate policy is to define the goals and objectives to be achieved. An effective certificate policy should further the goals and objectives of the Commission's natural gas regulatory policies. In particular, it should be designed to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas. It should also provide appropriate incentives for the optimal level of construction and efficient customer choices.

Commission policy should give the applicant an incentive to file a complete application that can be processed expeditiously and to develop a record that supports the need for the proposed project and the public benefits to be obtained. Commission certificate policy should also provide an incentive for applicants to structure their projects to avoid, or minimize, the potential adverse impacts that could result from construction of the project.

The Commission intends the certificate policy introduced in this order to provide an analytical framework for deciding, consistent with the goals and objectives stated above, when a proposed project is required by the public convenience and necessity. In some respects this policy is not a significant change from the kind of analysis employed currently in certificate cases. By stating more explicitly the Commission's analytical framework, the Commission can provide applicants and other participants in certificate proceedings a better understanding of how the Commission makes its decisions. By encouraging applicants to devote more effort before filing to minimize the adverse effects of a project, the policy gives them the ability to expedite the decisional process by working out contentious issues in advance. Thus, this policy will provide more certainty about the Commission's analytical process and provide participants in certificate proceedings with a framework for shaping the record that is needed by the Commission to expedite its decisional process.

III. Evaluation of Current Policy

A. Current Policy

Section 1(b) of the Natural Gas Act (NGA) gives the Commission jurisdiction over the transportation of natural gas in interstate commerce and the natural gas companies providing that transportation.[5] Section 7(c) of the NGA provides that no natural gas company shall transport natural gas or construct any facilities for such transportation without a certificate of public convenience and necessity issued by the Commission.[6]

In reaching a final determination on whether a project will be in the public convenience and necessity, the Commission performs a flexible balancing process during which it weighs the factors presented in a particular application. Among the factors that the Commission considers in the balancing process are the proposal's market support, economic, operational, and competitive benefits, and environmental impact.

Under the Commission's current certificate policy, an applicant for a certificate of public convenience and necessity to construct a new pipeline project must show market support through contractual commitments for at least 25 percent of the capacity for the application to be processed by the Commission. An applicant showing 10-year firm commitments for all of its capacity, and/or that revenues will exceed costs is eligible to receive a traditional certificate of public convenience and necessity.

An applicant unable to show the required level of commitment may still receive a certificate but it will be subject to a condition putting the applicant "at risk." In other words, if the project revenues fail to recover the costs, the pipeline rather than its customers will be responsible for the unrecovered costs. Alternatively, a project sponsor can apply for a certificate under Subpart E of Part 157 of the Commission's regulations for an optional certificate.[7] An optional certificate may be granted to an applicant without any market showing at all; however, in practice optional certificate applicants

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[5] 15 USC 717.

[6] 15 USC 717h.

[7] 18 CFR Part 157, Subpart E.

usually make some form of market showing. The rates for service provided through facilities constructed pursuant to an optional certificate must be designed to impose the economic risk of the project entirely on the applicant.

The Commission also has certificated projects that would serve no new market, but would provide some demonstrated system-benefit. Examples include projects intended to provide improved system reliability, access to new supplies, or more economic operations.

Generally, under the current policy, the Commission does not deny an application because of the possible economic impact of a proposed project on existing pipelines serving the same market or on the existing pipelines' customers. In addition, the Commission gives equal weight to contracts between an applicant and its affiliates and an applicant and unrelated third parties and does not look behind the contracts to determine whether the customer commitments represent genuine growth in market demand.[8]

Under section 7(h) of the NGA, a pipeline with a Commission-issued certificate has the right to exercise eminent domain to acquire the land necessary to construct and operate its proposed new pipeline when it cannot reach a voluntary agreement with the landowner.[9] In recent years, this has resulted in landowners becoming increasingly active before the Commission. Landowners and communities often object both to the taking of land and to the reduction of their land's value due to a pipeline's right-of-way running through the property. As part of its environmental review of pipeline projects, the Commission's environmental staff works to take these landowners' concerns into account, and to mitigate adverse impacts where possible and feasible.

Under the pricing policy for new facilities in Docket No. PL94-4-000,[10] the Commission determines, in the certificate proceeding authorizing the facilities' construction, the appropriate pricing for the facilities. Generally, the Commission applies a presumption in favor of rolled-in rates (rolling-in the expansion costs with the existing

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[8] See, e.g., Transcontinental Gas Pipe Line Corp., 82 FERC ¶ 61,084 at 61,316 (1998).

[9] 15 USC 717f(h).

[10] See Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines, 71 FERC ¶ 61,241 (1995).

facilities' costs) when the cost impact of the new facilities would result in a rate impact on existing customers of five percent or less, and some system benefits would occur. Existing customers generally bear these rate increases without being allowed to adjust their volumes.

When a pipeline proposes to charge a cost-based incremental rate (establishing separate costs-of-service and separate rates for the existing and expansion facilities) higher than its existing generally applicable rates, the Commission usually approves the proposal. However, the Commission generally will not accept a proposed incremental rate that is lower than the pipeline's existing generally applicable Part 284 rate.

B. Drawbacks of the Current Policy

1. Reliance on Contracts to Demonstrate Demand

Currently, the Commission uses the percentage of capacity under long-term contracts as the only measure of the demand for a proposed project. Many of the commenters have argued that this is too narrow a test. The reliance solely on long-term contracts to demonstrate demand does not test for all the public benefits that can be achieved by a proposed project. The public benefits may include such factors as the environmental advantages of gas over other fuels, lower fuel costs, access to new supply sources or the connection of new supply to the interstate grid, the elimination of pipeline facility constraints, better service from access to competitive transportation options, and the need for an adequate pipeline infrastructure. The amount of capacity under contract is not a good indicator of all these benefits.

The amount of capacity under contract also is not a sufficient indicator by itself of the need for a project, because the industry has been moving to a practice of relying on short-term contracts, and pipeline capacity is often managed by an entity that is not the actual purchaser of the gas. Using contracts as the primary indicator of market support for the proposed pipeline project also raises additional issues when the contracts are held by pipeline affiliates. Thus, the test relying on the percent of capacity contracted does not reflect the reality of the natural gas industry’s structure and presents difficult issues.

In addition, the current policy's preference for contracts with 10-year terms biases customer choices toward longer term contracts. Of course, there are other elements of the Commission’s policies that also have this effect. However, eliminating a specific requirement for a contract of a particular length is more consistent with the Commission's regulatory objective to provide appropriate incentives for efficient customer choices and the optimal level of construction, without biasing those choices through regulatory policies.

Finally, by relying almost exclusively on contract standards to establish the market need for a new project, the current policy makes it difficult to articulate to landowners and community interests why their land must be used for a new pipeline project.

All of these concerns raise difficult questions of establishing the public need for the project.

2. The Pricing of New Facilities

As the industry becomes more competitive the Commission needs to adapt its policies to ensure that they provide the correct regulatory incentives to achieve the Commission's policy goals and objectives. All of the Commission's natural gas policy goals and objectives are affected by its pricing policy, but directly affected are the goals of fostering competitive markets, protecting captive customers, and providing incentives for the optimal level of construction and efficient customer choice. The current pricing policy focuses primarily on the interests of the expanding pipeline and its existing and new shippers, giving little weight to the interests of competing pipelines or their captive customers. As a result, it no longer fits well with an industry that is increasingly characterized by competition between pipelines.

The current pricing policy sends the wrong price signals, as some commenters have argued, by masking the real cost of the expansions. This can result in overbuilding of capacity and subsidization of an incumbent pipeline in its competition with potential new entrants for expanding markets. The pricing policy's bias for rolled-in pricing also is inconsistent with a policy that encourages competition while seeking to provide incentives for the optimal level of construction and customer choice. This is because rolled-in pricing often results in projects that are subsidized by existing ratepayers. Under this policy the true costs of the project are not seen by the market or the new customers, leading to inefficient investment and contracting decisions. This in turn can exacerbate adverse environmental impacts, distort competition between pipelines for new customers, and financially penalize existing customers of expanding pipelines and of pipelines affected by the expansion.

Under existing policy, shippers' rates may change for a number of reasons. These include rolling-in of an expansion's costs, changes in the discounts given other customers, or changes in the contract quantities flowing on the system. As a customer's rates change in a rate case, it is generally unable to change its volumes, even though it may be paying more for capacity. This results in shippers bearing substantial risks of rate changes which they may be ill equipped to bear.

III. The New Policy

A. Summary of the Policy

As a result of the Commission's reassessment of its current policy, the Commission has decided to announce the criteria, set forth below, that it will use in deciding whether to authorize the construction of major new pipeline facilities. This section summarizes the analytical steps the Commission will use under this policy to balance the public benefits against the potential adverse consequences of an application for new pipeline construction. Each of these steps is described in greater detail in the later sections of this policy statement.

Once a certificate application is filed, the threshold question applicable to existing pipelines is whether the project can proceed without subsidies from their existing customers. As discussed below, this will usually mean that the project would be incrementally priced, if built by an existing pipeline, but there are cases where rolled in pricing would prevent subsidization of the project by the existing customers.[11]

The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the existing customers of the pipeline proposing the project, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. These three interests are discussed in more detail below. This is not intended to be a decisional step in the process for the Commission. Rather, this is a point where the Commission will review the efforts made by the applicant and could assist the applicant in finding ways to mitigate the effects, but the choice of how to structure the project at this stage is left to the applicant's discretion.

If the proposed project will not have any adverse effect on the existing customers of the expanding pipeline, existing pipelines in the market and their captive customers, or the economic interests of landowners and communities affected by the route of the new pipeline, then no balancing of benefits against adverse effects would be necessary. The Commission would proceed, as it does under current practice, to a preliminary

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[11]This policy does not apply to construction authorized under 18 CFR Part 157, Subparts E and F.

determination or a final order depending on the time required to complete an environmental assessment (EA) or environmental impact statement (EIS)(whichever is required in the case).

If residual adverse effects on the three interests are identified, after efforts have been made to minimize them, then the Commission will proceed to evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered. It is possible at this stage for the Commission to identify conditions that it could impose on the certificate that would further minimize or eliminate adverse impacts and take those into account in balancing the benefits against the adverse effects. If the result of the balancing is a conclusion that the public benefits outweigh the adverse effects then the next steps would be the same as for a project that had no adverse effects. That is, if the EA or EIS would take more than approximately 180 days then a preliminary determination could be issued, followed by the EA or EIS and the final order. If the EA would take less time, then it would be combined with the final order.

B. The Threshold Requirement - No Financial Subsidies

The threshold requirement in establishing the public convenience and necessity for existing pipelines proposing an expansion project is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers.[12] This does not mean that the project sponsor has to bear all the financial risk

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[12]Projects designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility, are for the benefit of existing customers. Increasing the rates of the existing customers to pay for these improvements is not a subsidy. Under current policy these kinds of projects are permitted to be rolled in and are not covered by the presumption of the current pricing

of the project; the risk can be shared with the new customers in preconstruction contracts, but it cannot be shifted to existing customers. For new pipeline companies, without existing customers, this requirement will have no application.

The requirement that the project be able to stand on its own financially without subsidies changes the current pricing policy which has a presumption in favor of rolled-in pricing. Eliminating the subsidization usually inherent in rolled-in rates recognizes that a policy of incrementally pricing facilities sends the proper price signals to the market. With a policy of incremental pricing, the market will then decide whether a project is financially viable. The commenters were divided on whether the Commission should change its current pricing policy. A number of commenters, however, urged the Commission to allow the market to decide which projects should be built, and this requirement is a way of accomplishing that result.

The requirement helps to address all of the interests that could be adversely affected. Existing customers of the expanding pipeline should not have to subsidize a project that does not serve them. Landowners should not be subject to eminent domain for projects that are not financially viable and therefore may not be viable in the marketplace. Existing pipelines should not have to compete against new entrants into their markets whose projects receive a financial subsidy (via rolled-in rates), and neither pipeline's captive customers should have to shoulder the costs of unused capacity that results from competing projects that are not financially viable. This is the only condition that uniformly serves to avoid adverse effects on all of the relevant interests and therefore should be a test for all proposed expansion projects by existing pipelines. It will be the predicate for the rest of the evaluation of a new project by an existing pipeline.

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policy. Great Lakes Gas Transmission Limited Partnership, 80 FERC ¶ 61,105 (1997) (Pricing policy statement not applicable to facilities constructed solely for flexibility and system reliability).

A requirement that the new project must be financially viable without subsidies does not eliminate the possibility that in some instances the project costs should be rolled into the rates of existing customers. In most instances incremental pricing will avoid subsidies for the new project, but the situation may be different in cases of inexpensive expansibility that is made possible because of earlier, costly construction. In that instance, because the existing customers bear the cost of the earlier, more costly construction in their rates, incremental pricing could result in the new customers receiving a subsidy from the existing customers because the new customers would not face the full cost of the construction that makes their new service possible. The issue of the rate treatment for such cheap expansibility is one that always should be resolved in advance, before the construction of the pipeline.

Another instance where a form of rolling in would be appropriate is where a pipeline has vintages of capacity and thus charges shippers different prices for the same service under incremental pricing, and some customers have the right of first refusal (ROFR) to renew their expiring contracts. Those customers could be allowed to exercise a ROFR at their original contract rate except when the incremental capacity is fully subscribed and there are competing bids for the existing customer's capacity. In that case, the existing customer could be required to match the highest competing bid up to a maximum rate which could be either an incremental rate or a "rolled-up rate" in which costs for expansions are accumulated to yield an average expansion rate. Although the focus of this policy statement is the analysis for deciding whether new capacity should be constructed, it is important for the Commission to articulate the direction of its policy on pricing existing capacity where a pipeline has engaged in expansions. This will enable existing and potential new shippers to make appropriate decisions pre-construction to protect their interests either in the certificate proceeding or in their contracts with the pipeline.

This policy leaves the pipeline responsible for the costs of new capacity that is not fully utilized and obviates the need for an "at risk" condition because it accomplishes the same purpose. Under this policy the pipeline bears the risk for any new capacity that is under-utilized, unless, as recommended by a number of commenters, it contracts with the new customers to share that risk by specifying what will happen to rates and volumes under specific circumstances. If the pipeline finds that new shippers are unwilling to share this risk, this may indicate to the pipeline that others do not share its vision of future demand. Similarly, the risks of construction cost over-runs should not be the responsibility of the pipeline's existing customers but should be apportioned between the pipeline and the new customers in their service contracts. Thus, in pipeline contracts for service on newly constructed facilities, pipelines should not rely on standard "Memphis clauses", but should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity and cost overruns and the rate treatment for "cheap expansibility."[13]

In sum, if an applicant can show that the project is financially viable without subsidies, then it will have established the first indicator of public benefit. Companies willing to invest in a project, without financial subsidies, will have shown an important indicator of market-based need for a project. Incremental pricing will also lead to the correct price signals for the new project and provide the appropriate incentive for the optimal level of construction. This can avoid unnecessary adverse impacts on landowners or existing pipelines and their captive customers. Therefore, this will be the threshold requirement for establishing that a project will satisfy the public convenience and necessity standard.

C. Factors to be Balanced in Assessing the Public Convenience and Necessity

[13] "Memphis clause" refers to an agreement that the pipeline may change the rate during the term of the contract by making rate filings under NGA section 4.

Ideally, an applicant will structure its proposed project to avoid adverse economic, competitive, environmental, or other effects on the relevant interests from the construction of the new project, and the Commission would be able to approve such projects promptly. Of course, elimination of all adverse effects will not be possible in every instance. When it is not possible, the Commission's policy objective is to encourage the applicant to minimize the adverse impact on each of the relevant interests. After the applicant makes efforts to minimize the adverse effects, construction projects that would have residual adverse effects would be approved only where the public benefits to be achieved from the project can be found to outweigh the adverse effects. Rather than relying only on one test for need, the Commission will consider all relevant factors reflecting on the need for the project. These might include, but would not be limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market. The objective would be for the applicant to make a sufficient showing of the public benefits of its proposed project to outweigh any residual adverse effects discussed below.

1. Consideration of Adverse Effects on Potentially Affected Interests

In deciding whether a proposal is required by the public convenience and necessity, the Commission will consider the effects of the project on all the affected interests; this means more than the interests of the applicant, the potential new customers, and the general societal interests.

Depending on the type of project, there are three major interests that may be adversely affected by approval of major certificate projects, and that must be considered by the Commission. These are: the interests of the applicant's existing customers, the interests of competing existing pipelines and their captive customers, and the interests of landowners and surrounding communities. There are other interests that may need to be separately considered in a certificate proceeding, such as environmental interests.

Of course, not every project will have an impact on each interest identified. Some projects will be proposed by new pipeline companies to serve new markets, so that there will be no adverse effects on the interests of existing customers; other projects may be constructed so that there may be no adverse effect on landowner interests.

a. Interests of existing customers of the pipeline applicant

The interests of the existing customers of the expanding pipeline may be adversely affected if the expansion results in their rates being increased or if the expansion causes a degradation in service.

b. Interests of existing pipelines that already serve the market and their captive customers

Pipelines that already serve the market into which the new capacity would be built are affected by the potential loss of market share and the possibility that they may be left with unsubscribed capacity investment. The Commission need not protect pipeline competitors from the effects of competition, but it does have an obligation to ensure fair competition. Recognizing the impact of a new project on existing pipelines serving the market is not synonymous with protecting incumbent pipelines from the risk of loss of market share to a new entrant, but rather, is a recognition that the impact on the incumbent pipeline is an interest to be taken into account in deciding whether to certificate a new project. The interests of the existing pipeline's captive customers are slightly different from the interests of the pipeline. The interests of the captive customers of the existing pipelines are affected because, under the Commission's current rate model, they can be asked to pay for the unsubscribed capacity in their rates.

c. Interests of landowners and the surrounding communities

Landowners whose land would be condemned for the new pipeline right-of-way, under eminent domain rights conveyed by the Commission's certificate, have an interest as does the community surrounding the right-of-way. The interest of these groups is to avoid unnecessary construction, and any adverse effects on their property associated with a permanent right-of- way. In some cases, the interests of the surrounding community may be represented by state or local agencies. Traditionally, the interests of the landowners and the surrounding community have been considered synonymous with the environmental impacts of a project; however, these interests can be distinct. Landowner property rights issues are different in character from other environmental issues considered under the National Environmental Policy Act of 1969 (NEPA).[14]

[14] 42 USC § 4321 et seq.

2. Indicators of Public Benefit

To demonstrate that its proposal is in the public convenience and necessity, an applicant must show public benefits that would be achieved by the project that are proportional to the project's adverse impacts. The objective is for the applicant to create a record that will enable the Commission to find that the benefits to be achieved by the project will outweigh the potential adverse effects, after efforts have been made by the applicant to mitigate these adverse effects. The types of public benefits that might be shown are quite diverse but could include meeting unserved demand, eliminating bottlenecks, access to new supplies, lower costs to consumers, providing new interconnects that improve the interstate grid, providing competitive alternatives, increasing electric reliability, or advancing clean air objectives. Any relevant evidence could be presented to support any public benefit the applicant may identify. This is a change from the current policy which relies primarily on one test to establish the need for the project.

The amount of evidence necessary to establish the need for a proposed project will depend on the potential adverse effects of the proposed project on the relevant interests. Thus, projects to serve new demand might be approved on a lesser showing of need and public benefits than those to serve markets already served by another pipeline. However, the evidence necessary to establish the need for the project will usually include a market study. There is no reason for an applicant to do a new market study of its own in every instance. An applicant could rely on generally available studies by EIA or GRI, for example, showing projections of market growth. If one of the benefits of a proposed project would be to lower gas or electric rates for consumers, then the applicant's market study would need to explain the basis for that projection. Vague assertions of public benefits will not be sufficient.

Although the Commission traditionally has required an applicant to present contracts to demonstrate need, that policy, as discussed above, no longer reflects the reality of the natural gas industry's structure, nor does it appear to minimize the adverse impacts on any of the relevant interests. Therefore, although contracts or precedent agreements always will be important evidence of demand for a project, the Commission will no longer require an applicant to present contracts for any specific percentage of the new capacity. Of course, if an applicant has entered into contracts or precedent agreements for the capacity, it will be expected to file the agreements in support of the project, and they would constitute significant evidence of demand for the project.

Eliminating a specific contract requirement reduces the significance of whether the contracts are with affiliated or unaffiliated shippers, which was the subject of a number of comments. A project that has precedent agreements with multiple new customers may present a greater indication of need than a project with only a precedent agreement with an affiliate. The new focus, however, will be on the impact of the project on the relevant interests balanced against the benefits to be gained from the project. As long as the project is built without subsidies from the existing ratepayers, the fact that it would be used by affiliated shippers is unlikely to create a rate impact on existing ratepayers. With respect to the impact on the other relevant interests, a project built on speculation (whether or not it will be used by affiliated shippers) will usually require more justification than a project built for a specific new market when balanced against the impact on the affected interests.

3. Assessing Public Benefits and Adverse Effects

The more interests adversely affected or the more adverse impact a project would have on a particular interest, the greater the showing of public benefits from the project required to balance the adverse impact. The objective is for the applicant to develop whatever record is necessary, and for the Commission to impose whatever conditions are necessary, for the Commission to be able to find that the benefits to the public from the project outweigh the adverse impact on the relevant interests.

It is difficult to construct helpful bright line standards or tests for this area. Bright line tests are unlikely to be flexible enough to resolve specific cases and to allow the Commission to take into account the different interests that must be considered. Indeed, the current contract test has become problematic. However, the analytical framework described here should give applicants more certainty and sufficient guidance to anticipate how to structure their projects and develop the record to facilitate the Commission's decisional process.

Under this policy, if project sponsors, proposing a new pipeline company, are able to acquire all, or substantially all, of the necessary right-of-way by negotiation prior to filing the application, and the proposal is to serve a new, previously unserved market, it would not adversely affect any of the three interests. Such a project would not need any additional indicators of need and may be readily approved if there are no environmental considerations. Under these circumstances landowners would not be subject to eminent domain proceedings, and because the pipeline was new, there would be no existing customers who might be called upon to subsidize the project. A similar result might be achieved by an existing pipeline extending into a new unserved market by negotiating for a right-of-way for the proposed expansion and following the first requirement for showing need, financing the project without financial subsidies. It would avoid adverse impacts to existing customers by pricing its new capacity incrementally and it is unlikely that other relevant interests would be adversely affected if the pipeline obtained the right-of-way by negotiation.

It may not be possible to acquire all the necessary right-of-way by negotiation. However, the company might minimize the effect of the project on landowners by acquiring as much right-of-way as possible. In that case, the applicant may be called upon to present some evidence of market demand, but under this sliding scale approach the benefits needed to be shown would be less than in a case where no land rights had been previously acquired by negotiation. For example, if an applicant had precedent agreements with multiple parties for most of the new capacity, that would be strong evidence of market demand and potential public benefits that could outweigh the inability to negotiate right-of-way agreements with some landowners. Similarly, a project to attach major new gas supplies to the interstate grid would have benefits that may outweigh the lack of some right-of-way agreements. A showing of significant public benefit would outweigh the modest use of federal eminent domain authority in this example.

In most cases it will not be possible to acquire all the necessary right-of-way by negotiation. Under this policy, a few holdout landowners cannot veto a project, as feared by some commenters, if the applicant provides support for the benefits of its proposal that justifies the issuance of a certificate and the exercise of the corresponding eminent domain rights. The strength of the benefit showing will need to be proportional to the applicant's proposed exercise of eminent domain procedures.

Of course, the Commission will continue to do an independent environmental review of projects, even if the project does not rely on the use of eminent domain and the applicant structures the project to avoid or minimize adverse impacts on any of the identified interests. The Commission anticipates no change to this aspect of its certificate policies. However, to the extent applicants minimize the adverse impacts of projects in advance, this should also lessen the adverse environmental impacts as well, making the NEPA analysis easier. The balancing of interests and benefits that will precede the environmental analysis will largely focus on economic interests such as the property rights of landowners. The other interests of landowners and the surrounding community, such as noise reduction or esthetic concerns will continue to be taken into account in the environmental analysis. If the environmental analysis following a preliminary determination indicates a preferred route other than the one proposed by the applicant, the earlier balancing of the public benefits of the project against its adverse effects would be reopened to take into account the adverse effects on landowners who would be affected by the changed route.

In another example of the proportional approach, a proposal that may have adverse impacts on customers of another pipeline may require evidence of additional benefits to consumers, such as lower rates for the customers to be served. The Commission might also consider how the proposal would affect the cost recovery of the existing pipeline, particularly the amount of unsubscribed capacity that would be created and who would bear that risk, before approving the project. This evaluation would be needed to ensure consideration of the interests of the existing pipeline and particularly its captive customers. Such consideration does not mean that the Commission would always favor existing pipelines and their captive customers. For instance, a proposed project may be so efficient and offer substantial benefits, such as significant service flexibility, so that the benefits would outweigh the adverse impact on existing pipelines and their captive customers.

A number of commenters were concerned that the Commission might give too much weight to the impact on the existing pipeline and its captive customers and undervalue the benefits that can arise from competitive alternatives. The Commission's focus is not to protect incumbent pipelines from the risk of loss of market share to a new entrant, but rather to take the impact into account in balancing the interests. In such a case the evidence of benefits will need to be more specific and detailed than the generalized benefits that arise from the availability of competitive alternatives. The interests of the captive customers are slightly different from the interests of the incumbent pipeline. The captive customers are affected if the incumbent pipeline shifts to the captive customers the costs associated with its unsubscribed capacity. Under the Commission's current rate model captive customers can be asked to pay for unsubscribed capacity in their rates, but the Commission has indicated that it will not permit all costs resulting from the loss of market share to be shifted to captive customers.[15] Whether and to what extent costs can be shifted is an issue to be resolved in the incumbent pipeline's rate case, but the potential impact on these captive customers is a factor to be taken into account in the certificate proceeding of the new entrant.

In sum, the Commission will approve an application for a certificate only if the public benefits from the project outweigh any adverse effects. Under this policy, pipelines seeking a certificate of public convenience and necessity authorizing the construction of facilities are encouraged to submit applications designed to avoid or minimize adverse effects on relevant interests including effects on existing customers of the applicant, existing pipelines serving the market and their captive customers, and affected landowners and communities. The threshold requirement for approval, that project sponsors must be prepared to develop the project without relying on subsidization by the sponsor's existing customers, protects all of the relevant interests. Applicants also must submit evidence of the public benefits to be achieved by the proposed project such

[15] El Paso Natural Gas Company, 72 FERC ¶ 61,083 (1995); Natural Gas Pipeline Company of America, 73 FERC ¶ 61,050 (1995).

as contracts, precedent agreements, studies of projected demand in the market to be served, or other evidence of public benefit of the project

V. Conclusion

At a time when the Commission is urged to authorize new pipeline capacity to meet an anticipated increase in the demand for natural gas, the Commission is also urged to act with caution to avoid unnecessary rights-of-way and the potential for overbuilding with the consequent effects on existing pipelines and their captive customers. This policy statement is intended to provide more certainty as to how the Commission will analyze certificate applications to balance these concerns. By encouraging applicants to devote more effort in advance of filing to minimize the adverse effects of a project, the policy gives them the ability to expedite the decisional process by working out contentious issues in advance. Thus, this policy will provide more guidance about the Commission's analytical process and provide participants in certificate proceedings with a framework for shaping the record that is needed by the Commission to expedite its decisional process.

Finally, this new policy will not be applied retroactively. A major purpose of the policy statement is to provide certainty about the decisionmaking process and the impacts that would result from approval of the project This includes providing participants in a certificate proceeding certainty as to economic impacts that will result from the certificate. It is important for the participants to know the economic consequences that can result before construction begins. After the economic decisions have been made it is difficult to undo those choices. Therefore, the new policy will not be applied retroactively to cases where the certificate has already issued and the investment decisions have been made.

By the Commission. Chairman Hoecker and Commissioners Breathitt and Hébert concurred with a separate statement attached.
(S E A L) Commissioner Bailey dissented with a separate statement statement attached.

David P. Boergers,
Secretary.

Policy Statement for Certification of New Interstate Natural Gas Pipeline Facilities

Docket No. PL99-3-000

(Issued September 15, 1999)

HOECKER, Chairman; BREATHITT and HEBERT, Commissioners, concurring;

Our intention is to apply this policy statement to any filings received by the Commission after July 29, 1998 (the issuance date of the Commission's Notice of Proposed Rulemaking regarding the Regulation of Short-term Natural Gas Transportation Services in Docket No. RM98-10-000 and Notice of Inquiry regarding Regulation of Interstate Natural Gas Transportation Services in Docket No. RM98-12-000), and not before.

James J. Hoecker
Chairman

Linda K. Breathitt
Commissioner

Curt L. Hébert
Commissioner

Certification of New Interstate Natural
Gas Facilities Docket No. PL99-3-000

(Issued September 15, 1999)

BAILEY, Commissioner, dissenting.

Respectfully, I will be dissenting from this policy statement.

The document puts forth the majority's statement of an analytical framework for use in certificate proceedings. Its goal is to give applicants and other participants in those proceedings a better understanding of how the Commission makes its decisions. This is always a good thing to do. But ultimately, I cannot sign on to this statement as representative of my approach to certificate policy for several reasons.

First and foremost, the document purports that the policy outlined is not a significant departure from the kind of analysis used currently in certificate cases. I do not share this view. I know that it does depart from the way I currently look at certificate issues. For example, I cannot say that the sliding scale evaluation process and the weighing and balancing process described in the statement actually reflects the way I look at things. Further, the pricing changes announced are in fact significant departures from current practice. Thus, the document is as much about pricing policy change as it is about articulating an analytical approach to certification questions. I do not completely agree with the statements regarding pricing contained in this document.

The announced policy will now require that new projects meet a pricing threshold before work can proceed on the application – that is they should be incrementally priced and not subsidized by existing customers. The intent behind this is to enhance our certainty that the market is determining which projects come to the Commission.

I do not disagree with the idea that incremental pricing is consistent with the idea of allowing markets to decide. I also recognize that it can protect existing customers from subsidizing expansions as well as insulate existing pipelines from subsidized competition. However, I find the policy statement to be far too categorical in its approach. I am not persuaded that we should depart from our existing policy statement on pricing that we adopted in 1995.

There is too little recognition here that some types of construction projects are not designed solely for new markets or customers, that existing customers can benefit from some projects, and that rolled-in pricing may still be appropriate. Thus, while I can agree with some of the articulated goals such as pricing should allocate risk appropriately, and that if done properly it can assist in avoiding construction of excess capacity, I would not adopt a threshold requirement that virtually precludes use of rolled-in rates.

Finally, I am at a loss to explain the genesis of this particular outcome. I recognize that certificate policy issues have been problematic for a long time. In attempts to address these issues we have had conferences to explore need issues and we have requested comments on certificate issues in the pending gas Notice of Proposed Rulemaking in Docket No. RM98-10-000 (84 FERC ¶ 61,087 (1998)) and the Notice of Inquiry in Docket No. RM98-12-000 (84 FERC ¶ 61,087 (1998)). The variety of views we have received in these efforts are summarized in the policy statement and it candidly recognizes the lack of clear direction on what path the Commission should follow. Given this lack of industry consensus, I question the advisability of trying to adopt a generic approach at this time. I would prefer to weigh further the relative merits of those comments before embarking on an attempt to articulate a certificate policy.

Vicky A. Bailey
Commissioner

Exhibit 12

LNG Exports in the Pacific Northwest – Jordan Cove Update

Pacific Northwest Economic Region
27th Annual Summit

July 25, 2017 • Portland, Oregon

Betsy Spomer

Executive Vice-President, Veresen
President & CEO, Jordan Cove LNG LLC

VERESEN Jordan Cove LNG

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Forward-looking information advisory

Certain information contained in this presentation constitutes forward-looking information under applicable Canadian securities laws. All information, other than statements of historical fact, which addresses activities, events or developments that we expect or anticipate may or will occur in the future, is forward-looking information. Forward-looking information typically contains statements with words such as "may", "estimate", "anticipate", "believe", "expect", "plan", "intend", "target", "project", "forecast" or similar words suggesting future outcomes or outlook. Forward-looking statements in this presentation include, but are not limited to, statements with respect to: the ability of Veresen to recognize synergies between Ruby and the Jordan Cove LNG project, the cost estimate, timing of, and our ability to successfully obtain regulatory approvals for Jordan Cove LNG and the Pacific Gas Connector Pipeline, the timing of decisions to proceed with construction of, and the in-service date of Jordan Cove LNG and the Pacific Gas Connector Pipeline and sources of gas supply to feed Jordan Cove LNG and the Pacific Gas Connector Pipeline.

The risks and uncertainties that may affect the operations, performance, development and results of our businesses include, but are not limited to, the following factors: our ability to successfully implement our strategic initiatives and achieve expected benefits; levels of oil and gas exploration and development activity; the status, credit risk and continued existence of contracted customers; the availability and price of capital; the availability and price of energy commodities; the availability of construction services and materials; fluctuations in foreign exchange and interest rates; our ability to successfully obtain regulatory approvals; changes in tax, regulatory, environmental, and other laws and regulations; competitive factors in the pipeline, NGL and power industries; operational breakdowns, failures, or other disruptions; and the prevailing economic conditions in North America. Additional information on these and other risks, uncertainties and factors that could affect our operations or financial results are included in our filings with the securities commissions or similar authorities in each of the provinces of Canada, as may be updated from time to time.

Although we believe the expectations conveyed by the forward-looking information are reasonable based on information available to us on the date of preparation, we can give no assurances as to future results, levels of activity and achievements. Readers should not place undue reliance on the information contained in this presentation, as actual results achieved will vary from the information provided herein and the variations may be material. We make no representation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained herein are made as of the date hereof, and, except as required by law, we do not undertake any obligation to update publicly or to revise any forward-looking information, whether as a result of new information, future events or otherwise. We expressly qualify any forward-looking information contained in this presentation by this cautionary statement.

Jordan Cove LNG

Jordan Cove LNG (JCLNG)

- 7.8 mtpa greenfield facility
- 264 acre site
- 7-mile transit to site – Port of Coos Bay

Pacific Connector Gas Pipeline (PCGP)

- Receipt interconnects with GTN and Ruby pipelines at Malin, Oregon
- 229 mile; 36" diameter
- ~1.2 bcf/d design capacity

VERESEN Jordan Cove LNG

Exhibit 12
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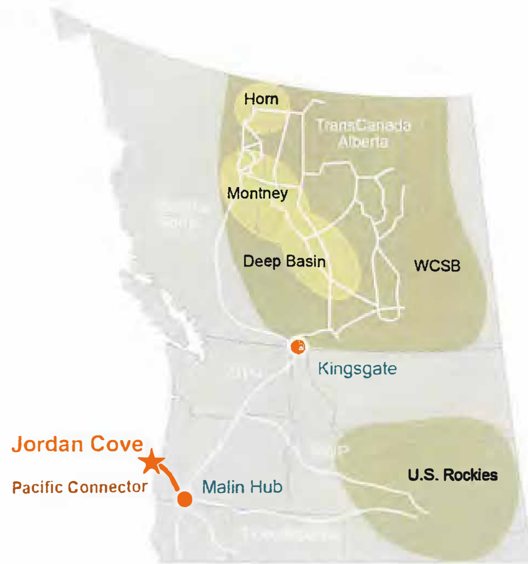
Direct access to two large gas basins

- Access to the U.S. Rockies (via Ruby Pipeline) and the Western Canada Sedimentary Basin (via Gas Transmission Northwest), each with multiple major producing areas



VERESEN Jordan Cove LNG

International Port of Coos Bay

Port was once the largest timber port in the world with 300-400 ship visits a year; now down to 30-40 visits per year; community in need of economic development..

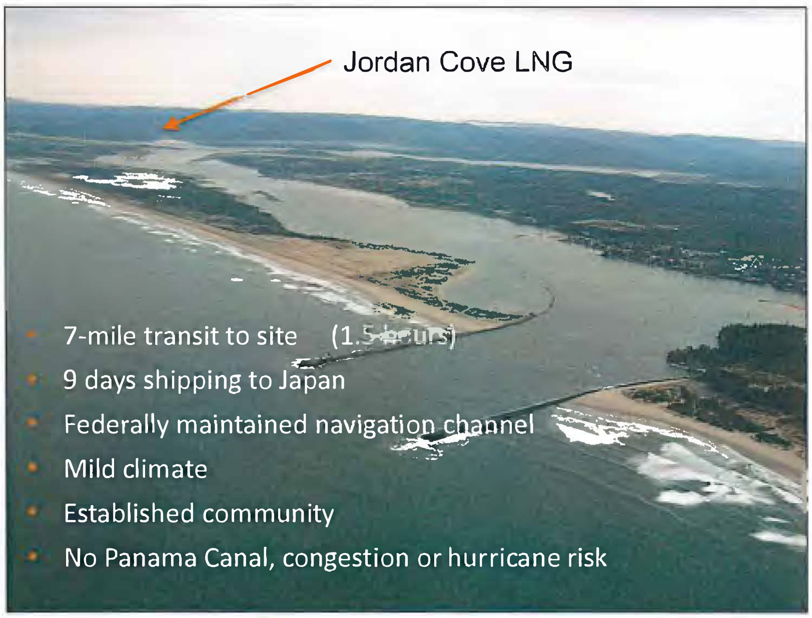


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Exhibit 12
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Market support

- Jordan Cove has reached commercial agreement with two major Japanese LNG companies and is progressing commercial discussions with others
  - JERA – liquefaction capacity of 1.5+ mtpa
    - Exclusive fuel procurement company for Japan's largest electric utilities
    - Single largest LNG buyer in the world; they make the market
  - ITOCHU – liquefaction capacity of 1.5 mtpa
    - Largest Japanese trading company in 2016
    - Long history in the global LNG trade
  - In advanced commercial discussions with two other Japanese buyers
    - Expected to take 2+ mtpa of liquefaction capacity
    - Also talking to Chinese and Korean buyers

Regulatory status

- Project received a clean final environmental impact study (FEIS) in September 2015
- FERC denied certificate application in March 2016 due to lack of market support
- Submitted request for rehearing (appeal) with two agreements for ~50% of plant capacity and transportation precedent services agreements for 77% of pipeline capacity
- After eight months, project's request for rehearing denied December 2016 – FERC unwilling to consider supplemental market information
- Submitted application for pre-filing to FERC January 23, 2017
  - Accepted into pre-filing February 10, 2017
  - Pre-filing process is a minimum of six months; 18+ months to FERC certificate

Jordan Cove's strategic rationale

When compared to other projects globally, we believe Jordan Cove LNG is cost competitive with all new global LNG supply alternatives into NE Asia.

Strengths:

- Competitive with Gulf of Mexico brownfield LNG projects' cost delivered into Asia
  - Right sized for current market conditions at 7 mtpa
- 9 days shipping from Coos Bay, Oregon to Tokyo
  - 22 days shipping from the Gulf of Mexico to Tokyo
  - No Panama Canal or hurricane risks
- Long-term gas supply from two large gas regions – US Rockies and Western Canada
  - Project served by two under-utilized large diameter pipeline systems
  - Limited local competition for natural gas
- Strong state and community support

Challenges:

- Permitting in the Pacific Northwest environment
  - No precedent for project of this scope and complexity – challenges State and Federal agencies
  - Mitigation of environmental impacts – Tribal cultural sites, endangered species

VERESEN Jordan Cove LNG

Why will this time be different?

- The market is ready – broad consensus on supply shortfall in 2022/23
- From a FERC perspective, the key will be to have:
  - 75%+ of binding transportation service agreements on the pipeline
  - 65% to 75% of private landowner voluntary right of way (ROW) agreements
    - Since the FERC denial, PCGP has secured 110 voluntary ROW agreements from a total of 259 private fee owners or > 40%; progress is being made daily
- Stakeholder management is critical
  - We made a number of project adjustments to address stakeholder concerns
    - Moved work force housing from North Bend, OR to the site
    - Worked with landowners to avoid or mitigate impacts from the pipeline
  - We are executing a strong and coherent stakeholder management plan
- FERC will have four (of five) new Commissioners before we are in front of the Commission in Q3/4 2018
- Administration is seeking to coordinate among federal agencies in permitting large infrastructure projects; project has a designated "project manager" (Fast 41) to facilitate inter-agency coordination

Thank you

VERESEN Jordan Cove LNG

Independent Statistics & Analysis
U.S. Energy Information Administration

Oil and Natural Gas Resources and Technology

March 2018

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

Exhibit B
Page 1 of 14

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

Future growth in U.S. crude oil and natural gas production is projected to be driven by the development of tight oil[1] and shale gas[2] resources. However, a great deal of uncertainty surrounds this result. In particular, future domestic tight oil and shale gas production depends on the quality of the resources, the evolution of technological and operational improvements to increase productivity per well and to reduce costs, and the market prices determined in a diverse market of producers and consumers, all of which are highly uncertain. This article provides background on the analysis of the estimated ultimate recovery per well (EUR)[3], a key assumption underlying the projections, and it provides a detailed discussion of the sensitivity of results across *Annual Energy Outlook 2018* (AEO2018) cases.

The outlook for domestic crude oil and natural gas production is highly sensitive to resource and technology assumptions. In the AEO2018 Reference case, domestic crude oil production increases over the next five years and then generally flattens after 2022, staying about 11 million to 12 million barrels per day (b/d) through 2050. Similarly, domestic dry natural gas production increases rapidly (more than 5% annually) through 2021 and then slows to an annual average growth rate of 1% through 2050, reaching 43.0 trillion cubic feet (Tcf) per year in 2050 in the Reference case. In the High Oil and Gas Resource and Technology case, domestic crude oil and dry natural gas production increases through 2050, reaching 19.1 million b/d and 55.3 Tcf/year, respectively, in 2050. In the Low Oil and Gas Resource and Technology case, domestic crude oil production decreases for most of the projection period, and dry natural gas production stays near 30 Tcf/year from 2018 through 2050.

Background

Production profiles from currently producing wells provide the basis for calculating existing EURs and provide insight about the potential productivity of new wells drilled in the same play. In examining the trend of EURs in a play, the life cycle of development provides a good framework for analyzing the results. Geology, technology, and economic conditions specific to the area being developed also need to be considered. Using the example of the Eagle Ford, the following discussion illustrates the common trends affecting the EUR of a horizontal oil well in a particular play.[4]

The development life cycle of a tight oil or shale gas play consists of four phases: (1) exploration and appraisal, (2) early development, (3) stabilization of production, and (4) maximization of recovery. Even

[1]The term *tight oil* does not have a specific technical, scientific, or geologic definition. *Tight oil* is an industry convention that generally refers to oil produced from very low-permeability shale, sandstone, and carbonate formations, with *permeability* being a measure of the ability of a fluid to flow through the rock. In limited areas of some very low-permeability formations, small volumes of oil have been produced for many decades.

[2] Shale gas production includes associated natural gas production in tight oil plays.

[3] Monthly production is fit to a decline curve for each well drilled with initial production in 2008 or later and that has at least four months of production data available. The mathematical form of the curve is initially hyperbolic, but it shifts to exponential when the annual decline rate reaches 10%. The EUR is the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30-year well lifetime. For more detail, see Appendix 2C in the documentation of the Oil and Gas Supply Module (https://www.eia.gov/outlooks/aeo/nems/documentation/ogsm/pdf/m063(2017).pdf).

[4] U.S. Energy Information Administration, *Annual Energy Outlook 2014*, Issues in Focus article "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level," https://www.eia.gov/outlooks/archive/aeo14/section_issues.cfm#tight_oil

though the play may have many producers with varying lease positions and specific operational objectives, the general pattern of the life cycle of a play follows this pattern. The length of each phase is largely determined by the quality and size of the resource, the availability of infrastructure and experienced personnel, and current market conditions during development.

Phase I—exploration and appraisal. The primary objective during this phase is to identify formations with potential commercial development by evaluating geologic characteristics (i.e., depth, porosity, thickness, total organic carbon, fluid saturations, etc.). Seismic and geophysical data are interpreted to assess potential crude oil and natural gas in the ground. Exploration and appraisal wells are also drilled to determine the size, quality and geographical extent of the play.

Phase II—early development. During this phase, more wells are drilled over a broader area of the play, and areas with the greatest potential (*sweet spots*[5]) are identified. In addition, this phase may see high levels of technological and operational innovations as producers determine how to more efficiently extract the hydrocarbons at the lowest per-unit costs. The average EUR for the formation usually increases the fastest during this phase.

Phase III—stabilization of production. During this phase, producers optimize lateral lengths,[6] well spacing, and completion design to account for their improved understanding of the resource to focus on reducing per-unit production costs. This optimization often results in a well production profile that has higher initial production rates, higher initial decline rates, and longer production tails than previous wells drilled in the same area but not necessarily an increase in the overall average EUR.

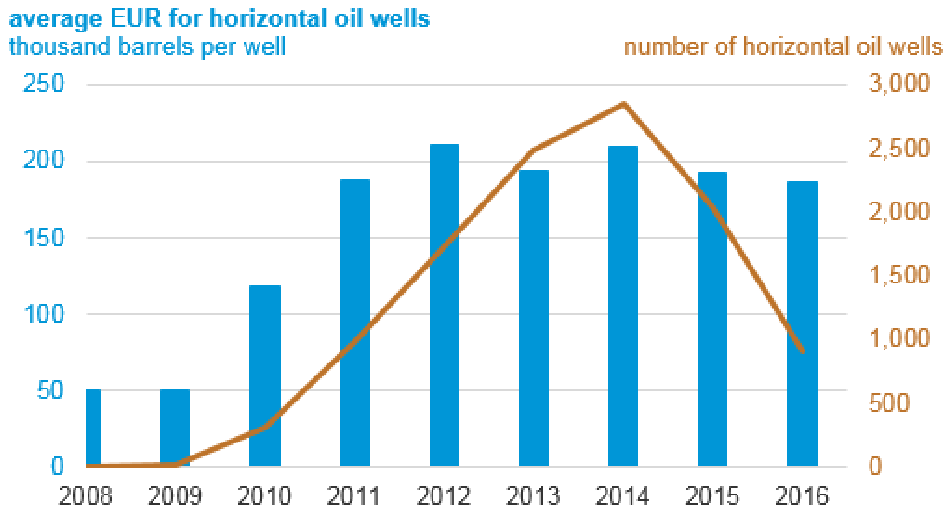
Phase IV—maximization of recovery. During this phase, drilling continues in core areas (reducing well spacing and increased well interference) and expands to less productive areas. As a result, the average EUR for the formation tends to decrease.

Development of a play usually begins slowly as producers secure leases and start drilling to determine if oil can be produced from that play given current technology. If the areas of exploration are determined to be economically viable, drilling will speed up quickly. For example, horizontal oil drilling in the Eagle Ford increased rapidly in 2010 when the West Texas Intermediate (WTI) spot oil price averaged slightly less than $90 per barrel (in real 2017 dollars) and continued to increase through 2014 as the WTI spot price remained higher than $97 per barrel (Figure 1). At the same time, the average EUR per horizontal oil well increased from about 50,000 barrels per well in 2008 to more than 200,000 barrels per well in 2014 as producers targeted the most productive counties and improved extraction techniques and operations to increase the productivity of the play.

[5] *Sweet spot* is an industry term for those select and limited areas within a play where the well EURs are significantly higher than those for the rest of the play—sometimes as much as 10 times higher than those for the lower-production areas within the play.

[6] *Lateral lengths* are the horizontal sections of a well.

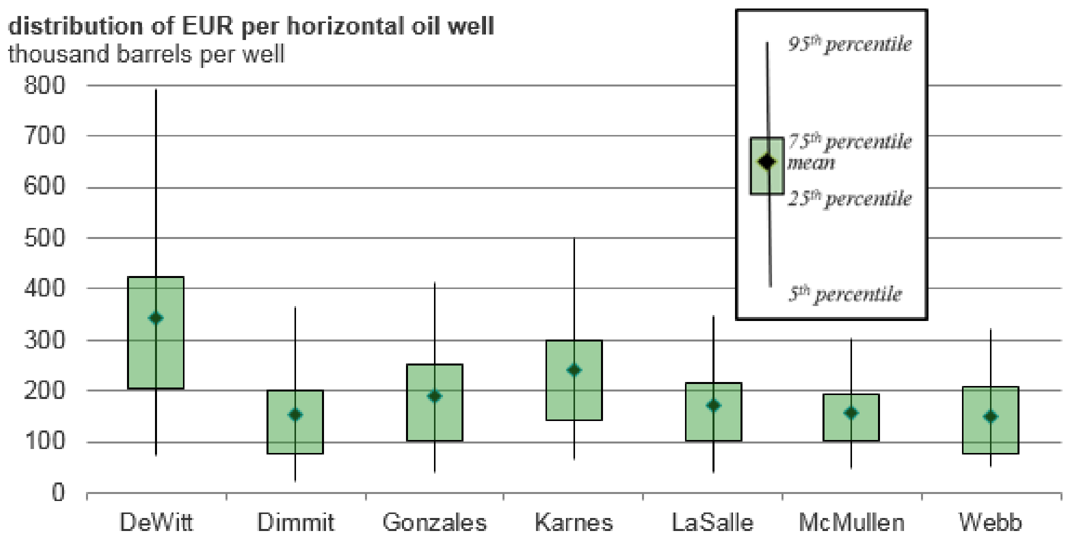
Figure 1. Average crude oil EUR and number of wells drilled in the Eagle Ford



Source: U.S. Energy Information Administration analysis of well level monthly production state administrative data provided by Drillinginfo, accessed August 2017.

The range of EURs across counties and within each county can be large, as shown in Figure 2. More than 70% of the horizontal oil wells drilled in the Eagle Ford from 2008–2016 were drilled in seven counties: the western counties—Dimmit, La Salle, McMullen, and Webb—and the central counties—DeWitt, Gonzales, and Karnes.

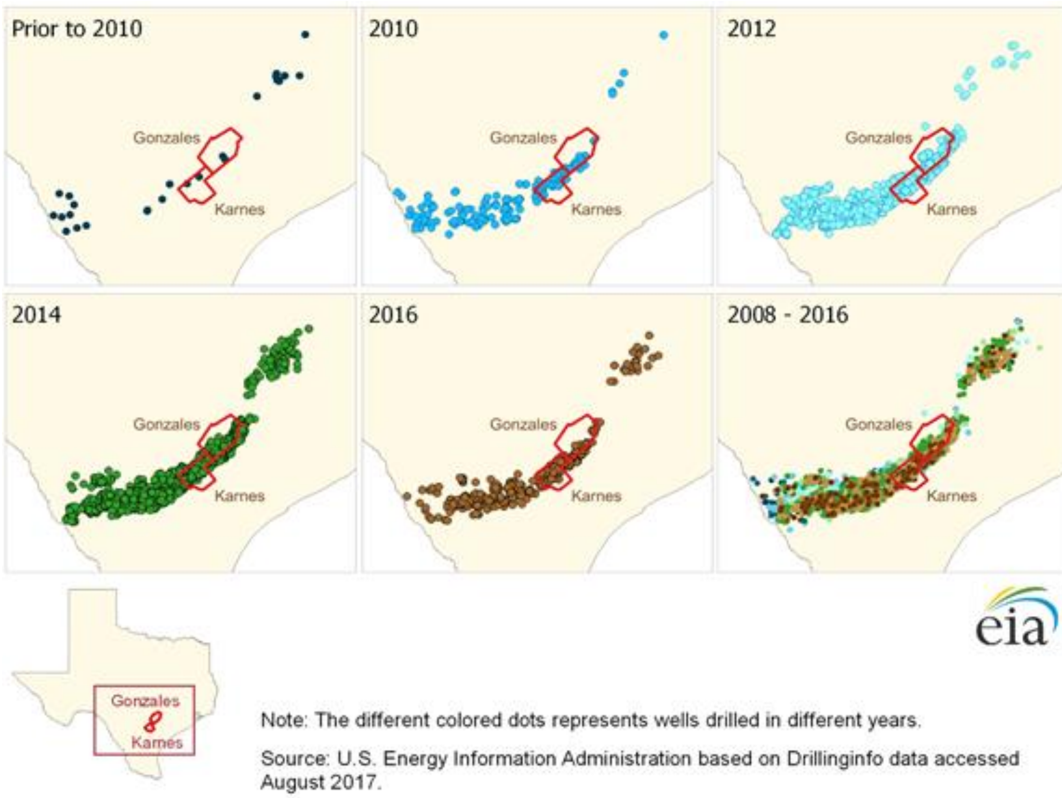
Figure 2. Distribution of crude oil EUR in seven counties of the Eagle Ford, 2008-2016



Source: U.S. Energy Information Administration analysis of Drillinginfo data accessed August 2017

When the WTI spot price dropped to $50 per barrel in the winter of 2014–2015, the number of horizontal oil wells drilled in 2015 and 2016 in the Eagle Ford slowed appreciably. The average EUR decreased slightly because continued drilling in the sweet spots resulted in diminishing returns as wells began to interfere with each other. Producers then reduced drilling in the less productive areas and continued to make operational improvements. The progression of horizontal oil well drilling in the Eagle Ford over time is shown in Figure 3.

Figure 3. Horizontal oil wells drilled in the Eagle Ford, 2008-2016

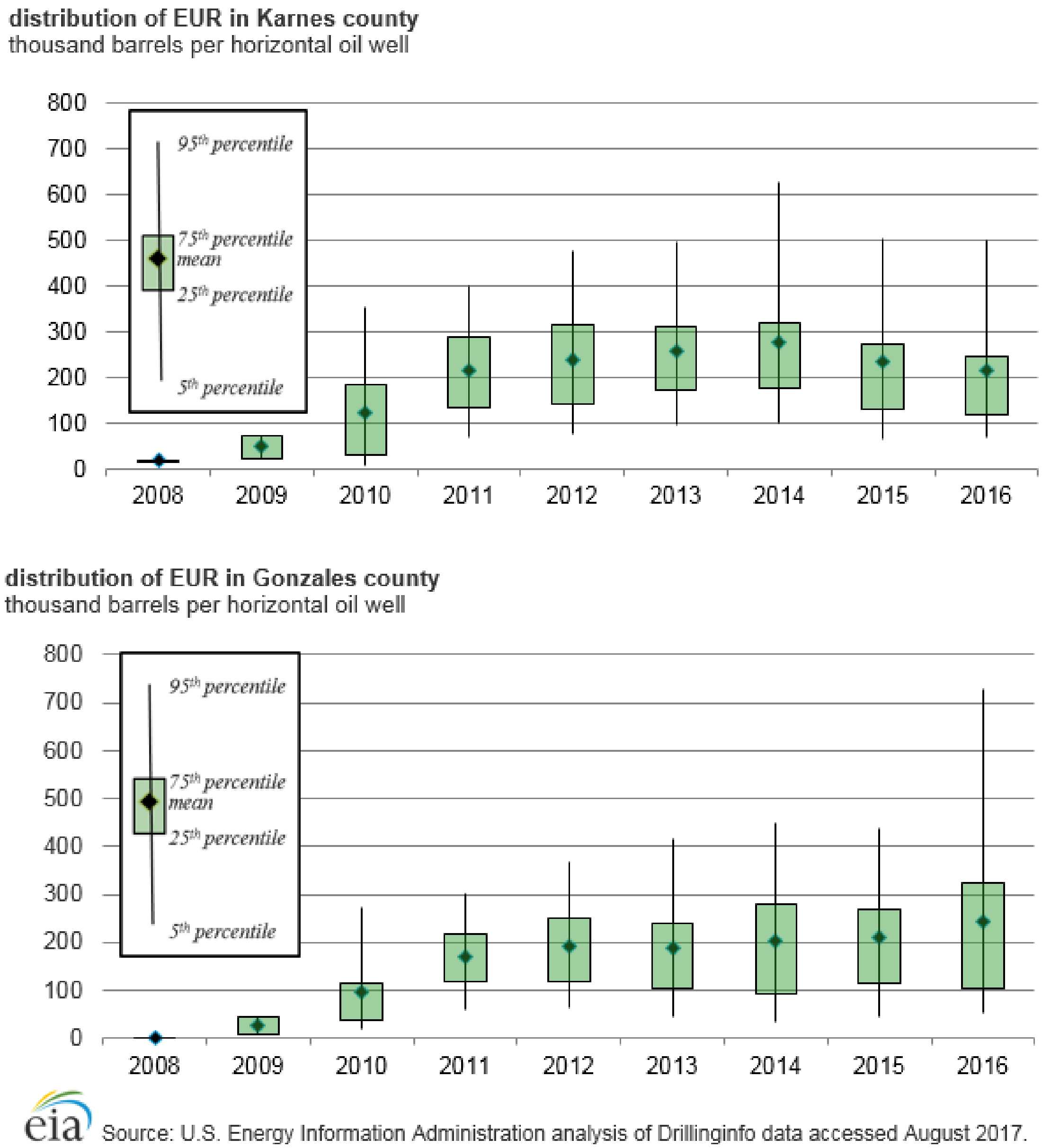


Note: The different colored dots represents wells drilled in different years.

Source: U.S. Energy Information Administration based on Drillinginfo data accessed August 2017.

Not surprisingly, for many of the counties in Eagle Ford, the change in EUR over time looks similar to the change in EUR for the whole play as illustrated in, Karnes County, one of the major areas of development in the area (Figure 4). However, the life cycle of a play does not necessarily proceed equally across all counties, as shown by another area in the play, Gonzales County. Thus, understanding the geology within a county is important to help identify the extent of sweet spots in the county, if any, to better reflect the productive potential as the county is drilled out.

Figure 4. Distribution of crude oil EUR in two counties



As development of a tight oil or shale gas play continues, the EUR per well decreases. This relationship means that higher prices or significant reduction in costs are needed to spur an additional increase in drilling to maintain constant production levels in a particular play.

Results

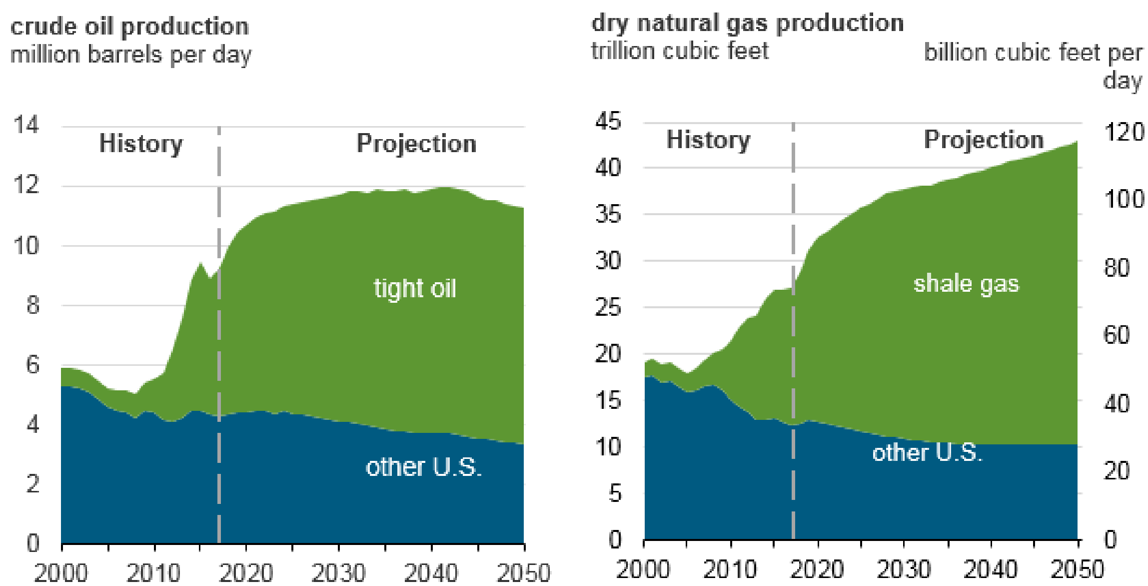
Even though the AEO2018 projections in the Reference case show a rapid increase in the production of oil and natural gas, particularly in the mid-term years, these results vary widely across the side cases constructed to measure the sensitivity of the results to the assumptions in the Reference case. These differences also affect the balance of trade related to oil and natural gas and other related energy markets.

Reference case

Over the past 10 years, tight oil and shale gas production in the United States has increased dramatically, accounting for 54% of crude oil production and 55% of dry natural gas production in 2017, compared with 17% for each in 2008 (Figure 5). This growth has been supported by development in the Appalachian Basin, the Williston Basin, the Western Gulf Basin and, more recently, the Permian Basin.

Total U.S. crude oil production in the AEO2018 Reference case increases over the next five years, from 9.2 million b/d in 2017 to 11.1 million b/d in 2022, and then generally flattens after 2022, staying about 11 million to 12 million b/d through 2050. Similarly, domestic dry natural gas production increases rapidly (more than 5% annually) through 2021 and then slows to an annual average growth rate of 1% through 2050 in the Reference case. With the increasing development of tight and shale resources (particularly in the Marcellus and Permian Basin plays), natural gas plant liquids production in the Reference case also increases through 2050, reaching almost 5.6 million b/d in 2050 compared with 3.7 million b/d in 2017.

Figure 5. U.S. crude oil and dry natural gas production, Reference case



Note: Shale gas production includes associated natural gas from tight oil plays.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018* Reference case

However, a great deal of uncertainty exists concerning the recovery of tight oil and shale gas resources in known plays, and in the potential for production from additional plays or other layers within currently productive formations that have not been tested. The AEO Assumptions Report chapter for the Oil and Gas Supply Module provides a summary table (Table 9.3) of EURs, well spacing, and other parameters by play for tight oil and shale gas.

Refinements to current technologies and new technological advances also can have significant (but uncertain) impacts on the recoverability of tight oil and shale gas in the United States. The AEO2018 uses a simplified approach to modeling the impact of technology advancement on U.S. crude oil and natural gas costs and productivity to capture a continually changing technological landscape. This approach incorporates assumptions about average annual improvement rates that represent ongoing innovation in upstream technologies.

Areas in tight oil, tight gas[7], and shale gas plays are divided into two productivity tiers with different assumed rates of technology change. The first tier (Tier 1) encompasses actively developing areas, and the second tier (Tier 2) encompasses areas not yet developing. Once development begins in a Tier 2 area (Tier 2 drilling ramp-up period), the rate of technological improvement doubles for wells drilling in the early development phase as producers determine how to efficiently extract the hydrocarbons and where the sweet spots are located (learning by doing). This area is then converted to Tier 1 so technological improvement for continued drilling will reflect the rates assumed for Tier 1 areas. This conversion captures the effects of diminishing returns on a per-well basis from decreasing well spacing as development progresses, the quick market penetration of technologies, and the ready application of industry practices and technologies at the time of development. The assumptions for the annual average rate of technological improvement are shown in Table 1.

Table 1. Onshore Lower 48 technology assumptions

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2	EUR-Tier 2 drilling ramp-up period
Tight oil, tight gas, & shale gas	-1.00%	-0.50%	1.00%	3.00%	6.00%
All other	-0.25%	-0.25%	0.25%	N.A.	N.A.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*

Side Cases

The AEO2018 High and Low Oil and Gas Resource and Technology cases are sensitivity cases that are based on assumptions resulting in higher and lower estimates of technically recoverable crude oil and natural gas resources than those in the Reference case. These cases allow for an examination of the potential effects of higher and lower domestic supply on spot prices, imports, and other energy markets (e.g., the electricity market), but they do not represent upper and lower bounds for future domestic oil and natural gas supply. The EUR for future drilling and rates of technological progress are critical assumptions and have a major effect on the outlook for domestic crude oil and natural gas production.

[7] The identification of tight gas as a separate production category began with the passage of the Natural Gas Policy Act of 1978 (NGPA), which established tight gas as a separate wellhead natural gas pricing category that could obtain unregulated market-determined prices. With the full deregulation of wellhead natural gas prices and the repeal of the associated Federal Energy Regulatory Commission (FERC) regulations, tight gas no longer has a specifically defined meaning (https://pubs.naruc.org/pub.cfm?id=5380A188-2354-D714-5108-9FFD2F8F1A72 Accessed 2/9/2018). These resources have been in production since the early 1980s and refer to natural gas produced from low-permeability sandstone and carbonate reservoirs. Tight gas and shale gas are reported separately in the AEO; however, the distinction between tight gas and shale gas is fading because both are produced from low-permeability rock primarily with horizontal drilling and hydraulic fracturing.

The High Oil and Gas Resource and Technology case reflects an assumed broad-based future increase across all crude oil and natural gas resources, not limited to tight oil and shale gas. In this case, the following assumptions differ from those used in the Reference case:

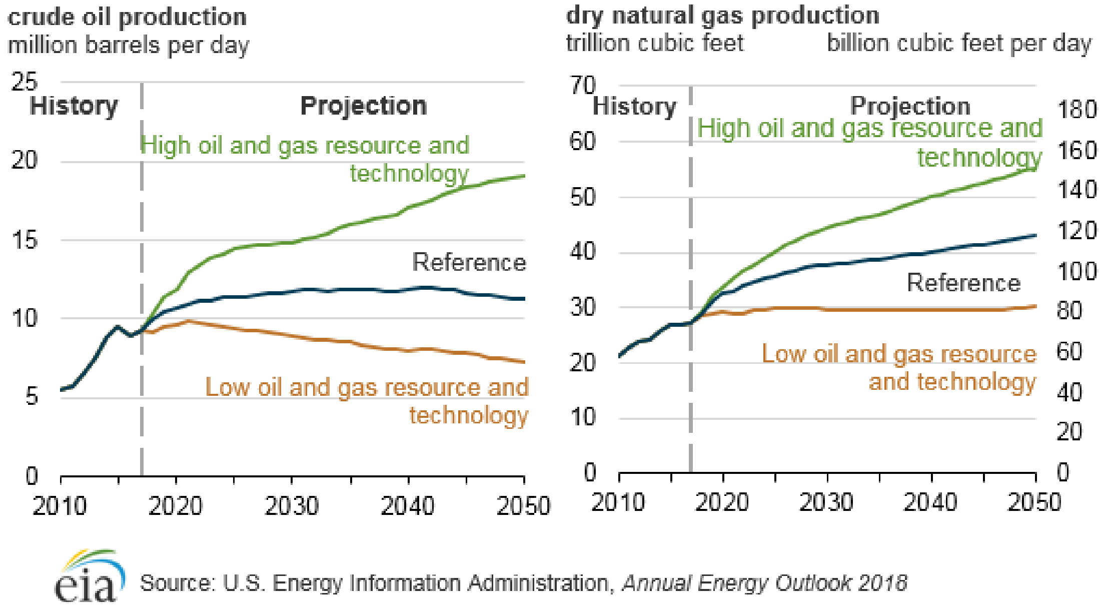
- 50% higher EURs for tight oil, tight gas, and shale gas wells
- Additional tight oil resources to capture the possibility that additional layers or new areas of low-permeability zones will be identified and developed
- 50% higher assumed rates of technological improvements that reduce costs and increase productivity in the United States
- 50% higher technically recoverable undiscovered resources in Alaska and the offshore Lower 48 states, reflecting more favorable resolution of the uncertainty surrounding undeveloped areas that have had little or no exploration and development activity, and where modern seismic survey data are lacking

In the Low Oil and Gas Resource and Technology case, the EURs per tight oil, tight gas, or shale gas well in the United States and undiscovered resources in Alaska and the offshore Lower 48 states are assumed to be 50% lower than in the Reference case. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the United States. All other resource assumptions are unchanged from those in the Reference case.

Impact on domestic crude oil and dry natural gas production

In the High Oil and Gas Resource and Technology case, U.S. crude oil and dry natural gas production increases through 2050, reaching about 19.1 million b/d and 55.3 Tcf per year, respectively, in 2050 (Figure 6). Domestic crude oil production decreases for most of the projection period, and dry natural gas production stays near 30 Tcf/year from 2018 through 2050 in the Low Oil and Gas Resource and Technology case.

Figure 6. U.S. crude oil and dry natural gas production in three cases, 2010-2050



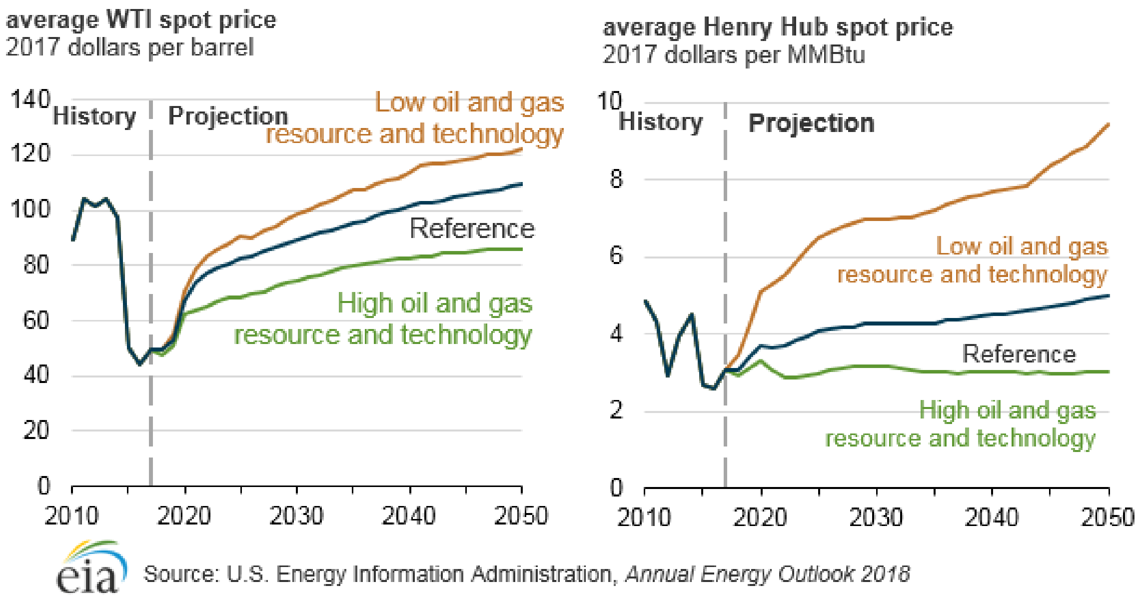
The difference in overall production across cases mostly reflects differences in tight oil and shale gas production. In the High Oil and Gas Resource and Technology case, higher well productivity reduces development and production costs per unit, which results in more and earlier development of tight oil and shale gas resources than in the Reference case. From 2017 through 2050, cumulative tight oil production in the High Oil and Gas Resource and Technology case is about 139 billion barrels, compared with about 93 billion barrels in the Reference Case, and cumulative shale gas production is about 1,109 Tcf in the High Oil and Gas Resource and Technology case, compared with 909 Tcf in the Reference case.

In the Low Oil and Gas Resource and Technology case, lower well productivity and rates of technological progress result in U.S. crude oil and dry natural gas production profiles that grow more slowly and result in lower levels in 2050 compared with the Reference case. Tight oil production peaks at 5.6 million b/d in 2021 and then declines through 2050. Cumulative tight oil production from 2017 through 2050 is about 63 billion barrels in the Low Oil and Gas Resource case, or 32% less than in the Reference Case. Shale gas production increase through 2050 but only reaches 22.1 Tcf in 2050 in the Low Oil and Gas Resource and Technology case compared with 32.7 Tcf in the Reference case. Cumulative shale gas production is about 663 Tcf in the Low Oil and Gas Resource and Technology case, or 27% less than in the Reference case.

Impact on spot prices

As a result of higher volumes of lower cost crude oil and natural gas supply in the High Oil and Gas Resource and Technology case, U.S. crude oil and natural gas spot prices are lower than in the Reference case (Figure 7). The West Texas Intermediate (WTI) spot price averages $86 per barrel (2017 dollars) in 2050 in the High Oil and Gas Resource and Technology case, compared with $110 per barrel in the Reference case. The Henry Hub spot price for natural gas remains relatively flat throughout the projection period, averaging $3 per million British thermal units (MMBtu) from 2017–2050.

Figure 7. Average WTI and Henry Hub spot prices in three cases, 2010-2050

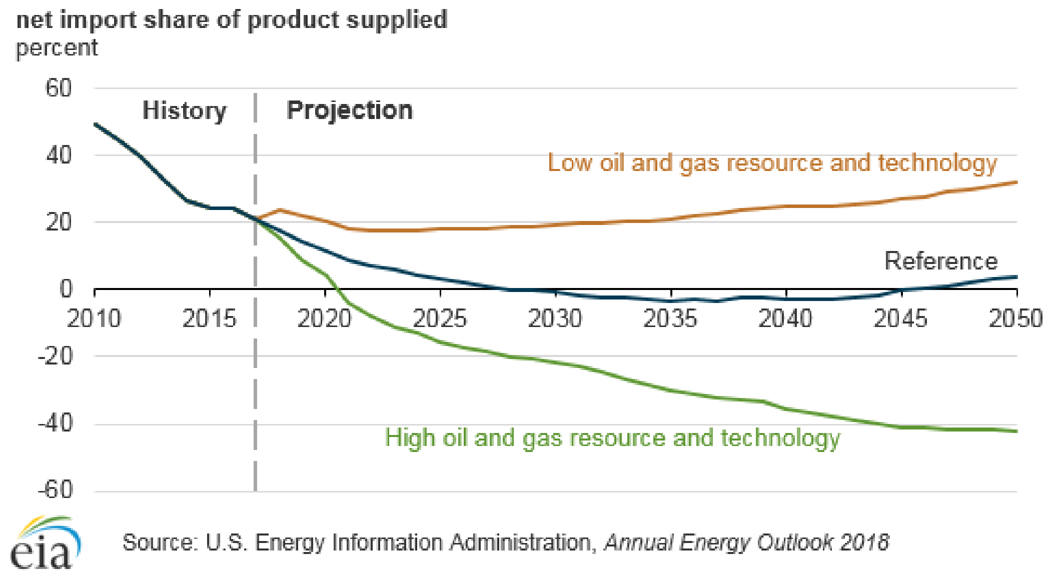


In the Low Oil and Gas Resource and Technology case, higher cost resources drive domestic prices higher than Reference case prices. Both the WTI and Henry Hub spot prices continue to generally increase through 2050—reaching $122 per barrel and more than $9 per MMBtu (2017 dollars) in 2050, respectively.

Impact on U.S. net import

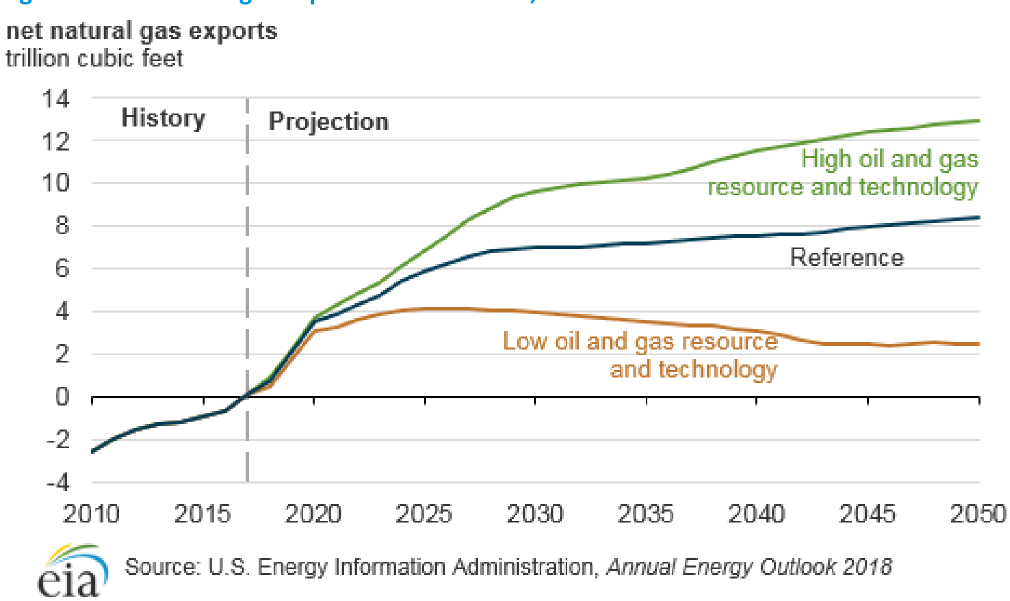
The variation in the domestic petroleum supply outlook across the Reference case and the High and Low Oil and Gas Resource cases results in significant variations in the share of net imports in total U.S. liquid fuels consumption (Figure 8). The net import share of liquids consumption has generally been declining since the high of near 60% in 2005 and was about 21% in 2017. In the Reference case, the United States becomes a net exporter of product supplied from 2029 through 2045. In the High Oil and Gas Resource and Technology case, the United States is a net exporter of petroleum on a volume basis from 2021 through 2050. Given declining domestic crude oil production in the Low Oil and Gas Resource and Technology case, net import share of liquids consumption remains higher than 18%, reaching almost 32% in 2050 in that case.

Figure 8. Net import share of U.S. liquids consumption in three cases, 2010-2050



Similarly, the variation in U.S. natural gas prices across these sensitivity cases results in significant variations in the level of net exports of natural gas, especially liquefied natural gas (LNG) (Figure 9). In all cases, the United States remains a net exporter of natural gas through 2050. In the High Oil and Gas Resource and Technology case, U.S. net exports of natural gas reach nearly 13 Tcf in 2050, as low U.S. natural gas prices make U.S. LNG exports competitive relative to other suppliers. With the higher U.S. natural gas prices in the Low Oil and Gas Resource and Technology case, cumulative net U.S. natural gas exports from 2017 through 2050 are more than 50% lower than in the Reference case.

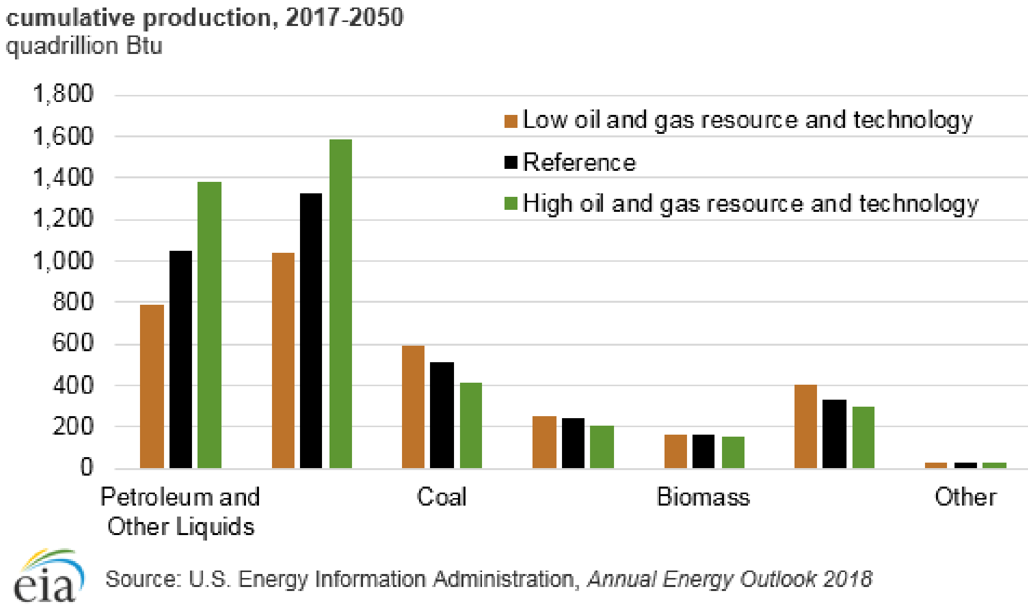
Figure 9. Net natural gas exports in three cases, 2010-2050



Impact on other energy markets

Changes in natural gas supply and the resulting change in prices have the greatest impact on coal and renewable production because demand in the electric power sector for these energy sources competes directly with natural gas (Figure 10). In the Low Oil and Gas Resource and Technology case with the Henry Hub spot price averaging almost $7 per MMBtu (2017 dollars) over the 2017–2050 period (compared with $4 per MMBtu in the Reference case), cumulative coal and other renewables production from 2017 through 2050 is 15% and 23% higher than in the Reference case on a Btu basis, respectively. With the average Henry Hub price at $3 per MMBtu in the High Oil and Gas Resource and Technology case over the same period, cumulative coal production is 96 quadrillion Btu (or 19%) lower than in the Reference case, and other renewables production is 33 quadrillion Btu (or 10%) lower than in the Reference case.

Figure 10. Cumulative production by source, 2017-2050



Calculating the Economic Benefits of U.S. LNG Exports

Prepared for LNG Allies

April 17, 2018

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Calculating the Economic Benefits of U.S. LNG Exports

At the request of LNG Allies, ICF has prepared tables and charts that present some of the benefits to the U.S. economy and energy markets of LNG exports from the United States. ICF prepared this information based on three EIA cases from the 2018 Annual Energy Outlook. Those three cases are the 2018 Reference Case, the High Oil & Gas Resources and Technology Case, and the High Oil Price Case.

For the calculation of impacts, ICF used methodologies we employed for the American Petroleum Institute (API) in two recent reports: Benefits and Opportunities of Natural Gas Use, Transportation, and Production (June 2017) and Impact of LNG Exports on the U.S. Economy: A Brief Update (Sept. 2017). Although the methodology used here to estimate GDP and job impacts is similar to that of the prior API reports, the results differ for two primary reasons: First, the underlying energy market projections are different. This report starts from the most recent AEO published in Feb. 2018, while the prior API reports used older and different cases from the 2016 and 2017 AEOs. Second, the current study uses more recent base year economic data (e.g., revenues and employment by industrial sector) and input/output coefficients among industrial sectors.

The first two economic impact measures we examine here are direct, indirect, and induced value added[1] and jobs related to LNG liquefaction plants. These impact measures are defined to include only the economic activity related to the construction and operation of the liquefaction plants and ports themselves and do not include the economic activity related to producing and transporting the natural gas used for liquefaction plant fuel and feedstock. Thus, to provide a full picture of the economic impacts, we also estimate the value added and jobs related to supplying natural gas to the liquefaction plants.

As shown in Figure 1, the cumulative direct, indirect, and induced value added from the LNG plants from 2013 to 2050 will range from $716 billion to $1.267 trillion for the three AEO cases. In that same period, the LNG plants would support 2.0 million to 3.9 million job-years of direct, indirect, and induced labor.

As shown in Figure 2, the cumulative direct, indirect, and induced value added from supplying natural gas to the liquefaction plants would range from $948 billion to $1.988 trillion for the three AEO cases from 2016 to 2050. The labor impacts of supplying natural gas in the three AEO cases would range from 5.3 to 11.6 million job-years through 2050.

Thus, considering the whole value chain (LNG Plants + Natural Gas Supply): (1) the cumulative direct, indirect, and induced value added from U.S. LNG exports would range from $1.664 trillion to $3.255 trillion for the three selected AEO-2018 cases over the 2013 to 2050 time frame; and (2) the direct, indirect, and induced employment benefits from U.S. LNG exports would range from 7.346 to 15.459 million job-years over that same period (an average of 205,403 to 432,897 direct, indirect, and induced jobs per year).

1. "Value added" can also be thought of as the contribution to Gross National Product (GDP) from one or more industrial sectors or geographic regions.

Exhibit 1. Economic Impacts from U.S. LNG Export Terminals

	Reference Case	High Oil & Gas Case	High Oil Price Case
Highest Annual LNG Exports Billion cubic feet per day (Bcf/d)	14.7	22.9	32.2
Highest Annual Value Added from LNG Terminals (Billion 2017$)	23.0	32.4	45.7
Cumulative Value Added from LNG Terminals (2013-2050, Billion 2017$)	716	976	1,267
Highest Annual Direct, Indirect, Induced Jobs from LNG Terminals (jobs)	142,534	142,534	160,807
Average Annual Direct, Indirect, Induced Jobs from LNG Terminals (jobs)	52,441	76,134	102,809
Cumulative Direct, Indirect, Induced Jobs from LNG Terminals (job-years)	1,992,770	2,893,087	3,906, 756

Exhibit 2. Economic Impacts from U.S. Natural Gas Supplied for LNG Fuel and Feedstock

	Reference Case	High Oil & Gas Case	High Oil Price Case
Highest Annual Value Added from Natural Gas for LNG Terminals (billion 2017$)	36.8	34.9	95.5
Cumulative Value Added from Natural Gas for LNG Terminals (2016-2050, billion 2017$)	948	909	1,988
Highest Annual Direct, Indirect, Induced Jobs from Natural Gas for LNG Terminals	182,844	259,908	476,543
Average Annual Direct, Indirect, Induced Jobs from Natural Gas for LNG Terminals	152,962	193,940	330,088
Cumulative Direct, Indirect, Induced Jobs from Natural Gas for LNG (job-years)	5,353,659	6,787,913	11,553,067

Note: Value added and jobs include direct, indirect, and induced impacts. LNG export plant construction began in 2013, so that is the first year for estimating economic impacts from the plants. U.S. LNG exports began in 2016, so that is the first year for estimating the impacts related to natural gas supply.

AEO Cases for 2018

EIA's Reference Case for the Annual Energy Outlook generally assumes that current laws and regulations affecting the energy sector are unchanged throughout the projection period. The potential impacts of any proposed legislation, regulations, and standards are not included. The underlying Reference Case demographic and economic assumptions reflect the current views of leading economic forecasters and demographers. For both the supply-side and demand-side, the Reference Case projection assumes gradual improvements in known technologies that increase the efficiency of energy production and utilization.

EIA addresses the uncertainty inherent in energy projections by developing alternative cases with different assumptions of macroeconomic growth, world oil prices, technological progress, and energy policies. For example in the High Oil and Gas Resource and Technology Case, assumptions of (a) faster upstream technology progress that lowers oil and gas production costs and (b) higher oil and gas resource availability than in the Reference Case allow for higher oil and gas production at lower prices. The Low Oil and Gas Resource and Technology Case is created by moving those same assumptions in the opposite direction. The High Oil Price Case is driven by both supply-side and demand-side assumptions that lead to much tighter global market balances and higher crude oil prices. The Low Oil Price Case is created from assumptions that increase oil supplies (at a given price), reduce petroleum demand (at a given price), and lead to lower prices than seen in the Reference Case.

Oil and Gas Prices for the AEO Cases

Exhibit 3 shows Brent Crude oil prices in 2017 dollars per barrel for the three selected AEO cases that ICF examined here. Natural gas prices at Henry Hub are shown in Exhibit 4 in 2017 dollars per million Btu. As would be expected, the High Oil Price Case generally has the highest oil and gas prices. The High Oil & Resources & Technology Case generally has the lowest oil and gas prices, reflecting the impacts of an assumed larger undiscovered oil and gas resource base and lower finding and developing cost per unit of production.

LNG Exports in the AEO Cases

The forecasted U.S. LNG exports are shown in Exhibit 5 for the three AEO cases and the estimated export capacity is shown in Exhibit 5. Since the AEO does not report LNG terminal capacity, ICF estimated the export capacity values shown here based on plants now under construction and an assumption that long-run capacity utilization rates will be 85%. Additions of new capacity contribute to value added through construction expenditures.

Exhibit 3.

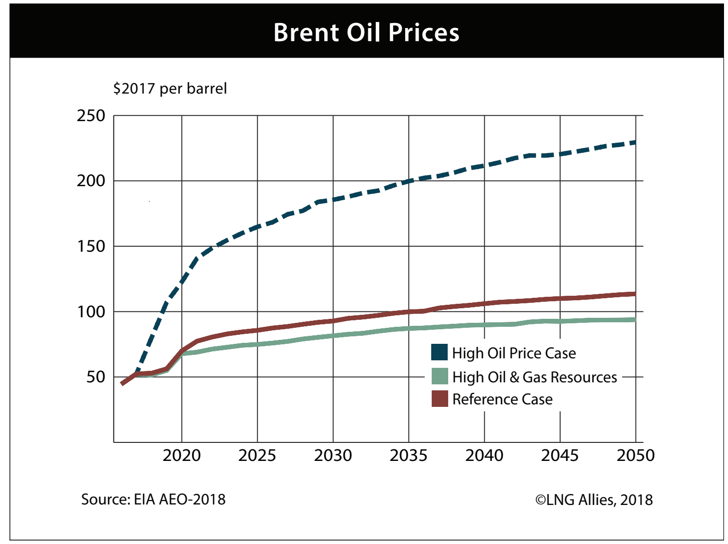


Exhibit 4.

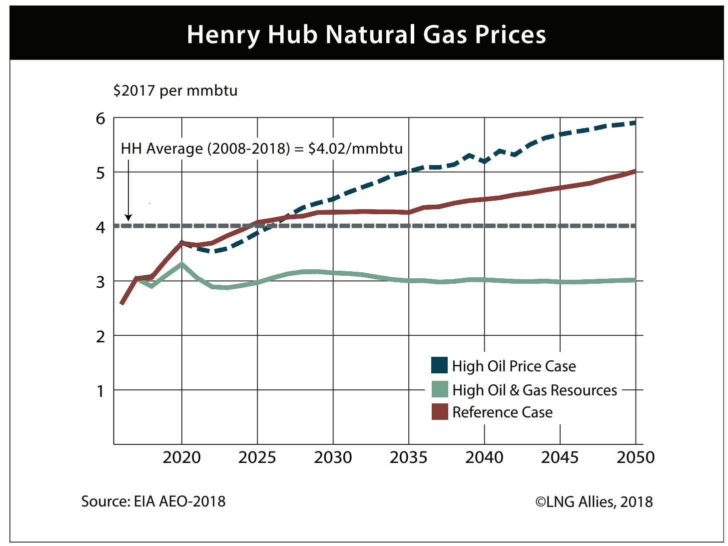


Exhibit 5.

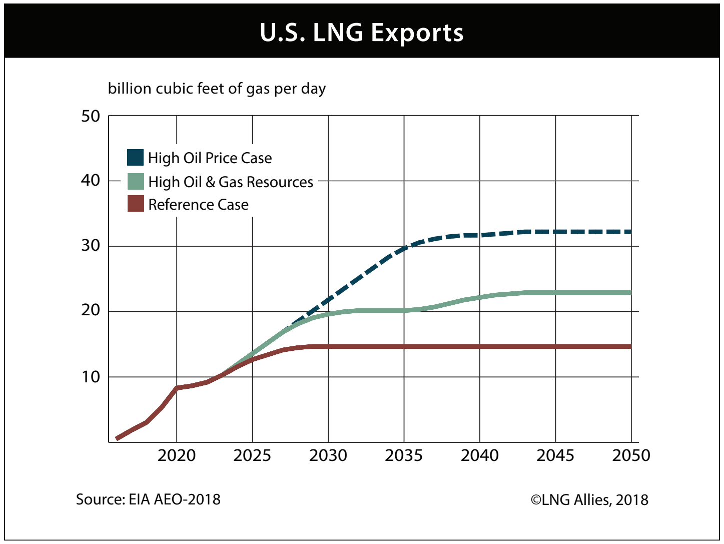
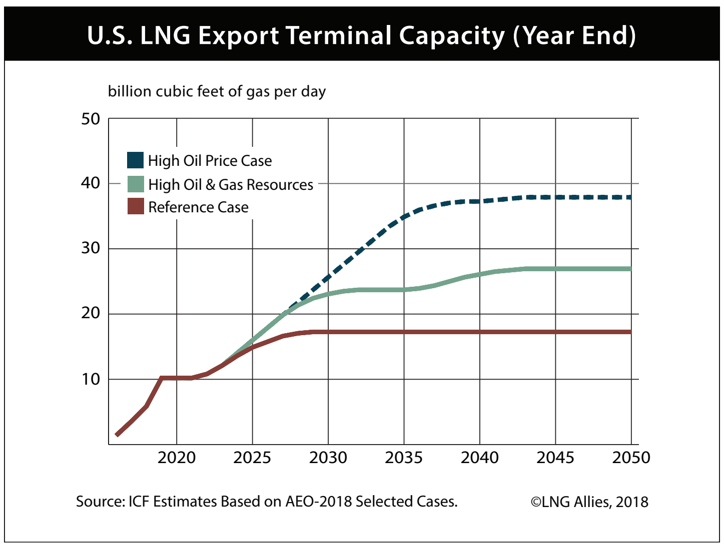


Exhibit 6.



Value Added and Employment for Liquefaction Plants

Exhibits 7 and 8 show direct, indirect, and induced value added and jobs related to liquefaction plants and associated port facilities for the three selected AEO cases. These charts do not include production and transportation of natural gas used as fuel and feedstock for plants.

Exhibit 7 shows value added by construction expenditures in the year the construction expenditures are incurred. Likewise, the associated jobs appear in Exhibit 8 during the years the plants are being constructed. The up and down patterns for value added and jobs occur as new plant capacity is added.

There is very little difference among the three AEO cases in terms of value added or associated jobs per unit of LNG exports. The small differences are due to the fact that more liquefaction plants are added in the High Oil & Gas Resources & Technology Case and the High Oil Price Case compared to the Reference Case. This means that the Reference Case has the highest number of operating years per plant and so the dollars and jobs associated with plant construction are spread over more units of LNG export by the year 2050.

Value Added and Employment for Natural Gas Supply for LNG Exports

Exhibits 9 and 10 show the direct, indirect, and induced valued added and jobs associated with producing, gathering, processing, and transporting natural gas that will be used as liquefaction plant fuel and feedstock. The AEO assumes that a volume of natural gas equivalent to 10% of LNG exports will be used as fuel at the liquefaction plants or to generate electricity for those U.S. liquefaction plants that will run their electric-drive refrigeration compressors using purchased electricity. Therefore, total natural gas needs are 110% of LNG export volumes.

The estimated value added in supplying natural gas is influenced mostly by the AEO's projected natural gas prices. Because the High Oil & Gas Resources & Technology Case has lower natural gas prices than the Reference Case, it has a long-run value added trend that is very close to that of the Reference Case, despite its larger LNG export volumes. The High Oil Price Case has both the highest natural gas prices and highest LNG export volumes among the three cases and so its supply-related value added is much larger than the other two cases.

The effort needed (measured as dollars expended or job-years) to produce a given amount of natural gas vary among the AEO cases. For example, in the High Oil & Gas Resources & Technology Case, wherein resources are larger and technologies are more advanced, less labor and dollars will be need compared to the Reference Case for each unit of gas produced. This is why the supply-related jobs in the High Oil & Gas Resources & Technology Case do not go up as much as the volume of gas required. On the other hand, in the High Oil Price Case, more expenditures and labor are needed per unit of production compared to the Reference Case and the number of jobs supported goes up by a larger percent than does the volume of gas needed.

Exhibit 7.

Value Added: LNG Terminals

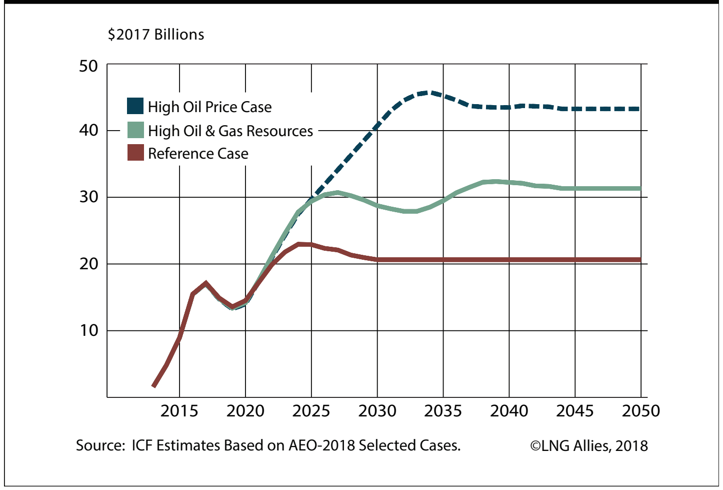


Exhibit 9.

Value Added: Natural Gas Supply for LNG Terminals

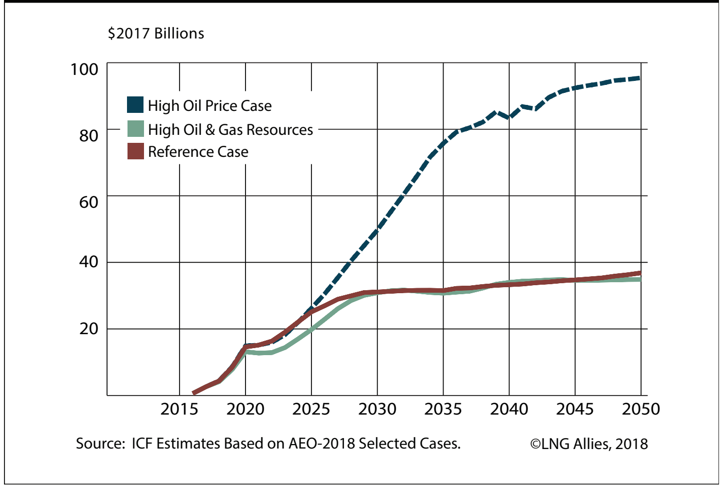


Exhibit 8.

Employment: LNG Terminals

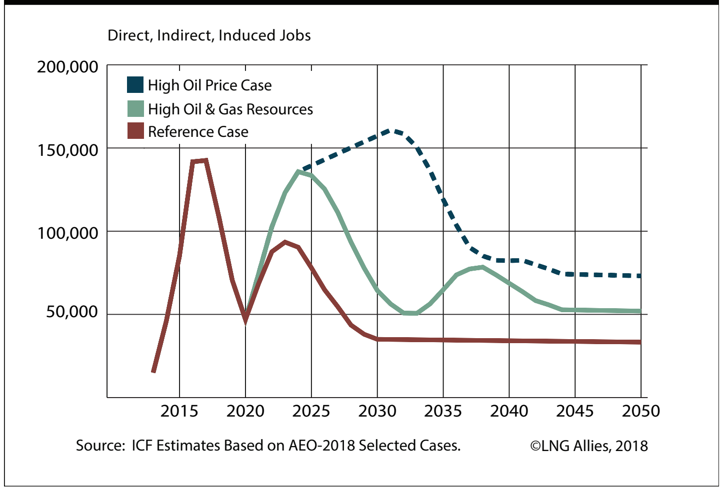


Exhibit 10.

Employment: Natural Gas Supply for LNG Terminals

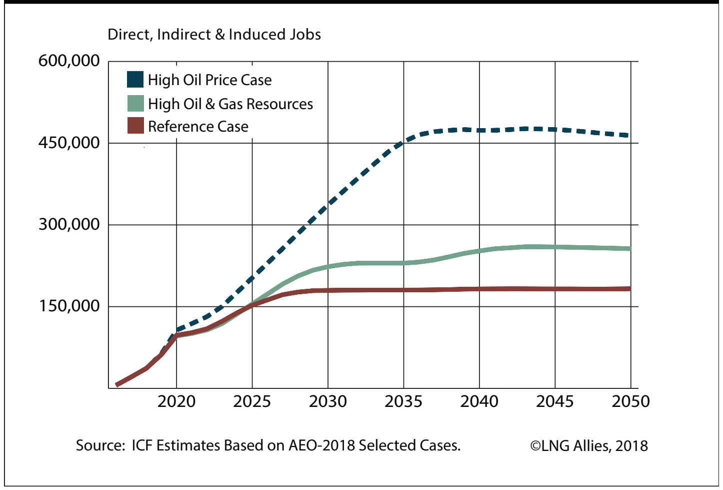


Exhibit 11.

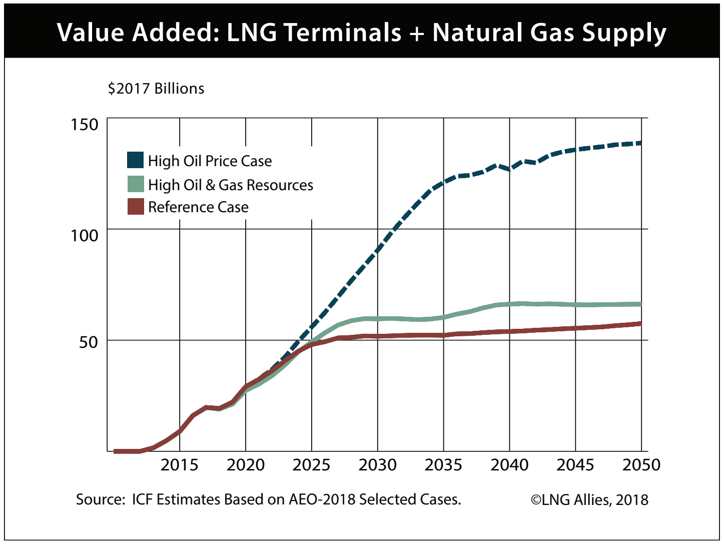
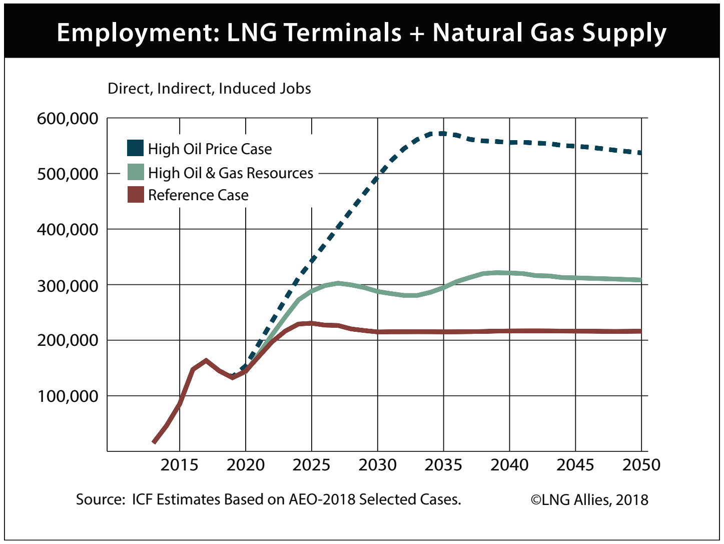


Exhibit 12.



Methodology for Impact Estimates

ICF estimated value added and jobs related to LNG exports using the 2018 Annual Energy Outlook, data from the Bureau of Labor Statistics and other public sources, and input-output relationships developed with the Impact Analysis for Planning (IMPLAN) model of the U.S. economy. This input-output (I-O) model is based on a social accounting matrix that incorporates all flows within the U.S. economy and is used to assess the aggregate economic impacts associated with a given level of an industry's output. For example, natural gas production requires oil and gas drilling and support services, equipment, and materials. Those direct impacts will lead to indirect impacts as intermediate inputs for those items (e.g., steel production to make casing and iron mining to make steel) also will see higher demand. The IMPLAN model also estimates induced impacts due to consumers' expenditures rising due to higher household incomes that are generated by the direct and indirect effects flowing through to the general economy. The term "induced impacts" is used in industry-level input-output modeling and applies to similar scenarios as does calculation of the Multiplier Effect used in macroeconomics.

These I-O relationships can be extracted into matrices that indicate the number of direct and indirect jobs in sector X per million dollars of output in sector Y. A matrix can also be defined as the number of direct and indirect jobs in sector X per physical unit of output in sector Y. Similar matrices can be constructed showing the value added in sector X per million dollars or per unit of production in sector Y. By multiplying these matrices by a base year or forecast year level of output in sector X (that is to say a given level of capital or O&M expenditures that lead to that sector X output) direct, indirect, and induced jobs and wages can be estimated. See Exhibit 13.

Exhibit 13.

Direct Impacts represent the immediate impacts (e.g., employment or output changes) in Sector X due to greater demand for and output from Sector X.

Indirect Impacts represent the impacts outside of Sector X in those industries that supply or contribute to the production of intermediate goods and services used by Sector X.

Induced or "Multiplier Effect" Impacts represent the cumulative impacts of the spending of income earned in the direct and indirect sectors and subsequent spending of income in each successive round. Examples include a restaurant worker who takes a vacation to Florida, or a store owner who sends children to college, based on higher income that arises from the initial activity in Sector X.

The level of output in an industry is often measured in terms of "value of shipments" and "value added." Value of shipments is the total value (price x quantity) of what an industry produces in terms of goods or services. Value added can be computed as value of shipment minus the value of imported intermediate goods and services (all along the supply chain) and is a measure of contribution to Gross Domestic Product (GDP). Calculating the value added to the U.S. economy in this way differs from calculating value added of just one specific industry whereby the costs of the intermediate goods and services are deducted whether imported or domestic. On the other hand, the value added for the aggregate GDP includes domestic intermediate goods and services (all along the supply chain) because they also are part of U.S. GDP, and so, only imported intermediate goods are subtracted.

The convention used by ICF is to estimate the value added associated with capital stock such as liquefaction plants in the year in which the capital expenditures are made. In this way the value added (GDP contribution) occurs in the same years as are the jobs associated with the construction of the capital stock and the mining and manufacturing of materials and equipment used in the capital stock. To avoid double counting of the GDP contribution from the capital stock, depreciation of the capital stock is subtracted when production occurs. More specifically, the equation used to estimate value added in given year is:

Value $Added_{i,t}$ = Value of $Shipments_{i,t}$ – Imported Intermediate $Goods_{i,t}$ – $Depreciation_{i,t}$ + Capital $Expenditures_{i,t}$ – Imported Capital $Goods_{i,t}$

Where:

Value $Added_{i,t}$ = the contribution of industry i to the U.S. GDP in year t.

Value of $Shipments_{i,t}$ = the total revenue received for goods and service produced by industry i in year t.

Imported Intermediate $Goods_{i,t}$ = the value of goods and services imported to U.S. for foreign countries for materials, feedstocks, operations and maintenance in year t.

$Depreciation_{i,t}$ = the cost of prior year's capital investments (which were counted in prior year's GDP) that must be subtracted to avoid double counting.

Capital $Expenditures_{i,t}$ = new capital investment made in year t.

Imported Capital $Goods_{i,t}$ = foreign purchases of goods and services used in new capital investment made in year t.

This method of calculating value added is different from what might be done by the Department of Commerce or other sources for a given industry in that we are adding in the value added by domestic intermediate goods (other than fuels and feedstocks). Our method is also different in that we count capital expenditures in the year in which they are made (so that they will align year-by-year with related construction and capital good jobs) and (to avoid double counting) remove annual depreciation. Conceptually, the method used by ICF should over time yield the same total value added as the Department of Commerce method, but might differ either in terms of which industry for which the value added is counted or in terms of the annual pattern.

* * *

BEFORE THE UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Connector Gas Pipeline, LLC	)	Docket No. CP13-492-000
Jordan Cove Energy Project, L.P.	)	Docket No. CP13-483-000

[CORRECTED] MOTION FOR LEAVE TO ANSWER AND ANSWER
of Evans Schaaf Family LLC, Deborah Evans and Ron Schaaf, Robert Barker, John Clarke, Oregon Women's Land Trust, Stacey McLaughlin and Craig McLaughlin

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission")[1], Intervenors Robert Barker, John Clarke, Oregon Women's Land Trust, Evans Schaaf Family LLC, Deborah Evans, Ron Schaaf, Stacey McLaughlin and Craig McLaughlin ("Intervenor landowners") hereby request leave to answer and also answer the Request for Rehearing of Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP ("Rehearing Request") filed on April 8, 2016 in the above-captioned docket. Intervenor landowners each own property along the proposed Pacific Connector Pipeline route and those properties and the landowners themselves would be substantially harmed by the proposed pipeline and any decision to authorize the Applicants to exercise the power of eminent domain.[2]

The Rehearing Request was filed in response to FERC's March 11, 2016 Order denying applications by the Jordan Cove Energy Project, L.P. ("JCEP") and Pacific Connector Gas Pipeline, LP ("PCGP," collectively "Applicants") for the Pacific Connector pipeline and Jordan Cove LNG export terminal projects.

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[1] 18 C.F.R. §§ 385.212, .213 (2015).
[2] Impacts to Intervenor landowners are described in our December§ 9, 2015 comments to FERC. http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20151210-5000.

The Applicants' Rehearing Request asks FERC to reverse its denial of the Applicants' projects and to accept a host of post-decision evidence the Applicants claim support reversal of FERC's recent denials. Intervenor landowners request that FERC deny the Applicants' request to re-open the record and deny Applicant's Rehearing Request.

From a procedural standpoint, the Applicants have had years to develop the factual record to demonstrate that their projects were in the public interest and have failed to do so. They now seek a belated reprieve from their failure by attempting to shoehorn claimed "new" evidence under 18 CFR § 385.713(c)(3) contending FERC's denial was "based on matters not available for consideration by the Commission." Applicants had more than ample time and opportunity to develop that evidence and Applicants have shown no compelling reason to reopen the record at this late date.

FERC's general rule of course is that "the record once closed will not be reopened."[3] The Commission can of course re-open the record when there are "extraordinary circumstances"[4], but only when "the movant has demonstrated the existence of extraordinary circumstances that outweigh the need for finality in the administrative process.[5]" There is nothing "extraordinary" about the non-binding agreements Applicants now offer and the benefits of finality exceed any claimed benefit of re-opening the record. As the Commission has stated. "[W]e recognize of course that changes have occurred since

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[3] Transwestern Pipeline Co., Opinion No.§ 238, 32 FERC ¶ 61,009 (1985), reh'g denied, Opinion No. 238-A, 36 FERC ¶ 61,175 at 61,453 (1986).
[4] CMS Midland, Inc., 56 FERC ¶ 61,177 at 61,624, reh'g denied, 56 FERC ¶ 61,361 (1991).
[5] *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 *citing East Texas Electric Cooperative, Inc. v. Central and South West Services, Inc.*, 94 FERC ¶ 61,218 at 61,801 (2001).

the close of the record. But such changes always occur. Yet litigation must come to an end at some point. Hence the general rule is that the record once closed will not be reopened.[6]

Even after FERC staff sent repeated information requests to the Applicants for evidence of market demand and evidence that the Applicants were making diligent efforts to obtain pipeline right-of-way easements, the Applicants' failed to provide any meaningful evidentiary response. Instead, the Applicants conflated their affirmative public interest obligations under § 7 of the NGA with the separate and distinct standard for LNG terminals under § 3 asserting that the two standards were essentially interchangeable. When FERC properly denied the Applicants' applications, it did so only after the Applicants had missed every reasonable opportunity to demonstrate both the commercial viability of their project and of credible efforts to obtain pipeline easements.

After close to ten years of having their properties hang in the high-impact limbo of the Pacific Connector Pipeline permitting process, FERC's denial decision gave landowners along the proposed pipeline a well-deserved piece of certainty. The Applicants are now essentially asking FERC for a post-denial "do-over" with a host of new facts that appear to be developed in large part directly in response to FERC's denial. We ask FERC to carefully review all of the confidential information submitted by the Applicants to determine whether it provides any genuine evidence addressing any of the criteria identified by FERC in its October 14, 2015 information request to the Applicants. We suspect it does not.

Additionally, FERC's repeated earlier data requests and Applicants' responses outlined in § 3. Market and Services of FERC's denial Order demonstrate that the Applicant

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[6] *Transwestern Pipeline Co.,* Opinion No. 238, 32 FERC ¶ 61,009 (1985), *reh'g denied,* Opinion No. 238-A, 36 FERC ¶ 61,175 at 61,453 (1986).

was given every opportunity to comply with FERC's policy standards and expectations of process but failed to do so.[7]

The Applicants now ask FERC to consider this quickly developed "new evidence," long-after the procedural timelines for providing such evidence have passed. Were FERC to allow this level of post-decision evidence it would establish a terrible precedent allowing applicants to essentially neglect their burden of providing genuine evidence of market demand and making reasonable efforts to obtain pipeline easements until after FERC issued a denial decision. Such a precedent would turn FERC's well-defined, well-understood project review process, on its head.

Contorting this process, as Applicants ask FERC to do, is particularly damaging to landowners who face serious impacts on their ability to use, sell, lease and plan for the future of their properties while the specter and uncertainty of a pipeline siting decision

[7] October 14, 2015 Letter from FERC to Pacific Connector: "Commission staff is not aware of a previous instance of having to make a finding of public convenience and necessity under § 7 of the NGA for major new pipeline on the basis that a related import/export facility is deemed to be not inconsistent with the public interest under § 3 of the NGA when the pipeline may need to rely significantly on eminent domain and has not provided evidence that a significant proportion of the pipeline's capacity has been subscribed under precedent agreements.

1. Provide the following information related to the capacity of the Pacific Connector pipeline:
    a. Discuss the status of negotiations between Jordan Cove, Pacific Connector, and the potential liquefaction and transportation customers.
    b. Has Pacific Connector entered into any commitments for firm service on its proposed pipeline? If so, please identify the shipper(s), quantities, terms, and rates.
    c. If Pacific Connector has entered into precedent agreements, when did, or when will Pacific Connector conduct an open season. Provide copies of any open season notices that have, or will be posted. Provide the results of the open season immediately, if the results are known, or within 5 days after the end of a pending open season.
2. Provide the following:
    a. The number of land parcels and acres making up the permanent and temporary right-of-way necessary for the construction and operation of the pipeline.
    b. The number and percentage of the land parcels and acres in Question 2(a) that are within or collocated with existing rights-of-way.
    c. The number and percentage of the land parcels and acres in Question 2(a) for which Pacific Connector has easements.

hangs over their property. From the perspective of fair and reasonable energy siting policy, FERC should deny the Applicants' request for a rehearing and the reversal of its denial.

As discussed below, even if FERC elects to consider what Applicants claim is late-breaking evidence of new-found market demand, the agreements and arguments they provide do not support FERC's reversal of its project denial or issuance of a certificate. The incentive for the Applicants to quickly cobble together inflated evidence of market demand is obvious. But the preliminary non-binding agreements for LNG with JERA and Itochu offered by the Applicants do not support a level of demand that would warrant FERC's reversal of its denial order. Similarly, the precedent agreements the Applicants make between themselves and with Macquarie Energy LLC ("Macquarie"), the Applicants' financial advisor and a substantial Veresen stockholder, appear to be nothing more than a thinly disguised effort to keep their project afloat, but they should not be confused with genuine market demand.

This reality appears especially true in light of the fundamental dynamics of the Applicants' target LNG market in Asia. The Applicants cannot and do not provide rational evidence as to how their greenfield project is able to compete in a low-priced LNG market that has a glut of new supply and a global and national field of competitors that can deliver LNG at a significantly lower cost.

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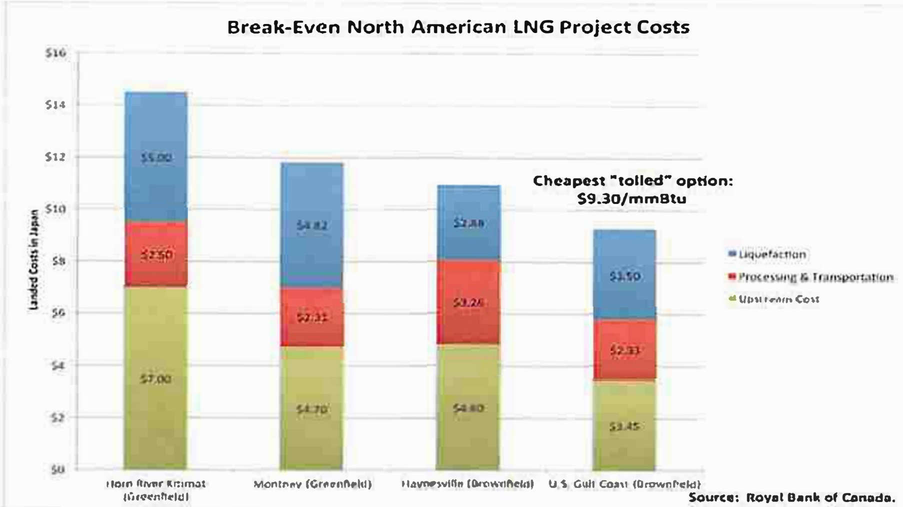

Figure 7. Break-even North American LNG project costs landed in Japan. Source: Royal Bank of Canada and Labyrinth Consulting Services, Inc.[8] Jordan Cove's break even costs certainly exceed that of brownfield projects and Jordan Cove's backers have identified $11/mmBtu as its expected price point for shipping LNG to Japan. *See* Intervenor landowner's December 9, 2015 letter to FERC.

Furthermore, the Applicants offer no evidence that they have made any reasonable effort towards securing additional pipeline rights-of-way. To the contrary, they admit they have not even begun such efforts "in earnest." Request 22. They instead ask FERC to give them the powerful tool of eminent domain absent any showing they have credibly worked to minimize the impact of eminent domain on landowners through negotiation. While the Applicants point to the Commission's approval of Cheniere Creole Trail Pipeline L.P as supporting its rehearing request, they ignore the fact the Cheniere project already had LNG trains 1-4 fully contracted and train 5 almost fully contracted prior to FERC's approval. They also ignore FERC's recognition in its approval that most of the Cheniere pipeline route was along existing rights-of-way.

In light of its weak evidence of demand and continuing failure to obtain landowner easements, the Applicant's effectively ask FERC to reverse its denial and approve their

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[8] *A Reality Check For U.S. Natural Gas Ambitions* - July 31, 2015 - http://oilprice.com/Energy/Natural-Gas/A-Reality-Check-For-US-Natural-Gas-Ambitions.html.

projects by conditioning its use of eminent domain on the execution of precedent agreements. Request 2. Approval conditions have value for project approvals where there is substantial evidence that *there is* market demand for a project and that the project *would be* in the public interest. Such conditions, however, should not and cannot serve as a substitute for the affirmative evidence required for FERC to make a public interest determination as required under § 7 of the Natural Gas Act (NGA). 15 USC § 717(f).

For the reasons addressed below, FERC should reject the Applicants' rehearing request.

1. The Applicants' Failure to Make Any Reasonable or Credible Effort to Obtain Easements Undermines Any Finding the Project is in the Public Interest.

While the Applicants base their request for reconsideration on exaggerated evidence of market demand, they do not and cannot argue that they have made any reasonable effort to work with landowners to obtain property easements for the pipeline. As FERC is aware, PCGP has obtained only 4.7% of the right-of-way easement acreage and 2.8% of the needed construction easement acreage. Applicants have not provided any evidence showing those percentages have increased in any meaningful way. Applicants have yet to begin negotiations with landowners in earnest as made evident by the incredibly low percentage of construction and ROW easements they have obtained to date.

Instead of making efforts to obtain the necessary easements through arm's length negotiation, the Applicants attempt to diminish the profound impacts that eminent domain would have on the purported 287 landowners along the pipeline route. Request 25. Like many of their claims, the Applicants do not cite to any evidence in the FERC record to demonstrate the source for the number "287". The Applicants also do not make clear whether 287 refers to the number of landowners who they believe may be subject to eminent domain for the permanent ROW, but that is what appears to be likely. Reducing individual landowners to mere statistics ignores the incredible impacts that pipeline construction, and the use of eminent domain to obtain construction easements, has on the large number of landowners along the pipeline route who have farms, homes, and a myriad of commercial and other uses on their properties.

Intervenor landowners believe the actual number of affected landowners is not 287, but 630. This estimate of 630 landowners was calculated by taking the total number of landowners listed in Appendix A of the FEIS ("Affected Landowners on or Adjacent to Proposed Facilities and Routes") and reducing it by subtracting the number of "public" landowners from the list. Any ambiguity regarding the total number of landowners who would in fact be impacted by the pipeline is directly attributable to the Applicants because of the lack of clear data in the FEIS they prepared. Even the FEIS noted, however, that, "[D]uring the scoping process, **many** landowners commented on the Pacific Connector pipeline."[9]

While Intervenor landowners believe the number of landowners impacted by the pipeline is significantly higher than 287, the specific number is less important point than the fact that for many landowners along the pipeline route, Applicants have not made even a token effort to obtain easements. This is completely inconsistent with FERC policy documents and the NGA. FERC Policy Statements 90 FERC ¶ 61,128; 88 FERC ¶ 61,227; 92 FERC ¶ 61,094.

The Applicants downplay their failure to obtain easements on the grounds that only a small percentage of the pipeline route would run through residentially zoned lands.

[9] FEIS 4-20.

Request 22. This is a specious argument at best because many homes that are in close proximity to the pipeline are located on rural properties not zoned as "residential." Moreover, irrespective of whether a landowners' use is for residential, farming, oyster farming, commercial or other purposes, the impact of taking a person's land against their will through the power of eminent domain should not be taken lightly or minimized.

The Applicants assert that FERC should issue a certificate by conditioning its power to utilize eminent domain on the Applicants' first obtaining service agreements. Request 26. If the Applicants cannot obtain service agreements there would not be any harm to the landowners they argue. This ignores the fact that the Applicants have the burden to demonstrate demand *before* a certificate is issued. 15 U.S.C. § 717(f). It is not surprising that the Applicants would like to secure a certificate and then sit back and wait to see if real market demand develops at some unspecified future date but that is wholly contrary to long-established FERC policy and the NGA. This concept also ignores the continuing impacts on Intervenors and many other landowners as they would be forced to live with the uncertainty of pipeline construction and eminent domain hanging over their properties for what amounts to an indefinite period. This constitutes a very real and significant threat to landowners' ability to make long-term decisions regarding the use of their properties including the sale and lease of such properties. We know already from hard experience that few buyers are willing to enter into a property purchase agreement if the threat of a 3' diameter pipeline and eminent domain proceeding are included in the property purchase.

It is also telling that the Applicants' Request states that, "[o]nce acquisition of PCGP's right of way begins in earnest, it is unlikely to require extensive use of the power of eminent domain…" Request 22 (emp. added.) Applicants similarly explained, "[t]here is no need at this point for PCGP to have begun a broader effort to acquire, or to obtain options on the remainder of the right of way." *Id.* The continuing inability of the Applicants to demonstrate the presence of current market demand is underscored as well by the Applicants' request for up to eight years to complete its 420 MW South Dunes Power Plant.[10]

That years into project planning PCGP admits that it has not begun easement acquisition "in earnest" should disqualify it from obtaining a certificate at this point. Every pipeline applicant would surely enjoy having the actual power of eminent domain pursuant to a certificate before it started negotiation with any landowners. Giving project applicants this level of power over landowners would exacerbate an already imbalanced bargaining position and is contrary to the goals underlying FERC's certificate policies. FERC Policy Statements, 90 FERC ¶ 61,128; 88 FERC ¶ 61,227; 92 FERC ¶ 61,094. If the Applicants are issued a certificate despite their admitted lack of effort to work with landowners along the pipeline route it would set a precedent that would quickly become the norm for other pipeline developers.

2. The Applicants' Preliminary Agreements Do Not Provide Evidence of Project Demand Sufficient to Support a Public Interest Determination.

In light of the continuing drop in the price of Asian LNG, the global oversupply of LNG, and the shrinking Asian demand for LNG, the Applicants' preliminary and non-binding agreements for capacity only, and excluding liquefaction and tolling costs, fall far short of

[10] Energy Facility Siting Council SDPP Final Proposed Order and Appendices 2015-10-12, page 15. https://www.oregon.gov/energy/Siting/docs/SDP/Proposed%20Order/SDP%20Final%20Proposed%20Order%20and%20Appendices%202015-10-12.pdf.

the evidence that should be required to provide a credible basis for reversing FERC's denial -- evidence that has been repeatedly sought by FERC staff.

The Applicants' attempt to inflate its preliminary agreements with JERA and other parties into a sign of strong demand for the Jordan Cove project is flawed for a number of reasons. The preliminary agreement is just that, preliminary and non-binding. Despite FERC's repeated requests for evidence of "commitments for firm service" and its plans to hold an open season, the Applicants' Request still does not provide any concrete timing for when it expects to have either service agreements or an open season.

Applicants offer no credible evidence that JERA actually intends to truly commit to a 20-year binding contract any time soon with this greenfield LNG terminal. Moreover, as a "greenfield," terminal, it will necessarily have significantly higher prices than a number of current and planned brownfield projects with available LNG supply. Indeed, there are real reasons to question the likelihood that JERA will ever reach a final agreement with Jordan Cove at a price the terminal could realistically meet. It is also worth noting that JERA, as an LNG buyer, only benefits from the oversupply of LNG and the prospect of a potential Jordan Cove terminal only furthers its clear self-interest in maintaining depressed LNG prices.

JERA's commitment is particularly questionable in light of its recent announcement it was significantly reducing its reliance on long-term LNG contracts as Japan's LNG demand predictions continue to shrink. "We want to change drastically," Jera's president Yuji Kakimi told a news conference. As reported by Platts:

> Maturing long-term contracts to buy LNG will be replaced with short-term contracts, spot buying, and long-term offtake volume from projects Jera has stakes in, Kakimi said. As of this July, Jera's long-term offtake volume will be 35 million mt/year, which it planned to cut to 15 million mt/year by its 2030-31 year.

See Exhibit 1, "Japan's Jera to change LNG buying strategy under 15-year plan", Feb. 10, 2016.

As similarly reported:

> JERA, which buys around 80 percent of its gas on long-term contracts, will only contract volumes to cover the absolute minimum of fuel needed, using the most optimistic scenarios for rebooting its nuclear power plants and the take-up for renewable energy being promoted by the government. Additional requirements for gas will be met with mid-term and short-term contracts or spot purchases, Kakimi [Jera's President] said.

See Exhibit 2, "Japan's Jera says will significantly cut long-term LNG contracts", Reuters Oct. 21, 2015.

In light of the current depressed state of LNG market fundamentals, JERA is even considering selling LNG supply it already has under contract with Freeport LNG to Europe. *See* Exhibit 3, "Jera eyes selling US Freeport LNG volume to Europe as alternative to Japan", Platts May 28, 2015. The notion that JERA is likely to complete a binding 20-year agreement with Jordan Cove anytime soon is inconsistent with both its new business strategy and the fundamentals of the LNG market.

The Applicants' preliminary agreements with gas trader ITOCHU is similarly speculative. While the Applicants assert their preliminary agreement with JERA was underway prior to FERC's March 11, 2016 denial order, it is telling that they make no similar claim as to ITOCHU PA or its precedent agreement with Macquarie'. While the Applicants have a clear incentive to attempt to quickly create the illusion of market demand, there is little evidence to support the contention that these preliminary agreements with JERA or ITOCHU reflect genuine evidence of actual market demand.

The Applicants' incentive for the precedent agreement between themselves for 592,354 Dth/d on the pipeline is a transparent contrived ploy to create the illusion of demand and hardly substitutes for the type of hard evidence of market demand that would give FERC or the public any rational basis for finding there is now true demand for the project. PCGP's precedent agreement with Macquarie, PCGP's financial advisor for the project and also a substantial Veresen stockholder, is similarly disingenuous. *See* Exhibits 4 and 5[11].

The Applicants are desperate to find new evidence of market demand and are understandably concerned that FERC's denial, if allowed to stand, will mean the primary project players could see years of investment, however misguided, lost. In light of this motivation, the timing of these new "agreements" and the speed at which they were completed must be seriously questioned. Intervenor landowners submit that there is little basis for interpreting these agreements as reflecting genuine market demand as opposed to a quick scramble to create some contrived basis for a rehearing request.

The preliminary agreement with Avista for a token amount of gas is similarly insufficient evidence of demand for pipeline capacity. While Avista may be supportive of the project from a political perspective, the small gas volumes in its precedent agreement can fairly be seen as part of the effort to create a fig leaf of demand. In addition to the minimal quantity of gas at issue, the suggestion that, "PCGP is committed to serving local communities located along the pipeline and has agreed to install taps for natural gas deliveries to these smaller communities" is entirely speculative. The Applicants assert that, "this substantial new quantity of capacity will enable significant economic development in

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11 https://www.macquarieresearch.com/rp/web/guest/searchdisclosures?p_p_id=Disclosure_WAR_portletsresearch&p_p_lifecycle=0&p_p_state=exclusive&p_p_mode=view&_Disclosure_WAR_portletsresearch_sort=company&_Disclosure_WAR_portletsresearch_dir=asc&_Disclosure_WAR_portletsresearch_page=243&_Disclosure_WAR_portletsresearch_implicitModel=true&_Disclosure_WAR_portletsresearch_action=filterDisclosureResult.

the region by attracting new industries and providing additional natural gas to existing industrial, commercial and residential users throughout southern Oregon." Request 6. They cite, however, no actual evidence that added gas supply would attract the "new industry" and no evidence that expanded gas supply would trigger industrial expansion or is even needed. While this local supply was of course never a core purpose of the pipeline project, it is also relevant to note that neither a local demand nor the related industrial expansion was considered in the project FEIS.

3. The Applicants' Claims of Market Demand Have to be Considered in Light of Weak LNG Markets.

The Applicants' Rehearing Request glosses over the basic market realities of the current LNG market and specifically the Asian LNG market their project was intended to target. The Applicants assert in their Request that, "[t]he fact that the Applicants had not provided more evidence of customer commitment to the Project as of the date of the March 11 Order reflects circumstances in the global LNG market, and should not be taken as an indication that the Project does not have market support." Request 11. But the most powerful "circumstances in the global LNG market" right now are the continuing low price and over supply of LNG. The Applicants' suggestion that there is a more complicated reason for their failure to secure customer commitments is without merit and does not warrant FERC's rehearing.

In that regard, it is worth comparing the extensive evidence of market demand that was presented to FERC prior to its approval of the Sabine Pass, Corpus Christi, Magnolia and Freeport LNG terminals with the very limited evidence of demand the Applicants have provided. The chart below illustrates key milestones obtained by each of six LNG terminals leading up to FERC approval. Information in this chart came from a combination of FERC order documents and news releases issued by the individual LNG companies. The Applicants, by comparison, were never able to secure long term binding contracts, easements or financing for locked-in engineering, procurement and construction contracts (EPC) for this significant greenfield project over similar time durations, further indication of the array of challenges this project has faced from the beginning.

Comparison of U.S. LNG Export Terminals Key Milestones

<---- TIME LINE OF LNG PROJECTS ----

	Cheniere Sabine Pass (Trains 1-4)	Freeport LNG (Trains 1-3)	Cheniere Corpus Christi (Trains 1-3)	Cheniere Sabine Pass (Trains 5-6)	Magnolia LNG (Trains 1-4)	Jordan Cove (Trains 1-4)
Total Capacity	16 mtpa	13.2 mpta	13.5 mtpa	9 mtpa	8 mpta	6.8 mpta
New Pipeline			23 mi, 48"	94.8 mi, 42"		232 mi, 36"
FERC Pre-filing Approval	8/4/2010	12/1/2010	12/16/2011	3/8/2013	1/1/2013	6/1/2012
MOU/HOA/Term Sheets*	5	0	0	0	4	0
Binding 20 Yr Contracts^	0	0	0	2 - (3.75)	0	0
Filed Application	1/31/2011	12/9/2011	8/31/2012	9/30/2013	4/30/2014	5/21/2013
MOU/HOA/Term Sheets	2	0	0	0	0	3 (2013)
Binding 20 Yr Contracts	1 (3.5)	5 (13.2)	1 (.8)	0	1 (2.0)	0
Signed EPC	11/13/2011	12/1/2013	12/9/2013	6/15/2013	11/13/2015	0
Binding 20 Yr Contracts	4 (10.5)	0	8 (6.48)	0	0	0
Final EIS	12/28/2011	6/16/2014	10/8/2014	12/12/2014	11/13/2015	9/30/2015
Binding 20 Yr Contracts	0	0	1 (.77)	0	0	0
FERC Approval	4/16/2012	7/30/2014	12/30/2014	4/6/2015	4/15/2016	DENIED (3-11-2016)
Notice to Proceed	8/9/2012	11/1/2014	5/13/2015	6/30/2015		
Binding 20 Yr Contracts	(2.0)	0	1 (.6)	0		
Total Binding Contracts	**16 mtpa**	**13.2 mpta**	**8.65**	**3.75 mtpa**	**2.0 mpta**	**0 mpta**
Volume Uncontracted~	0 mpta	0 mpta	4.85 mpta	.75 (Train 5)	6.0 mpta	

*Non-binding Memorandums of Understanding, Heads of Agreements and Term Sheet Agreements reported by companies
^ Legally binding 20 year Liquefaction Tolling Agreements, Use or Pay and Sales and Purchase Agreements.
~ Based on contracts announced in press releases, these could vary if data wasn't announced.

KEY:	Preliminary Agreements	Binding Contracts (vol.)	Key Milestone Dates	FERC Approval	Total Binding 20 Yr Contracts	Volume NOT contracted

As evidenced by Sabine Pass LNG's experience, where only three of the seven original MOU signers ultimately signed binding 20 year contracts, **preliminary agreements even under favorable market conditions can be weak evidence of demand and often do not translate into binding long-term agreements.**

The Applicants point to speculative evidence of future demand that is at odds with the fundamental market shifts that have sent LNG prices to 18-year record lows this month.[12] While the Applicants point to speculative global demand increases in LNG as an "opportunity looming," they ignore the realities that LNG imports into their target Asian markets are only projected to decrease further in 2020 and even global projections of when demand may balance supply extend from 2025 to 2030.[13] As discussed in Intervenor landowners' previous comments, the combination of Japan's restart of its nuclear generators, an increased reliance on renewables, and the abundance of lower priced alternative sources of LNG are projected to only further depress Asian LNG demand for Jordan Cove LNG in 2020. *See* Exhibit 6, "Japan LNG demand expected to fall by 2020 on nuclear restarts, renewables", Platts Dec 15, 2015; Exhibit 7, "S. Korea secures 23.5 mil mt in 2027 LNG term deals, 62% of expected demand", Platts, Oct. 7, 2015.

A recent LNG export market analysis prepared for U.S. DOE underscores the fact that global LNG market demand is unlikely to grow to the point of creating demand for the Jordan Cove project until 2030.[14] Such realities undermine the Applicants' claims that speculative demand increases in 2020 constitute sufficient evidence of a current demand for LNG.

As one market assessment[15] recently explained:

> The traditional prime Asian LNG buyers have all cut back their demand forecasts. With the optimistically predicted restart of numerous nuclear reactors in Japan and continuation of lower consumption levels, Japan

[12]http://www.desmogblog.com/2016/04/14/will-lng-exports-save-shale-gas-drilling-industry-s-rofitability-not-so-fast

[13]http://oilprice.com/Energy/Energy-General/*The-Great-Glut-Why-LNG-Markets-Might-Not-Balance-Before-2025*.html.

[14] *The Macroeconomic Impact of Increasing U.S. LNG Exports*, October 29, 2015, online at energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[15] http://www.energylawexchange.com/the-top-10-questions-facing-the-lng-industry-in-2016.

predicts its LNG demand is declin[ing] – in one estimate, to 77 MTPA in 2020 as compared to 86 MTPA in 2014.[35] Kogas, the second largest LNG buyer in the world after Jera, has also revised its demand forecast downwards.[36] Likewise, demand growth for China has dampened with recently lowered forecasts – in one forecast, by 15% for the upcoming few years.[37]

Furthermore, the Applicants' submittals do nothing to change the major competitive disadvantage that greenfield projects like the Jordan Cove terminal have when compared to a brownfield project such as Freeport LNG or the streamlined, turn-key construction of Magnolia LNG—each benefiting from existing and nearby infrastructure and able to offer LNG at prices well below Jordan Cove. *See* Exhibit 8, "Magnolia LNG Executes EPC Contract with KBR-SK JV", Magnolia LNG Nov. 16, 2015. While the Applicants of course rely on the geographic proximity of the Jordan Cove project to the Asian market, they offer no tangible evidence that that proximity translates to LNG prices for Asian customers that are lower than the diversity and portfolio sourcing of Jordan Cove's global competitors which have either completed or near completed projects.

CONCLUSION

For these reasons, Intervenor landowners ask FERC to deny the Applicants' request for a rehearing.

Respectfully submitted,
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CERTIFICATE OF FILING

I certify that on April 26, 2016, I filed the foregoing [Corrected] Motion to File Answer and Answer by efiling with:

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

s/ *Jeri G. Zwick*
Jeri G. Zwick
Legal Assistant to Thane W. Tienson

Exhibit 1

Platts

Japan's Jera to change LNG buying strategy under 15-year plan

Tokyo (Platts)--10 Feb 2016 658 am EST/1158 GMT

Japan's Jera Co -- a joint venture between Chubu Electric and Tokyo Electric Power Co -- outlined a 15-year business plan Wednesday that will see its LNG buying become more flexible, resulting in fewer long-term contracts.

"We want to change drastically," Jera president Yuji Kakimi told a news conference.

Maturing long-term contracts to buy LNG will be replaced with short-term contracts, spot buying, and long-term offtake volume from projects Jera has stakes in, Kakimi said.

As of this July, Jera's long-term offtake volume will be 35 million mt/year, which it planned to cut to 15 million mt/year by its 2030-31 year.

The business plan includes boosting domestic as well as overseas power generation businesses and to enhance LNG trading capability.

"We want to trade LNG, handling several million mt of volume," Kakimi said.

Jera also aims to increase the number of LNG ships in its fleet to about 30 by 2030-31, from 16.

By 2030-31, Jera expects to have 30-40 million mt/year of contracted LNG volume, compared with 40 million mt/year now, while its contracted coal volume will grow to 20-30 million mt/year from 20 million mt/year.

Its long-term business plan was unveiled at a time when Japanese LNG demand was expected to fall with the restart of nuclear reactors and growing solar power.

Given Japan is liberalizing its domestic retail electricity and gas markets, cheap fuel sources, such as coal, were also expected to gain currency.

GOING GLOBAL

Jera reshuffled top management,including a new chairman in Hendrik Gordenker, who has been a senior adviser and external expert for Jera since last May and is also a former partner at law firm White & Case LLP in Tokyo.

Gordenker said he will be involved in various functions including global strategy as well as communicating with stakeholders worldwide.

"We have to establish Jera in order to go to the international stage with global approach," he said.

Ahead of the start of US Freeport project in 2018, Jera has been preparing to hire local LNG traders in its Houston office, Kakimi said.

Kakimi also reiterated that offtake volume from the US Freeport project will be brought to Japan or sold in Europe.

Jera has a natural gas liquefaction tolling agreement with Freeport LNG in Texas.

Under the supply deal, Chubu will be able to offtake 2.2 million mt/year of LNG with no destination restrictions.

As for its power generation business, Jera said it aims to increase overseas power generation capacity to 20 GW by 2030-31 from a current 6 GW, and domestic capacity to 12 GW from 650 MW.

--Eriko Amaha, eriko.amaha@platts.com
--Edited by Dan Lalor, daniel.lalor@platts.com

Exhibit 2

Reuters

Japan's Jera says will significantly cut long-term LNG contracts

TOKYO | By Osamu Tsukimori and Yuka Obayashi

Jera Co President Yuji Kakimi poses for a picture before the Reuters Commodities Summit in Tokyo, Japan October 21, 2015.
Reuters/Toru Hanai

Japan's JERA Co, set to become the world's biggest buyer of liquefied natural gas (LNG) next year, plans to significantly cut the amount of gas it purchases on long-term contracts, the company's president told the Reuters Global Commodities Summit.

JERA, a joint venture set up by Tokyo Electric Power (Tepco) (9501.T) and Chubu Electric Power (9502.T) to initially handle fuel procurement with a possibility of eventually taking over thermal power stations, has more than 10 million tonnes of gas on long-term contracts that expire by around 2020.

But the company will not automatically renew them, President Yuji Kakimi said.

The move puts more question marks over planned big LNG projects, which rely on long-term contracts to get financing approved, amid a downturn in commodities markets that has cut investment in many areas.

JERA, which buys around 80 percent of its gas on long-term contracts, will only contract volumes to cover the absolute minimum of fuel needed, using the most optimistic scenarios for rebooting its nuclear power plants and the take-up for renewable energy being promoted by the government.

Additional requirements for gas will be met with mid-term and short-term contracts or spot purchases, Kakimi said.

"Our original mission of procuring at a similar level to Europe and the U.S. is close to being achieved with oil price falling, but even if oil prices rose, we have to make sure that (procurement) costs are capped," he said.

JERA will surpass Korea Gas Corp (036460.KS) as the world's single biggest buyer of LNG with annual purchases of around 40 million tonnes once it fully integrates the partners' existing contracts next summer.

Kakimi said Jera's annual purchases of gas are expected to decline in line with government forecasts, implying the company will be burning around 28 million tonnes a year by 2030.

He also said the company is expanding Chubu Electric's unit in Houston to start LNG trading opportunities when the Freeport LNG project, in which Chubu invests in, starts export in 2018.

CUTTING COAL PROCUREMENT COST

JERA also aims to broaden its sources of coal to lower its reliance on high-quality Australian coals in order to cut costs.

Australia is by far the biggest supplier to Japan, accounting for nearly 80 percent of Japan's thermal coal imports in the first eight months of this year.

"Since it looks difficult to see more flows from Indonesia under current market circumstances, it is important to develop new sources such as Russia, the U.S., Colombia and Africa," Kakimi said.

JERA, which buys about 20 million tonnes of thermal coal a year, is also interested in buying into in coal mines to hedge against rises in coal prices, he said.

He declined to say how much a stake it aims to buy, but said stakes equivalent to 30-40 percent of its procurement would be "too much" under the current market.

Thermal coal benchmarks hit record lows earlier this month due to a sharp slowdown in demand, especially in Asia, and with overall mining output remaining stubbornly high.

Kakimi thinks prices have hit bottom.

"I actually said last year the prices had hit the bottom, but they kept on falling," he said. "But I really think the market is at the bottom as mines have been closing and coal mining companies have been putting themselves up on sale."

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(Additional reporting by Billy Mallard, Kentaro Hamada, Kazuhiko Tamaki and Hitoshi Ishida; Editing by Aaron Sheldrick and Michael Perry)

Exhibit 3

EXHIBIT 3

Interview: Jera eyes selling US Freeport LNG volume to Europe as alternative to Japan

Tokyo (Platts)--28 May 2015 552 am EDT/952 GMT

Japan's Jera, the joint venture between Tokyo Electric Power Company and Chubu Electric, eyes selling volumes from the US Freeport LNG project to Europe or other markets as an alternative, if it is not economically viable to bring the LNG to Japan, the company's president said this week.

"At current prices, US LNG could be more expensive [for the Japanese market]. In such a case, we could consider options where we buy spot cargoes in Asia [for the domestic market] and sell US LNG to other markets," Jera President Yuji Kakimi told Platts in an interview, adding that selling into Europe or South America are options.

"The Freeport project offers us flexibility and will allow us to trade by hedging risks. We could take advantage of differences in prices between markets and move LNG accordingly," he added.

The Platts JKM for July delivery cargoes was assessed at $7.75/MMBtu Wednesday.

Article continues below...

In comparison, US LNG could land in Asia at around $9/MMBtu, based on Wednesday's $2.815/MMBtu settlement for the NYMEX June Henry Hub gas futures contract and using Cheniere's Sabine Pass pricing as a reference.

Financial terms and details of the tolling agreement Chubu Electric signed with Freeport LNG are not clear.

Chubu Electric has a natural gas liquefaction tolling agreement with Freeport LNG in Texas. Under the supply deal, Chubu will be able to offtake 2.2 million mt/year of LNG with no destination restrictions.

Tepco has contracts for the supply of 800,000 mt/year -- two 400,000 mt/year contracts -- of lean LNG from the US Cameron LNG project, in Louisiana, for over 20 years from 2017, under deals with Japanese trading houses Mitsui & Co. and Mitsubishi Corp.

Tepco is, meanwhile, revamping its LNG receiving facilities so that they are able to accept up to 10 million mt/year of lean LNG -- which has a lower calorific value per unit than conventional LNG.

Kakimi said Jera should have geographically balanced LNG supply sources and also balanced indexations, but declined to say exactly how much volume Jera would aim to have under contracts with oil-linked or natural gas hub-linked pricing in its portfolio.

He, however, noted that Chubu Electric has said it aims to cut oil-linked contracts to 50% of the total.

"We can use this as an example," Kakimi said. "Chubu Electric has not said what the other half should consist of, but Henry Hub-linked, NBP-linked and JKM-linked, and other various benchmarks can be used," he added.

UNCERTAINTIES AHEAD

The establishment of Jera comes ahead of Japan's plan to fully deregulate the country's retail power and gas markets in 2016 and 2017, respectively.

Jera started up on April 30 with about 50 staff, and the integration between Tepco's and Chubu Electric's fuel transport and fuel trading business is expected to be completed by October.

The number of staff will be increased to around 400 people by summer next year, when a wide range of businesses -- such as existing upstream assets, fuel sale and purchase agreements and overseas power generation -- are brought together.

Between Tepco and Chubu Electric, their total LNG procurement is around 40 million mt/year and coal procurement is 19 million mt/year.

Jera hopes to reduce fuel costs by leveraging its large procurement volumes, although Kakimi said there are uncertainties over future LNG demand because of the restart of nuclear reactors, growing solar power, various plans to build coal-fired plants and liberalization of domestic energy markets.

"I think we can cover real demand with long-term contracts, but potential demand that could change because of these factors should be covered by something else such as contracts with mid-term or short-terms," he added.

Kakimi also said a tender is an effective way to procure LNG when there is ample supply in the market.

In December, the two utilities held a tender for the joint procurement of six LNG cargoes for delivery during fiscal 2015-16 (April-March).

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--Edited by Geetha Narayanasamy, geetha.narayanasamy@platts.com

Exhibit 4

VERESEN

Q2

For the Six Months Ended June 30, 2014

Suite 900, Livingston Place | 222 – 3rd Avenue SW | Calgary AB T2P 0B4
T (403) 296-0140 F (403) 213-3648

Veresen Announces 2014 Second Quarter Results and Updates Guidance

CALGARY, ALBERTA (August 6, 2014) – Veresen Inc. ("Veresen" or the "Company") (TSX: VSN) announced today financial and operating results for the three months ended June 30, 2014.

Highlights

- Veresen generated distributable cash[1] of $63.7 million ($0.29 per Common Share) in the second quarter of 2014 compared to $49.2 million ($0.25 per Common Share) in the second quarter of 2013.
- Veresen recorded a net loss attributable to Common Shares of $2.4 million ($0.01 net loss per Common Share) in the second quarter of 2014 compared to net income attributable to Common Shares of $11.5 million ($0.06 net income per Common Share) in the second quarter of 2013.
- Cash from operating activities was $47.9 million in the second quarter of 2014 compared to $55.0 million in the second quarter of 2013.
- In July, Jordan Cove LNG achieved a key regulatory milestone with the receipt of the Notice of Schedule for the environmental review of the LNG terminal and related pipeline from the Federal Energy Regulatory Commission ("FERC").
- Alliance Pipeline filed an application with the National Energy Board ("NEB") for regulatory approval of the tolls and tariff provisions required for Alliance to implement its proposed new services.

"We continue to make good progress in advancing our key strategic initiatives, including the re-contracting of the Alliance Pipeline and development of Jordan Cove LNG. During the first half of 2014, we also completed key financing activities to bolster our financial strength and flexibility," said Don Althoff, President and CEO.

"The filing of Alliance Pipeline's revised toll and tariff application with the NEB, is an important milestone in the re-contracting process. Signing of Precedent Agreements with producers and shippers is ongoing as we move through the regulatory process with the NEB."

Don Althoff added, "With the receipt of our Notice of Schedule from the FERC for our Jordan Cove LNG project, we now have a line of sight to obtaining our Final Environmental Impact Statement, and I'm confident we will obtain this critical permit."

[1] This is not a standard measure under GAAP and may not be comparable to similar measures used by other entities. See the reconciliation of distributable cash to cash from operating activities in the tables attached to this news release.

Financial Highlights	Three months ended June 30		Six months ended June 30	
($ Millions, except per Common Share amounts)	**2014**	2013	**2014**	2013
Net income (loss) before tax				
Pipeline	**30.0**	27.5	**61.5**	52.3
Midstream	**8.7**	15.6	**42.6**	27.0
Power	**1.7**	9.5	**(2.0)**	10.5
Veresen – Corporate	**(40.6)**	(26.6)	**(69.3)**	(53.5)
	(0.2)	26.0	**32.8**	36.3
Gain on sale of assets	**-**	-	**14.3**	-
Tax recovery (expense)	**1.9**	(12.3)	**(10.0)**	(19.2)
Net income	**1.7**	13.7	**37.1**	17.1
Preferred Share dividends	**(4.1)**	(2.2)	**(8.2)**	(4.4)
Net income (loss) attributable to Common Shares	**(2.4)**	11.5	**28.9**	12.7
Per Common Share ($)	**(0.01)**	0.06	**0.14**	0.06

Financial Performance

For the three months ended June 30, 2014, Veresen recorded a net loss attributable to Common Shares of $2.4 million or $0.01 net loss per Common Share compared to net income of $11.5 million or $0.06 per Common Share for the same period last year. The decrease in earnings was primarily driven by higher project development spending related to Jordan Cove LNG, lower midstream earnings, and the revaluation of the York Energy Centre interest rate hedge.

Higher project development spending in the second quarter of 2014 reflects Veresen's efforts to further advance Jordan Cove LNG following its receipt of a conditional order from the U.S. Department of Energy to export liquefied natural gas to those countries that do not have Free Trade Agreement status with the U.S. As Veresen has continued to de-risk this project, the Company has dedicated additional resources towards its commercial, engineering and financing activities and, as anticipated, development spending has increased accordingly.

The Midstream business generated net income of $8.7 million before tax for the three months ended June 30, 2014 compared to $15.6 million for the same period in 2013. Hythe/Steeprock generated consistent earnings relative to the comparative period, while Aux Sable's results were negatively impacted by lower NGL margins resulting from higher gas prices.

A revaluation of the York Energy Centre interest rate hedge resulted in an $11.7 million reduction in second quarter Power earnings compared to the same period last year. Partially offsetting this reduction was the receipt of a $3.9 million retroactive adjustment related to York Energy Centre's power purchase agreement with the Ontario Power Authority.

Second quarter 2014 results also reflect an increase in Pipeline earnings from Alliance, primarily due to higher negotiated depreciation rates and contributions from the Tioga Lateral pipeline.

Distributable Cash

($ Millions, except per Common Share amounts)	Three months ended June 30 2014	2013	Six months ended June 30 2014	2013
Pipeline	**40.6**	37.9	**81.6**	76.4
Midstream	**27.0**	23.7	**69.7**	50.9
Power	**17.8**	7.1	**24.9**	16.9
Veresen – Corporate	**(15.0)**	(15.8)	**(32.0)**	(34.3)
Current tax	**(2.6)**	(1.5)	**(6.7)**	(1.7)
Preferred Share dividends	**(4.1)**	(2.2)	**(8.2)**	(4.4)
Distributable Cash [(1)]	**63.7**	49.2	**129.3**	103.8
Per Common Share ($)	**0.29**	0.25	**0.62**	0.52

(1) See the reconciliation of distributable cash to cash from operating activities in the tables attached to this news release.

For the three months ended June 30, 2014, Veresen generated distributable cash of $63.7 million or $0.29 per Common Share compared to $49.2 million or $0.25 Common Share for the same period in 2013. Higher distributable cash reflects increased contributions from each of Veresen's Pipeline, Midstream and Power businesses, partially offset by higher taxes and Preferred Share dividends.

Overview of Business Segments

Pipelines

In the second quarter of 2014, Alliance Pipeline filed an application with the NEB for regulatory approval of the tolls and tariff provisions required to implement Alliance's proposed new services commencing December 1, 2015. The NEB application is a key milestone for Alliance as it reflects a move to a new business model under new natural gas transportation agreements. Regulatory approval will allow Alliance to offer its customers a menu of new services and competitive tolls replacing the 15-year service contracts that expire November 30, 2015.

Alliance's new services offering reflects extensive market consultation and includes full-path and segmented receipt and delivery services, a new Canadian trading pool, and a revised hydrocarbon dewpoint specification. Alliance plans to file a regulatory application with the FERC in 2015 to revise its U.S. tariff.

Alliance continues to be in active negotiations with prospective and existing shippers with respect to re-contracting its pipeline capacity post-2015. The signing of binding Precedent Agreements will be timed with the RGP agreements that Aux Sable is negotiating with the producer community.

Midstream

Veresen's maintenance turnaround at the Steeprock natural gas processing plant in British Columbia was completed on budget and on schedule in June 2014. Turnaround activities were performed in a manner consistent with Veresen's ongoing commitment to the health and safety of its employees and contractors, and safeguarding of the environment. The majority of the costs associated with the turnaround will be recovered under Veresen's Midstream Services Agreement with Encana Corporation.

Aux Sable continues to work with producers within an economic radius of the Alliance pipeline to provide options and value for natural gas and natural gas liquids ("NGLs") to reach large and liquid U.S. markets. Aux Sable holds several RGP agreements with producers that will enhance the value of the producers' NGLs.

In June 2014, Aux Sable executed an additional long-term RGP agreement with 7G. The agreement significantly increases the volumes originally agreed to by the companies in February 2013. Under this new long-term agreement, volumes of liquids-rich natural gas are expected to ramp up to 500 mmcf/d. These supplies will be processed at Aux Sable's extraction and fractionation facilities located in Channahon, Illinois.

Power

Construction of the Dasque-Middle run-of-river project in northwest British Columbia is proceeding as planned and it is expected to be in-service in the fourth quarter of 2014. Construction of the 33 MW St. Columban wind project is progressing, with commercial in-service expected in the first half of 2015. The 40 MW Grand Valley III wind project continues to advance through the regulatory process. Testing and commissioning of the 13 MW Whitecourt waste heat facility is ongoing and the facility is expected to be in service by the fourth quarter of 2014.

Jordan Cove LNG

In July 2014, Jordan Cove LNG and the associated Pacific Connector Gas Pipeline received their collective Notice of Schedule for environmental review from the FERC. Receipt of this schedule is an important milestone in the regulatory process. FERC's schedule calls for a final EIS to be issued on February 27, 2015. Based on this schedule, Veresen has reviewed and updated its project timeline and expects to make a final investment decision in mid-2015. With a four-year construction period, commercial LNG production is targeted for mid- to late-2019. Once the FERC issues Jordan Cove LNG its Draft Environment Impact Statement, a public hearing process is initiated.

Veresen continues to be in active negotiations to secure long-term arrangements to produce LNG for international customers. Veresen's objective is to execute binding agreements this year for all of Jordan Cove LNG's initial capacity of 6 million tonnes per annum.

Veresen also continues to negotiate the engineering, procurement and construction contract with a joint venture formed by Kiewit and Black & Veatch for the design and construction the LNG terminal. Veresen expects the EPC contract to be completed in late 2014, following which a Class 1 cost estimate and schedule will be generated by the contractor.

In the second quarter of 2014, Veresen engaged Macquarie Capital as its financial advisor for the Jordan Cove LNG project.

2014 Guidance Update

Veresen has narrowed its guidance for 2014 distributable cash to be in the range of $1.02 per Common Share to $1.20 per Common Share, with a midpoint of $1.11 per Common Share. Further details concerning 2014 guidance can be found in the "Invest" section of Veresen's web site at www.veresninc.com.

Exhibit 5

Company	Bloomberg Ticker	Country / Region	Disclosure Type	Disclosure
Veresen	VSN CN	Canada	General	Macquarie and its affiliates collectively and beneficially own or control 1% or more of any class of Veresen Inc's equity securities.
Verifone Systems Inc.		United States	General	Macquarie Group Limited together with its affiliates, beneficially owns 1% or more of a class of common equity securities of Verifone Systems Inc.
Verisign Inc.		United States	General	Macquarie Group Limited together with its affiliates, beneficially owns 1% or more of a class of common equity securities of Verisign Inc.
VGI Global Media PCL	VGI BKK	Thailand	General	Macquarie Securities (Thailand) Limited may be an issuer of derivative warrants on the securities mentioned in this report.
VGI Global Media PCL	VGI BKK	Thailand	General	Macquarie Group Limited together with its affiliates beneficially owns 1% or more of the equity securities of VGI Global Media PCL.
Vicinity Centres	VCX AU	Australia	General	MACQUARIE CAPITAL (AUSTRALIA) LIMITED or one of its affiliates has provided Federation Centres Ltd with investment advisory services in the past 12 months, for which it received compensation.
Vicwest	VIC CN	Canada	General	Macquarie Capital Markets North America Ltd., which is a registered broker-dealer and member of FINRA, accepts responsibility for the contents of reports issued by Macquarie Capital Markets Canada Ltd in the United States and sent to US persons. Any US person wishing to effect transactions in the securities described in the reports issued by Macquarie Capital Markets Canada Ltd should do so with Macquarie Capital Markets North America Ltd. The Research Distribution Policy of Macquarie Capital Markets Canada Ltd is to allow all clients that are entitled to have equal access to our research.
Vietnam Sun Corp		Vietnam	General	Macquarie Group Limited together with its affiliates beneficially owns 1% or more of the equity securities of Vietnam Sun Corp.
Vijaya Bank	VJYBK IN	India	General	Macquarie Group Limited together with its affiliates may have a beneficial interest in the debt securities of the companies mentioned in this report.
Village Roadshow	VRL AU	Australia	General	Macquarie Group Limited together with its affiliates beneficially owns 1% or more of the equity securities of Village Roadshow Ltd.

EXHIBIT 5

2,562 disclosures found in 257 pages, displaying 2,421 to 2,430.

First Prev238 239 240 241 242 243 244 245 246 247Next Last

Exhibit 6

Platts

Japan LNG demand expected to fall by 2020 on nuclear restarts, renewables

Tokyo (Platts)--15 Dec 2015 1234 am EST/534 GMT

Restart of nuclear reactors in Japan, growing renewable sources of energy and a slow economy are expected to push down the country's LNG consumption by 2020 by as much as 10.5% from 2014 levels, Eclipse Energy said this week.

Japan's LNG demand is expected to drop to 77 million mt by 2020 from a record 86 million mt reached in 2014, according to Eclipse, an analytics unit of Platts.

In 2015 itself, Japan bought 3 million mt less LNG in the first 10 months compared with a year earlier.

Kyushu Electric restarted its two 890 MW nuclear reactors at Sendai in August and October, ending Japan's 23 months of nuclear-free period since September 2013.

Kyushu Electric's LNG consumption in September dropped to the lowest level since May 2011, data from the Ministry of Economy, Trade and Industry showed.

From September to November, Kyushu Electric received seven cargoes at its Tobata terminal, down from 13 in the same period last year, according to Platts ship trade-flow software cFlow. Near this terminal is the 1.8 GW Shin Kokura gas-fired station.

Kyushu Electric's Oita LNG terminal, adjacent to its newer 2.295 GW Shin Oita gas-fired power station, received nine cargoes over September-November, the same number of vessels as last year, cFlow showed.

Eclipse estimates that if Kyushu Electric's two 1.18 GW Genkai nuclear reactors start up, it would replace up to around 3-4 LNG cargoes a month. US LNG EXPECTED IN WINTER

By 2019, five more nuclear reactors are expected to restart, including Shikoku Electric's 890 MW No. 3 Ikata reactor, Tohoku Electric's 1.1 GW No. 1 Higashidori reactor, Hokkaido Electric's 912 MW No. 3 Tomari reactor, Hokuriku Electric's 1.206 GW No. 2 Shika reactor and Chugoku Electric's new 1.373 GW No. 3 Shimane reactor.

Summer LNG imports are expected to fall post 2017 because of a growth in renewables capacity in Japan.

Meanwhile demand is expected to drop over the next four years amid a slower economy, and Japan is expected to see an increase in LNG imported through long-term contracts rather than spot, Eclipse said.

Its contracted volume is expected to grow from 82.3 million mt in 2017 to 88.2 million mt in 2019 and 84.8 million mt in 2020, while Japan's LNG demand is projected to drop from 78.2 million mt in 2017 to 77.2 million mt in 2020, according to Eclipse.

"Our forecasts suggest that US-sourced LNG is only called on during the winter peak season at least until 2020," it said.

Japan has so far contracted to buy around 17 million mt/year of LNG from US Freeport, Cameron and Cove Point projects. Eclipse projects just 20-25% utilization of the Japanese tolling contracts in 2018-2019 but a steady increase early

in the next decade rising to about 50% utilization.

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--Edited by E Shailaja Nair, shailaja.nair@platts.com

Exhibit 7

From http://www.platts.com/latest-news/natural-gas/seoul/s-korea-secures-235-mil-mt-in-2027-lng-term-deals-27868046

Platts

S Korea secures 23.5 mil mt in 2027 LNG term deals, 62% of expected demand

Seoul (Platts)--7 Oct 2015 519 am EDT/919 GM

South Korea has secured 2027 term contracts for 23.5 million mt or 62.3% of the 37.7 million mt it expects to need that year, state-run Korea Gas Corp. said Thursday.

The country has secured 34 million mt for 2015, above the 33.9 million it needs for the year, according to a Kogas report submitted to the National Assembly.

Kogas, which has a monopoly on domestic natural gas sales, expects South Korea's 2015 LNG consumption to be 34 million mt, down from an earlier outlook of 39.8 million due to weak power demand on relatively higher prices of LNG and rising nuclear power output.

Kogas said its revised forecast was made on the basis on sluggish January-July domestic sales, which fell 8.8% year on year.

Kogas planned to import 33.84 million mt in 2015, down 7.4% from 36.33 million mt imported in 2014, given weaker demand.

"Short-term LNG shortage will be made up by short-term contracts to cover winter demand and spot purchasing if necessary, while long-term shortage would be partly filled by volumes from overseas projects in which Kogas is involved," the report said.

Kogas imported 18.35 million mt of LNG over January-July, including 13.08 million mt or 71.3% from the Middle East and South Asia.

It bought 7.32 million mt or 39.9% of its January-July imports from Qatar and 2.45 million mt or 13.4% from Oman, the report said.

It imported 1.87 million mt from Malaysia, 1.44 million mt from Indonesia, 1.15 million mt from Russia and 790,000 mt from Australia in January-July. The other 3.33 million mt came from 10 minor suppliers, including Nigeria, Equatorial Guinea and Brunei.

Of Kogas' total January-July imports, 15.11 million mt or 82.3% came under long- and mid-term contracts, 2.16 million mt or 11.8% was imported under short-term contracts, and 1.08 million mt or 5.9% came from spot buying.

"Under its plans for long- and mid-term contracts, Kogas is seeking more volumes from Australia and North America so as to ease the dependence on Middle East and South Asian nations," the report said.

"In particular, Kogas is pushing to bring in more volumes from projects in which Kogas holds stakes, such as LNG Canada."

Kogas and its partners launched LNG Canada, a project to produce 12 million mt/year of LNG from two trains at Kitimat in the western province of British Columbia in May 2013.

Kogas currently holds a 15% interest in Shell-led LNG Canada after selling a 5% stake to Shell in May last year as part of efforts to reduce its debt.

"Kogas is still pushing to sell additional 5%, which will reduce its stake to 10%," a company official said.

Kogas pushed for sell the 5% stake by the end of 2014 but failed amid the slump in energy prices in the second half of last year.

Kogas, which imported 0.93 million mt from projects in which it holds stakes in 2014, aims to increase the volume to 2.42 million mt in 2017.

The company currently has 15 contracts covering 24.12 million-31.44 million mt/year in imports for 2015-2019.

The deals include 4.92 million mt/year from Qatari RasGas, 2.1 million mt/year from RasGas II and 1.5 million-2 million mt/year from RasGas III, 4.06 million mt/year from Oman's OLNG, and 2 million mt/year from Yemen's YLNG, among others.

Kogas plans to import 2.8 million mt/year from the Sabine Pass terminal in Louisiana from 2017.

It originally planned to buy 3.5 million mt/year from Sabine Pass, but Kogas signed a deal with Total in January 2014 to resell 700,000 mt/year in a bid to reduce import volumes to South Korea.

Under the deal, Kogas will take 2.8 million mt/year while Total will get the remaining 700,000 mt/year.

Kogas also has three mid-term contracts in which Kogas imports 2.73 million-3.88 million mt/year for 2015-2016, the report said.

Besides Kogas, two more South Korean firms are importing LNG directly from overseas sources.

Posco, the country's top steelmaker, has been importing 550,000 mt/year from the BP-led Tangguh LNG consortium in Indonesia since July 2005 under a 20-year contract.

SK E&S, the country's top city gas provider and an affiliate of the country's top oil refiner SK Innovation, also has been importing 600,000 mt/year of LNG directly from Tangguh since 2005 under a 20-year contract.

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--Edited by Meghan Gordon, meghan.gordon@platts.com

Exhibit 8

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One Lakeshore Drive, Suite 1810
Lake Charles, Louisiana 70629

FOR IMMEDIATE RELEASE
November 16, 2015

Magnolia LNG Executes EPC Contract With KBR-SK JV

Lake Charles, La.—Magnolia LNG, LLC, is pleased to advise that it has agreed to a legally binding lump sum turnkey (LSTK) engineering, procurement and construction contract (EPC Contract) with the KBR-SKE&C joint venture (KSJV) in relation to the Magnolia LNG Lake Charles project.

Contract Highlights:

- EPC Contract LSTK cost of $4.354 billion for four LNG trains and associated facilities;
- EPC guaranteed production of 7.6 mtpa (million tons per annum), or 0.8 mtpa greater than previous guidance;
- The EPC Contract LSTK plant design utilizes the patented OSMR® technology;
- Installed capacity cost/tonne range of $495 to $544 based on final design at FID;
- LNG plant fuel gas consumption of 8%, or 92% feed gas production efficiency guaranteed;
- EPC Contract LSTK price is valid to April 30, 2016.

The EPC Contract covers the engineering, procurement and construction of four LNG production trains with design capacity of 2 mtpa or greater each, two 160,000m3 full containment storage tanks, LNG marine and ship loading facilities, supporting infrastructure and all required post-FID approvals and licenses.

On August 24, 2015, Magnolia LNG announced selection of the Siemens Energy Inc. (Siemens) process compression and driver equipment. The increased power available from the Siemens equipment potentially enables higher final plant design capacity which, following completion of remaining engineering and analysis, will be confirmed prior to Final Investment Decision (FID). As a result, Magnolia LNG's per ton EPC cost may reduce within the range of $495/ton to $544/ton based on the final installed capacity design.

The EPC guaranteed production totalling 7.6 mtpa for the four-train Magnolia LNG project will not change.

The KSJV also provided pricing on a reduced (three train) project scope. The take out cost for one train, estimated by KSJV at $630 million, is subject to final confirmation by December 31, 2015.

Other Costs:

Post-FID costs to commercial operations date in early 2019, which include owner's engineer, O&M mobilisation, insurance, commissioning gas, regulatory, other minor contracts, and capitalized overhead costs, are expected to range between 13.5% ($585 million) and 15.5% ($675 million) of the EPC Contract price. These estimates exclude capitalised interest during construction.

Equity and debt transaction costs, letter of credit fees, and financing costs will be determined at the time of FID, based on final terms agreed with BNP Paribas, lenders and equity providers.

Managing Director's Comments

Magnolia LNG's President and Chief Executive Officer, Maurice Brand said, "We are pleased to announce the final lump sum turn-key EPC contract pricing details after significant efforts by the KSJV and the Magnolia project team, managed by Magnolia LNG's Chief Operating Officer, John Baguley. I want to thank the KBR and SKE&C leadership for their diligence and hard work on delivering the LSTK pricing. The total EPC capital cost in the range of $495 to $544 per ton of LNG plant capacity (for the 8 mtpa or greater plant) establishes a new low for U.S. Gulf Coast projects and is substantially lower compared with recent LNG projects around the world."

"With execution of the EPC contract in hand, we shall continue with final engineering activities but will not commit to out-sized, non-cancellable commitments in advance of execution of offtake agreements for at least 4 mtpa of additional sales," continued Brand.

"The EPC Contract costs agreed with KSJV reinforce the view of Liquefied Natural Gas Limited (LNGL)—Magnolia LNG's parent company—that our business model of mid-scale, modular based LNG trains of nominally 2 mtpa design capacity, incorporating the LNGL's OSMR® LNG liquefaction process is valid, providing a sustainable long-term business platform that can be replicated in future projects."

Revenue Sharing Agreement

For a period of up to 15 years following the declaration of commercial start date for each train, the KSJV may be eligible for annual revenue sharing payments ranging from $0 to $30 million across the four-train plant (maximum of about $0.07/mmBtu per annum). Annual amounts to be paid to the KSJV reflect a near linear inclining slope starting at $0 for production below 1.7 mtpa up to $30 million for production over 2.0 mtpa, with all annual payments based on actual LNG production achieved in a year reflected on a per train average across the 8 mtpa or greater liquefaction plant.

The revenue sharing arrangement, associated with KSJV's support of the initial scaled commercialisation of LNGL's OSMR® technology and construction approach, when combined with operating and other costs across the 8 mtpa or greater plant is expected to approximate $0.50/mmBtu. The target cost amount of $0.50/mmBtu represents the estimated operating cost implicit in the unchanged EBITDA guidance of approximately $2.50/mmBtu across the four train project.

KSJV Comments

"We are delighted to work with Magnolia LNG on this ground-breaking project for more innovative, cost effective, efficient and greener LNG," said Stuart Bradie, KBR President and CEO. "KBR's long history of success in global LNG, ammonia and plant modularization make us a natural fit for this exciting project and we are pleased to have the opportunity to bring our unique skills, together with our self-perform construction capability and outstanding safety record, to create exceptional value for Magnolia LNG," continued Bradie.

For more information on the Magnolia LNG project, please visit www.MagnoliaLNG.com.

About the Magnolia LNG Project

The Magnolia LNG project is 100% owned by Magnolia LNG, LLC, which is a wholly owned subsidiary company of Liquefied Natural Gas Limited. The project comprises the proposed development of an 8-mtpa LNG project on a 115-acre site, located on an established LNG shipping channel in the Lake Charles District, State of Louisiana, United States of America. The project is based on the development of four LNG production trains of 2 mtpa each using the LNGL's wholly owned OSMR® LNG process technology. Magnolia LNG's business model provides liquefaction services to LNG buyers who pay a monthly fixed capacity fee, plus all LNG plant operating and maintenance costs. LNG buyers contract for liquefaction services under two contract models – a Liquefaction Tolling Agreement, whereby the LNG export terminal is only responsible for processing natural gas into LNG, and an LNG Sales and Purchase Agreement under which the customer buys LNG on a free on board basis (FOB).

About Liquefied Natural Gas Limited

Liquefied Natural Gas Limited is an Australian listed company (Code: LNG and OTC ADR: LNGLY) focused on development of mid-scale LNG plants. LNGL's business strategy aims to deliver

KINDER MORGAN

The Role of Natural Gas Liquids (NGLs) in the American Petrochemical Boom

U.S. domestic natural gas production experienced an unprecedented increase over the past decade. This was largely due to continual advancements in drilling and producing technologies, such as hydraulic fracturing and horizontal drilling, coupled with access to prolific shale plays. In just 10 years, natural gas production in the U.S. increased from 18.5 trillion cubic feet in 2006, to over 26.4 trillion cubic feet in 2016—an increase of approximately 42 percent.[1,2]

In recent years, many Americans have experienced the benefits that increased domestic oil and gas production provides, such as lower costs for home heating and automobile gasoline, lower electricity costs, decreased electricity-sector emissions and reduced reliance on foreign countries for energy imports. What we talk about less is the fact that this shale revolution in America has also resulted in an “NGL revolution.”

In addition to methane, natural gas contains hydrocarbons known as natural gas liquids (NGLs), like ethane, propane, butane, isobutane and pentane. Natural gas processing plants and refineries remove (or condense) NGLs as a liquid from the vaporous natural gas stream.

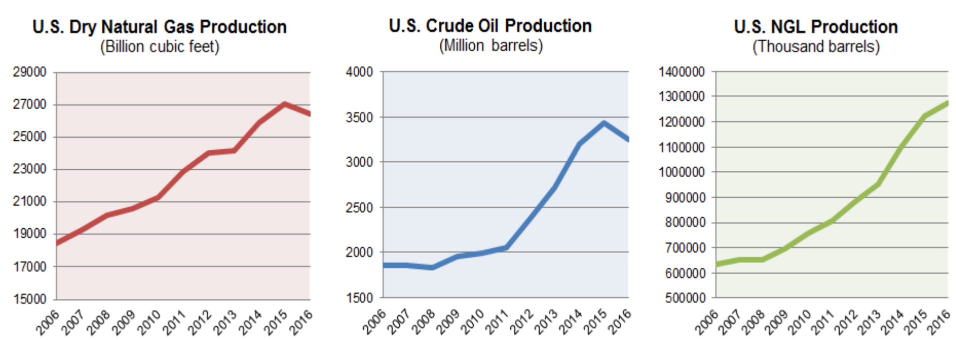

FIGURE 1: Comparison of U.S. natural gas, oil and NGL production. (Source: EIA, 2016 Data)

Given the substantial growth in natural gas production, it’s no surprise that NGL production in the U.S. has boomed—increasing over 100 percent in just 10 years from approximately 634 million barrels in 2006 to approximately 1.36 billion barrels in 2017.[3] [i] The increased availability of domestic NGLs is a major boon to the U.S. petrochemical and manufacturing industries, as well as a benefit to U.S. consumers. See Figure 1 above for a comparison of the increases in U.S. domestic natural gas, crude oil and NGL production over the past 10 years.

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[i] NOTE: EIA figures for NGL production do NOT include ethane rejected back into the gas stream

NGLs play an underappreciated and essential role in in our lives as feedstocks for thousands of consumer goods. For example, a pair of athletic or running shoes likely contains at least three different NGL-derived petrochemicals. The outsole and midsole of the shoe is probably made from durable polyurethane foam: a derivative of the petrochemical **propylene**.

The insole cushion that your foot rests on is made of ethylene vinyl acetate (EVA): a derivative of the petrochemical **ethylene**. The exterior top and sides of the shoe is often nylon: a derivative of the petrochemical **benzene**. That's at least three different NGL-derived petrochemicals in just a pair of shoes.[4,5] NGLs aren't limited to plastics and clothing though, they are the key ingredient in almost everything in our lives including building materials, bicycles, plastic bottles, shopping bags, car parts, heating fuels, carpeting, synthetic fabrics, medications, skis, snowboards, hiking boots, backpacks and even baby diapers. So what are NGLs and where do they come from?

WHAT ARE NGLs?

Natural gas is a mixture of hydrocarbon gases and the ratio of these different components (gases) varies. The vast majority of natural gas, 70-90 percent, is methane.[6] The remaining 10-30 percent is various NGLs, including ethane, propane, butane and pentane.[7] While NGLs are gaseous at underground pressure, the molecules condense at atmospheric pressure and turn into liquids.[8] The composition of natural gas can vary by geographic region, the geological age of the deposit, the depth of the gas and many other factors. Natural gas that contains a lot of NGLs and condensates is referred to as **wet gas**, while gas that is primarily methane, with little to no liquids in it when extracted, is referred to as **dry gas**.[9]

When natural gas is extracted during production, it must be processed to separate the pure natural gas (methane) from the various other hydrocarbons and fluids to produce what is known as pipeline-quality dry natural gas.

Once natural gas comes out of the wellhead, any oil and water present in the gas is removed either at the wellhead or at a nearby processing facility. Once the gas is transported to a nearby natural gas **processing facility**, other non-NGL liquids, such as sulfur, helium and carbon dioxide, are removed and then the NGLs are removed.[10] The process of separating the NGLs from the natural gas stream is a complicated process involving multiple steps. Once NGLs are separated from the natural gas stream, they must then themselves be separated.

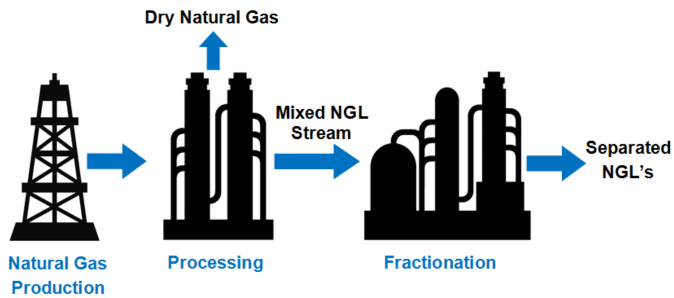

FIGURE 2: Natural gas processing steps

The process of separating various NGLs is called **fractionation**. Since each molecule (ethane, propane, etc.) has a different boiling point, the hydrocarbon stream goes through multiple fractionators, each with a different temperature. This removes a different NGL at each step, starting with the lightest hydrocarbons and working up to the heaviest. Typically ethane is removed first, followed by propane, butane and isobutane.[11] After these NGLs are removed and the natural gas meets the pipeline quality standards for the pipeline it will be transported on, it is sent to natural gas utilities, power generators and industrial customers. See Figure 2 above for a flowchart of the process.

FIGURE 3: A view of Kinder Morgan's Houston Central Plant, which processes NGLs

WHAT ARE NGLS USED FOR?

Of the approximately 1.36 billion barrels of U.S. NGLs produced in 2017, 33 percent was propane, 38 percent ethane, 12 percent pentane, 8 percent normal butane and 9 percent was isobutane.[12]

NGLs are used for a variety of purposes in almost all sectors of the U.S. economy. **Ethane** is used almost exclusively in the production of ethylene, which is then turned into plastics. **Propane** is mostly used for heating and as a petrochemical feedstock. **Butane** and **isobutane** are typically blended into petroleum products to create various fuels.[13] See Figure 4 below for the various types of NGLs and how they are most commonly used.

Natural Gas Liquid (NGL)	Applications	Primary Sectors
Ethane	Ethylene for plastics production; petrochemical feedstock	Industrial
Propane	Residential and commercial heating; cooking fuel; petrochemical feedstock	Industrial, Residential, Commercial
Butane	Petrochemical feedstock; blending with propane or gasoline	Industrial, Transportation
Isobutane	Refinery feedstock; petrochemical feedstock	Industrial
Pentane	Natural gasoline; blowing agent for polystyrene foam	Transportation
Pentanes Plus	Blending with vehicle fuel; exported for bitumen production	Transportation

FIGURE 4: Primary NGL applications and sectors[14]

The largest customer for NGLs, particularly ethane, is the chemical industry. Ethane is valuable because the industry uses it to create ethylene, which is the raw ingredient in most types of plastics. The complex process of converting ethane into ethylene is called **cracking**. Ethane cracker facilities heat the gas to approximately 1,500 degrees Fahrenheit to change the chemical composition of the ethane molecules resulting predominantly in ethylene. The ethylene is then cooled rapidly so it can be transported via pipelines in its liquid state."[15] Other chemicals can then be added to create entirely new compounds that are made into many of the consumer products we use every day.

In addition to ethylene, other chemicals derived from NGLs include **propylene**, **benzene**, **methanol** and **butadiene**. Although we may not recognize their names immediately, these products are building blocks in consumer items and applications most of us use daily.

- **Propylene and its derivatives** are often found in the form polypropylene which is used for injection-molded plastics for everything from bottle caps to automotive plastics, toys and electronics parts. Polypropylene is also used for disposable plastic shopping bags, carpeting, luggage and backpacks. Propylene is a component in polyurethane foam, fiberglass composites and disposable diapers.[16]

- **Benzene and its derivatives** are combined with ethylene to make styrene and polystyrene plastics, and are also used to create phenol. Phenol is used in pharmaceuticals such as aspirin, detergents and pesticides. Benzene is also used to produce cyclohexane, which is a precursor to nylon, one of the most common synthetic fabrics used for textiles, parachutes, nylon stockings, toothbrush bristles, carpeting, rugs and umbrellas.[17]

- **Methanol and its derivatives**, also known as wood alcohol, are used to make gasoline additives, formaldehyde and urea for plywood, insulation and particle board, as well as to make acetic acid for latex paints, adhesives and acrylic signs.[18]

- **Butadiene and its derivatives** are used to make artificial rubbers for tires, hoses, conveyor belts and shoes.[19]

NGLs and LPG Exports

Some NGLs, namely butane and propane, have even more applications because they can be liquefied into what is referred to as “liquefied petroleum gas” (LPG) and stored in a tank for transportation. LPGs are considered a subset of NGLs. While LPG is mostly used in the U.S. for outdoor grilling and for home heating in areas without access to piped natural gas, it is heavily used in many other countries to power vehicles and as a home cooking fuel.

The U.S. has increasingly become an exporter of LPG—exporting over 367 million barrels of LPGs in 2016, a drastic increase from the 54 million barrels of LPGs exported five years earlier in 2011.[20] Currently, China is the largest LPG importer followed by India and Japan.[21] The U.S. exported LPG to over 60 different countries in 2017 alone.[22]

Additionally, many developing countries are developing their LPG infrastructure so their citizens can switch to the more efficient LPGs from dirtier biomass (firewood, animal dung, etc.) that is widely used. The World Health Organization (WHO) estimates 3 billion people globally cook and heat their homes using biomass and over 4 million people globally die annually from premature deaths caused by indoor pollution resulting from biomass.[23] This presents a major opportunity for American LPGs to provide a safer alternative for home heating and cooking around the world.

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HOW NGLs GROW THE ECONOMY

U.S. petrochemical manufacturers are now benefiting from an increased supply of low-cost NGLs. This gives these producers a large competitive advantage versus manufacturers in other countries that do not have an abundant supply of NGLs. The American Fuel & Petrochemical Manufacturers association estimates that feedstocks account for 60 to 70 percent of the total cost to manufacture petrochemicals.[24] Even a small drop in the cost of these feedstocks is a major benefit to U.S. manufacturers. Since natural gas prices in the U.S. fell by 75 percent between 2005 and 2013, while remaining flat or rising in most of the rest of the world, U.S. chemical manufacturers that use natural gas as a feedstock or energy source have seen a major competitive advantage compared to other parts of the world.[25]

The increased availability of low-cost energy and NGLs has encouraged U.S. petrochemical manufacturers to expand their businesses. The American Chemistry Council reported that capital spending on new facilities and upgrades to existing facilities in the chemical industry increased 12 percent in 2014 and 18 percent in 2015.[26] It also reports that as of March 2017, 294 chemical manufacturing projects cumulatively valued at $179 billion in capital investment had been proposed, were under construction, or were recently completed in the U.S. as a result of the shale gas boom.[27]

Furthermore, foreign companies that are attracted to America's large supply of NGLs are building 60 percent of those projects. [28] These companies, both foreign and domestic, are helping to create more manufacturing and refining jobs in the U.S.

CHALLENGES FOR CONTINUED DEVELOPMENT

As the U.S. continues to increase its supply of natural gas and NGLs, continued development of the infrastructure to move them and the facilities to process them are vital. A recent report performed for the Interstate Natural Gas Association of America found that NGL production will continue to rise during the upcoming decades, but that this growth is dependent on the continued development of transportation capabilities, ethane crackers and markets for the NGLs.[29] The main challenge that the NGL and petrochemical industries must address is transportation logistics from natural gas producing areas to fractionation facilities.

In 2016, approximately 50 percent of all U.S. NGLs were fractionated in Texas and Louisiana.[30] Yet that same year, Texas and Louisiana combined accounted for only about one-third of U.S. natural gas production.[31] This means that in order for fractionation facilities to continue operating at full capacity, NGLs must be shipped to where those facilities are located. Yet shipping NGLs can be difficult. They are expensive to handle, store and transport compared with other refined products because they require high pressure and/or low temperature to maintain their liquid state.[32] The U.S. has built several large NGL pipelines in recent years, but the length of time associated with siting, permitting and constructing a pipeline makes it challenging for pipeline companies to keep transportation capacity on pace with production.

In fact, industry in America currently produces more NGLs than it is able to transport to customers.[33] If takeaway capacity or markets are not available, the ethane is rejected, meaning a small amount of it is left within the natural gas stream (within federal and pipeline operator guidelines) or flared. This is wasted product that could be very valuable if facilities were available to move and process it.

Although many companies are constructing or proposing new cracking facilities to process NGLs, they too have not been able to keep up with the boom in production. The EIA projected in its 2018 Annual Report that natural gas liquid production will likely double between 2017 and 2050, largely as a result of global petrochemical industry demands.[34] Projects currently under construction or completed since 2013 will increase the U.S. capacity to produce ethylene from ethane by 31 percent—from 29 million metric tons per year to 38 million metric tons per year.[35]

The U.S. EIA has identified 14 proposed ethylene production plants, or crackers, that will come on-line in the U.S. by 2020. Twelve of these plants are located in Texas and Louisiana on the Gulf Coast, and just two are located in northern states: one in Pennsylvania and one in Ohio.[36] See Figure 5 below for a map of several of these proposed facilities.

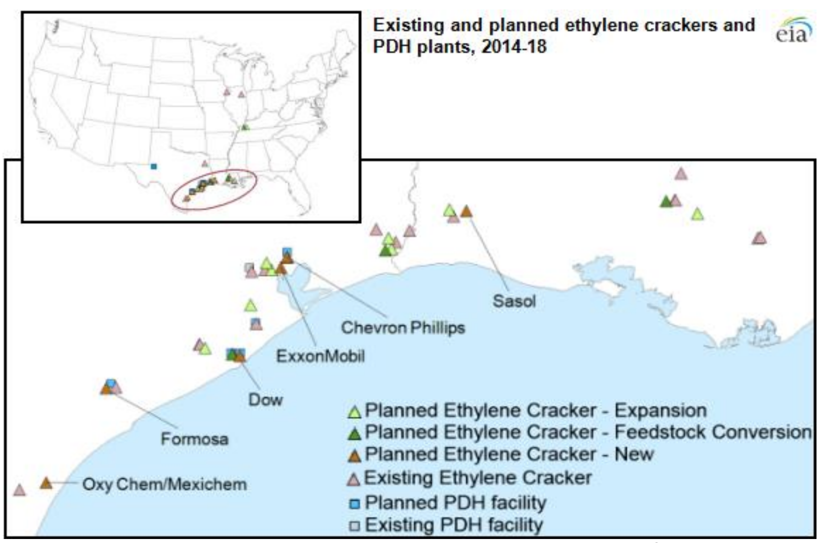

FIGURE 5: Proposed ethylene crackers and PDH plants.[37]

Ethane crackers are very expensive facilities that take several years to develop. A Shell cracking facility proposed to begin construction in Pennsylvania is estimated to cost nearly $6 billion.[38] In many cases, constructing a cracker near a shale-gas

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producing area is far more expensive than constructing an NGL pipeline to service an existing cracking facility farther away. More transportation capacity is needed to transport NGLs from the shale regions to existing and planned fractionation facilities.

AN UPSIDE OF SURPLUS

Since the U.S. is unable to consume all the NGLs it produces, more are available for export which helps reduce our trade deficit. Industry first started shipping NGLs by pipeline to Canada and recently developed facilities to ship NGLs by tanker overseas and now U.S. exports of propane and butane have risen rapidly.
Since the U.S. is not able to crack and process all the ethane it produces domestically, we also have begun shipping ethane abroad in recent years. Ethane exports from the U.S. increased from zero in 2013 to approximately 34.7 million barrels in 2016.[39]

One example of this export trend is Kinder Morgan's recently completed Utopia Pipeline. Utopia is a 270-mile pipeline which transports NGLs from Harrison County in the Utica shale fields of southern Ohio, to Kinder Morgan's existing pipeline and facilities in Fulton County, Ohio, then north to plastics manufacturers in Windsor, Ontario, Canada.[40] The pipeline has a current capacity of 50,000 barrels per day (bpd) and is expandable to more than 75,000 bpd. The project solves the current NGL challenge of getting the product to customers. NGLs are plentiful in southern Ohio and the Utica Shale where natural gas development has boomed in recent years. However, sufficient capacity to convert NGLs into derivative products is not available in that region. Fortunately, the export solution that Kinder Morgan proposes—connecting U.S. NGL producers with plastics customers in Canada—is also good for the American balance of trade.

CONCLUSION

There are many immediate benefits of increased U.S. domestic natural gas production: lower costs for home heating and electricity, reduced emissions from power generation plants as they switch from coal and oil to natural gas, and a decreased reliance on foreign countries for energy. However, the secondary benefits of the domestic gas boom are also incredibly important to the U.S. economy. Increased domestic natural gas, oil and NGL production is strengthening the refining and petrochemical industry, restoring the manufacturing sector and making America a global energy superpower. Kinder Morgan intends to play a part in enabling this success story by moving these products safely and efficiently from production to economic use.

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https://about.bnef.com/blog/the-future-of-lng/

The Future of LNG

May 4, 2018

By Maggie Kuang
Head of APAC LNG
Bloomberg New Energy Finance

The shale revolution is leading the world to a future of abundant and affordable oil and gas. The technology of liquefying natural gas (LNG) is increasingly used to ship gas produced in cost-competitive regions to where gas demand is growing but where local gas production is falling. Structural reforms in the power and gas sectors and rising competition from renewables and alternative fuels are reshaping the global LNG industry. In this article, Bloomberg New Energy Finance (BNEF) elaborates on the implications and describes the future of LNG.

Diverse drivers to LNG demand

Traditionally, LNG has been used largely for power generation. However, this is changing as market conditions in traditional LNG-importing countries change and new importers with different dynamics join the market. BNEF expects:

- The growth in demand for LNG used for baseload power generation will be limited as gas in many major economies can't compete with renewables.
- Rising renewable penetration will expand LNG's role in providing flexible power generation to balance the electricity grid in many major economies.
- The use of LNG in the industrial and transport sectors will push up gas demand, particularly in Asia where environmental concerns are on the rise.
- The opportunity for LNG in baseload power will be mostly in floating storage and regasification-based emerging markets that are plagued by power shortages.

Demand shift from JKT to other Asian countries

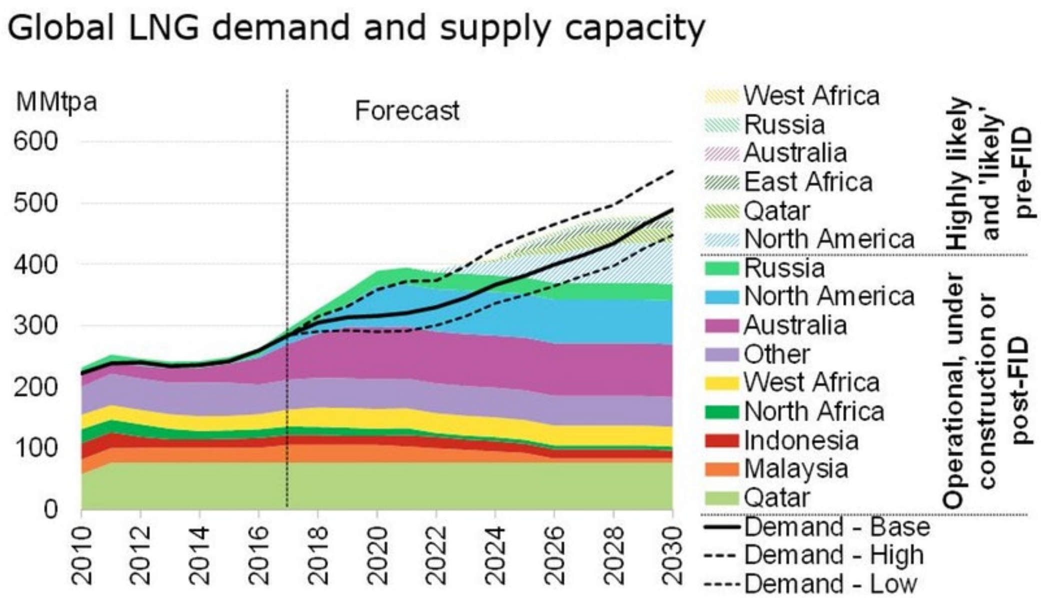
Asia will continue to lead the growth in demand for LNG, with BNEF forecasting the region will maintain its 70% market share in the coming decade. However, demand growth is shifting from the traditional Asian markets of Japan, South Korea and Taiwan — often referred to as JKT — to 'emerging Asia' led by China, India, South and Southeast Asia.

JKT's share of global LNG trade is likely to fall from today's 49% to 25% in 2030. In Japan, nuclear restarts are driving down gas power generation which is fueled by imported LNG. In South Korea, LNG demand is likely to be flat as new coal and nuclear power, which is cheaper than gas power, is scheduled to come online in coming years. In addition, the growth of renewables is becoming a threat to gas in the longer term.

With strong policy support, a jump in LNG demand is difficult to see. Taiwan's LNG demand growth will be largely constrained by its LNG-receiving capacity.

In contrast, 'emerging Asia' will become the engine driving the growth in demand for LNG. The share of combined LNG demand from these countries globally will rise from today's 23% to 42% in 2030. Improving macroeconomics, stricter implementation of environmental policies and ongoing gas market reforms will continue to push up China's gas consumption and LNG imports. India's LNG demand is expected to be largely driven by industrial sectors where fuel-switching opportunities exist for LNG as a feedstock. In South and Southeast Asia, LNG demand will be primarily driven by power demand growth and a reduction in local gas production.

Global LNG demand/supply-capacity balance



Note: 'Highly-likely' and 'likely' pre-FID projects are included on this chart. The likelihood of a project being built by 2030 is assessed based on the project's regulatory stage, project size, infrastructures, developers' financial strength, offtake contracts, and sovereign risks.

Source: Bloomberg New Energy Finance, Poten & Partners, customs data.

How big is the demand growth?

The world consumed 285MMt of LNG in 2017. The substantial expansion of global LNG trade in 2017 is unlikely to repeat in 2018 and further slowdown is expected in 2019-22. Global LNG demand is expected to reach 330MMtpa by 2022. Post 2022, a significant decline in domestic production in Southeast Asia and Europe will drive a rebound in global LNG demand growth. By 2030, BNEF expects to see global LNG demand reaching 490MMtpa.

Demand could accelerate quickly in various markets, though. Upside potential in demand growth of 40-65MMtpa exists across different countries in the world, including China, South Korea, Japan, India, Pakistan, Bangladesh, Europe and Kuwait.

For China, policy strength and economic growth are the wild cards, while the biggest uncertainty in Japan is nuclear restarts. For South Asia, the price of LNG and progress toward expanding infrastructure are the major contributors to a swing in demand. For Europe, LNG prices and geopolitics will be the key triggers.

“Lowering LNG prices during the early 2020s and accelerating infrastructure build-out in South Asia are the key to unlocking LNG demand in the region,” BNEF analyst Maggie Kuang said. “The market needs to take action now to grab the opportunity then.”

Evolving LNG purchase models

Traditionally, LNG importers buy LNG via long-term, take-or-pay, and delivery location-fixed contracts. As LNG demand becomes less certain due to competition from renewables, alternative fuels and market liberalization, LNG buyers are in need of flexible LNG contracts more than ever. Such contracts would allow buyers to reduce volumes, cut tenures, and request different delivery locations when needed. However, negotiations between buyers and sellers haven’t been easy.

BNEF data shows that the signing of new LNG term contracts has been declining every year since 2014. Only 20MMtpa of new contracts were signed in 2017, 10MMtpa lower than the previous year. Of the 20MMtpa signed volumes, only 1MMtpa had tenure shorter than 5 years. Short-term contracts were able to be sold only by portfolio players, trading houses, and suppliers with old projects whose marginal cost of supply is low.

Requests for flexible volumes and tenures pose significant challenges in terms of project finance for new supply projects. The nature of traditional project financing does not accept high uncertainties on project cash flows resulting from flexible contracts. Portfolio players and trading houses will need to participate in financing or offtaking future supply projects given their expertise on optimizing assets and hedging risks.

Traditionally, contracted LNG prices are mostly linked to oil prices, though LNG buyers have shown a strong desire to delink from oil prices in case of a spike in the future. However, such voices have faded at times of lower oil prices and there has been no consensus from buyers on the most suitable indexation option in LNG contracts. Depending on where oil and gas hub prices are, LNG buyers are expected to switch between the two from time to time.

Buyers have been making efforts to establish Asia gas hubs. The argument is that regional gas hubs are needed to create a gas-on-gas indexation that reflects local demand and supply. Such Asian indexes are then expected to find increasing relevance as benchmarks/reference points in long-term LNG contracts.

Japan, China, and India have all seen some progress in setting up the required trading platforms. To discover the right price point, these planned hubs will need sufficient number of market players and volumes of transactions of gas and/or LNG. From market players’ perspective, free competition between pipeline gas, LNG, indigenous production, and substitutes fuels will best reflect gas fundamentals and help discover the fair price for LNG. However, it would be hard to see full competition among these fuels without a liquid and liberalized gas market, connected by extensive pipelines serving a sufficiently large gas demand.

A supply shortage risk and price spike ahead?

BNEF anticipates about 30-33MMtpa of new capacity will be added from 2018-20. Australia has the last batch of projects to come on-stream before the end of 2018 but full ramp-up will take a couple of years. The boom in U.S. LNG supply will end in 2020. Global capacity will peak at 396MMtpa in 2021 and will begin to fall behind demand post 2025. To support further demand growth, final investment decisions (FID) on new supply projects will need to be made in the next few years to provide sufficient supply post 2025.

Given an average 5-year lead time in LNG project development and construction, 2018-20 is a crucial window in which to reach final investment decisions. The earlier a project takes an FID, the better it is positioned to price its supplies/volumes. “However, many projects are facing financing hurdles at the moment as buyers want flexible contracts — which is not going to help these projects secure financing,” BNEF’s Kuang said. Bundling multiple short-term contracts to cover 10-20 years on a single project is being tested out with some banks’ project finance teams. “The risk of running into supply shortages might be just a small possibility, but we are also unlikely to see a sudden wave of new projects taking FID,” Kuang added. As a result, prices could rise in the long term, but BNEF is skeptical that a trend will emerge in which prices skyrocket.

BNEF considers that there is roughly 362MMtpa of pre-FID capacity with any chance of coming online by 2030. Of that capacity, about 118MMtpa is likely to achieve FIDs over the next 5 years based on BNEF’s assessment. Half will be located in the U.S., while others will likely come from Qatar, Mozambique, and Papua New Guinea. BNEF’s analysis of the likelihood that a project will be built by 2030 is based on factors such as how far it has advanced with regulators, size, infrastructure, a developer’s financial strength, the existence of offtake contracts and sovereign risks.

For more detail about BNEF’s coverage and analysis of LNG markets, read a public excerpt of our Global LNG Outlook.

This article was originally published on the KNect365 website and is republished here with permission. You can read the original article here. BNEF’s Head of EMEA, Seb Henbest, will discuss this and other energy-related topics at the Flame conference on May 16 in Amsterdam. You can find out more about the agenda here.

https://seekingalpha.com/article/4120262-pembina-pipelines-pba-ceo-michael-dilger-q3-2017-results-earnings-call-transcript?page=1

Pembina Pipeline's (PBA) CEO Michael Dilger on Q3 2017 Results - Earnings Call Transcript

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Pembina Pipeline Corp. (NYSE:PBA)

Q3 2017 Results Earnings Conference Call

November 3, 2017, 10:00 AM ET

Executives

Scott Burrows – Senior Vice President of Finance and Chief Financial Officer

Michael Dilger – President and Chief Executive Officer

Stuart Taylor – Senior Vice President, NGL and Natural Gas Facilities

Jason Wiun – Vice President, Conventional Pipeline

Cam Goldade – Vice President Capital Markets

Analysts

Elias Foscolos – Industrial Alliance Securities

Linda Ezergailis – TD Securities

Robert Kwan – RBC Capital Markets

Andrew Kuske – Credit Suisse

Robert Catellier – CIBC

Robert Hope – Scotiabank

Jeremy Tonet – JP Morgan

Ben Pham – BMO Capital Markets

Operator

Good morning. My name is Stacy, and I will be your conference operator today. At this time, I would like to welcome everyone to the Pembina Pipeline Corporation 2017 Third Quarter Results Conference Call. All lines have been placed on mute to prevent any background noise. After the speakers' remarks, there will be a question-and-answer session [Operator Instructions]. Thank you.

Mr. Scott Burrows, Senior Vice President and Chief Financial Officer. You may begin your conference.

. . .

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Operator

Your next question comes from Andrew Kuske from Credit Suisse. Your line is open.

Andrew Kuske

Thank you. Good morning I think the question is probably for Mick and obviously you just closed the Veresen deal, you've got a product portfolio of assets on what was already a pretty big footprint in Western Canada. But when you look at your network of assets and just the capital that you're allocating in the future. Really, what's missing in your portfolio at this stage. So, if you had your wish list out, what would you want to put on the portfolio, whether organically building it or buying it. What's really missing in the value chain for you?

Michael Dilger

Well, I think it's what every person in the energy business in Alberta want for Christmas is access to global markets. You know when we see the gas price in Tokyo and reflect on what that could mean, we could you know net that back to western Canada through Jordon Cove and associates pipelines or the propane price what that means to Western Canadian producers if we can get world pricing or world pricing for polypropylene. If Pembina and others that we wish well actually sincerely can connect Western Canada to the rest of the world that's really the Christmas present we all want. And we think is fantastic for our industry, but also for all Canadians. The amount of money that we are leaving on the table as a country, it's absolutely sad, we're a single customer industry and that's just got to change. So, that's the biggest thing that's missing from my perspective.

. . .

http://business.financialpost.com/commodities/energy/pembina-pipelines-new-purpose-get-canadas-oil-and-gas-to-the-rest-of-the-world

Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world

CEO shifts to getting hydrocarbons to the U.S. and Asia, especially in light of Canada's infrastructure problems, which he thinks will only get worse

By Claudia Cattaneo
February 16, 2018
Last Updated
February 20, 2018

Political priorities come and go, especially when it comes to energy these days, and Pembina Pipeline Corp. has been adding value one piece of infrastructure at a time since the days of Louis St. Laurent.

Its most recent growth spurt, much of it through the oil and gas downturn, has boosted its enterprise value to $26.7 billion, from $14.4 billion in 2014 when current chief executive Mick Dilger took over, and from $3 billion 10 years ago.

With that kind of pedigree, you could do worse than pay attention to Dilger, who believes it would be better for governments to help improve the value of existing resources rather than chase new energy sources.

Canada, he points out, sits on some of the world's best and largest deposits of natural gas, which could be the bridge fuel to both help solve the climate change challenge by replacing coal and turn the country into a green superpower.

"How bad does it have to get in Canada before people care?" Dilger said in an interview in the company's Calgary headquarters. "Monies don't come from governments. They come from adding value, and maybe parts of Canada have had it too good and we need some pain before people start to wake up. It's also frustrating to me because I am mindful of the environment."

Pembina is little known outside Western Canada, partly because it rarely seeks publicity, partly because much of its business has been in energy-friendly Alberta.

It grew from a single oil pipeline built in 1954 by Alberta's Mannix dynasty to transport oil from the Pembina oil discovery in Drayton Valley, Alta. The company is now widely held — the Mannix family remains a shareholder — and is now Canada's third-largest pipeline company after Enbridge Inc. and TransCanada Corp.

Pembina has achieved its lofty position by building or buying infrastructure to serve its oil and gas customers in Western Canada, specifically pipelines linked to the oilsands in Alberta and shale discoveries such as the Montney and the Duvernay, storage tanks, fractionation plants that separate light hydrocarbon mixtures into individual substances, and gas-processing facilities.

The next projects in its core geography continue to reflect its time-tested mantra: do the most with the molecules you have.

The projects include a proposed $4-billion petrochemical plant in Sturgeon County in Alberta's Heartland with equal partner Petrochemical Industries Co. of Kuwait, and a $250-million liquefied petroleum gas export terminal in Prince Rupert, B.C.

"We think we have a purpose beyond what we have done, which is to play our part alongside other sector companies to **get our hydrocarbons to the rest of the world**," Dilger said.

But its next game-changing project could be in the United States. Pembina is making progress on reviving the US $10-billion Jordan Cove Energy Project, a liquefied natural gas export terminal on the Oregon coast to process Western Canadian gas, which is in great demand in Asia, but prices have languished because of a lack of export infrastructure.

"We think we have a purpose beyond what we have done, which is to play our part alongside other sector companies to get our hydrocarbons to the rest of the world"
-Mick Dilger-

Jordan Cove was part of Pembina's acquisition of Veresen Inc. last year, part of a $100-billion U.S. buying spree by Canada's top three pipeline companies over the past three years.

In addition to Pembina's purchase of Veresen, whose assets are half in the U.S., Enbridge bought Spectra Energy Corp. and TransCanada purchased Columbia Pipeline Group Inc.

The U.S. is where Pembina's larger competitors have already spread out to get around Canada's infrastructure gridlock and to take advantage of the more favourable business environment down south.

"That is $100-billion worth of money that could have been spent in Canada," said Dilger, a 54-year-old accountant by trade. "Think about that: the royalties, the jobs. The trend is, as their economy gets more pro business and pro-development, and ours goes the other way, capital will flee Canada. Those are all irrefutable conclusions to the way we are going, versus the way they are going."

The struggling but advanced Jordan Cove LNG project was denied an export permit by the U.S. Federal Energy Regulatory Commission two years ago because of a lack of customers even during a period of weak LNG prices, but Pembina has since filed a new permit application and expects a ruling this November.


An artist's rendering of the Jordan Cove project. Handout/Jordan Cove Energy

"We believe (the project) filed a winning application this time," Dilger said. "They had tremendous local support and federal support. I am not trying to predict what is going to happen in 2023 with commodity prices. But today, the price of gas in Tokyo is US $11. The price of gas in Alberta on a bad day is like $1. It costs you $5 to $6 to get it there. So there is a massive arbitrage today. I don't know what it's going to be in 2023, but there is a lot of interest right now."

Pembina is trying to secure customers and finish pipeline engineering, but if everything works out, the company will be in a position to make a final investment decision as soon as the end of 2018, Dilger said, which might mean the project could be completed in 2023.

"Pembina was smart to keep the project alive because the LNG market is coming to them now," said Dan Tsubouchi, chief market strategist at Stream Asset Financial Management, who believes global LNG demand is recovering a lot faster than previously anticipated.

Buying Veresen also gave Pembina two strategic Canadian gas export assets: a 50 per cent interest in the Alliance natural gas pipeline from Western Canada to Chicago (the rest is owned by Enbridge), and a roughly 43 per cent stake in a natural-gas-processing venture, Aux Sable.

But Dilger worries Canada's energy infrastructure problems will only get worse because of reforms announced by Ottawa last week to modernize the regulatory and environmental reviews of energy projects.

For example, allowing anyone in Canada to have an opinion on whether a major project should go ahead politicizes reviews and puts the country down a "very dangerous" path, he said.

There are three LNG projects making progress on the B.C. coast — LNG Canada led by Royal Dutch Shell PLC with partners PetroChina, Korea Gas Corp. and Mitsubishi Corp. of Japan;

Woodfibre LNG, owned by the RGE Group of companies based in Singapore; and Kitimat LNG, a joint venture between Chevron Corp. and Australia's Woodside Petroleum Ltd. — but politics and high costs have been a long-running challenge.

Jordan Cove, meanwhile, would process up to 1.3 billion cubic feet a day of both Western Canadian gas or U.S. Rockies gas into LNG for export to Asia, but it's not the only energy export project that could take Canadian energy in the U.S. to reach Asian markets.

The proposed Eagle Spirit oil pipeline is also moving forward with plans to establish a tanker terminal in Alaska to export Canadian oil and get around the federal Liberal government's tanker ban.

Dilger believes Jordan Cove has a higher chance of success under Pembina than it had under Veresen because it has the money to finance it, the expertise to build both the plant and a 400-kilometre pipeline through tough terrain, and the relationships with Western Canadian producers and Asian customers to make it viable.

Some day, Pembina would like to build an LNG facility on the B.C. coast, too, Dilger said, but Jordan Cove has key advantages: it is cheaper to build a pipeline to receive Western Canadian gas from existing networks than build over the Canadian Rockies; its location near larger population centres means there is labour available to build it; and shorter travel time to Asian markets versus the U.S. Gulf Coast means lower transportation costs for its LNG.

Another priority is the expansion of the Alliance pipeline, one of Canada's large gas export highways into the Chicago hub.

Pembina will move ahead with Veresen's plans to expand the system by up to 500 million cubic feet a day, adding to the current level of 1.8 billion cubic feet a day, by using compression. A binding open season for interested shippers is under way.

"The best market in North America right now is Chicago," Dilger said, "I'd like to see Canadian gas get there and get some higher netbacks."

The Veresen acquisition diversified Pembina's assets into gas and into a new region, he said, but it also fits with the company's integrated business model, which he said is better than having disparate energy businesses geographically.

As for moving into new energy sources such as wind and solar, Dilger doesn't see the value proposition for his company, adding: "How's that working for Ontario so far?"

Financial Post

• Email: ccattaneo@nationalpost.com

Pacific Connector Gas Pipeline, LP
Open Season Notice
July 18th, noon Central to August 17th, noon Central

Pacific Connector Gas Pipeline, LP ("PCGP") is holding an Open Season for its Pacific Connector Gas Pipeline ("Pipeline"). The Pipeline will provide firm transportation service from interconnections with Ruby Pipeline and Gas Transmission Northwest near Malin, Oregon to the Jordan Cove LNG Terminal in Coos Bay, Oregon.

With this Open Season, PCGP invites parties interested in obtaining firm Pipeline capacity to submit a Transportation Services Precedent Agreement ("TSPA"). After the Open Season closes, PCGP will allocate capacity among bidders with valid TSPAs as described below. The anticipated service commencement date for this Pipeline is the fourth quarter of 2022. At least one party has expressed interest in firm transportation service on the Pipeline commencing at the in-service date of the Jordan Cove LNG Terminal, but PCGP would be willing to consider bids for firm transportation service commencing as early as the in-service date of the Pipeline.

PCGP's marketing activities to date have led to the commitments by Anchor Shippers for 96% of the capacity in the Pipeline. Any bidder who submits a valid bid for 70,000 dekatherms ("Dth") per day ("Dth/d") or more and for a term of 10 years or more shall be considered an "Anchor Shipper" on the Pipeline, and the capacity it requests in its Anchor Shipper bid shall only be pro-rated with other Anchor Shipper bids. Anchor Shippers may receive certain rate and rate-related benefits which may not be offered to other potential Pipeline shippers.

Pipeline Description

The Pipeline is a proposal to construct and operate an approximately 229-mile long, 36-inch diameter interstate natural gas pipeline originating near Malin in Klamath County, Oregon and terminating at the Jordan Cove LNG Terminal in Coos County, Oregon. The Pipeline will transport up to 1,200,000 Dth/d of natural gas from interconnects with Ruby Pipeline LLC and Gas Transmission Northwest LLC near Malin, Oregon to the Jordan Cove LNG Terminal for processing, liquefaction, and export.

Pipeline Rates

The applicable recourse reservation rates for service on the Pipeline are estimated to be $ 1.33 per Dth per day. Final rates are dependent upon the scope and final facilities required to satisfy the firm service requests for shippers who have executed binding TSPAs. Shippers will pay the applicable recourse rate or a mutually agreeable negotiated rate for service on the Pipeline.

Nomination Process

To ensure firm transportation service on the Pipeline, a shipper must execute a binding TSPA by the specified date, which constitutes a bid in this Open Season.

The Open Season begins at 12 pm Central on July 18th 2017 and concludes at 12 pm Central on August 17th, 2017. During this period, interested shippers must complete and submit a TSPA that specifies the following:

Contract demand (Dth/d);
Primary receipt points;
Primary delivery points; and
Recourse or negotiated rate.

To receive a form TSPA, or to submit a TSPA executed by a duly authorized representative, contact:

Pacific Connector Gas Pipeline, LP
Attention: Matt Sullivan
5615 Kirby Drive
Houston, TX 77005
Phone: (713) 400-2800
Email: PCGP@vereseninc.com

PCGP reserves the right to reject any TSPA that is not received before the end of the Open Season. After the Open Season concludes, PCGP will contact all shippers who have submitted valid TSPAs to advise them of status.

Allocation of Capacity

PCGP will allocate up to 1,200,000 Dth/d of the pipeline capacity first to qualifying Anchor Shippers executing binding TSPAs before the end of the Open Season and next to other (non-anchor shippers) bidders that have executed binding TSPAs before the end of the Open Season. With respect to Anchor Shippers, PCGP will prorate capacity, to the extent necessary, taking into account the contract demand and the quantities at the primary points subscribed under each such binding TSPAs, on a not unduly discriminatory basis. A bidder's status as an Anchor Shipper, and the Anchor Shipper's attendant rights, will continue to apply even if the pro-rated amount of capacity awarded to such bidder is less than 70,000 Dth/d. If one or more bidders qualify as Anchor Shippers, capacity will not be allocated to other (non-Anchor Shipper) bidders until Anchor Shipper bids have been satisfied. Among other (non-Anchor Shipper) bidders with valid executed TSPAs, PCGP will allocate capacity on a net present value basis, with PCGP having the discretion to award capacity to any bidder or combination of bidders whose TSPAs provide the highest net present value per Dth.

Limitations and Reservations

PCGP may but is not required to reject any TSPA that is incomplete, is inconsistent with the terms and conditions outlined in this open season notice, contains additional or modified terms, or is otherwise deficient in any respect. PCGP reserves the right to request that a party modify its proposed receipt or delivery points to the extent that PCGP determines that the points in the party's bid will unduly increase the costs of the overall Pipeline or otherwise adversely affect the scope of the Pipeline in light of the other TSPAs received prior to or as part of this Open Season. PCGP reserves the right to reject TSPAs in the event that requesting parties are unable to meet applicable creditworthiness requirements.

Communications

Interested shippers may contact Matt Sullivan at (713) 400-2800 to discuss any questions or seek additional information about this open season.

HTTPS://WWW.REUTERS.COM/ARTICLE/US-LOCKHEED-F35-EXCLUSIVE/LOCKHEED-RESUMES-F-35-JET-DELIVERIES-TO-PENTAGON-IDUSKBN1I827Q

MARKET NEWS

OCTOBER 11, 2017 / 12:44 PM / 7 MONTHS AGO

CORRECTED-Petronas' Canadian unit to look at other LNG opportunities -exec

Reuters Staff

3 MIN READ

(In Oct 11 item, corrects Petronas reserves total in second paragraph to 50 trillion cubic feet, instead of 50 trillion cubic feet a day)

By Nia Williams

CALGARY, Alberta, Oct 11 (Reuters) - Progress Energy, a wholly-owned unit of Malaysia's Petronas, will look at other liquefied natural gas opportunities as a way to monetize its Canadian gas assets after Petronas scrapped a $29 billion LNG project this year, a company executive said on Wednesday.

Petronas, the Malaysian state-owned energy company, abandoned plans to build the Pacific Northwest LNG plant in northern British Columbia in July due to weak prices, leaving Progress with 800,000 acres of land rights in the Montney shale play and 50 trillion cubic feet of reserves.

Since the project was scrapped, Calgary-based Progress said it planned to make money out of its huge natural gas operations in the Montney, which spans northeast British Columbia and northwest Alberta, but gave few details of how it would do that.

Progress's vice president of production, Dennis Lawrence, told an energy conference in Calgary on Wednesday that the company had spent a significant amount of money acquiring that position over the last five years and it was time to get the gas to market.

“We are in the very early stages of this but we will look hard at other LNG opportunities, we will look hard at petrochemical opportunities,” Lawrence said in a panel discussion. “That’s not a process you figure out in a month or two.”

Lawrence did not specify which LNG opportunities Progress would look at. In August Canada’s Globe and Mail newspaper reported that Petronas was considering acquiring a minority stake in the LNG Canada project, a joint venture led by Royal Dutch Shell.

Petronas bought Progress in 2012 to supply the Pacific Northwest LNG project.

Progress has signed up as an anchor shipper on a proposed pipeline that will connect gas from the Montney to the Alberta market hub and feed it into the North American market. Last week it said it was looking to sell its Deep Basin oil and gas asset in Alberta.

LNG Canada’s chief executive, Andy Calitz, who also took part in the panel discussion, said his company will be ready to make a final investment decision on the $32 billion project in 2018.

The joint venture group last year delayed a final decision to find ways to reduce costs. (Reporting by Nia Williams; Editing by Leslie Adler)