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Exhibits 1-15 to 10/17/17 Letter from Landye Bennett Blumstein LLP on behalf of Evans Schaaf Family LLC, Ron Schaaf, and Deborah Evans
Jordan Cove
Docket No. 12-32-LNG

Exhibit 1

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ATTORNEYS

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Admitted in Oregon and Washington

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%283240 9921%29%2Epdf&folder=9804562&fileid=14687464&trial=1

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

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

[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

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[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]

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[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%2832409921%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:

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[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)

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. The Jordan Cove LNG Terminal Proposal in Docket No. CP13-483-000

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. <u>Request for Blanket Certificates</u>

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,

<u>The Commission orders</u>:

(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

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)

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[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]

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[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
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* Anita R. Wilson
* Christopher J. Terhune
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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]

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[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

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[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

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[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

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[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

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[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.

[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.

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[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

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[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

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[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,

/s/ Elizabeth Spomer
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

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

My Commission Expires:

08/18/20

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

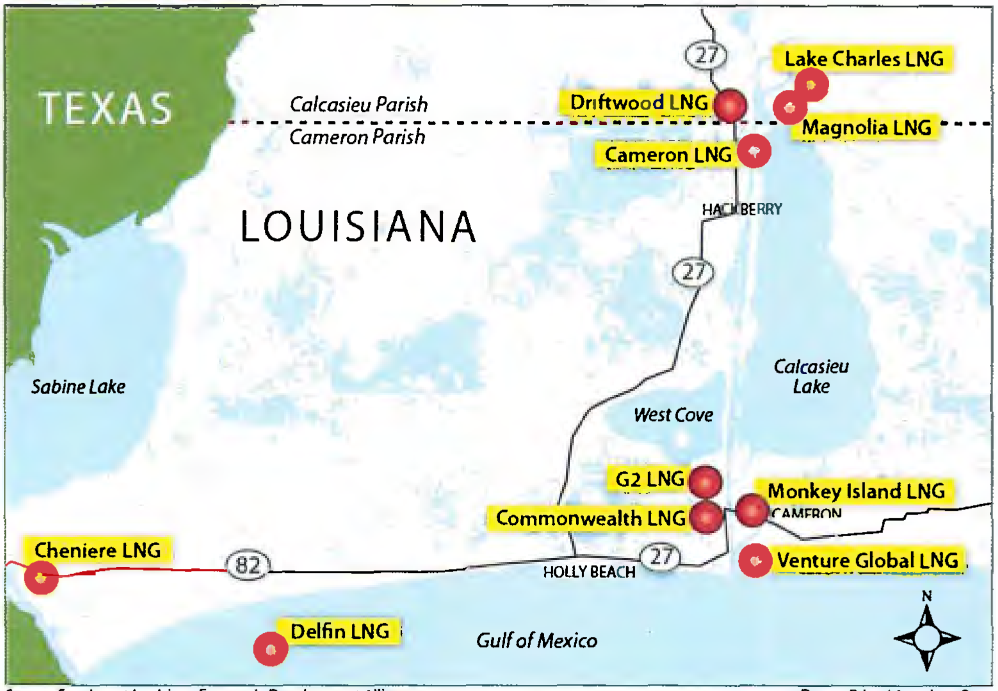
Source: World Gas Intelligence

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.

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.

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.

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

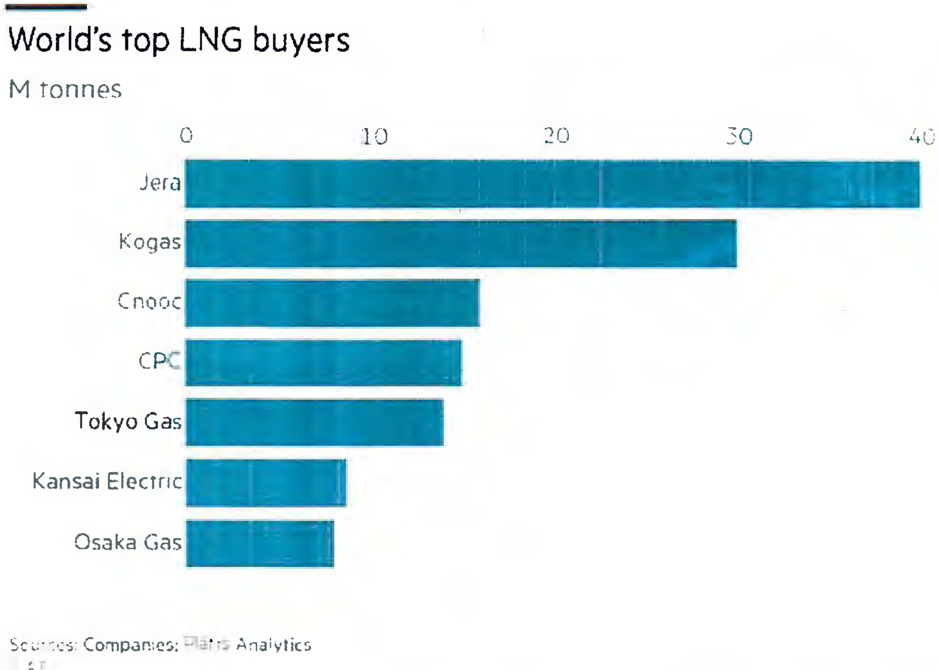
The head of the world's biggest buyer of liquefied natural gas has warned producers that they need to become more competitive on price and allow for more flexible contracts if they want to usher in a "golden age" of gas in Asia.

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.



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.

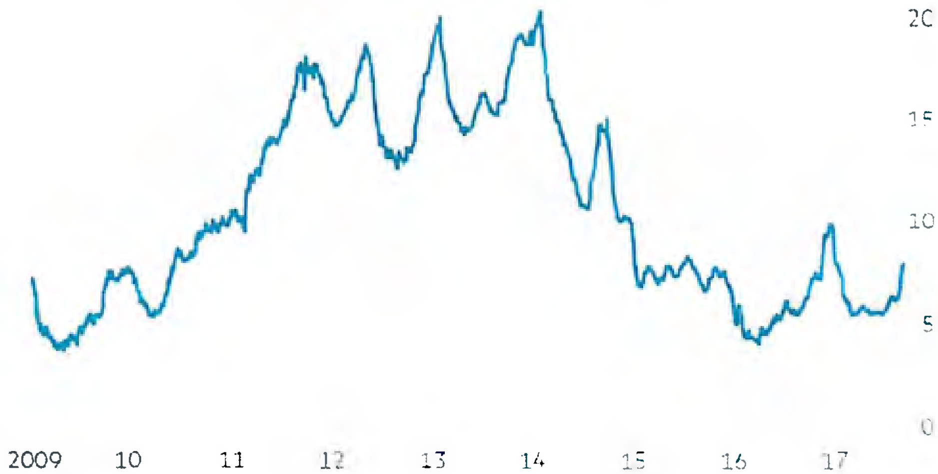
"Buyers now want the freedom to trade with whom they want rather than locking in security [of supply]," said Bernadette Cullinane, head of Australian oil and gas at Deloitte.

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.

Exhibit 6
Page 2 of 5

Asian LNG price

Platts Japan Korea marker ($ per million Btu)



Source: S&P Global Platts

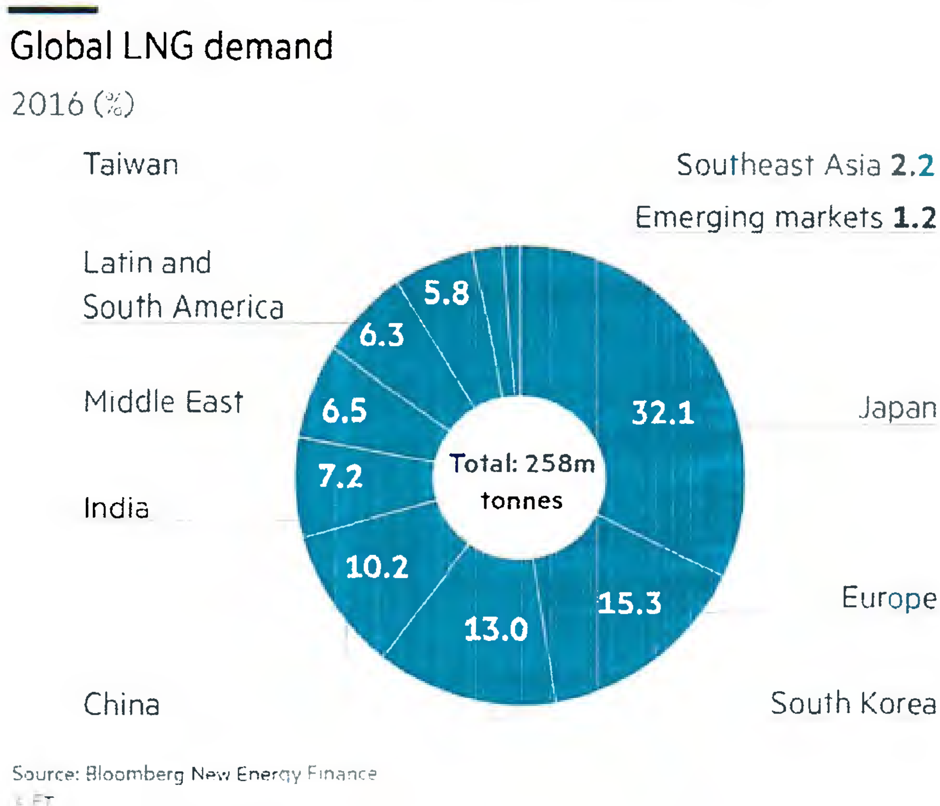
"I highly value LNG from the US. Before [US exports] and after — the market has completely changed," he said.

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.

Exhibit 6
Page 3 of 5



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.

Exhibit 6
Page 4 of 5

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.

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

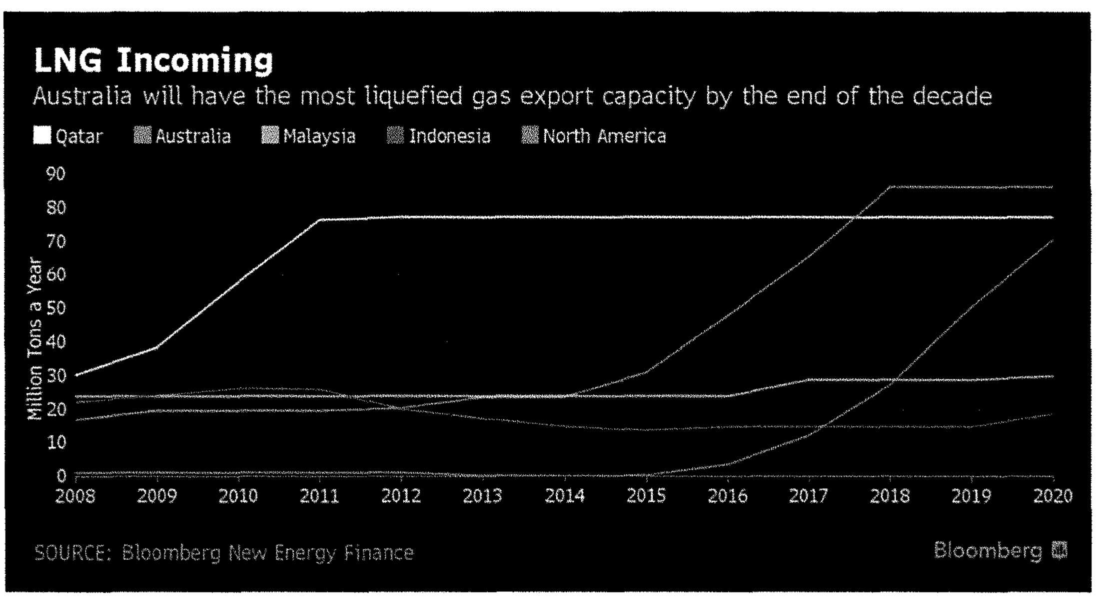
Tuesday. "As it stands there is unlikely to be another large greenfield LNG development" in Western Australia.

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.



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

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."

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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.

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.

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.

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[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

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[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

[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

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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Page 1 of 10

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.

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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

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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

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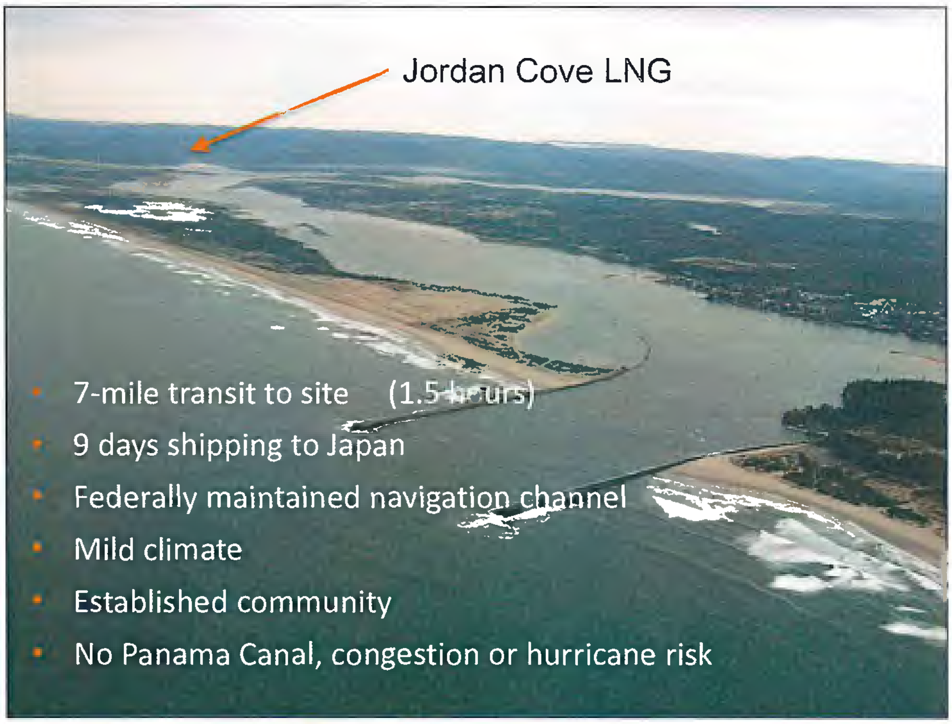
International Port of Coos Bay

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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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

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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

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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

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Exhibit 2

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

OFFICE OF FOSSIL ENERGY

JORDAN COVE ENERGY PROJECT, L.P.	)))	FE DOCKET NO. 12-32-LNG

ORDER CONDITIONALLY GRANTING LONG-TERM
MULTI-CONTRACT AUTHORIZATION TO EXPORT
LIQUEFIED NATURAL GAS BY VESSEL
FROM THE JORDAN COVE LNG TERMINAL IN COOS BAY, OREGON
TO NON-FREE TRADE AGREEMENT NATIONS

DOE/FE ORDER NO. 3413

MARCH 24, 2014

TABLE OF CONTENTS

FREQUENTLY USED ACRONYMS

AEO	Annual Energy Outlook
APGA	American Public Gas Association
Bcf/d	Billion Cubic Feet per Day
Bcf/yr	Billion Cubic Feet per Year
CO_2	Carbon Dioxide
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EITE	Energy Intensive, Trade Exposed
EPA	U.S. Environmental Protection Agency
EUR	Estimated Ultimate Recovery
FDI	Foreign Direct Investment
FE	Office of Fossil Energy, U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
FLEX	Freeport LNG Expansion, L.P., *et al*.
FTA	Free Trade Agreement
GDP	Gross Domestic Product
GNGM	Global Natural Gas Model
ICF	ICF International
IECA	Industrial Energy Consumers of America
JCLNG	Jordan Cove LNG L.P.
kWh	Kilowatt-Hour
LNG	Liquefied Natural Gas
LTA	Liquefaction Tolling Agreement
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
mtpa	Million Metric Tons per Annum
NEI	National Export Initiative
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NERA	NERA Economic Consulting
$N_{ew}ERA$	NERA's Macroeconomic Model
NGA	Natural Gas Act
NGLs	Natural Gas Liquids
NOA	Notice of Availability
PCGP	Pacific Connector Gas Pipeline
Tcf/yr	Trillion Cubic Feet per Year
TRR	Technically Recoverable Resources
TSA	Terminal Service Agreement

I. INTRODUCTION

On March 23, 2012, Jordan Cove Energy Project, L.P. (Jordan Cove) filed an application (Application)[1] with the Office of Fossil Energy of the Department of Energy (DOE/FE) under section 3 of the Natural Gas Act (NGA)[2] for long-term, multi-contract authorization to export as LNG both (i) domestically produced natural gas, and (ii) natural gas produced in Canada and imported into the United States. Jordan Cove seeks to export this LNG by vessel to nations with which the United States has not entered a free trade agreement (FTA) providing for national treatment for trade in natural gas (non-FTA countries).[3] Jordan Cove requests authorization to export up to the equivalent of approximately 292 billion cubic feet of natural gas per year (Bcf/yr) (0.8 Bcf per day (Bcf/d), or approximately 6 million metric tons per annum (mtpa) of liquefied natural gas (LNG), for a 25-year period commencing on the earlier of the date of first export or seven years from the date the requested authorization is granted.[4]

The proposed exports would originate from a liquefaction and export terminal to be located in Coos Bay, Oregon (Jordan Cove LNG Terminal or Terminal). Jordan Cove is requesting authorization to export the LNG on its own behalf or as an agent for other entities who hold title to LNG, after registering each such entity with DOE/FE. For the reasons discussed below, this Order conditionally authorizes Jordan Cove to export LNG in a volume equivalent to 292 Bcf/yr of natural gas, or 0.8 Bcf/d, for a 20-year term.

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[1] Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export LNG to Non-Free Trade Agreement Countries, FE Docket No. 12-32-LNG (Dec. 21, 2011) [hereinafter Jordan Cove App.].

[2] 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-002.04F (July 11, 2013).

[3] Jordan Cove previously sought authorization to export LNG by vessel up to the equivalent of 438 Bcf/yr of natural gas (1.2 Bcf/d) for a 30-year term to nations with which the United States currently has, or in the future enters into, a FTA requiring national treatment for trade in natural gas and LNG (FTA countries). DOE/FE granted that authorization by order dated December 7, 2011 (Jordan Cove FTA Order). On March 18, 2014, DOE/FE also authorized Jordan Cove to import natural gas from Canada to the Jordan Cove Terminal to support this requested export authorization. *See infra* Section IV.A (procedural history of orders granted to Jordan Cove).

[4] DOE regulations require applicants to provide requested export volumes in terms of Bcf of natural gas. 10 C.F.R. § 590.202(b)(1). Accordingly, as discussed below, DOE/FE will authorize Jordan Cove's requested export in the equivalent of Bcf/yr of natural gas. *See infra* Sections X.F & XII.A.

On June 6, 2012, DOE/FE published a Notice of Jordan Cove's Application in the Federal Register.[5] The Notice of Application called on interested persons to submit protests, motions to intervene, notices of intervention, and comments by August 6, 2012. In response to the Notice of Application, DOE/FE received five timely filed motions to intervene and comment or protest respectively from the American Public Gas Association (APGA); Sierra Club; Citizens Against LNG, Inc.; Landowners United; and, jointly, Rogue Riverkeeper and the Klamath-Siskiyou Wildlands Center (collectively, KS Wild). In addition, DOE/FE received 35 timely filed and five additional late-filed comments in support of the Application; three timely filed and two late-filed comments opposing the Application (without a request to intervene);[6] and comments from an individual (Derrick Hindery) raising environmental concerns but taking no position on the merits of the Application. Additional procedural history is set forth below in Section VII.

Previously, on May 20, 2011, DOE/FE issued *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 (*Sabine Pass*), the Department's first order conditionally granting a long-term authorization to export LNG produced in the lower-48 states to non-FTA countries.[7] In that order, DOE/FE conditionally authorized Sabine Pass to export a volume of LNG equivalent to 2.2 Bcf/d of natural gas. In August 2011, DOE/FE determined that further study of the economic impacts of LNG exports was warranted to better inform its public interest review under section 3 of the NGA.[8] By that time, DOE/FE had received two additional applications for authorization

[5] Jordan Cove Energy Project, L.P., Application to Export Domestic Liquefied Natural Gas to Non-Free Trade Agreement Nations, 77 Fed. Reg. 33,446 (Feb. 23, 2012) [hereinafter Notice of Application].

[6] Paula Jones filed both a timely comment against the Application as well as a late-filed comment against the Application. Both submissions are counted above.

[7] *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations (May 20, 2011) [hereinafter *Sabine Pass*]. In August 2012, DOE/FE granted final authorization. *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961-A, Final Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations (Aug. 7, 2012).

[8] DOE/FE stated in *Sabine Pass* that it "will evaluate the cumulative impact of the [Sabine Pass] authorization and any future authorizations for export authority when considering any subsequent application for such authority." DOE/FE Order No. 2961, at 33.

to export LNG to non-FTA countries—one from Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (collectively, Freeport or FLEX)[9] and one from Lake Charles Exports, LLC (Lake Charles Exports).[10] Together, the *Sabine Pass* conditional order, the Freeport application, and the Lake Charles application proposed LNG export authorizations totaling the equivalent of up to 5.6 Bcf/d of natural gas. DOE/FE expected that more non-FTA export applications would be filed imminently. Indeed, by the end of 2011, several more applications had been filed, including a second application by Freeport[11] and an application filed by Cameron LNG, LLC.[12]

In light of these developments,[13] DOE/FE engaged the U.S. Energy Information Administration (EIA) and NERA Economic Consulting (NERA) to conduct a two-part study of the economic impacts of LNG exports.[14] First, in August 2011, DOE/FE requested that EIA assess how prescribed levels of natural gas exports above baseline cases could affect domestic energy markets. Using its National Energy Modeling System (NEMS), EIA examined the

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[9] On May 17, 2013, DOE/FE granted FLEX's first non-FTA export application, conditionally authorizing it to export domestically-produced LNG in a volume equivalent to 1.4 Bcf/d of natural gas for a period of 20 years. *See Freeport LNG Expansion, L.P., et al.*, DOE/FE Order No. 3282, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (May 17, 2013) [hereinafter *Freeport I*].

[10] On August 7, 2013, DOE/FE conditionally authorized Lake Charles Exports to export domestically-produced LNG in a volume equivalent to 2.0 Bcf/d of natural gas for a period of 20 years. *See Lake Charles Exports, LLC*, DOE/FE Order No. 3324, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal to Non-Free Trade Agreement Nations (Aug. 7, 2013) [hereinafter *Lake Charles Exports*].

[11] On November 15, 2013, DOE/FE granted in part FLEX's second non-FTA export application, authorizing the export of LNG in a volume equivalent to 0.4 Bfd/d of natural gas. *See Freeport LNG Expansion, L.P., et al.*, DOE/FE Order No. 3357, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (Nov. 15, 2013) [hereinafter *Freeport II*].

[12] On February 11, 2014, DOE/FE conditionally authorized Cameron to export domestically-produced LNG in a volume equivalent to 1.7 Bcf/d of natural gas for a period of 20 years. *See Cameron LNG, LLC*, DOE/FE Order No. 3391, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cameron LNG Terminal in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations (May 17, 2013) [hereinafter *Cameron*].

[13] As of the date of this Order (and excluding Jordan Cove's Application), 24 applications for long-term export of LNG to non-FTA countries, in a volume of LNG equivalent to approximately 26.59 Bcf/d of natural gas, are pending before DOE/FE. The total volume of LNG at issue in the approved and pending non-FTA applications filed with DOE/FE to date, including Jordan Cove's Application, is equivalent to approximately 35.86 Bcf/d of natural gas.

[14] *See* 2012 LNG Export Study, 77 Fed. Reg. 73,627 (Dec. 11, 2012), *available at* http://energy.gov/sites/prod/files/2013/04/f0/fr_notice_two_part_study.pdf (Federal Register Notice of Availability of the LNG Export Study).

impact of two DOE/FE-prescribed levels of assumed natural gas exports (at 6 Bcf/d and 12 Bcf/d) under numerous scenarios and cases based on projections from EIA's 2011 *Annual Energy Outlook* (AEO 2011), the most recent EIA projections available at the time.[15] The scenarios and cases examined by EIA included a variety of supply, demand, and price outlooks. EIA published its study, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, in January 2012.[16] Second, in October 2011, DOE contracted with NERA to incorporate the forthcoming EIA case study output from the NEMS model into NERA's general equilibrium model of the U.S. economy. NERA analyzed the potential macroeconomic impacts of LNG exports under a range of global natural gas supply and demand scenarios, including scenarios with unlimited LNG exports. DOE published the NERA Study, *Macroeconomic Impacts of LNG Exports from the United States*, in December 2012.[17]

On December 11, 2012, DOE/FE published a Notice of Availability (NOA) of the EIA and NERA studies (collectively, the 2012 LNG Export Study or Study).[18] DOE/FE invited public comment on the Study, and stated that its disposition of the present case and 14 other LNG export applications then pending would be informed by the Study and the comments received in response thereto.[19] The NOA required initial comments by January 24, 2013, and reply comments between January 25 and February 25, 2013.[20] DOE/FE received over 188,000 initial comments and over

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[15] The Annual Energy Outlook (AEO) presents long-term projections of energy supply, demand, and prices. It is based on results from EIA's NEMS model. *See* discussion of the AEO projections at Section VIII.A *infra*.
[16] *See* LNG Export Study – Related Documents, *available at* http://energy.gov/fe/downloads/lng-export-study-related-documents (EIA Analysis (Study - Part 1)).
[17] *See id*. (NERA Economic Consulting Analysis (Study - Part 2)).
[18] 77 Fed. Reg. at 73,627.
[19] *Id*. at 73,628.
[20] *Id.* at 73,627. On January 28, 2013, DOE issued a Procedural Order accepting for filing any initial comments that had been received as of 11:59 p.m., Eastern time, on January 27, 2013.

2,700 reply comments, of which approximately 800 were unique.[21] The comments also included 11 economic studies prepared by commenters or organizations under contract to commenters.

The public comments represent a diverse range of interests and perspectives, including those of federal, state, and local political leaders; large public companies; public interest organizations; academia; industry associations; foreign interests; and thousands of U.S. citizens. While the majority of comments are short letters expressing support or opposition to the LNG Export Study or to LNG exports in general, others contained detailed statements of differing points of views. The comments were posted on the DOE/FE website and entered into the public records of the 15 LNG export proceedings identified in the NOA, including the present proceeding.[22] As discussed below, DOE/FE has carefully examined the comments and has considered them in its review of Jordan Cove's Application. Additional details about Jordan Cove, the liquefaction project, and the requested export authorization are discussed below.

II. SUMMARY OF FINDINGS AND CONCLUSIONS

Based on a review of the complete record and for the reasons set forth below, DOE/FE has concluded that the opponents of the Jordan Cove Application have not demonstrated that the requested authorization will be inconsistent with the public interest and finds that the exports proposed in this Application are likely to yield net economic benefits to the United States. DOE/FE further finds that Jordan Cove's proposed exports should be conditionally authorized at a volumetric rate not to exceed the capacity of the facilities to be used in the proposed export

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[21] Because many comments were nearly identical form letters, DOE/FE organized the initial comments into 399 docket entries, and the reply comments into 375 entries. *See* http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/export_study_initial_comments.html (Initial Comments – LNG Export Study) & http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/export_study_reply_comments.html (Reply Comments – LNG Export Study).

[22] *See* 77 Fed. Reg. at 73,629 & n.4.

operations and subject to satisfactory completion of environmental review and other terms and conditions discussed below.

III. PUBLIC INTEREST STANDARD

Section 3(a) of the NGA sets forth the standard for review of Jordan Cove's Application:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy[23]] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.

15 U.S.C. § 717b(a). This provision creates a rebuttable presumption that a proposed export of natural gas is in the public interest. DOE/FE must grant such an application unless opponents of the application overcome that presumption by making an affirmative showing of inconsistency with the public interest.[24]

While section 3(a) establishes a broad public interest standard and a presumption favoring export authorizations, the statute does not define "public interest" or identify criteria that must be considered. In prior decisions, however, DOE/FE has identified a range of factors that it evaluates when reviewing an application for export authorization. These factors include economic impacts, international impacts, security of natural gas supply, and environmental

[23] The Secretary's authority was established by the Department of Energy Organization Act, 42 U.S.C. § 7172, which transferred jurisdiction over imports and export authorizations from the Federal Power Commission to the Secretary of Energy.

[24] *See, e.g.*, *Sabine Pass*, Order No. 2961, at 28; *Phillips Alaska Natural Gas Corp. & Marathon Oil Co.*, DOE/FE Order No. 1473, Order Extending Authorization to Export Liquefied Natural Gas from Alaska, at 13 (April 2, 1999), citing *Panhandle Producers & Royalty Owners Ass'n v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987).

impacts, among others. To conduct this review, DOE/FE looks to record evidence developed in the application proceeding.[25]

DOE/FE's prior decisions have also looked to certain principles established in its 1984 Policy Guidelines.[26] The goals of the Policy Guidelines are to minimize federal control and involvement in energy markets and to promote a balanced and mixed energy resource system. The Guidelines provide that:

> The market, not government, should determine the price and other contract terms of imported [or exported] natural gas …. The federal government's primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market.[27]

While nominally applicable to natural gas import cases, DOE/FE subsequently held in Order No. 1473 that the same policies should be applied to natural gas export applications.[28]

In Order No. 1473, DOE/FE stated that it was guided by DOE Delegation Order No. 0204-111. That delegation order, which authorized the Administrator of the Economic Regulatory Administration to exercise the agency's review authority under NGA section 3, directed the Administrator to regulate exports "based on a consideration of the domestic need for the gas to be exported and such other matters as the Administrator finds in the circumstances of a

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[25] *See, e.g.*, *Sabine Pass*, DOE/FE Order No. 2961, at 28-42 (reviewing record evidence in issuing conditional authorization); *Freeport LNG*, DOE/FE Order No. 3282, at 109-14 (discussing same); and *Lake Charles Exports*, DOE/FE Order No. 3324, at 121-27.
[26] New Policy Guidelines and Delegations Order Relating to Regulation of Imported Natural Gas, 49 Fed. Reg. 6684 (Feb. 22, 1984) [hereinafter 1984 Policy Guidelines].
[27] *Id*. at 6685.
[28] *Phillips Alaska Natural Gas*, DOE/FE Order No. 1473, at 14, citing *Yukon Pacific Corp.*, DOE/FE Order No. 350, Order Granting Authorization to Export Liquefied Natural Gas from Alaska, 1 FE ¶ 70,259, at 71,128 (1989).

particular case to be appropriate."[29] In February 1989, the Assistant Secretary for Fossil Energy assumed the delegated responsibilities of the Administrator of ERA.[30]

Although DOE Delegation Order No. 0204-111 is no longer in effect, DOE/FE's review of export applications has continued to focus on: (i) the domestic need for the natural gas proposed to be exported, (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies, (iii) whether the arrangement is consistent with DOE/FE's policy of promoting market competition, and (iv) any other factors bearing on the public interest described herein.

IV. DESCRIPTION OF REQUEST

Jordan Cove requests authorization to export as LNG natural gas produced in the United States and natural gas produced in Canada and imported into the United States. Jordan Cove has applied for long-term, multi-contract authorization to export this LNG by vessel to non-FTA nations. Jordan Cove seeks authorization to export up to the equivalent of approximately 292 Bcf/yr (0.8 Bcf/d), or approximately six mtpa of LNG, for a 25-year period. The exports would originate from a proposed liquefaction and LNG export Terminal in Coos Bay, Oregon. Jordan Cove is requesting this authorization to export LNG on its own behalf or as an agent for other entities who hold title to LNG, after registering each such entity with DOE/FE. Jordan Cove requests that the authorization commence on the date of first export, with such first export to occur no later than seven years following the grant of the authorization requested. Jordan Cove states that the requested term ties directly to the need for Jordan Cove and its customers to enter into sufficiently long-term contracts both to meet its customers' needs and to

[29] DOE Delegation Order No. 0204-111, at 1; *see also* 49 Fed. Reg. at 6690.
[30] *See* Applications for Authorization to Construct, Operate, or Modify Facilities Used for the Export or Import of Natural Gas, 62 Fed. Reg. 30,435, 30,437 n.15 (June 4, 1997) (citing DOE Delegation Order No. 0204-127, 54 Fed. Reg. 11,436 (Mar. 20, 1989)).

finance the construction and operation of its liquefaction project.

A. Background

1. Description of Applicant and Facility

Jordan Cove states that it is a Delaware limited partnership authorized to do business in the State of Oregon and that its principal place of business is Coos Bay, Oregon. Jordan Cove further states that its general partner is Jordan Cove Energy Project L.L.C., a Delaware limited liability company, and that both Jordan Cove and its general partner are owned by two limited partners.

The Application states that the first limited partner is Fort Chicago LNG II U.S.L.P., a Delaware limited partnership. Subsequently, in a different proceeding, DOE/FE was informed that Fort Chicago's name was changed to Jordan Cove LNG L.P. (JCLNG) as of August 19, 2013.[31] JCLNG owns seventy-five percent of Jordan Cove. JCLNG is wholly owned and controlled, indirectly, by Veresen, Inc., a Canadian corporation based in Calgary, Alberta. Jordan Cove's second limited partner is Energy Projects Development L.L.C., a Colorado limited liability company, which owns twenty-five percent of Jordan Cove. Jordan Cove states that Energy Projects Development is owned by various private individuals, all of whom are U.S. citizens.

In 2009, the Federal Energy Regulatory Commission (FERC) authorized Jordan Cove to construct a facility to receive imports of LNG for regasification[32] at the Terminal site, but FERC subsequently vacated that authorization when it became clear that Jordan Cove intended

[31] *See* Jordan Cove LNG L.P., Application for Long-Term Authorization to Import Natural Gas from Canada, DOE/FE Docket No. 13-141-000 (Oct. 21, 2013).

[32] Jordan Cove's construction and operation of an LNG import terminal at this location was authorized by FERC in Pacific Connector Gas Pipeline, LP; Jordan Cove Energy Project, L.P., 129 FERC ¶ 61,234 (2009), reh. granted in part, 139 FERC ¶ 61,040 (2012).

to use the Terminal for exports of LNG rather than imports.[33] Jordan Cove subsequently applied to FERC to construct and operate an LNG liquefaction export facility at the same site. That application is currently pending FERC review.[34]

2. Procedural History

As noted above, in DOE/FE Order No. 3041 issued on December 7, 2011, DOE/FE authorized Jordan Cove to export LNG by vessel to FTA countries in a volume equivalent to approximately 438 Bcf/yr of natural gas (1.2 Bcf/d) for a 30-year term. Jordan Cove states in its current Application that the proposed export volume in this proceeding is not additive to its export volume authorized in that FTA order.

On October 21, 2013, JCLNG (Jordan Cove's parent company) submitted an application to DOE/FE for a long-term authorization to import natural gas by pipeline from Canada in a volume of 565.75 Bcf/yr for a 25-year term, commencing on the earlier of the date of first export or the date ten years from the date the requested authorization is granted.

This import application referred also to a September 9, 2013 application by JCLNG for export authorization made to Canada's National Energy Board (NEB). The import application characterized the NEB export application as its twin application, and stated that, if granted, they would afford access to Canadian natural gas supplies for the proposed Jordan Cove LNG Terminal. On February 20, 2014, the NEB issued a Letter Decision in File OF-EI-Gas-GL-J705-2013-01 01 granting JCLNG's application for a License to export natural gas to the United

[33] On rehearing of the order authorizing siting, construction, and operation of an import terminal at Coos Bay, FERC vacated the previous authorizations without prejudice to Jordan Cove prosecuting an application for authorization to site, construct, and operate an LNG export terminal. 139 FERC ¶61,040 (2012).

[34] Following a pre-filing proceeding in FERC Docket No. PF12-7-000, Jordan Cove submitted the application for FERC authorization of the export Terminal on May 21, 2013, in FERC Docket No. CP13-483-000. Jordan Cove formally notified DOE/FE of these developments by letter received on May 22, 2013.

States. On March 18, 2014, in DOE/FE Order No. 3412, DOE/FE granted JCLNG's application to import a like volume of natural gas into the United States for delivery to the Terminal.[35]

B. Liquefaction Project

In the Application, Jordan Cove states that the Terminal will be located on the North Spit of Coos Bay in Coos County, Oregon. Jordan Cove intends to modify the previously authorized import facilities in order to adapt the Terminal for export operations. According to Jordan Cove, the modified facilities that will be used for exports include two 160 cubic meter LNG full-containment storage tanks, a single marine berth capable of accommodating LNG vessels up to Q-flex size, and on-site utilities and services. Jordan Cove's plans also include large diameter LNG piping configured for exports and electrically driven liquefaction equipment. The proposed Terminal facilities will have the capability to allow export of six mtpa. Jordan Cove accordingly proposes to construct four natural gas liquefaction trains, each with the export capacity of 1.5 mtpa. Approximately 90 LNG carriers per year will be required to transport the LNG to locations in the United States and around the world.[36] A complete description of the proposed terminal facilities is contained in the application currently pending before FERC in Docket No. CP13-483-000 for authority to site, construct, and operate an LNG export terminal. Once the Terminal facilities are placed in service, Jordan Cove plans to have natural gas delivered to the Terminal through a proposed natural gas pipeline, the Pacific Connector Gas Pipeline (PCGP), described below.

[35] *Jordan Cove LNG, L.P.*, DOE/FE Order 3412, Order Granting Long-Term Multi-Contract Authorization to Import Natural Gas From Canada to the Proposed Jordan Cove LNG Terminal in the Port of Coos Bay, Oregon (Mar. 18, 2014).
[36] Resource Report 4, dated May 2013, at page 4-1, in FERC Docket No. CP13-483-000.

C. Business Model

Jordan Cove requests authorization to export LNG on its own behalf or as agent for others pursuant to one or more long-term agreements that do not exceed the term of the requested authorization. Jordan Cove plans to execute commercial arrangements in the form of Liquefaction Tolling Agreements (LTAs), under which an individual customer that holds title to natural gas will have the right to deliver that gas to Jordan Cove's Terminal for liquefaction services and to receive LNG in exchange for a processing fee paid to Jordan Cove.

Jordan Cove states that it will file, or cause others to file, under seal executed contracts associated with the long-term supply of natural gas to, or the long-term export of LNG from, the Jordan Cove Terminal, including LTAs, within 30 days of their execution.

Under Jordan Cove's LTA business model, the decision whether to utilize liquefaction capacity will be made by the LTA customer. Thus, according to Jordan Cove, if the marginal cost of producing or purchasing natural gas, liquefying it, and transporting the resulting LNG to a destination market is higher than another competing source of supply in any month, the LTA customer may forego its nomination rights for that month.

The Application states that, when any such agreement is executed and transaction specific information required under 10 C.F.R. § 590.202(b) becomes available, Jordan Cove will comply with that provision. Further, Jordan Cove states that it is prepared to accept conditions on its authorization consistent with the conditions imposed in recent DOE/FE orders, including requirements applicable when the title holder to the LNG at the point of export is not Jordan Cove.

Specifically, Jordan Cove states that it will include in any LTA (or any other contract made by Jordan Cove for the sale or transfer of LNG exported under its authorization) the requisite contract provision by which the customer commits to: (1) resell or transfer the LNG for delivery only to authorized countries or to purchasers that have agreed to so limit their direct or indirect resale or transfer; (2) cause the provision of a report to Jordan Cove that identifies the country of destination for actual deliveries; and (3) include in any resale contract conditions to insure that Jordan Cove is made aware of all actual destination countries.

Further, when Jordan Cove uses its authorization to export LNG on behalf of or as agent for any other title holder at the point of export, Jordan Cove states that it will register or ensure the registration of such title holder. The registration will include the registrant's acknowledgement and agreement to supply Jordan Cove with all necessary information and copies of contracts, including the registrant's agreement to: (1) comply with the requirements of Jordan Cove's authorization and DOE's regulations; (2) include in any of its contracts the requisite contract provision described above; and (3) file with DOE/FE under seal within 30 days of their execution (or supply to Jordan Cove for such filing) executed contracts associated with the long-term supply of natural gas to, or the long-term export of LNG from, the Jordan Cove Terminal.

D. Source of Natural Gas

Jordan Cove requests authorization to export LNG from natural gas produced in the United States and natural gas produced in Canada and imported into the United States. Jordan Cove proposes to transport natural gas by pipeline to the Terminal over the PCGP, which is currently pending review by the FERC in Docket No. CP13-492-000.[37] As planned, the PCGP will consist of a 234-mile-long, 36-inch-diameter natural gas pipeline extending from the outlet of the Jordan Cove LNG Terminal to a point near Malin, in Klamath County, Oregon, on the

[37] The FERC issued a certificate of public convenience and necessity for construction of the PCGP under section 7 of the NGA when it authorized the siting, construction, and operation of Jordan Cove's import terminal. 129 FERC ¶ 61,234 (2009). However, when the FERC vacated the authorization for the import terminal, it also vacated the certificate for the PCGP. 139 FERC ¶ 61,040 (2012). The proposal for the PCGP has been renewed in FERC Docket No. CP13-492-000.

Oregon/California border. Jordan Cove proposes that the PCGP will connect to the Northwest United States market hub at Malin, thereby providing access to gas supplies in both the United States and Canada.

Jordan Cove expects the PCGP to interconnect at the Malin Hub with: (i) the Gas Transmission Northwest Pipeline, which delivers gas from western Canada, and delivers gas from the U.S. Rockies via its Stanfield interconnection; (ii) the Ruby Pipeline, which delivers gas from western Wyoming, northwestern Colorado, and northern Utah; and (iii) PG&E Redwood Path, serving northern California. In sum, Jordan Cove states that the LNG to be exported from its Terminal is likely to be sourced from Canadian and U.S. Rocky Mountain supply basins.

E. Environmental Review

FERC is responsible for ensuring that the siting, construction, and operation of LNG facilities are consistent with the public interest under section 3 of the NGA. FERC is also the lead agency for purposes of review of the Jordan Cove Terminal under the National Environmental Policy Act of 1969 (NEPA). DOE/FE is participating in that environmental review as a cooperating agency.

Jordan Cove requests that DOE/FE issue a conditional order approving its export authorization pending satisfactory completion of the environmental review and approval of the Terminal. DOE/FE's regulations[38] and precedent[39] support such an approach, and we find good cause for granting Jordan Cove's request for a conditional order. Accordingly, this conditional

[38] 10 C.F.R. § 590.402 (authorizing the Assistant Secretary to "issue a conditional order at any time during a proceeding prior to issuance of a final opinion and order").

[39] *See*, *e.g.*, *Sabine Pass*, Order No. 2961, at 40-41, 43 (Ordering Paragraph F); *Freeport LNG*, Order No. 3282, at 120-21, 123 (Ordering Paragraph F); and *Lake Charles Exports*, Order No. 3324 at 15-16, 135-36 (Ordering Paragraph F).

Order makes preliminary findings on all issues except the environmental issues in this proceeding.

DOE/FE is attaching a condition to this export authorization ordering that Jordan Cove's authorization is contingent on both its satisfactory completion of the environmental review process and its on-going compliance with any and all preventative and mitigating measures imposed at the Jordan Cove Terminal by federal or state agencies. When the environmental review is complete, DOE/FE will reconsider this conditional authorization in light of the information gathered as part of that review.

V. APPLICANT'S PUBLIC INTEREST ANALYSIS

Jordan Cove states that its Application is wholly consistent with the public interest standard, as applied by DOE/FE in prior decisions. In this regard, Jordan Cove refers to DOE/FE's "longstanding position that 'Section 3(a) creates a rebuttable presumption that a proposed export of natural gas is in the public interest, and DOE must grant such an application unless those who oppose the application overcome that presumption by mak[ing] an affirmative showing of inconsistency with the public interest.'"[40] Jordan Cove refers also to DOE's 1984 Policy Guidelines which indicate that the agency's primary responsibility in authorizing exports will be "to evaluate the need for the gas and whether the [export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market."[41]

Jordan Cove maintains that its Application promotes the goals set forth in the 1984 Policy Guidelines because its export proposal is a market-driven response to the availability of abundant

[40] Application at 7 (citing *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, FE Docket No. 10-111-LNG (May 20, 2011)).
[41] *Id.* at 7-8 (citing Policy Guidelines and Delegation Orders Relating to the Regulation of Imported Natural Gas, 49 Fed. Reg. 6684 (Feb. 22, 1984) (DOE Policy Guidelines)).

domestic supply and rising international demand for natural gas. Additionally, Jordan Cove contends that granting its Application will serve the public interest in multiple other ways:

> It will permit exports when competitive and otherwise promote healthy domestic and international natural gas markets. Jordan Cove exports will not pose any threat to the security of domestic natural gas supplies. To the contrary, they will result in significant economic benefits. The demand created by the exports will stimulate increased revenues and jobs in upstream industries, which in turn will benefit the overall U.S. economy. The construction and operation of the Jordan Cove Project will also create jobs and produce revenues to the benefit of the local and regional economies. And, Jordan Cove exports will have positive international trade impacts for the United States. In sum, the Jordan Cove Project's economic benefits advance the Administration's efforts to expand exports, create jobs and otherwise stimulate the beleaguered U.S. economy.[42]

To demonstrate these claimed public interest benefits, Jordan Cove appended six studies to its Application:

(1) *Jordan Cove LNG Export Project Market Analysis Study* (Jan. 2012) by Navigant Consulting, Inc., analyzing gas supply and demand outlooks and modeling potential price effects of the proposed exports for the North American natural gas market to 2045 (Navigant Study);

(2) *Whitepaper: Analysis of the EIA Export Report 'Effect of Increased Natural Gas Exports on Domestic Energy Markets,' Dated January 19, 2012* (Feb. 2012), by Navigant Consulting, Inc. on the EIA Report (Navigant Whitepaper);

(3) *An Economic Impact Analysis of the Construction of an LNG Terminal and Natural Gas Pipeline in Oregon* (Mar. 6, 2012) by ECONorthwest, examining impacts on the states of Oregon and Washington of the construction of the Jordan Cove Project (Construction Study);

(4) *An Economic Impact Analysis of Jordan Cove LNG Terminal and Pacific Connector Gas Pipeline Operations* (Mar. 23, 2012) by ECONorthwest, examining impacts on the local communities of the operations of the Jordan Cove Project (Operations Study);

(5) *Upstream Economic Contributions of the Jordan Cove Energy Project* (Feb. 29, 2012) by ECONorthwest, quantifying direct and indirect contributions of the Jordan Cove Project to the United States economy (Upstream Contributions Study); and

(6) *Effect of the Jordan Cove Energy Project's LNG Exports on United States*

[42] *Id.* at 9.

> *Balance of Trade* (Mar. 20, 2012) by ECONorthwest, analyzing the impact of the Jordan Cove Project on the nation's balance of trade (Balance of Trade Study).

Below, we discuss these studies in more detail.

A. Domestic Natural Gas Supplies

Jordan Cove asserts that ample natural gas supplies exist to serve this country's domestic gas needs and the proposed LNG exports by Jordan Cove and other exporters. According to Jordan Cove, this claim is supported by the Navigant Study, which identifies shale gas production growth as the biggest contributor to overall gas supply abundance. The consequence, Jordan Cove states, are a 28 percent increase in U.S. total gas production from 2005 (49.7 Bcf per day (Bcf/d)) to 2011 (63.6 Bcf/d) and significantly increased estimates of shale gas resources. Jordan Cove states that Navigant's 2008 study estimated U.S. shale gas and total gas reserves at 842 trillion cubic feet (Tcf) and 2247 Tcf, respectively, not far from the EIA's AEO 2011 estimates of 827 Tcf and 2543 Tcf. Jordan Cove maintains that these reserves constitute sufficient supply at current usage rates for 94 to more than 100 years, well beyond the terms of the proposed export authorizations.

Especially in its initial years, Jordan Cove intends to draw significantly on Canadian as opposed to U.S. natural gas supplies for its export volumes. The Navigant Study, according to Jordan Cove, refers to recent estimates by the British Columbia Ministry of Energy and Mines and the National Energy Board of Canada showing that the marketable gas in place in the Horn River Basin alone is between 61 and 96 Tcf, with total gas in place estimated at 372 Tcf. Jordan Cove states that the other major shale basin in British Columbia, the Montney, is estimated to contain 65 Tcf of recoverable resources and other recent estimates of these resources are even higher and point to a resource base with a reserve life of 350 to 1,000 years based upon current total demand in British Columbia of one Bcf of gas per day.

Jordan Cove maintains that gas reserves and gas production are likely to continue to rise and that North America is in the early phases of discovery of natural gas resources. Based on the Navigant Study, Jordan Cove states that it expects this trend towards a larger resource base will continue in the near term in both the United States and Canada and that gas production will continue to grow steadily throughout the Navigant Study's forecast period to 2045. Jordan Cove further states that Navigant's Spring 2011 Reference Case projects U.S. dry gas production to grow to 81.6 Bcf/d by 2045 and that production could go higher in response to demand from proposed LNG liquefaction facilities and/or independent increases in the robust supply resource base. Jordan Cove adds that the Navigant Study shows that this growth potential is enhanced by the fact that the reduced geologic risk and resulting reliability of shale gas discovery and production makes it responsive to demand and by the fact that the presence of natural gas liquids (NGLs) in some shale formations adds an incentive for development.

B. Domestic Natural Gas Demand

Jordan Cove states that the Navigant Study projects steady growth in natural gas demand, led by electric generation demand, with modest contributions from industrial, residential, commercial and vehicle demand. The Navigant Study, according to Jordan Cove, also projects that natural gas will remain competitive with oil and other fuels. Jordan Cove also states that the Navigant Study concludes that, even as that domestic demand is projected to grow throughout the forecast period to 2045, North American gas resources are adequate to satisfy domestic demand as well as the added demand of the LNG exports proposed by Jordan Cove, even when other LNG exports are also assumed.

C. Impact of the Proposed Exports on Domestic Prices of Natural Gas

Jordan Cove asserts that its proposed exports will have a minimal impact on natural gas prices. In support of its position, Jordan Cove refers to four scenarios used in the Navigant Study:

(1) The Jordan Cove Reference Case, which draws on Navigant's Spring 2011 Reference Case extended to 2045, and assumes that the Louisiana Sabine Pass and the British Columbia Kitimat LNG export facilities will be operational;

(2) The Jordan Cove Export Case, which assumes exports of 0.9 Bcf/d beginning in 2017 (based on a projected export capacity at the Terminal of 0.9 Bcf/d);[43]

(3) The Aggregate Export Case, which adds to the Jordan Cove Export Case generic LNG export capacity of 2.0 Bcf/d in the Gulf and 1.0 Bcf/d on the U.S. Eastern seaboard, for a total of 6.6 Bcf/d of North American LNG export capacity; and

(4) The GHG Demand Case, which further increases demand using figures from Navigant's Spring 2011 Carbon Case Forecast, reflecting a high rate of coal to gas substitution driven by assumed laws and regulations aimed at lowering greenhouse gas (GHG) impacts.

Jordan Cove states that Navigant projected price impacts for the forecast period under each of the above scenarios at three locations: Henry Hub; Sumas (the United States-Canadian border point that provides a proxy for prices paid in the population centers of the Pacific Northwest (Seattle and Portland)); and Malin (the California-Oregon border point at which gas volumes will enter PCGP for transport to the Jordan Cove facility).

According to Jordan Cove, the price impacts under all of these scenarios and locations are negligible in the national market and minimal in the Pacific Northwest market. In particular:

- Prices do not vary by more than 4 cents from those in the Reference Case.
- Sumas prices are essentially flat in 2025 and 2035 and are only 3.9% higher in 2045; Malin prices are higher by 2.1, 3.1, and 7.2 percent respectively at each interval.
- Jordan Cove Export Case prices and Aggregate Export Case prices at all three locations are below $8.00 until the end of the forecast period in 2045.

[43] *See* Jordan Cove App. at 13 & Navigant Market Analysis Study at 29.

- Comparing the projected prices under the Aggregate Export Case to the Jordan Cove Export Case, the price increases are larger in 2025 (ranging from 4.9% at Malin to 6.7% at Henry Hub), which reflects the concurrent addition of the other assumed LNG export facilities, but these increases moderate as the market recalibrates (at Henry Hub decreasing from 4.3% in 2035 to 3.0% in 2045 and at both Sumas and Malin decreasing from 3.8% in 2035 to 3.4% in 2045).

- The projected incremental price increases are less moderate in the GHG Demand Case, ranging from 13.6% to 20.6% over the Aggregate Export Case prices at 2025, 2035, and 2045, but these are due to policy-driven growth in demand.

Jordan Cove additionally contends that the price outputs in all scenarios in the Navigant Study would have been lower had Navigant not been as conservative as it was in its modeling assumptions. In particular, Jordan Cove states, Navigant assumed that there will be no new gas supply basins; the empirical production data used by Navigant does not reflect the rapid ramp-up in development; no unannounced pipeline and storage infrastructure projects are assumed; and a high 90 percent load factor for export facilities is assumed.

In response to the EIA Study, Jordan Cove commissioned the Navigant Whitepaper. According to Jordan Cove, the Navigant Whitepaper explains:

> The high price outputs projected in parts of the EIA Study – in particular, a 54% gas price increase in 2018 – result 'from mixing a baseline case and an export scenario [low supply and high exports] that, by their very nature, do not represent a realistic real-world scenario' and points out that the EIA Report effectively acknowledged as much. Moreover, the 54% figure is only a maximum single-year metric out of line with the average price changes that more accurately measure sustained impact.[44]

Jordan Cove further states that the Navigant Whitepaper found that the price impact of the High Shale EUR baseline case and the low/slow export scenario is the "least unrealistic" scenario reviewed by EIA. That scenario, Jordan Cove asserts, results in a maximum-year price increase 74% lower than the quoted 54% figure. Yet even that price increase is likely overstated in Jordan Cove's view because

[44] Jordan Cove App. at 16 (quoting Navigant Whitepaper at 6).

- EIA's low export scenario of 6 Bcf/d is high; by comparison, the Navigant Study assumed an export level of 5.9 Bcf/d, which was designed as a "high end figure."

- Even though EIA's High Shale EUR baseline case was intended to be the high supply alternative, it understated actual production levels in the U.S. in March of 2011, and was about 19% below actual levels at the end of the year.

- AEO projections historically have understated shale gas production.

- Because the EIA Report only examines exports to be made from Gulf Coast projects, and does not include an East Coast project, it is bound to intensify the price impacts.

Jordan Cove submits that EIA's Low Shale EUR case should not be relied upon because its forecast is much lower than the AEO 2011 Reference Case forecast and is clearly out of line with current developments. Also, Jordan Cove contends that even the High Shale EUR case is problematic because its forecast, while higher than the AEO 2011 Reference Case forecast, was appreciably lower than the conservative forecast in the Navigant Study.

Moreover, Jordan Cove maintains that the EIA Report is not pertinent to the Jordan Cove Project since the EIA Report focuses only on exports from Gulf Coast projects whereas the Jordan Cove proposal involves the exportation of U.S. West Coast gas sourced from Canada and the U.S. Rockies, with Canadian gas constituting the more significant portion initially. On the other hand, Jordan Cove points out that the Navigant Study examines exports from the U.S. Pacific, Atlantic, and Gulf coasts, as well as from British Columbia in Canada, and therefore is the more relevant and accurate measure of the price impacts of the proposed Jordan Cove exports.

D. Impact of LNG Exports on Natural Gas Markets

Jordan Cove states that LNG exports in general and its proposed exports in particular will have a beneficial impact on natural gas markets. According to Jordan Cove, this will come about because exports will direct gas to new markets and this will support increased production of natural gas from shale formations with the consequence of reduced price volatility.

E. Local, Regional, and National Economic Benefits

Jordan Cove states that the Construction Study measures the economic impact of its proposal, including both the Terminal and the PGCP, on the Oregon and Washington economies during the years 2014 through 2017. After excluding costs such as real estate payments that are not typically sources of construction output, Jordan Cove states that the remaining direct construction costs for these projects, measured in 2011 dollars, will be $4.494 billion. Jordan Cove further states that this figure is a measure of the direct economic impact of the undertaking and $1.366 billion of this amount will be spent in the two study area states.

Based on IMPLAN economic modeling software, Jordan Cove states that the indirect impact on economic output in Oregon and Washington over the four-year construction period will be approximately $1.17 billion and that the induced output over the same period, arising primarily from household spending by workers will be $973.5 million. Further, measuring the net value of, or value added by, proposed construction, Jordan Cove states that the Construction Study estimates an increase in the regional gross domestic product (GDP) of $1.738 billion in total for 2014-2017, or an average of $434.6 million a year.

Jordan Cove maintains that the jobs impact also will be consequential. On average, according to Jordan Cove, implementation of the proposal will employ 1,768 workers a year, and will create 1,530 indirect and 1,838 induced jobs a year. In addition, Jordan Cove maintains that the labor income from the direct and secondary employment associated with the project will average $182.6 million and $147.4 million a year, respectively, and will total $330 million a year. Over the projected 2014-2017 construction period, Jordan Cove asserts that the total contribution to labor income from all associated jobs will exceed $1.3 billion.

Jordan Cove also states that there will be continuing economic benefits to the local economy in Coos County after liquefaction and export operations commence in 2017. According to Jordan Cove, the Operations Study measured these benefits in 2018 because that year will be representative of a typical operating year according to Jordan Cove. Jordan Cove states that the source of the impacts will be spending for various payrolls and for contributions (in lieu of property taxes) towards education and urban renewal.

Jordan Cove maintains that these impacts will include 99 direct jobs at the Terminal and the PCGP, 51 indirect jobs paid by Jordan Cove (Sheriff's deputies, firefighters, tugboat crews and emergency planners), 404 other indirect jobs, and 182 induced jobs for a total of 736 jobs in Coos County. The total labor income impact in the typical operating year is projected at $32.9 million.

The direct GDP impact of the LNG Terminal is projected at $1.29 billion. The portion of the GDP impact of the PCGP attributed to Coos County is projected to be $35 million. The net increase in the GDP of Coos County after the indirect and induced impacts are included is projected at $1.36 billion. Jordan Cove states that the projected GDP impact, which is in line with size of the project, will be of extraordinary importance to Coos County, where the GDP in 2010 was $1.74 billion.

Jordan Cove states that this impact analysis reflects the downstream impacts of annual contributions by Jordan Cove in the amount of $20 million for public K-12 education and $10 million for projects of the Bay Area Urban Renewal Association. Jordan Cove further states that the downstream impact analysis does not include the property taxes to be paid by the PCGP, but it does calculate them. According to Jordan Cove, the PCGP will contribute property taxes of $2.4 million to Coos County and $8.8 million to the three other counties along its route.

In addition to the above benefits, Jordan Cove maintains, based on the Upstream Contributions Study, that the project will open new markets for natural gas and new demand for gas in turn will benefit upstream industries. Jordan Cove identifies direct economic contributions to four domestic industries, including interstate natural gas pipeline transportation, natural gas extraction, natural gas exploration and development (E&D), and state and local government activities attributable to state gas severance taxes. These direct impacts are calculated in terms of the value of each industry's economic output over what it would have been without the exports. IMPLAN economic modeling is used also to calculate domestic secondary economic impacts, both indirect and induced. In summary, Jordan Cove states that the Upstream Contributions Study shows that the demand on upstream industries from the Jordan Cove exports will contribute an average of $3.9 billion in direct, indirect, and induced annual outputs and will create an annual average of 20,359 new jobs.

F. Balance of Trade

Jordan Cove states that its proposal will advance the Administration's agenda to boost exports. Based on the Balance of Trade Study, Jordan Cove asserts that the overall impact of the project will be a net improvement in the balance of trade for the United States. While the importation of gas from Canada for export from the Jordan Cove Terminal will have a negative balance of trade impact, Jordan Cove states that this negative impact will be offset by the value of the LNG exports and by the value of the increased exports of the NGLs that will be a byproduct of the increased domestic gas production. The Balance of Trade Study, according to Jordan Cove, shows that, as the proportion of domestic gas used for Jordan Cove LNG exports grows through the study period, the improvement in the balance of trade will increase from $2.1 billion in 2020 to $4.9 billion in 2045.

G. International Benefits

Jordan Cove maintains that there are several "difficult to quantify" international benefits that will be realized from a grant of its Application. These include: (1) promoting international markets and development of additional resources, both domestically and internationally; (2) enabling overseas generators to switch from oil or coal to cleaner natural gas with its environmental benefits; (3) assisting countries with limited resources to broaden and diversify their supply base, which will contribute to transparency, efficiency, and liquidity of international natural gas markets; (4) encouraging liberalized trade and greater diversification of global supplies; and (5) decoupling international natural gas prices from oil prices, thereby leading to lower natural gas prices.

H. Additional Considerations

Jordan Cove identifies several additional considerations in support of a grant of its Application:

- As a terminal on the West Coast of the United States, the Jordan Cove facility is uniquely positioned to source its natural gas from Canadian and U.S. Rockies supply basins and to serve Asian demand without the longer routes necessary from the Gulf Coast.
- Given North America's enormous shale gas resources and the Asian demand for its production, there is little doubt that Pacific Northwest LNG export facilities will be built. British Columbia is actively promoting export terminals on the Canadian West Coast and has committed to having its first LNG plant up and running by 2015, with a total of three LNG facilities operating by 2020. The proposed Jordan Cove Terminal represents a fungible substitute for a British Columbia export terminal that will bring distinct advantages to the United States beginning with the economic benefits already set forth of creating U.S. infrastructure and expanding U.S. trade. In addition, building the Jordan Cove Terminal and the

PCGP will draw Canadian gas southwards, creating an additional pathway for Canadian supplies to the U.S. Pacific Northwest. If, in the future, U.S. demand grows and U.S. natural gas prices moves higher, Canadian producers will be able to utilize that new pathway to supply the U.S. market. The advantage to the United States will be the dampening price effect of these incremental Canadian supplies.

- The Jordan Cove Terminal could provide access to LNG for the isolated markets in Hawaii (where consumers pay high prices for electricity generated using primarily fuel oil and coal) and the Cook Inlet region of Alaska (where there is dwindling deliverability of natural gas). Jordan Cove states that utilities in both locales have indicated that they are looking to "piggy-back" their small demand quantities on shipments by customers with large enough base-load demand to support the construction of an LNG terminal. Jordan Cove maintains that a West Coast terminal that would offer gas at prices indexed to a North American basis would be able to serve the smaller ships appropriate to their demand quantities.

- Natural gas customers along the route of the PCGP, particularly those west of the Cascades, stand to benefit from the Jordan Cove project. Their growth in demand alone would not be sufficient to justify the investment in a pipeline like the PCGP, but they too will be able to "piggy-back" on the LNG Terminal customers whose contracts with PCGP will underpin its construction. The incremental capacity available on PCGP will bring additional natural gas supplies to their otherwise isolated market areas with beneficial price effects.

VI. LNG EXPORT STUDY

DOE/FE recognized in *Sabine Pass* that the cumulative impact of *Sabine Pass* and additional future LNG export authorizations could affect the public interest. To address this issue, DOE/FE undertook a two-part Study of the cumulative economic impact of LNG exports.

The first part of the Study was conducted by EIA and looked at the potential impact of additional natural gas exports on domestic energy consumption, production, and prices under several export scenarios prescribed by DOE/FE. The EIA Study did not evaluate macroeconomic impacts of LNG exports on the U.S. economy. The second part of the Study, performed by NERA Economic Consulting, assessed the potential macroeconomic impact of LNG exports using its energy-economy model (the "N_{ew}ERA" model). NERA built on the EIA Study requested by DOE/FE by calibrating the NERA U.S. natural gas supply model to the results of the study by EIA. The EIA Study was limited to the relationship between export levels and domestic prices without considering whether those quantities of exports could be sold at high enough world prices to support the calculated domestic prices. NERA used its Global Natural Gas Model ("GNGM") to estimate expected levels of U.S. LNG exports under several scenarios for global natural gas supply and demand. A more detailed discussion of each study follows.

A. EIA Study, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*

1. Methodology

DOE/FE asked EIA to assess how four scenarios of increased natural gas exports could affect domestic energy markets, particularly consumption, production, and prices. The four scenarios assumed LNG exports of:

- 6 Bcf/d, phased in at a rate of 1 Bcf/d per year (low/slow scenario);
- 6 Bcf/d phased in at a rate of 3 Bcf/d per year (low/rapid scenario);
- 12 Bcf/d phased in at a rate of 1 Bcf/d per year (high/slow scenario); and
- 12 Bcf/d phased in at a rate of 3 Bcf/d per year (high/rapid scenario).

According to EIA, total marketed natural gas production in 2011 was approximately 66 Bcf/d. Thus, exports of 6 Bcf/d and 12 Bcf/d represent roughly 9 percent and 18 percent of natural gas production in 2011, respectively.

DOE/FE also requested that EIA consider the above four scenarios of increased natural gas exports in the context of four cases from EIA's AEO 2011. These four cases are:

- The AEO 2011 Reference Case;
- The High Shale Estimated Ultimate Recovery (EUR) case (reflecting optimistic assumptions about domestic natural gas supply, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference Case);
- The Low Shale EUR case (reflecting pessimistic assumptions about domestic natural gas supply, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference Case); and
- The High Economic Growth case (assuming the U.S. gross domestic product will grow at an average annual rate of 3.2 percent from 2009 to 2035, compared to 2.7 percent in the Reference Case, which increases domestic energy demand).

Taken together, the four scenarios with different additional export levels imposed from the indicated baseline case (no additional exports) presented 16 case scenarios:

Table 1: Case Scenarios Considered By EIA in Analyzing Impacts of LNG Exports

	AEO 2011 Cases	**Export Scenarios**
1	AEO 2011 Reference	Low/Slow
2	AEO 2011 Reference	Low/Rapid
3	AEO 2011 Reference	High/Slow
4	AEO 2011 Reference	High/Rapid
5	High EUR	Low/Slow
6	High EUR	Low/Rapid
7	High EUR	High/Slow
8	High EUR	High/Rapid
9	Low EUR	Low/Slow
10	Low EUR	Low/Rapid
11	Low EUR	High/Slow
12	Low EUR	High/Rapid
13	High Economic Growth	Low/Slow
14	High Economic Growth	Low/Rapid
15	High Economic Growth	High/Slow

16	High Economic Growth	High/Rapid

EIA used the final AEO 2011 projections issued in April 2011 as the starting point for its analysis and applied the NEMS model. Because NEMS did not generate a projection of LNG export demand, EIA specified additional natural gas demand levels as a proxy for projected export levels consistent with the scenarios prescribed by DOE/FE.

EIA assigned these additional exports to the West South Central Census Division. This meant that EIA effectively assumed that the incremental LNG exports would be shipped out of the Gulf Coast states or Texas.

EIA also counted any additional natural gas consumed during the liquefaction process within the total additional export volumes specified in the DOE/FE scenarios. Therefore the net volumes of LNG produced for export were roughly 10 percent below the gross volumes considered in each export scenario. By way of illustration, the cases where cumulative export volumes are 6 Bcf/d, liquefaction would consume 0.6 Bcf/d and net exports of 5.4 Bcf/d.

EIA made other changes in modeled flows of gas into and out of the lower-48 United States where necessary to analyze the increased export scenarios.[45] Additionally, EIA assumed that a pipeline transporting Alaskan natural gas into the lower-48 states would not be built during the forecast period, thereby isolating the lower-48 states' supply response.

2. Scope of EIA Study

In the Preface to its Study, EIA identifies several limiting factors governing use of the Study results:

[45] U.S. natural gas exports to Canada and U.S. natural gas imports from Mexico are exogenously specified in all the AEO 2011 cases. U.S. imports of natural gas from Canada are endogenously set in the model and continue to be so for this study. However, U.S. natural gas exports to Mexico and U.S. LNG imports that are normally determined endogenously within the model were set to the levels projected in the associated AEO 2011 cases for this study. EIA Study at 2-3.

> The projections in this report are not statements of what *will* happen but of what *might* happen, given the assumptions and methodologies used. The Reference case in this report is a business-as-usual trend estimate, reflecting known technology and technological and demographic trends, and current laws and regulations. Thus, it provides a policy-neutral starting point that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes.[46]

Additionally, the EIA Study recognizes that projections of energy markets over a 25-year period are highly uncertain, and that many events—such as supply disruptions, policy changes, and technological breakthroughs—cannot be foreseen. Other acknowledged limitations on the scope of the EIA Study include:

- The NEMS model is not a world energy model, and therefore does not address the interaction between the potential for additional U.S. natural gas exports and developments in world natural gas markets;
- Global natural gas markets are not integrated, and their nature could change substantially in response to significant changes in natural gas trading patterns;
- Macroeconomic results were not included in the analysis because energy exports are not explicitly represented in the NEMS macroeconomic module; and
- The domestic focus of the NEMS model makes it unable to account for all interactions between energy prices and supply/demand in energy-intensive industries that are globally competitive.

3. Natural Gas Markets

The EIA Study recognized that natural gas markets are not integrated globally and natural gas prices span a wide range. EIA stated that the current large disparity in natural gas prices across major world regions is likely to narrow as markets become more globally integrated. However, key questions remain as to how quickly and to what extent convergence might occur.

U.S. market conditions are also variable, according to EIA, and lower or higher U.S. natural gas prices would tend to make additional exports more or less likely. EIA pointed out

[46] EIA Study at ii (emphasis in original).

that prospects for LNG exports depend greatly on the cost-competitiveness of liquefaction projects in the United States relative to those at other locations.

EIA observed that relatively high shipping costs from the United States may add a cost disadvantage compared to exporting countries closer to key markets, such as in Asia. EIA notes that LNG projects in the United States would frequently compete not just against other LNG projects, but also against pipeline projects from traditional natural gas sources or projects to develop shale gas in Asia or Europe.

4. Results of EIA Study

EIA generally found that LNG exports will lead to higher domestic natural gas prices, increased domestic natural gas production, reduced domestic natural gas consumption, and increased natural gas imports from Canada via pipeline. The impacts of exports, according to EIA, included:

- **Increased natural gas prices at the wellhead.** EIA stated that larger export levels would lead to larger domestic price increases; rapid increases in export levels would lead to large initial price increases that moderate somewhat in a few years; and slower increases in export levels would lead to more gradual price increases but eventually would produce higher average prices during the decade between 2025 and 2035.

- **Increased natural gas production and supply.** Increased exports would result in a supply response, *i.e.,* increased natural gas production that would satisfy about 60 to 70 percent of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, EIA stated that about three-quarters of this increased production would come from shale sources.

- **Decreased natural gas consumption.** Due to higher prices, EIA projects a decrease in the volume of gas consumed domestically. EIA states that the electric power sector, by switching to coal and renewable fuels, would account for the majority of this decrease but indicates that there also would be a small reduction in natural gas use in all sectors from efficiency improvements and conservation.

- **Increased end-user natural gas and electricity delivered prices.** EIA states that even while consuming less, on average, consumers will see an increase in their natural gas and electricity expenditures.

Additional details regarding these conclusions are discussed in the following sections.

5. Wellhead Price Increases

EIA projects that natural gas prices will increase in the Reference Cases even absent expansion of natural gas exports. This baseline increase in natural gas prices bears an inverse relationship to projected increases in the volumes of natural gas produced from shale resources. Thus, in the high shale EUR Reference Case, the long-term natural gas price is lower than it is in the low shale EUR case.

While EIA projected a rising baseline price of gas without exports, EIA also found that the price of gas will increase over the rising baseline when exports occur. Exports are projected to impact natural gas prices in two ways. First, the export scenarios that contained rapid growth in exports experienced large initial price increases that moderated in the long run, while cases projecting a slow growth in exports experienced more gradual price increases. Second, cases with larger cumulative exports resulted in higher prices in the long-term relative to those cases with lower overall export levels. The largest price increase over the baseline exists in the Low Shale EUR case. The High Shale EUR case yields the smallest price response.

6. Increased Natural Gas Production and Supply

EIA projected that most of the additional natural gas needed for export would be provided by increased domestic production with a minor contribution from increased pipeline imports from Canada. The remaining portion of the increased export volumes would be offset by decreases in consumption resulting from the higher prices associated with the increased exports.

7. Decreased Natural Gas Consumption

EIA projected that greater export levels would lead to decreases in natural gas consumption. Most of this projected decrease would occur in the electric power sector. Increased coal-fired generation accounts for about 65 percent of the projected decrease in natural gas-fired generation. However, EIA also noted that the degree to which coal might be used in lieu of natural gas depends on what regulations are in place. As noted above, EIA's projections reflected the laws and regulations in place at the time AEO 2011 was produced.

EIA further projected that small increases in renewable generation would contribute to reduced natural gas-fired generation. Relatively speaking, the role of renewables would be greater in a higher-gas-price environment (*i.e.*, the Low Shale EUR case) when renewables can more successfully compete with coal, and also in a higher-generation environment (*i.e.*, the High Economic Growth case), particularly in the later years.

EIA projected that increased natural gas exports would result in reductions in industrial natural gas consumption. However, the NEMS model does not capture the link between energy prices and the supply/demand of industrial commodities in global industries. To the extent that the location of production is sensitive to changes in natural gas prices, EIA acknowledged that industrial natural gas demand would be more responsive than shown in its analysis.

8. Increased End-User Natural Gas and Electricity Delivered Prices

EIA projected that, with increased natural gas exports, consumers would consume less and pay more on both their natural gas and electricity bills, and generally pay a little less for liquid fuels.

EIA projected that the degree of change to total natural gas bills with added exports varies significantly among economic sectors. This is because the natural gas commodity charge represents significantly different portions of each natural gas consuming sector's bill. However, EIA projected that natural gas expenditures would increase at the highest percentages in the industrial sector, where low transmission and distribution charges constitute a relatively small part of the delivered natural gas price.

EIA projected that average electricity prices would increase between 0.14 and 0.29 cents per kilowatt-hour (kWh) (between 2 and 3 percent) when gas exports are added. The greatest projected increase in electricity prices occurs in 2019 under the Low Shale EUR case for the high export/rapid growth export scenario, with an increase of 0.85 cents per kWh (9 percent).

EIA projected that, on average between 2015 and 2035, total U.S. end-use electricity expenditures as a result of added exports would increase between $5 billion to $10 billion (between 1 to 3 percent), depending on the export scenario. The High Macroeconomic Growth case shows the greatest average annual increase in natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $6 billion to $12 billion.

9. Impact on Natural Gas Producer Revenues

As part of its analysis, EIA considered the impact of natural gas exports on natural gas producer revenues. According to EIA, total additional natural gas revenues to producers from exports would increase from 2015 to 2035 between $14 billion and $32 billion over the AEO 2011 Reference Case, depending on the export scenario. These revenues reflect dollars spent to purchase and move the natural gas to the export facility, but do not include any revenues associated with the liquefaction and shipping process.

EIA cautioned that these projected increases in natural gas producer revenues do not represent profits and a large portion of the additional revenues would be expended to cover the costs associated with increased production, such as for equipment (*e.g.*, drilling rigs) and labor. In contrast, the additional revenues resulting from the higher price of natural gas that would have been produced and sold to largely domestic customers even in the absence of the additional exports posited in the analysis would preponderantly reflect increased profits for producers and resource owners.

10. Impacts Beyond the Natural Gas Industry

EIA stated that, other than impacts on their energy expenditures, impacts on non-energy sectors were generally beyond the scope of its study. However, EIA did project impacts on total energy use and energy-related CO_2 emissions. EIA projected that annual primary energy consumption in the AEO 2011 Reference Case will average 108 quadrillion Btu between 2015 and 2035, with a growth rate of 0.6 percent. Also, cumulative CO_2 emissions are projected to total 125,000 million metric tons for that 20-year period.

According to EIA, the changes in overall energy consumption would largely reflect changes in the electric power sector. While additional exports would result in decreased natural gas consumption, changes in overall energy consumption would be relatively minor as much of the decrease in natural gas consumption would be replaced with increased coal consumption.

While lower domestic natural gas deliveries resulting from added exports are projected to reduce natural gas related CO_2 emissions, EIA projected that the increased use of coal in the electric sector would generally result in a net increase in domestic CO_2 emissions. Exceptions occur in scenarios where renewables are better able to compete against natural gas and coal. However, when also accounting for emissions related to natural gas used in the liquefaction process, EIA projected that additional exports would increase domestic CO_2 levels under all cases and scenarios, particularly in the earlier years of the projection period. EIA did not evaluate the effect of U.S. LNG exports on global CO_2 emissions.

B. NERA Study, *Macroeconomic Impacts of LNG Exports from the United States*

Because the NEMS model used by EIA did not account for the impact of energy price changes on global energy utilization patterns and did not include a full macroeconomic model, DOE/FE commissioned NERA to provide such an analysis. NERA developed a two-step approach. First, it modeled energy markets by drawing on several of the scenarios that EIA had developed and adding global market scenarios developed through its GNGM model. Second, using its "N_{ew}ERA" energy-economy model, NERA drew conclusions regarding the domestic macroeconomic impacts of LNG exports. The impacts measured using the N_{ew}ERA macroeconomic model included price, welfare,[47] gross domestic product (GDP), aggregate consumption, aggregate investment, natural gas export revenues, sectoral output,[48] and wages and other household incomes. In addition, NERA identified impacts that would affect certain energy intensive, trade exposed (EITE) industries, as discussed below.

[47] According to NERA, the measure of welfare used in its study is known as the "equivalent variation" and is the amount of income a household would be willing to give up in the case without LNG exports to achieve the benefits of LNG exports. NERA states that it measured welfare in present value terms, and therefore captures in a single number benefits and costs that might vary year by year over the period. NERA study at 6, n.5 & 55.

[48] NERA evaluated seven key sectors of the U.S. economy: agriculture, energy intensive sector, electricity, natural gas, motor vehicle, manufacturing, refined petroleum products, and services. *Id*. at 9.

1. Overview of NERA's Findings

NERA's key findings include the following:

- **Net economic benefits across all scenarios.** Across all the scenarios studied, NERA projected that the United States would gain net economic benefits from allowing LNG exports. For every market scenario examined, net economic benefits increased as the level of LNG exports increased. Scenarios with unlimited exports had higher net economic benefits than corresponding cases with limited exports. In all cases, the benefits that come from export expansion outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports have net economic benefits in spite of higher domestic natural gas prices.

Net benefits to the United States would be highest if the United States is able to produce large quantities of gas from shale at low cost, if world demand for natural gas increases rapidly, and if LNG supplies from other regions are limited. If the promise of shale gas is not fulfilled and costs of producing gas in the United States rise substantially, or if there are ample supplies of LNG from other regions to satisfy world demand, the United States would not export LNG. Under these conditions, allowing exports of LNG would cause no change in natural gas prices and do no harm to the overall economy.

- **Natural gas price increases.** U.S. natural gas prices would increase if the United States exports LNG. However, the global market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if U.S. wellhead price rises above the cost of competing supplies.

Natural gas price changes attributable to LNG exports remain in a relatively narrow range across the entire range of scenarios. Natural gas price increases at the time LNG exports could begin range from zero to $0.33 (2010$/Mcf). Price increases that would be observed after five more years of potentially growing exports could range from $0.22 to $1.11 (2010$/Mcf). The higher end of the range is reached only under conditions of ample U.S. supplies and low domestic natural gas prices, with smaller price increases when U.S. supplies are more costly and domestic prices higher.

- **Socio-economic impacts.** How increased LNG exports will affect different socioeconomic groups will depend on their income sources. Like other trade measures, LNG exports will cause shifts in industrial output and employment and in sources of income. Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase. Different socioeconomic groups depend on different sources of income; workers with retirement savings that include shares of natural resource companies will benefit from higher incomes to those companies. Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or government transfers, in particular, might not participate in these benefits.

- **Competitive impacts and impact on employment.** Serious competitive impacts are likely to be confined to narrow segments of industry. About 10 percent of U.S. manufacturing, measured by value of shipments, has both energy expenditures greater than 5 percent of the value of its output and serious exposure to foreign competition. Employment in these energy-intensive industries is about one-half of one percent of total U.S. employment.

LNG exports are unlikely to affect the overall level of employment in the United States. There will be some shifts in the number of workers across industries, with those industries associated with natural gas production and exports attracting workers away from other industries. In no scenario is the shift in employment out of any industry projected to be larger than normal rates of turnover of employees in those industries.

Additional discussion of the above key findings is offered below and in the NERA Study itself.

2. Overview of NERA's Methodology

NERA states that it attempted to answer two principal questions:

- At what price can various quantities of LNG exports be sold?
- What are the economic impacts on the United States of LNG exports?

To answer these questions, NERA used the GNGM model to estimate expected levels of U.S. LNG exports under several scenarios for global natural gas supply and demand. NERA also relied on the EIA Study to characterize how U.S. natural gas supply, demand, and prices would respond if the specified level of LNG exports were achieved. Further, NERA examined the same 16 scenarios for LNG exports analyzed by EIA but added additional scenarios to reflect global supply and demand. These additional scenarios were constructed on the basis of NERA's analytical model of global natural gas markets, as described below.

The resulting scenarios ranged from Reference Case conditions to stress cases with high costs of producing natural gas in the United States and exceptionally large demand for U.S. LNG exports in world markets. The three scenarios chosen for the U.S. resource outlook were the EIA Reference Case, based on AEO 2011, and two cases assuming different levels of EUR from new gas shale development. Outcomes of the EIA high demand case fell between the High and Low EUR cases and, therefore, would not have changed the range of results. The three different international outlooks were: (1) a Reference Case, based on EIA's International Energy Outlook 2011; (2) a Demand Shock case with increased worldwide natural gas demand caused by shutdowns of some nuclear capacity; and (3) a Supply/Demand Shock case that added to the Demand Shock a supply shock that assumed key LNG exporting regions did not increase their exports above current levels.

When the global and U.S. scenarios were combined with seven scenarios specifying limits on exports and export growth, NERA's analysis covered 63 possible scenarios. From these 63 scenarios, 21 scenarios resulted in some level of LNG export from the United States. Of these 21 scenarios, the GNGM model identified 13 "N$_{ew}$ERA scenarios" that spanned the range of economic impacts from all of the scenarios and eliminated scenarios with essentially identical outcomes. The 13 scenarios included:

Table 2: N$_{ew}$ERA Scenarios Analyzed by NERA

	U.S. Scenarios	**International Demand and Supply Scenarios**	**Export Scenarios**
1	Reference	Supply and Demand Shock	Low/Rapid
2	Reference	Supply and Demand Shock	Low/Slow
3	Reference	Supply and Demand Shock	High/Rapid
4	Reference	Supply and Demand Shock	High/Slow
5	Reference	Demand Shock	Low/Rapid
6	Reference	Demand Shock	Low/Slow
7	Reference	Demand Shock	Low/Slowest
8	High EUR	Supply and Demand Shock	High/Rapid
9	High EUR	Supply and Demand Shock	High/Slow
10	High EUR	Supply and Demand Shock	Low/Rapid
11	High EUR	Supply and Demand Shock	Low/Slow
12	High EUR	Supply and Demand Shock	Low/Slowest
13	Low EUR	Supply and Demand Shock	Low/Slowest

To project the macroeconomic impacts of the above scenarios, NERA used its N$_{ew}$ERA model to compare the impacts of each of the 13 export scenarios to baselines with no LNG exports. NERA thus derived a range of projected impacts on the U.S. economy, including impacts on welfare, aggregate consumption, disposable income, GDP, and loss of wage income.

3. Scope of the NERA Study

NERA started its analysis with the domestic economic AEO 2011 cases and the export scenarios present in the EIA Study.[49] In addition to the export scenarios used by EIA, NERA added two export cases, including the "low/slowest case" and a "no restraints" case in which no regulatory restraints on exports existed. The low/slowest case assumed exports of 6 Bcf/d, with a growth rate of 0.5 Bcf/d per year, which is half the growth rate in the slow scenarios used by EIA.

Because NERA, unlike EIA, modeled the international gas market, NERA also created three international gas market scenarios not contained in the EIA Study. The first was a business as usual Reference Case. The second assumed an international demand shock with increased worldwide natural gas demand caused by shutdowns of some nuclear capacity. Finally, NERA created an international scenario that added to the demand shock a supply shock that assumed key LNG exporting regions did not increase their exports above current levels.

While these additional aspects of the analysis expanded the scope of the NERA Study relative to the study conducted by EIA, significant elements of the dynamics of the global natural gas trade and its domestic economic implications were outside the scope of the NERA Study or beyond the reach of the modeling tools used.[50] NERA expressly excluded the following factors from its analysis:

- The extent to which an overbuilding of liquefaction capacity could affect the ability to finance the projects and profitably export natural gas;
- The extent to which engineering or infrastructure limitations would impact the rate at which liquefaction capacity would come online, potentially impacting the cost of that capacity;
- The locations of the liquefaction facilities, or alternatives;

[49] For a full discussion of the scope, see pages 3-15 of the NERA Study, http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.
[50] For a full discussion of the unexplored factors, see Appendix E of the NERA Study, http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

- The impacts of the liquefaction and exportation of natural gas on various regions within the United States;
- The extent to which the impacts of LNG export vary among different socio-economic groups; and
- The extent to which macroeconomic impacts to the United States would vary if the liquefaction projects were funded through foreign direct investment.

4. NERA's Global Natural Gas Model

The GNGM model is designed to estimate natural gas production, consumption, and trade in the major gas producing or consuming regions.[51] The model attempts to maximize the difference between surplus and cost, constrained by various factors including liquefaction capacity and pipeline constraints. The model divides the world into 12 regions and specifies supply and demand curves for each region. The regions are: Africa, Canada, China/India, Central and South America, Europe, Former Soviet Union, Korea/Japan, Middle East, Oceania, Sakhalin, Southeast Asia, and the United States. The GNGM model's production and consumption assumptions for these regions are based on projections contained in the Reference Cases of EIA's AEO 2011 and International Energy Outlook 2011. NERA ran the GNGM model in five-year increments between 2015 and 2035.

According to NERA, the characteristics of a regional market will affect LNG trading patterns and the pricing of natural gas within the region. With respect to trading patterns, NERA observed that a significant portion of LNG, such as LNG moving to Europe, is traded on a long-term basis using dedicated supplies and dedicated vessels moving to identified markets. On the other hand, NERA stated that some LNG markets, particularly those in Asia, operate on the basis of open market competitive bids in which LNG is delivered to those who value it the

[51] For a full discussion of GNGM, see page 20 of the NERA Study, http://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

most. NERA also found that Southeast Asian and Australian suppliers most often market LNG to Asian markets; African suppliers deliver LNG most often to Europe; and Middle Eastern suppliers deliver LNG both to Europe and Asia.

With respect to the pricing of LNG in global markets, NERA states that the price differential, or "basis," between two regions reflects the difference in the pricing mechanism for each regional market. If pricing for two market hubs were set by the same mechanism and there were no constraints in the transportation system, the basis would simply be the cost of transportation between the two market hubs. NERA asserts, however, that different pricing mechanisms set the price in each regional market, so the basis is often not set by transportation differences alone.

NERA offers the following example: Japan depends on LNG as its source for natural gas and indexes LNG prices to crude oil prices. For Europe, on the other hand, NERA states that LNG is only one of three potential sources of supply for natural gas. The others are interregional pipelines and indigenous production. According to NERA, the competition for market share between these alternative sources of supply will establish the basis for LNG prices in Europe. NERA further states that within North America, pricing at Henry Hub has been for the most part set by competition between different North American supply sources and has been independent of pricing in Japan and Europe.

5. The N_{ew}ERA Macroeconomic Model

NERA developed the N_{ew}ERA model to forecast how, under a range of domestic and international supply and demand conditions, U.S. LNG exports could affect the U.S. economy.[52] Like other general equilibrium models, N_{ew}ERA is designed to analyze long-

[52] For a full discussion of the N_{ew}ERA macroeconomic model, see pages 20 to 22 of the NERA Study, http://fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

term economic trends. NERA explained that, in any given year, actual prices, employment, or economic activity may differ from the projected levels.

The version of N_{ew}ERA used in NERA's analysis considered all sectors of the U.S. economy. In short, the model:

- Contains supply curves for domestic natural gas,
- Accounts for imports of Canadian pipeline gas and other foreign imports,
- Recognizes the potential for increases to U.S. liquefaction capacity, and
- Recognizes changes in international demand for domestically produced natural gas.

As discussed below, the results of the N_{ew}ERA model address changes in demand and supply of all goods and services, prices of all commodities, and impacts from LNG exports to U.S. trade, including changes in imports and exports. As with the GNGM model, NERA ran the N_{ew}ERA model in five-year increments for 2015 through 2035.

6. Relationship to the EIA Study

As explained above, EIA's study focused on potential impacts of natural gas exports to domestic energy markets. Specifically, the study considered impacts to natural gas supply, demand, and prices within the United States. To provide a fuller scope of analysis, DOE asked NERA to examine the net macroeconomic impact of domestic LNG exports on the U.S. economy. To conduct this analysis, NERA first modeled international demand for U.S. LNG utilizing its GNGM model. NERA then incorporated the results from the GNGM model into its N_{ew}ERA model, using the same parameters governing natural gas supply and demand that EIA used in the NEMS model.

NERA concluded that, in many cases, the global natural gas market would not accept the full amount of exports assumed in the EIA scenarios at export prices high enough to cover the U.S. wellhead prices calculated by EIA. In these cases, NERA replaced the export levels and price impacts found in the EIA scenarios with lower levels of exports (and prices) estimated by the GNGM model. These lower export levels were applied to the N_{ew}ERA model to generate projected impacts to the U.S. economy from LNG exports.

7. Key Assumptions and Parameters of the NERA Study

NERA implemented the following key assumptions and parameters, in part to retain consistency with EIA's NEMS model:

i. All scenarios were derived from the AEO 2011 and incorporated EIA's assumptions about energy and environmental policies, baseline coal, oil and natural gas prices, economic and energy demand growth, and technology availability and cost in the corresponding AEO cases.

ii. U.S. exports compete with LNG exports from other nations, who are assumed to behave competitively and to adjust their export quantities in response to prevailing prices. The single exception to this assumption is that the export decisions of the global LNG market's one dominant supplier, Qatar, were assumed to be independent of the level of U.S. exports.

iii. Prices for natural gas used for LNG production were based on the Henry Hub price, plus a 15 percent markup (to cover operating costs of the liquefaction process).

iv. The LNG tolling (or reservation) fee—paid by the exporter to the operator of the liquefaction terminal for the right to reserve capacity—was based on a return of capital to the operator.

v. All financing of investment was assumed to originate from U.S. sources.

vi. The United States is assumed to have full employment, meaning that U.S.

unemployment rates and the total number of jobs in the United States will not change across all cases.

8. Results of the NERA Study

As a result of its two-step analysis, the NERA Study yielded two sets of results, reported in five-year intervals beginning with 2015.[53] First, the GNGM model produced information regarding the conditions that will support exports of natural gas from the United States. Second, the N_{ew}ERA model provided information about the domestic macroeconomic impacts of natural gas exports. NERA found:

- **<u>LNG exports would result in higher U.S. natural gas prices.</u>** NERA found that the United States would only be able to market LNG successfully with higher global demand or lower U.S. costs of production than in the Reference Cases. According to NERA, the market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if the U.S. wellhead price rises above the cost of competing supplies. In particular, under NERA's modeling, the U.S. natural gas price does not become linked to oil prices in any of the cases examined.

- **<u>Macroeconomic impacts of LNG exports are positive in all cases.</u>** NERA found that the United States would experience net economic benefits from increased LNG exports in all cases studied. Only three cases had U.S. exports greater than the 12 Bcf/d maximum exports allowed in the cases analyzed by EIA.[54] NERA estimated economic impacts for these three cases with no constraint on exports, and found that even with exports reaching levels greater than

[53] These calendar years are not actual, but represent modeling intervals after exports begin. For example, if the United States does not begin LNG exports until 2016, one year should be added to the dates for each year that exports commence after 2015.
[54] The first case combined U.S. Reference natural gas production with an international supply and demand shock. The second combined the High EUR domestic case with an international demand shock. The third combined the High EUR domestic case with an international supply and demand shock. NERA sSudy at 6.

12 Bcf/d and associated higher prices than in the constrained cases, there were net economic benefits from allowing unlimited exports in all cases.

Across the scenarios, NERA projected that U.S. economic welfare would consistently increase as the volume of natural gas exports increased, including in scenarios with unlimited exports. The reason given was that even though domestic natural gas prices are pulled up by LNG exports, the value of those exports also rises so that there is a net gain for the U.S. economy measured by a broad metric of economic welfare or by more common measures such as real household income or real GDP. Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefaction services. The net result is an increase in U.S. households' real income and welfare. NERA noted, however, that net benefits to the U.S. economy could be larger if U.S. businesses were to take more of a merchant role. NERA assumed that foreign purchasers would take title to LNG when it is loaded at a U.S. port, so that any profits that could be made by transporting and selling in importing countries accrue to foreign entities. In cases where exports are constrained to maximum permitted levels, this business model sacrifices additional value from LNG exports that could accrue to the United States.

- **Sources of income would shift.** NERA states that at the same time that LNG exports create higher total income in the United States, exports would shift the composition of income so that both wage income and income from capital investment decline. NERA's measure of total income is GDP measured from the income side, that is, by adding up income from labor, capital, and natural resources and adjusting for taxes and transfers. According to NERA, expansion of

LNG exports would have two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries, but it also creates two additional sources of income. First, additional income would come in the form of higher export revenues and wealth transfers from incremental LNG exports at higher prices paid by overseas purchasers. Second, U.S. households also would benefit from higher natural gas resource income or rents. These benefits differentiate market-driven expansion of LNG exports from actions that only raise domestic prices without creating additional sources of income. According to NERA, the benefits that come from export expansion would more than outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports would have net economic benefits in spite of higher natural gas prices. According to NERA, this is the outcome that economic theory describes when barriers to trade are removed.

- **Some groups and industries will experience negative effects of LNG exports.** NERA concluded that, through retirement savings, an increasingly large number of workers will share in the higher income received by natural resource companies participating in LNG export-related activities. Nevertheless, impacts will not be positive for all groups in the economy. According to NERA, households with income solely from wages or transfers, in particular, might not participate in these benefits. NERA stated that higher natural gas prices can also be expected to have negative effects on output and employment, particularly in sectors that make intensive use of natural gas, while other sectors not so affected could experience gains. There clearly would be greater activity and employment in natural gas production and transportation and in construction of liquefaction facilities. Overall, NERA projected that declines in output in other sectors would be accompanied by similar reductions in worker compensation in those sectors, indicating that there will be some shifting of labor between different industries. However, even in the year of peak impacts, the largest projected change in wage income by industry would be no more than one percent, and even if all of this decline were attributable to lower employment relative to the baseline, NERA concluded that no sector analyzed in its study would experience reductions in employment more rapid than normal turnover. In fact, NERA asserted that most of the changes in real worker compensation are likely to take the form of lower than expected real wage growth, due to the increase in natural gas prices relative to nominal wage growth.

- **Peak natural gas export levels (as specified by DOE/FE for the EIA Study) and resulting price increases are not likely.** The export volumes selected by DOE/FE for the EIA Study define the maximum exports allowed in each scenario for the NERA macroeconomic analysis. Based on its analysis of global natural gas supply and demand, NERA projected achievable levels of exports for each scenario. The NERA scenarios that found a lower level of exports than the limits specified by DOE/FE are shown in Figure 5 of the NERA Study, as modified from Tcf/yr to Bcf/d below.

**Table 3: NERA Export Volumes in Bcf/d,
Adapted from Figure 5 of the NERA Report**

NERA Export Volumes (in Bcf/d)	2015	2020	2025	2030	2035
U.S. Reference Case with International Demand Shock and lower than Low/Slow export levels	***1.02***	2.69	3.92	3.27	***6.00***
U.S. Reference Case with International Demand Shock and lower than Low/Rapid export levels	2.80	2.69	3.92	3.27	3.76
U.S. Reference Case with International Supply/Demand Shock and lower than High/Slow export levels	***1.02***	6.00	10.77	***12.00***	***12.00***

U.S. Reference Case with International Supply/Demand Shock and lower than High/Rapid export levels	***3.02***	***8.00***	10.77	***12.00***	***12.00***
U.S. High Shale EUR with International Supply/Demand Shock at Low/Slowest export levels	***0.50***	2.69	3.92	3.27	3.76

The cells in bold italics indicate the years in which the model's limit on exports is binding. All scenarios hit the export limits in 2015 except the NERA export volume case with Low/Rapid exports. In no case does the U.S. wellhead price increase by more than $1.11/Mcf due to market-determined levels of exports. Even in cases in which no limits were placed on exports, competition between the United States and competing suppliers of LNG limits increases in both U.S. LNG exports and U.S. natural gas prices.

To match the characterization of U.S. supply and demand for natural gas in EIA's NEMS model, NERA calibrated its macroeconomic model so that for the same level of LNG exports assumed in the EIA Study, the NERA model reproduced the prices projected by EIA. Thus natural gas price responses were similar in scenarios where NERA export volumes were at the EIA export volumes. However, NERA determined that the high export limits were not economical in the U.S. Reference Case and that in these scenarios there would be lower exports than assumed by EIA. Because NERA estimated lower export volumes than were specified by DOE/FE for the EIA Study, U.S. natural gas prices do not reach the highest levels projected by EIA. NERA states that this implies no disagreement with the EIA Study. Instead, it reflects the fact that at the highest wellhead prices estimated by EIA, world demand for U.S. exports would fall far short of the levels of exports assumed in the EIA Study. Additionally, NERA found that U.S. wellhead prices would not become linked to oil prices in the sense of rising to oil price parity in any of the cases analyzed, even if the United States were exporting to regions where natural gas prices are presently linked to oil. NERA asserts that costs of liquefaction, transportation, and regasification would keep U.S. prices well below those in importing regions.

- **Serious competitive impacts are likely to be confined to narrow segments of U.S. industry.** NERA gave special attention to the potential impact of LNG exports on EITE industries. NERA examined impacts on manufacturing industries where energy expenditures are greater than 5 percent of the value of the output created and the industries face serious exposure to foreign competition. Such industries, according to NERA, comprise about 10 percent of U.S. manufacturing and employment in these industries is one-half of one percent of total U.S. employment. NERA did not project that such energy-intensive industries as a whole would sustain a loss in employment or output greater than one percent in any year in any of the cases examined and pointed out that such a drop in employment would be less than normal rates of turnover of employees in the relevant industries.

- **Even with unlimited exports, there would be net economic benefits to the United States.** NERA estimated economic impacts associated with unlimited exports in cases in which even the High, Rapid limits were binding. In these cases, both LNG exports and prices were determined by global supply and demand. Even in these cases, NERA found that U.S. natural gas prices would not rise to oil parity or to levels observed in consuming regions, and net economic benefits to the U.S. increased over the corresponding cases with limited exports. To examine U.S. economic impacts under cases with even higher natural gas prices and levels of exports than in the unlimited export cases, NERA also estimated economic impacts associated with the highest levels of exports and U.S. natural gas prices in the EIA analysis, regardless of whether those quantities could actually be sold at the assumed netback prices. The price received for exports in these cases was calculated in the same way as in the cases based on NERA's GNGM model, by adding the tolling fee plus a 15 percent markup over Henry Hub to the Henry Hub price. Even with the highest prices estimated by EIA for these hypothetical cases, NERA found net economic benefits to the United States, with the net economic benefits growing as export volumes rise. Addressing this finding, NERA explained that LNG export revenues from sales to other countries at those high prices would more than offset the costs of freeing that gas for export.

VII. MOTIONS TO INTERVENE, COMMENTS, AND PROTEST IN RESPONSE TO THE NOTICE OF APPLICATION

A. Overview

As noted above, DOE/FE received 35 timely filed and five additional late-filed comments in support of the Application; three timely filed and two late-filed comments opposing the Application without motions to intervene; comments from Derrick Hindery raising environmental concerns but taking no position on the merits of the Application; and five timely filed motions to intervene and comment or protest from the APGA, Sierra Club, Citizens Against LNG, Landowners United, and KS Wild.

No party opposed the submission of the late-filed pleadings, and we find that no party will be unduly prejudiced by our consideration of those pleadings. Accordingly, the late-filed comments will be accepted for filing.

B. Comments Supporting the Application

The comments submitted in support of Jordan Cove's Application generally address the benefits the commenters expect to occur if the requested authorization is granted.[55] Of the 40

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[55] Following the close of the comment period, DOE/FE received five comments in support of the authorization and two comments requesting denial of the authorization. These late-filed comments were submitted by Sandra Geiser-Messerle, Executive Director of the South Coast Development Council, Inc.; Ronald Cox, Vice President of Power Supply, Hawaiian Electric Company; Q.T. Freeman, Chairman of Cardinal Services; Donna Opitz; and Christopher

comments in support, 29 were a single form letter. The 40 comments describe economic benefits the Jordan Cove project allegedly would bring to the Coos Bay region of Oregon. State Representatives Bruce Hanna, Arnie Roblan, Joanne Verger, Dennis Richardson, Sal Esquivel, Wally Wicks, and Tim Freeman highlight the job creation aspects of the project. In particular, they forecast the creation of more than 2,600 construction jobs with an average of more than 900 jobs over three-and-a-half years of construction, as well as 150 permanent jobs with salaries twice the average per capita income in Southern Oregon. Additionally, they note that Jordan Cove and the PCGP will pay between $25 and 30 million per year in local taxes, and provide needed economic development to the underutilized Coos Bay Port. Twenty-eight other commenters, including Edward Metcalf of the Coquille Indian Tribe, maintain that such benefits will accrue to the Coos Bay area and provide long-term economic growth. Sandra Geiser-Messerle of South Coast Development Council, Inc. and Jon A. Barton explain that the project will greatly help to alleviate poverty in Coos County. Loran Wiese, City Councilor of Coquille, Oregon, notes that any job creation is welcome.

Several entities highlight other economic benefits of the project, such as the ability to supply LNG to Hawaii and the boon to the regional construction trade. Dale Sause of Sause Bros. Ocean Towing Co., Evan J. Griffith of Matanuska Electric Association, Scott L. Vuillemot of American Marine Corp. and Pacific Environmental Corp., and Ronald R. Cox of Hawaiian Electric Co. state that creating a large LNG production facility at Coos Bay would make it possible to ship LNG to Hawaii so it could be used as a fuel source there and throughout the Pacific. Additionally, Patrick B. Smith of Lane, Coos, Curry, Douglas Building Trades Council notes that the construction jobs associated with the Jordan Cove project will allow the Trade

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R. Johnson. Comments requesting denial were submitted by Jan Dilley and Paula A. Jones. Because these comments were received within 5 days of the close of the comment period, DOE/FE finds that acceptance of these comments will not prejudice other parties to this proceeding, and therefore accepts these comments for filing.

Council's members to work at home for three years instead of traveling for their jobs, and will provide apprenticeship opportunities.

C. Comments Opposing the Application

The comments submitted opposing the Application discuss safety, environmental, and land use concerns, and challenge the economic benefits claimed for the Jordan Cove project. In particular, Paula Jones and Wim de Vriend emphasize that the Terminal will be built in an earthquake and tsunami zone, thereby placing nearby residents in danger of an LNG leak. Russell, Sandra, and Kristofer Lyon state that their family cattle ranch lies in the path of the PCGP and are at risk of losing their land via eminent domain if the pipeline is approved. De Vriend states that taking land when there is no gas shortage in the United States is against the public interest. Jan Dilley contends that the project should not be approved until Jordan Cove fully complies with NEPA. De Vriend concurs and highlights that the project will damage the region's waterways. Regarding the Project's claimed benefits of economic development, de Vriend states that Coos Bay Port has historically mismanaged projects, leading the region to see no economic development or job creation opportunities from the projects. Likewise, Paula Jones argues that any economic benefit from the project will ultimately support Canada and not the United States. Lastly, Derrick Hindery, while not expressly supporting or opposing the project, cautions that the project still requires permits for LNG facility operations and has not conducted an EIS addressing supply chains and any environmental impacts.

D. APGA's Motion to Intervene and Protest

APGA states that it is an association of municipal gas distribution systems, public utility districts, and other public agencies. APGA maintains that Jordan Cove's request for authority to export domestically produced LNG is inconsistent with the public interest. APGA cites the EIA

Study (discussed *infra* in Section VI.A) for the proposition that exporting domestic LNG[56] will significantly increase domestic natural gas prices. APGA also refers to an early release version of EIA's Annual Energy Outlook 2012 (AEO 2012) that, it states, substantially reduced the level of estimated technically recoverable natural gas in the Marcellus Shale. APGA argues these assessments undermine the premise of the Application that vast recoverable reserves will keep domestic gas prices low despite LNG exports. To the contrary, APGA contends that price increases associated with exports of LNG will jeopardize the viability of natural gas as a "bridge-fuel" in the transition away from carbon-intensive and otherwise environmentally problematic coal-fired electricity generation. APGA states:

> Inflated natural gas prices will also inhibit efforts to foster natural gas as a transportation fuel, which is important to wean the U.S. from its historic, dangerous dependence on foreign oil. Furthermore, high natural gas prices and resulting increases in the price of electricity will reverse the nascent trend toward renewed domestic manufacturing before it gains momentum.[57]

APGA also maintains that Jordan Cove's plan to export LNG will not be economically viable because recoverable domestic natural gas resources may be less robust than projected, especially given looming environmental costs and regulations, and because foreign alternatives will eventually remove the price arbitrage opportunity that Jordan Cove seeks to use to its advantage.

Jordan Cove's Application, according to APGA, is one of 14 applications submitted to DOE/FE seeking authority to export LNG to FTA and non-FTA nations. APGA argues that the quantity of domestic natural gas at issue in this and related proceedings, approximately 18.70 Bcf/d for FTA exports and 14.61 Bcf/d for non-FTA exports, is roughly 27 percent of the total marketed production in the United States in 2011 (66 Bcf/d). APGA contends that authorization

[56] APGA states that the Application should be treated as a proposal to export domestically produced natural gas notwithstanding the fact that a portion of the exported volumes will have been produced in Canada. *See* Mot. for Leave to Intervene and Protest of the American Public Gas Association, at 3 n.2 (Aug. 6, 2012) [hereinafter APGA Mot.].

[57] *Id*. at 3.

of this large quantity for export will have a substantial impact on natural gas demand, will increase domestic natural gas and electricity prices, and will limit natural gas supply at a time when the nation has an opportunity to forge a path toward energy independence. As a consequence, APGA contends, the proposed exports are inconsistent with the public interest.

APGA argues that, ultimately, Jordan Cove's exports will fail to compete with natural gas exports by other nations. APGA also argues that "DOE/FE should not pursue policies that directly increase natural gas commodity prices for American consumers, thereby making natural gas less competitive in this country as a replacement for foreign-sourced fuels or for fuels that are less clean and more carbon-intensive."[58]

APGA states that the Navigant Study on which Jordan Cove relies failed to consider the cumulative impact of actual proposed exports, in several respects:

- Navigant assumed 6.6 Bcf/d of exports for its Aggregate Export Case, whereas the total export capacity that is the subject of export applications to date is 18.70 Bcf/d of FTA exports and 14.61 of non-FTA exports.

- Navigant included the proposed Kitimat LNG export facility in its analysis but failed to include two other proposed export facilities in British Columbia and a proposed expansion of the Kitimat facility. According to APGA, Canadian facilities are relevant to this proceeding because, like the Jordan Cove Terminal, they would also export gas from Western Canada to Asian markets.

- The Navigant Study failed to consider the possibility of a second LNG terminal on the Oregon coast even though LNG Development Company, LLC had hired Navigant to conduct a similar study of the price impact of proposed exports from a terminal near Astoria, Oregon, in

[58] *Id*. at 6.

DOE/FE Docket No. 12-77-LNG.

- The Navigant Study failed to consider the full 1.2 Bcf/d in FTA export authority received by Jordan Cove in DOE/FE Order No. 3041.

- The Navigant Study projected ample volumes of technically recoverable natural gas but the EIA subsequently reduced its estimate of unproved technically recoverable gas in AEO 2012. This reduction, according to APGA, largely reflects a decrease in estimates for the Marcellus Shale from 410 Tcf to 141 Tcf, a 65 percent reduction due to a report from the United States Geological Service (USGS). APGA states that the reduction appeared in the Annual Energy Outlook 2012 Early Release in January 2012. According to APGA, Jordan Cove suggested in the Application that EIA would increase the estimate in its full version of AEO 2012. However, APGA states that EIA stood by its reduced projection in AEO 2012.

While APGA contends that the Navigant Study ignored the true volume of pending exports and relied on outdated and inflated estimates of technically recoverable natural gas, the Navigant Study still found that prices at the Malin hub will be 26 percent higher under the GHG Demand Case than the Reference Case in the year 2025 and 28 percent higher in the year 2045. APGA insists that the GHG Demand Case is the most realistic scenario considered by Navigant. APGA claims that the switch from coal-fired electricity to natural gas is already occurring and that DOE/FE must consider these trends in its review of the domestic need for the natural gas that Jordan Cove plans to export and also must consider the results of the EIA Study.

APGA points out that all of the scenarios analyzed by EIA forecast that LNG exports will increase domestic natural gas prices. Yet, according to APGA, the Navigant Study considered only one volume of future aggregate exports—6.6 Bcf/d from both the United States and Canada. This volume of exports, APGA charges, is near EIA's low export scenario from the United

States only. APGA states that the Navigant Study uses 6.6 Bcf/d figure as projected export capacity through 2045 without considering the potential of divergent growth rates in export capacity or an expansion of export capacity. APGA charges that the Navigant Study did not account for the slow or rapid development of export capabilities, the potential for different gas reserve scenarios, or economic growth trends. APGA states that even the High Shale EUR scenario was lower than the inflated projected production levels on which Navigant relied.

APGA further states that EIA "concluded that 'rapid increases in export levels lead to large initial price increases,' but that slower increases in export levels will, 'eventually produce higher average prices during the decade between 2025 and 2035.'"[59] Given the number of export applications that DOE/FE has received to date and the total export capacity requested of roughly 14 Bcf/d and 13.71 Bcf/d to FTA and non-FTA nations respectively, APGA submits that the "high/rapid" export scenario analyzed by EIA is the most realistic scenario. According to APGA, the "high/rapid" scenario produces price increases of 36 to 54 percent by 2018. On the other hand, given the reduction in technically recoverable gas in the AEO 2012 overview report, APGA states that the AEO 2011 Reference Case may be the more accurate scenario considered in the EIA report. APGA states that the high/rapid scenario in the Low Shale EUR case projects that natural gas prices will increase by 54 percent in 2018 and that, even under the slow/low scenario in the Low Shale EUR case, exports will increase domestic wellhead prices by 20 percent in 2020.

APGA also asserts that future natural gas prices may be even higher than projected in the EIA Study because the EIA assumed that domestic prices would only be affected by domestic supply/demand factors and because other factors may limit economically recoverable domestic supplies. These other factors, according to APGA, include increased regulation of hydraulic

[59] *Id*. at 11 (quoting EIA Study at 6).

fracturing and pending coal plant retirements.

APGA states that the relatively low natural gas prices currently being experienced in the United States give the nation an opportunity to end its dependence on coal and foreign oil (by using natural gas as a bridge-fuel), to attract renewed domestic manufacturing, and to stimulate displacement of gasoline with compressed natural gas (CNG) fueled vehicles. APGA argues that increased prices due to exports will jeopardize each of these prospects and, ultimately, national security and national wellbeing. APGA also contends that sustained low prices for natural gas will help to keep electricity prices from spiking higher during the transition to lower-carbon fuels. A spike in electricity prices, APGA adds, will have rippling effects on the U.S. economy.

APGA contends that, while Jordan Cove's application cites the jobs that the proposed exports will create, it does not acknowledge the many jobs in other sectors of the economy that may be destroyed. According to APGA, economic data show that when domestic energy prices increase, the country loses manufacturing jobs, especially in the fertilizer, plastics, chemicals, and steel industries.

APGA argues that shale gas is a world-wide phenomenon and maintains that the United States, rather than allowing the export of its domestic gas resources, should export its technology and expertise to help other nations develop their own non-conventional natural gas reserves. In this regard, APGA argues that Jordan Cove's proposed exports will not prove economical in the long-run:

> As other nations develop their resources and export capacity and as U.S. natural gas prices increase due to the very exports Jordan Cove proposes, international and domestic prices will converge, leaving the U.S. with the worst of all worlds, *i.e.*, higher domestic prices that thwart energy independence and that undermine the competitiveness of the manufacturing sector that relies heavily on natural gas as a process fuel.[60]

[60] *Id*. at 15.

APGA maintains that Jordan Cove in particular will have to compete against exports of Canadian natural gas from British Columbia. APGA asserts that the exports from Canada's Pacific Coast will not have the added cost faced by Jordan Cove of shipping to the Malin hub and through the PCGP.

APGA also argues that domestic natural gas is at a disadvantage in the world market compared to gas from Qatar and states that Australia hopes to overtake Qatar as the world's largest exporter of LNG. In this environment, APGA doubts the ability of U.S.-sourced LNG to compete internationally because of the high capital costs of building an LNG export facility. APGA refers to an estimate by the Brookings Institution that the price spreads between the United States and potential export markets must remain intact for at least 10 to 12 years for investors to recoup the pre-planning and facility construction costs associated with LNG terminals.

E. Sierra Club's Motion to Intervene and Protest

Sierra Club filed a motion to intervene and protest. Sierra Club states that its "many thousands of members have a direct interest in ensuring that domestic natural gas production is conducted safely, and that any exports do not adversely affect domestic consumers."[61] Sierra Club further states that, as of July 2012, it had 15,525 members in Oregon and 601,141 members overall. Sierra Club moves to intervene to protect its members' interests that, it claims, will be put at risk by the environmental and economic consequences of the Jordan Cove proposal and maintains that the Application is not consistent with the public interest.

Sierra Club asserts that DOE/FE may not conditionally approve Jordan Cove's proposal without a proper NEPA analysis that fully analyzes the direct, indirect, and cumulative impacts of increased natural gas production linked to the proposed exports. Such an analysis, according

[61] Sierra Club's Motion to Intervene, Protest, and Comments (Feb. 6, 2012), at 1 [hereinafter Sierra Club Mot.]

to Sierra Club, is required by the public interest standard of the NGA and not solely by NEPA. Sierra Club maintains that this analysis should involve a full EIS that weighs, among other factors, the upstream impacts of the Terminal and the PCGP, and considers a full range of alternatives, including not exporting LNG from Coos Bay and not exporting LNG to any non-FTA country.[62] Because Jordan Cove's proposal is one of several natural gas export proposals, Sierra Club asserts that DOE/FE should prepare a programmatic EIS that considers the cumulative impacts of all of the proposals.

Sierra Club further contends Jordan Cove's application is not supported by adequate economic analysis and charges that Jordan Cove's predictions of job creation and other economic benefits are uncertain and overstated. According to Sierra Club, these predictions are derived from flawed IMPLAN input-output models. This method of analysis, according to Sierra Club, fails to account for the boom-bust cycles inherent in resource production and is unable to identify which of the predicted jobs and benefits would have occurred anyway.

Sierra Club maintains that the Jordan Cove proposal will increase domestic gas prices and harm manufacturing industries and the jobs they support. Sierra Club claims that the EIA Study demonstrates that Jordan Cove's proposal will significantly increase demand for natural gas, thereby driving up gas prices and limiting or eliminating manufacturing and farming jobs. Sierra Club contends that Jordan Cove's critiques of the EIA Study are mistaken. Additionally, Sierra Club maintains that even if DOE/FE accepted Jordan Cove's predictions of lesser price impacts, those impacts constitute a significant harm to the public interest. Sierra Club maintains that, absent a strong showing that the EIA estimates are inferior to Jordan Cove's estimates, use of the industry (*i.e.*, Jordan Cove) estimates would be arbitrary and capricious. Yet, Sierra Club

[62] Sierra Club identifies several other alternative possibilities which, it insists, at a minimum should have been considered. *Id*. at 13-15.

states, Jordan Cove has made no such showing.

Sierra Club insists that DOE/FE must evaluate the cumulative impact of Jordan Cove's proposal in light of all other export proposals that have already been approved or are reasonably foreseeable. Sierra Club argues that Jordan Cove is incorrect in contending that only the "low" export scenario of 6 Bcf/d used in the EIA Study is an appropriate measure of the likely impact of granting the Application. For the same reason, Sierra Club criticizes Jordan Cove's independent forecast of the effects of aggregate LNG exports of 6.6 Bcf/d. Sierra Club likewise criticizes the EIA Study's "high" export scenario because it considers only 60 percent of the LNG export applications currently pending. The likelihood that not all of the proposed export operations will come to fruition, according to Sierra Club, does not render the cumulative impacts of all of the proposals (at 100 percent operational levels) so remote and speculative that some lesser quantity would be appropriately studied.

Even apart from the cumulative impact of all pending proposals on natural gas prices, Sierra Club states that Jordan Cove's proposal in isolation will have a significant impact. According to Sierra Club, the Application predicts that gas prices in the Pacific Northwest will increase by 3.9 to 7.2 percent. Sierra Club maintains that the EIA explains that such an increase is detrimental to consumers and Jordan Cove has offered no argument to show why these increases are not contrary to the public interest.

Sierra Club also faults the Jordan Cove's analysis for assuming that (a) the geographical distribution of export operations will be different than proposed in the various applications submitted to DOE/FE; and (b) the geographical distribution of the export operations that will be approved will alter the cumulative price impact of the proposals. In particular, Sierra Club notes that the pending proposals cover a potential of more than 18 Bcf/d of LNG exports from the Gulf whereas, without justification, Jordan Cove assumes less than 6 Bcf/d of exports from the Gulf.

Sierra Club states that there is a "strong case" that DOE/FE should review the price impact of Jordan Cove's proposal in light of the "high export/low shale EUR" scenario in the EIA Study.[63] This is because, according to Sierra Club: (a) the volume of proposed exports are greater than the EIA Study's "high" export case; and (b) current estimates of total reserves are much lower than those used in the EIA Study, *i.e.* EIA's 2012 Annual Energy Outlook cut the estimates of total domestic gas reserves by over 40 percent from the 2011 AEO estimates used in the EIA Study (from 827 Tcf to 482 Tcf).

Sierra Club notes that all of EIA's scenarios predict greater price increases than Jordan Cove's Application. According to Sierra Club:

- Natural gas bills paid by residential, commercial, and industrial end-users will increase by 3 to 9 percent over a comparable baseline with no exports; and
- Electricity bills will increase from 1 to 3 percent in the rapid growth cases while the slower growth cases tend to show natural gas bills increasing more towards the end of the projection period.

Sierra states that, due to these price increases, EIA predicts higher gas bills and decreased consumption by all consumer classifications. Sierra Club charges that these price increases will be very large in absolute terms—gas and electricity bills will increase by $9 billion per year in the low/slow scenario and up to $20 billion per year in other scenarios. This will, according to Sierra Club, have a deep impact on industries dependent on natural gas, including farming, steel production, fertilizer manufacturing, and chemical manufacturing.

Sierra Club accordingly maintains that the result will be job losses or stymied job growth that will offset job growth projected from the export operations. In this regard, Sierra Club

[63] Sierra Club Mot. at 60.

maintains that empirical studies of communities in which the shale gas boom has occurred reveal a boom-bust economic cycle and creation of temporary transient jobs rather than permanent full time jobs.

Further, Sierra Club contends that the IMPLAN model on which Jordan Cove relies and other input-output models fail to consider counterfactuals and foregone opportunities, *i.e.*, the models map the consequences of a particular expenditure, but do not ask how the economy might have grown had investors and regulators made different choices. Nor, according to Sierra Club, do these models consider how the particular choice at issue might displace other economic activity."[64] Sierra Club asserts that input-output studies cannot determine how many jobs are created because the models do not consider whether the jobs, particularly jobs associated with natural gas production activities, might have been created even in the absence of the spending associated with Jordan Cove's proposal.

Additionally, Sierra Club contends that input-output studies may not reflect actual spending patterns or other distributional effects. For example, Sierra Club maintains that landowners with gas production leases may elect to save their money rather than spend it. Sierra Club charges that input-output models "are static, in that they provide a series of one-year snapshots. Thus, Sierra Club maintains that Jordan Cove's study measures 'job-years' but not jobs held year to year."[65]

Sierra Club further maintains that the input-output model used by Jordan Cove "claims 'credit' for every job connected to [the] entire share of the domestic production of 0.8 Bcf/d of gas Jordan Cove seeks to export."[66] Sierra Club agrees that new volumes of gas will be produced in response to Jordan Cove's proposed exports and that this increment of new

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[64] *Id*. at 63.
[65] *Id*.
[66] *Id.* at 64.

production will generate new jobs. But Sierra Club maintains that the Jordan Cove analysis is flawed because it did not identify the jobs specifically related to the proposed exports.

Moreover, Sierra Club contends that an input-output model is not readily able to evaluate rapid or large changes to the economy (such as may be associated with the "boom" in shale gas production). Nor, according to Sierra Club, is such an analysis able to deal with the complicated series of individual choices and community disruptions associated with a boom in economic activity.

Sierra Club's claims that its analysis shows that the economic benefit of the Jordan Cove proposal will be much smaller than Jordan Cove has projected and that there will be offsetting economic harms. Relying on a study conducted by Amanda Weinstein and Mark Partridge,[67] Sierra Club states that the number of jobs created by the shale gas boom in Pennsylvania were not as large as claimed by industry. From 2004 to 2010, according to Sierra Club, Bureau of Labor statistics show that only 10,000 jobs in the oil and gas sector were added within the state.

According to Sierra Club, the boom-bust cycle is typically characterized by a period of rapid growth in economic activity followed by a rapid decrease. Sierra Club states that even during the boom, few jobs will be created because the natural gas extraction industry is capital intensive. The boom cycle, Sierra Club also states, will cost local communities in expenditures for everything from road maintenance and public safety to schools. Citing a study by Susan Christopherson of the economic impacts associated with Marcellus Shale gas extraction activities,[68] Sierra Club asserts that when the bust follows due to depletion of commercially recoverable resources, local communities will suffer because population and jobs will depart the

[67] Amanda Weinstein and Mark Partridge, *The Economic Value of Shale Natural Gas in Ohio*, Ohio State University (December 2010) (Weinstein study). *Id.* at 64-65.

[68] Sierra Club relies on detailed studies from Cornell University's Department of City and Regional Planning. Sierra Club specifically cites Susan Christopherson, CaRDI Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issues* [hereinafter Christopherson study]. Sierra Club Mot. at 66.

region and there will be fewer people to support the boomtown infrastructure. Sierra Club adds that the boom-bust cycle will be exacerbated due to the long-term regional industrialization associated with the large and geologically complex development of the Marcellus Shale.

Other factors, according to Sierra Club, that undercut the economic benefits of Jordan Cove's proposal include the difficulty in converting technical natural gas field jobs directly into sustainable, well-paying local employment; the uneven employment patterns and high turnover rates in the natural gas industry; a panoply of development and environmental issues; and threats to the tourism industry for many parts of the Marcellus region, including New York's Southern Tier. Sierra Club concludes:

> [A] simple economic model, like the input-output model, like IMPLAN, cannot reliably capture the consequences of transforming an entire region of the country…. That transformation will benefit some discrete actors considerably, and some communities, if they are able to navigate the durable challenges of boom and bust economics.[69]

Sierra Club further asserts that the record in this proceeding is inadequate to support a decision to approve Jordan Cove's proposal. Additionally, if DOE/FE grants Jordan Cove's Application, Sierra Club contends that DOE/FE must impose rigorous monitoring conditions that cover (1) regional and national economic dislocations and disruptions caused by natural gas extraction, including by the industry's boom-and-bust cycle; (2) increases in gas and electricity prices and resulting shifts to more polluting fuels; and (3) environmental impacts. Sierra Club states that in setting forth these monitoring conditions, DOE/FE must provide specific monitoring terms and thresholds that will trigger agency actions of various types. Failure to provide such monitoring conditions, Sierra Club argues, would violate the NGA.

[69] *Id*. at 68.

F. Notice of Intervention, Protest, and Comments of Citizens Against LNG

Citizens Against LNG states that it is a grassroots organization formed during FERC's pre-filing phase of the Jordan Cove and PCGP import project review, and that it represents over 4,000 citizens in Southern Oregon that would be negatively affected by the Jordan Cove project.[70]

Citizens Against LNG states that the Jordan Cove Application, if granted, would be detrimental to the public interest. Citizens Against LNG argues that the proposed exports would hurt consumers by raising domestic natural gas prices. Referring to the Low Shale EUR case set forth in the EIA Study, Citizens Against LNG states that natural gas prices would increase as much as 54 percent. Referring as well to a report prepared by the staff of then-Representative Edward J. Markey,[71] Citizens Against LNG asserts that natural gas price increases due to exports would substantially increase energy bills for American consumers and could potentially have catastrophic effects on U.S. manufacturing.

Additionally, Citizens Against LNG argues that potential job gains in manufacturing if exports are not permitted are large compared to the jobs that may be created by natural gas exports. Also, according to Citizens Against LNG, any job gains from the Jordan Cove proposal would be more than offset by job losses in manufacturing. Citizens Against LNG maintains that approval of the Jordan Cove proposal would cause Coos Bay to suffer a devastating level of unemployment after the construction phase of the Terminal and the PCGP is completed.

[70] Citizens Against LNG Notice of Intervention, Protest, and Comments (Aug. 6, 2012) [hereinafter Citizens Against LNG Mot.]. Although labeled as a "Notice of Intervention," only a state commission may intervene by notice; therefore, the Citizens Against LNG submission will be construed as a motion to intervene under our regulations. *See*, 10 C.F.R. 590.303.

[71] Democratic Staff of H. Comm. on Nat. Res., *Drill Here, Sell There, Pay More: The Painful Price of Exporting Natural Gas* (2012), *available at* http://democrats.naturalresources.house.gov/sites/democrats.naturalresources.house.gov/files/2012-03-01__RPT_NGReport.pdf.

Citizens Against LNG points to the construction of a natural gas pipeline in 2003-2004 from Coos Bay to the Williams Northwest Grants Pass lateral pipeline. According to Citizens Against LNG, the developers of that pipeline promised 2,900 jobs for Coos County but "those jobs never materialized and that pipeline currently is only operating at 5 to 7 percent of its capacity."[72]

Citizens Against LNG states that Jordan Cove estimates that construction of the Terminal would create 1,100 jobs but those jobs would last only 14 months and that there would be massive unemployment thereafter. Also, Citizens Against LNG maintains that the PCGP would only generate 5 permanent employees and that the 56 to 99 jobs forecast by Jordan Cove would not make a significant dent on the jobs needed in the area, which already suffers from high unemployment. When jobs lost due to the proposed Jordan Cove facilities are taken into account, Citizens Against LNG asserts there would be a net decrease in the number of area jobs.

Citizens Against LNG disputes Jordan Cove's claim of local tax benefits from the project. Specifically, it maintains that the Terminal will not provide tax revenue to local government because the facility will sit in an Enterprise Zone and will be exempt from paying taxes for 3 or more years.

Citizens Against LNG further contends that supplies of water across the United States are not adequate to sustain the practice of hydraulic fracturing used to produce large quantities of natural gas. Citizens Against LNG contends that the environmental impacts from fracking "could spell a reduction or even a halting of fracking in some areas…."[73] Citizens Against LNG maintains that natural gas prices are likely to rise due to water shortages and that the exports proposed by Jordan Cove will drive up prices even further. According to Citizens Against LNG,

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[72] Citizens Against LNG Comment Letter at 4.
[73] Citizens Against LNG Comment Letter at 11.

by creating demand for more natural gas, the Jordan Cove project will indirectly exacerbate water scarcity.

Citizens Against LNG argues that Jordan Cove's prediction about sustained Asian demand for natural gas is likely mistaken. Citizens Against LNG bases this statement on a report of the International Energy Agency (IEA) that stated that at the end of 2011, China's remaining recoverable resources of unconventional gas totaled almost 50 trillion cubic meters (TCM) and described China's plans to develop this resource:

> These [plans] call for coalbed methane production of more than 30 bcm [billion cubic meters] and for shale gas production of 6.5 bcm in 2015; the targets for shale gas output in 2020 are between 60 and 100 bcm. They are accompanied by the goal to add 1 tcm of coalbed methane and 600 bcm of shale gas to proven reserves of unconventional gas by 2015.[74]

The same IEA report, according to Citizens Against LNG, indicates that Eastern Europe and Eurasia are planning to "vastly increase production" and they can supply natural gas to Asia by pipeline.[75] Citizens Against LNG maintains that these developments likely will create an oversupply of natural gas in Asia. In turn, according to Citizens Against LNG, the Jordan Cove project will become "economically unviable," and will be mothballed, but only after causing substantial adverse impacts on private landowners and the environment during its construction.

Citizens Against LNG charges that the process of liquefying natural gas and shipping the LNG from the United States to foreign destinations is costly and will have negative environmental impacts in terms of greenhouse gas (GHG) emissions. Citizens Against LNG refers to a report by Jaramillo, *et al*. that examined the amount of LNG consumed as fuel over long distances and found that a "loaded tanker with a rated power of 20MW, and 0.12% daily

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[74] Citizens Against LNG Comment Letter at 7 n.11 (citing International Energy Agency (2012), "Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas," at 115-20).
[75] *Id.*, citing IEA report at 87.

boil-off rate would consume 3.88 million cubic feet of gas per day…."[76] The report further found, according to Citizens Against LNG, that LNG could travel distances from 2,700 to 11,700 nautical miles when transported for international delivery. According to Citizens Against LNG, the environmental benefits of natural gas fade away when the GHG emissions associated with the export and import of LNG are taken into account.

Citizens Against LNG contends that the Jordan Cove proposal is also against the public interest because Jordan Cove is owned and controlled by foreign investors and, therefore, the profits from the enterprise will leave the United States. Citizens Against LNG notes that 75 percent of Jordan Cove and its general partner are owned by Fort Chicago LNG II U.S.L.P., which in turn is owned and controlled through a number of intermediaries by Veresen. Citizens Against LNG maintains that Veresen is a Canadian limited partnership in which only Canadians are allowed to invest.

Citizens Against LNG maintains also that the Application failed to analyze the economic impacts of Jordan Cove's proposal on local tourism and recreation; commercial and recreational fishing; and timber production. Citizens Against LNG refers to the significant economic contributions made to the economy by each of these industries and implies that the approval of the Jordan Cove proposal will have negative economic and environmental impacts. More specifically, Citizens Against LNG raises the following matters:

- Tourism, according to Citizens Against LNG, contributed more than a billion dollars to Coos County from 2007 to 2011and steadily increased from $94.5 million in 1991 to $220.1 million in 2011. Additionally, Citizens Against LNG states that there are 3,090 jobs in

[76] Citizens Against LNG Comment Letter at 9 n.15 (citing Jaramillo, P., et al. (Sep. 2007) "Comparative Life-Cycle Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation," Environ Sci Technol. 41(17); 6290-96).

Coos County related to the tourism industry and these jobs are "*a direct result of not developing our beaches, dunes, and coastline*."[77]

- With respect to commercial and recreational fishing, Citizens Against LNG notes that $20.1 million worth of fish and shell fish were landed at Charleston in 2006 but Jordan Cove's proposed pipeline construction will destroy restored fish runs in Southern Oregon and damage oyster beds. Citizens Against LNG also states that the ECONorthwest study did not account for the time it would take the Department of Homeland Security to clear Coos Bay before an LNG tanker would transit through the Bay, nor provide an accurate number of potential ship transits. For each transit of an LNG tanker through Coos Bay, according to Citizens Against LNG, a security zone that in some cases would encompass the entire width of Coos Bay will have to be established and other boat traffic will have to be shut down from 90 minutes to 2 hours. According to Citizens Against LNG, this will be an extreme hardship on the commercial fishing fleet that also needs high slack tides in order to transit Coos Bay.

- Timber production also will be negatively affected by the Jordan Cove proposal, according to Citizens Against LNG. Citizens Against LNG identifies several alleged negative environmental impacts but also maintains that the Jordan Cove project will significantly increase the cost of timber production, that timber production is a low profit margin business, and these increased costs are likely to drive some businesses to close. Timber industry jobs will also be lost, Citizens of LNG states, due to the flooding of the market with 144 miles of forestlands that will be clear-cut for pipeline construction.[78]

- Citizens Against LNG charges that the thermal radiation zones and flammable vapor dispersion zones associated with the Terminal will interfere with and preclude other uses

[77] Citizens Against LNG Comment Letter at 11.
[78] Insofar as Citizens Against LNG raise other objections relating to the environmental impact of the Jordan Cove proposal, those will be addressed following the completion of the FERC's review of the project.

of the Port. Citizens Against LNG refers specifically to a plan to develop a wind energy project at the Port and to the Port's proposed Oregon Gateway cargo terminal, which will not be permitted to operate in these hazard zones. Citizens Against LNG maintains that the Coast Guard has established a 150-yard security zone around each LNG tanker berthed at the docking facility, plus a moving 500 yard security/safety zone around each LNG tanker. According to Citizens Against LNG, these security/safety zones mean that, realistically, the Port only will be able to serve LNG terminal purposes. Moreover, Citizens Against LNG state that the ECONorthwest study assumes that there will only be 80 to 90 shipments per year, not the "more realistic" number of 186 to 232.

G. Landowners United Notice of Intervention and Protest

Landowners United, representing itself as a grassroots organization of landowners who will be directly affected by the PCGP, submitted a Notice of Intervention and Protest.[79] Landowners United maintained that the proposed LNG terminal, storage tanks, and liquefaction facility "is not a well conceived or appropriate industry for the Southern Oregon Coast and that LNG represents an unacceptable risk to the people of the State of Oregon."[80] Landowners United also asserts that approval of the Jordan Cove project will drive up the price of natural gas domestically to the detriment of the U.S. economy.

H. Comments and Motion to Intervene of KS Wild

KS Wild states that it is a non-profit public interest conservation organization with approximately 3,000 members. It maintains that its members, staff, and board regularly use and enjoy the Rogue River-Siskiyou, Umpqua and Fremont-Winema National Forests, Medford, Roseburg and Coos Bay BLM Districts, and the Rogue River and its tributaries for hiking,

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[79] Landowners United's submission will be construed as a motion to intervene. 10 C.F.R. § 590.303.
[80] Landowners United Intervention and Protest, at 1.

camping, hunting, fishing, nature study, scientific study, photography, swimming and general recreational and aesthetic purposes. KS Wild states further that its members have been actively involved in oversight of public resource management in these areas. KS Wild asks for intervenor status and seeks to join in Sierra Club's motion to intervene and protest.

I. Answers of Applicant and Citizens Against LNG's Response

On August 29, 2012, Jordan Cove filed an "Answer of Jordan Cove Energy Project, L.P. to Protests." Jordan Cove appended a study, *The Impact of the Jordan Cove Energy Project on Coos Bay Housing and Schools* (Housing and Schools Study)[81] to its Answer.[82] On September 13, 2012, Citizens Against LNG filed a response to Jordan Cove's Answer.[83]

1. Answer of Jordan Cove to Protests

Jordan Cove maintains that the opponents of its proposal to export LNG have failed to overcome the statutory presumption that the proposal is consistent with the public interest. Insofar as Sierra Club and other opponents of the proposal have submitted arguments related to the environmental review and potential environmental impacts of the proposal, Jordan Cove submits that the arguments are not properly raised in this proceeding.

Jordan Cove likewise rejects Sierra Club's argument that DOE may not issue a conditional authorization prior to the completion of environmental review. Jordan Cove submits that Sierra Club is incorrect in asserting that the issuance of a conditional order means that DOE/FE has completed its public interest determination. Further, Jordan Cove maintains that

[81] ECONorthwest, The Impact of the Jordan Cove Energy Project on Coos County Housing and Schools (May 14, 2012).

[82] DOE/FE issued a letter order on August 17, 2012 (reissued August 20, 2012) providing Jordan Cove until August 29, 2012 to submit its Answer to the protests.

[83] Hereinafter "Citizens Against LNG Response." Neither the Notice of Application in this proceeding nor DOE's regulations provide an opportunity for responses to answers to protests. *See*, 10 C.F.R. 590.304. DOE/FE, however, finds that no party has opposed the submission of the Citizens Against LNG response and no party will be unduly prejudiced by our consideration of the pleading. Accordingly, the Citizens Against LNG Response will be accepted for filing.

the position taken by Sierra Club is contrary to years of established practice (dating to the 1980's) by DOE/FE and, previously, by the Economic Regulatory Administration. DOE/FE's authority to issue conditional orders, according to Jordan Cove, is supported by the language of NGA section 3, which authorizes DOE/FE to impose "such terms and conditions as [it] may find necessary or appropriate."[84] Jordan Cove submits that the inclusion of identical language in the 2005 amendment of NGA section 3[85] represents additional affirmation of this authority by Congress. Jordan Cove notes that the authority to issue conditional orders is also expressly set forth in DOE's regulations at 10 C.F.R. § 590.402 and points out that courts have upheld the authority of various regulatory agencies to issue conditional orders. Jordan Cove maintains as well that Sierra Club has not identified any legal authority to support its contrary position.

Jordan Cove further criticizes Sierra Club's contention that issuance of a conditional order prior to completion of environmental review is prohibited because of DOE regulations at 10 C.F.R. § 1021.211 and Council on Environmental Quality NEPA regulations at 40 C.F.R. § 1506.1(a). Jordan Cove asserts that DOE and CEQ regulations prohibit an "action" prior to issuance of a decision on an EIS but that DOE/FE's issuance of a conditional order does not constitute an "action" for these purposes. This is so, argues Jordan Cove, because DOE and CEQ regulations, respectively 10 C.F.R. § 1021.104(b) and 40 C.F.R. § 1508.18(b)(4), define an "action" as approval of a project. Jordan Cove submits that without a final order, there can be no "action" that has an adverse environmental impact or that limits the choice of alternatives. Moreover, Jordan Cove maintains that, given the tremendous investments of time and money and the long lead times involved in export projects, DOE/FE's practice of issuing conditional orders is an important signal to project sponsors and potential customers. This contributes to an

[84] 15 U.S.C. § 717b(a).
[85] 15 U.S.C. § 717b(e)(3)(A). This provision was added by section 311 of the Energy Policy Act of 2005 (Pub. L. 109-58 (Aug. 8, 2005)).

efficient regulatory process, according to Jordan Cove, because there would be no reason to complete the EIS process if DOE/FE determines that a proposed export is not consistent with the public interest for non-environmental reasons.

Jordan Cove also defends its reliance on studies that employed the IMPLAN methodology. Jordan Cove maintains that the IMPLAN methodology is transparent and allows the inclusion of data specific to its proposal. In this regard, Jordan Cove states that Sierra Club's general criticisms of IMPLAN do not apply in this case, *i.e.* contrary to Sierra Club's charge: (1) the ECONorthwest analysis accounts for earnings used for taxes, savings, or spending outside of Oregon and Washington; and (2) ECONorthwest measured the number of jobs created in each year by defining one job as 2,080 hours worked and did not count every position on a construction project as a "job" even if the position lasted only a few weeks.

Jordan Cove disputes Sierra Club's charge that the IMPLAN methodology is flawed because it does not consider counterfactuals and foregone opportunities. According to Jordan Cove, Sierra Club's insistence that DOE/FE must consider how the economy might have grown had investors and regulators made different choices is beyond any reasonable jurisdictional scope. Jordan Cove adds that the studies based on the IMPLAN model form only part of the case submitted in support of the proposed exports. Jordan Cove notes that the IMPLAN model is widely used by over 2000 public and private institutions, including many federal and state government agencies. Citing five different economic studies from 2012, Jordan Cove maintains that even Sierra Club frequently relies on IMPLAN analysis when supportive of its cause.[86]

Jordan Cove charges that the opponents of the Application have not carried their burden to show that the proposal is contrary to the public interest. Jordan Cove asserts that Sierra Club did not submit an economic analysis of the proposal in this proceeding but, instead, relied on

[86] Answer of Jordan Cove at 11 n.32.

studies concerning the economic impacts of the development of the Marcellus Shale. Such information, Jordan Cove states, is irrelevant to the current proceeding where the source of natural gas is Canada and the U.S. Rocky Mountains. Jordan Cove argues as well that the boom-bust cycle described in Sierra Club's submissions is unlikely to occur in respect to the present proposal because the exploration risk is significantly less and the production process is more manageable than conventional gas development. Jordan Cove states: "Thus supply is much more responsive to demand and there is no reason to expect a bust cycle for the predicted employment increase…."[87] Jordan Cove notes that the benefits documented in the Upstream Contributions Study are domestic U.S. benefits and did not include the benefits in Canada.

Jordan Cove responds as well to Citizens Against LNG's charge that, once construction is completed, the proposal will cause massive unemployment. According to Jordan Cove, Citizens Against LNG relies on outdated construction employment data from the final EIS for the import proposal and ignores the Construction Study in this proceeding. Jordan Cove maintains that direct employment data indicates that the Terminal and PCGP will average 1,768 jobs over a four year period with total direct labor income over that period of $730 million. Most of these jobs, Jordan Cove asserts, will be in Coos Bay and surrounding areas. Jordan Cove submits that the temporary jobs created by this construction effort are going to be a "lifeline" for workers searching for longer term work. Also, according to Jordan Cove, for post-construction regional unemployment to be higher than current unemployment, temporary construction workers would have to relocate to Coos Bay permanently in large numbers. But Jordan Cove points out that the Housing and School Study estimated an increase of 244 households, not large enough to increase unemployment, and that increase could be absorbed by the permanent jobs that Jordan Cove will create. Jordan Cove claims that there will be 736 permanent jobs, including 150 directly funded

[87] *Id.* at 13.

by Jordan Cove and PCGP, and an additional 586 indirectly supported.

Jordan Cove disputes Citizens Against LNG's argument that the proposal will have other negative net economic impacts. While Citizens Against LNG quotes from the final EIS in the import project proceeding, Jordan Cove argues that Citizens Against LNG has ignored the overall conclusion in that final EIS that the impacts of the proposed import facility would be "less than significant," provided proper mitigation measures were deployed. Jordan Cove also disputes Citizens Against LNG's claim that the Terminal will not provide tax revenue to local government because the facility will sit in an Enterprise Zone. Jordan Cove states that the tax exemption is of limited duration, and that Jordan Cove has committed to compensate Coos County by making a $30 million annual contribution, including $20 million for public K-12 education and $10 million for projects of the Bay Area Urban Renewal Association.

Jordan Cove asserts that APGA and Sierra Club have erred in criticizing the Navigant Study. With respect to supply projections, Jordan Cove states that the opponents are incorrect in arguing that the relevant export volumes for study are the total volumes of all proposed projects or the sum of requested FTA and non-FTA export volumes. The relevant export volumes for study, according to Citizens Against LNG, are the quantities that are likely to be exported. Jordan Cove accordingly rejects APGA's suggestion that a range of aggregate export capacities needs to be examined. Jordan Cove asserts that most expert opinion indicates that it is unlikely that LNG exports from the United States will exceed 6 Bcf/d. Jordan Cove states that the standard supported by Sierra Club does not relate to economic modeling but solely to NEPA analysis.

Jordan Cove also rejects the APGA/Sierra Club criticism that the Navigant Study was flawed because AEO 2012 projected a reduction in unproved technically recoverable shale gas.

Even with this reduction, Jordan Cove maintains that the total recoverable natural gas resource is ample (representing more than 90 years of supply). Additionally, Jordan Cove states that production is the key relevant statistic for these purposes and EIA recognized that changes in the resource estimate will not have a significant impact on projected natural gas production, consumption, and prices.

Jordan Cove reiterates that the Navigant Study was based on "conservative" estimates of production in that those forecasts incorporate only actual current production and do not incorporate undeveloped plays such as the Utica Shale. On the other hand, drawing from the Navigant Whitepaper, Jordan Cove maintains that the supply forecasts in the EIA Study are too low, some of its scenario combinations are unrealistic, some of its single year effects are not representative, and its focus solely on Gulf Coast exports is not pertinent to Jordan Cove. In particular, Jordan Cove notes the absence of a West Coast facility in the EIA Study: "The salient fact is that the supplies to be exported from the Jordan Cove Terminal will be sourced initially primarily from Canada and otherwise from the U.S. Rockies and, had that fact been reflected in the EIA Study, it would have had a dampening impact on EIA's price projections."[88]

Jordan Cove maintains that the price impact of its proposal most likely will be moderate and states that the focus of the opponents of the proposal on EIA's Low Shale EUR Case and the High/Rapid export scenario is erroneous. This focus, Jordan Cove charges, is premised on the appropriateness of examining the volume of proposed exports or total export capacity requested rather than actual volumes likely to be exported (discussed above). Jordan Cove maintains that EIA's Low Shale production forecast is extremely low and highly unlikely: "[I]t starts out at less than half of current actual production levels … and even by 2035 it still lags behind the current

[88] *Id.* at 23.

production levels."[89]

Jordan Cove also rejects APGA's claim that Navigant's GHG Demand Case is "most realistic" because it factors in the switch from coal-fired electric generation to natural gas that is already occurring. Jordan Cove points out that this fuel-switching phenomenon is reflected in all scenarios in the Navigant Study. The GHG Demand Case, Jordan Cove asserts, is notable because it reflects additional GHG reduction regulation. But Jordan Cove states that legislation to regulate GHGs is losing favor, thereby rendering the GHG Demand Case a less appropriate scenario. Jordan Cove also states that the GHG Demand Case did not factor in a supply response to additional GHG regulation in the form of a general infrastructure build-out.

Jordan Cove argues that DOE/FE should focus on price levels in the more likely scenarios. While the EIA's High Shale EUR Case has defects, Jordan Cove maintains that it is the most reasonable EIA case. Jordan Cove states that the price levels in the High Shale EUR Case, even for the High/Rapid export scenario, are in line with the $4 to $6 price level identified in the Navigant Study as needed to support the development of shale gas. Jordan Cove states that this price range also is within the range for "long-run equilibrium price" estimated by Dr. Kenneth Medlock III in an August 2012 report entitled *US LNG Exports: Truth and Consequence*.[90]

Jordan Cove submits that the best measurement of the price impacts of its proposal is Navigant's Jordan Cove Export Case. The per MMBtu price levels in this Case average $5.18 at Sumas, $5.22 at Malin, and $5.46 at Henry Hub over the first half of the 29-year forecast period (2017-2045); and $7.24 at Sumas, $7.28 at Malin, and $7.60 at Henry Hub over the second half

[89] *Id.* at 24.
[90] *Id.* at 25 n.73 (citing Kenneth Medlock, *US LNG Exports: Truth and Consequence* (2012), *available at* http://bakerinstitute.org/media/files/Research/da5493d4/US_LNG_Exports_-_Truth_and_Consequence_Final_Aug12-1.pdf).

of the forecast period. In the Aggregate Export Case, which assumes LNG export volumes of 6.6 Bcf/d, the average price levels in the first half of the forecast period are $5.47 at Sumas, $5.50 at Malin, and $5.84 at Henry Hub; in the second half of the forecast period, the respective prices are $751 at Sumas, $7.56 at Malin, and $7.92 at Henry Hub. Jordan Cove states that the export volumes of 6.6 Bcf/d in the Aggregate Export Case are in line with the consensus view of a likely export volume of 6.0 Bcf/d and yet, according to Jordan Cove, the price increases are "still relatively minor"[91] (although larger than in the Jordan Cove Export Case). Jordan Cove stresses also that the projected price increases for the second half of the forecast period may be overstated since Navigant assumed no new gas supply basins and no unannounced pipeline and storage projects other than expansions necessary to avoid bottlenecks in modeling.

Jordan Cove disputes APGA's claim that LNG exports will limit natural gas supply. Instead, Jordan Cove maintains that LNG exports will provide a new market in a currently oversupplied market and will spur exploration and development of shale gas assets in North America, thereby contributing to the long-term sustainability of the gas market and to reduced price volatility.

Jordan Cove also challenges claims by the opponents of its Application that jobs will be lost due to LNG exports. Jordan Cove observes that Citizens Against LNG quotes a letter from Industrial Energy Consumers of America to the Brookings Institution to support its position. Jordan Cove maintains that the letter did not say that manufacturing jobs would be lost, but merely advises that decisions about exports should include an analysis of the potential impact on the domestic economy and job creation. Jordan Cove also notes that the American Chemistry Council does not oppose exports, contrary to reports, and in fact issued a press release criticizing inaccurate reporting and endorsing a free market approach.

[91] *Id.* at 26.

Jordan Cove denies APGA's claim that LNG exports will undermine the use of natural gas as a bridge fuel.[92] Jordan Cove states that APGA did not submit any economic modeling to support its claim, and points out that Navigant's studies indicate that the ramp up of coal-to-gas switching will mostly have occurred before the price impacts of Jordan Cove's exports begin. Also, Jordan Cove maintains that other factors, including abundant supplies, environmental regulations, and other reasons for generators to abandon inefficient older coal-fired power plants will continue to favor fuel-switching.

Jordan Cove agrees that DOE/FE should to the maximum extent consistent with its statutory obligations allow natural gas markets to operate freely. Insofar as APGA contends that the proposed exports will not prove economical and Citizens Against LNG argues that Asian demand projections may be incorrect, Jordan Cove insists that its decision to take on the market risk of the proposal is not a relevant factor for DOE/FE's public interest analysis.

2. Citizens Against LNG's Response to Jordan Cove's Answer

Citizens Against LNG submitted a response[93] to Jordan Cove's Answer in order to argue that DOE/FE should undertake an independent economic analysis of the reports prepared by ECONorthwest and used by Jordan Cove to support its proposal. Citizens Against LNG explains that, in October 2006, the South Coast Development Council relied on another ECONorthwest report when it supported Jordan Cove's application for FERC authorization to construct an import facility. According to Citizens Against LNG, FERC relied on that report in the preparation of its EIS on the import facility proposal. Although Jordan Cove ultimately did not implement the FERC authorization for an import facility, Citizens Against LNG maintains that the ECONorthwest report was incorrect because it did not include negative economic impacts

[92] *Id.* at 28 n.81.
[93] Citizens Against LNG Response at 2.

that would have resulted if the import authorization had been implemented and the import project "obviously" would not have produced the economic benefits and jobs predicted in the report.

Citizens Against LNG also refers to a report prepared by ECONorthwest in 2008 used in support of a proposed expansion of the Salmon Harbor resort in Winchester Bay, Oregon. According to Citizens Against LNG, the United States Department of Agriculture (USDA), after investigating, found that the projections in the ECONorthwest were not feasible and USDA consequently pulled its funding for the expansion.

Based on these developments, Citizens Against LNG maintains that DOE should not rely on the ECONorthwest reports submitted by Jordan Cove in this proceeding, but should undertake its own analysis of the economic benefits and losses from the Jordan Cove proposal. Citizens Against LNG refers to DOE's 2006 Passamaquoddy Whole Bay Study (Part 1)[94] as an example of a suitable analysis.

VIII. COMMENTS ON THE LNG EXPORT STUDY AND DOE/FE ANALYSIS

In the NOA, DOE/FE sought public comment on the EIA and NERA studies, including the modeling scenarios used in both studies. DOE/FE specifically invited comment on "the impact of LNG exports on: domestic energy consumption, production, and prices, and particularly the macroeconomic factors identified in the NERA analysis, including Gross Domestic Product (GDP), welfare analysis, consumption, U.S. economic sector analysis, and … any other factors included in the analyses."[95] DOE noted that, "[w]hile this invitation to comment covers a broad range of issues, the Department may disregard comments that are not germane to the present inquiry."[96]

[94] Yellow Wood Associates, Inc., *Report on Potential Economic and Fiscal Impacts of LNG Terminals on the Whole Passamaquoddy Bay* (2006).
[95] 77 Fed. Reg. at 73,629.
[96] *Id.*

As explained in the Introduction, DOE/FE spent several months reviewing the more than 188,000 initial and 2,700 reply comments received in response to the NOA. Given the volume of comments, it is neither practical nor desirable for DOE/FE to summarize each of them. Therefore, DOE/FE identifies below both: (i) the pertinent arguments by topic, with reference to representative comments, and (ii) DOE/FE's basis for the conclusions that it drew in reviewing those comments. In so doing, DOE/FE will respond to the relevant, significant issues raised by the commenters.[97]

A. Data Inputs and Estimates of Natural Gas Demand

1. Comments

Several commenters, including Sierra Club,[98] Dow Chemical Company (Dow), along with U.S. Representative Edward Markey, U.S. Senator Ron Wyden, Alcoa, Save Our Supplies, the Industrial Energy Consumers of America (IECA), and Jannette Barth, challenge the data used as inputs to the LNG Export Study. Most of these commenters assert that NERA should have used projections from AEO 2012 or AEO 2013, rather than from AEO 2011, to produce a more accurate picture of the current and likely future state of the natural gas market and the likely macroeconomic impacts of LNG exports. These commenters assert that the AEO 2011 projections significantly underestimate actual and future demand for natural gas, especially in the U.S. electric, manufacturing, and transportation sectors, and in international markets. Some commenters identify additional factors, other than the vintage of the AEO 2011 data, to support their arguments that NERA underestimated present and future demand for natural gas. For example, Save Our Supplies argues that NERA underestimated international demand because

[97] *See, e.g.*, *Public Citizen v. F.A.A.*, 988 F.2d 186, 197 (D.C. Cir. 1993).
[98] Sierra Club filed comments on behalf of itself and a coalition of non-profit organizations, including Catskill Citizens for Safe Energy, Center for Biological Diversity, Clean Air Council, Columbia Riverkeeper, Delaware Riverkeeper, Lower Susquehanna Riverkeeper, Shenandoah Riverkeeper, and Upper Green River Alliance [hereinafter Sierra Club].

the GNGM model did not appear to account for the continued growth of international LNG import infrastructure. Together, these commenters assert that the NERA Study underestimated future demand for natural gas and, consequently, underestimated the likely increases to natural gas prices from LNG exports.

A number of commenters, including Sierra Club, Dow, Senator Wyden, Representative Markey, Jannette Barth, and Save Our Supplies maintain that, as compared to AEO 2011, the AEO 2013 Early Release Overview projects a substantial increase in demand for natural gas in the industrial manufacturing sector.[99] Dow claims that there has been a manufacturing renaissance since completion of AEO 2011 involving announcements of approximately 100 capital investments representing some $95 billion in new spending and millions of jobs driven largely by the supply and price outlook for natural gas. These investments, according to Dow, will add about 5 million new jobs and 6 Bcf/d of industrial gas demand by 2020, which Dow states is nearly a 30 percent increase in industrial demand relative to 2009, the baseline year for AEO 2011.

Dow also asserts that projections of future natural gas demand by industry are more than double the demand predicted in AEO 2011's High EUR case, which includes significantly higher demand than the Reference Case. In addition to significantly higher projections of demand for manufacturing, Dow refers to projections from Wood Mackenzie, CERA, and others that indicate a potential increase of transportation demand from 0.2 to 1.5 Bcf/d from 2013 to 2020. This compares to AEO 2011's projection of a modest increase for natural gas demand in the

[99] During the time of the comment period on the LNG Export Study, the AEO 2013 Early Release was the most current AEO available, and is therefore discussed in many of the comments. On May 2, 2013, after the comment period had closed, EIA issued its final AEO 2013 projections. *See* U.S. Energy Information Administration, *Annual Energy Outlook 2013 with Projections to 2040* (April 2013), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf [hereinafter AEO 2013]. Where appropriate, this Order uses the final projections from AEO 2013, which is the most current information available at this time.

transportation sector of 0.1 to 0.2 Bcf/d of natural gas. Dow states that the higher level of demand derived from Wood Mackenzie and CERA is the result of a projection of fleet vehicles converting to LNG and compressed natural gas.

According to Dow, AEO 2011 projects that natural gas demand for power generation will decrease through the end of the decade, whereas Wood Mackenzie and CERA predict that natural gas use in the power sector will increase 14 percent by 2020, ultimately resulting in 24.7 Bcf/d of power sector demand. This projected increase is due to unidentified, anticipated changes in carbon policy, renewables policy, and nuclear policy favoring the use of natural gas in the power sector.

In addition to criticizing the projections of demand based on AEO 2011, Dow maintains that the level of exports authorized to date and additional exports that may be authorized in the future will drive up demand levels even higher. Specifically, Dow asserts that NERA's conclusion that prices will not increase by more than $1.11/Mcf is based on a faulty assumption that natural gas exports will never rise above 6.72 Tcf/yr, or roughly 18.5 Bcf/d by 2025. Dow points out that authorized exports to FTA nations as of January 1, 2013 had already reached approximately 28 Bcf/d. Dow complains that NERA did not consider what would happen if exports attained the authorized levels. In that event, Dow asserts that domestic gas prices undoubtedly would spike. Other commenters, such as Citizens Against LNG, make similar arguments. Citizens Against LNG alleges that the NERA Study is flawed because it failed to estimate the impact of the full potential volume of exports of approximately 31.41 Bcf/d to FTA nations and 24.80 Bcf/d to non-FTA nations.

Contrary to the above arguments, several commenters, such as DCP, Lakes Charles Exports, and Gulf LNG Liquefaction Company, LLC (Gulf LNG), argue that NERA reasonably relied on data from AEO 2011. These commenters state that NERA used the AEO 2011 data because the EIA portion of the LNG Export Study used that data, and DOE/FE sought to ensure consistency across both parts of the LNG Export Study. Further, a number of commenters, including America's Natural Gas Alliance, Exxon Mobil Corporation (ExxonMobil), Golden Pass Products LLC, American Petroleum Institute, former Secretary of Energy Spencer Abraham, Carl Foster, and the Western Energy Alliance, argue that NERA's use of the AEO 2011 data does not undermine the results of the LNG Export Study. These commenters contend that the AEO 2013 Early Release data show higher production of natural gas and a more elastic supply of natural gas than the AEO 2011 data used by NERA, indicating that the domestic resource base could more easily accommodate increasing domestic demand as well as demand from new LNG export projects.

With respect to Dow's claim that there is $95 billion of new investment in domestic manufacturing, Lake Charles Exports and Secretary Abraham argue that many of the projects listed by Dow are currently under consideration and not projected to commence operation until far into the future. These commenters assert that Dow provided no information as to when or whether these projects will materialize. The commenters conclude that there is no reasonable basis to believe that these domestic manufacturing investments will lead to an additional 6 Bcf/d in domestic natural gas demand as claimed by Dow.

2. DOE/FE Analysis

a. Use of AEO 2011 Projections

DOE's basis for relying on AEO 2011. The LNG Export Study was based on AEO 2011 projections, which were the most recent, final projections available in August 2011 when DOE commissioned the EIA Study, and also in October 2011 when DOE commissioned the

NERA Study. As explained above, the NERA Study was designed so that NERA would use the results from the EIA Study as inputs to the NERA model to ensure congruence between the two studies, which together formed the single LNG Export Study. If both studies had not relied on the same data, meaningful comparison and cross-analysis of the two studies would have been impossible.

Although some commenters have asserted that DOE should have required EIA and NERA to use newer projections than those in AEO 2011, this argument does not acknowledge either the timing of the AEO publication cycles, or the lead time required of EIA and NERA to conduct their work. Using the final AEO 2011 projections, EIA published its study on January 19, 2012. Only four days later, on January 23, 2012, EIA published the 2012 AEO "Early Release Overview," which was a preliminary, abridged version of EIA's forthcoming AEO 2012. It would not have been possible for EIA to use the 2012 Early Release projections in its study without starting over once that data had been published.

Indeed, EIA did not publish the final AEO 2012 until June 2012, six months after EIA had published its study for this proceeding. By that time, the NERA Study was well underway. NERA published its final report in December 2012—the same month that EIA released the AEO 2013 Early Release Overview. As stated above, EIA did not publish the final AEO 2013 projections until May 2, 2013.

In an undertaking of this scope and magnitude, it was perfectly reasonable to base the LNG Export Study on AEO 2011, which contained the best, most authoritative economic projections available when DOE/FE commissioned the EIA and NERA studies. Once both studies were underway, a decision to use AEO 2012 or AEO 2013 Early Release projections would have required EIA and NERA to abandon their existing work and redo much, if not all, of their analyses.

Courts have repeatedly recognized that agencies are not required to redo a study simply because newer data become available, "particularly given the many months required to conduct full [analysis] with … new data."[100] Requiring DOE to start over with new data "would lead to significant costs and potentially endless delays."[101] Moreover, under the commenters' rationale, DOE's LNG Export Study and administrative process would run indefinitely, as DOE would have to start over with new AEO projections whenever they became available. As the Supreme Court has observed, if an agency were required to rehear new evidence before it issues a final administrative decision, "there would be little hope that the administrative process could ever be consummated in an order that would not be subject to reopening."[102]

No material change using post-AEO 2011 projections. Further, we are not persuaded that using post-AEO 2011 EIA projections would have materially affected the findings of the LNG Export Study. Commenters point to the fact that AEO 2012 and the AEO 2013 Early Release Overview forecast greater domestic natural gas consumption in the years ahead than did AEO 2011. The commenters are correct in this observation, but it is also true that AEO 2012 and the AEO 2013 Early Release Overview projected much greater domestic natural gas production than did AEO 2011. For example, in the LNG Export Study proceeding, Jordan Cove submitted an analysis from Navigant correctly noting the increasing gas production projections in the later EIA analyses: For the period of 2013-2035, there was an average percentage increase in forecast total domestic natural

[100] *Theodore Roosevelt Conserv. P'ship v. Salazar*, 616 F.3d 497, 511 (D.C. Cir. 2010) (quotations and citations omitted) (alteration in original).
[101] *Sierra Club v. U.S. Envtl. Prot. Agency*, 356 F.3d 296, 308 (D.C. Cir. 2004) (upholding EPA's decision to use an existing computer model in lieu of a newly-released version).
[102] *Vermont Yankee Nuclear Power Corp. v. Natural Res. Def. Council*, 435 U.S. 519, 554-55 (1978).

gas consumption between AEO 2011 and AEO 2013 of 5.6 percent, while the increase in forecast total natural gas production was 16 percent. This important context helps explain why the AEO 2013 assumptions actually indicate the beneficial market impacts that come from LNG exports.[103]

Using the later-published final AEO 2013 Reference Case (see Table 4 below) illustrates that, although total natural gas consumption projected for 2035 was projected to increase by 6 Bcf/d between AEO 2011 and 2013 (from 72.7 Bcf/d to 78.7 Bcf/d), total domestic dry gas production was projected to increase by more than twice that amount, increasing by 13.8 Bcf/d (from 72.1 Bcf/d to 85.9 Bcf/d). In addition, the projected 2035 Henry Hub price declined from $7.07/MMBtu to $6.32/MMBtu, despite net exports (including both pipeline and LNG exports) rising from -0.5 Bcf/d in AEO 2011 to +7.0 Bcf/d in AEO 2013. Although the data used in Table 4 for "AEO 2013 Reference Case" refer to the final AEO 2013 projections, the data are unchanged from EIA's projections in the AEO 2013 Early Release Overview. As the table shows, the final AEO 2013 Reference Case projects domestic supply and demand conditions that are more, not less, favorable to exports.

On December 16, 2013, EIA issued its most recent projections for 2035 in the AEO 2014 Early Release Overview.[104] As depicted in Table 4, projections from that report reflect net LNG exports from the United States in a volume equivalent to 9.2 Bcf/d of natural gas.[105] Of this projected volume, 7.4 Bcf/d are exports from the lower-48 states, 0.4 Bcf/d are imports to the

[103] Comments of Navigant Consulting, Inc., at 6 (attached to Initial Comments of Jordan Cove Energy Project, L.P.).
[104] U.S. Energy Information Administration, *AEO 2014 Early Release Overview* (Dec. 16, 2013), *available at* http://www.eia.gov/forecasts/aeo/er/?src=home-b4 [hereinafter AEO 2014 Early Release Overview].
[105] *See* AEO 2014 Early Release Overview Table, "Natural Gas Imports and Exports," *available at* http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014ER&subject=8-AEO2014ER&table=76-AEO2014ER&region=0-0&cases=ref2014er-d102413a & AEO 2014 Early Release Overview at 2 (Fig. 4), *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf.

lower-48 states, and 2.2 Bcf/d are exports from Alaska.[106] This estimate compares with projected net LNG imports of 0.4 Bcf/d in the lower-48 for 2035 in the AEO 2011 Reference Case. The 2035 Henry Hub price in the AEO 2014 Early Release Reference Case is $6.92/MMBtu, down from $7.31/MMBtu in the AEO 2011 Reference Case (both in 2012 dollars).

Table 4 also compares the AEO 2014 Early Release Reference Case to the AEO 2013 Reference Case, indicating that:

- Total natural gas consumption for 2035 is projected to increase by 4.7 Bcf/d, from 78.7 Bcf/d to 83.4 Bcf/d;

- Net exports (including both pipeline and LNG exports, including 2.2 Bcf/d of LNG exports from Alaska) are projected to increase by 8.1 Bcf/d, from 7.0 Bcf/d to 15.1 Bcf/d; and

- The projected 2035 Henry Hub price is projected to increase by $0.49/MMBtu, from $6.43/MMBtu to $6.92/MMBtu (in 2012 dollars).

Indeed, in comparing the AEO 2014 Early Release and AEO 2013 Reference Case projections, total domestic dry gas production is projected to rise by 13 Bcf/d of natural gas, from 85.9 Bcf/d to 98.9 Bcf/d (although this increase includes Alaska natural gas production). We also note EIA's projection in the AEO 2014 Early Release Overview that domestic prices of natural gas will rise due to both increased domestic demand and exports, but that these price increases will be followed by "[a] sustained increase in production … leading to slower price growth over the rest of the projection period."[107] These post-AEO 2011 projections in no way undermine our conclusion regarding the consistency of the proposed exports with the public interest.

Moreover, we find that our review of the post-AEO 2011 data is responsive to the Jordan Cove's contention, based on the Navigant Whitepaper submitted in this

[106] *Id.*
[107] AEO 2014 Early Release Overview at 7, *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf.

proceeding, that the EIA Study was based on outdated and overly modest projections of gas supply. Likewise, it is responsive to the arguments of the opponents of the Application challenging Jordan Cove's projection of 6.6 Bcf/d of export capacity in the Aggregate Export Case. Our analysis has examined the most recent supply data available, as well as projections of export capacity that exceed 6.6 Bcf/d of natural gas.

Table 4: Comparison of AEO Cases

Projections for 2035	**AEO 2011 Reference Case**	**AEO 2012 Reference Case**	**AEO 2013 Reference Case**	**AEO 2014 Early Release Reference Case**	**AEO 2011 High Shale EUR Case**
Total Natural Gas Consumption (Bcf/d)	72.7	73.0	78.7	83.4	81.2
Electric Power Sector Consumption (Bcf/d)	21.6	24.5	25.9	29.2	26.4
Transportation Sector Consumption (Bcf/d)	0.4	0.4	1.6	1.3	0.7
Domestic Dry Gas Production (Bcf/d)	72.1	76.5	85.9	98.9	82.5
Net Natural Gas Exports by Pipeline (Bcf/d)	-0.1	1.9	3.0	5.9	1.9
Net Natural Gas Exports as LNG (Bcf/d)	-0.4	1.8	4.0	9.2	-0.4
Henry Hub Price, $/MMBtu (Reference Basis)	$7.07 (2009$)	$7.37 (2010$)	$6.32 (2011$)	$6.92 (2012$)	$5.35 (2009$)
Henry Hub Price (2012$ Basis)	$7.31/MMBtu	$7.62/MMBtu	$6.43/MMBtu	$6.92/MMBtu	$5.53/MMBtu

Note: AEO 2011 through AEO 2013 did not include Alaska LNG exports. As stated above, in the AEO 2014 Early Release Overview, EIA's projection of LNG exports from the lower-48 states in 2035 is 7.4 Bcf/d, LNG imports from the lower-48 states are 0.4 Bcf/d, and LNG exports from Alaska are 2.2 Bcf/d—for projected net LNG exports from the United States of 9.2 Bcf/d of natural gas.

We again note that NERA also modeled a wide range of possible future supply and demand conditions, thereby reducing the dependence of its results on the accuracy of the AEO 2011 Reference Case. The AEO 2011 High Shale EUR case, for example, is represented in the table above showing EIA's AEO 2011 assumption of no new LNG exports. The AEO 2011 High Shale EUR case projected natural gas consumption growth that was even greater than the AEO 2013 Reference Case and domestic natural gas production growth that was less than the AEO 2013 Reference Case. Using the AEO 2011 High Shale EUR as a baseline, NERA modeled LNG exports across a range of international market conditions and found positive economic benefits to the U.S. economy in all cases where LNG exports were economically viable.[108] The inclusion of the AEO 2011 High Shale EUR case in NERA's analysis reinforces our conclusion that there is no reason to believe that using AEO 2013 Reference Case projections would have altered the central conclusion of the LNG Export Study.

Further, as reflected in the comments submitted by Lake Charles Exports[109] and Secretary Abraham,[110] Dow does not substantiate its claim that $95 billion of new investment in the manufacturing sector has led (or will lead) to an increase of 6 Bcf/d in incremental domestic consumption of natural gas by 2020. In making these estimates, Dow includes many projects that merely have been announced or that are under consideration with start dates far into the future. Dow provides no information as to when or whether these projects will be constructed or will begin operations.

b. Significance of Prior FTA Authorizations

Dow argues that the 28 Bcf/d of exports authorized to FTA countries (as of the date of Dow's comment) shows that the LNG Export Study underestimated future demand for natural

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[108] NERA study at 6.
[109] Reply Comments of Lake Charles Exports, LLC at 12-13.
[110] Reply Comments of Secretary Spencer Abraham at 8.

gas.[111] However, the volume of authorized exports to FTA countries is by no means a reliable predictor of the number and capacity of LNG export facilities that will ultimately be financed, constructed, and placed in operation.[112] Indeed, while many of the FTA authorizations have been in place for several years, DOE/FE is not aware of any application submitted to date in which a liquefaction facility was planned with the sole purpose of exporting LNG to FTA countries. Therefore, we are not persuaded that the current FTA authorizations undermine the assumptions of the LNG Export Study.

We note also that applicants typically request both FTA and non-FTA export authorizations for the entire output capacity of their proposed export facilities. Thus, as we explained above, the FTA and non-FTA authorizations are not additive. Citizens Against LNG contends that the NERA Study failed to consider the full potential volume of exports of 31.41 Bcf/d to FTA nations and 24.80 Bcf/d to non-FTA nations, but this argument is incorrect insofar as Citizens Against LNG is claiming that FTA and non-FTA authorization volumes must be added to calculate demand caused by LNG exports. Nevertheless, it bears mention that NERA did remove export constraints in its model for several of the cases evaluated. NERA found that, at the price required in the United States to free up 55 Bcf/d for export, there would be zero global demand for U.S. exports under any combination of domestic and international supply and

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[111] As of the date of this Order, DOE/FE has authorized the export of 37.96 Bcf/d of natural gas to FTA countries.

[112] As America's Natural Gas Alliance explains, when domestic gas supply was forecast to be insufficient to meet domestic demand, many LNG import facilities were proposed, but few were constructed. Specifically, from 2000 through 2010, over 40 applications to build new LNG import facilities were submitted to federal agencies, but only eight new facilities were built. The increase in domestic natural gas production had reduced the need for imported LNG. Further, of those import facilities constructed, public records show their use has declined. In 2004, the United States imported 244 cargoes of LNG at the four terminals existing at that time. By comparison, in 2012, only 64 cargoes were imported at seven of the 12 terminals then in existence. Five of the 12 existing terminals did not receive any cargoes in 2012. *See* http://www.marad.dot.gov/ports_landing_page/deepwater_port_licensing/deepwater_port_licensing.htm; http://www.ferc.gov/industries/gas/indus-act/lng.asp; *Natural Gas Imports and Exports Fourth Quarter Report 2004*, DOE/FE-0485, Office of Natural Gas Regulatory Activities, Office of Fossil Energy, U.S. Department of Energy; *Natural Gas Imports and Exports Fourth Quarter Report 2012*, DOE/FE-0563, Office of Natural Gas Regulatory Activities, Office of Fossil Energy, U.S. Department of Energy; http://www.fe.doe.gov/programs/gasregulation/publications/LNG_2012_rev.pdf.

demand conditions evaluated. Thus, the 55 Bcf/d case was found to be infeasible and was not included in the macroeconomic analysis.

B. Distributional Impacts

1. GDP Versus Welfare

a. Comments

Several commenters, including Sierra Club, allege that the NERA Study overstated the likely macroeconomic benefits from LNG exports. The National Resources Defense Council (NRDC), Sierra Club, and Clean Ocean Action, among others, maintain that NERA incorrectly conflated growth in GDP with growth in welfare. By concluding that LNG exports would create a net benefit to the economy, NERA also allegedly relied too much on the fact that exports would increase GDP and failed to give adequate weight to projected natural gas price increases and to deleterious socio-economic, sectoral, and regional impacts on consumers, households, and the middle class, including wage-earners.

A number of other commenters, including American Petroleum Institute, Paul Eikelboom, Gary Lambert, and Helen Rice, however, assert that LNG exports will create jobs and boost the economy. For example, American Petroleum Institute states that a report by ICF International shows that LNG exports will result in a net gain in employment in the United States and that the job impacts of LNG exports will grow larger as export volumes rise.

b. DOE/FE Analysis

The NERA Study presented the macroeconomic impacts of LNG exports using the different statistical measures noted above—price, welfare, GDP, aggregate consumption, aggregate investment, natural gas export revenues, sectoral output, and wages and other household incomes. NERA did not confuse the concepts of welfare growth and GDP growth. The study clearly shows that NERA distinguished these concepts and separately examined the macroeconomic impacts of LNG exports using both measures.[113] Welfare is a term of art in economics that measures the well-being of consumers and reflects changes in the value placed on consumption and leisure by individuals. NERA calculated welfare in the study as the "equivalent variation," which measures the amount of money that, if taken away from the average household, would make the household no better off with LNG exports than without.[114] GDP, as NERA explained, is "another economic metric that is often used to evaluate the effectiveness of a policy by measuring the level of total economic activity in the economy."[115] NERA thus acknowledged the distinction between GDP and welfare, yet used both metrics, among others, to ensure that its conclusions were robust across various measures.

2. Sectoral Impacts

a. Comments

Numerous commenters debate whether LNG exports will impact the domestic EITE sectors disproportionately, at too high of a cost to the U.S. economy to justify exporting LNG. Specifically, Dow, the Fertilizer Institute, Alcoa, and other commenters assert that higher natural gas prices caused by the demand for LNG exports will make it difficult for U.S. manufacturing to compete in global markets, reversing the gains these industries have made in recent years due to low domestic gas prices. According to these commenters, LNG exports will lead to lost jobs and lower wages in the EITE sectors—such as the chemical, fertilizer, and primary metal manufacturing sectors. These commenters, together with the Aluminum Association, the American Iron and Steel Institute, and others, contend that EITE jobs tend to be high-paying, highly-skilled, and of strategic national importance, whereas they allege that jobs created due to LNG exports will be short-lived and potentially of lower value to the U.S. economy. In this

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[113] NERA study at 6.
[114] *Id.*
[115] *Id.* at 56.

regard, Alcoa, Representative Markey, and IECA, among others, charge that NERA failed to analyze the unique tradeoffs between the domestic natural gas industry—which obviously stands to benefit from LNG exports—and EITE industries, which they argue will feel the brunt of higher gas prices and price volatility brought on by LNG exports.

In addition, Dow argues that the NERA model should have addressed industry-specific impacts. Dow submits that NERA erred by positing that the impact of expanded natural gas exports will affect the chemical, paper, and plastic industries in the same ways. It contends that the single bundled sector represented in the NERA model as the energy intensive sector is actually comprised of five sectors, and that NERA mistakenly assumed that average behavior from the EITE sector is representative of each of the five sectors:

> By bundling these industries, NERA applies the same labor, capital, fuel, and other material inputs in the same way across industries. Such an aggregation mutes the true impact to the industries, especially the chemical products industry. The chemical products subsector varies significantly from the other four industries in terms of value added to the economy (GDP) and energy consumption by fuel source ….[116]

According to Dow, the chemical industry is composed of dozens of different business models with different inputs and outputs. Consequently, Dow contends that "[s]hoe horning the chemical industry into an aggregated EIS [energy intensive sector] is not appropriate for studying the impact of LNG exports on the economy."[117]

More broadly, Dow maintains that NERA gave significant weight to a narrow economic benefit from LNG exports, but did not consider the greater economic value (the "value-added multiplier effect") when natural gas is used in the United States to manufacture finished goods for export, instead of being exported as LNG. Similarly, the Fertilizer Institute offers a study prepared at its request by Charles Rivers Associates to support its claim that NERA

[116] Initial Comments of Dow Chem. Co. at 27.
[117] *Id*. at 28.

underestimated the economic value of the fertilizer industry to the broader economy. Dow also contends that "take-or-pay" contracts used in the international trade of LNG will cause export activities to continue even if not economically warranted, thereby prolonging higher domestic gas prices.[118]

Senator Wyden, Representative Markey, Dow, and others contend that NERA misinterpreted a government-prepared 2009 Interagency Report that evaluated the effects of proposed greenhouse gas cap-and-trade legislation on EITE industries. According to these commenters, the findings in the Interagency Report led Congress to conclude that it was unacceptable to raise energy prices on EITE manufacturers because of the adverse employment implications across the economy. These commenters charge that the NERA Study, while borrowing heavily from the Waxman-Markey congressional debate, did not address the predictions of adverse employment impacts. Dow cites statistics from the Bureau of Economic Analysis indicating that, in 2011, total employment in the oil and gas industry was 171,000 while the chemical industry employed 785,000, the plastic and rubber industry employed 635,000, and the paper industry employed 388,000.[119] In addition, the Fertilizer Institute claims that the NERA Study should have assumed that the fertilizer industry directly supported 7,565 jobs while the NERA Study states that there were 3,920 jobs directly supported by the fertilizer industry.

On the other hand, a number of commenters, including ExxonMobil, American Petroleum Institute, the Energy Policy Research Foundation, Inc., and General Electric Oil & Gas, dispute these arguments. They specifically challenge the notion that an LNG export industry cannot co-exist with a growing domestic manufacturing base, and that EITE industries should be given priority, whether directly or indirectly, over the LNG industry.

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[118] *Id*. at 16-17.
[119] *Id*. at 28 (Dow table citing figures from the U.S. Bureau of Economic Analysis, *Gross Domestic Product by Industry Data*).

ExxonMobil supports NERA's conclusion that exports will yield net economic benefits to the United States, and states that, in fact, NERA understated those benefits because (among other reasons) NERA did not factor in the greater supply of natural gas liquids (NGLs) that will be produced in conjunction with increased natural gas production due to exports. The Institute for 21st Century Energy (an affiliate of the U.S. Chamber of Commerce) and the American Petroleum Institute, among others, note that additional production of NGLs will benefit chemical companies with U.S. plants because NGLs, such as ethane, are critical feedstock in chemical manufacturing processes. These commenters state that an increase in the supply of NGLs will exert downward price pressure on the cost of manufactured goods that use NGLs as a feedstock, thereby at least in part offsetting for those industries (primarily EITE industries) any increases in domestic natural gas prices associated with LNG exports.

ExxonMobil, American Petroleum Institute, Shell Oil Company, and many other commenters emphasize the size and productivity of the U.S. natural gas resource base, stating that there is an abundance of natural gas to support both LNG export demand and continued growth in the EITE industries. According to ExxonMobil, Western Energy Alliance, Energy Policy Research Foundation, Inc., and others, the vast supply of natural gas in the United States will continue to support current gains in domestic manufacturing, even as LNG exports take place. They state that LNG exports will both sustain and increase domestic production of natural gas, which, in turn, will provide EITE industries with a greater supply of natural gas at more stable prices, allowing them to stay globally competitive. According to these commenters, opponents of LNG exports are incorrect in speculating that natural gas used for export otherwise would be used for domestic manufacturing when, in fact, the natural gas likely would not be extracted if there is not increased demand created by LNG exports.

Further, 110 members of the U.S. Congress,[120] ExxonMobil, and others maintain that there would be serious consequences to hindering the export of LNG. If exports are prohibited or constrained, they believe the United States will lose economic benefits that other countries will capture as those countries begin extracting their shale gas resources and competing in the global LNG export market. Numerous commenters, including ExxonMobil, the National Association of Manufacturers, and the Energy Policy Research Foundation, Inc., similarly assert that it would not be in the public interest for DOE to limit LNG exports, in contravention of U.S. free trade principles. As noted above, these commenters state that restricting exports of natural gas would subsidize domestic manufacturing at the expense of the larger U.S. economy. They contend that the U.S. Government should not suppress trade in one industry to benefit other industries.

b. DOE/FE Analysis

With respect to the argument that natural gas confers greater value on the U.S. economy when used in manufacturing than when produced for export, we observe that more natural gas is likely to be produced domestically if LNG exports are authorized than if they are prohibited. There is no one-for-one trade-off between gas used in manufacturing and gas diverted for export. Although commenters are correct that such a trade-off may exist at the margin, this competition between the demand for natural gas for domestic consumption and the demand for natural gas for export is captured in the N_{ew}ERA model. The model projected that under the majority of scenarios examined, no exports would occur, thereby indicating that, for those scenarios, the gas was of greater value to domestic consumers than to foreign ones. On the other hand, in supply and demand conditions where exports were projected to occur and were not prohibited or limited, the model found that greater economic value was being placed on the LNG by foreign

[120] 110 members of the U.S. House of Representatives filed a single set of comments in support of LNG exports.

markets and, at the same time, greater economic benefits, both in terms of welfare and GDP accrued to the U.S. economy due to those exports.

NERA grouped the U.S. economy into a workable number of supply and demand sectors as appropriate for a macroeconomic model of this nature. NERA divided the EITE industries into five categories: paper and pulp manufacturing, chemical manufacturing, glass manufacturing, cement manufacturing, and primary metal manufacturing, including iron, steel and aluminum. NERA projected that the overall impact across these categories will be relatively muted, with no individual industry experiencing a dramatic negative impact:

> Serious competitive impacts are likely to be confined to narrow segments of industry. About 10% of U.S. manufacturing, measured by value of shipments, has both energy expenditures greater than 5% of the value of its output and serious exposure to foreign competition. Employment in industries with these characteristics is about one-half of one percent of total U.S. employment. LNG exports are not likely to affect the overall level of employment in the U.S. There will be some shifts in the number of workers across industries, with those industries associated with natural gas production and exports attracting workers away from other industries. In no scenario is the shift in employment out of any industry projected to be larger than normal rates of turnover of employees in those industries.[121]

Some commenters contend that NERA grouped the EITE industries too broadly and assert that greater economic harms could have been identified by focusing more narrowly on the most gas-dependent industries. While we take these concerns seriously, ultimately we are guided by the principle that the public interest requires us to look to the impacts to the U.S. economy as a whole, without privileging the commercial interests of any industry over another.

[121] NERA study at 2.

Similarly, with respect to the argument that some industries derive greater economic value from natural gas than others, we continue to be guided by the long-standing principle established in our Policy Guidelines that resource allocation decisions of this nature are better left to the market, rather than the Department, to resolve.

The Fertilizer Institute charges that the industry-specific employment data used by NERA is erroneous. The Fertilizer Institute claims that NERA underestimated employment directly supported by the nitrogen fertilizer industry and should have used a figure of 7,565 positions. However, NERA drew industry-specific employment data from the U.S. Census Bureau's Economic Census for 2007, which remains the most recent Economic Census data available. In estimating 3,920 positions directly supported by the nitrogen fertilizer industry, NERA selected a figure that is reasonably supported by an authoritative source.[122]

With respect to the Interagency Report prepared for the Waxman-Markey bill, we note that NERA used that report solely as a means of identifying industry segments that would be most acutely affected by higher energy costs, not as a way of determining the magnitude of such impacts. Therefore, although we acknowledge that the Interagency Report was prepared in a different context, we find nothing unreasonable in NERA's use of the Interagency Report.

3. Household and Distributional Impacts

a. Comments

Several commenters maintain that, for most citizens, the macroeconomic benefits of LNG exports, if any, will be minimal. These commenters contend that the main beneficiaries of LNG exports will be a narrow band of the population, chiefly wealthy individuals in the natural gas industry, foreign investors, and those holding stock or having retirement plans invested in natural gas companies.

[122] *Id*. at 69.

Other commenters assert that a majority of Americans will experience negative economic impacts, such as higher gas and electric bills, due to LNG exports. Senator Wyden, Dow, and Sierra Club, among others, contend that the NERA Study examined impacts on the labor market in terms of wages but failed to consider employment levels in terms of job equivalents or employment income. According to Clean Ocean Action, Dow, and Sierra Club, NERA also incorrectly assumed full employment and overestimated the positive job impacts associated with LNG exports. Dow, among others, charge that the NERA Study failed to adequately consider the cost of LNG exports in terms of lost jobs in the manufacturing sector and the cost of retraining workers for the LNG industry.

Several commenters support the LNG Export Study and argue that the macroeconomic impacts of LNG exports favor the public interest. ExxonMobil, the Center for Liquefied Natural Gas, and others, including several applicants for LNG export authorizations, submit that the NERA Study is comprehensive and rigorous and that LNG exports are in the public interest. ExxonMobil supports NERA's conclusion that exports will yield net economic benefits but asserts that the study understates the potential employment benefits from LNG exports. ExxonMobil argues that, because the NERA model assumed full employment, it did not identify the positive impact LNG exports would have on jobs. ExxonMobil observes that the economy is far from full employment, with forecasts prepared by the Congressional Budget Office in 2012 showing the unemployment rate above a full employment level through most of this decade. By exporting LNG, ExxonMobil argues, the U.S. economy can reach full employment faster than it can without exports. ExxonMobil also contends that the lingering effects of the recession mean that capital is underutilized today; and that, where there is significant slack in the economy, there is no necessary trade-off between jobs in one sector versus another.

b. DOE/FE Analysis

NERA examined three components of household income directly affected by natural gas exports: income from wages, income from capital holdings (stocks, etc.), and income from resource ownership (royalties, rents, etc.). The NERA Study projected that for the economy as a whole, increases in resource income earned in the natural gas production process more than offset reductions in wage and capital income earned from all other activities outside of the natural gas production process. The NERA Study acknowledged, however, that exports would be accompanied by a shifting of income sources, and stated that some segments of the economy are likely not to participate in the benefits of LNG exports but are likely to face increased energy costs.

DOE believes that the public interest generally favors authorizing proposals to export natural gas that have been shown to lead to net benefits to the U.S. economy. While there may be circumstances in which the distributional consequences of an authorizing decision could be shown to be so negative as to outweigh net positive benefits to the U.S. economy as a whole, we do not see sufficiently compelling evidence that those circumstances are present here. None of the commenters advancing this argument has performed a quantitative analysis of the distributional consequences of authorizing LNG exports at the household level. Given the finding in the LNG Export Study that exports will benefit the economy as a whole, and absent stronger record evidence on the distributional consequences of authorizing the exports proposed by DCP, we cannot say that those exports are inconsistent with the public interest on these grounds.

4. Regional Impacts

a. Comments

Many commenters addressed the issue of negative and positive regional impacts potentially associated with LNG exports. Commenters including Alice Zinnes, Keith Schue, Jannette Barth, APGA, Alex Bomstein, and Sierra Club assert that shale gas production associated with increasing LNG exports will trap local communities in a "boom-and-bust" cycle associated with extractive natural gas drilling. In a phenomenon they refer to as the "resource curse," they argue that natural gas production will cause long-term economic damage to local communities, leaving the communities poorer once the gas resource is depleted. Jennifer Davis, Dina DeWald, Andrew Goff, and others agree that shale gas development and production will have a negative impact on local industries that are incompatible with extraction-related activities, such as agriculture and tourism. Numerous commenters, including Hope Punnett, Robert M. Ross, the Environmental Working Group, Citizens Against LNG, and Sierra Club, enumerate specific ways in which they allege local communities near shale gas production areas or pipelines could be adversely affected if LNG exports lead to increased natural gas production. They cite increased noise, property devaluation, degradation of infrastructure, environmental and public health issues, and safety risks, among other issues.

Many other commenters seek to rebut these concerns by identifying the positive regional benefits associated with LNG exports, both in regions where shale development and production occur, and the regions in which LNG export terminals may be located. Commenters including FLEX, the Independent Petroleum Association of America, and scores of local, state, and federal political leaders—including 110 Members of the U.S. House of Representatives and several U.S.

Senators[123]—cite regional economic benefits associated with each LNG project, including the potential for thousands of new jobs, substantial direct and indirect business income, and millions of dollars in new tax revenue. Further, U.S. Representative Charles W. Boustany, Jr., 14 members of the Ohio House of Representatives, and numerous other commenters assert that authorizing exports of LNG will help to sustain natural gas exploration and production efforts, which will mitigate any local "boom-bust" cycle.

Finally, several other commenters, including Southern LNG Company, L.L.C., and Gulf LNG, assert that any general consideration of regional impacts is outside the scope of the NERA Study and is most appropriately considered by DOE/FE in reviewing individual export applications.

b. DOE/FE Analysis

We agree with the commenters who contend that a general consideration of regional impacts is outside of the scope of the LNG Export Study, and that regional impacts are appropriately considered by DOE/FE on a case-by-case basis during the review of each LNG export application. The case-specific issue of regional impacts is discussed *infra* at Section IX.B.

C. Estimates of Domestic Natural Gas Supplies

1. Comments

Several commenters assert that, in addition to underestimating the demand for domestically produced natural gas, the NERA Study overestimated future domestic supplies of natural gas. Representative Markey, for example, argues that current projections provide for only 20 to 40 years of domestic natural gas supplies but NERA did not adequately consider these

[123] U.S. Senators James Inhofe, Lisa Murkowski, David Vitter, Mary Landrieu, Heidi Heitkamp, and John Cornyn submitted comments generally supporting LNG exports.

projections. Senator Wyden, the Fertilizer Institute, and others maintain that the NERA Study purports to treat the United States and Canada as a single North American market, but its assumptions ignore the potential effect of Canadian LNG exports to international markets.[124] These commenters are largely concerned that NERA has overestimated domestic supplies and that having lower supplies than estimated will exacerbate the likely price increases due to exports.

Contrary to these arguments, many commenters, such as American Petroleum Institute and Shell, argue that the United States has abundant domestic natural gas reserves. Center for LNG and Cheniere Energy argue that EIA and NERA underestimated the domestic natural gas resource base and, therefore likely overestimated the price impacts of LNG exports.

Dow, however, is concerned about certain indirect impacts that could arise if domestic supplies are exported. It asserts that domestic gas production would be unable to keep up with the demand required to meet unlimited LNG exports and that one-third of new shale gas production will be required to replace a decline in conventional gas production. Dow maintains that, as a consequence, gas production will have to ramp up significantly and this development will mean that gas supply will be diverted away from domestic industrial and other sectors of the economy:

> There would need to be rapid deployment of new drilling rigs, increased steel pipe manufacturing and an expanded work force throughout the value chain to be able to service such unprecedented growth in [natural gas] production. With an already well-documented skills shortage in the labor market, basic supply and demand economics will prevail and drive labor prices higher, which would in turn have a chilling impact on investment in the manufacturing sector.[125]

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[124] In his comments, Senator Wyden stated that Canada's National Energy Board has approved two LNG export projects in British Columbia and is considering a third. According to Senator Wyden, these projects could begin in 2014 and result in LNG exports totaling 9 Bcf/d. DOE/FE notes that Canada has approved the third LNG export project mentioned by Senator Wyden—the Royal Dutch Shell Plc project.

[125] Initial Comments of Dow Chem. Co. at 16.

Other commenters take a somewhat longer view of the potential indirect impacts of LNG exports on domestic energy supplies. These commenters contend that, to become energy independent, the United States must preserve its supply of finite domestic energy resources, not export them. They argue that authorizing LNG exports will hasten the depletion of this country's natural gas resource base, the size of which is uncertain. Moreover, they assert, investment in LNG exports will take away from potential investment in renewable energy supplies, which will compound this country's dependency on fossil fuels.

Some commenters, such as Dow, IECA, and Citizens Against LNG, maintain that the NERA Study does not address significant policy changes that could impact domestic natural gas supply. These comments are focused in two areas: availability of energy production tax credits and uncertainty surrounding future environmental regulation regarding hydraulic fracturing. Specifically, Dow points to the possible elimination of energy production tax credits and states that elimination of this tax credit could result in a 5 percent decline in natural gas production and the loss of nearly 60,000 barrels per day of oil production. Dow, along with Jannette Barth, IECA and Citizens Against LNG, argue that potential state and federal environmental regulations pertaining to hydraulic fracturing should have been considered by NERA. These commenters assert that these potential additional regulatory costs and could lower supply, increase demand, and raise prices of natural gas.

2. DOE/FE Analysis

a. Measures of Supply

Before turning to a consideration of the specific comments, it is important to clarify the various measures of supply used by commenters. DOE/FE notes that, by three measures of supply, there are adequate natural gas resources to meet demand associated with DCP's requested authorization. Because these supply estimates have changed over time, however, DOE/FE will continue to monitor them to inform future decisions. These estimates include:

i) AEO natural gas estimates of production, price, and other domestic industry fundamentals. As shown in Table 4 above, the Reference Case projection of dry natural gas production in 2035 increased significantly (by 13.8 Bcf/d) in AEO 2013 compared with AEO 2011, while projections of domestic natural gas consumption in 2035 also increased in AEO 2013 compared with AEO 2011 (by 6.0 Bcf/d). Even with higher production and consumption, the 2035 projected natural gas market price in the Reference Case declined from $7.07/MM Btu (2009$) in AEO 2011 to $6.32/MM Btu (2011$) in AEO 2013. Further, as Table 4 shows, the AEO 2013 Reference Case has many similarities with the AEO 2011 High EUR case in which shale gas resources produced per well are 50% higher than in the AEO 2011 Reference Case. The implication of the latest EIA projections is that a greater quantity of natural gas is projected to be available at a lower cost than estimated just two years ago.

ii) Proved reserves of natural gas. Proved reserves of natural gas have been increasing. Proved reserves are those volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The R/P ratio measures the number of years of production (P) that proved reserves (R) represent at current production rates. Typically industry maintains proved reserves at about 10 years of production, but as the table below demonstrates, reserves have increased from 9.2 years of production in 2000 to 13.7 years of production in 2010, the latest year statistics are available. Of particular note is that, since 2000, proved reserves have increased 72 percent to 304,625 Bcf, while production has increased only 16 percent, demonstrating the growing supply of natural gas available under existing economic and operating conditions.

Table 5: U.S. Dry Natural Gas Proved Reserves[126]

	Proved Reserves (R)		U.S. Dry Natural Gas Estimated Production (P)		
Year	**(Bcf)**	**Percent change versus year 2000**	**(Bcf)**	**Percent change versus year 2000**	**R/P Ratio - Years**
2000	177,427	--	19,219	--	9.2
2005	204,385	15	18,458	-4	11.1
2010	304,625	72	22,239	16	13.7

iii) Technically recoverable resources (TRR). Technically recoverable resources have also increased significantly. Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability. They include both proved reserves and unproved resources.[127]

DOE/FE notes that EIA's natural gas TRR estimates have varied from below 2,000 Tcf in AEO 2010 to more than 2,500 Tcf in AEO 2011 and 2,335 Tcf in AEO 2013.[128] These TRR estimates include proved and unproved TRR shale gas resources, which have fluctuated in recent AEOs, as the EIA continues to monitor and estimate this resource base. For example, in AEO 2010, unproved shale gas TRR was estimated at 347 Tcf, which increased to 827 Tcf in AEO 2011, and was revised to 543 Tcf in AEO 2013.

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[126] EIA, *U.S. Dry Natural Gas Proved Reserves* (Aug. 2, 2012), *available at* http://www.eia.gov/dnav/ng/ng_enr_dry_dcu_nus_a.htm (additional calculations conducted to produce percentage change and R/P ratios).

[127] Unproved resources are generally less well known and therefore less precisely quantifiable than proved reserves, and their eventual recovery is less assured.

[128] *See* U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013* (May 2013), Table 9.2. Technically recoverable U.S. natural gas resources as of January 1, 2011, at 121, *available at*: http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2013).pdf.

b. Supply Impacts

While the AEO 2011 TRR estimates were higher than the AEO 2013 estimates, we do not agree that NERA employed overly optimistic projections of domestic gas supply. The EIA and NERA studies conclude that for the period of the analysis, the United States is projected to have ample supplies of natural gas resources that can meet domestic needs for natural gas and the LNG export market. Additionally, most projections of domestic natural gas resources extend beyond 20 to 40 years. While not all TRR is currently economical to produce, it is instructive to note that EIA's recent estimate of TRR equates to over 90 years of natural gas supply at the 2012 domestic consumption level of 25.63 Tcf. Moreover, given the supply projections under each of the above measures, we find that granting the requested authorization is unlikely to affect adversely the availability of natural gas supplies to domestic consumers such as would negate the net economic benefits to the United States.

We further find that, given these estimates of supply, the projected price increases and increased price volatility that could develop in response to a grant of the requested LNG export authorization are not likely to negate the net economic benefits of the exports. This issue is further discussed below. With regard to the adequacy of supply, however, it bears noting that while Dow contends that U.S. natural gas production would not be able to meet unlimited LNG exports and domestic demand, the NERA Study supports a different conclusion. The NERA Study included scenarios in which LNG exports were unconstrained. In these cases, LNG exports from the United States compete with LNG exports from all other international natural gas sources. Should the U.S. resource base be less robust and more expensive than anticipated, U.S. LNG exports would be less competitive in the world market, thereby resulting in lower export levels, and, in some instances, no exports, from the United States. By way of example, NERA modeled a number of Low EUR scenarios, which had U.S. resources that were less robust and more expensive than other cases. In these Low EUR scenarios, U.S. wellhead natural gas prices were driven up by higher production costs to meet domestic demand, and in those cases prices increased to a level that choked off demand for exports so that LNG exports were limited or disappeared, leaving the available natural gas for domestic use. In other unconstrained cases evaluated with the High EUR scenarios, domestic natural gas production was able to keep up with the demand required to meet the unconstrained LNG export scenario. In this case, the EIA scenarios reflect the changes that would occur in the domestic market and reflect the limitations, as modeled in the NEMS model, of domestic natural gas production and consumption by different sectors of the economy. In all of these cases, the supply and price response to LNG exports did not negate the net economic benefit to the economy from the exports.

c. Supply Impacts Related to Alternative Energy Sources

To the degree that natural gas prices may increase, alternative sources of energy will become more attractive to consumers and investors. Accordingly, in nearly every year in which natural gas exports were reflected in the EIA Study, electricity from renewable energy resources increased compared to the no export case. Therefore, we do not agree with the suggestion that LNG exports would diminish investment in renewable energy.

d. Supply Impacts Related to Canadian LNG Exports

DOE/FE also disagrees with the argument that the NERA Study erred in its treatment of potential Canadian LNG exports to international markets. Although DOE/FE did not ask NERA to evaluate potential LNG exports from Canada, we note that LNG exports from Canada would compete with U.S. exports, thereby most likely reducing U.S. exports. Therefore, treating U.S. and Canadian LNG exports as those from a single market is a reasonable assumption, and would be consistent with the unconstrained LNG export cases evaluated by NERA, with the price impact more or less in line with the cases evaluated by NERA. DOE/FE would expect that benefits estimated to accrue to the United States from U.S. LNG exports likely would be similar to the benefits that would accrue to Canada resulting from Canadian LNG exports.

The LNG Export Study did not evaluate the steps to become energy independent, as that was not part of the criteria evaluated. However, the NERA Study concluded that the United States has ample supplies of natural gas resources that can both meet domestic needs for natural gas *and* allow for participation in the LNG export market, without a significant impact on supplies or prices for the period of the analysis under the assumptions made.

e. Supply Impacts Related to Tax Law and Environmental Policy

NERA stated that the NewERA macroeconomic model includes a simple tax representation in which indirect taxes are included in the output values and not explicitly modeled.[129] NERA thus assumed no changes specific to existing law governing production tax credits. EIA did the same. On the other hand, at DOE/FE direction, NERA and EIA accounted for potential variability in domestic natural gas supply such as would occur due to changes in environmental regulation and other factors, including changes to production tax credits. They did so by incorporating the High EUR and Low EUR scenarios into their model.[130]

We find that it was reasonable for EIA and NERA to use the High EUR and Low EUR cases to capture a range of factors that may impact domestic natural gas supply. We further find that, given the range of scenarios studied, the decision not to specifically model the possible revocation of production tax credits or changes to environmental regulation does not lessen the reliability of the EIA or NERA studies. As a practical matter, EIA and NERA were required to

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[129] NERA study at 110.
[130] *Id.* at 25.

establish certain key assumptions as a foundation for their studies. They reasonably evaluated alternative scenarios that would capture possible changes that would affect natural gas supplies.

D. Modeling the LNG Export Business

1. Comments

Some commenters complain that NERA failed to capture accurately the business model being employed by those involved in the business of LNG exports. Sierra Club states that NERA erroneously modeled the fossil fuel industry by assuming a zero-profit condition. Some commenters, including NRDC, maintain that NERA failed to consider that LNG exports will take place pursuant to long-term, *e.g.*, 25-year, contracts containing take-or-pay provisions, rather than contracts containing flexible or market-sensitive pricing provisions. IECA makes a similar argument in its reply comments. According to these commenters, the take-or-pay provisions in long-term contracts will inhibit the free flow of price signals. The commenters argue that NERA incorrectly assumed that: (1) exports of LNG from the United States would cease if the gap in prices between domestic and foreign supplies is closed; and (2) a foreign country will cease purchases of U.S.-sourced LNG if the country gains access to less expensive supplies. These commenters maintain that take-or-pay provisions in long-term contracts will have the effect of driving LNG exports even under circumstances when it would be more economical for the same natural gas to be sold in the domestic market. In this regard, Dow criticizes NERA's assertion that the global market for natural gas will limit how high U.S. natural gas prices can rise as a result of export activity because importing nations will not purchase U.S. supplies if U.S. wellhead prices rise above the cost of competing supplies. Dow contends that this arbitrage phenomenon may occur in competitive markets but does not make sense in the global LNG market due to the broad use of long term take-or-pay contracts.

Additionally, several commenters, including Representative Markey, NRDC, Sierra Club, Citizens Against LNG, and Alcoa, charge that NERA incorrectly assumed that the financing of investments in natural gas supplies for export and in the LNG export projects that will be used for export operations would originate from U.S. sources. These commenters assert that, in fact, a substantial portion of the investment is being made by foreign entities and these foreign entities, not domestic corporations, will reap the benefits of export activity in the form of royalties, tolling fees, income, and tax proceeds from the resale of LNG overseas. Contrary to these arguments, FLEX and Lake Charles Exports argue that foreign financing of LNG export projects is beneficial. These commenters argue that foreign direct investment in the U.S. LNG industry frees up domestic capital for other investments. These commenters conclude that, as a result, NERA's results likely underestimate the benefits to the U.S. economy that will result from LNG exports.

Another commenter, Save Our Supplies, contends that the structure of international markets for natural gas and LNG and the high cost of building international LNG export infrastructure will give a cost advantage to U.S. LNG exports. This cost advantage, coupled with greater international demand than projected by NERA, allegedly will exacerbate the projected price increases within the United States due to LNG exports. More generally, Save Our Supplies claims that NERA made a series of incorrect assumptions concerning the structure of international natural gas markets. These include erroneously assuming that international natural gas markets are competitive. Save Our Supplies identifies the following three considerations: (1) the international market is not perfectly competitive because there are barriers to entry, trade, and foreign investment due in part to the participation of state-sponsored enterprises; (2) there is an international oligopoly in oil that, because of a link between the international price of oil and the international price of natural gas in certain markets, makes it impossible for the international market in natural gas to be perfectly competitive; and (3) NERA erroneously assumed that natural gas is a "perfect substitute" for oil in all circumstances.[131] Based on these comments, Save Our Supplies challenges the NERA Study for allegedly assuming that Qatari and Russian suppliers of natural gas will cut their prices to compete with the lower priced supplies available from the United States. Save Our Supplies argues that such price competition will not be significant and, therefore, that there will be greater demand for U.S.-exported LNG. According to some commenters, NERA's asserted underestimate of international demand for natural gas was also exacerbated by its failure to account for the construction of natural gas infrastructure on a global basis. According to these commenters, NERA appears to underestimate both the supply cost of international LNG projects and the magnitude and trajectory of global LNG demand. NERA also appears to underestimate U.S. natural gas demand and potentially the elasticity of the U.S. natural gas supply curve.

A number of commenters take an opposing position by arguing that the domestic natural gas resource base is sufficient to meet both the domestic and international demand for U.S. natural gas. Center for LNG, Cheniere, and others go further by arguing that EIA and NERA underestimated the size of the resource base, and therefore overestimated the potential domestic price impacts of LNG exports. Dominion Cove Point LNG, America's Natural Gas Alliance and others argue that the international market will constrain the total volume of natural gas exported from the United States.

Several commenters, including Sierra Club and Dow, argue that NERA overestimated LNG transaction costs (*e.g.*, costs of liquefaction, transportation, and insurance). Sierra Club argues that NERA overstated the transportation costs associated with the export of U.S. gas by

[131] Initial Comments of Save Our Supplies at 34, 41.

assuming all LNG would be exported from the Gulf Coast. Sierra Club states that several export terminals are planned for the West Coast, where it will be less expensive to transport gas to the Asian market than it would be from the Gulf Coast. Dow states that NERA's estimate of transportation and insurance costs for shipping LNG to Asia would be on the order of $2.60/Mcf. Dow claims that official trade statistics published by the U.S. Census Bureau, however, establish that these costs would be closer to $0.50/Mcf. Commenters such as Dow and Sierra Club state that had NERA properly accounted for LNG transaction costs, the foreseeable volumes of LNG exports would have exceeded those predicted by NERA, thereby intensifying the impact of LNG exports on U.S. natural gas prices. For this reason Sierra Club and Dow argue that NERA's projected price ceiling on domestic natural gas is too low. In addition, numerous individual members of the Sierra Club contend that NERA appears to have misrepresented the amount of natural gas used by LNG terminals in the liquefaction process, which understates the demand associated with exports.

2. DOE/FE Analysis

As explained below, we find that the NERA Study reflects an accurate understanding of the contractual terms and market environment affecting the fossil fuel industry and, more narrowly, provides a plausible future scenario of international trade in LNG with U.S. exports. It is DOE/FE's view also that NERA's conclusions of the impact of LNG exports would not have materially changed with alternative international market assumptions. In this regard, we note that NERA included one scenario in which LNG exports reached 23 Bcf/d, with a positive impact on the U.S. economy. We find as follows:

a. Zero Profit Condition

Sierra Club's charge that NERA erroneously modeled the fossil fuel industry by assuming a zero-profit condition appears to reflect a misunderstanding of the term "zero-profit" as used by NERA. The "zero-profit condition" assumed in the NERA Study does not mean that firms in the natural gas industry will not make a "profit" as that word is ordinarily used. Rather, the zero-profit condition means only that firms will not make a profit above the risk-adjusted cost of capital. The assumption of a zero-profit condition is another way of saying that the model assumes a competitive market for natural gas, because in competitive markets new firms can enter and drive any profits above a risk-adjusted cost of capital down to zero. The assumption of a competitive market for natural gas production in the United States is valid given that natural gas wellhead prices have been deregulated for over thirty years.[132] Moreover, Sierra Club and other commenters have not provided any evidence to suggest a lack of competition in the market for U.S. natural gas production.

b. Contract Terms

We disagree with the contention that NERA erred in the assumptions it used to model the export contracts that will be used by authorization holders. NERA assumed that these contracts will include payments to the exporting facility in the form of a tolling charge that is fixed based on the total export capacity reserved under the tolling agreement plus 115% of the Henry Hub price for each unit of gas that is liquefied. These assumptions correspond closely with the 20-year tolling agreement filed publicly with DOE by Sabine Pass on April 2, 2013. In that filing,

[132] Natural Gas Policy Act of 1978, 15 U.S.C. § 3301, *et seq.* (establishing a policy for phasing out the regulation of wellhead prices).

the tolling agreement carries a tolling fee (or “reservation charge”) with a per unit liquefaction charge of 115% of the Henry Hub price.[133]

Because there is neither a throughput obligation nor a fixed commodity price in the commercial arrangements assumed by NERA (or in the publicly filed Sabine Pass contract), the supplies of natural gas or LNG subject to the contracts are not locked up for the export market. Instead, as NERA has properly assumed for purposes of its model, foreign and U.S. purchasers will compete for domestically produced supplies and, if the domestic price rises, the owners of the gas (in most cases, either the authorization holder or the foreign purchasers that are party to the export-related contracts) will have an incentive to sell the gas into the domestic market rather than the international market.

Commenters criticizing NERA’s model on these assumptions have not submitted evidence to support their position that contracts will lock up natural gas for export. Moreover, we find it unlikely that a broad cross-section of commercial parties would lock themselves permanently into arrangements whereby LNG will be exported from the United States even when it is uneconomical to do so. Even contracts entered improvidently may be amended when there is a possibility for mutual benefit in doing so, as there would be in a case where domestic gas prices exceed netback prices.

c. Foreign Direct Investment

As described above, several commenters charge that the NERA Study incorrectly assumed that the financing of investments in natural gas supplies for export and in LNG liquefaction and export facilities would come from domestic sources. An examination of the

[133] *Sabine Pass Liquefaction LLC*, LNG Sale and Purchase Agreement with Centrica PLC, FE Docket No. 13-42-LNG at 51-52 (Apr. 2, 2013).

NERA Study indicates that claim is not valid as to natural gas supplies. Early in the study, NERA noted as follows:

> Net benefits to the U.S. economy could be larger if U.S. businesses were to take more of a merchant role. Based on business models now being proposed, this study assumes that foreign purchasers take title to LNG when it is loaded at a United States port, so that any profits that could be made by transporting and selling in importing countries accrue to foreign entities. In the cases where exports are constrained to maximum permitted levels, this business model sacrifices additional value from LNG exports that could accrue to the United States.[134]

On the other hand, the commenters are correct to the extent they argue that the NERA Study assumed that the financing for the liquefaction and export facilities associated with LNG exports would come solely from domestic sources. The NERA Study indicates that the timing of macroeconomic effects could be affected as a consequence:

> In this report it is assumed that all of the investment in liquefaction facilities and in increased natural gas drilling and extraction come from domestic sources. Macroeconomic effects could be different if these facilities and activities were financed by foreign direct investment ("FDI") that was additional to baseline capital flows into the U.S. FDI would largely affect the timing of macroeconomic effects, but quantifying these differences would require consideration of additional scenarios in which the business model was varied.[135]

In the above statement, NERA has indicated that the timing of the impacts of LNG exports could change due to FDI. On the other hand, NERA has not stated that the nature of the impacts will change and no commenter has introduced evidence that FDI will produce negative economic benefits. Indeed, Lake Charles Exports explains why FDI may enhance the economic benefits to the United States:

> NERA thus acknowledged the possibility that investment necessary for LNG exports may come from foreign sources. The NERA model's assumption of domestic investment explicitly fails to capture the macroeconomic benefits that will result from the injection of any foreign investment into natural gas production and infrastructure.

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[134] NERA study at 6-7.
[135] *Id.* at 211.

> The United States has the leading economy in the world in part because the US is the leading destination of international flows of capital. Each dollar of new foreign investment capital into the US results in an equivalent increase in US GDP. The main positive components of GDP are private consumption, investment, government expenditures, and exports. Any foreign direct investment stemming from the development of a US LNG industry would not decrease domestic capital investment, but would merely free up such domestic capital for other investments. Therefore the total amount of investment in the US would increase, dollar-for-dollar, with foreign investment, increasing US GDP by the same amount. If that foreign investment earns a return and, after taxation by US local, state and federal governments, some of that return is repatriated, this reflects a small countervailing outflow (which seems to be what, for example, Representative Markey is focusing on). Nonetheless, foreign direct investment remains a major net contributor to the US economy. The 2012 LNG Export Study's simplifying assumption regarding the source of investment in LNG production infrastructure fails to capture the benefits of any capital provided from foreign sources and thus understates the impact of such investment on US GDP.[136]

Accordingly, while FDI may be used to finance purchases of natural gas for export as LNG and the construction of LNG liquefaction and export facilities, we are not persuaded that the inflow of foreign capital for these purposes would be inconsistent with the public interest or would lessen the net economic benefits projected in the LNG Export Study.

d. International Natural Gas Markets

We are not persuaded by Save Our Supplies' claim that a projected cost advantage to exports of LNG from the United States as opposed to exports from other gas producing nations will necessarily exacerbate projected price increases within the United States due to LNG exports. This argument assumes that LNG will be available for export at a landed price overseas that is competitive with the international price set by foreign competitors. But NERA concluded that in many cases, the world natural gas market would not accept the full amount of exports assumed in the EIA scenarios at prices high enough to cover the U.S. wellhead domestic prices

[136] Reply Comments of Lake Charles Exports at 31 (citations omitted).

calculated by the EIA. Alternatively, foreign competitors supplying natural gas and LNG in international markets may match or, possibly, undercut the landed price of LNG exported from the United States.

With respect to the competitiveness of global LNG markets, NERA assumed that the production decisions of the world's dominant producer, Qatar, would be fixed no matter what the level of U.S. exports and that, generally, "there is a competitive market with exogenously determined export limits chosen by each exporting region and determined by their liquefaction capacity."[137] NERA described these assumptions as a "a middle ground between assuming that the dominant producer will limit exports sufficiently to maintain the current premium apparent in the prices paid in regions like Japan and Korea, or that dominant exporters will remove production constraints because with U.S. entry their market shares fall to levels that do not justify propping up prices for the entire market."[138] We find this to be a reasonable simplifying assumption and note further that even imperfectly competitive markets are not static. The arrival of new entrants, such as U.S.-based LNG exporters, may well have a disruptive impact on markets where competition may presently be constrained.

Finally, we note that NERA also modeled a "supply shock" case that assumed key LNG exporting regions did not increase their exports above current levels. NERA found positive economic benefits to the United States in each supply shock scenario in which the United States exports LNG. These results strengthen our conclusion that the prospect of non-competitive behavior in global LNG markets is unlikely to have a material impact on the central conclusions of the LNG Export Study.

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[137] NERA study at 34.
[138] *Id*. at 34-35.

e. Estimates of LNG Transaction Costs

We disagree with the comments from Sierra Club and Dow arguing that NERA overestimated LNG transaction costs, including liquefaction, transportation, insurance, and the like. NERA based its liquefaction, shipping costs and regasification costs on a review of publicly available literature, including the International Group of LNG Importers 2010 LNG Industry report and other sources referenced in the NERA Study.[139]

With respect to transportation costs, Dow states that NERA's estimate of shipping cost to Asia was on the order of \$2.60/Mcf, while statistics presented by Dow claim these to be \$0.50/Mcf. In presenting this figure, Dow relies on trade statistics reported by the U.S. Census Bureau based on the average cost of insurance and freight expenses associated with U.S. *imports* of LNG in 2010 and 2011. As NERA points out, however, LNG transportation costs in large measure are a function of the distance traveled. Therefore, data on LNG imports, which largely travel shorter distances,[140] do not furnish a reliable basis for drawing inferences regarding transportation costs for LNG exports to Asia. Further, NERA provided a detailed description of the assumed transportation cost buildup, which is based on a daily charter rate of \$65,000, and other reasonable assumptions.[141] Dow does not provide evidence challenging the accuracy of the information used by NERA or NERA's method of calculating transportation costs. Nor does Dow provide other evidence of daily charter rates.

As for the cost of natural gas consumed in the liquefaction process, NERA's model assumes a consumption level equal to 9 percent of the natural gas feedstock, a cost that is

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[139] *Id.* at 84-90.

[140] DOE/FE statistics show that the majority of LNG imports to the United States for 2010 and 2011 came from Atlantic Basin/North African sources. More than one-third of U.S. LNG imports in 2010 and 2011 came from Trinidad and Tobago, and none came from East Asia. *See* DOE/FE 2010 LNG Import Annual Report and DOE/FE 2011 LNG Import Annual Report, *available at* http://fossil.energy.gov/programs/gasregulation/publications/.

[141] NERA study at 87.

included in the NERA model. NERA based this assumption on publicly available information of liquefaction costs. Similarly, EIA assumed that 10 percent of feedstock was consumed in the liquefaction process.

Therefore, we find that NERA's cost build-up is appropriate and that the estimated costs for delivering LNG to end users considered in the NERA Study are reasonable.

E. Cost of Environmental Externalities

1. Comments

Sierra Club, along with Delaware Riverkeeper Network,[142] Jannette Barth, NRDC, Dow, and Save Our Supplies, among others, maintain that LNG exports will increase demand for natural gas, thereby increasing negative environmental and economic consequences associated with natural gas production. These commenters assert that NERA failed to consider the cost of environmental externalities that would follow such exports. The externalities identified by these commenters include:

- Environmental costs associated with producing more natural gas to support LNG exports, including the costs, risks, and impacts associated with hydraulic fracturing and drilling to produce natural gas;
- Opportunity costs associated with the construction of natural gas production, transport, and export facilities, including the costs of investing in shale gas infrastructure to support LNG exports, as opposed to investing in renewable or sustainable energy infrastructure;
- Costs and implications associated with eminent domain necessary to build new pipelines to transport natural gas; and
- Potential for switching from natural gas-fired electric generation to coal-fired generation, if higher domestic prices cause domestic electric generation to favor coal-fired generation at the margins.

[142] Delaware Riverkeeper Network filed comments on behalf of itself and more than 80 other organizations.

2. DOE/FE Analysis

As explained herein, the authorization granted by this Order is conditioned (among other things) on the satisfactory completion of the environmental review of the Jordan Cove Terminal under NEPA in FERC Docket No. CP13-483-000 and the PCGP in FERC Docket No. CP13-492-000, and on issuance by DOE/FE of findings of no significant impact or records of decision pursuant to NEPA.[143]

As further explained below, persons wishing to raise questions regarding the environmental review of the present Application are responsible for doing so within the FERC proceedings. Insofar as a participant in the FERC proceeding actively raises concerns over the scope or substance of environmental review but is unsuccessful in securing that agency's consideration of its stated interests, DOE/FE reserves the right to address the stated interests within this proceeding. However, absent a showing of good cause for a failure of interested persons to participate in the FERC environmental review proceeding, DOE/FE may dismiss such claims if raised out of time in this proceeding.

F. Prices and Volatility

1. Natural Gas Price Volatility

a. Comments

Several commenters, such as Huntsman Corporation, address potential natural gas price volatility associated with LNG exports. Janette Barth, Dow, Sierra Club, and Save Our Supplies, among others, state that NERA did not account for price volatility. Sierra Club points to the results of the LNG Export Study, which project higher domestic natural gas price impacts when exports phase in rapidly. Additionally, Sierra Club argues that, pending the pace of DOE/FE

[143] *See* 10 C.F.R. § 590.402 (authorizing DOE/FE to issue a conditional order prior to issuance of a final opinion and order).

approvals, demand for domestic natural gas may increase more rapidly than production, leading to periods of scarcity and price spikes. Sierra Club also contends that there is little evidence that domestic natural gas price volatility will be reduced by LNG exports.

America's Natural Gas Alliance argues that there is no evidence that LNG exports will increase volatility. According to the Alliance, LNG exports will lead to increased investment in domestic gas production, which will help protect against price volatility. American Petroleum Institute contends that the NERA and Brookings studies project natural gas prices to remain in a narrow, low range through 2030 in all scenarios. Further, American Petroleum Institute points out that in October 2009, a Dow representative testified before the Senate Energy and Natural Resources Committee that the U.S. chemical industry could operate successfully if natural gas prices remain in the $6-8 MMBtu range. American Petroleum Institute asserts that recent studies projecting natural gas prices—even with high, unconstrained levels of LNG export—do not forecast natural gas prices higher than that range. Several commenters, including America's Natural Gas Alliance and American Petroleum Institute, further assert that the market will have significant advanced notice of LNG export facilities. As a result, natural gas producers will be able to adjust supply to meet anticipated increases in demand. American Petroleum Institute also argues that, because the facilities and liquefaction trains at each facility will be built in sequence, a market buffer will be created where supply will grow incrementally and supply shocks will not be created in the market. Additionally, Lake Charles Exports argues that Dow's analysis of domestic natural gas exports is incorrect, and the additional investment in domestic natural gas reserve development associated with increases in LNG exports will insulate the United States from natural gas price volatility.

The Bipartisan Policy Center, through its own analysis, forecasts that LNG exports are unlikely to result in large domestic price impacts. The Bipartisan Policy Center states that the results of its analysis indicate that LNG exports are likely to have only modest impacts on domestic natural gas prices—and that LNG export levels will adjust as domestic prices rise or fall.

b. DOE/FE Analysis

Natural gas price volatility can be measured in terms of short term changes—daily or monthly volatility—or over longer periods. Short term volatility is largely determined by weather patterns, localized service outages, and other factors that appear unlikely to be affected substantially by DOE export authorization decisions. Moreover, NERA's study was a long-term analysis covering a 20-year period that correctly did not focus on short term shocks or volatility.

To the extent commenters are concerned about the risk of large upward price spikes sustained over longer periods, such as those that occurred in 2005 and 2008, we do not agree that LNG exports will necessarily exacerbate this risk. First, as noted above, when domestic wholesale gas prices rise above the LNG netback price, LNG export demand is likely to diminish, if not disappear altogether. Therefore, under some international market conditions, LNG export facilities are likely to make natural gas demand in the United States more price-elastic and less conducive to sustained upward spikes. Second, in light of our findings regarding domestic natural gas reserves explained above, we see no reason why LNG exports would interfere with the market's supply response to increased prices. In any capital intensive industry, investments are made based on observed and anticipated market signals. In natural gas markets, if prices or expected prices rise above the level required to provide an attractive return on investment for new reserves and production, industry will make that investment to capture the anticipated profit. These investments spur development of reserves and production and increase availability of natural gas, exerting downward pressure on prices. This is part of the normal business cycle that has been captured in EIA's supply curves and, consequently, in NERA's analysis. On balance, we are not persuaded that LNG exports will substantially increase the volatility of domestic natural gas prices.

2. Linking the Domestic Price of Natural Gas to World Prices

a. Comments

Several commenters, including APGA, Dow, and IECA, argue that LNG exports could link domestic natural gas prices to the price of natural gas in the world market, and that this could exacerbate the potential increase in domestic natural gas prices as well as increase price volatility. A number of other commenters, however, contend that domestic prices would not become linked to world prices. Citing the importance of the domestic natural gas price in determining the level of exports, the Bipartisan Policy Center and Southern LNG Company argue that domestic natural gas prices will remain independent of international prices.

In its reply comments, Dow expands on its argument that domestic natural gas prices will become linked to international prices. Dow argues that exports to Asia, where natural gas prices are "oil-indexed," will invariably lead to increases in domestic price. Dow also argues that it is incorrect to assume liquefaction, transportation and regasification costs will act as a buffer against world prices, pointing to the experience in Australia in which LNG exports resulted in a tripling of domestic natural gas prices. In reply comments, American Petroleum Institute and several LNG export applicants argue that natural gas prices will not rise to global prices because the market will limit the amount of U.S. natural gas that will be exported, since liquefaction, transportation and regasification costs act as a cushion. These commenters argue that if this cushion disappears and the U.S. export price rises to the global LNG price, market forces will bring U.S. exports to a halt. Several LNG export applicants also contend that the availability of bi-directional terminals will serve to limit domestic price increases.

b. DOE/FE Analysis

The NERA Study examined whether LNG exports from the United States will cause domestic prices to rise to the level of international prices and found that such a result is unlikely. NERA asserts that there will always be a difference between the international LNG price and the U.S. market price. That difference will be represented by the cost of inland transportation, liquefaction, shipping, and regasification. NERA's model assumes competition among different suppliers such that Asian buyers would have no incentive to buy natural gas from the United States if the delivered price after liquefaction and transportation is higher than the alternative delivered LNG price from other sources. DOE/FE agrees that a competitive market would behave in this manner and U.S. natural gas prices would be lower than international LNG prices in such a market by at least the costs previously described. Further, the introduction of LNG exported from the United States into the international market would tend to exert downward pressure on the prevailing higher delivered price for LNG in those foreign markets and could weaken the "oil-indexed" pricing terms.

In addition, all proposed LNG exports from the United States in applications DOE/FE has received to date would be pursuant to long-term contracts. To the extent that these contracts supply end-users in foreign markets, these exports represent a base-load demand for U.S. natural gas. As a base load, the United States market would adjust to this increased demand through increases in production, and plan for its delivery utilizing the significant production and storage infrastructure that exists. On average, prices would rise to levels that provide incentives for full marginal cost recovery for the incremental production of natural gas needed to meet this demand.

Hence we agree with those commenters, such as the Bipartisan Policy Center, that maintain that LNG exports from the United States will have difficulty competing with LNG exports from other countries unless domestic U.S. natural gas can be produced much cheaper. They point out that the international supply of natural gas is growing, and the mobility of that supply is increasing as other countries develop their own LNG export capabilities. Further, there is no evidence before us that demonstrates that the prices of natural gas or LNG in the international market are more volatile than the prices in the U.S. domestic market.

G. Integrity of the LNG Export Study

1. Comments

Several commenters, such as Clean Ocean Action and Sierra Club, argue that DOE/FE cannot rely on the NERA report unless DOE/FE discloses more details about the process by which DOE/FE selected NERA to conduct the study, DOE/FE's funding mechanism for paying NERA, and DOE/FE's involvement (if any) in guiding the study or reviewing drafts of the study prior to publication. In addition to Sierra Club, commenters Eugene Bruce, Ellen Osuna, Dow, and IECA assert that DOE/FE cannot rely on the study because NERA has not disclosed all technical details of its proprietary N_{ew}ERA model to the public. According to Sierra Club, DOE/FE "has refused to make [all of] this information available for review during the public comment period."[144] Further, Sierra Club, Save Our Supplies and several other commenters argue that, due to this alleged lack of transparency, DOE/FE should conduct a new study of the potential cumulative impacts of granting LNG export licenses for shipment to non-FTA countries. Sierra Club and other commenters also contend that NERA and/or NERA's Vice

[144] Reply Comments of Sierra Club at 20.

President (and the principal author of the NERA Study) Mr. David Montgomery may be biased in favor of LNG exports, which they argue necessitates a new study by a different contractor.

2. DOE/FE Analysis

DOE has evaluated all submissions in this proceeding on their own merits, including the LNG Export Study and the arguments and analyses submitted by commenters. NERA conducted the study within DOE/FE's requested parameters (which are included as Appendix F to the NERA Study) and provided detailed information regarding its assumptions, model design and methodology, and results. This information is set forth at length in the NERA Study and is discussed in Section VII.B.2 and 5 of this Order. As evidenced by the number of detailed comments received, including additional studies offered by several of the commenters, NERA's explanation of its modeling design, methodology, and results has provided a sufficient basis both for the public to provide meaningful comments and for the Department to evaluate NERA's conclusions.

H. Peer Review

1. Comments

Dow, along with Eugene Bruce, IECA, and others, charge that the NERA Study is invalid because NERA failed to validate its proprietary N_{ew}ERA model by means of technical peer review. These commenters argue that technical peer review is required by the Office of Management and Budget's (OMB) guidance entitled, "Final Information Quality Bulletin for Peer Review" (OMB Bulletin).[145] The OMB Bulletin establishes that "important scientific information shall be peer reviewed by qualified scientists before it is disseminated by the Federal government." Dow asserts that the NERA Study should be considered "highly influential scientific information," subject to the highest standards outlined in the OMB Bulletin, and/or

[145] Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664 (Jan. 14, 2005).

subject to internal DOE peer review guidelines. Due in part to these concerns, several commenters, including Sierra Club and Save Our Supplies, urge that DOE/FE commission a new study by another independent contractor.

Cameron LNG, LLC, in its reply comments, counters that the OMB Bulletin does not apply to adjudications or permit proceedings such as this one. Cameron therefore asserts that the public comment period held by DOE/FE on the LNG Export Study is more than adequate for DOE/FE to obtain constructive review of both the EIA and NERA studies.

2. DOE/FE Analysis

The OMB Bulletin establishes a framework for independent, expert review of influential scientific information before the information is publicly disseminated. It defines "scientific information" as "factual inputs, data, models, analyses, technical information, or scientific assessments based on the behavioral and social sciences, public health and medical sciences, life and earth sciences, engineering, or physical sciences."[146] "Scientific information" does not include opinions where the presentation makes it clear the information is "opinion rather than fact or the agency's views."[147] Further, the OMB Bulletin, while applicable to rulemakings, provides that "official disseminations that arise in adjudications and permit proceedings" are exempt from peer review, unless "the agency determines that peer review is practical and appropriate …."[148]

We have considered commenters' request for peer review in light of the OMB Bulletin. Because this proceeding is an adjudication, peer review is not required unless DOE/FE determines that such review is appropriate. After consideration, we find that peer review is not required because the conclusions reached in the LNG Export Study are in the nature of expert

[146] *Id*. at 2675.
[147] *Id.*
[148] *Id*. at 2677.

opinion, not scientific fact, and also because the principal purpose of peer review of government-sourced documents—ensuring the government is well-informed by independently produced expert analyses—was accomplished in this proceeding.

Both the EIA and NERA studies use market assumptions to project a range of possible future results. No claim is made by the authors of either study that the studies contain scientific fact. To the contrary, both studies caution the reader on the limits to their economic projections. The EIA Study states: "The projections in this report are not statements of what *will* happen but of what *might* happen, given the assumptions and methodologies used."[149] Similarly, the NERA Study was developed around assumptions of future scenarios and repeatedly acknowledges the uncertainties that could shift the results within the range of likely outcomes.[150]

Further, the procedures followed by DOE/FE in this proceeding have allowed numerous commenting parties and third-party experts to offer differing analyses. The comments included several expert studies critiquing the LNG Export Study. For example, Professor Wallace Tyner of Purdue University, submitted results from a study that shows different results from NERA's. Sierra Club submitted a study by Synapse Energy Economics, Inc., that examined NERA's study and pointed out alleged "problems and omissions" in NERA's analysis.[151] Conversely, Southern LNG Company, Gulf LNG, and Jordan Cove Energy Project each submitted a study by Navigant that concluded that NERA's analyses were sound.[152]

DOE/FE has carefully weighed these competing analyses and viewpoints, and has conducted its own internal review of the LNG Export Study. In so doing, DOE/FE has

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[149] EIA Study at ii.
[150] *See, e.g.*, NERA Study at 25-26.
[151] Synapse Energy Economics, Inc., *Will LNG Exports Benefit the United States Economy?* (Jan. 23, 2013), at 1, submitted with Initial Comments of Sierra Club.
[152] *See, e.g.*, Navigant Consulting, Inc. and Navigant Economics, Analysis of the Department of Energy's LNG Export Study (Jan. 24, 2013), App. A of Initial Comments of Gulf LNG.

recognized that its ultimate decision on the pending export applications would benefit from a public exchange of judgments and expert opinions.[153] The major purpose motivating the OMB Bulletin—to ensure that the government is well-informed by independent, expert analysis—was accomplished in this proceeding without the need for peer review.

I. Procedural Arguments

1. Comments

Several commenters, including Sierra Club, Senator Wyden, NRDC, and others argue that the current public interest standard, which focuses on meeting the nation's "essential domestic needs" for natural gas, is too narrow and that DOE/FE must undertake a rulemaking to establish criteria for making such a determination under the NGA. Similarly, Sierra Club, Alcoa, IECA, and CarbonX Energy Company, Inc., argue that DOE/FE should articulate, in the context of a separate rulemaking proceeding, the framework it will use in making its public interest determinations for individual export applications. Dow makes a related comment, stating that each of the individual LNG export dockets contains an insufficient record on which to base a public interest determination on the cumulative impact of LNG exports, and therefore DOE/FE is required to conduct a notice and comment rulemaking before it decides on any of the pending LNG export applications.

Dow, Sierra Club, Save Our Supplies, and other commenters contend that DOE/FE should conduct a public hearing regarding the applicable public interest standard in light of the cumulative impacts of LNG exports. Additionally, several commenters request that DOE/FE reopen the dockets of LNG export applicants to solicit additional public comment. Commenter Mary Altmann argues that DOE/FE should invite public comment on individual LNG

[153] *See* 77 Fed. Reg. at 73,628 ("The LNG Export Study and the comments that DOE/FE receives … will help to inform our determination of the public interest in each case.")

applications before approving exports. IECA argues that many commenters could not reasonably have been expected to intervene in individual license proceedings at the time license applications were filed, since they had no way of anticipating that more than 20 applications would eventually be filed. IECA argues that DOE/FE, therefore, has no alternative other than to allow every interested party to intervene in each proceeding. Along these same lines, CarbonX requests that its comment on the LNG export study be incorporated into the dockets for each pending LNG export applications.

Several commenters raise issues associated with their ability to comment on economic studies conducted by third parties and whether DOE/FE may rely on such studies in making a determination. Regarding DOE/FE's request for public comment in the NOA, Sierra Club, IECA, and others argue that DOE/FE narrowly instructed parties to address only the EIA and NERA studies. Proponents of this argument assert that DOE/FE cannot assess whether it is in the public interest to issue additional LNG export permits by addressing only one aspect of the public interest analysis (*i.e.*, potential impacts on energy costs). Similarly, Sierra Club, IECA, CarbonX, and others, assert that citations to third-party studies in the record do not discharge DOE/FE's responsibility to evaluate the public interest because the studies are based on undisclosed proprietary data and models with limited information regarding their development and age.

Other commenters argue that DOE/FE should act now to decide each pending export application. These commenters contend additional administrative process is neither necessary nor appropriate as DOE/FE has already provided the "opportunity for hearing" required under NGA section 3(a) to make its public interest determination. Commenters such as ExxonMobil and the Center for Liquefied Natural Gas argue that the initial and reply comments submitted in response to the LNG Export Study do not change the NGA statutory and regulatory requirements that place the burden of proof on opponents to demonstrate, with sufficient evidence, that each application is inconsistent with the public interest. These commenters argue that the record before DOE/FE regarding each individual application is sufficient for DOE/FE to determine whether LNG exports have been shown to be inconsistent with the public interest.

2. DOE/FE Analysis

Fundamentally, all of the above requests for procedural relief challenge the adequacy of the opportunity that we have given to the public to participate in this proceeding and the adequacy of the record developed to support our decision in this proceeding.

With respect to opportunity for public participation, we find that the public has been given ample opportunity to participate in this proceeding, as well as the other pending LNG export proceedings. Within this proceeding, Jordan Cove's Notice of Application, published in the Federal Register on June 6, 2012, contained a detailed description of Jordan Cove's Application, and invited the public to submit protests, motions to intervene, notices of intervention, and comments.[154] As required by DOE regulations, similar notices of application have been published in the Federal Register in each of the other non-FTA export application proceedings. Additionally, in December 2012, DOE/FE published the NOA in the Federal Register.[155] As explained above, the NOA described the content and purpose of the EIA and NERA studies, invited the public to submit initial and reply comments, and stated that these comments will be part of the record in each individual docket proceeding.[156] DOE/FE thus has taken appropriate and necessary steps by offering the public multiple opportunities to participate in the non-FTA LNG export proceedings.

[154] 76 Fed. Reg. at 34,212-15.
[155] 77 Fed. Reg. at 73,627.
[156] *Id*. at 73,628.

We also find the record is adequate to support the action we are taking in this Order. DOE/FE has reviewed all of the submissions made in this proceeding. Moreover, this Order sets out the reasons that support each of the determinations contained herein. Consequently, we do not find it is necessary or appropriate to delay issuance of this Order to augment the record, either through a rulemaking or public hearing. In this regard, we note that DOE/FE retains broad discretion to decide what procedures to use in fulfilling its statutory responsibilities under the NGA,[157] and our view is that the record is sufficient to support the actions that we are taking. The requests for additional procedures summarized above are denied.

IX. DISCUSSION AND CONCLUSIONS

To avoid repetition, the following discussion focuses on arguments and evidence presented by the applicant, commenters, and intervenors to the extent that DOE/FE has not already addressed the same or substantially similar arguments in its response to comments on the LNG Export Study (Section VI).

A. Motions to Intervene

The five motions to intervene submitted, respectively, by APGA, Sierra Club, Citizens Against LNG, Landowners United, and KS Wild are unopposed. As such, the motions to intervene are deemed granted. 10 C.F.R. § 590.303(g).

B. Jordan Cove's Application

In total, Jordan Cove introduced seven studies to support its Application: (1) the Navigant Study; (2) the Navigant Whitepaper; (3) the Construction Study; (4) the Operations Study; (5) the Upstream Contributions Study; (6) the Balance of Trade Study; and (7) the Housing and Schools Study.

[157] *See, e.g.*, *Process Gas Consumers v. FERC*, 930 F.2d 926, 929 (D.C. Cir. 1991).

As summarized above, APGA and Sierra Club argued that the proposed exports would not yield economic benefits but, in fact, would increase natural gas prices and result in other deleterious economic and societal impacts. APGA and Sierra Club maintained that the data from 2011 was outdated and that more recent data indicated that exports of LNG would result in significantly higher prices to the long-run detriment of the U.S. economy. Sierra Club additionally raised concerns over Jordan Cove's use of an input-output model, challenged the sustainability of economic benefits in regions tied to resource extraction industries, and insisted that DOE/FE may not lawfully issue a conditional authorization in advance of the completion of environmental review of the project.

We have considered the comments and protests presented in opposition to the Application and, for the reasons discussed below, find that those comments and protests do not overcome the rebuttable presumption that the proposed exports are consistent with the public interest.

1. Regional Impacts

Jordan Cove asserts that the project will stimulate local, regional, and national economies through direct and indirect job creation, increased economic activity, and tax revenues. These claimed benefits are largely based on the analyses contained in the Construction Study, the Operations Study, the Upstream Contributions Study, and the Balance of Trade Study.

Sierra Club does not offer its own analysis specific to the local and regional economic impacts of the Jordan Cove proposal, but challenges the economic benefits raised in the Application because Jordan Cove supported them using an input-output analysis allegedly based on a series of economic "snapshots" in time. This type of analysis, according to Sierra Club, fails to provide a continuous picture of economic impacts, and does not consider a full range of counterfactual scenarios. Sierra Club also challenges Jordan Cove's claimed regional benefits. Sierra Club focuses principally on the durability of economic benefits in producing regions in Pennsylvania and New York where Marcellus Shale drilling is occurring. Sierra Club asserts that any "boom" in economic activity will be followed by a bust, and that the prospect of such an event demonstrates that a grant of the requested authorization is inconsistent with the public interest.

We find that the record contains substantial evidence of regional economic benefits from a grant of the Application. As indicated above, Sierra Club did not offer its own analysis of the specific local and regional impacts anticipated from the Jordan Cove proposal. We further find that the studies submitted by Jordan Cove are not inherently flawed simply because they are based on a series of snapshots of the effects of certain predicted inputs, or because all of the potential counterfactuals raised by Sierra Club were not factored into the analysis. These characteristics of the studies do not mean that the results are unreasonable. Moreover, the results of the studies are generally confirmed on a national scale by the NERA Study.

Further, we reject Sierra Club's claims that exports will have a negative impact on employment. Sierra Club points to the Weinstein study to support its position. However, we have considered the analysis contained in the Weinstein study in several recent orders, and found that the Weinstein Study showed only a statistically insignificant decline in employment in the regions studied in the years before a drilling boom (2001 to 2005) compared to the years during the drilling boom (2005 to 2009). Further, this small decline could have been the result of other factors, particularly since the years of the drilling boom coincided with a national economic recession. On the other hand, comparing the same time periods, we also found that the Weinstein study showed substantial gains in economic growth rates in counties with drilling operations as opposed to those without. For the same reasons provided in *Dominion Cove Point, Freeport II*, and *Cameron*, we reject Sierra Club's arguments here.[158]

Sierra Club also contends more broadly that extractive industries suffer from boom-bust cycles and therefore provide little lasting benefit to local communities. To the extent Sierra Club is claiming that the exports proposed by Jordan Cove will physically exhaust existing resources, we refer to Section VIII.C in which we conclude that record evidence indicates that there will be substantial supply into the foreseeable future. To the extent that the "bust" cycles Sierra Club envisions are brought on by price declines that render existing resources uneconomic to produce, we do not see compelling evidence that the exports will exacerbate this risk. If anything, it seems more likely that Jordan Cove's ability to export to non-FTA countries will deepen and diversify the market for U.S.-produced natural gas, making the potential for a precipitous price-driven downturn in production activities less likely, not more likely.

2. Price Impacts

As discussed above, the LNG Export Study projected the economic impacts of LNG exports in a range of scenarios, including scenarios that equaled and exceeded the current amount of LNG exports authorized in the final and conditional non-FTA export authorizations to date (8.47 Bcf/d of natural gas) plus the additional 0.8 Bcf/d volume of exports requested by Jordan Cove in this proceeding. The LNG Export Study concluded that LNG exports at these levels (*e.g.*, 6 Bcf/d of natural gas and higher) would result in higher U.S. natural gas prices, but that these price changes would remain in a relatively narrow range across the scenarios studied. NERA's analysis indicates that, after five years of increasing LNG exports, wellhead natural gas price increases could range from $0.22 to $1.11 (2010$/Mcf) depending on the market-

[158] *See Dominion Cove*, DOE/FE Order No. 3331, at 136-38; *Freeport II*, DOE/FE Order No. 3359, at 148-51; *Cameron*, DOE/FE Order No. 3391, at 127-29.

determined level of exports. However, even with these estimated price increases, NERA found that the United States would experience net economic benefits from increased LNG exports in all cases studied. *See supra* Section VI.B.1, 8.

Both APGA and Sierra Club contend that Jordan Cove relied on outdated EIA projections from AEO 2011. This is the same set of projections used in the LNG Export Study, and was the most recent, final set of projections available at the time. For several of the same reasons that we reject arguments that the LNG Export Study was based on outdated projections, we reject similar arguments raised by APGA and Sierra Club in this proceeding. As discussed above, the updated AEO 2014 Early Release Reference Case projections from EIA suggest domestic supply and demand conditions that are more favorable, not less favorable, to exports. Specifically, the most recent outlook in the AEO 2014 Early Release Reference Case for 2035 reflects LNG exports of 7.4 Bcf/d in the lower-48, net natural gas pipeline exports of 5.9 Bcf/d, and market price $0.39/MMBtu below the AEO 2011 Reference Case price, in constant 2012 dollars. It should be noted that, for 2035, the AEO 2011 Reference Case forecast 0.5 Bcf/d of net imports (not exports) of natural gas plus LNG. Accordingly, we reject the intervenors' arguments and find that, as to the impact of these LNG exports on domestic gas prices, intervenors have not overcome the statutory presumption that the requested authorization is consistent with the public interest.

3. Conditional Authorization

Sierra Club contends that DOE/FE may not lawfully issue a conditional authorization until a full EIS has been issued, on the theory that a conditional authorization may limit the choice of reasonable alternatives or determine subsequent development. We disagree with Sierra Club's contention. As we have explained elsewhere, we are attaching a condition to this export authorization ordering that Jordan Cove's authorization is contingent on both its satisfactory completion of the environmental review process and its on-going compliance with any and all preventative and mitigative measures imposed at the Jordan Cove Terminal by federal or state agencies. When the environmental review is complete, DOE/FE will reconsider its public interest determination in light of the information gathered as part of that review. This procedure will not foreclose the choice of reasonable alternatives or influence subsequent development.

C. Significance of the LNG Export Study

For the reasons discussed above, DOE/FE commissioned the LNG Export Study and invited the submission of responsive comments. DOE/FE has analyzed this material and determined that the LNG Export Study provides substantial support for conditionally granting Jordan Cove's Application. The conclusion of the LNG Export Study is that the United States will experience net economic benefits from issuance of authorizations to export domestically produced LNG. We have evaluated the initial and reply comments submitted in response to the LNG Export Study. Various commenters have criticized the data used as inputs to the LNG Export Study and numerous aspects of the models, assumptions, and design of the Study. As discussed above, however, we find that the LNG Export Study is fundamentally sound and supports the proposition that the proposed authorization will not be inconsistent with the public interest.

D. Benefits of International Trade

We have not limited our review to the contents of the LNG Export Study but have considered a wide range of other information. For example, the National Export Initiative, established by Executive Order, sets an Administration goal to "improve conditions that directly affect the private sector's ability to export" and to "enhance and coordinate Federal efforts to facilitate the creation of jobs in the United States through the promotion of exports."[159]

We have also considered the international consequences of our decision. We review applications to export LNG to non-FTA nations under section 3(a) of the NGA. The United States' commitment to free trade is one factor bearing on that review. An efficient, transparent international market for natural gas with diverse sources of supply provides both economic and strategic benefits to the United States and our allies. Indeed, increased production of domestic natural gas has significantly reduced the need for the United States to import LNG. In global trade, LNG shipments that would have been destined to U.S. markets have been redirected to Europe and Asia, improving energy security for many of our key trading partners. To the extent U.S. exports can diversify global LNG supplies, and increase the volumes of LNG available globally, it will improve energy security for many U.S. allies and trading partners. As such, authorizing U.S. exports may advance the public interest for reasons that are distinct from and additional to the economic benefits identified in the LNG Export Study.

E. Other Considerations

Our decision is not premised on an uncritical acceptance of the general conclusion of the LNG Export Study of net economic benefits from LNG exports. Both the LNG Export Study and many public comments identify significant uncertainties and even potential negative impacts from LNG exports. The economic impacts of higher natural gas prices and potential increases in gas price volatility are two of the factors that we view most seriously. Yet we also have taken into account factors that could mitigate such impacts, such as the current oversupply situation and data indicating that the natural gas industry would increase natural gas supply in response to

[159] NEI, 75 Fed. Reg. at 12,433.

increasing exports. Further, we note that it is far from certain that all or even most of the proposed LNG export projects will ever be realized because of the time, difficulty, and expense of commercializing, financing, and constructing LNG export terminals, as well as the uncertainties inherent in the global market demand for LNG. On balance, we find that the potential negative impacts of Jordan Cove's proposed exports are outweighed by the likely net economic benefits and by other non-economic or indirect benefits.

More generally, DOE/FE continues to subscribe to the principle set forth in our 1984 Policy Guidelines[160] that, under most circumstances, the market is the most efficient means of allocating natural gas supplies. However, agency intervention may be necessary to protect the public in the event there is insufficient domestic natural gas for domestic use. There may be other circumstances as well that cannot be foreseen that would require agency action.[161] Given these possibilities, DOE/FE recognizes the need to monitor market developments closely as the impact of successive authorizations of LNG exports unfolds.

F. Conclusion

We have reviewed the evidence in the record and have not found an adequate basis to conclude that Jordan Cove's export of LNG to non-FTA countries will be inconsistent with the public interest. For that reason, we are authorizing Jordan Cove's proposed exports to non-FTA countries subject to the limitations and conditions described in this Order.

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[160] 49 Fed. Reg. at 6684.

[161] We understand that some commenters on the LNG Export Study, including Jayanta Sinha, President of GAIL Global, Inc., would like DOE to clarify the circumstances under which the agency would exercise its authority to revoke (in whole or in part) previously issued LNG export authorizations. We cannot precisely identify all the circumstances under which such action would be taken. We reiterate our observation in *Sabine Pass* that: "In the event of any unforeseen developments of such significant consequence as to put the public interest at risk, DOE/FE is fully authorized to take action as necessary to protect the public interest. Specifically, DOE/FE is authorized by section 3(a) of the Natural Gas Act … to make a supplemental order as necessary or appropriate to protect the public interest. Additionally, DOE is authorized by section 16 of the Natural Gas Act 'to perform any and all acts and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate' to carry out its responsibilities." *Sabine Pass*, Order No. 2961, at 33 n.45 (quoting 15 U.S.C. § 717*o*).

We have considered the cumulative impacts of past authorizations in our decision. In this case, we do not find that opponents of the Application have overcome the statutory presumption that the proposed export authorization is consistent with the public interest. By authorizing exports of LNG in a volume equivalent to 0.8 Bcf/d of natural gas (292 Bcf/yr) in this proceeding, DOE/FE will have cumulatively authorized non-FTA exports totaling 9.27 Bcf/d of natural gas, or 3.384 Tcf/yr, for the one final and six conditional export authorizations granted to date—Sabine Pass (2.2 Bcf/d), Freeport I (1.4 Bcf/d), Lake Charles Exports (2.0 Bcf/d), Dominion Cove Point (0.77 Bcf/d), Freeport II (0.4 Bcf/d), Cameron (1.7 Bcf/d), and the current authorization (0.8 Bcf/d). This total export volume is within the range of scenarios analyzed in the EIA and NERA studies. NERA found that in all such scenarios—assuming either 6 Bcf/d or 12 Bcf/d of export volumes—the United States would experience net economic benefits. As discussed above, the submissions of the intervenors do not undermine the reasonableness of the findings in the LNG Export Study. We also note that EIA's most recent projections, set forth in the AEO 2014 Early Release Overview, continue to show market conditions that will accommodate increased exports of natural gas. As explained in Section VIII.A., when compared to the AEO 2013 Reference Case, the AEO 2014 Early Release Reference Case projects marked increases in domestic natural gas production—well in excess of what is required to meet projected increases in domestic consumption.

DOE/FE will continue taking a measured approach in reviewing the other pending applications to export domestically produced LNG. Specifically, DOE/FE will continue to assess the cumulative impacts of each succeeding request for export authorization on the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals. In keeping with the performance of its statutory responsibilities, DOE/FE will attach appropriate and necessary terms and conditions to authorizations to ensure that the authorizations are utilized in a timely manner and that authorizations are not issued except where the applicant can show that there are or will be facilities capable of handling the proposed export volumes and existing and forecast supplies that support that action. Other conditions will be applied as necessary.

The reasons in support of proceeding cautiously are several: (1) the LNG Export Study, like any study based on assumptions and economic projections, is inherently limited in its predictive accuracy; (2) applications to export significant quantities of domestically produced LNG are a new phenomena with uncertain impacts; and (3) the market for natural gas has experienced rapid reversals in the past and is again changing rapidly due to economic, technological, and regulatory developments. The market of the future very likely will not resemble the market of today. In recognition of these factors, DOE/FE intends to monitor developments that could tend to undermine the public interest in grants of successive applications for exports of domestically produced LNG and, as previously stated, to attach terms and conditions to the authorization in this proceeding and to succeeding LNG export authorizations as are necessary for protection of the public interest.

We emphasize that the conditional authorization announced in this Order applies only to the exports proposed by Jordan Cove. In connection with the LNG Export Study, DOE received numerous comments relating to the total volume of LNG exports to non-FTA countries that might ultimately be authorized, as well as comments relating to the timing and sequencing of possible future authorizations.[162] All comments related to the LNG Export Study will become

[162] Several commenters on the LNG Export Study, including Susan Sakmar, Leny Mathews, Alcoa Energy, IECA, and Citizens Against LNG, advocate against unlimited LNG exports. These commenters urge DOE/FE to limit the total volume of LNG to be exported, assert that DOE/FE should issue a policy detailing its plan for granting LNG export licenses and for monitoring cumulative impacts, and propose that DOE/FE "phase in" the approval of LNG export projects to minimize potential price impacts. Although DOE/FE is not taking any of these actions at this time, it is monitoring the LNG export landscape as it evolves, as explained above. Because these comments are now

part of any export proceeding for which the LNG Export Study is used to inform DOE's public interest determination. Because we are acting only on the Application before us and make no decisions regarding future cases, comments relating to the total volume of LNG exports ultimately authorized or the timing or sequencing of possible future authorizations need not be decided in this proceeding.

X. TERMS AND CONDITIONS

To ensure that the authorization issued by this Order is not inconsistent with the public interest, DOE/FE has attached the following terms and conditions to the authorization. The reasons for each term or condition are explained below. Jordan Cove must abide by each term and condition or face rescission of its authorization or other appropriate sanction.

A. Term of the Authorization

Jordan Cove has requested a 25-year term for the authorization commencing on the earlier of the date of first export or the date seven years from the date the requested authorization is granted. However, because the NERA study contains projections over a 20-year period beginning from the date of first export,[163] we believe that caution recommends limiting this conditional authorization to no longer than a 20-year term beginning from the earlier of the date of first export or the date seven years from the date that a final order authorizing the exports is issued. In imposing this condition, we are mindful that LNG export facilities are capital intensive and that, to obtain financing for such projects, there must be a reasonable expectation that the authorization will continue for a term sufficient to support repayment. We find that a 20-

part of the record in each individual docket proceeding, *see* 77 Fed. Reg. at 73,629, DOE/FE will consider them in the course of reviewing each application and the cumulative impact of prior authorizations.

[163] NERA Study at 5 ("Results are reported in 5-year intervals starting in 2015. These calendar years should not be interpreted literally but represent intervals after exports begin. Thus if the U.S. does not begin LNG exports until 2016 or later, one year should be added to the dates for each year that exports commence after 2015.").

year term is likely sufficient to achieve this result. It is also consistent with the 20-year term authorized by DOE/FE in the four other non-FTA export authorizations issued to date.[164]

B. Commencement of Operations Within Seven Years

Jordan Cove requested this conditional authorization to commence on the earlier of the date of first export or seven years from the date of the issuance of this Order. Consistent with the final and conditional non-FTA authorizations granted to date,[165] DOE/FE will impose the condition that Jordan Cove must commence commercial LNG export operations no later than seven years from the date of issuance of this Order. The purpose of this condition is to ensure that other entities that may seek similar authorizations are not frustrated in their efforts to obtain those authorizations by authorization holders that are not engaged in actual export operations.

C. Transfer, Assignment, or Change in Control

DOE/FE's natural gas import/export regulations prohibit authorization holders from transferring or assigning authorizations to import or export natural gas without specific authorization by the Assistant Secretary for Fossil Energy.[166] As a condition of the similar authorization issued to Sabine Pass in Order No. 2961, DOE/FE found that the requirement for prior approval by the Assistant Secretary under its regulations applies to any change of effective control of the authorization holder either through asset sale or stock transfer or by other means. This condition was deemed necessary to ensure that, prior to any transfer or change in control, DOE/FE will be given an adequate opportunity to assess the public interest impacts of such a transfer or change.

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[164] *See*, *e.g.*, *Sabine Pass*, DOE/FE Order No. 2961-A, at 29; *Freeport LNG*, DOE/FE Order No. 3282, at 122; *Lake Charles Exports*, DOE/FE Order No. 3324, at 135; and *Dominion Cove Point*, DOE/FE Order No 3331, at 151.
[165] *See*, *e.g.*, *Sabine Pass*, DOE/FE Order No. 2961-A, at 33; *Freeport LNG*, DOE/FE Order No. 3282, at 122; *Lake Charles Exports*, DOE/FE Order No. 3324, at 128; *Freeport II*, DOE/FE Order No. 3357, at 158.
[166] 10 C.F.R. § 590.405.

To clarify its interpretation of its regulations, DOE/FE will construe a change of control to mean a change, directly or indirectly, of the power to direct the management or policies of an entity whether such power is exercised through one or more intermediary companies or pursuant to an agreement, written or oral, and whether such power is established through ownership or voting of securities, or common directors, officers, or stockholders, or voting trusts, holding trusts, or debt holdings, or contract, or any other direct or indirect means. A rebuttable presumption that control exists will arise from the ownership or the power to vote, directly or indirectly, 10 percent or more of the voting securities of such entity.

D. Agency Rights

As described above, Jordan Cove requests authorization to export LNG on its behalf and as agent for other entities who themselves hold title to the LNG. DOE/FE previously addressed the issue of Agency Rights in Order No. 2913,[167] which granted FLEX authority to export LNG to FTA countries. In that order, DOE/FE approved a proposal by FLEX to register each LNG title holder for whom FLEX sought to export LNG as agent. DOE/FE found that this proposal was an acceptable alternative to the non-binding policy adopted by DOE/FE in *Dow Chemical*, which established that the title for all LNG authorized for export must be held by the authorization holder at the point of export.[168] We find that the same policy considerations that supported DOE/FE's acceptance of the alternative registration proposal in Order No. 2913 apply here as well. DOE/FE reiterated its policy on Agency Rights procedures in *Gulf Coast LNG Export, LLC*.[169] In *Gulf Coast*, DOE/FE confirmed that, in LNG export orders in which Agency Rights have been granted, DOE/FE shall require registration materials filed for, or by, an LNG

[167] *Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC*, DOE/FE Order No. 2913, Order Granting Long-Term Authorization to Export Liquefied Natural Gas from Freeport LNG Terminal to Free Trade Nations (Feb. 10, 2011).
[168] *Dow Chem. Co.*, DOE/FE Order No. 2859, at 7-8, *discussed in Freeport LNG*, DOE/FE Order No. 2913, at 7-8.
[169] *Gulf Coast LNG Export, LLC*, DOE/FE Order No. 3163, Order Granting Long-Term Multi-Contract Authority to Export LNG by Vessel from the Proposed Brownsville Terminal to Free Trade Agreement Nations (Oct. 16, 2012).

title-holder (Registrant) to include the same company identification information and long-term contract information of the Registrant as if the Registrant had filed an application to export LNG on its own behalf.[170]

To ensure that the public interest is served, the authorization granted herein shall be conditioned to require that where Jordan Cove proposes to export LNG as agent for other entities who hold title to the LNG (Registrants), Jordan Cove must register with DOE/FE those entities on whose behalf it will export LNG in accordance with the procedures and requirements described herein.

E. Contract Provisions for the Sale or Transfer of LNG to be Exported

DOE/FE's regulations require applicants to supply transaction-specific factual information "to the extent practicable."[171] Additionally, DOE/FE regulations allow confidential treatment of the information supplied in support of or in opposition to an application if the submitting party requests such treatment, shows why the information should be exempted from public disclosure, and DOE/FE determines it will be afforded confidential treatment in accordance with 10 C.F.R. § 1004.11.[172]

DOE/FE will require that Jordan Cove file or cause to be filed with DOE/FE any relevant long-term commercial agreements, including LTAs, pursuant to which Jordan Cove exports LNG as agent for a Registrant. *See supra* Section IV.C.

DOE/FE finds that the submission of all such agreements or contracts within 30 days of their execution using the procedures described below will be consistent with the "to the extent practicable" requirement of section 590.202(b). By way of example and without limitation, a "relevant long-term commercial agreement" would include an agreement with a minimum term

[170] *See id*. at 7-8.
[171] 10 C.F.R. § 590.202(b).
[172] *Id*. § 590.202(e).

of two years, an agreement to provide gas processing or liquefaction services at the Jordan Cove Terminal, a long-term sales contract involving natural gas or LNG stored or liquefied at the Jordan Cove Terminal, or an agreement to provide export services from the Jordan Cove Terminal.

In addition, DOE/FE finds that section 590.202(c) of DOE/FE's regulations[173] requires that Jordan Cove file, or cause to be filed, all long-term contracts associated with the long-term supply of natural gas to the Jordan Cove Terminal, whether signed by Jordan Cove or the Registrant, within 30 days of their execution.

DOE/FE recognizes that some information in Jordan Cove's or a Registrant's long-term commercial agreements associated with the export of LNG, and/or long-term contracts associated with the long-term supply of natural gas to the Jordan Cove Terminal, may be commercially sensitive. DOE/FE therefore will provide Jordan Cove the option to file or cause to be filed either unredacted contracts, or in the alternative (A) Jordan Cove may file, or cause to be filed, long-term contracts under seal, but it also will file either: i) a copy of each long-term contract with commercially sensitive information redacted, or ii) a summary of all major provisions of the contract(s) including, but not limited to, the parties to each contract, contract term, quantity, any take or pay or equivalent provisions/conditions, destinations, re-sale provisions, and other relevant provisions; and (B) the filing must demonstrate why the redacted information should be exempted from public disclosure.

To ensure that DOE/FE destination and reporting requirements included in this Order are conveyed to subsequent title holders, DOE/FE will include as a condition of this authorization that future contracts for the sale or transfer of LNG exported pursuant to this Order shall include an acknowledgement of these requirements.

[173] *Id*. § 590.202(c).

F. Export Quantity

Jordan Cove has sought export authorization in a volume equivalent to 0.8 Bcf/d of natural gas. As set forth herein, this Order authorizes the export of LNG in the full amount requested by Jordan Cove, up to the equivalent of 292 Bcf/yr of natural gas.

G. Combined FTA and Non-FTA Export Authorization Volume

In this proceeding, Jordan Cove seeks authorization to export 292 Bcf/yr of natural gas to non-FTA countries under NGA section 3(a). Jordan Cove's proposal for the LNG Terminal now pending before FERC in Docket No. CP13-483-000 is for a total take-away capacity of 6 mtpa, which is roughly equivalent to the volumes requested for export in this proceeding. As stated above, Jordan Cove is currently authorized pursuant to DOE/FE Order No. 3041 to export LNG from the same Terminal to FTA countries in an amount equivalent to 438 Bcf/yr of natural gas.

The volumes authorized for export in this proceeding to non-FTA nations will not be considered additive to the volumes previously authorized for export to FTA nations. DOE/FE's policy is not to authorize exports that exceed the capacity of a LNG export terminal.[174] The source of LNG proposed for both of Jordan Cove's export authorizations is from the proposed Jordan Cove Terminal. To ensure that Jordan Cove's combined FTA and non-FTA export authorizations do not exceed the capacity of that facility, Jordan Cove may not treat the volumes authorized for export in this proceeding as additive to the volumes authorized for export to FTA nations in Order No. 3041.

[174] *See Freeport II* at 162 ("There is no basis for authorizing exports in excess of the maximum liquefaction capacity of a planned facility.").

H. Environmental Review

As explained above, DOE/FE intends to complete its NEPA review as a cooperating agency in FERC's review of the Jordan Cove project. The authorization issued in this Order will be conditioned on Jordan Cove's satisfactory completion of the environmental review process.[175]

Accordingly, this conditional Order makes preliminary findings and indicates to the parties DOE/FE's determination at this time on all but the environmental issues in this proceeding. All parties are advised that the issues addressed herein regarding the export of natural gas will be reexamined at the time of DOE/FE's review of the FERC environmental analysis. Inasmuch as DOE/FE is a cooperating agency in the FERC environmental review, persons wishing to raise questions regarding the environmental review of the present Application are responsible for doing so within the FERC proceedings. As explained in the *Sabine Pass* orders, DOE/FE's participation as a cooperating agency in the FERC proceeding is intended to avoid duplication of effort by agencies with overlapping environmental review responsibilities, to achieve early coordination among agencies, and to concentrate public participation in a single forum.[176]

Insofar as a participant in the FERC proceeding actively raises concerns over the scope or substance of environmental review but is unsuccessful in securing that agency's consideration of its stated interests, DOE/FE reserves the right to address the stated interests within this proceeding. However, absent a showing of good cause for a failure of interested persons to participate in the FERC environmental review proceeding, DOE/FE may dismiss such claims if raised out of time in this proceeding.

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[175] 10 C.F.R. § 590.402 (authorizing DOE/FE to issue a conditional order prior to issuance of a final opinion and order).

[176] *Sabine Pass*, DOE/FE Order No. 2961, at 40-41; *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961-B, Opinion and Order Denying Request for Rehearing of Order Denying Motion for Late Intervention, Dismissing Request for Rehearing of Order No. 2961-A, and Dismissing Motion for a Stay Pendente Lite, at 4 (Jan. 25, 2013).

XI. FINDINGS

On the basis of the findings and conclusions set forth above, we find that it has not been shown that a grant of the requested authorization will be inconsistent with the public interest, and we further find that the Application should be granted subject to the terms and conditions set forth herein.

XII. ORDER

Pursuant to section 3 of the Natural Gas Act, it is ordered that:

A. Jordan Cove is authorized to export domestically produced LNG by vessel from the Jordan Cove Terminal on the North Spit of Coos Bay in Coos County, Oregon, up to the equivalent of 292 Bcf/yr of natural gas for a term of 20 years to commence on the earlier of the date of first export or seven years from the date that this Order is issued. Jordan Cove is authorized to export this LNG on its own behalf and as agent for other entities who hold title to the natural gas, pursuant to one or more long-term contracts (a contract greater than two years).

B. Jordan Cove must commence export operations using the planned liquefaction facilities no later than seven years from the date of issuance of this Order.

C. The LNG export quantity authorized in this Order is equivalent to 292 Bcf/yr of natural gas. This quantity is not additive to Jordan Cove's FTA authorization, set forth in DOE/FE Order No. 3041.

D. This LNG may be exported to any country with which the United States does not have an FTA requiring the national treatment for trade in natural gas, which currently has or in the future develops the capacity to import LNG, and with which trade is not prohibited by United States law or policy.

E. Jordan Cove shall ensure that all transactions authorized by this Order are permitted and lawful under United States laws and policies, including the rules, regulations, orders, policies, and other determinations of the Office of Foreign Assets Control of the United States Department of the Treasury and FERC. Failure to comply with this requirement could result in rescission of this authorization and/or other civil or criminal remedies.

F. The authorization granted by this Order is conditioned on Jordan Cove's satisfactory completion of the environmental review process under NEPA in FERC Docket Nos. CP13-483-000 and CP13-492-000, and on issuance by DOE/FE of findings of no significant impact or a record of decision pursuant to NEPA. Additionally, the authorization is conditioned on Jordan Cove's on-going compliance with any and all preventative and mitigative measures at the Jordan Cove Terminal imposed by federal or state agencies.

G. (i) Jordan Cove shall file, or cause others to file, with the Office of Oil and Gas Global Security and Supply a non-redacted copy of <u>all executed long-term contracts associated with the long-term export of LNG</u> on its own behalf or as agent for other entities from the Jordan Cove Terminal. The non-redacted copies may be filed under seal and must be filed within 30 days of their execution. Additionally, if Jordan Cove has filed the contracts described in the preceding sentence under seal or subject to a claim of confidentiality or privilege, within 30 days of their execution, Jordan Cove shall also file, or cause others to file, for public posting either: i) a redacted version of the contracts described in the preceding sentence, or ii) major provisions of the contracts. In these filings, Jordan Cove shall state why the redacted or non-disclosed information should be exempted from public disclosure.

(ii) Jordan Cove shall file, or cause others to file, with the Office of Oil and Gas Global Security and Supply a non-redacted copy of <u>all executed long-term contracts associated with the long-term supply of natural gas</u> to the Jordan Cove Terminal. The non-redacted copies may be filed under seal and must be filed within 30 days of their execution. Additionally, if Jordan Cove has filed the contracts described in the preceding sentence under seal or subject to a claim of confidentiality or privilege, within 30 days of their execution, Jordan Cove shall also file, or cause others to file, for public posting either: i) a redacted version of the contracts described in the preceding sentence, or ii) major provisions of the contracts. In these filings, Jordan Cove shall state why the redacted or non-disclosed information should be exempted from public disclosure.

H. Jordan Cove, or others for whom Jordan Cove acts as agent, shall include the following provision in any agreement or other contract for the sale or transfer of LNG exported pursuant to this Order:

> Customer or purchaser acknowledges and agrees that it will resell or transfer LNG purchased hereunder for delivery only to countries identified in Ordering Paragraph D of DOE Order No. 3413, issued March 24, 2014, in FE Docket No. 12-32-LNG, and/or to purchasers that have agreed in writing to limit their direct or indirect resale or transfer of such LNG to such countries. Customer or purchaser further commits to cause a report to be provided to Jordan Cove Energy Project, L.P. that identifies the country of destination, upon delivery, into which the exported LNG was actually delivered, and to include in any resale contract for such LNG the necessary conditions to insure that Jordan Cove Energy Project, L.P. is made aware of all such actual destination countries.

I.   Jordan Cove is permitted to use its authorization in order to export LNG as agent for other entities, after registering the other parties with DOE/FE. Registration materials shall include an acknowledgement and agreement by the Registrant to supply Jordan Cove with all information necessary to permit Jordan Cove to register that person or entity with DOE/FE, including: (1) the Registrant's agreement to comply with this Order and all applicable requirements of DOE/FE's regulations at 10 C.F.R. Part 590, including but not limited to destination restrictions; (2) the exact legal name of the Registrant, state/location of incorporation/registration, primary place of doing business, and the Registrant's ownership structure, including the ultimate parent entity if the Registrant is a subsidiary or affiliate of another entity; (3) the name, title, mailing address, e-mail address, and telephone number of a corporate officer or employee of the registrant to whom inquiries may be directed; and (4) within 30 days of execution, a copy of any long-term contracts not previously filed with DOE/FE, described in Ordering Paragraph (G) of this Order.

J. Each registration submitted pursuant to this Order shall have current information on file with DOE/FE. Any changes in company name, contact information, change in term of the long-term contract, termination of the long-term contract, or other relevant modification, shall be filed with DOE/FE within 30 days of such change(s).

K. As a condition of this authorization, Jordan Cove shall ensure that all persons required by this Order to register with DOE/FE have done so. Any failure by Jordan Cove to ensure that all such persons or entities are registered with DOE/FE shall be grounds for rescinding in whole or in part the authorization.

L. Within two weeks after the first export of domestically produced LNG occurs from the Jordan Cove Terminal in Coos Bay, Coos County, Oregon, Jordan Cove shall provide written notification of the date that the first export of LNG authorized in Ordering Paragraph A above occurred.

M. Jordan Cove shall file with the Office of Oil and Gas Global Security and Supply, on a semi-annual basis, written reports describing the progress of the proposed liquefaction and pipeline project. The reports shall be filed on or by April 1 and October 1 of each year, and shall include information on the progress of the liquefaction and pipeline project, the date the liquefaction facility is expected to be operational, and the status of the long-term contracts associated with the long-term export of LNG and any long-term supply contracts.

N. Prior to any change in control of the authorization holder, Jordan Cove must obtain the approval of the Assistant Secretary for Fossil Energy. For purposes of this Ordering Paragraph, a "change of control" shall include any change, directly or indirectly, of the power to direct the management or policies of Jordan Cove, whether such power is exercised through one or more intermediary companies or pursuant to an agreement, written or oral, and whether such power is established through ownership or voting of securities, or common directors, officers, or stockholders, or voting trusts, holding trusts, or debt holdings, or contract, or any other direct or indirect means.

O. Monthly Reports: With respect to the LNG exports authorized by this Order, Jordan Cove shall file with the Office of Oil and Gas Global Security and Supply, within 30 days following the last day of each calendar month, a report indicating whether exports of LNG have been made. The first monthly report required by this Order is due not later than the 30th day of the month following the month of first export. In subsequent months, if exports have not occurred, a report of "no activity" for that month must be filed. If exports of LNG have occurred, the report must give the following details of each LNG cargo: (1) the name(s) of the authorized exporter registered with DOE/FE; (2) the name of the U.S. export terminal; (3) the name of the LNG tanker; (4) the date of departure from the U.S. export terminal; (5) the country (or countries) of destination into which the exported LNG was actually delivered; (6) the name of the supplier/seller; (7) the volume in Mcf; (8) the price at point of export per million British thermal units (MMBtu); (9) the duration of the supply agreement; and (10) the name(s) of the purchaser(s).

(Approved by the Office of Management and Budget under OMB Control No. 1901-0294)

P. All monthly report filings shall be made to U.S. Department of Energy (FE-34), Office of Fossil Energy, Office of Oil and Gas Global Security and Supply, P.O. Box 44375, Washington, D.C. 20026-4375, Attention: Natural Gas Reports. Alternatively, reports may be e-mailed to ngreports@hq.doe.gov or may be faxed to Natural Gas Reports at (202) 586-6050.

Q. The motions to intervene submitted in this proceeding by Sierra Club; APGA; Citizens Against LNG, Inc.; Landowners United; and, jointly, Rogue Riverkeeper and the Klamath-Siskiyou Wildlands Center are granted.

R. The Citizens Against LNG's Response is accepted for filing.

Issued in Washington, D.C., on March 24, 2014.

Christopher A. Smith
Principal Deputy Assistant Secretary
Office of Fossil Energy

Exhibit 3

Independent Statistics & Analysis
U.S. Energy Information Administration

Effect of Increased Natural Gas Exports on Domestic Energy Markets

as requested by the Office of Fossil Energy

January 2012

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

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.

Contacts

The Office of Energy Analysis prepared this report under the guidance of John Conti, Assistant Administrator for Energy Analysis. General questions concerning the report can be directed to Michael Schaal (michael.schaal@eia.gov, 202/586-5590), Director, Office of Petroleum, Natural Gas and Biofuels Analysis; and Angelina LaRose, Team Lead, Natural Gas Markets Team (angelina.larose@eia.gov, 202/586-6135).

Technical information concerning the content of the report may be obtained from Joe Benneche (joseph.benneche@eia.gov, 202/586-6132).

Preface

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report, therefore, should not be construed as representing those of the Department of Energy or other Federal agencies.

The projections in this report are not statements of what *will* happen but of what *might* happen, given the assumptions and methodologies used. The Reference case in this report is a business-as-usual trend estimate, reflecting known technology and technological and demographic trends, and current laws and regulations. Thus, it provides a policy-neutral starting point that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes.

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Introduction

This report responds to an August 2011 request from the Department of Energy's Office of Fossil Energy (DOE/FE) for an analysis of "the impact of increased domestic natural gas demand, as exports." Appendix A provides a copy of the DOE/FE request letter. Specifically, DOE/FE asked the U.S. Energy Information Administration (EIA) to assess how specified scenarios of increased natural gas exports could affect domestic energy markets, focusing on consumption, production, and prices.

DOE/FE provided four scenarios of export-related increases in natural gas demand (Figure 1) to be considered:

- 6 billion cubic feet per day (Bcf/d), phased in at a rate of 1 Bcf/d per year (low/slow scenario),
- 6 Bcf/d phased in at a rate of 3 Bcf/d per year (low/rapid scenario),
- 12 Bcf/d phased in at a rate of 1 Bcf/d per year (high/slow scenario), and
- 12 Bcf/d phased in at a rate of 3 Bcf/d per year (high/rapid scenario).

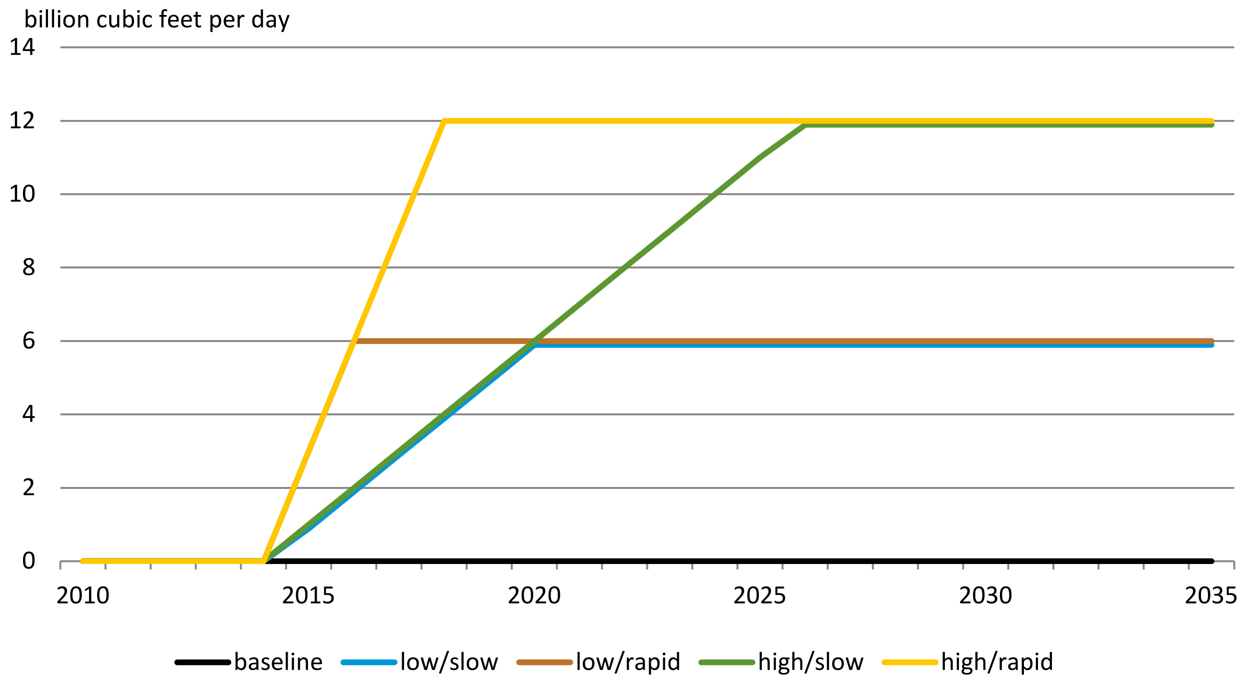
Total marketed natural gas production in 2011 was about 66 Bcf/d. The two ultimate levels of increased natural gas demand due to additional exports in the DOE/FE scenarios represent roughly 9 percent or 18 percent of current production.

DOE/FE requested that EIA consider the four scenarios of increased natural gas exports in the context of four cases from the EIA's *2011 Annual Energy Outlook* (*AEO2011*) that reflect varying perspectives on the domestic natural gas supply situation and the growth rate of the U.S. economy. These are:

- the *AEO2011* Reference case,
- the High Shale Estimated Ultimate Recovery (EUR) case (reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case),
- the Low Shale EUR case (reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case), and
- the High Economic Growth case (assuming the U.S. gross domestic product will grow at an average annual rate of 3.2 percent from 2009 to 2035, compared to 2.7 percent in the Reference case, which increases domestic energy demand).

DOE/FE requested this study as one input to their assessment of the potential impact of current and possible future applications to export domestically produced natural gas. Under Section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b), DOE must evaluate applications to import and export natural gas and liquefied natural gas (LNG) to or from the United States. The NGA requires DOE to grant a permit unless it finds that such action is not consistent with the public interest. As a practical matter, the need for DOE to make a public interest judgment applies only to trade involving countries that have not entered into a free trade agreement (FTA) with the United States requiring the national treatment for trade in natural gas and LNG. The NGA provides that applications involving imports from or exports to an FTA country are deemed to be in the public interest and shall be granted without modification or delay. Key countries with FTAs include Canada and Mexico, which engage in significant natural gas trade with the United States via pipeline. A FTA with South Korea, currently the world's second largest importer of LNG, which does not currently receive domestically produced natural gas from the United States, has been ratified by both the U.S. and South Korean legislatures, but had not yet entered into force as of the writing of this report.

Figure 1. Four scenarios of increased natural gas exports specified in the analysis request



Source: U.S. Energy Information Administration based on DOE Office of Fossil Energy request letter

Analysis approach

EIA used the *AEO2011* Reference case issued in April 2011 as the starting point for its analysis and made several changes to the model to accommodate increased exports. EIA exogenously specified additional natural gas exports from the United States in the National Energy Modeling System (NEMS), as the current version of NEMS does not generate an endogenous projection of LNG exports. EIA assigned these additional exports to the West South Central Census Division.[1] Any additional natural gas consumed during the liquefaction process is counted within the total additional export volumes specified in the DOE/FE scenarios. Therefore the net volumes of LNG produced for export are roughly 10 percent below the gross volumes considered in each export scenario.

Other changes in modeled flows of gas into and out of the lower-48 United States were necessary to analyze the increased export scenarios. U.S. natural gas exports to Canada and U.S. natural gas imports from Mexico are exogenously specified in all of the *AEO2011* cases. U.S. imports of natural gas from

[1] This effectively assumes that incremental LNG exports would be shipped out of the Gulf Coast States of Texas or Louisiana.

Canada are endogenously set in the model and continue to be so for this study. However, U.S. natural gas exports to Mexico and U.S. LNG imports that are normally determined endogenously within the model were set to the levels projected in the associated *AEO2011* cases for this study. Additionally, EIA assumed that an Alaska pipeline, which would transport Alaskan produced natural gas into the lower-48 United States, would not be built during the forecast period in any of the cases in order to isolate the lower-48 United States supply response. Due to this restriction, both the *AEO2011* High Economic Growth and Low Shale EUR cases were rerun, as those cases had the Alaska pipeline entering service during the projection period in the published *AEO2011*.

Caveats regarding interpretation of the analysis results

EIA recognizes that projections of energy markets over a 25-year period are highly uncertain and subject to many events that cannot be foreseen, such as supply disruptions, policy changes, and technological breakthroughs. This is particularly true in projecting the effects of exporting significant natural gas volumes from the United States due to the following factors:

- NEMS is not a world energy model and does not address the interaction between the potential for additional U.S. natural gas exports and developments in world natural gas markets.
- Global natural gas markets are not integrated and their nature could change substantially in response to significant changes in natural gas trading patterns. Future opportunities to profitably export natural gas from the United States depend on the future of global natural gas markets, the inclusion of relevant terms in specific contracts to export natural gas, as well as on the assumptions in the various cases analyzed.
- Macroeconomic results have not been included in the analysis because the links between the energy and macroeconomic modules in NEMS do not include energy exports.
- NEMS domestic focus makes it unable to account for all interactions between energy prices and supply/demand in energy-intensive industries that are globally competitive. Most of the domestic industrial activity impacts in NEMS are due to changes in the composition of final demands rather than changes in energy prices. Given its domestic focus, NEMS does not account for the impact of energy price changes on the global utilization pattern for existing capacity or the siting of new capacity inside or outside of the United States in energy-intensive industries.

Representation of natural gas markets

Unlike the oil market, current natural gas markets are not integrated globally. In today's markets, natural gas prices span a range from \$0.75 per million British thermal units (MMBtu) in Saudi Arabia to \$4 per MMBtu in the United States and \$16 per MMBtu in Asian markets that rely on LNG imports. Prices in European markets, which reflect a mix of spot prices and contract prices with some indexation to oil, fall between U.S and Asian prices. Spot market prices at the U.K. National Balancing Point averaged \$9.21 per MMBtu during November 2011.

Liquefaction projects typically take four or more years to permit and build and are planned to run for at least 20 years. As a result, expectations of future competitive conditions over the lifetime of a project play a critical role in investment decisions. The current large disparity in natural gas prices across major world regions, a major driver of U.S. producers' interest in possible liquefaction projects to increase natural gas exports, is likely to narrow as natural gas markets become more globally integrated. Key questions remain regarding how quickly convergence might occur and to what extent it will involve all or only some global regions. In particular, it is unclear how far converged prices may reflect purely "gas on gas" competition, a continuing relationship between natural gas and oil prices as in Asia (and to a lesser extent in Europe), or some intermediate outcome. As an example of the dynamic quality of global gas markets, recent regulatory changes combined with abundant supplies and muted demands appear to have put pressure on Europe's oil-linked contract gas prices.

U.S. market conditions are also quite variable, as monthly average Henry Hub spot prices have ranged from over $12 to under $3 per MMBtu over the past five years. Furthermore, while projected Henry Hub prices in the *AEO2011* Reference case reach $7.07 per MMBtu in 2035, in the High and Low Shale EUR cases prices in 2035 range from $5.35 per MMBtu to $9.26 per MMBtu.[2] For purposes of this study, the scenarios of additional exports posited by DOE/FE in their request do not vary across the different baseline cases that are considered. In reality, given available prices in export markets, lower or higher U.S. natural gas prices would tend to make any given volume of additional exports more or less likely.

The prospects for U.S. LNG exports depend greatly on the cost-competitiveness of liquefaction projects in the United States relative to those at other locations. The investment to add liquefaction capacity to an existing regasification terminal in the United States is significant, typically several times the original cost of a regasification-only terminal. However, the ability to make use of existing infrastructure, including natural gas processing plants, pipelines, and storage and loading facilities means that U.S. regasification terminals can reduce costs relative to those that would be incurred by a "greenfield" LNG facility. Many of the currently proposed LNG supply projects elsewhere in the world are integrated standalone projects that would produce, liquefy, and export stranded natural gas. These projects would require much more new infrastructure, entailing not only the construction of the liquefaction plant from the ground up, but also storage, loading, and production facilities, as well pipelines and natural gas processing facilities.

While the additional infrastructure for integrated standalone projects adds considerably to their cost, such projects can be sited at locations where they can make use of inexpensive or stranded natural gas resources that would have minimal value independent of the project. Also, while these projects may require processing facilities to remove impurities and liquids from the gas, the value of the separated liquids can improve the overall project economics. On the other hand, liquefaction projects proposed for the lower-48 United States plan to use pipeline gas drawn from the largest and most liquid natural gas market in the world. Natural gas in the U.S. pipeline system has a much greater inherent value than stranded natural gas, and most of the valuable natural gas liquids have already been removed.

Future exports of U.S. LNG depend on other factors as well. Potential buyers may place additional value on the greater diversity of supply that North American liquefaction projects provide. Also, the degree of regulatory and other risks are much lower for projects proposed in countries like the United States,

[2] All prices in this report are in 2009 dollars unless otherwise noted. For the Low Shale EUR case used in this study the Henry Hub price in 2035 is $9.75 per MMBtu, slightly higher than in the AEO2011 case with the Alaska pipeline projected to be built towards the end of the projection period.

Canada, and Australia than for those proposed in countries like Iran, Venezuela, and Nigeria. However, due to relatively high shipping costs, LNG from the United States may have an added cost disadvantage in competing against countries closer to key markets, such as in Asia. Finally, LNG projects in the United States would frequently compete not just against other LNG projects, but against other natural gas supply projects aimed at similar markets, such as pipeline projects from traditional natural gas sources or projects to develop shale gas in Asia or Europe.

Macroeconomic considerations related to energy exports and global competition in energy-intensive industries

Macroeconomic results have not been included in the analysis because energy exports are not explicitly represented in the NEMS macroeconomic module. [3] The macroeconomic module takes energy prices, energy production, and energy consumption as inputs (or assumptions) from NEMS energy modules. The macroeconomic module then calculates economic drivers that are passed back as inputs to the NEMS energy modules. Each energy module in NEMS uses different economic inputs; however these economic concepts are encompassed by U.S. gross domestic product (GDP), a summary measure describing the value of goods and services produced in the economy.[4]

The net exports component of GDP in the macroeconomic module, however, does not specifically account for energy exports. As a result, increases in energy exports generated in the NEMS energy modules are not reflected as increases in net exports of goods and services in the macroeconomic module. This results in an underestimation of GDP, all else equal. The components of GDP are calculated based on this underestimated amount as well, and do not reflect the increases in energy exports. This is particularly important in the industrial sector, where the value of its output will not reflect the increased energy exports either.

The value of output in the domestic industrial sector in NEMS depends in general on both domestic and global demand for its products, and on the price of inputs. Differences in these factors between countries will also influence where available production capacity is utilized and where new production capacity is built in globally competitive industries. For energy-intensive industries, the price of energy is particularly important to utilization decisions for existing plants and siting decisions for new ones. Given its domestic focus, however, NEMS does not account for the impact of energy price changes on global utilization pattern of existing capacity or the siting of new capacity inside or outside of the United States in energy-intensive industries. Capturing these linkages requires an international model of the particular industry in question, paired with a global macroeconomic model.

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[3] In the macroeconomic model, energy exports are used in two places: estimating exports of industrial supplies and materials and estimating energy's impact on the overall production of the economy. To assess their impact on overall production, energy exports are included in the residual between energy supply (domestic production plus imports) and energy demand. This residual also includes changes in inventory.

[4] GDP is defined as the sum of consumption, investment, government expenditure and net exports (equal to exports minus imports).

Summary of Results

Increased natural gas exports lead to higher domestic natural gas prices, increased domestic natural gas production, reduced domestic natural gas consumption, and increased natural gas imports from Canada via pipeline.

Impacts overview

- **Increased natural gas exports lead to increased natural gas prices.** Larger export levels lead to larger domestic price increases, while rapid increases in export levels lead to large initial price increases that moderate somewhat in a few years. Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices during the decade between 2025 and 2035.

- **Natural gas markets in the United States balance in response to increased natural gas exports largely through increased natural gas production.** Increased natural gas production satisfies about 60 to 70 percent of the increase in natural gas exports, with a minor additional contribution from increased imports from Canada. Across most cases, about three-quarters of this increased production is from shale sources.

- **The remaining portion is supplied by natural gas that would have been consumed domestically if not for the higher prices.** The electric power sector accounts for the majority of the decrease in delivered natural gas. Due to higher prices, the electric power sector primarily shifts to coal-fired generation, and secondarily to renewable sources, though there is some decrease in total generation due to the higher price of natural gas. There is also a small reduction in natural gas use in all sectors from efficiency improvements and conservation.

- **Even while consuming less, on average, consumers will see an increase in their natural gas and electricity expenditures.** On average, from 2015 to 2035, natural gas bills paid by end-use consumers in the residential, commercial, and industrial sectors combined increase 3 to 9 percent over a comparable baseline case with no exports, depending on the export scenario and case, while increases in electricity bills paid by end-use customers range from 1 to 3 percent. In the rapid growth cases, the increase is notably greater in the early years relative to the later years. The slower export growth cases tend to show natural gas bills increasing more towards the end of the projection period.

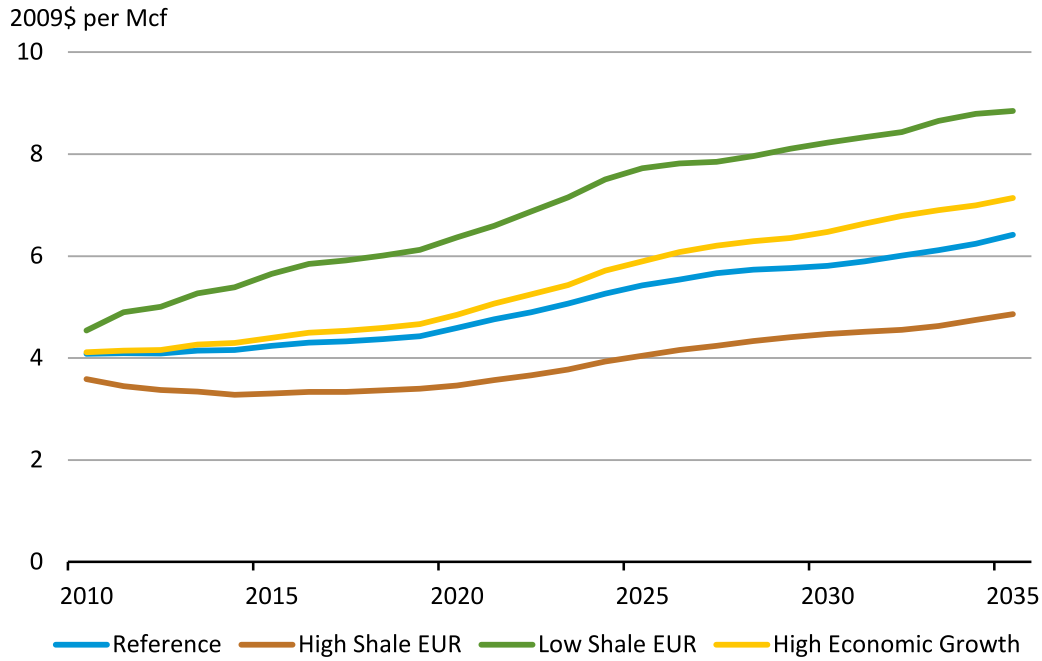
Natural gas prices

Wellhead natural gas prices in the baseline cases (no additional exports)

EIA projects that U.S. natural gas prices are projected to rise over the long run, even before considering the possibility of additional exports (Figure 2). The projected price increase varies considerably, depending on the assumptions one makes about future gas supplies and economic growth. Under the Reference case, domestic wellhead prices rise by about 57 percent between 2010 and 2035. But different assumptions produce different results. Under the more optimistic resource assumptions of the High Shale EUR case, prices actually fall at first and rise by only 36 percent by 2035. In contrast, under the more pessimistic resource assumptions of the Low Shale EUR case, prices nearly double by 2035.

While natural gas prices rise across all four baseline cases (no additional exports) considered in this report, it should be noted that natural gas prices in all of the cases are far lower than the price of crude oil when considered on an energy-equivalent basis. Projected natural gas prices in 2020 range from $3.46 to $6.37 per thousand cubic feet (Mcf) across the four baseline cases, which roughly corresponds to an oil price range of $20 to $36 per barrel in energy-equivalent terms. In 2030, projected baseline natural gas prices range from $4.47 to $8.23 per Mcf in the four baseline cases, which roughly corresponds to an oil price range of $25 to $47 per barrel in energy-equivalent terms.

Figure 2. Natural gas wellhead prices in the baseline cases (no additional exports)



Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—relationship between wellhead and delivered natural gas prices

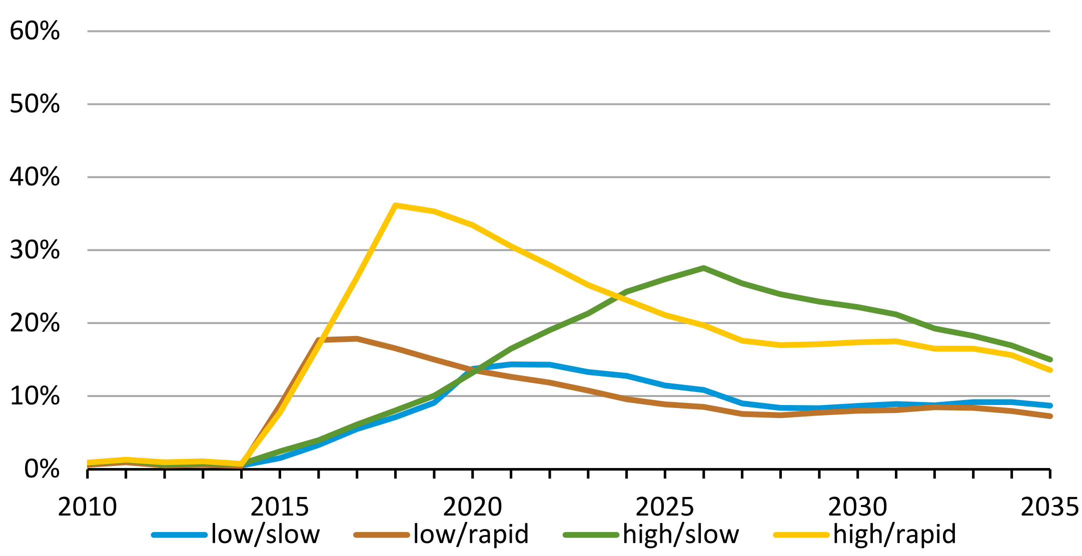
Increases in natural gas prices at the wellhead translate to similar absolute increases in delivered prices to customers under all export scenarios and baseline cases. However, delivered prices include transportation charges (for most customers) and distribution charges (especially for residential and commercial customers). These charges change to much less of a degree than the wellhead price does under different export scenarios. As a result, the percentage change in prices that industrial and electric customers pay tends to be somewhat lower than the change in the wellhead price. The percentage change in prices that residential and commercial customers pay is significantly lower. Summary statistics on delivered prices are provided in Appendix B. More detailed results on delivered prices and other report results can be found in the standard NEMS output tables that are posted online.

Export scenarios – wellhead price changes under the Reference case.

Increased exports of natural gas lead to increased wellhead prices in all cases and scenarios. The basic pattern is evident in considering how prices would change under the Reference case (Figure 3):

- The pattern of price increases reflects both the ultimate level of exports and the rate at which increased exports are phased in. In the low/slow scenario (which phases in 6 Bcf/d of exports over six years), wellhead price impacts peak at about 14% ($0.70/Mcf) in 2022. However, the wellhead price differential falls below 10 percent by about 2026.
- In contrast, rapid increases in export levels lead to large initial price increases that would moderate somewhat in a few years. In the high/rapid scenario (which phases in 12 Bcf/d of exports over four years), wellhead prices are about 36 percent higher ($1.58/Mcf) in 2018 than in the no-additional-exports scenario. But the differential falls below 20 percent by about 2026. The sharp projected price increases during the phase-in period reflect what would be needed to balance the market through changes in production, consumption, and import levels in a compressed timeframe.
- Slower increases in export levels lead to more gradual price increases but eventually produce higher average prices, especially during the decade between 2025 and 2035. The differential between wellhead prices in the high/slow scenario and the no-additional-exports scenario peaks in 2026 at about 28 percent ($1.53/Mcf), and prices remain higher than in the high/rapid scenario. The lower prices in the early years of the scenarios with slow export growth leads to more domestic investment in additional natural gas burning equipment, which increases demand somewhat in later years, relative to rapid export growth scenarios.

Figure 3. Natural gas wellhead price difference from *AEO2011* Reference case with different additional export levels imposed

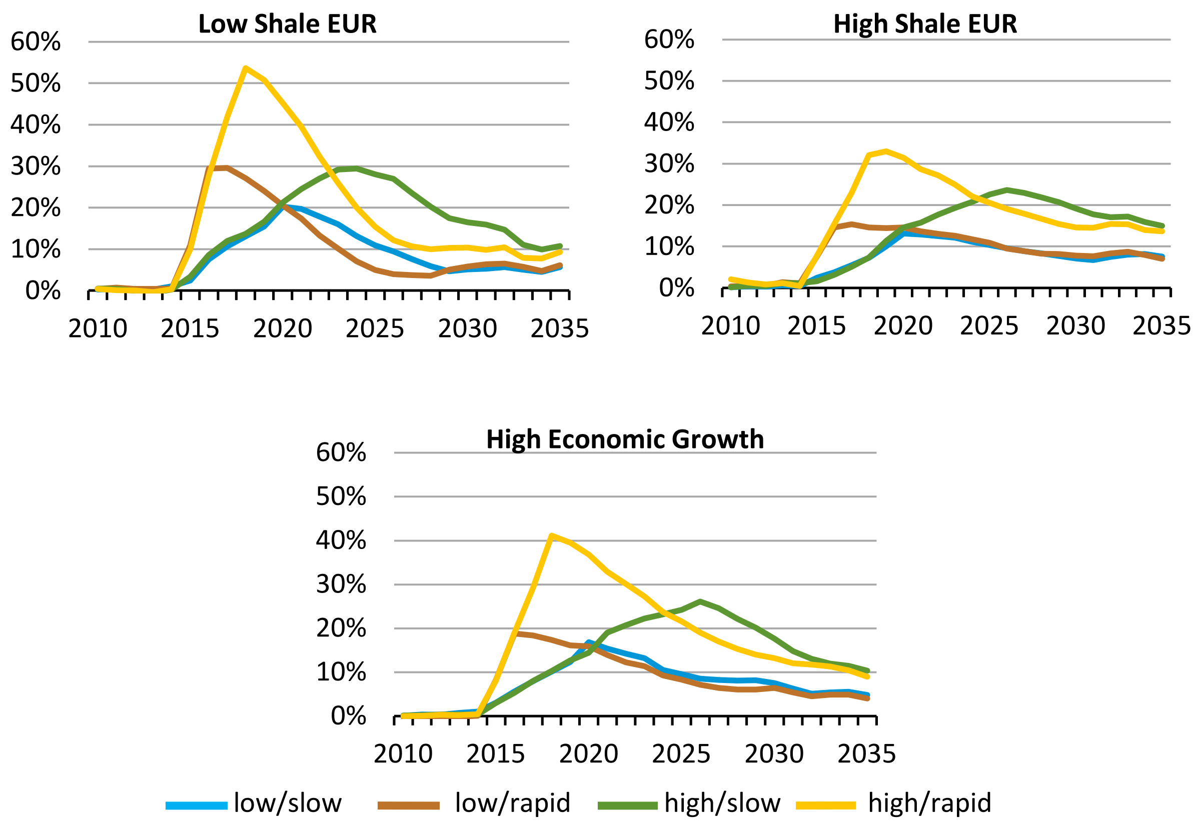


Source: U.S. Energy Information Administration, National Energy Modeling System

Export scenarios—wellhead price changes under alternative baseline cases

The effect of increasing exports on natural gas prices varies somewhat under alternative baseline case assumptions about resource availability and economic growth. However, the basic patterns remain the same: higher export levels would lead to higher prices, rapid increases in exports would lead to sharp price increases, and slower export increases would lead to slower but more lasting price increases. But the relative size of the price increases changes with changing assumptions (Figure 4).

Figure 4. Natural gas wellhead price difference from indicated baseline case (no additional exports) with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

In particular, with more pessimistic assumptions about the Nation's natural gas resource base (the Low Shale EUR case), wellhead prices in all export scenarios initially increase more in percentage terms over the baseline case (no additional exports) than occurs under Reference case conditions. For example, in the Low Shale EUR case the rapid introduction of 12 Bcf/d of exports results in a 54 percent ($3.23/Mcf) increase in the wellhead price in 2018; whereas under Reference case conditions with the same export scenario the price increases in 2018 by only 36 percent ($1.58/Mcf).[5] But the percentage price increase falls in later years under the Low Shale EUR case, even below the price response under Reference case conditions. Under Low Shale EUR conditions, the addition of exports ultimately results in wellhead prices exceeding the $9 per Mcf threshold, with this occurring as early as 2018 in the high/rapid scenario.

[5] The percentage rise in prices for the low EUR case also represents a larger absolute price increase because it is calculated on the higher baseline price under the same pessimistic resource assumptions.

More robust economic growth shows a similar pattern – higher initial percentage price increases and lower percentage increases in later years. On the other hand, with more optimistic resource assumptions (the High Shale EUR case), the percentage price rise would be slightly smaller than under Reference case conditions, and result in wellhead prices never exceeding the $6 per Mcf threshold.

Natural gas supply and consumption

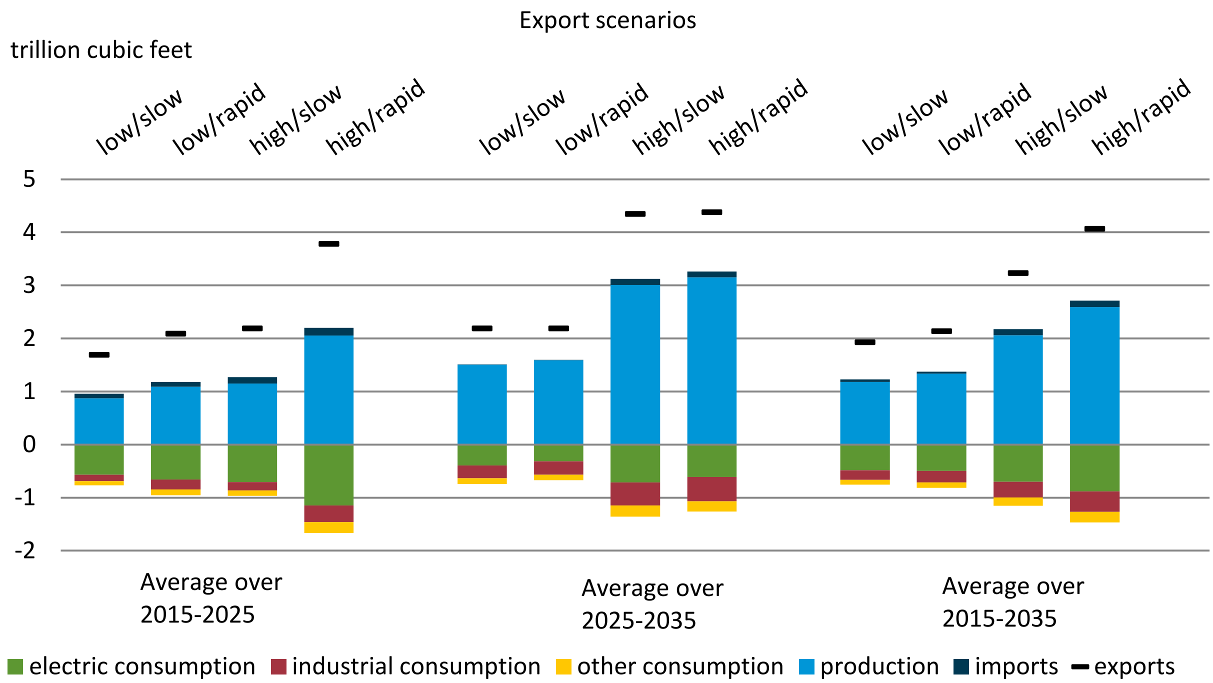
In the AEO2011 Reference case, total domestic natural gas production grows from 22.4 trillion cubic feet (Tcf) in 2015 to 26.3 Tcf in 2035, averaging 24.2 Tcf for the 2015-2035 period. U.S. net imports of natural gas decline from 11 percent of total supply in 2015 to 1 percent in 2035, with lower net imports from Canada and higher net exports to Mexico. The industrial sector consumes an average of 8.1 Tcf of natural gas (34.2% of delivered volumes) between 2015 and 2035, with 7.1 Tcf, 4.8 Tcf, and 3.6 Tcf consumed in the electric power, residential, and commercial sectors respectively.

Under the scenarios specified for this analysis, increased natural gas exports lead to higher domestic natural gas prices, which lead to reduced domestic consumption, and increased domestic production and pipeline imports from Canada (Figure 5). Lower domestic consumption dampens the degree to which supplies must increase to satisfy the additional natural gas exports. Accordingly, in order to accommodate the increased exports in each of the four export scenarios, the mix of production, consumption, and imports changes relative to the associated baseline case. In all of the export scenarios across all four baseline cases, a majority of the additional natural gas needed for export is provided by increased domestic production, with a minor contribution from increased pipeline imports from Canada. The remaining portion of the increased export volumes is offset by decreases in consumption resulting from the higher prices associated with the increased exports.

The absolute value of the sum of changes in consumption (delivered volumes), production, and imports (represented by the total bar in Figure 5) approximately[6] equals the average change in exports. Under Reference case conditions, about 63 percent, on average, of the increase in exports in each of the four scenarios is accounted for by increased production, with most of the remainder from decreased consumption from 2015 to 2035. The percentage of exports accounted for by increased production is slightly lower in the earlier years and slightly higher in the later years. While this same basic relationship between added exports and increased production is similar under the other cases, the percentage of added exports accounted for by increased production is somewhat less under a Low Shale EUR environment and more under a High Economic Growth environment.

[6] The figure displays the changes in delivered volumes of natural gas to residential, commercial, industrial, vehicle transportation, and electric generation customers. There are also some minor differences in natural gas used for lease, plant, and pipeline fuel use which are not included.

Figure 5. Average change in annual natural gas delivered, produced, and imported from *AEO2011* Reference case with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

One seeming anomaly that can be seen in Figure 5 is in the 2025 to 2035 timeframe: the decrease in consumption is somewhat lower in the rapid export penetration relative to the slow export penetration scenarios. This is largely attributed to slightly lower prices in the later years of the rapid export penetration scenarios relative to the slow penetration scenarios.

Supply

Increases in natural gas production that contribute to additional natural gas exports from the relative baseline scenario come predominately from shale sources. On average, across all cases and export scenarios, the shares of the increase in total domestic production coming from shale gas, tight gas, coalbed, and other sources are 72 percent, 13 percent, 8 percent, and 7 percent, respectively. Most of the export scenarios are also accompanied by a slight increase in pipeline imports from Canada. Under the Low Shale EUR case (which just applies to domestic shale), imports from Canada contribute to a greater degree than in other cases.

Consumption by sector

In general, greater export levels lead to higher domestic prices and larger decreases in consumption, although the price and consumption differences across the scenarios narrow in the later part of the projection period.

Electric power generation

In the AEO2011 Reference case, electric power generation averages 4,692 billion kilowatthours (bkWh) over the 2015-2035 period. Natural gas generation averages 23 percent of total power generation, increasing from 1,000 bkWh in 2015 to 1,288 bkWh in 2035. Coal, nuclear, and renewables provide an average of 43 percent, 19 percent, and 14 percent of generation, respectively, with a minimal contribution from liquids.

In scenarios with increased natural gas exports, most of the decrease in natural gas consumption occurs in the electric power sector (Figure 5). Most of the tradeoff in electric generators' natural gas use is between natural gas and coal, especially in the early years (Figure 6), when there is excess coal-fired capacity to allow for additional generation. Over the projection period, excess coal capacity progressively declines, along with the degree by which coal-fired generation can be increased in response to higher natural gas prices.[7] Increased coal-fired generation accounts for about 65 percent of the decrease in natural gas-fired generation under Reference case conditions.

The increased use of coal for power generation results in an average increase in coal production from 2015 to 2035 over Reference case levels of between 2 and 4 percent across export scenarios. Accordingly, coal prices also increase slightly which, along with higher gas prices, drive up electricity prices. The resulting increase in electricity prices reduces total electricity demand, also offsetting some of the drop in natural gas-fired generation. The decline in total electricity demand tends to be less in the earlier years.

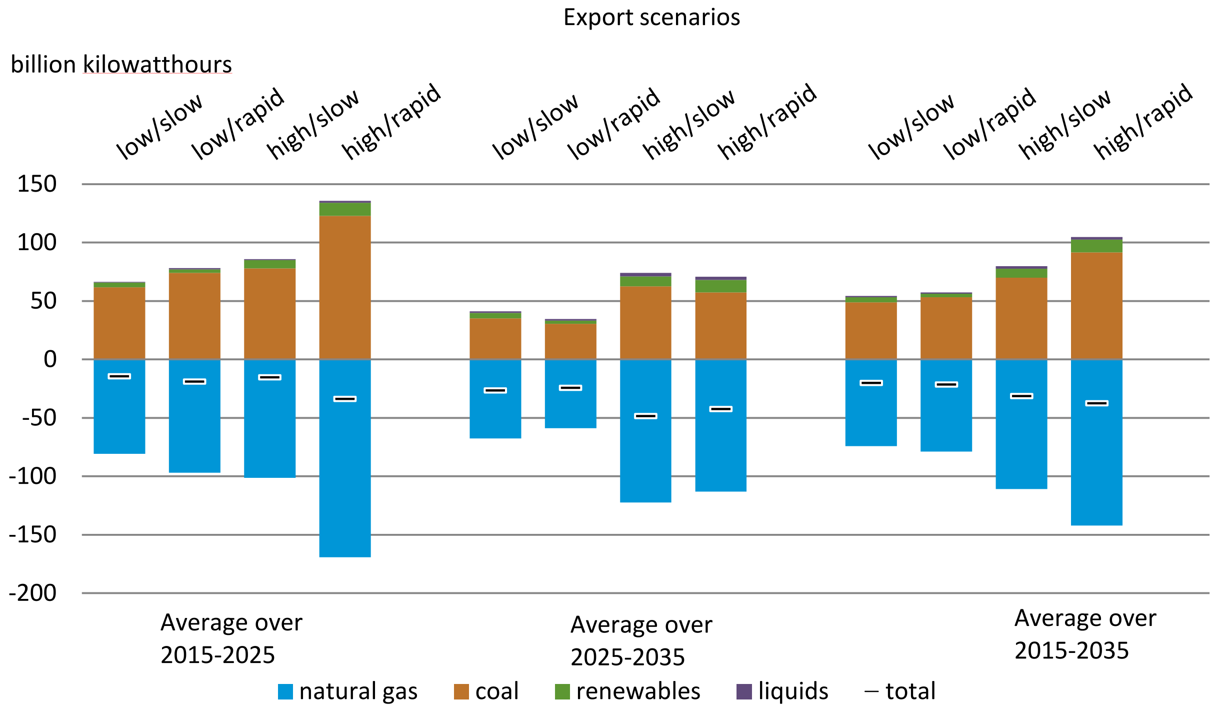
In addition, small increases in renewable generation contribute to reduced natural gas-fired generation. Relatively speaking, the role of renewables is greater in a higher-gas-price environment (i.e., the Low Shale EUR case), when they can more successfully compete with coal, and in a higher-generation environment (i.e., the High Economic Growth case), particularly in the later years.

Industrial sector

Reductions in industrial natural gas consumption in scenarios with increased natural gas exports tend to grow over time. In general, higher gas prices earlier in the projection period in these scenarios provide some disincentive for natural gas-fired equipment purchases (such as natural gas-fired combined heat and power (CHP) capacity) by industrial consumers, which has a lasting impact on their projected use of natural gas.

[7] The degree to which coal might be used in lieu of natural gas depends on what regulations are in-place that might restrict coal use. These scenarios reflect current laws and regulations in place at the time the *AEO2011* was produced.

Figure 6. Average change in annual electric generation from *AEO2011* Reference case with different additional export levels imposed



Source: U.S. Energy Information Administration, National Energy Modeling System

Note: Nucleargeneration levels do not change in the Reference case scenarios.

As noted in the discussion of caveats in the first section of this report, the NEMS model does not explicitly address the linkage between energy prices and the supply/demand of industrial commodities in global industries. To the extent that the location of production is very sensitive to changes in natural gas prices, industrial natural gas demand would be more responsive than shown in this analysis.

Other sectors

Natural gas consumption in the other sectors (residential, commercial, and compressed natural gas vehicles) also decreases in response to the higher gas prices associated with increased exports, although less significantly than in the electric and industrial sectors. Even so, under Reference case conditions residential and commercial consumption decreases from 1 to 2 percent and from 2 to 3 percent, respectively, across the export scenarios, on average from 2015 to 2035. Their use of electricity also declines marginally in response to higher electricity prices. In response to higher natural gas and electricity prices, residential and commercial customers directly cut back their energy usage and/or purchase more efficient equipment.

Exports to Canada and Mexico

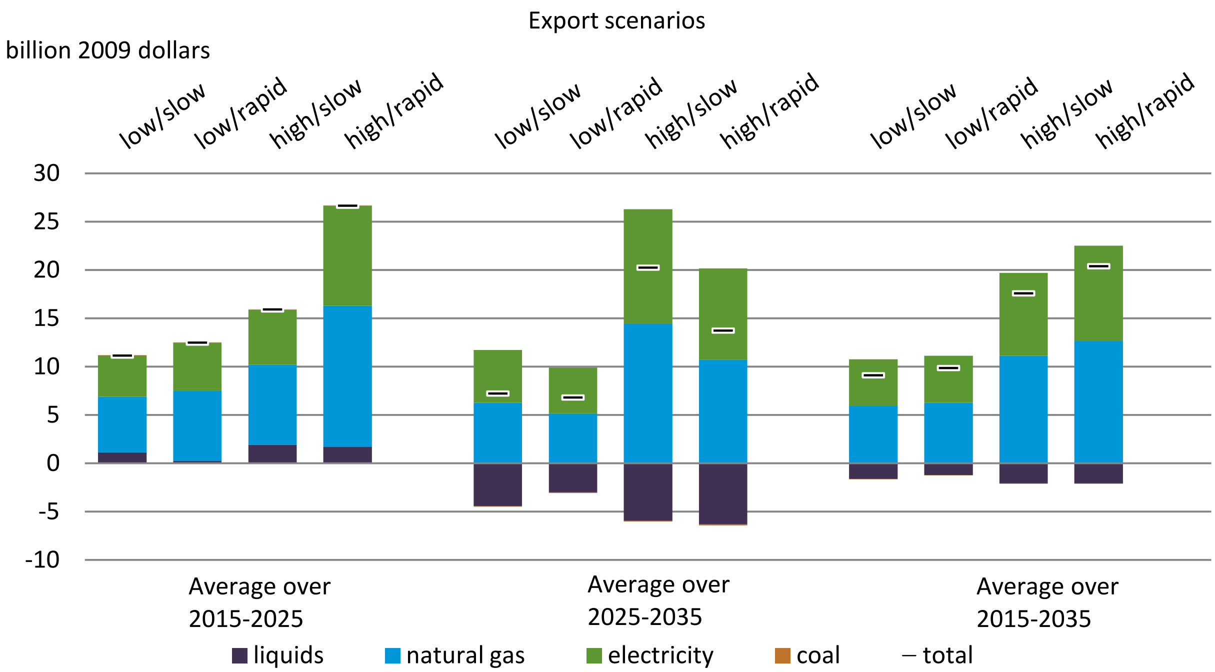
If exports to Canada and Mexico were allowed to vary under these additional export scenarios, they would likely respond similarly to domestic consumption and decrease in response to higher natural gas prices.

End-use energy expenditures

The AEO2011 Reference case projects annual average end-use energy expenditures of $1,490 billion over the 2015-2035 period. Of that, $975 billion per year is spent on liquids, $368 billion on electricity bills, $140 billion on natural gas bills, and $7 billion on coal expenditures.

From an end-user perspective in the scenarios with additional gas exports, consumers will consume less and pay more on both their natural gas and electricity bill, and generally a little less for liquid fuels (Figure 7). Under Reference case conditions, increased end-use expenditures on natural gas as a result of additional exports average about 56 percent of the total additional expenditures for natural gas and electricity combined. For example, under Reference case conditions in the low/slow scenario, end-use consumers together are expected to increase their total energy expenditures by $9 billion per year, or 0.6 percent on average from 2015 to 2035. Under the high/rapid scenarios, consumed total energy expenditures increase by $20 billion per year, or 1.4 percent on average, between 2015 and 2035.

Figure 7. Average change in annual end-use energy expenditures from *AEO2011* Reference case as a result of additional natural gas exports



Source: U.S. Energy Information Administration, National Energy Modeling System

Natural gas expenditures

As discussed earlier, given the lower consumption levels in response to the higher prices from increased exports, the percentage change in the dollars expended by customers for natural gas is less than the percentage change in the delivered prices. In general, the relative pattern of total end-use expenditures across time, export scenarios, and cases, is similar to the relative pattern shown in the wellhead prices in Figures 3 and 4. The higher export volume scenarios result in greater increases in expenditures, while those with rapid export penetration show increases peaking earlier and at higher levels than their slow export penetration counterpart, which show bills increasing more towards the end of the projection period. Under Reference case conditions, the greatest single year increase in total end-use consumer bills is 16 percent, while the lowest single year increase is less than 1 percent. In all but three export scenarios and cases, the higher average increase over the comparable baseline scenario in natural gas bills paid by end-use consumers occurred during the early years. The greatest percentage increase in end-use expenditures over the comparable baseline level in a single year (26 percent) occurs in the high/rapid scenario under the Low Shale EUR case.

On average between 2015 and 2035, total U.S. end-use natural gas expenditures as a result of added exports, under Reference case conditions, increase between $6 billion to $13 billion (between 3 to 9 percent), depending on the export scenario. The Low Shale EUR case shows the greatest average annual increase in end-use natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $7 billion to $15 billion.

At the sector level, since the natural gas commodity charge represents significantly different portions of each natural gas consuming sector's bill, the degree to which each sector is projected to see their total bill change with added exports varies significantly (Table 1). Natural gas expenditures increase at the highest percentages in the industrial sector, where low transmission and distribution charges constitute a relatively small part of the delivered natural gas price.

Table 1. Change in natural gas expenditures by end use consumers from AEO2011 Reference case with different additional export levels imposed

Sector	Scenario	Average 2015-2025	Average 2025-2035	Average 2015-2035	Maximum Annual Change	Minimum Annual Change
Residential	low/slow	3.2%	3.3%	3.2%	4.7%	0.5%
Residential	low/rapid	4.2%	2.9%	3.6%	5.4%	2.2%
Residential	high/slow	4.4%	7.1%	5.6%	8.9%	0.9%
Residential	high/rapid	8.3%	5.7%	7.0%	10.9%	2.5%
Commercial	low/slow	3.2%	3.2%	3.2%	4.8%	0.6%
Commercial	low/rapid	4.3%	2.7%	3.5%	5.8%	2.0%
Commercial	high/slow	4.6%	6.9%	5.6%	8.9%	0.9%
Commercial	high/rapid	8.3%	5.4%	6.9%	11.4%	2.7%
Industrial	low/slow	7.2%	5.8%	6.4%	11.1%	1.2%
Industrial	low/rapid	9.4%	4.6%	7.1%	14.0%	3.5%
Industrial	high/slow	10.2%	14.7%	12.2%	19.3%	2.0%
Industrial	high/rapid	18.7%	10.4%	14.6%	26.9%	5.2%

Source: U.S. Energy Information Administration, National Energy Modeling System

The results in Table 1 do not reflect changes in natural gas expenditures in the electric power sector. The projected overall decrease in natural gas use by generators is significant enough to result in a decrease in natural gas expenditures for that sector, largely during 2015-2025. However, electric generators will see an increase in their overall costs of power generation that will be reflected in higher electricity bills for consumers.

Electricity expenditures

On average across the projection period, electricity prices under Reference case conditions increase by between 0.14 and 0.29 cents per kilowatthour (kWh) (between 2 and 3 percent) when gas exports are added. The greatest increase in the electricity price occurs in 2019 under the Low Shale EUR case for the high export/rapid growth export scenario, with an increase of 0.85 cents per kWh (9 percent).

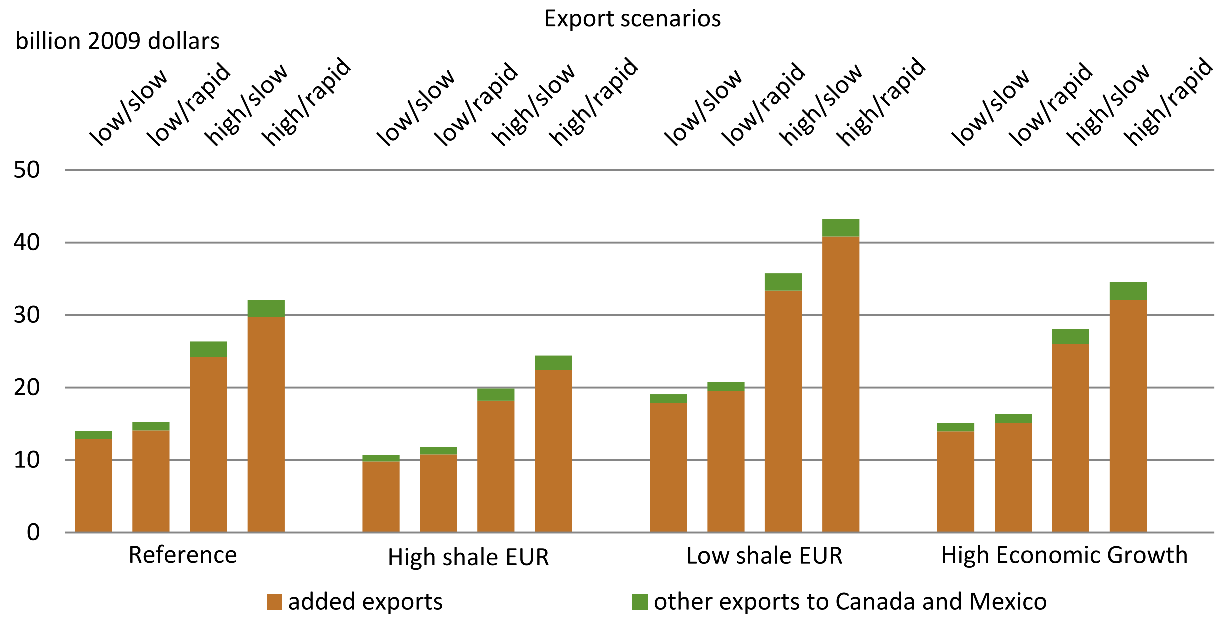
Similar to natural gas, higher electricity prices due to the increased exports reduce end-use consumption making the percentage change in end-use electricity expenditures less than the percentage change in delivered electricity prices; additionally, the percentage increase in end-use electricity expenditures will be lower for the residential and commercial sectors and higher for the industrial sector. Under Reference case conditions, the greatest single year increase in total end-use consumer electricity bills is 4 percent, while the lowest single year increase is negligible. The greatest percentage increase in end-use electricity expenditures over the comparable baseline level in a single year (7 percent) occurs in the high/rapid scenario under the Low Shale EUR case.

On average between 2015 and 2035, total U.S. end-use electricity expenditures as a result of added exports, under Reference case conditions, increase between $5 billion to $10 billion (between 1 to 3 percent), depending on the export scenario. The High Macroeconomic Growth case shows the greatest average annual increase in natural gas expenditures over the same time period, with increases over the baseline (no additional exports) scenario ranging from $6 billion to $12 billion.

Natural gas producer revenues

Total additional natural gas revenues to producers from exports increase on an average annual basis from 2015 to 2035 between $14 billion and $32 billion over the *AEO2011* Reference case, depending on the export scenario (Figure 8). These revenues largely come from the added exports defining the scenarios, as well as other exports to Canada and Mexico in the model that see higher prices under the additional export scenarios, even though the volumes are assumed not to vary. Revenues associated with the added exports reflect dollars spent to purchase and move the natural gas to the export facility, but do not include any revenues associated with the liquefaction and shipping process. The Low Shale EUR case shows the greatest average annual increase in revenues over the 2015 to 2035 time period, with revenues ranging from over $19 billion to $43 billion, due to the relatively high natural gas wellhead prices in that case. These figures represent increased revenues, not profits. A large portion of the additional export revenues will cover the increased costs associated with supplying the increased level of production required when natural gas exports are increased, such as for equipment (e.g., drilling rigs) and labor. In contrast, the additional revenues resulting from the higher price of natural gas that would have been produced and sold to largely domestic customers even in the absence of the additional exports posited in the analysis scenarios would preponderantly reflect increased profits for producers and resource owners.

Figure 8. Average annual increase in domestic natural gas export revenues from indicated baseline case (no additional exports) with different additional export levels imposed, 2015-2035



Source: U.S. Energy Information Administration, National Energy Modeling System

Impacts beyond the natural gas industry

While the natural gas industry would be directly impacted by increased exports, there are indirect impacts on other energy sectors. The electric generation industry shows the largest impact, followed by the coal industry.

As discussed earlier, higher natural gas prices lead electric generators to burn more coal and less natural gas. Coal producers benefit from the increased coal demand. On average, from 2015 to 2035, coal minemouth prices, production, and revenues increase by at most 1.1, 5.5, and 6.2 percent, respectively, across the increased export scenarios applied to all cases.

Domestic petroleum production in the form of lease condensate and natural gas plant liquids also rises due to increased natural gas drilling. For example, under Reference case conditions, in the scenario with the greatest overall response (high/rapid exports), total domestic energy production is 4.13 quadrillion British thermal units (Btu) per year (4.7 percent), which is greater on average from 2015 to 2035 than in the baseline scenario, while total domestic energy consumption is only 0.12 quadrillion Btu (0.1 percent) lower.

Effects on non-energy sectors, other than impacts on their energy expenditures, are generally beyond the scope of this report for reasons described previously.

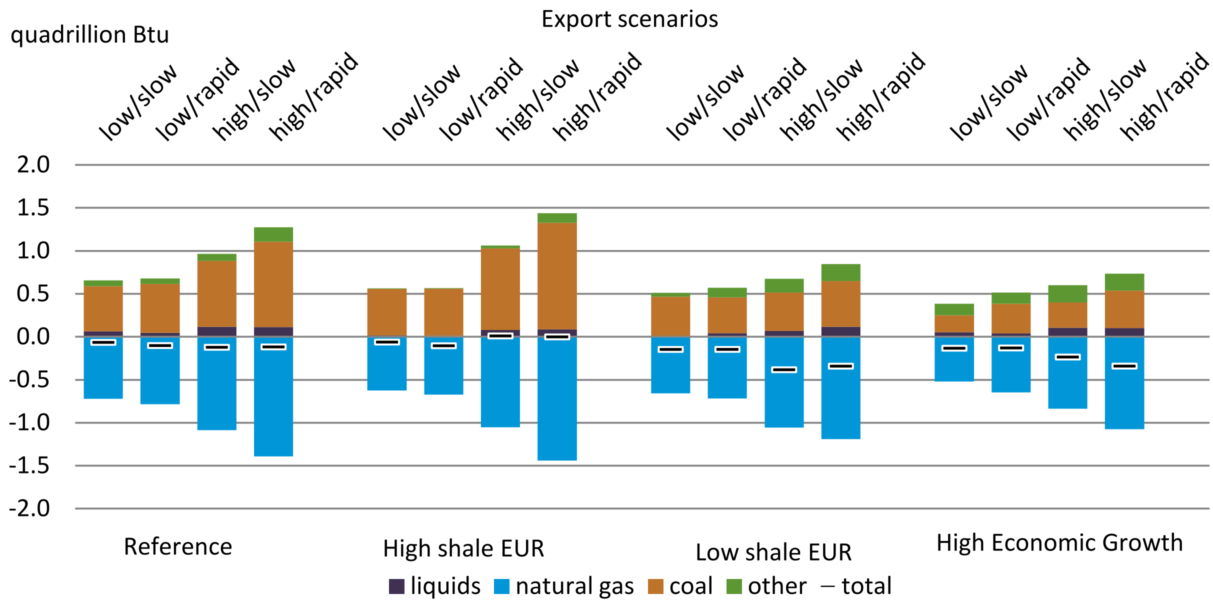
Total energy use and energy-related carbon dioxide emissions

Annual primary energy consumption in the AEO2011 Reference case, measured in Btu, averages 108 quadrillion Btu between 2015 and 2035, with a growth rate of 0.6 percent. Cumulative carbon dioxide (CO_2) emissions total 125,000 million metric tons for that twenty-year period.

The changes in overall energy consumption across scenarios and cases are largely reflective of what occurs in the electric power sector. While additional exports result in decreased natural gas consumption, changes in overall energy consumption are relatively minor as much of the decrease in natural gas consumption is replaced with increased coal consumption (Figure 9). In fact, in some of the earlier years total energy consumption increases with added exports since directly replacing natural gas with coal in electricity generation requires more Btu, as the heat rates (Btu per kWh) for coal generators exceed those for natural gas generators.

On average from 2015 to 2035 under Reference case conditions, decreased natural gas consumption as a result of added exports are countered proportionately by increased coal consumption (72 percent), increased liquid fuel consumption (8 percent), other increased consumption, such as from renewable generation sources (9 percent), and decreases in total consumption (11 percent). In the earlier years, the amount of natural gas to coal switching is greater, and coal plays a more dominant role in replacing the decreased levels of natural gas consumption, which also tend to be greater in the earlier years. Switching from natural gas to coal is less significant in later years, partially as a result of a greater proportion of switching into renewable generation. As a result decreased natural gas consumption from added exports more directly results in decreased total energy consumption via the end-use consumer cutting back energy use in response to higher prices. This basic pattern similarly occurs under the Low Shale EUR and High Economic Growth cases – less switching from natural gas into coal and more into renewable than under Reference case conditions, as well as greater decreases in total energy consumption as a result of added exports.

Figure 9. Average annual change from indicated baseline case (no additional exports) in total primary energy consumed with different additional export levels imposed, 2015-2035



Source: U.S. Energy Information Administration, National Energy Modeling System
Note: Other includes renewable and nuclear generation.

While lower domestic natural gas deliveries resulting from added exports reduce natural gas related CO_2 emissions, the increased use of coal in the electric sector generally results in a net increase in overall

CO_2 emissions. The exceptions occur in environments when renewables are better able to compete against natural gas and coal. However, when also accounting for emissions related to natural gas used in the liquefaction process, additional exports increase CO_2 levels under all cases and export scenarios, particularly in the earlier years of the projection period. Table 2 displays the cumulative CO_2 emissions levels from 2015 to 2035 in all cases and scenarios, with the change relative to the associated baseline case.

Table 2. Cumulative CO_2 emissions from 2015 to 2035 associated with additional natural gas export levels imposed (million metric tons CO_2 and percentage)

Case	no added exports	low/slow	low/rapid	high/slow	high/rapid
Reference					
Cumulative carbon dioxide emissions	125,056	125,699	125,707	126,038	126,283
Change from baseline		643	651	982	1,227
Percentage change from baseline		0.5%	0.5%	0.8%	1.0%
High Shale EUR					
Cumulative carbon dioxide emissions	124,230	124,888	124,883	125,531	125,817
Change from baseline		658	653	1,301	1,587
Percentage change from baseline		0.5%	0.5%	1.0%	1.3%
Low Shale EUR					
Cumulative carbon dioxide emissions	125,162	125,606	125,556	125,497	125,670
Change from baseline		444	394	335	508
Percentage change from baseline		0.4%	0.3%	0.3%	0.4%
High Economic Growth					
Cumulative carbon dioxide emissions	131,675	131,862	132,016	131,957	132,095
Change from baseline		187	341	282	420
Percentage change from baseline		0.1%	0.3%	0.2%	0.3%

Source: U.S. Energy Information Administration, National Energy Modeling System, with emissions related to natural gas assumed to be consumed in the liquefaction process included.

Appendix A. Request Letter

Department of Energy
Washington, DC 20585
August 15, 2011

MEMORANDUM

TO: HOWARD K. GRUENSPECHT
ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: CHARLES D. MCCONNELL
CHIEF OPERATING OFFICER
OFFICE OF FOSSIL ENERGY

SUBJECT: <u>ACTION:</u> Request for EIA to Perform a Domestic Natural Gas Export Case Study

ISSUE: The Department of Energy's (DOE) Office of Fossil Energy (FE) must determine whether exports of liquefied natural gas (LNG) to non-free trade agreement countries are not inconsistent with the public interest. An independent case study analysis of the impact of increased domestic natural gas demand, as exports, under different incremental demand scenarios, performed by the Energy Information Administration (EIA) will be useful to assist DOE/FE in making future public interest determinations.

BACKGROUND: DOE/FE has been delegated the statutory responsibility under section 3 of the Natural Gas Act (NGA) (15 U.S.C. § 717b) to evaluate and approve or deny applications to import and export natural gas and liquefied natural gas to or from the United States. Applications to DOE/FE to export natural gas and LNG to non-free trade agreement countries are reviewed under section 3(a) of the NGA, under which FE must determine if the proposed export arrangements meet the public interest requirements of section 3 of the NGA.

To-date, DOE/FE has received applications for authority to export domestically produced LNG by vessel from three proposed liquefaction facilities, one application to export LNG by ISO containers on cargo carriers, and additional applications could be submitted by others in the future. Applications submitted to DOE/FE total 5.6 billion cubic feet per day (Bcf/day) of natural gas to be exported from the United States, equal to over 8 percent of U.S. natural gas consumption in 2015 compared to the EIA reference case projection of 68.8 Bcf/day in 2015.[1]

Studies and analyses submitted with, and in support of, LNG export applications to DOE/FE evaluated the impact LNG exports could have on domestic natural gas supply.

[1] *EIA Annual Energy Outlook 2011 (AEO2011)*

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demand and market prices. It would be helpful in DOE/FE reviews of these applications, and other potential applications, to understand the implications of additional natural gas demand (as exports) on domestic energy consumption, production, and prices under different scenarios.

Understanding that the domestic natural gas market is sensitive to a number of factors, including those highlighted on page 37 of the *AEO2011*, we request that EIA include sensitivity cases to explore some of these uncertainties, using the modeling analysis presented in the *AEO2011* as a starting point. The results of this study will be beneficial to DOE/FE by providing an independent assessment of how increased natural gas exports could affect domestic markets, and could be used in making future public interest determinations. The specific request of the study is provided in the attachment. We would like to receive the study, along with an analysis and commentary of the results by October 2011, and recognize that the study may be made available on EIA's website.

We are available to further discuss the study with your staff as they begin the study to clarify any issues associated with this request as needed.

RECOMMENDATION: That you approve this request.

APPROVE:______________ DISAPPROVE: ________________ DATE: _______

ATTACHMENTS:
Impact of Higher Demand for U.S. Natural Gas on Domestic Energy Markets
Background: (15 U.S.C. § 717b)

Impact of Higher Demand for U.S. Natural Gas on Domestic Energy Markets

The Office of Fossil Energy (FE) requests the Energy Information Administration (EIA) to evaluate the impact of increased natural gas demand, reflecting possible exports of U.S. natural gas, on domestic energy markets using the modeling analysis presented in the *Annual Energy Outlook 2011 (AEO2011)* as a starting point. In discussions with EIA we learned that EIA's National Energy Modeling System is not designed to capture the impact of increased export-driven demand for natural gas on economy-wide economic indicators such as gross domestic product and employment, and that it does not include a representation of global natural gas markets. Therefore, EIA should focus its analysis on the implications of additional natural gas demand on domestic energy consumption, production, and prices.

The study should address scenarios reflecting export-related increases in natural gas demand of between 6 billion cubic feet per day (Bcf/d) and 12 Bcf/d that are phased in at rates of between 1 Bcf/d per year and 3 Bcf/d per year starting in 2015. Understanding that the domestic natural gas market is sensitive to a number of factors, including those highlighted on page 37 of the *AEO2011*, we request that EIA include sensitivity cases to explore some of these uncertainties. We are particularly interested in sensitivity cases relating to alternative recovery economics for shale gas resources, as in the *AEO2011 Low and High Shale EUR* cases, and a sensitivity case with increased baseline natural gas demand as in the *AEO2011 High Economic Growth* case.

The study report should review and synthesize the results obtained in the modeling work and include, as needed, discussions of context, caveats, issues and limitations that are relevant to the study. Please include tables or figures that summarize impacts on annual domestic natural gas prices, domestic natural gas production and consumption levels, domestic expenditures for natural gas and other relevant fuels, and revenues associated with the incremental export demand for natural gas. The standard *AEO 2011* reporting tables should also be provided, with the exception of tables reporting information that EIA considers to be spurious or misleading given the limitations of its modeling tools in addressing the study questions.

We would like to receive the completed analysis by October 2011 and recognize that EIA may post the study on its website after providing it to us.

Thank you for your attention to this request. Please do not hesitate to contact me (Charles D. McConnell) or John Anderson at 6-0521, if you have any questions.

Source: http://uscode.house.gov/download/pls/15C15B.txt

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-CITE-
    15 USC Sec. 717b                                             01/07/2011

-EXPCITE-
    TITLE 15 - COMMERCE AND TRADE
    CHAPTER 15B - NATURAL GAS

-HEAD-
    Sec. 717b. Exportation or importation of natural gas; LNG terminals

-STATUTE-
    (a) Mandatory authorization order
      After six months from June 21, 1938, no person shall export any
    natural gas from the United States to a foreign country or import
    any natural gas from a foreign country without first having secured
    an order of the Commission authorizing it to do so. The Commission
    shall issue such order upon application, unless, after opportunity
    for hearing, it finds that the proposed exportation or importation
    will not be consistent with the public interest. The Commission may
    by its order grant such application, in whole or in part, with such
    modification and upon such terms and conditions as the Commission
    may find necessary or appropriate, and may from time to time, after
    opportunity for hearing, and for good cause shown, make such
    supplemental order in the premises as it may find necessary or
    appropriate.
    (b) Free trade agreements
      With respect to natural gas which is imported into the United
    States from a nation with which there is in effect a free trade
    agreement requiring national treatment for trade in natural gas,
    and with respect to liquefied natural gas -
        (1) the importation of such natural gas shall be treated as a
      "first sale" within the meaning of section 3301(21) of this
      title; and
        (2) the Commission shall not, on the basis of national origin,
      treat any such imported natural gas on an unjust, unreasonable,
      unduly discriminatory, or preferential basis.
    (c) Expedited application and approval process
      For purposes of subsection (a) of this section, the importation
    of the natural gas referred to in subsection (b) of this section,
    or the exportation of natural gas to a nation with which there is
    in effect a free trade agreement requiring national treatment for
    trade in natural gas, shall be deemed to be consistent with the
    public interest, and applications for such importation or
    exportation shall be granted without modification or delay.
    (d) Construction with other laws
      Except as specifically provided in this chapter, nothing in this
    chapter affects the rights of States under -
        (1) the Coastal Zone Management Act of 1972 (16 U.S.C. 1451 et
      seq.);
        (2) the Clean Air Act (42 U.S.C. 7401 et seq.); or
        (3) the Federal Water Pollution Control Act (33 U.S.C. 1251 et
      seq.).
    (e) LNG terminals
      (1) The Commission shall have the exclusive authority to approve
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or deny an application for the siting, construction, expansion, or operation of an LNG terminal. Except as specifically provided in this chapter, nothing in this chapter is intended to affect otherwise applicable law related to any Federal agency's authorities or responsibilities related to LNG terminals.

(2) Upon the filing of any application to site, construct, expand, or operate an LNG terminal, the Commission shall -

(A) set the matter for hearing;

(B) give reasonable notice of the hearing to all interested persons, including the State commission of the State in which the LNG terminal is located and, if not the same, the Governor-appointed State agency described in section 717b-1 of this title;

(C) decide the matter in accordance with this subsection; and

(D) issue or deny the appropriate order accordingly.

(3)(A) Except as provided in subparagraph (B), the Commission may approve an application described in paragraph (2), in whole or part, with such modifications and upon such terms and conditions as the Commission find (!1) necessary or appropriate.

(B) Before January 1, 2015, the Commission shall not -

(i) deny an application solely on the basis that the applicant proposes to use the LNG terminal exclusively or partially for gas that the applicant or an affiliate of the applicant will supply to the facility; or

(ii) condition an order on -

(I) a requirement that the LNG terminal offer service to customers other than the applicant, or any affiliate of the applicant, securing the order;

(II) any regulation of the rates, charges, terms, or conditions of service of the LNG terminal; or

(III) a requirement to file with the Commission schedules or contracts related to the rates, charges, terms, or conditions of service of the LNG terminal.

(C) Subparagraph (B) shall cease to have effect on January 1, 2030.

(4) An order issued for an LNG terminal that also offers service to customers on an open access basis shall not result in subsidization of expansion capacity by existing customers, degradation of service to existing customers, or undue discrimination against existing customers as to their terms or conditions of service at the facility, as all of those terms are defined by the Commission.

(f) Military installations

(1) In this subsection, the term "military installation" -

(A) means a base, camp, post, range, station, yard, center, or homeport facility for any ship or other activity under the jurisdiction of the Department of Defense, including any leased facility, that is located within a State, the District of Columbia, or any territory of the United States; and

(B) does not include any facility used primarily for civil works, rivers and harbors projects, or flood control projects, as determined by the Secretary of Defense.

(2) The Commission shall enter into a memorandum of understanding

with the Secretary of Defense for the purpose of ensuring that the Commission coordinate and consult (2) with the Secretary of Defense on the siting, construction, expansion, or operation of liquefied natural gas facilities that may affect an active military installation.

(3) The Commission shall obtain the concurrence of the Secretary of Defense before authorizing the siting, construction, expansion, or operation of liquefied natural gas facilities affecting the training or activities of an active military installation.

-SOURCE-

(June 21, 1938, ch. 556, Sec. 3, 52 Stat. 822; Pub. L. 102-486, title II, Sec. 201, Oct. 24, 1992, 106 Stat. 2866; Pub. L. 109-58, title III, Sec. 311(c), Aug. 8, 2005, 119 Stat. 685.)

-REFTEXT-

REFERENCES IN TEXT

The Coastal Zone Management Act of 1972, referred to in subsec. (d)(1), is title III of Pub. L. 89-454 as added by Pub. L. 92-583, Oct. 27, 1972, 86 Stat. 1280, as amended, which is classified generally to chapter 33 (Sec. 1451 et seq.) of Title 16, Conservation. For complete classification of this Act to the Code, see Short Title note set out under section 1451 of Title 16 and Tables.

The Clean Air Act, referred to in subsec. (d)(2), is act July 14, 1955, ch. 360, 69 Stat. 322, as amended, which is classified generally to chapter 85 (Sec. 7401 et seq.) of Title 42, The Public Health and Welfare. For complete classification of this Act to the Code, see Short Title note set out under section 7401 of Title 42 and Tables.

The Federal Water Pollution Control Act, referred to in subsec. (d)(3), is act June 30, 1948, ch. 758, as amended generally by Pub. L. 92-500, Sec. 2, Oct. 18, 1972, 86 Stat. 816, which is classified generally to chapter 26 (Sec. 1251 et seq.) of Title 33, Navigation and Navigable Waters. For complete classification of this Act to the Code, see Short Title note set out under section 1251 of Title 33 and Tables.

-MISC1-

AMENDMENTS

2005 - Pub. L. 109-58, Sec. 311(c)(1), inserted "; LNG terminals" after "natural gas" in section catchline.

Subsecs. (d) to (f). Pub. L. 109-58, Sec. 311(c)(2), added subsecs. (d) to (f).

1992 - Pub. L. 102-486 designated existing provisions as subsec. (a) and added subsecs. (b) and (c).

-TRANS-

TRANSFER OF FUNCTIONS

Enforcement functions of Secretary or other official in Department of Energy and Commission, Commissioners, or other official in Federal Energy Regulatory Commission related to compliance with authorizations for importation of natural gas from Alberta as pre-deliveries of Alaskan gas issued under this section with respect to pre-construction, construction, and initial operation of transportation system for Canadian and Alaskan natural gas transferred to the Federal Inspector, Office of Federal Inspector for Alaska Natural Gas Transportation System, until first anniversary of date of initial operation of Alaska Natural Gas Transportation System, see Reorg. Plan No. 1 of 1979, Secs. 102(d), 203(a), 44 F.R. 33663, 33666, 93 Stat. 1373, 1376, effective July 1, 1979, set out under section 719e of this title. Office of Federal Inspector for the Alaska Natural Gas Transportation System abolished and functions and authority vested in Inspector transferred to Secretary of Energy by section 3012(b) of Pub. L. 102-486, set out as an Abolition of Office of Federal Inspector note under section 719e of this title. Functions and authority vested in Secretary of Energy subsequently transferred to Federal Coordinator for Alaska Natural Gas Transportation Projects by section 720d(f) of this title.

DELEGATION OF FUNCTIONS

Functions of President respecting certain facilities constructed and maintained on United States borders delegated to Secretary of State, see Ex. Ord. No. 11423, Aug. 16, 1968, 33 F.R. 11741, set out as a note under section 301 of Title 3, The President.

-EXEC-

EX. ORD. NO. 10485. PERFORMANCE OF FUNCTIONS RESPECTING ELECTRIC POWER AND NATURAL GAS FACILITIES LOCATED ON UNITED STATES BORDERS

Ex. Ord. No. 10485, Sept. 3, 1953, 18 F.R. 5397, as amended by Ex. Ord. No. 12038, Feb. 3, 1978, 43 F.R. 4957, provided:

Section 1. (a) The Secretary of Energy is hereby designated and empowered to perform the following-described functions:

(1) To receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the transmission of electric energy between the United States and a foreign country.

(2) To receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the exportation or importation of natural gas to or from a foreign country.

(3) Upon finding the issuance of the permit to be consistent with the public interest, and, after obtaining the favorable recommendations of the Secretary of State and the Secretary of Defense thereon, to issue to the applicant, as appropriate, a permit for such construction, operation, maintenance, or connection. The Secretary of Energy shall have the power to attach to the issuance of the permit and to the exercise of the rights granted thereunder such conditions as the public interest may in its judgment require.

(b) In any case wherein the Secretary of Energy, the Secretary of State, and the Secretary of Defense cannot agree as to whether or not a permit should be issued, the Secretary of Energy shall submit to the President for approval or disapproval the application for a permit with the respective views of the Secretary of Energy, the Secretary of State and the Secretary of Defense.

Sec. 2. [Deleted.]

Sec. 3. The Secretary of Energy is authorized to issue such rules and regulations, and to prescribe such procedures, as it may from time to time deem necessary or desirable for the exercise of the authority delegated to it by this order.

Sec. 4. All Presidential Permits heretofore issued pursuant to Executive Order No. 8202 of July 13, 1939, and in force at the time of the issuance of this order, and all permits issued hereunder, shall remain in full force and effect until modified or revoked by the President or by the Secretary of Energy.

Sec. 5. Executive Order No. 8202 of July 13, 1939, is hereby revoked.

-FOOTNOTE-

(!1) So in original. Probably should be "finds".

(!2) So in original. Probably should be "coordinates and consults".

-End-

Appendix B. Summary Tables

Table B1. U.S. Annual Average Values from 2015 to 2025

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(1.90)	(0.29)	0.11	0.17	1.74	(1.32)	0.32	0.70	0.79	2.35	(2.72)	(1.17)	(0.88)	(0.73)	0.66	(2.00)	(0.38)	0.01	0.07	1.64
gross imports	3.62	3.70	3.70	3.74	3.76	3.19	3.25	3.26	3.27	3.31	4.27	4.42	4.53	4.48	4.68	3.70	3.78	3.79	3.82	3.85
gross exports	1.72	3.41	3.81	3.91	5.50	1.87	3.56	3.96	4.06	5.65	1.56	3.25	3.65	3.75	5.34	1.70	3.39	3.79	3.89	5.49
Dry Production	23.27	24.15	24.37	24.42	25.33	26.24	27.28	27.51	27.57	28.41	19.80	20.72	20.78	20.99	21.83	23.85	24.90	25.10	25.22	26.20
shale gas	8.34	8.96	9.17	9.13	9.90	11.90	12.66	12.87	12.89	13.64	3.88	4.42	4.63	4.53	5.22	8.73	9.49	9.70	9.69	10.51
other	14.93	15.18	15.20	15.29	15.43	14.34	14.61	14.65	14.68	14.77	15.91	16.30	16.15	16.45	16.62	15.12	15.41	15.39	15.53	15.70
Delivered Volumes (1)	23.34	22.57	22.38	22.37	21.68	25.58	24.94	24.79	24.75	24.00	20.82	20.13	19.90	19.94	19.35	23.99	23.37	23.17	23.22	22.60
electric generators	6.81	6.25	6.16	6.11	5.67	8.35	7.94	7.88	7.80	7.30	5.07	4.66	4.55	4.54	4.23	6.99	6.63	6.53	6.54	6.21
industrial	8.14	8.01	7.95	7.98	7.83	8.55	8.40	8.34	8.37	8.19	7.74	7.58	7.51	7.56	7.38	8.50	8.34	8.27	8.30	8.12
residential	4.83	4.80	4.79	4.79	4.75	4.94	4.92	4.90	4.91	4.87	4.68	4.63	4.61	4.62	4.57	4.90	4.86	4.85	4.85	4.81
commercial	3.48	3.44	3.42	3.42	3.37	3.65	3.61	3.59	3.60	3.55	3.27	3.20	3.17	3.18	3.11	3.52	3.46	3.45	3.45	3.39
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	11.19	11.63	11.77	11.81	12.33	9.92	10.24	10.37	10.36	10.72	13.23	14.05	14.27	14.42	15.10	11.56	12.09	12.21	12.29	12.87
commercial	9.23	9.66	9.79	9.83	10.34	7.97	8.28	8.40	8.39	8.74	11.27	12.09	12.31	12.46	13.16	9.60	10.12	10.24	10.31	10.88
industrial	5.59	6.10	6.25	6.32	6.91	4.41	4.80	4.95	4.94	5.41	7.50	8.40	8.62	8.83	9.59	5.89	6.49	6.63	6.73	7.41
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	4.70	5.17	5.30	5.37	5.91	3.56	3.90	4.02	4.03	4.42	6.52	7.41	7.63	7.84	8.64	4.99	5.54	5.66	5.77	6.39
Henry Hub Price (2009$/MMBtu)	5.17	5.69	5.83	5.91	6.51	3.92	4.29	4.43	4.43	4.87	7.18	8.16	8.41	8.64	9.51	5.49	6.10	6.23	6.35	7.04
Coal Minemouth Price (2009$/short-ton)	32.67	32.76	32.89	32.89	32.89	32.33	32.69	32.52	32.59	32.77	32.91	33.15	33.10	32.97	33.04	33.23	33.18	33.06	33.33	33.28
End-Use Electricity Price (2009 cents/KWh)	8.85	8.98	9.00	9.02	9.17	8.56	8.62	8.67	8.64	8.70	9.44	9.64	9.71	9.78	9.97	9.08	9.26	9.27	9.32	9.46
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	9.47	20.64	23.25	25.10	37.74	7.51	16.01	18.17	19.27	28.89	12.83	29.03	32.72	36.09	53.91	10.04	22.11	24.82	26.97	40.81
Domestic Supply Revenues (3)	160.19	175.25	179.33	181.70	199.21	147.33	159.55	163.65	164.23	177.50	177.88	201.92	206.65	213.21	236.34	171.34	190.13	193.88	197.79	218.78
production revenues (4)	109.53	125.29	129.41	132.23	150.47	93.68	106.70	111.00	111.90	126.30	129.24	154.00	158.75	165.84	189.27	119.39	138.71	142.53	146.83	168.64
delivery revenues (5)	50.65	49.97	49.92	49.46	48.74	53.65	52.85	52.65	52.33	51.20	48.64	47.92	47.91	47.37	47.07	51.94	51.41	51.36	50.96	50.14
Import Revenues (6)	17.44	19.22	19.72	19.92	21.97	12.09	13.35	13.86	13.83	15.35	28.00	31.62	33.03	33.32	36.58	18.96	21.07	21.66	21.94	24.19
END-USE ENERGY EXPENDITURES (B 2009$)	1,398.11	1,409.25	1,410.59	1,414.03	1,424.75	1,368.25	1,375.50	1,377.65	1,379.69	1,386.87	1,448.36	1,465.24	1,469.02	1,473.83	1,482.50	1,485.34	1,498.28	1,499.67	1,504.03	1,514.65
liquids	913.43	914.55	913.66	915.34	915.15	908.98	909.65	908.67	911.23	911.57	920.92	921.56	921.21	920.98	916.83	971.80	971.63	971.22	972.09	970.98
natural gas	128.00	133.77	135.27	136.30	142.58	113.26	117.51	119.11	119.24	123.94	151.16	161.03	163.24	165.90	173.42	136.49	143.47	144.71	146.37	153.61
electricity	349.77	354.03	354.76	355.46	360.10	339.21	341.51	343.06	342.39	344.53	369.28	375.68	377.60	379.98	385.31	369.58	375.70	376.28	378.08	382.59
coal	6.90	6.91	6.91	6.93	6.92	6.80	6.82	6.81	6.83	6.83	6.99	6.98	6.97	6.97	6.94	7.47	7.49	7.46	7.49	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	67.88	67.68	67.59	67.67	67.37	68.58	68.40	68.28	68.37	68.11	66.93	66.63	66.49	66.54	66.20	70.23	70.02	69.89	69.98	69.64
liquids	36.71	36.74	36.74	36.78	36.78	36.67	36.71	36.71	36.74	36.75	36.71	36.72	36.71	36.74	36.73	38.13	38.18	38.16	38.20	38.20
natural gas	16.04	15.85	15.76	15.81	15.55	16.76	16.55	16.45	16.49	16.23	15.22	14.97	14.86	14.91	14.65	16.49	16.26	16.16	16.21	15.92
electricity	13.44	13.41	13.41	13.41	13.37	13.48	13.47	13.46	13.48	13.47	13.32	13.26	13.24	13.22	13.16	13.84	13.81	13.80	13.79	13.75
coal	1.68	1.68	1.68	1.68	1.67	1.67	1.67	1.67	1.67	1.67	1.68	1.68	1.68	1.68	1.67	1.77	1.77	1.77	1.77	1.76
ELECTRIC GENERATION (billion kWh)	4,456.38	4,441.98	4,437.47	4,441.10	4,422.62	4,492.78	4,484.65	4,477.63	4,483.35	4,471.75	4,391.20	4,369.32	4,360.19	4,356.29	4,329.07	4,594.62	4,577.41	4,572.19	4,572.39	4,552.42
coal	1,921.25	1,982.85	1,995.33	1,999.09	2,044.09	1,756.51	1,808.90	1,813.78	1,828.74	1,885.58	2,093.76	2,132.35	2,134.49	2,123.82	2,139.82	2,004.09	2,036.83	2,052.54	2,043.09	2,073.78
gas	999.19	918.42	902.15	898.01	829.83	1,232.25	1,170.15	1,158.31	1,147.99	1,070.38	733.83	671.33	653.23	655.42	608.52	1,036.47	978.19	959.84	964.71	909.63
nuclear	866.34	866.34	866.34	866.34	866.34	850.50	850.50	850.50	851.17	855.05	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34	866.34
renewables	610.16	614.27	613.17	617.16	621.29	593.01	594.47	595.24	594.57	599.35	636.27	638.25	645.09	648.70	651.89	626.90	634.74	632.26	636.59	641.06
other	59.43	60.11	60.48	60.50	61.08	60.51	60.63	59.80	60.87	61.39	61.00	61.04	61.03	62.00	62.50	60.83	61.30	61.21	61.65	61.61
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	104.89	104.90	104.87	104.98	104.91	105.24	105.25	105.14	105.32	105.27	104.34	104.16	104.07	104.06	103.75	108.35	108.31	108.25	108.36	108.12
Imports	28.62	28.75	28.72	28.78	28.90	27.69	27.73	27.77	27.87	27.94	29.78	29.83	29.92	29.98	30.08	30.06	30.22	30.21	30.24	30.28
Exports	7.06	8.76	9.15	9.26	10.86	7.20	8.92	9.32	9.43	11.03	6.85	8.54	8.93	9.01	10.60	7.10	8.80	9.20	9.30	10.90
Production	83.14	84.73	85.12	85.28	86.71	84.63	86.34	86.60	86.79	88.26	81.15	82.63	82.84	82.86	84.05	85.16	86.66	87.01	87.18	88.52
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	5,793.73	5,832.23	5,837.67	5,846.39	5,869.62	5,754.36	5,787.50	5,787.31	5,804.76	5,833.35	5,832.09	5,853.23	5,846.94	5,841.58	5,843.35	6,017.09	6,037.23	6,043.12	6,043.12	6,055.08

Table B2. Differential from Base in U.S. Average Annual Values from 2015 to 2025 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	1.61	2.00	2.07	3.64	1.64	2.02	2.11	3.67	1.55	1.84	1.99	3.38	1.62	2.01	2.07	3.64
gross imports	0.08	0.09	0.12	0.15	0.05	0.07	0.08	0.12	0.14	0.25	0.20	0.41	0.07	0.08	0.12	0.14
gross exports	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78	1.69	2.09	2.19	3.78
Dry Production	0.87	1.09	1.15	2.05	1.04	1.28	1.33	2.17	0.92	0.98	1.19	2.04	1.05	1.24	1.37	2.35
shale gas	0.62	0.82	0.79	1.55	0.77	0.97	0.99	1.74	0.53	0.75	0.65	1.33	0.76	0.97	0.96	1.78
other	0.25	0.27	0.36	0.50	0.27	0.31	0.34	0.43	0.39	0.24	0.54	0.71	0.29	0.27	0.41	0.57
Delivered Volumes (1)	(0.77)	(0.95)	(0.97)	(1.66)	(0.64)	(0.80)	(0.84)	(1.59)	(0.69)	(0.91)	(0.88)	(1.46)	(0.62)	(0.82)	(0.77)	(1.39)
electric generators	(0.57)	(0.66)	(0.71)	(1.15)	(0.42)	(0.47)	(0.55)	(1.05)	(0.41)	(0.52)	(0.53)	(0.84)	(0.36)	(0.46)	(0.45)	(0.78)
industrial	(0.13)	(0.19)	(0.16)	(0.32)	(0.15)	(0.22)	(0.19)	(0.36)	(0.15)	(0.23)	(0.18)	(0.35)	(0.16)	(0.23)	(0.20)	(0.38)
residential	(0.03)	(0.04)	(0.04)	(0.08)	(0.03)	(0.04)	(0.04)	(0.07)	(0.05)	(0.07)	(0.07)	(0.11)	(0.04)	(0.05)	(0.05)	(0.09)
commercial	(0.05)	(0.06)	(0.06)	(0.11)	(0.04)	(0.06)	(0.05)	(0.10)	(0.07)	(0.09)	(0.09)	(0.15)	(0.05)	(0.07)	(0.07)	(0.13)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.44	0.58	0.62	1.14	0.32	0.45	0.44	0.80	0.81	1.03	1.18	1.87	0.53	0.65	0.72	1.31
commercial	0.43	0.57	0.61	1.12	0.31	0.43	0.42	0.76	0.82	1.04	1.19	1.89	0.52	0.64	0.71	1.28
industrial	0.51	0.66	0.73	1.32	0.39	0.54	0.54	1.00	0.90	1.13	1.33	2.09	0.61	0.74	0.85	1.52
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.47	0.60	0.68	1.21	0.33	0.46	0.47	0.86	0.88	1.11	1.32	2.11	0.55	0.67	0.77	1.40
Henry Hub Price (2009$/MMBtu)	0.52	0.66	0.74	1.34	0.37	0.51	0.51	0.95	0.97	1.22	1.46	2.33	0.60	0.74	0.85	1.54
Coal Minemouth Price (2009$/short-ton)	0.09	0.21	0.22	0.22	0.36	0.19	0.26	0.44	0.24	0.19	0.06	0.13	(0.05)	(0.17)	0.11	0.06
End-Use Electricity Price (2009 cents/KWh)	0.13	0.15	0.17	0.31	0.06	0.11	0.08	0.14	0.20	0.27	0.34	0.53	0.17	0.19	0.24	0.38
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	11.17	13.77	15.63	28.26	8.50	10.65	11.75	21.38	16.20	19.89	23.25	41.08	12.07	14.79	16.93	30.78
Domestic Supply Revenues (3)	15.07	19.14	21.51	39.02	12.22	16.32	16.91	30.17	24.04	28.77	35.33	58.46	18.79	22.55	26.46	47.44
production revenues (4)	15.75	19.88	22.70	40.93	13.02	17.31	18.22	32.62	24.76	29.51	36.60	60.03	19.32	23.13	27.44	49.24
delivery revenues (5)	(0.68)	(0.74)	(1.19)	(1.91)	(0.80)	(0.99)	(1.32)	(2.45)	(0.72)	(0.74)	(1.28)	(1.58)	(0.53)	(0.59)	(0.98)	(1.80)
Import Revenues (6)	1.78	2.28	2.48	4.53	1.26	1.77	1.74	3.26	3.62	5.03	5.32	8.58	2.12	2.70	2.99	5.24
END-USE ENERGY EXPENDITURES (B 2009$)	11.15	12.49	15.92	26.65	7.26	9.40	11.44	18.63	16.89	20.67	25.47	34.14	12.94	14.33	18.69	29.31
liquids	1.12	0.22	1.91	1.72	0.68	(0.30)	2.26	2.60	0.64	0.29	0.05	(4.09)	(0.18)	(0.59)	0.29	(0.82)
natural gas	5.76	7.26	8.30	14.58	4.26	5.85	5.98	10.68	9.86	12.07	14.73	22.25	6.98	8.22	9.88	17.12
electricity	4.26	4.99	5.69	10.32	2.31	3.85	3.18	5.32	6.39	8.31	10.70	16.02	6.12	6.70	8.50	13.01
coal	0.01	0.01	0.03	0.02	0.02	0.00	0.03	0.03	(0.00)	(0.01)	(0.01)	(0.04)	0.02	(0.01)	0.02	(0.00)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.20)	(0.29)	(0.21)	(0.50)	(0.18)	(0.30)	(0.21)	(0.47)	(0.30)	(0.44)	(0.38)	(0.73)	(0.22)	(0.34)	(0.26)	(0.60)
liquids	0.03	0.03	0.06	0.06	0.04	0.04	0.07	0.08	0.01	(0.00)	0.03	0.02	0.05	0.03	0.07	0.07
natural gas	(0.19)	(0.28)	(0.23)	(0.49)	(0.22)	(0.32)	(0.27)	(0.53)	(0.25)	(0.36)	(0.31)	(0.57)	(0.24)	(0.34)	(0.28)	(0.57)
electricity	(0.03)	(0.04)	(0.04)	(0.08)	(0.00)	(0.02)	(0.00)	(0.01)	(0.06)	(0.08)	(0.09)	(0.16)	(0.03)	(0.04)	(0.05)	(0.09)
coal	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.00)	0.00	(0.00)	(0.00)	(0.01)	(0.00)	(0.01)	(0.00)	(0.00)	0.00	(0.01)
ELECTRIC GENERATION (billion kWh)	(14.39)	(18.91)	(15.27)	(33.75)	(8.13)	(15.15)	(9.43)	(21.02)	(21.89)	(31.02)	(34.92)	(62.13)	(17.21)	(22.43)	(22.23)	(42.20)
coal	61.59	74.07	77.84	122.84	52.39	57.26	72.23	129.07	38.59	40.73	30.06	46.06	32.74	48.46	39.01	69.70
gas	(80.76)	(97.03)	(101.17)	(169.36)	(62.10)	(73.94)	(84.25)	(161.86)	(62.50)	(80.59)	(78.41)	(125.31)	(58.28)	(76.63)	(71.76)	(126.84)
nuclear	-	-	-	-	0.00	0.00	0.67	4.55	(0.00)	-	-	(0.00)	-	-	-	-
renewables	4.10	3.00	7.00	11.12	1.46	2.24	1.57	6.35	1.98	8.82	12.43	15.61	7.85	5.36	9.70	14.17
other	0.67	1.04	1.07	1.64	0.11	(0.71)	0.36	0.88	0.04	0.03	1.00	1.50	0.47	0.38	0.82	0.78
PRIMARY ENERGY (quadrillion Btu)																
Consumption	0.02	(0.02)	0.09	0.02	0.01	(0.09)	0.08	0.03	(0.18)	(0.27)	(0.28)	(0.59)	(0.03)	(0.10)	0.01	(0.23)
Imports	0.13	0.10	0.16	0.28	0.04	0.08	0.18	0.26	0.05	0.14	0.20	0.30	0.16	0.15	0.18	0.22
Exports	1.70	2.09	2.20	3.79	1.72	2.12	2.23	3.83	1.69	2.08	2.16	3.75	1.70	2.10	2.20	3.80
Production	1.59	1.98	2.14	3.58	1.71	1.96	2.16	3.63	1.47	1.69	1.71	2.90	1.50	1.85	2.02	3.36
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	38.50	43.94	52.67	75.90	33.14	32.94	50.39	78.99	21.14	14.85	9.48	11.26	20.14	26.03	26.03	37.99

Table B3. U.S. Annual Average Values from 2025 to 2035

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(0.71)	1.48	1.48	3.52	3.57	0.10	2.16	2.15	4.19	4.20	(2.09)	(0.21)	(0.33)	1.83	1.76	(0.88)	1.29	1.29	3.21	3.38
gross imports	2.98	2.99	2.98	3.10	3.09	2.47	2.60	2.61	2.73	2.75	3.99	4.30	4.42	4.41	4.52	3.09	3.11	3.11	3.35	3.21
gross exports	2.28	4.47	4.47	6.62	6.66	2.57	4.76	4.76	6.91	6.95	1.90	4.09	4.09	6.25	6.28	2.21	4.40	4.40	6.56	6.59
Dry Production	25.07	26.58	26.66	28.08	28.23	28.73	30.16	30.21	31.50	31.51	20.98	22.22	22.24	23.61	23.89	26.84	28.59	28.55	29.99	30.31
shale gas	10.96	12.08	12.10	13.10	13.27	15.51	16.70	16.75	17.75	17.74	5.22	6.06	6.13	6.78	6.97	12.19	13.49	13.47	14.49	14.75
other	14.12	14.49	14.56	14.98	14.96	13.21	13.46	13.47	13.75	13.77	15.76	16.16	16.11	16.83	16.91	14.65	15.10	15.08	15.50	15.56
Delivered Volumes (1)	23.96	23.22	23.29	22.60	22.70	26.63	25.94	26.00	25.19	25.19	21.41	20.69	20.82	19.97	20.27	25.80	25.29	25.26	24.72	24.85
electric generators	7.27	6.87	6.95	6.56	6.66	8.89	8.55	8.65	8.11	8.20	5.78	5.28	5.41	4.82	5.08	8.21	8.04	8.03	7.77	7.93
industrial	8.06	7.82	7.81	7.62	7.60	8.68	8.45	8.42	8.25	8.16	7.47	7.34	7.32	7.20	7.19	8.68	8.43	8.40	8.22	8.18
residential	4.82	4.78	4.78	4.73	4.74	4.95	4.91	4.91	4.88	4.88	4.64	4.61	4.61	4.56	4.58	5.01	4.97	4.97	4.93	4.94
commercial	3.68	3.62	3.62	3.56	3.57	3.91	3.85	3.85	3.80	3.80	3.40	3.36	3.37	3.29	3.32	3.75	3.70	3.71	3.66	3.66
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	12.90	13.45	13.39	14.05	13.85	11.31	11.66	11.68	12.10	11.98	15.49	15.96	15.83	16.76	16.27	13.70	14.13	14.06	14.67	14.51
commercial	10.61	11.15	11.09	11.73	11.54	9.01	9.34	9.36	9.75	9.63	13.24	13.71	13.58	14.53	14.02	11.39	11.80	11.73	12.32	12.15
industrial	6.82	7.43	7.36	8.26	7.98	5.39	5.86	5.88	6.46	6.32	9.30	9.79	9.66	10.69	10.09	7.50	8.05	7.96	8.82	8.59
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	5.88	6.42	6.35	7.14	6.88	4.45	4.82	4.83	5.31	5.17	8.25	8.77	8.68	9.69	9.10	6.52	6.98	6.90	7.67	7.43
Henry Hub Price (2009$/MMBtu)	6.47	7.06	6.99	7.86	7.58	4.90	5.30	5.31	5.85	5.69	9.08	9.66	9.56	10.67	10.02	7.18	7.68	7.60	8.45	8.18
Coal Minemouth Price (2009$/short-ton)	33.46	33.51	33.43	33.68	33.43	33.20	33.45	33.21	33.42	33.25	33.77	34.11	33.89	33.76	33.85	34.30	34.01	33.95	33.99	34.16
End-Use Electricity Price (2009 cents/KWh)	9.02	9.17	9.15	9.36	9.28	8.57	8.65	8.67	8.75	8.69	9.86	9.98	9.94	10.25	10.06	9.50	9.67	9.63	9.90	9.78
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	12.81	29.82	29.50	50.58	48.98	10.46	23.42	23.49	38.88	38.06	17.38	39.57	38.98	66.69	62.90	14.21	32.48	32.11	54.16	52.87
Domestic Supply Revenues (3)	199.45	221.98	220.95	249.66	244.39	184.30	200.41	201.19	220.08	216.08	222.71	243.85	242.19	276.77	266.61	230.96	254.64	252.33	282.66	278.95
production revenues (4)	147.54	170.77	169.47	200.63	194.52	128.09	145.41	146.06	167.45	162.93	173.25	194.92	193.13	228.66	217.47	175.63	199.91	197.44	230.19	225.48
delivery revenues (5)	51.91	51.21	51.48	49.03	49.87	56.21	55.00	55.13	52.63	53.14	49.47	48.94	49.06	48.11	49.13	55.33	54.74	54.89	52.47	53.47
Import Revenues (6)	18.06	19.89	19.65	22.97	22.09	11.69	13.64	13.75	16.04	15.80	33.87	37.50	37.30	41.19	39.73	20.96	22.75	22.52	26.35	24.99
END-USE ENERGY EXPENDITURES (B 2009$)	1,582.70	1,589.93	1,589.52	1,602.94	1,596.44	1,543.37	1,552.01	1,553.43	1,559.62	1,552.40	1,648.34	1,658.55	1,651.04	1,673.64	1,651.53	1,766.94	1,773.78	1,770.57	1,786.74	1,777.53
liquids	1,036.91	1,032.47	1,033.91	1,030.97	1,030.61	1,032.78	1,033.84	1,034.44	1,031.39	1,028.44	1,044.39	1,046.22	1,041.53	1,044.12	1,034.65	1,156.40	1,151.96	1,151.22	1,149.05	1,147.03
natural gas	152.47	158.71	157.65	166.94	163.18	136.00	140.12	140.18	146.00	143.37	180.36	184.84	183.01	194.25	187.01	172.16	177.27	175.86	185.15	181.63
electricity	386.65	392.12	391.36	398.45	396.09	368.01	371.51	372.27	375.68	374.08	416.91	420.84	419.85	428.68	423.29	430.75	436.99	435.94	445.06	441.40
coal	6.67	6.62	6.61	6.59	6.56	6.57	6.54	6.53	6.54	6.51	6.68	6.64	6.65	6.59	6.58	7.63	7.55	7.54	7.48	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	70.29	69.92	69.90	69.59	69.57	71.26	70.89	70.87	70.66	70.61	68.84	68.56	68.64	68.25	68.43	74.98	74.60	74.59	74.25	74.26
liquids	37.85	37.84	37.82	37.84	37.83	37.75	37.74	37.75	37.81	37.80	37.74	37.71	37.77	37.73	37.81	40.67	40.66	40.65	40.64	40.64
natural gas	16.26	15.95	15.94	15.69	15.66	17.32	16.97	16.93	16.66	16.58	15.13	14.92	14.92	14.71	14.73	17.13	16.83	16.81	16.58	16.53
electricity	14.59	14.55	14.56	14.48	14.52	14.61	14.62	14.62	14.61	14.66	14.39	14.35	14.38	14.25	14.32	15.43	15.39	15.41	15.31	15.37
coal	1.59	1.58	1.58	1.57	1.57	1.58	1.57	1.57	1.57	1.57	1.58	1.57	1.57	1.56	1.56	1.74	1.73	1.73	1.72	1.72
ELECTRIC GENERATION (billion kWh)	4,926.27	4,899.77	4,902.00	4,877.85	4,883.87	4,985.61	4,970.39	4,968.96	4,955.47	4,962.16	4,805.29	4,785.02	4,792.39	4,749.29	4,771.60	5,218.96	5,192.01	5,194.85	5,161.80	5,172.17
coal	2,142.71	2,177.86	2,173.08	2,205.23	2,199.91	1,965.65	2,017.08	2,010.40	2,076.04	2,072.01	2,250.96	2,299.95	2,288.43	2,318.37	2,307.93	2,230.53	2,234.24	2,247.81	2,248.95	2,243.60
gas	1,143.09	1,075.44	1,084.20	1,020.61	1,029.93	1,418.58	1,349.39	1,356.51	1,272.85	1,275.05	878.08	797.50	812.65	731.17	762.84	1,317.28	1,273.98	1,266.15	1,220.40	1,234.87
nuclear	876.67	876.67	876.67	876.67	876.67	858.29	858.29	858.29	858.29	863.83	876.67	878.22	878.27	879.99	878.26	876.67	877.25	876.67	877.38	876.67
renewables	702.87	707.59	705.79	711.29	713.75	681.48	683.24	681.93	685.54	688.71	734.07	743.56	747.72	752.68	756.76	730.61	742.46	740.48	748.18	750.94
other	60.93	62.21	62.25	64.05	63.60	61.62	62.40	61.82	62.74	62.56	65.51	65.81	65.32	67.09	65.81	63.87	64.07	63.73	66.89	66.09
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	111.05	110.88	110.85	110.69	110.76	111.50	111.37	111.37	111.45	111.46	109.71	109.57	109.69	109.18	109.59	117.72	117.47	117.54	117.22	117.23
Imports	27.93	27.63	27.67	27.60	27.46	26.80	26.78	26.86	27.04	26.99	29.22	29.38	29.42	29.45	29.40	30.26	30.04	29.97	30.09	29.72
Exports	7.91	10.13	10.13	12.29	12.32	8.18	10.39	10.40	12.58	12.62	7.54	9.74	9.72	11.88	11.94	7.97	10.17	10.18	12.32	12.36
Production	90.96	93.37	93.26	95.38	95.65	92.89	95.05	94.99	97.21	97.27	87.86	89.79	89.86	91.50	92.04	95.31	97.52	97.67	99.38	99.80
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	6,114.82	6,136.49	6,131.49	6,155.61	6,152.88	6,074.00	6,103.94	6,102.31	6,151.52	6,146.61	6,084.64	6,103.94	6,106.49	6,104.89	6,120.61	6,521.09	6,517.76	6,525.31	6,521.52	6,520.16

Table B4. Differential from Base in U.S. Average Annual Values from 2025 to 2035 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	2.18	2.19	4.23	4.28	2.06	2.05	4.09	4.10	1.88	1.76	3.93	3.85	2.17	2.17	4.09	4.26
gross imports	0.01	0.00	0.12	0.10	0.13	0.14	0.26	0.28	0.31	0.43	0.42	0.53	0.02	0.02	0.26	0.12
gross exports	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38	2.19	2.19	4.35	4.38
Dry Production	1.51	1.59	3.00	3.15	1.43	1.49	2.77	2.78	1.24	1.25	2.62	2.90	1.74	1.71	3.15	3.47
shale gas	1.13	1.15	2.14	2.31	1.18	1.23	2.24	2.23	0.84	0.91	1.55	1.75	1.29	1.28	2.30	2.56
other	0.38	0.44	0.86	0.84	0.25	0.25	0.53	0.55	0.40	0.35	1.07	1.16	0.45	0.43	0.85	0.91
Delivered Volumes (1)	(0.75)	(0.67)	(1.36)	(1.26)	(0.69)	(0.63)	(1.43)	(1.43)	(0.72)	(0.59)	(1.44)	(1.13)	(0.51)	(0.54)	(1.08)	(0.95)
electric generators	(0.40)	(0.32)	(0.71)	(0.61)	(0.35)	(0.25)	(0.79)	(0.70)	(0.50)	(0.37)	(0.96)	(0.69)	(0.17)	(0.19)	(0.45)	(0.28)
industrial	(0.24)	(0.25)	(0.44)	(0.46)	(0.24)	(0.27)	(0.43)	(0.53)	(0.13)	(0.15)	(0.27)	(0.28)	(0.25)	(0.27)	(0.46)	(0.49)
residential	(0.04)	(0.04)	(0.08)	(0.08)	(0.03)	(0.03)	(0.07)	(0.06)	(0.03)	(0.03)	(0.08)	(0.06)	(0.04)	(0.03)	(0.07)	(0.07)
commercial	(0.06)	(0.06)	(0.12)	(0.11)	(0.05)	(0.06)	(0.11)	(0.10)	(0.05)	(0.04)	(0.11)	(0.08)	(0.05)	(0.04)	(0.10)	(0.09)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.55	0.48	1.15	0.95	0.35	0.37	0.79	0.67	0.46	0.33	1.27	0.78	0.43	0.35	0.97	0.81
commercial	0.54	0.48	1.12	0.92	0.33	0.34	0.73	0.61	0.47	0.34	1.29	0.78	0.41	0.34	0.93	0.76
industrial	0.62	0.54	1.44	1.16	0.46	0.48	1.07	0.92	0.49	0.36	1.39	0.78	0.55	0.46	1.32	1.09
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.54	0.47	1.27	1.01	0.36	0.38	0.86	0.71	0.52	0.43	1.44	0.85	0.45	0.38	1.15	0.90
Henry Hub Price (2009$/MMBtu)	0.60	0.52	1.39	1.11	0.40	0.41	0.95	0.79	0.57	0.47	1.59	0.94	0.50	0.42	1.26	1.00
Coal Minemouth Price (2009$/short-ton)	0.05	(0.03)	0.22	(0.03)	0.25	0.01	0.22	0.05	0.34	0.12	(0.01)	0.08	(0.29)	(0.35)	(0.30)	(0.14)
End-Use Electricity Price (2009 cents/KWh)	0.16	0.13	0.35	0.27	0.08	0.10	0.18	0.12	0.12	0.08	0.38	0.20	0.17	0.13	0.40	0.28
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	17.01	16.69	37.77	36.17	12.96	13.03	28.42	27.60	22.19	21.60	49.31	45.52	18.27	17.90	39.95	38.66
Domestic Supply Revenues (3)	22.53	21.50	50.21	44.94	16.11	16.89	35.77	31.78	21.14	19.48	54.05	43.89	23.68	21.37	51.70	47.99
production revenues (4)	23.23	21.93	53.09	46.98	17.31	17.97	39.36	34.84	21.67	19.88	55.41	44.23	24.28	21.81	54.56	49.85
delivery revenues (5)	(0.71)	(0.44)	(2.88)	(2.04)	(1.21)	(1.08)	(3.58)	(3.06)	(0.53)	(0.40)	(1.36)	(0.33)	(0.60)	(0.44)	(2.86)	(1.87)
Import Revenues (6)	1.82	1.59	4.91	4.02	1.95	2.06	4.35	4.11	3.63	3.43	7.32	5.87	1.79	1.56	5.39	4.03
END-USE ENERGY EXPENDITURES (B 2009$)	7.22	6.81	20.24	13.73	8.64	10.06	16.25	9.03	10.21	2.71	25.31	3.19	6.84	3.63	19.81	10.59
liquids	(4.45)	(3.01)	(5.94)	(6.31)	1.05	1.66	(1.39)	(4.34)	1.83	(2.86)	(0.27)	(9.74)	(4.43)	(5.17)	(7.34)	(9.37)
natural gas	6.25	5.18	14.47	10.71	4.12	4.18	10.00	7.37	4.49	2.65	13.90	6.65	5.12	3.70	12.99	9.47
electricity	5.47	4.71	11.80	9.44	3.50	4.26	7.68	6.07	3.94	2.94	11.78	6.39	6.24	5.19	14.31	10.65
coal	(0.05)	(0.07)	(0.08)	(0.11)	(0.03)	(0.04)	(0.03)	(0.06)	(0.04)	(0.03)	(0.09)	(0.11)	(0.08)	(0.09)	(0.15)	(0.16)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.37)	(0.38)	(0.70)	(0.71)	(0.37)	(0.39)	(0.60)	(0.65)	(0.28)	(0.20)	(0.60)	(0.42)	(0.38)	(0.39)	(0.73)	(0.72)
liquids	(0.00)	(0.02)	(0.01)	(0.02)	(0.01)	0.00	0.06	0.06	(0.03)	0.03	(0.01)	0.07	(0.02)	(0.03)	(0.03)	(0.03)
natural gas	(0.31)	(0.32)	(0.57)	(0.60)	(0.35)	(0.39)	(0.65)	(0.74)	(0.21)	(0.21)	(0.42)	(0.40)	(0.30)	(0.32)	(0.54)	(0.60)
electricity	(0.04)	(0.03)	(0.11)	(0.07)	0.00	0.01	(0.00)	0.04	(0.04)	(0.01)	(0.14)	(0.07)	(0.05)	(0.02)	(0.13)	(0.07)
coal	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)	(0.02)	(0.03)
ELECTRIC GENERATION (billion kWh)	(26.50)	(24.27)	(48.42)	(42.40)	(15.22)	(16.66)	(30.14)	(23.45)	(20.26)	(12.90)	(55.99)	(33.69)	(26.95)	(24.11)	(57.15)	(46.78)
coal	35.15	30.37	62.53	57.20	51.43	44.76	110.39	106.36	48.98	37.46	67.41	56.97	3.71	17.28	18.42	13.07
gas	(67.65)	(58.89)	(122.48)	(113.16)	(69.19)	(62.06)	(145.72)	(143.53)	(80.58)	(65.43)	(146.91)	(115.24)	(43.30)	(51.13)	(96.88)	(82.41)
nuclear	-	(0.00)	-	-	0.00	0.00	0.00	5.55	1.54	1.60	3.32	1.59	0.58	0.00	0.71	0.00
renewables	4.72	2.92	8.41	10.87	1.76	0.46	4.07	7.23	9.49	13.65	18.61	22.69	11.85	9.87	17.57	20.33
other	1.28	1.33	3.12	2.68	0.77	0.19	1.12	0.94	0.30	(0.19)	1.58	0.31	0.20	(0.13)	3.02	2.22
PRIMARY ENERGY (quadrillion Btu)																
Consumption	(0.16)	(0.20)	(0.35)	(0.29)	(0.13)	(0.13)	(0.05)	(0.04)	(0.13)	(0.02)	(0.53)	(0.12)	(0.25)	(0.18)	(0.50)	(0.49)
Imports	(0.30)	(0.26)	(0.33)	(0.47)	(0.03)	0.05	0.23	0.19	0.16	0.20	0.23	0.18	(0.22)	(0.30)	(0.17)	(0.54)
Exports	2.21	2.21	4.37	4.41	2.21	2.22	4.40	4.43	2.20	2.19	4.35	4.41	2.20	2.21	4.35	4.39
Production	2.41	2.30	4.42	4.69	2.16	2.10	4.32	4.38	1.93	2.00	3.65	4.18	2.20	2.36	4.07	4.49
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	21.67	16.67	40.79	38.07	29.94	28.31	77.52	72.61	19.31	21.85	20.25	35.98	(3.33)	4.21	0.43	(0.93)

Table B5. U.S. Annual Average Values from 2015 to 2035

	Reference					High Shale EUR					Low Shale EUR					High Macroeconomic Growth				
	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid	baseline	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																				
Net Exports	(1.31)	0.57	0.78	1.81	2.63	(0.63)	1.21	1.41	2.44	3.24	(2.40)	(0.70)	(0.60)	0.52	1.21	(1.45)	0.44	0.64	1.60	2.49
gross imports	3.31	3.35	3.35	3.42	3.43	2.84	2.94	2.95	3.01	3.04	4.13	4.36	4.46	4.44	4.59	3.40	3.45	3.45	3.59	3.53
gross exports	2.00	3.93	4.13	5.23	6.06	2.22	4.15	4.35	5.45	6.28	1.73	3.66	3.86	4.96	5.79	1.95	3.88	4.09	5.19	6.02
Dry Production	24.18	25.37	25.52	26.24	26.78	27.48	28.71	28.86	29.52	29.95	20.40	21.47	21.51	22.28	22.86	25.37	26.75	26.83	27.60	28.26
shale gas	9.65	10.51	10.63	11.10	11.56	13.70	14.67	14.79	15.30	15.67	4.56	5.23	5.37	5.64	6.08	10.47	11.48	11.58	12.08	12.62
other	14.54	14.85	14.89	15.15	15.21	13.78	14.04	14.06	14.22	14.28	15.84	16.24	16.14	16.64	16.78	14.90	15.27	15.25	15.53	15.65
Delivered Volumes (1)	23.67	22.91	22.85	22.52	22.20	26.12	25.46	25.41	25.00	24.61	21.12	20.42	20.36	19.97	19.81	24.92	24.35	24.23	24.01	23.75
electric generators	7.06	6.58	6.57	6.36	6.18	8.64	8.26	8.28	7.98	7.77	5.44	4.97	4.98	4.69	4.66	7.63	7.36	7.29	7.18	7.09
industrial	8.10	7.92	7.88	7.81	7.72	8.62	8.42	8.38	8.31	8.18	7.60	7.46	7.42	7.38	7.29	8.59	8.39	8.34	8.27	8.16
residential	4.82	4.79	4.78	4.76	4.75	4.94	4.91	4.91	4.89	4.88	4.66	4.62	4.61	4.59	4.57	4.95	4.92	4.91	4.90	4.87
commercial	3.58	3.53	3.52	3.49	3.47	3.78	3.73	3.72	3.70	3.68	3.34	3.28	3.27	3.24	3.22	3.64	3.59	3.58	3.56	3.53
NATURAL GAS END-USE PRICES (2009$/Mcf)																				
residential	12.04	12.53	12.57	12.91	13.08	10.61	10.95	11.02	11.22	11.35	14.35	14.98	15.06	15.55	15.69	12.63	13.10	13.13	13.45	13.68
commercial	9.91	10.39	10.44	10.76	10.93	8.49	8.80	8.88	9.06	9.18	12.24	12.88	12.95	13.46	13.60	10.49	10.95	10.98	11.29	11.50
industrial	6.20	6.76	6.80	7.26	7.44	4.90	5.32	5.41	5.69	5.86	8.38	9.07	9.15	9.71	9.84	6.69	7.26	7.29	7.75	7.99
OTHER PRICES																				
Natural Gas Wellhead Price (2009$/Mcf)	5.28	5.78	5.82	6.23	6.39	4.01	4.35	4.42	4.66	4.79	7.37	8.06	8.16	8.71	8.87	5.75	6.25	6.28	6.69	6.90
Henry Hub Price (2009$/MMBtu)	5.81	6.36	6.41	6.86	7.03	4.41	4.79	4.87	5.12	5.27	8.12	8.88	8.98	9.60	9.77	6.33	6.88	6.91	7.36	7.60
Coal Minemouth Price (2009$/short-ton)	33.06	33.12	33.15	33.29	33.18	32.77	33.07	32.87	32.99	33.00	33.34	33.64	33.50	33.38	33.46	33.74	33.60	33.52	33.66	33.72
End-Use Electricity Price (2009 cents/KWh)	8.94	9.08	9.08	9.19	9.22	8.56	8.63	8.67	8.70	8.70	9.65	9.81	9.83	10.00	10.02	9.29	9.46	9.45	9.60	9.62
NATURAL GAS REVENUES (B 2009$)																				
Export Revenues (2)	11.13	25.11	26.34	37.49	43.23	8.98	19.64	20.80	28.85	33.39	15.07	34.12	35.85	50.80	58.30	12.11	27.19	28.43	40.19	46.69
Domestic Supply Revenues (3)	179.79	198.43	200.12	215.08	221.64	165.83	179.88	182.38	191.82	196.70	200.15	222.46	224.55	243.87	251.43	201.24	222.30	223.13	239.62	248.66
production revenues (4)	128.46	147.79	149.40	165.76	172.31	110.87	125.92	128.47	139.27	144.50	151.06	173.98	176.05	196.01	203.32	147.54	169.19	169.97	187.82	196.82
delivery revenues (5)	51.32	50.64	50.72	49.32	49.33	54.96	53.96	53.92	52.55	52.21	49.09	48.48	48.50	47.86	48.12	53.70	53.12	53.16	51.79	51.84
Import Revenues (6)	17.77	19.53	19.69	21.37	22.03	11.92	13.52	13.84	14.94	15.61	30.84	34.49	35.15	37.10	38.16	19.97	21.90	22.09	24.07	24.58
END-USE ENERGY EXPENDITURES (B 2009$)	1,489.93	1,499.04	1,499.79	1,507.51	1,510.31	1,455.15	1,463.17	1,465.18	1,469.08	1,469.35	1,547.09	1,561.08	1,559.57	1,572.52	1,567.30	1,625.45	1,635.66	1,634.71	1,644.67	1,646.03
liquids	974.71	973.09	973.49	972.64	972.64	970.30	971.23	971.23	970.91	969.68	981.60	983.31	980.57	982.05	975.74	1,063.35	1,061.47	1,060.75	1,060.30	1,058.97
natural gas	140.16	146.09	146.41	151.27	152.79	124.61	128.76	129.62	132.45	133.62	165.55	172.70	173.21	179.55	180.30	154.27	160.27	160.24	165.41	167.51
electricity	368.28	373.10	373.13	376.85	378.14	353.56	356.51	357.67	359.05	359.38	393.11	398.26	398.98	404.14	404.50	400.29	406.41	406.21	411.48	412.09
coal	6.78	6.76	6.75	6.75	6.74	6.68	6.68	6.67	6.68	6.67	6.83	6.81	6.81	6.78	6.76	7.54	7.51	7.50	7.48	7.46
END-USE ENERGY CONSUMPTION (quadrillion Btu)	69.09	68.81	68.75	68.64	68.49	69.93	69.65	69.59	69.52	69.37	67.90	67.61	67.58	67.42	67.33	72.62	72.33	72.26	72.14	71.97
liquids	37.29	37.30	37.29	37.31	37.31	37.21	37.23	37.24	37.28	37.28	37.24	37.23	37.25	37.25	37.28	39.42	39.43	39.42	39.43	39.44
natural gas	16.15	15.90	15.85	15.76	15.61	17.04	16.76	16.69	16.58	16.41	15.18	14.95	14.89	14.82	14.69	16.81	16.55	16.49	16.41	16.23
electricity	14.02	13.98	13.98	13.95	13.95	14.05	14.05	14.04	14.04	14.06	13.85	13.81	13.81	13.74	13.74	14.64	14.60	14.61	14.55	14.56
coal	1.63	1.63	1.63	1.63	1.62	1.62	1.62	1.62	1.62	1.62	1.63	1.62	1.62	1.62	1.61	1.76	1.75	1.75	1.74	1.74
ELECTRIC GENERATION (billion kWh)	4,691.78	4,671.70	4,670.36	4,660.47	4,654.31	4,740.10	4,728.42	4,724.32	4,720.03	4,717.90	4,599.04	4,578.46	4,576.69	4,554.90	4,551.26	4,907.86	4,886.10	4,884.89	4,868.85	4,864.09
coal	2,030.24	2,078.96	2,083.33	2,100.15	2,121.75	1,860.54	1,912.06	1,912.09	1,949.35	1,977.66	2,171.63	2,216.91	2,212.07	2,221.68	2,224.94	2,114.85	2,134.13	2,149.63	2,144.11	2,158.39
gas	1,074.40	1,000.10	995.54	963.40	932.18	1,328.06	1,262.83	1,259.57	1,215.21	1,175.80	808.02	735.39	733.01	695.09	685.68	1,181.25	1,129.59	1,115.49	1,096.96	1,074.83
nuclear	871.23	871.23	871.23	871.23	871.23	854.18	854.18	854.18	854.53	859.21	871.23	872.04	872.07	872.97	872.07	871.23	871.54	871.23	871.61	871.23
renewables	655.74	660.26	658.89	663.43	666.81	636.24	637.87	637.72	639.17	643.29	684.94	690.77	696.38	700.70	704.42	678.14	688.13	686.04	691.94	695.77
other	60.17	61.15	61.37	62.26	62.34	61.08	61.49	60.76	61.77	61.93	63.21	63.35	63.16	64.47	64.16	62.38	62.71	62.50	64.24	63.86
PRIMARY ENERGY (quadrillion Btu)																				
Consumption	107.97	107.90	107.87	107.85	107.85	108.38	108.31	108.27	108.38	108.37	107.04	106.89	106.89	106.66	106.70	113.05	112.91	112.92	112.81	112.71
Imports	28.28	28.20	28.21	28.18	28.19	27.27	27.28	27.34	27.47	27.49	29.50	29.62	29.68	29.71	29.75	30.17	30.14	30.09	30.17	30.02
Exports	7.48	9.43	9.63	10.73	11.57	7.69	9.64	9.86	10.96	11.81	7.19	9.12	9.32	10.41	11.25	7.53	9.47	9.68	10.77	11.61
Production	87.04	89.04	89.18	90.30	91.17	88.73	90.66	90.77	91.94	92.73	84.52	86.20	86.35	87.18	88.04	90.24	92.09	92.35	93.26	94.16
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	5,955.05	5,985.66	5,986.04	6,001.82	6,013.46	5,915.71	5,947.04	5,946.80	5,977.68	5,991.27	5,960.10	5,981.23	5,978.85	5,976.06	5,984.27	6,270.24	6,279.14	6,286.47	6,283.68	6,290.23

Table B6. Differential from Base in U.S. Average Annual Values from 2015 to 2035 when Exports are Added

	Reference				High Shale EUR				Low Shale EUR				High Macroeconomic Growth			
	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid	low/ slow	low/ rapid	high/ slow	high/ rapid
NATURAL GAS VOLUMES (Tcf)																
Net Exports	1.89	2.10	3.12	3.95	1.84	2.03	3.06	3.87	1.70	1.81	2.92	3.61	1.89	2.09	3.05	3.94
gross imports	0.04	0.04	0.11	0.12	0.09	0.10	0.17	0.20	0.23	0.33	0.31	0.46	0.04	0.05	0.19	0.13
gross exports	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07	1.93	2.14	3.23	4.07
Dry Production	1.18	1.33	2.06	2.59	1.23	1.38	2.04	2.47	1.06	1.11	1.88	2.45	1.38	1.46	2.23	2.89
shale gas	0.86	0.98	1.45	1.91	0.97	1.09	1.60	1.97	0.67	0.81	1.08	1.52	1.01	1.11	1.61	2.15
other	0.32	0.35	0.61	0.68	0.26	0.28	0.44	0.50	0.40	0.30	0.80	0.93	0.37	0.35	0.62	0.74
Delivered Volumes (1)	(0.76)	(0.82)	(1.15)	(1.47)	(0.66)	(0.71)	(1.12)	(1.51)	(0.71)	(0.77)	(1.15)	(1.31)	(0.57)	(0.69)	(0.91)	(1.17)
electric generators	(0.48)	(0.49)	(0.70)	(0.88)	(0.38)	(0.36)	(0.66)	(0.87)	(0.46)	(0.46)	(0.75)	(0.78)	(0.27)	(0.34)	(0.45)	(0.54)
industrial	(0.18)	(0.22)	(0.29)	(0.38)	(0.19)	(0.24)	(0.31)	(0.44)	(0.14)	(0.19)	(0.22)	(0.32)	(0.20)	(0.25)	(0.32)	(0.43)
residential	(0.04)	(0.04)	(0.06)	(0.08)	(0.03)	(0.04)	(0.05)	(0.06)	(0.04)	(0.05)	(0.07)	(0.09)	(0.04)	(0.04)	(0.06)	(0.08)
commercial	(0.05)	(0.06)	(0.09)	(0.11)	(0.05)	(0.06)	(0.08)	(0.10)	(0.06)	(0.07)	(0.10)	(0.12)	(0.05)	(0.06)	(0.08)	(0.11)
NATURAL GAS END-USE PRICES (2009$/Mcf)																
residential	0.49	0.53	0.87	1.04	0.33	0.41	0.60	0.73	0.64	0.71	1.20	1.34	0.47	0.50	0.82	1.05
commercial	0.48	0.52	0.84	1.02	0.31	0.39	0.57	0.69	0.64	0.71	1.22	1.35	0.46	0.49	0.80	1.02
industrial	0.56	0.60	1.07	1.24	0.42	0.51	0.79	0.96	0.69	0.77	1.33	1.46	0.57	0.60	1.06	1.30
OTHER PRICES																
Natural Gas Wellhead Price (2009$/Mcf)	0.50	0.54	0.95	1.11	0.34	0.42	0.65	0.79	0.69	0.79	1.34	1.50	0.50	0.52	0.94	1.15
Henry Hub Price (2009$/MMBtu)	0.55	0.59	1.05	1.22	0.38	0.46	0.72	0.87	0.77	0.87	1.48	1.65	0.55	0.58	1.03	1.26
Coal Minemouth Price (2009$/short-ton)	0.06	0.09	0.22	0.12	0.30	0.11	0.22	0.24	0.29	0.16	0.04	0.12	(0.14)	(0.22)	(0.08)	(0.02)
End-Use Electricity Price (2009 cents/KWh)	0.14	0.14	0.25	0.29	0.07	0.10	0.13	0.13	0.16	0.18	0.35	0.37	0.17	0.16	0.31	0.33
NATURAL GAS REVENUES (B 2009$)																
Export Revenues (2)	13.99	15.22	26.36	32.10	10.66	11.82	19.87	24.41	19.05	20.78	35.73	43.23	15.08	16.32	28.08	34.57
Domestic Supply Revenues (3)	18.64	20.34	35.29	41.85	14.05	16.55	25.99	30.88	22.30	24.39	43.72	51.28	21.06	21.88	38.37	47.42
production revenues (4)	19.33	20.94	37.29	43.84	15.05	17.60	28.40	33.63	22.92	24.98	44.95	52.25	21.64	22.43	40.28	49.28
delivery revenues (5)	(0.69)	(0.60)	(2.00)	(1.99)	(1.00)	(1.04)	(2.41)	(2.75)	(0.61)	(0.59)	(1.23)	(0.97)	(0.58)	(0.54)	(1.91)	(1.86)
Import Revenues (6)	1.76	1.93	3.60	4.26	1.60	1.92	3.02	3.69	3.65	4.31	6.26	7.31	1.93	2.12	4.11	4.61
END-USE ENERGY EXPENDITURES (B 2009$)	9.11	9.86	17.59	20.39	8.02	10.03	13.93	14.19	13.98	12.47	25.42	20.21	10.22	9.26	19.22	20.58
liquids	(1.63)	(1.22)	(2.07)	(2.07)	0.92	0.92	0.61	(0.62)	1.70	(1.04)	0.45	(5.86)	(1.88)	(2.60)	(3.05)	(4.38)
natural gas	5.94	6.26	11.12	12.63	4.15	5.01	7.84	9.01	7.15	7.66	14.00	14.75	6.00	5.98	11.14	13.24
electricity	4.82	4.86	8.57	9.87	2.95	4.11	5.49	5.82	5.15	5.87	11.03	11.39	6.12	5.92	11.19	11.80
coal	(0.02)	(0.03)	(0.03)	(0.04)	(0.01)	(0.02)	(0.00)	(0.02)	(0.02)	(0.02)	(0.05)	(0.07)	(0.03)	(0.04)	(0.06)	(0.08)
END-USE ENERGY CONSUMPTION (quadrillion Btu)	(0.28)	(0.34)	(0.45)	(0.60)	(0.27)	(0.34)	(0.41)	(0.55)	(0.29)	(0.32)	(0.48)	(0.57)	(0.30)	(0.36)	(0.49)	(0.65)
liquids	0.01	0.00	0.03	0.03	0.02	0.02	0.06	0.07	(0.01)	0.02	0.01	0.04	0.02	0.00	0.02	0.02
natural gas	(0.25)	(0.30)	(0.40)	(0.54)	(0.28)	(0.35)	(0.46)	(0.63)	(0.23)	(0.29)	(0.36)	(0.49)	(0.27)	(0.33)	(0.41)	(0.58)
electricity	(0.04)	(0.03)	(0.07)	(0.07)	(0.00)	(0.00)	(0.00)	0.02	(0.05)	(0.05)	(0.11)	(0.11)	(0.04)	(0.03)	(0.09)	(0.08)
coal	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.02)
ELECTRIC GENERATION (billion kWh)	(20.08)	(21.43)	(31.31)	(37.47)	(11.67)	(15.77)	(20.07)	(22.20)	(20.58)	(22.35)	(44.13)	(47.78)	(21.76)	(22.98)	(39.01)	(43.78)
coal	48.72	53.09	69.91	91.51	51.52	51.55	88.82	117.12	45.28	40.44	50.04	53.31	19.28	34.78	29.25	43.53
gas	(74.30)	(78.86)	(111.00)	(142.22)	(65.24)	(68.49)	(112.86)	(152.26)	(72.63)	(75.01)	(112.93)	(122.34)	(51.66)	(65.76)	(84.29)	(106.42)
nuclear	-	(0.00)	-	-	0.00	0.00	0.35	5.02	0.81	0.84	1.74	0.83	0.30	0.00	0.37	0.00
renewables	4.52	3.15	7.69	11.07	1.63	1.48	2.94	7.06	5.84	11.44	15.76	19.48	9.99	7.89	13.80	17.63
other	0.98	1.20	2.09	2.17	0.41	(0.32)	0.69	0.86	0.13	(0.06)	1.25	0.94	0.33	0.11	1.86	1.48
PRIMARY ENERGY (quadrillion Btu)																
Consumption	(0.07)	(0.10)	(0.12)	(0.12)	(0.06)	(0.11)	0.01	(0.00)	(0.15)	(0.15)	(0.38)	(0.34)	(0.13)	(0.13)	(0.24)	(0.34)
Imports	(0.09)	(0.08)	(0.10)	(0.10)	0.01	0.07	0.20	0.22	0.12	0.18	0.21	0.25	(0.03)	(0.07)	0.00	(0.15)
Exports	1.94	2.15	3.25	4.09	1.96	2.17	3.28	4.12	1.93	2.13	3.22	4.06	1.94	2.15	3.24	4.08
Production	2.00	2.14	3.26	4.13	1.93	2.03	3.20	4.00	1.68	1.83	2.66	3.52	1.85	2.11	3.02	3.92
ENERGY RELATED CO_2 EMISSIONS (including liquefaction)(million metric tons)	30.62	30.99	46.77	58.42	31.33	31.09	61.96	75.56	21.14	18.75	15.96	24.18	8.90	16.23	13.44	19.99

FOOTNOTES
(1) total includes components below plus deliveries to the transportation sector
(2) export volumes added for this study times the Henry Hub price plus an assumed transport fee to the liquefaction facility of 20 cents per Mcf, plus sum of all other export volumes (i.e., to Canada and Mexico) times the associated price at the border
(3) represents producer revenues at the wellhead plus other revenues extracted before final gas delivery.
(4) dry gas production times average wellhead or first-purchase price
(5) represented revenues extracted as gas moves from the first-purchase wellhead price to final delivery
(6) import volumes times the associated price at the border

Projections: EIA, Annual Energy Outlook 2011 National Energy Modeling system runs ref2011.d020911a, rflexslw.d090911a, rflexrpd.d090911a, rfhexslw.d090911a, rfhesrpd.d090911a, hshleur.d020911a, helexslw.d090911a, helexrpd.d090911a, hehexslw.d090911a, hehexrpd.d090911a, feleur.d090811a, lelexslw.d090911a, lelexrpd.d090911a, lehexslw.d090911a, lehexrpd.d090911a, fehdem.d090811a, hmlexslw.d090911a, hmlexrpd.d090911a, hmhexslw.d090911a, hmhexrpd.d090911a

Exhibit 4

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Washington, DC 20585

December 3, 2012

Attn: Deputy Assistant Secretary Christopher Smith

Dear Mr. Smith

I am transmitting with this letter a clean copy of NERA's report on the macroeconomic impacts of LNG exports from the United States that was contracted for by the Department of Energy.

Sincerely,

W. David Montgomery
Senior Vice President

Enclosure

document8

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Macroeconomic Impacts of LNG Exports from the United States

NERA
Economic Consulting

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[1] The opinions expressed herein do not necessarily represent the views of NERA Economic Consulting or any other NERA consultant.

Contents

Table of Figures

List of Acronyms

AEO 2011	Annual Energy Outlook 2011	GNP	Gross national product
AGR	Agricultural sector	IEA WEO	International Energy Agency World Energy Outlook
CES	Constant elasticity of substitution	IEO	International Energy Outlook
COL	Coal sector	JCC	Japanese Customs-cleared crude
CRU	Crude oil sector	LNG	Liquefied natural gas
DOE/FE	U.S. Department of Energy, Office of Fossil Energy	M_V	Motor Vehicle manufacturing sector
EIA	Energy Information Administration	MAN	Other manufacturing sector
EIS	Energy-intensive sector	Mcf	Thousand cubic feet
EITE	Energy-intensive trade exposed	MMBtu	Million British thermal units
ELE	Electricity sector	MMTPA	Million metric tonne per annum
EUR	Estimated ultimate recovery	NAICS	North American Industry Classification System
FDI	Foreign direct investment	NBP	National Balancing Point
FSU	Former Soviet Union	OIL	Refining sector
GAS	Natural gas sector	SRV	Commercial sector
GDP	Gross domestic product	Tcf	Trillion cubic feet
GIIGNL	International Group of LNG Importers	TRK	Commercial trucking sector
GNGM	Global Natural Gas Model	TRN	Other commercial transportation sector

Scenario Naming Convention

The following is the naming convention used for all the scenarios. Lists of all the possible U.S., international, U.S. LNG export, and quota rent cases are shown below.

Generic Naming Convention:

U.S. Case_International Case_U.S. LNG Export Case_Quota Rent Case

U.S. Cases:

USREF	US Reference case
HEUR	High Shale EUR
LEUR	Low Shale EUR

International Cases:

INTREF	International Reference case
D	International Demand Shock
SD	International Supply/Demand Shock

U.S. LNG Export Cases

NX	No-Export Capacity	LS	Low/Slow	HS	High/Slow
LSS	Low/Slowest	LR	Low/Rapid	HR	High/Rapid
NC	No-Export Constraint				

Quota Rent Cases:

HEUR_SD_LSS_QR	US High Shale EUR with International Supply/Demand Shock at Low/Slowest export levels with quota rent
HEUR_SD_HR_QR	US High Shale EUR with International Supply/Demand Shock at High/Rapid export levels with quota rent

N$_{ew}$Era Baselines:

Bau_REF	No LNG export expansion case consistent with AEO 2011 Reference case
Bau_HEUR	No LNG export expansion case consistent with AEO 2011 High Shale EUR case
Bau_LEUR	No LNG export expansion case consistent with AEO 2011 Low Shale EUR case

Scenarios Analyzed by N$_{ew}$Era

USREF_D_LSS	US Reference case with International Demand Shock and lower than Low/Slowest export levels
USREF_D_LS	US Reference case with International Demand Shock and lower than Low/Slow export levels
USREF_D_LR	US Reference case with International Demand Shock and lower than Low/Rapid export levels
USREF_SD_LS	US Reference case with International Supply/Demand Shock at Low/Slow export levels
USREF_SD_LR	US Reference case with International Supply/Demand Shock at Low/Rapid export levels
USREF_SD_HS	US Reference case with International Supply/Demand Shock and lower than High/Slow export levels
USREF_SD_HR	US Reference case with International Supply/Demand Shock and lower than High/Rapid export levels
USREF_SD_NC	US Reference case with International Supply/Demand Shock and No Constraint on exports
HEUR_D_NC	US High Shale EUR with International Demand Shock and No Constraint on exports
HEUR_SD_LSS	US High Shale EUR with International Supply/Demand Shock at Low/Slowest export levels
HEUR_SD_LS	US High Shale EUR with International Supply/Demand Shock at Low/Slow export levels
HEUR_SD_LR	US High Shale EUR with International Supply/Demand Shock at Low/Rapid export levels
HEUR_SD_HS	US High Shale EUR with International Supply/Demand Shock at High/Slow export levels
HEUR_SD_HR	US High Shale EUR with International Supply/Demand Shock at High/Rapid export levels
HEUR_SD_NC	US High Shale EUR with International Supply/Demand Shock and No Constraint on exports
LEUR_SD_LSS	US Low Shale EUR with International Supply/Demand Shock at Low/Slowest export levels

EXECUTIVE SUMMARY

Approach

At the request of the U.S. Department of Energy, Office of Fossil Energy ("DOE/FE"), NERA Economic Consulting assessed the potential macroeconomic impact of liquefied natural gas ("LNG") exports using its energy-economy model (the "N_{ew}ERA" model). NERA built on the earlier U.S. Energy Information Administration ("EIA") study requested by DOE/FE by calibrating its U.S. natural gas supply model to the results of the study by EIA. The EIA study was limited to the relationship between export levels and domestic prices without considering whether or not those quantities of exports could be sold at high enough world prices to support the calculated domestic prices. The EIA study did not evaluate macroeconomic impacts.

NERA's Global Natural Gas Model ("GNGM") was used to estimate expected levels of U.S. LNG exports under several scenarios for global natural gas supply and demand.

NERA's N_{ew}ERA energy-economy model was used to determine the U.S. macroeconomic impacts resulting from those LNG exports.

Key Findings

This report contains an analysis of the impact of exports of LNG on the U.S. economy under a wide range of different assumptions about levels of exports, global market conditions, and the cost of producing natural gas in the U.S. These assumptions were combined first into a set of scenarios that explored the range of fundamental factors driving natural gas supply and demand. These market scenarios ranged from relatively normal conditions to stress cases with high costs of producing natural gas in the U.S. and exceptionally large demand for U.S. LNG exports in world markets. The economic impacts of different limits on LNG exports were examined under each of the market scenarios. Export limits were set at levels that ranged from zero to unlimited in each of the scenarios.

Across all these scenarios, the U.S. was projected to gain net economic benefits from allowing LNG exports. Moreover, for every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased. In particular, scenarios with unlimited exports always had higher net economic benefits than corresponding cases with limited exports.

In all of these cases, benefits that come from export expansion more than outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports have net economic benefits in spite of higher domestic natural gas prices. This is exactly the outcome that economic theory describes when barriers to trade are removed.

Net benefits to the U.S. would be highest if the U.S. becomes able to produce large quantities of gas from shale at low cost, if world demand for natural gas increases rapidly, and if LNG supplies from other regions are limited. If the promise of shale gas is not fulfilled and costs of producing gas in the U.S. rise substantially, or if there are ample supplies of LNG from other regions to satisfy world demand, the U.S. would not export LNG. Under these conditions, allowing exports of LNG would cause no change in natural gas prices and do no harm to the overall economy.

U.S. natural gas prices increase when the U.S. exports LNG. But the global market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if U.S. wellhead price rises above the cost of competing supplies. In particular, the U.S. natural gas price does not become linked to oil prices in any of the cases examined.

Natural gas price changes attributable to LNG exports remain in a relatively narrow range across the entire range of scenarios. Natural gas price increases at the time LNG exports could begin range from zero to $0.33 (2010$/Mcf). The largest price increases that would be observed after 5 more years of potentially growing exports could range from $0.22 to $1.11 (2010$/Mcf). The higher end of the range is reached only under conditions of ample U.S. supplies and low domestic natural gas prices, with smaller price increases when U.S. supplies are more costly and domestic prices higher.

How increased LNG exports will affect different socioeconomic groups will depend on their income sources. Like other trade measures, LNG exports will cause shifts in industrial output and employment and in sources of income. Overall, both total labor compensation and income from investment are projected to decline, and income to owners of natural gas resources will increase. Different socioeconomic groups depend on different sources of income, though through retirement savings an increasingly large number of workers share in the benefits of higher income to natural resource companies whose shares they own. Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or government transfers, in particular, might not participate in these benefits.

Serious competitive impacts are likely to be confined to narrow segments of industry. About 10% of U.S. manufacturing, measured by value of shipments, has both energy expenditures greater than 5% of the value of its output and serious exposure to foreign competition. Employment in industries with these characteristics is about one-half of one percent of total U.S. employment.

LNG exports are not likely to affect the overall level of employment in the U.S. There will be some shifts in the number of workers across industries, with those industries associated with natural gas production and exports attracting workers away from other industries. In no scenario is the shift in employment out of any industry projected to be larger than normal rates of turnover of employees in those industries.

I. SUMMARY

A. What NERA Was Asked to Do

NERA Economic Consulting was asked by the DOE/FE to use its N_{ew}ERA model to evaluate the macroeconomic impact of LNG exports. NERA's analysis follows on from the study of impacts of LNG exports on U.S. natural gas prices performed by the U.S. EIA "Effect of Increased Natural Gas Exports on Domestic Energy Markets," hereafter referred to as the "EIA Study."[2]

NERA's analysis addressed the same 16 scenarios for LNG exports analyzed by EIA. These scenarios incorporated different assumptions about U.S. natural gas supply and demand and different export levels as specified by DOE/FE:

- U.S. scenarios: Reference, High Demand, High Natural Gas Resource, and Low Natural Gas Resource cases.
- U.S. LNG export levels reflecting either slow or rapid increases to limits of
  - Low Level: 6 billion cubic feet per day
  - High Level: 12 billion cubic feet per day

DOE also asked NERA to examine a lower export level, with capacity rising at a slower rate to 6 billion cubic feet per day and cases with no export constraints.

The EIA study was confined to effects of specified levels of exports on natural gas prices within the U.S. EIA was not asked to estimate the price that foreign purchasers would be willing to pay for the specified quantities of exports. The EIA study, in other words, was limited to the relationship between export levels and domestic prices without, for example, considering whether or not those quantities of exports could be sold at high enough world prices to support the calculated domestic prices. Thus before carrying out its macroeconomic analysis, NERA had to estimate the export or world prices at which various quantities of U.S. LNG exports could be sold on the world market. This proved quite important in that NERA concluded that in many cases, the world natural gas market would not accept the full amount of exports assumed in the EIA scenarios at export prices high enough to cover the U.S. wellhead domestic prices calculated by the EIA.

To evaluate the feasibility of exporting the specified quantities of natural gas, NERA developed additional scenarios for global natural gas supply and demand, yielding a total of 63 scenarios when the global and U.S. scenarios were combined. NERA then used the GNGM to estimate the market-determined export price that would be received by exporters of natural gas from the United States in the combined scenarios.

NERA selected 13 of these scenarios that spanned the range of economic impacts from all the scenarios for discussion in this report and eliminated scenarios that had essentially identical

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2 Available at: www.eia.gov/analysis/requests/fe/.

outcomes for LNG exports and prices.[3] These scenarios are described in Figure 1. NERA then analyzed impacts on the U.S. economy of these levels of exports and the resulting changes in the U.S. trade balance and in natural gas prices, supply, and demand.

Figure 1: Feasible Scenarios Analyzed in the Macroeconomic Model

U.S. Market Outlook	Reference		High Shale EUR		Low Shale EUR	
Int'l Market Outlook	**Demand Shock**	**Supply/ Demand Shock**	**Demand Shock**	**Supply/ Demand Shock**	**Demand Shock**	**Supply/ Demand Shock**
Export Volume/ Pace	**Scenario Name**					
Low/Slow	**USREF_D_LS**	*USREF_SD_LS*		*HEUR_SD_LS*		
Low/Rapid	**USREF_D_LR**	*USREF_SD_LR*		*HEUR_SD_LR*		
High/Slow		**USREF_SD_HS**		*HEUR_SD_HS*		
High/Rapid		**USREF_SD_HR**		*HEUR_SD_HR*		
Low/ Slowest	**USREF_D_LSS**			*HEUR_SD_LSS*		**LEUR_SD_LSS**

Scenarios in italics use DOE/FE defined export volumes.
Scenarios in bold use NERA determined export volumes.
Results for all cases are provided in Appendix C.

The three scenarios chosen for the U.S. resource outlook were the EIA Reference cases, based on the Annual Energy Outlook ("AEO") 2011, and two cases assuming different levels of estimated ultimate recovery ("EUR") from new gas shale development. Outcomes of the EIA high demand case fell between the high and low EUR cases and therefore would not have changed the range of results. The three different international outlooks were a reference case, based on the EIA International Energy Outlook ("IEO") 2011, a Demand Shock case with increased worldwide natural gas demand caused by shutdowns of some nuclear capacity, and a Supply/Demand Shock case which added to the Demand Shock a supply shock that assumed key LNG exporting regions did not increase their exports above current levels.

NERA concluded that in many cases the world natural gas market would not accept the full amount of exports specified by FE in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA. In particular, NERA found that there would be no U.S. exports in the International Reference case with U.S. Reference case conditions. In the U.S. Reference case with an International Demand Shock, exports were projected but in quantities below any of the export limits. In these cases, NERA replaced the export levels specified by DOE/FE and prices estimated by EIA with lower levels of exports (and, *a fortiori* prices) estimated by GNGM

[3] The scenarios not presented in this report had nearly identical macroeconomic impacts to those that are included, so that the number of scenarios discussed could be reduced to make the exposition clearer and less duplicative.

that are indicated in bold black in Figure 1. For sensitivity analysis, NERA also examined cases projecting zero exports and also cases with no limit placed on exports.

B. Key Assumptions

All the scenarios were derived from the AEO 2011, and incorporated the assumptions about energy and environmental policies, baseline coal, oil and natural gas prices, economic and energy demand growth, and technology availability and cost in the corresponding AEO cases.

The global LNG market was treated as a largely competitive market with one dominant supplier, Qatar, whose decisions about exports were assumed to be fixed no matter what the level of U.S. exports. U.S. exports compete with those from the other suppliers, who are assumed to behave as competitors and adjust their exports in light of the price they are offered. In this market, LNG exports from the U.S. necessarily lower the price received by U.S. exporters below levels that might be calculated based on current prices or prices projected without U.S exports, and in particular U.S. natural gas prices do not become linked to world oil prices.

It is outside the scope of this study to analyze alternative responses by other LNG suppliers in order to determine what would be in their best economic interest or how they might behave strategically to maximize their gains. This would require a different kind of model that addresses imperfect competition in global LNG markets and could explain the apparent ability of some large exporters to charge some importing countries at prices higher than the cost of production plus transportation.

Key assumptions in analyzing U.S. economic impacts were as follows: prices for natural gas used for LNG production were based on the U.S. wellhead price plus a percentage markup, the LNG tolling fee was based on a return of capital to the developer, and financing of investment was assumed to originate from U.S. sources. In order to remain consistent with the EIA analysis, the N_{ew}ERA model was calibrated to give the same results for natural gas prices as EIA at the same levels of LNG exports so that the parameters governing natural gas supply and demand in N_{ew}ERA were consistent with EIA's NEMS model.

Results are reported in 5-year intervals starting in 2015. These calendar years should not be interpreted literally but represent intervals after exports begin. Thus if the U.S. does not begin LNG exports until 2016 or later, one year should be added to the dates for each year that exports commence after 2015.

Like other general equilibrium models, N_{ew}ERA is a model of long run economic growth such that in any given year, prices, employment, or economic activity might fluctuate above or below projected levels. It is used in this study not to give unconditional forecasts of natural gas prices, but to indicate how, under different conditions, different decisions about levels of exports would affect the performance of the economy. In this kind of comparison, computable general equilibrium models generally give consistent and robust results.

Consistent with its equilibrium nature, N_{ew}ERA does not address questions of how rapidly the economy will recover from the recession and generally assumes that aggregate unemployment rates remain the same in all cases. As is discussed below, $N_{ew}ERA$ does estimate changes in worker compensation in total and by industry that can serve as an indicator of pressure on labor markets and displacement of workers due to some industries growing more quickly and others less quickly than assumed in the baseline.

C. Key Results

1. Impacts of LNG Exports on U.S. Natural Gas Prices

In its analysis of global markets, NERA found that the U.S. would only be able to market LNG successfully with higher global demand or lower U.S. costs of production than in the Reference cases. The market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if the U.S. wellhead price rises above the cost of competing supplies. In particular, the U.S. natural gas price does not become linked to oil prices in any of the cases examined.

2. Macroeconomic Impacts of LNG Exports are Positive in All Cases

In all of the scenarios analyzed in this study, NERA found that the U.S. would experience net economic benefits from increased LNG exports.[4] Only three of the cases analyzed with the global model had U.S. exports greater than the 12Bcf/d maximum exports allowed in the cases analyzed by EIA. These were the USREF_SD, the HEUR_D and the HEUR_SD cases. NERA estimated economic impacts for these three cases with no constraint on exports, and found that even with exports reaching levels greater than 12 Bcf/d and associated higher prices than in the constrained cases, there were net economic benefits from allowing unlimited exports in all cases.

Across the scenarios, U.S. economic welfare consistently increases as the volume of natural gas exports increased. This includes scenarios in which there are unlimited exports. The reason for this is that even though domestic natural gas prices are pulled up by LNG exports, the value of those exports also rises so that there is a net gain for the U.S. economy measured by a broad metric of economic welfare (Figure 2) or by more common measures such as real household income or real GDP. Although there are costs to consumers of higher energy prices and lower consumption and producers incur higher costs to supply the additional natural gas for export, these costs are more than offset by increases in export revenues along with a wealth transfer from overseas received in the form of payments for liquefaction services. The net result is an increase in U.S. households' real income and welfare.[5]

Net benefits to the U.S. economy could be larger if U.S. businesses were to take more of a merchant role. Based on business models now being proposed, this study assumes that foreign

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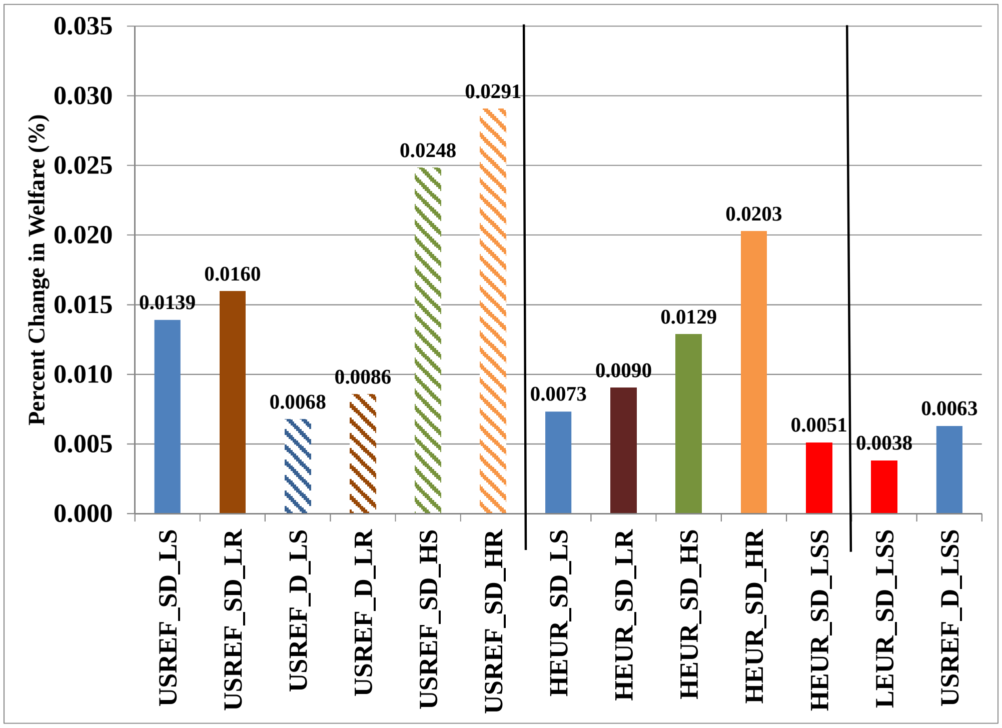
[4] NERA did not run the EIA High Growth case because the results would be similar to the REF case.

[5] In this report, the measure of welfare is technically known as the "equivalent variation" and it is the amount of income that a household would be willing to give up in the case without LNG exports in order to achieve the benefits of LNG exports. It is measured in present value terms, and therefore captures in a single number benefits and costs that might vary year by year over the period.

purchasers take title to LNG when it is loaded at a United States port, so that any profits that could be made by transporting and selling in importing countries accrue to foreign entities. In the cases where exports are constrained to maximum permitted levels, this business model sacrifices additional value from LNG exports that could accrue to the United States.

Figure 2: Percentage Change in Welfare (%)[6]



3. Sources of Income Would Shift

At the same time that LNG exports create higher income in total in the U.S., they shift the composition of income so that both wage income and income from capital investment are reduced. Our measure of total income is GDP measured from the income side, that is, by adding up income from labor, capital and natural resources and adjusting for taxes and transfers. Expansion of LNG exports has two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries, but it also creates two additional sources of income. First, additional income comes in the form of higher export revenues and wealth transfers from incremental LNG exports at higher prices paid by overseas purchasers. Second, U.S. households also benefit from higher natural gas resource income or rents. These benefits distinctly differentiate market-driven expansion of LNG exports from actions that only raise domestic prices without creating additional sources of income. The benefits that come from export expansion more than outweigh the losses from reduced capital and wage income to U.S. consumers, and hence LNG exports have net economic benefits in spite

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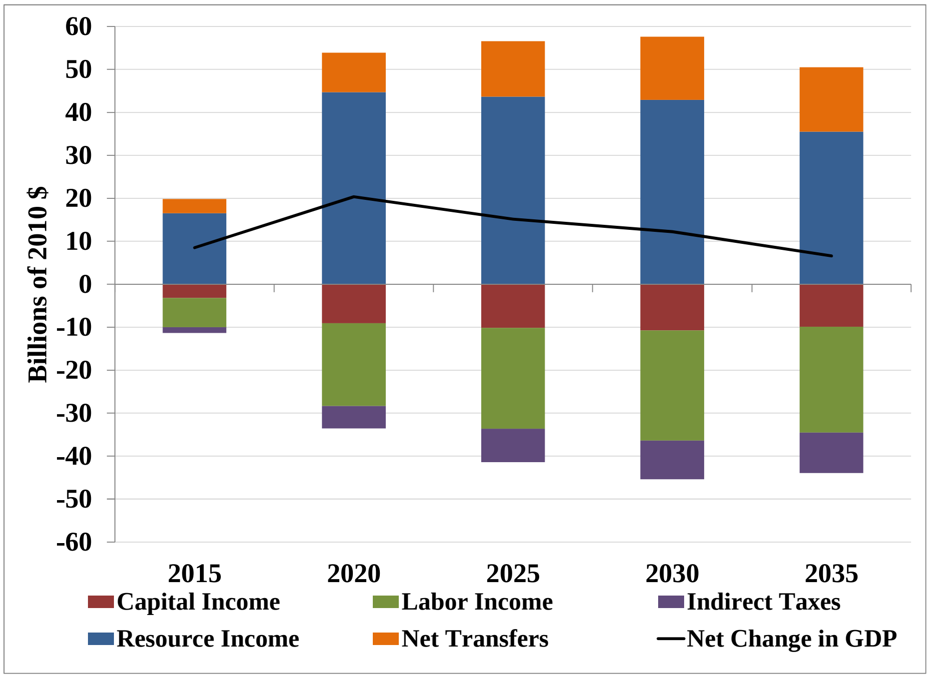
6 Welfare is calculated as a single number that represents in present value terms the amount that households are made better (worse) off over the entire time horizon from 2015 to 2035.

of higher natural gas prices. This is exactly the outcome that economic theory describes when barriers to trade are removed.

Figure 3 illustrates these shifts in income components for the USREF_SD_HR scenario, though the pattern is the same in all. First, Figure 3 shows that GDP increases in all years in this case, as it does in other cases (see Appendix C). Labor and investment income are reduced by about $10 billion in 2015 and $45 billion in 2030, offset by increases in resource income to natural gas producers and property owners and by net transfers that represent that improvement in the U.S. trade balance due to exporting a more valuable product (natural gas). Note that these are positive but, on the scale of the entire economy, very small net effects.

Figure 3: Change in Income Components and Total GDP in USREF_SD_HR (Billions of 2010$)



4. Some Groups and Industries Will Experience Negative Effects of LNG Exports

Different socioeconomic groups depend on different sources of income, though through retirement savings an increasingly large number of workers will share in the benefits of higher income to natural resource companies whose shares they own. Nevertheless, impacts will not be positive for all groups in the economy. Households with income solely from wages or transfers, in particular, will not participate in these benefits.

Higher natural gas prices in 2015 can also be expected to have negative effects on output and employment, particularly in sectors that make intensive use of natural gas, while other sectors not so affected could experience gains. There would clearly be greater activity and employment in natural gas production and transportation and in construction of liquefaction facilities. Figure

4 shows changes in total wage income for the natural gas sector and for other key sectors[7] of the economy in 2015. Overall, declines in output in other sectors are accompanied by similar reductions in worker compensation in those sectors, indicating that there will be some shifting of labor between different industries. However, even in the year of peak impacts the largest change in wage income by industry is no more than 1%, and even if all of this decline were attributable to lower employment relative to the baseline, no sector analyzed in this study would experience reductions in employment more rapid than normal turnover. In fact, most of the changes in real worker compensation are likely to take the form of lower than expected real wage growth, due to the increase in natural gas prices relative to nominal wage growth.

Figure 4: Change in Total Wage Income by Industry in 2015 (%)

	AGR	EIS	ELE	GAS	M_V	MAN	OIL	SRV
USREF_SD_LS	-0.12	-0.13	-0.06	0.88	-0.10	-0.08	0.01	0.00
USREF_SD_LR	-0.22	-0.28	-0.18	2.54	-0.24	-0.19	0.01	-0.04
USREF_D_LS	-0.08	-0.10	-0.06	0.87	-0.08	-0.07	0.00	-0.01
USREF_D_LR	-0.18	-0.23	-0.16	2.35	-0.21	-0.16	0.00	-0.05
USREF_SD_HS	-0.15	-0.18	-0.06	0.88	-0.11	-0.10	0.01	0.00
USREF_SD_HR	-0.27	-0.33	-0.18	2.54	-0.26	-0.22	0.01	-0.03
USREF_D_LSS	-0.06	-0.07	-0.03	0.43	-0.05	-0.04	0.00	0.00
HEUR_SD_LS	-0.10	-0.11	-0.05	0.71	-0.09	-0.07	0.01	0.00
HEUR_SD_LR	-0.19	-0.23	-0.16	2.04	-0.22	-0.16	0.00	-0.04
HEUR_SD_HS	-0.12	-0.14	-0.05	0.71	-0.09	-0.08	0.01	0.00
HEUR_SD_HR	-0.25	-0.30	-0.16	2.05	-0.25	-0.20	0.01	-0.02
HEUR_SD_LSS	-0.06	-0.07	-0.02	0.35	-0.04	-0.04	0.00	0.00
LEUR_SD_LSS	-0.02	-0.02	0.00	0.00	0.00	-0.01	0.00	0.01

5. Peak Natural Gas Export Levels, Specified by DOE/FE for the EIA Study, and Resulting Price Increases Are Not Likely

The export volumes selected by DOE/FE for the EIA Study define the maximum exports allowed in each scenario for the NERA macroeconomic analysis. Based on its analysis of global natural gas supply and demand under different assumptions, NERA projected achievable levels of exports for each scenario. The NERA scenarios that find a lower level of exports than the limits specified by DOE are shown in Figure 5. The cells in italics (red) indicate the years in which the

[7] Other key sectors of the economy include: AGR – Agriculture, EIS-Energy Intensive Sectors, ELE-Electricity, GAS-Natural gas, M_V-Motor Vehicle, MAN-Manufacturing, OIL-Refined Petroleum Products, and SRV-Services.

limit on exports is binding.[8] All scenarios hit the export limits in 2015 except the NERA export volume case with Low/Rapid exports.

Figure 5: NERA Export Volumes (Tcf)

NERA Export Volumes	2015	2020	2025	2030	2035
USREF_D_LS	***0.37***	0.98	1.43	1.19	***2.19***
USREF_D_LR	1.02	0.98	1.43	1.19	1.37
USREF_SD_HS	***0.37***	2.19	3.93	***4.38***	***4.38***
USREF_SD_HR	***1.1***	***2.92***	3.93	***4.38***	***4.38***
USREF_D_LSS	***0.18***	0.98	1.43	1.19	1.37

As seen in Figure 6, in no case does the U.S. wellhead price increase by more than $1.09/Mcf due to market-determined levels of exports. Even in cases in which no limits were placed on exports, competition between the U.S. and competing suppliers of LNG exports and buyer resistance limits increases in both U.S. LNG exports and U.S. natural gas prices.

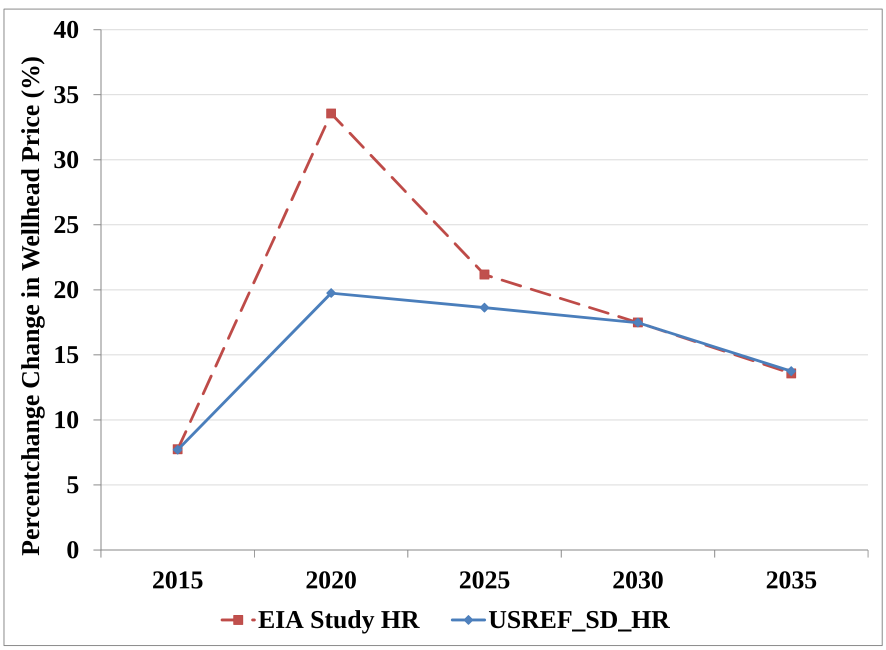
To match the characterization of U.S. supply and demand for natural gas in EIA's NEMS model, NERA calibrated its macroeconomic model so that for the same level of LNG exports as assumed in the EIA Study, the NERA model reproduced the prices projected by EIA. Thus natural gas price responses were similar in scenarios where NERA export volumes were at the EIA export volumes. However, the current study determined that the high export limits were not economic in the U.S. Reference case and that in these scenarios there would be lower exports than assumed by EIA. Because the current study estimated lower export volumes than were specified by FE for the EIA study, U.S. natural gas prices do not reach the highest levels projected by EIA (see Figure 7).

[8] The U.S. LNG export capacity binds when the market equilibrium level of exports as determined by the model exceeds the maximum LNG export capacity assumed in that scenario.

Figure 6: Prices and Export Levels in Representative Scenarios for Year 2035

U.S. Scenarios	International Scenarios	Quota Scenarios	U.S. Wellhead Price (2010$/Mcf)	U.S. Export (Tcf)	Price Relative to Reference case (2010$/Mcf)
USREF	INTREF	NX	$6.41		
USREF	INTREF	NC	$6.41	0	$0.00
USREF	D	HR	$6.66	1.37	$0.25
USREF	D	NC	$6.66	1.37	$0.25
USREF	SD	HR	$7.24	4.38	$0.83
USREF	SD	NC	$7.50	5.75	$1.09
HEUR	INTREF	NX	$4.88		
HEUR	INTREF	LR	$5.16	2.19	$0.28
HEUR	INTREF	NC	$5.31	3.38	$0.43
HEUR	D	NC	$5.60	5.61	$0.72
HEUR	SD	LSS	$5.16	2.19	$0.28
HEUR	SD	NC	$5.97	8.39	$1.09
LEUR	INTREF	NX	$8.70		
LEUR	INTREF	NC	$8.70	0	$0.00
LEUR	D	NC	$8.70	0	$0.00
LEUR	SD	NC	$8.86	0.52	$0.16

Figure 7: Comparison of EIA and NERA Maximum Wellhead Price Increases



The reason is simple and implies no disagreement between this report and EIA's - the analysis of world supply and demand indicates that at the highest wellhead prices estimated by EIA, world demand for U.S. exports would fall far short of the levels of exports assumed in the EIA Study.

In none of the scenarios analyzed in this study do U.S. wellhead prices become linked to oil prices in the sense of rising to oil price parity, even if the U.S. is exporting to regions where natural gas prices are linked to oil. The reason is that costs of liquefaction, transportation, and regasification keep U.S. prices well below those in importing regions.

6. Serious Competitive Impacts are Likely to be Confined to Narrow Segments of Industry

About 10% of U.S. manufacturing, measured by value of shipments, has energy expenditures greater than 5% of the value of its output and serious exposure to foreign competition. Employment in industries with these characteristics is one-half of one percent of total U.S. employment. These energy-intensive, trade-exposed industries for the most part process raw natural resources into bulk commodities. Value added in these industries as a percentage of value of shipments is about one-half of what it is in the remainder of manufacturing. In no scenario are energy-intensive industries as a whole projected to have a loss in employment or output greater than 1% in any year, which is less than normal rates of turnover of employees in the relevant industries.

7. Even with Unlimited Exports, There Would Be Net Economic Benefits to the U.S.

NERA also estimated economic impacts associated with unlimited exports in cases in which even the High, Rapid limits were binding. In these cases, both LNG exports and prices were determined by global supply and demand. Even in these cases, U.S. natural gas prices did not rise to oil parity or to levels observed in consuming regions, and net economic benefits to the U.S. increased over the corresponding cases with limited exports.

To examine U.S. economic impacts under cases with even higher natural gas prices and levels of exports than in the unlimited export cases, NERA also estimated economic impacts associated with the highest levels of exports and U.S. natural gas prices in the EIA analysis, regardless of whether or not those quantities could actually be sold at the assumed netback prices. The price received for exports in these cases was calculated in the same way as in the cases based on NERA’s GNGM, by adding the tolling fee plus a 15% markup over Henry Hub to the Henry Hub price. Even with the highest prices estimated by EIA for these hypothetical cases, NERA found that there would be net economic benefits to the U.S., and the benefits became larger, the higher the level of exports. This is because the export revenues from sales to other countries at those high prices more than offset the costs of freeing that gas up for export.

II. INTRODUCTION

This section describes the issues that DOE/FE asked to be addressed in this study and then describes the scope of both the EIA Study and the NERA analysis that make up the two-part study commissioned by the DOE/FE.

A. Statement of the Problem

1. At What Price Can Various Quantities of LNG Exports be Sold?

An analysis of U.S. LNG export potential requires consideration of not only the impact of additional demand on U.S. production costs, but also consideration of the price levels that would make U.S. LNG economical in the world market. For the U.S. natural gas market, LNG exports would represent an additional component of natural gas demand that must be met from U.S. supplies. For the global market, U.S. LNG exports represent another component of supply that must compete with supply from other regions of the world. As the demand for U.S. natural gas increases, so will the cost of producing incremental volumes. But U.S. LNG exports will compete with LNG produced from other regions of the world. At some U.S. price level, it will become more economic for a region other than the U.S. to provide the next unit of natural gas to meet global demand. A worldwide natural gas supply and demand model assists in determining under what conditions and limits this pricing point is reached.

2. What are the Economic Impacts on the U.S. of LNG Exports?

U.S. LNG exports have positive impacts on some segments of the U.S. economy and negative impacts on others. On the positive side, U.S. LNG exports provide an opportunity for natural gas producers to realize additional profits by selling incremental volumes of natural gas. Exports of natural gas will improve the U.S. balance of trade and result in a wealth transfer into the U.S. Construction of the liquefaction facilities to produce LNG will require capital investment. If this capital originates from sources outside the U.S., it will represent another form of wealth transfer into the U.S. Households will benefit from the additional wealth transferred into the U.S. If they, or their pensions, hold stock in natural gas producers, they will benefit from the increase in the value of their investment.

On the negative side, producing incremental natural gas volumes will increase the marginal cost of supply and therefore raise domestic natural gas prices and increase the value of natural gas in general. Households will be negatively affected by having to pay higher prices for the natural gas they use for heating and cooking. Domestic industries for which natural gas is a significant component of their cost structure will experience increases in their cost of production, which will adversely impact their competitive position in a global market and harm U.S. consumers who purchase their goods.

Natural gas is also an important fuel for electricity generation, providing about 20% of the fuel inputs to electricity generation. Moreover, in many regions and times of the year natural gas-fired generation sets the price of electricity so that increases in natural gas prices can impact electricity prices. These price increases will also propagate through the economy and affect both household energy bills and costs for businesses.

B. Scope of NERA and EIA Study

NERA Economic Consulting was asked by the U.S. DOE/FE to evaluate the macroeconomic impact of LNG exports using a general equilibrium model of the U.S. economy with an emphasis on the energy sector and natural gas in particular. NERA incorporated the U.S. EIA's case study output from the National Energy Modeling System ("NEMS") into the natural gas production module in its N_{ew}ERA model by calibrating natural gas supply and cost curves in the N_{ew}ERA macroeconomic model. NERA's task was to use this model to evaluate the impact that LNG exports could have on multiple economic factors, primarily U.S. gross domestic product ("GDP"), employment, and real income. The complete statement of work is attached as Appendix F.

1. EIA Study

The DOE/FE requested that the U.S. EIA perform an analysis of "the impact of increased domestic natural gas demand, as exports."[9] Specifically, DOE/FE asked the EIA to assess how specified scenarios of increased natural gas exports could affect domestic energy markets, focusing on consumption, production, and prices.

DOE/FE requested that EIA analyze four scenarios of LNG export-related increases in natural gas demand:

1. 6 billion cubic feet per day (Bcf/d), phased in at a rate of 1 Bcf/d per year (Low/Slow scenario);

2. 6 Bcf/d phased in at a rate of 3 Bcf/d per year (Low/Rapid scenario);

3. 12 Bcf/d phased in at a rate of 1 Bcf/d per year (High/Slow scenario); and

4. 12 Bcf/d phased in at a rate of 3 Bcf/d per year (High/Rapid scenario).

Total U.S. marketed natural gas production in 2011 was about 66 Bcf/d. Additional LNG exports at 6 Bcf/d represents roughly 9 percent of current production and 12 Bcf/d represents roughly18 percent of current production.

DOE/FE requested that EIA analyze for each of the four LNG export scenarios four cases from the EIA AEO 2011. These scenarios reflect different perspectives on the domestic natural gas supply situation and the growth rate of the U.S. economy. These are:

1. The AEO 2011 Reference case;

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[9] U.S. EIA, "Effects of Increased Natural Gas Exports on Domestic Energy Markets," p. 20.

2. The High Shale EUR case (reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case);

3. The Low Shale EUR case (reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case); and

4. The High Economic Growth case (assuming the U.S. gross domestic product will grow at an average annual rate of 3.2 percent from 2009 to 2035, compared to 2.7 percent in the Reference case, which increases domestic energy demand).

In January 2012, EIA released the results of its analysis in a report entitled "Effect of Increased Natural Gas Exports on Domestic Energy Markets," hereafter referred to as the "EIA Study".

2. NERA Study

NERA relied on the EIA Study to characterize how U.S. natural gas supply, demand, and prices would respond if the specified levels of LNG exports were achieved. However, the EIA study was not intended to address the question of how large the demand for U.S. LNG exports would be under different wellhead prices in the United States. That became the first question that NERA had to answer: at what price could U.S. LNG exports be sold in the world market, and how much would this price change as the amount of exports offered into the world market increased?

NERA's analysis of global LNG markets leads to the conclusion that in many cases the world market would not accept the full amount assumed in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA. In these cases, NERA replaced the export levels and price impacts found in the EIA scenarios with lower levels of exports (and *a fortiori* prices) estimated by the GNGM. These lower export levels were applied to the N_{ew}ERA model to generate macroeconomic impacts. In order to remain tied to the EIA analysis, the N_{ew}ERA model was calibrated to give the same natural gas price responses as EIA for the same assumptions about the level of LNG exports. This was done by incorporating in N_{ew}ERA the same assumptions about how U.S. natural gas supply and demand would be affected by changes in the U.S. natural gas wellhead price as implied by the NEMS model used in the EIA study.

C. Organization of the Report

This report begins by discussing what NERA was asked to do and the methodology followed by NERA. This discussion of methodology includes the key assumptions made by NERA in its analysis and a description of the models utilized. Then construction of scenarios for U.S. LNG exports is described, followed by presentation of the results and a discussion of their economic implications.

III. DESCRIPTION OF WORLDWIDE NATURAL GAS MARKETS AND NERA'S ANALYTICAL MODELS

A. Natural Gas Market Description

1. Worldwide

The global natural gas market consists of a collection of distinctive regional markets. Each regional market is characterized by its location, availability of indigenous resource, pipeline infrastructure, accessibility to natural gas from other regions of the world, and its rate of growth in natural gas demand. Some regions are connected to other regions by pipelines, others by LNG facilities, and some operate relatively autonomously.

In general, a region will meet its natural gas demand first with indigenous production, second with gas deliveries by pipelines connected to other regions, and third with LNG shipments. In 2010, natural gas consumption worldwide reached 113 Tcf. As shown in Figure 8, most natural gas demand in a region is met by natural gas production in the same region. In 2010, approximately 9.7 Tcf or almost 9% of demand was met by LNG.

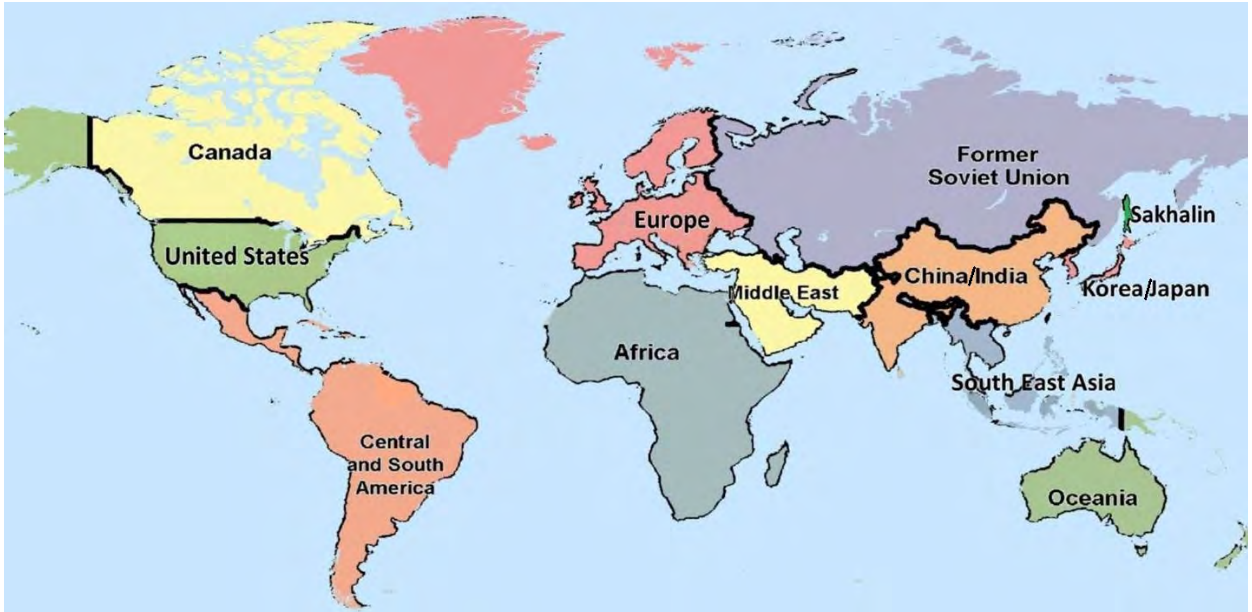
Figure 8: Global Natural Gas Demand and Production (Tcf)

	Production	Consumption
Africa	7.80	3.90
Canada	6.10	3.30
China/India	4.60	5.70
C&S America	6.80	6.60
Europe	9.50	19.20
FSU	28.87	24.30
Korea/Japan	0.20	5.00
Middle East	16.30	12.50
Oceania	2.10	1.20
Sakhalin	0.43	0.00
Southeast Asia	9.30	7.40
U.S.	21.10	23.80
Total World	113.10	112.90

Some regions are rich in natural gas resources and others are experiencing rapid growth in demand. The combination of these two characteristics determines whether the region operates as a net importer or exporter of natural gas. The characteristics of a regional market also have an impact on natural gas pricing mechanisms. The following describes the characteristics of the regional natural gas markets considered in this report.

We present our discussion in terms of regions because we have grouped countries into major exporting, importing, and demand regions for our modeling purposes. For our analysis, we grouped the world into 12 regions: U.S., Canada, Korea/Japan, China/India, Europe, Oceania, Southeast Asia, Africa, Central and South America, former Soviet Union, Middle East and Sakhalin. These regions are shown in Figure 9.

Figure 9: Regional Groupings for the Global Natural Gas Model



Japan and Korea are countries that have little indigenous natural gas resource and no prospects for gas pipelines connecting to other regions. Both countries depend almost entirely upon LNG imports to meet their natural gas demand. As a result, both countries are very dependent upon reliable sources of LNG. This is reflective in their contracting practices and willingness to have LNG prices tied to petroleum prices (petroleum is a potential substitute for natural gas). This dependence would become even more acute if Japan were to implement a policy to move away from nuclear power generation and toward greater reliance on natural gas-fired generation.

In contrast, China and India are countries that do have some indigenous natural gas resources, but these resources alone are insufficient to meet their natural gas demand. Both countries are situated such that additional natural gas pipelines from other regions of the world could possibly be built to meet a part of their natural gas needs, but such projects face geopolitical challenges. Natural gas demand in these countries is growing rapidly as a result of expanding economies, improving wealth and a desire to use cleaner burning fuels. LNG will be an important component of their natural gas supply portfolio. These countries demand more than they can produce and the pricing mechanism for their LNG purchases reflects this.

Europe also has insufficient indigenous natural gas production to meet its natural gas demand. It does, however, have extensive pipeline connections to both Africa and the Former Soviet Union ("FSU"). Despite having a gap between production and consumption, Europe's growth in natural gas demand is modest. As a result, LNG is one of several options for meeting natural gas demand. The competition among indigenous natural gas supplies, pipeline imports, and LNG imports has resulted in a market in which there is growing pressure to move away from petroleum index pricing toward natural gas index pricing.

FSU is one of the world's leading natural gas producers. It can easily accommodate its own internal natural gas demand in part because of its slow demand growth. It has ample natural gas supplies that it exports by pipeline (in most instances pipelines, if practical, are a more economical method to transport natural gas than LNG) to Europe and could potentially export by pipeline to China. FSU has subsidized pricing within its own region but has used its market power to insist upon petroleum index pricing for its exports.

The Middle East (primarily Qatar and Iran) has access to vast natural gas resources, which are inexpensive to produce. These resources are more than ample to supply a relatively small but growing demand for natural gas in the Middle East. Since the Middle East is located relatively far from other major natural gas demand regions (Asia and Europe), gas pipeline projects have not materialized, although they have been discussed. LNG represents one attractive means for Qatar to monetize its natural gas resource, and it has become the world's largest LNG producer. However, Qatar has decided to restrain its sales of LNG.

Southeast Asia and Australia are also regions with abundant low cost natural gas resources. They can in the near term (Southeast Asia with its rapid economic growth will require increasing natural gas volumes in the future) accommodate their domestic demand with additional volumes to export. Given the vast distances and the isolation by water, pipeline projects that move natural gas to primary Asian markets are not practical. As a result, LNG is a very attractive mean to monetize their resource.

The combined market of Central and South America is relatively small for natural gas. The region has managed to meet its demand with its own indigenous supplies. It has exported some LNG to European markets. Central and South America has untapped natural gas resources that could result in growing LNG exports.

The North American region has a large natural gas demand but has historically been able to satisfy its demand with indigenous resources. It has a small LNG import/export industry driven by specific niche markets. Thus, it has mostly functioned as a semi-autonomous market, separate from the rest of the world.

2. LNG Trade Patterns

LNG Trading patterns are determined by a number of criteria: short-term demand, availability of supplies, and proximity of supply projects to markets. A significant portion of LNG is traded on a long-term basis using dedicated supplies, transported with dedicated vessels to identified markets. Other LNG cargoes are traded on an open market moving to the highest valued customer. Southeast Asian and Australian suppliers often supply Asian markets, whereas African suppliers most often serve Europe. Because of their relative location, Middle East suppliers can and do ship to both Europe and Asia. Figure 10 lists 2010 LNG shipping totals with the leftmost column representing the exporters and the top row representing the importing regions.

Figure 10: 2010 LNG Trade (Tcf)

From\To	Africa	Canada	China/ India	C&S America	Europe	FSU	Korea/ Japan	Middle East	Oceania	Sakhalin	Southeast Asia	U.S.	**Total Exports**
Africa		0.03	0.05	0.31	1.33		0.24	0.21			0.07	0.31	**2.54**
Canada													**0.00**
China/India													**0.00**
C&S America		0.00		0.01	0.02		0.00					0.01	**0.05**
Europe				0.01	0.11		0.05	0.01			0.00		**0.18**
FSU													**0.00**
Korea/Japan													**0.00**
Middle East		0.01	0.44	0.08	1.15		1.28	0.10			0.15	0.08	**3.29**
Oceania			0.17				0.62				0.04		**0.83**
Sakhalin			0.02				0.39	0.00			0.02		**0.43**
Southeast Asia			0.14	0.06			1.92	0.01			0.21		**2.34**
U.S.							0.03						**0.03**
Total Imports	**0.00**	**0.04**	**0.81**	**0.47**	**2.61**	**0.00**	**4.53**	**0.34**	**0.00**	**0.00**	**0.49**	**0.40**	9.70

Source: "The LNG Industry 2010," GIIGNL.

3. Basis Differentials

The basis[10] between two different regional gas market hubs reflects the difference in the pricing mechanism for each regional market. If pricing for both market hubs were set by the same mechanism and there were no constraints in the transportation system, the basis would simply be the cost of transportation between the two market hubs. Different pricing mechanisms, however, set the price in each regional market, so the basis is often not set by transportation differences alone. For example, the basis between natural gas prices in Japan and Europe's natural gas prices reflects the differences in natural gas supply sources for both markets. Japan depends completely upon LNG as it source for natural gas and indexes the LNG price to crude. For Europe, LNG is only one of several potential sources of supply for natural gas, others being interregional pipelines and indigenous natural gas production. The pricing at the National Balancing Point ("NBP") reflects the competition for market share between these three sources. Because of its limited LNG terminals for export or import, North America pricing at Henry Hub has been for the most part set by competition between different North American supply sources of natural gas and has been independent of pricing in Japan and Europe. If the marginal supply source for natural gas in Europe and North America were to become LNG, then the pricing in the two regions would be set by LNG transportation differences.

B. NERA's Global Natural Gas Model

The GNGM is a partial-equilibrium model designed to estimate the amount of natural gas production, consumption, and trade by major world natural gas consuming and/or producing regions. The model maximizes the sum of consumers' and producers' surplus less transportation costs, subject to mass balancing constraints and regasification, liquefaction, and pipeline capacity constraints.

The model divides the world into the 12 regions described above. These regions are largely adapted from the EIA IEO regional definitions, with some modifications to address the LNG-intensive regions. The model's international natural gas consumption and production projections for these regions are based upon the EIA's AEO and IEO 2011 Reference cases.

The supply of natural gas in each region is represented by a constant elasticity of substitution ("CES") supply curve. The demand curve for natural gas has a similar functional form as the supply curve. As with the supply curves, the demand curve in each region is represented by a CES function (Appendix A).

C. N_{ew}ERA Macroeconomic Model

NERA developed the N_{ew}ERA model to forecast the impact of policy, regulatory, and economic factors on the energy sectors and the economy. When evaluating policies that have significant

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10 The basis is the difference in price between two different natural gas market hubs.

impacts on the entire economy, one needs to use a model that captures the effects as they ripple through all sectors of the economy and the associated feedback effects. The version of the N_{ew}ERA model used for this analysis includes a macroeconomic model with all sectors of the economy.

The macroeconomic model incorporates all production sectors, including liquefaction plants for LNG exports, and final demand of the economy. The consequences are transmitted throughout the economy as sectors respond until the economy reaches equilibrium. The production and consumption functions employed in the model enable gradual substitution of inputs in response to relative price changes, thus avoiding all-or-nothing solutions.

There are great uncertainties about how the U.S. natural gas market will evolve, and the N_{ew}ERA model is designed explicitly to address the key factors affecting future natural gas demand, supply, and prices. One of the major uncertainties is the availability of shale gas in the United States. To account for this uncertainty and the subsequent effect it could have on the domestic markets, the N_{ew}ERA model includes resource supply curves for U.S. natural gas. The model also accounts for foreign imports, in particular pipeline imports from Canada, and the potential build-up of liquefaction plants for LNG exports. N_{ew}ERA also has a supply (demand) curve for U.S. imports (exports) that represents how the global LNG market price would react to changes in U.S. imports or exports. On a practical level, there are also other important uncertainties about the ownership of LNG plants and how the LNG contracts will be formulated. These have important consequences on how much revenue can be earned by the U.S. and hence overall macroeconomic impacts. In the N_{ew}ERA model it is possible to represent these variations in domestic versus foreign ownership of assets and capture of export revenues to better understand the issues.

U.S. wellhead natural gas prices are not precisely the same in the GNGM and the U.S. N_{ew}ERA model. Supply curves in both models were calibrated to the EIA implicit supply curves, but the GNGM has a more simplified representation of U.S. natural gas supply and demand than the more detailed N_{ew}ERA model so that the two models solve for slightly different prices with the same levels of LNG exports. The differences are not material to any of the results in the study.

The N_{ew}ERA model includes other energy markets. In particular, it represents the domestic and international crude oil and refined petroleum markets.

We balance the international trade account in the N_{ew}ERA model by constraining changes in the current account deficit over the model horizon. The condition is that the net present value of the foreign indebtedness over the model horizon remains at the benchmark year level. This prevents distortions in economic effects that would result from perpetual increase in borrowing, but does not overly constrain the model by requiring current account balance in each year.

This treatment of the current account deficit does not mean that there cannot be trade benefits from LNG exports. Although trade will be in balance over time, the terms of trade shift in favor of the U.S. because of LNG exports. That is, by exporting goods of greater value to overseas customers, the U.S. is able to import larger quantities of goods than it would able to if the same domestic resources were devoted to producing exports of lesser value. Allowing high value exports to proceed has a similar effect on terms of trade as would an increase in the world price of existing exports or an increase in productivity in export industries. In all these cases, the U.S. gains more imported goods in exchange for the same amount of effort being devoted to production of goods for export. The opposite is also possible, in that a drop in the world price of U.S. exports or a subsidy that promoted exports of lesser value would move terms of trade against the U.S., in that with the same effort put into producing exports the U.S. would receive less imports in exchange and terms of trade would move against the U.S. The fact that LNG will be exported only if there is sufficient market demand ensures that terms of trade will improve if LNG exports take place.

The N_{ew}ERA model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, disposable income and changes in income from labor, capital, and resources.

IV. DESCRIPTION OF SCENARIOS

EIA's analysis combined assumptions about levels of natural gas exports with assumptions about uncertain factors that will drive U.S. natural gas supply and demand to create 16 scenarios. EIA's analysis did not and was not intended to address the question of whether these quantities could be sold into world markets under the conditions assumed in each scenario. Since global demand for LNG exports from the United States also depends on a number of uncertain factors, NERA designed scenarios for global supply and demand to capture those uncertainties. The global scenarios were based on different sets of assumptions about natural gas supply and demand outside the United States. The combination of assumptions about maximum permitted levels of exports, U.S. supply and demand conditions, and global supply and demand conditions yielded 63 distinct scenarios to be considered.

The full range of scenarios that we considered included the different combinations of international supply and demand, availability of domestic natural gas, and LNG export capabilities. The remainder of this section discusses this range of scenarios.

A. How Worldwide Scenarios and U.S. Scenarios Were Designed

1. World Outlooks

The International scenarios were designed to examine the role of U.S. LNG in the world market (Figure 11). Before determining the macroeconomic impacts in the U.S., one must know the circumstances under which U.S. LNG would be absorbed into the world market, the level of exports that would be economic on the world market and the value (netback) of exported LNG in the U.S. In order to accomplish this, several International scenarios were developed that allowed for growing worldwide demand for natural gas and an increasing market for LNG. These were of more interest to this study because the alternative of lower worldwide demand would mean little or no U.S. LNG exports, which would have little or no impact on the U.S. economy.

Figure 11: International Scenarios

Case Name	Japan Nuclear Plants Retired	Korean Nuclear Plants Retired	Planned Liquefaction Capacity in Other Regions Is Built
International Reference	No	No	Yes
Demand Shock	Yes	No	Yes
Supply/Demand Shock	Yes	Yes	No

a. International Reference Case: A Plausible Baseline Forecast of Future Global Demand and Supply

The International Reference case is intended to provide a plausible baseline forecast for global natural gas demand, supply, and prices from today through the year 2035. The supply and demand volumes are based upon EIA IEO 2011 with countries aggregated to the regions in the NERA Global Natural Gas Model. The regional natural gas pricing is intended to model the pricing mechanisms in force in the regions today and their expected evolution in the future. Data to develop these pricing forecasts were derived from both the EIA and the International Energy Agency's World Energy Outlook 2011 ("IEA WEO").

Our specific assumptions for the global cases are described in Appendix A.

b. Uncertainties about Global Natural Gas Demand and Supply

To reflect some of the uncertainty in demand for U.S. LNG exports, we analyzed additional scenarios that potentially increased U.S. LNG exports. Increasing rather than decreasing exports is of more interest in this study because it is the greater level of LNG exports that would result in larger impact on the U.S. economy. The two additional International scenarios increase either world demand alone or increase world demand while simultaneously constraining the development of some new LNG supply sources outside the U.S. Both scenarios would result in a greater opportunity for U.S. LNG to be sold in the world market.

- The first additional scenario ("Demand Shock") creates an example of increased demand by assuming that Japan converts all its nuclear power generation to natural gas-fired generation. This scenario creates additional demand for LNG in the already tight Asian market. Because Japan lacks domestic natural gas resources, the incremental demand could only be served by additional LNG volumes.

- The second scenario ("Supply/Demand Shock") is intended to test a boundary limit on the international market for U.S. LNG exports. This scenario assumes that both Japan and Korea convert their nuclear demand to natural gas and on the supply side it is assumed that no new liquefaction projects that are currently in the planning stages will be built in Oceania, Southeast Asia, or Africa. The precise quantitative shifts assumed in world supply and demand are described in Appendix A.

Neither of these scenarios is intended to be a prediction of the future. Their apparent precision (Asian market) is only there because differential transportation costs make it necessary to be specific about where non-U.S. demand and supply are located in order to assess the potential demand for U.S. natural gas. Many other, and possibly more likely, scenarios could be constructed, and some would lead to higher and others to lower exports. The scenarios that we modeled are intended as only one possible illustration of conditions that could create higher demand for U.S. LNG exports.

2. U.S. Scenarios Address Three Factors

a. Decisions about the Upper Limit on Exports

One of the primary purposes of this study is to evaluate the impacts of different levels of natural gas exports. The levels of exports that are used in constructing the U.S. scenarios are the four levels specified by the DOE/FE as part of EIA's Study. In addition, the DOE requested that we add one additional level of exports, "Slowest," to address additional uncertainties about how rapidly liquefaction capacity could be built that were not captured by the EIA analysis. Lastly, we evaluated a No-Export constraint scenario, whereby we could determine the maximum quantity of exports that would be demanded based purely on the economics of the natural gas market and a No-Export capacity scenario to provide a point of comparison for impacts of LNG exports.

b. Uncertainties about U.S. Natural Gas Demand and Supply

The advances in drilling technology that created the current shale gas boom are still sufficiently recent that there remains significant uncertainty as to the long-term natural gas supply outlook for the U.S. In addition to the uncertain geological resource, there are also other uncertainties such as how much it will cost to extract the natural gas, and many regulatory uncertainties including concerns about seismic activity, and impacts on water supplies that may lead to limits on shale gas development.

On the demand side there has been a considerable shift to natural gas in the electric sector in recent years as a result of the low natural gas prices. Looking into the future, there are expected to be many retirements of existing coal-fired generators as a result of the low natural gas prices and new EPA regulations encouraging natural gas use. As a result, most new baseload capacity being added today is fueled with natural gas. Industrial demand for natural gas is also tied to price levels. The current low prices have increased projected outputs from some natural gas-intensive industries like chemicals manufacturing. The shift toward natural gas could be accelerated by pending and possible future air, water, and waste regulations and climate change policies. Thus, the potential exists for significant increases in natural gas demand across the U.S. economy.

Combining uncertainties about the U.S. outlooks for natural gas supply and demand results in a wide range of projections for the prices, at which natural gas may be available for export.

To reflect this uncertainty, the EIA, in its AEO 2011, included several sensitivity cases in addition to its Reference Case. For natural gas supply, the two most significant are the Low Shale EUR and High Shale EUR sensitivity cases. We also adopt these cases, in addition to the Reference Case supply conditions, in evaluating the potential for exports of natural gas.

B. Matrix of U.S. Scenarios

The full range of potential U.S. scenarios was constructed based on two factors: 1) U.S. supply and 2) LNG export quotas. There are three different U.S. supply outlooks:[11]

1. Reference ("USREF"): the AEO 2011 Reference case;

2. High Shale Estimated Ultimate Recovery ("HEUR") case: reflecting more optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent higher than in the Reference case; and

3. Low Shale EUR case ("LEUR"): reflecting less optimistic assumptions about domestic natural gas supply prospects, with the EUR per shale gas well for new, undrilled wells assumed to be 50 percent lower than in the Reference case.[12]

As for the LNG export quotas, we considered six different LNG export quota trajectories, all starting in 2015:

1. Low/Slow ("LS"): 6 Bcf/d, phased in at a rate of 1 Bcf/d per year;

2. Low/Rapid ("LR"): 6 Bcf/d phased in at a rate of 3 Bcf/d per year;

3. High/Slow ("HS"): 12 Bcf/d phased in at a rate of 1 Bcf/d per year;

4. High/Rapid ("HR"): 12 Bcf/d phased in at a rate of 3 Bcf/d per year;

5. Low/Slowest ("LSS"): 6 Bcf/d phased in at a rate of 0.5 Bcf/d per year; and

6. No-Export Constraint: No limits on U.S. LNG export capacity were set and therefore our Global Natural Gas Model determined exports entirely based on the relative economics.

The combination of these two factors results in the matrix of 18 (3 supply forecasts for each of 6 export quota trajectories) potential U.S. scenarios in Figure 12.

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[11] We eliminate a fourth case, High Demand, run by EIA because the range of demand uncertainty is expected to be within the range spanned by the three cases.

[12] While the statement of work also described a supply outlook using EIA's High Economic Growth case, we found that the results would have been identical to those in the Reference case, and thus, we did not separately analyze that case.

Figure 12: Matrix of U.S. Scenarios

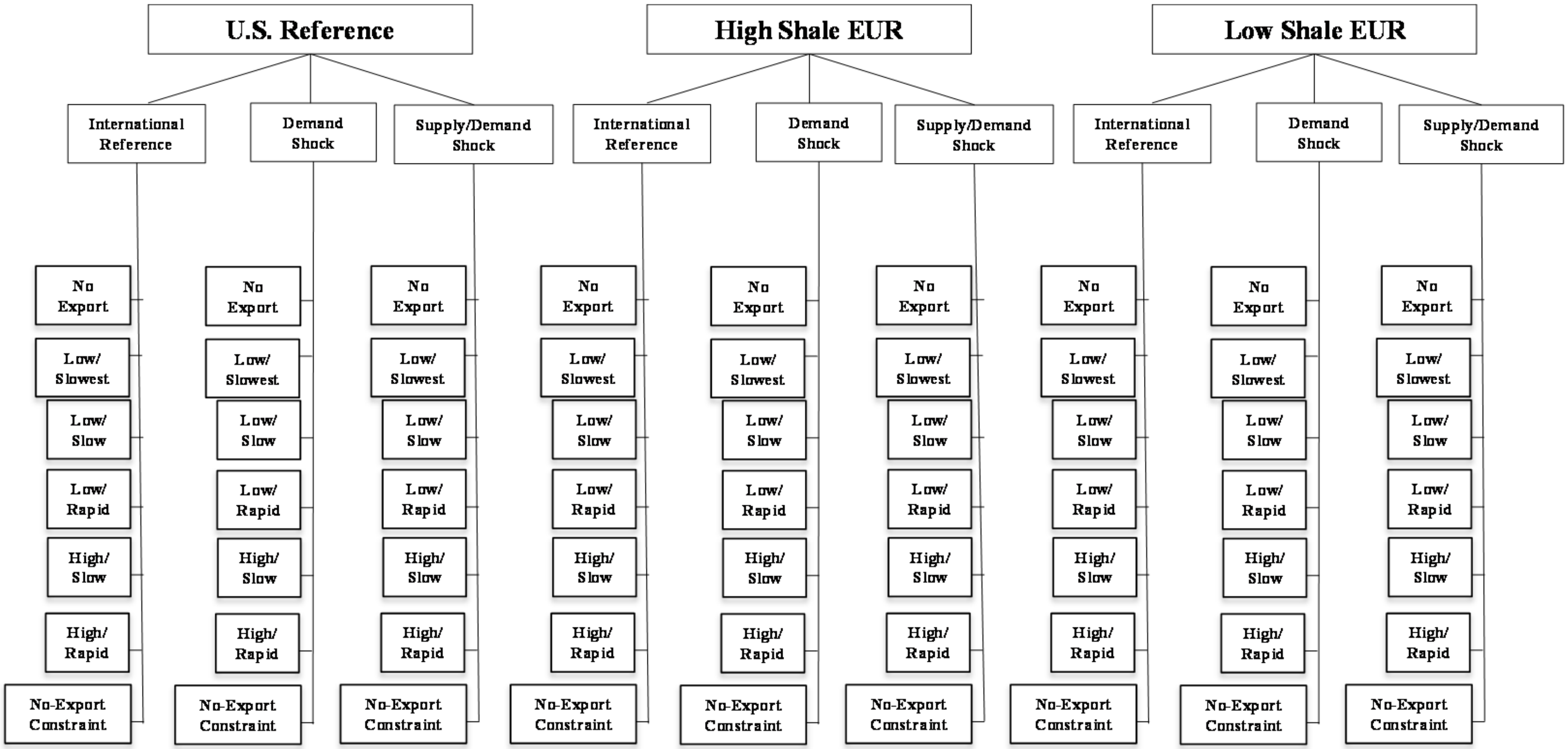
U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity	U.S. Supply	LNG Export Capacity
Reference	Low/Slow	High EUR	Low/Slow	Low EUR	Low/Slow
Reference	Low/Rapid	High EUR	Low/Rapid	Low EUR	Low/Rapid
Reference	High/Slow	High EUR	High/Slow	Low EUR	High/Slow
Reference	High/Rapid	High EUR	High/Rapid	Low EUR	High/Rapid
Reference	Low/Slowest	High EUR	Low/Slowest	Low EUR	Low/Slowest
Reference	Unlimited	High EUR	Unlimited	Low EUR	Unlimited

In addition, we created a "No-Export Capacity" scenario for each of the three U.S. supply cases.

C. Matrix of Worldwide Natural Gas Scenarios

NERA used its Global Natural Gas Model to analyze international impacts resulting from potential U.S. LNG exports. As shown in Figure 13, a matrix of scenarios combining the three worldwide scenarios with three U.S. supply scenarios and the seven rates of U.S. LNG capacity expansion resulted in a total of 63 different scenarios that were analyzed.

Figure 13: Tree of All 63 Scenarios



V. GLOBAL NATURAL GAS MODEL RESULTS

A. NERA Worldwide Supply and Demand Baseline

NERA's Baseline is based upon EIA's projected production and demand volumes from its 2011 IEO and AEO Reference cases with some modifications.

To develop a worldwide supply and consumption baseline, we first adjusted the IEO's estimates for production and consumption in the ten non-North American regions. Then we adjusted the IEO projections for two North American regions. For the ten non-North American regions, we computed the average of the IEO's estimate for worldwide production and demand excluding North American production, consumption and LNG imports. Then, we scaled the production in each of these ten regions individually by the ratio of this average and the original production in these ten regions. We used a similar methodology for determining demand in these ten regions.

Next, we calibrated both the U.S. imports from Canada and U.S. LNG imports. U.S. pipeline imports from Canada varied for each of the three U.S. supply cases: AEO reference, High Shale EUR, and Low Shale EUR. U.S. LNG imports were next calculated as the difference between total U.S. imports less pipeline imports. This calculation was repeated for each U.S. supply case. The calculated LNG imports are consistent with the official AEO numbers.

For LNG exporting regions, we checked that they had sufficient liquefaction capacity so that their calibrated production was less than or equal to their demand plus their liquefaction and inter-regional pipeline capacity. If not, we adjusted the region's liquefaction capacity so that this condition held with equality. For the Middle East, we imposed a limit on the level of 4.64 Tcf on its LNG exports. Since its liquefaction capacity exceeds its export limit, the Middle East supply must be less than or equal to its demand plus its LNG export limit. If this condition failed to hold, we adjusted Middle East supply until Middle East supply equaled its demand plus its LNG export limit.

In calibrating the FSU, NERA assumes that the recalibrated (as per the above adjustment made to the IEO data) production is correct and any oversupply created by the calibration of supply and demand is exported by pipeline.

For LNG importing regions, we checked to determine if, after performing the recalibration described above, the demand in each importing region was less than the sum of their domestic natural gas production, regasification capacity, and inter-regional pipeline capacity. In each region where this condition failed, we expanded its regasification capacity until this condition held with equality. Figure 14 reports the resulting natural gas productions to which we calibrated each region in our GNGM. Figure 15 reports the resulting natural gas demand to which we calibrated each region in our GNGM.

Figure 14: Baseline Natural Gas Production (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	7.80	9.70	11.10	12.20	13.30	14.10
Canada	6.10	7.00	7.70	8.30	8.70	9.00
China/India	4.60	5.60	6.70	8.00	9.60	9.70
C&S America	6.80	7.90	8.30	9.20	10.50	11.70
Europe	9.50	8.10	7.40	7.50	7.90	8.30
FSU	28.87	30.05	32.12	34.89	37.77	39.94
Korea/Japan	0.20	0.20	0.20	0.20	0.20	0.20
Middle East	16.30	19.70	22.40	24.60	26.70	28.80
Oceania	2.10	2.60	3.10	3.80	4.80	5.70
Sakhalin	0.43	0.45	0.48	0.51	0.53	0.56
Southeast Asia	9.30	10.00	10.70	11.60	12.60	13.40
U.S.	21.10	22.40	23.40	24.00	25.10	26.40
World	113.10	123.70	133.60	144.80	157.70	167.80

Figure 15: Baseline Natural Gas Demand (Tcf)

	2010	2015	2020	2025	2030	2035
Africa	3.90	4.70	5.90	7.10	8.30	9.10
Canada	3.30	3.50	3.70	4.20	4.60	5.00
China/India	5.70	8.60	10.70	13.10	15.10	16.60
C&S America	6.60	7.40	8.90	10.50	12.20	14.40
Europe	19.20	19.80	20.40	20.90	22.00	23.20
FSU	24.30	24.30	24.50	24.90	25.80	26.50
Korea/Japan	5.00	5.20	5.30	5.70	5.90	5.90
Middle East	12.50	14.70	17.00	19.10	21.30	24.00
Oceania	1.20	1.30	1.50	1.80	2.00	2.20
Sakhalin	0.00	0.00	0.00	0.00	0.00	0.00
Southeast Asia	7.40	8.50	10.00	12.00	13.90	15.30
U.S.	23.80	25.10	25.30	25.10	25.90	26.50
World	112.90	123.10	133.20	144.40	157.00	168.70