BEFORE THE CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of:

Preparation of the
2009 Integrated Energy Policy Report

Docket No. 09-IEP-1J

CLEARWATER PORT, LLC COMMENTS ON MAY 14, 2009 JOINT COMMITTEE WORKSHOP ON NATURAL GAS ACTIVITIES AND STAFF DRAFT REPORT ON LIQUEFIED NATURAL GAS UNCERTAINTY ISSUES (CEC-200-2009-006-SD)

Clearwater Port, LLC, ("Clearwater Port") a subsidiary of NorthernStar Natural Gas Inc. ("NorthernStar") would like to thank the Commission for the opportunity to comment on the staff draft report, Liquefied Natural Gas Uncertainty Issues,(CEC-200-2009-006-SD) (hereinafter "staff LNG report") and presentations from the May 14, 2009 workshop. Staff is to be commended for their efforts to identify the sources of uncertainty inherent in any energy resource forecast.

Clearwater Port requests that the Commission take into account the comments, data and analyses provided with this filing in the final IEPR report as it relates to natural gas infrastructure and the potential for LNG to meet California's future natural gas demand.

This submittal is organized as follows:

1. Updated information is requested to be included in the final IEPR report to reflect recent changes in the market for natural gas and LNG imports.
2. A correction to the description of the FERC LNG approval process relating to a "Request for Rehearing" on the Bradwood Landing Project is provided, together with an analysis of recent District Court decisions related to State vs. Federal LNG terminal siting authority.
3. Additional information is provided regarding additional studies on LNG lifecycle GHG emissions.
4. Comments are provided on the staff analysis of Kitimat LNG project announcements.
5. An analysis of factors that could drive increased LNG imports to U.S. west coast, together with supporting presentation material, is included.

Clearwater Port Requests The IEPR Committee Update Information Contained In The Staff LNG Report To Reflect Recent Changes In The Market For Natural Gas And LNG Imports.

Clearwater Port requests that staff update the underlying tables and related graphs to reflect recent increases in U.S. LNG imports and price changes. While there is always a desire to ensure information contained within a report is as current as practical, LNG imports have recently increased, reversing a trend and in line with predictions by experts referenced in the staff LNG report. We believe this change warrants inclusion in the staff LNG report and strengthens some of the Summary Conclusions contained in the staff LNG report. The current text of the staff LNG report reads:

> *Ignoring these uncertainties, the current trend is that LNG is not coming to the United States because domestic natural gas prices are too low relative to world natural gas prices, which are more closely linked to crude oil prices. The gap between U.S. prices and world prices may be a function of natural gas shale deposits that have finally allowed U.S. natural gas supply to increase. In the meantime, the immediate rush to develop U.S. LNG terminals has slowed. Some terminals are asking for export authority, although except for the Kitimat terminal in British Columbia, most are simply asking to export gas that arrived as LNG. Any immediate increase seen in LNG deliveries is more likely to occur as European-destined LNG seeks a home once their storage facilities become constrained, or as demand in Japan responds to the recession and to the restart of the Kashiwazaki Kariwa nuclear reactor.*[1]

We suggest updating the final report through May 31st, or the latest period for which publicly sourced data is available on LNG imports to the United States. Specifically, Platts LNG Daily[2] reported the following spot prices for 2009 (in $/MMBtu):

	JULY	AUGUST
Japan/Korea Marker	$4.00- $4.10	$4.15-$4.25
Henry Hub	$3.964	$4.078
National Balancing Point	$4.425	$4.704

[1] California Energy Commission, *Liquefied Natural Gas Uncertainty Issues*, Draft Staff Paper, CEC-200-2009-006-SD (May 14, 2009), P. 22.

[2] See *Platts LNG Daily*, Volume 6, Number 62 (June 1, 2009).

Capturing the most up-to-date price information in the final IEPR report provides important implications as to the accuracy of the IEPR's conclusions. For example, the Jan – May Henry Hub ("HH") average price was $4.19/MMBTU.[3] During the same period, there were nearly 70 LNG cargoes delivered in the U.S. This information shows that LNG can and is being delivered into the U.S. market as a price taker at prices equivalent to domestic gas. This evidence will provide for the most accurate final IEPR report as possible and helps dispel the myth that LNG is more expensive than domestic gas.

To help bolster the conclusions in the IEPR Report, we offer Volume 6, Number 62 of Platts LNG Daily which includes up-to-date price information. We also offer a Northernstar power point detailing various aspects of west-coast LNG development. Both of these documents are attached in Appendix 1.

The IEPR Committee Should Correct The Description Of The FERC LNG Approval Process Relating To A "Request for Rehearing" On The Bradwood Landing Project

Clearwater Port is a subsidiary of NorthernStar. NorthernStar is also the company developing the Bradwood Landing project in Oregon. While we believe the characterization that FERC's approval of Bradwood's certificate order set off a "firestorm of protest" is subjective, it is worth reminding readers that it is not uncommon for organizations to file legal challenges to energy infrastructure projects at various steps in the approval process. We appreciate that Staff has been careful to avoid drawing conclusions about the merits or the probability of success of such challenges.

In Oregon, Governor Kulongoski has been careful to avoid taking a position for or against a specific LNG project. The State of Oregon's general position is that FERC acted prematurely by issuing its certificate order with conditions prior to the State of Oregon completing its permit review process. Requests for Rehearing are part of normal FERC process; denial is required before action can be brought in a federal court of appeals. As correctly reported, those arguments have now advanced to the 9th Circuit Court of Appeals.

Since the release of the staff LNG report, there have been significant developments addressing this very issue. On March 13, 2009, the U.S. Court of Appeals for the D.C. Circuit ("the court") dismissed a petition by the Delaware Department of Natural Resources and Environmental Control ("Delaware"), holding that Delaware lacked standing to challenge certain orders by the Federal Energy Regulatory Commission ("FERC" or the "Commission").[4] Delaware challenged the FERC orders that conditionally approved an application by Crown Landing LLC ("Crown Landing") under the Natural Gas Act ("NGA") to site, construct and operate a liquefied natural

[3] See gas price data posted on the Intercontinental Exchange, available at: www.theice.com

[4] Delaware Department of Natural Resources and Environmental Control v. FERC, No. 07-1007 (D.C. Cir. 2009).

gas ("LNG") terminal at the mouth of the Delaware River. Delaware claimed that FERC had exceeded its statutory authority by conditionally approving the application for Crown Landing before the requirements of the Coastal Zone Management Act ("CZMA") and Clean Air Act ("CAA") had been satisfied. In holding that Delaware lacked standing to challenge the FERC orders, the court concluded that Delaware had suffered no injury in fact. This case demonstrates the routine nature of challenges to energy infrastructure projects and that challenges are often brought even when the challenging party lacks legal standing to challenge the project.

Clearwater Port requests that the IEPR Committee consider the Crown Landing case and include in its discussion that challenges to energy infrastructure projects are routine. We have attached the Crown Landing case and summary of the case by the law firm, Van Ness Feldman as Appendix 2 to Clearwater Port's comments.

Clearwater Port Offers Additional information Regarding LNG lifecycle GHG emissions

The staff LNG report makes the following request for information regarding the greenhouse gas ("GHG") emissions analysis[5]: *How do life-cycle carbon emissions for LNG compare to that of coal-fired generation, and how might they be addressed?*

In response to this request, we are providing two studies that address this comparison to coal. These studies are attached as Appendix 3. The first study was conducted by PACE Global Energy Services: Comparative Life-Cycle Analysis of GHG Emissions from Select Hydrocarbon Fuels, May 25, 2007. Because it is in the public domain, we are also including another comparison study, Life Cycle Carbon and Emissions Analysis, July 8, 2008, by ICF International.

The purpose of each study was to compare the lifecycle greenhouse gas (GHG) emissions associated with intensity of fuels imported into Oregon for the purpose of electric power generation. All GHG emissions associated with the fuel, from origin to the burner tip, were estimated so that the emissions intensity of each supply chain could be compared directly. While the methodologies vary slightly, both studies arrive at similar conclusions, adding additional weight to the staff's draft conclusion in the staff LNG report that:

> When compared with coal, it is generally believed that the carbon footprint for LNG is significantly smaller. It has long been known that domestically produced natural gas emits much less greenhouse gases than coal. LNG has the added processes of liquefaction, shipping and regasification. Even with these additional processes, the carbon footprint of LNG is still found to be less than that of coal

With respect to how the issue should be addressed by regulators, we offer the following comments: CO_2 emissions are a global, not local concern. The emission of a CO_2 molecule in

[5] Staff LNG report, P. 22.

California will have the same arguable effect on global temperatures as a molecule of CO2 emitted in China.[6] Additionally, the United Nations has recognized that developing countries are integral to providing effective, equitable solutions to climate change. If LNG originates from a developed country, the emissions associated with LNG production and transportation are part of the country's national greenhouse gas inventory under the UNFCCC (United Nations Framework Convention on Climate Change, 1992 aka Rio Accords).[7] These countries either already are or in the future will be subject to a greenhouse gas emissions cap and reduction obligation.

Some LNG originates from developing countries that lack a ready domestic market for natural gas and which do not have an emissions cap or reduction obligation under the Kyoto Protocol. If the gas is not liquefied and transported to markets, it is flared and vented to the atmosphere as CO2. On the other hand, the gas could be captured and converted to LNG and exported. Under that scenario, some of that gas will be used to provide the energy for liquefaction and transport of LNG to destination markets. However, there will be an environmental benefit if useful energy is produced from gas, rather than the alternative use, flaring.

Furthermore, the use of LNG would result in significant system-wide reductions in down-stream GHG emissions sources through: 1) the displacement of coal-fired generation; 2) the supply of fuel to new gas facilities and resulting displacement of less-efficient generation and 3) by supporting the integration of intermittent renewable generation. With respect to the GHG emissions attributable to coal generation compared to LNG, Clearwater Port agrees with staff that LNG contributes far less GHG emissions than coal. In support of this assertion, Clearwater Port offers the analysis of PACE (Attached as Appendix 3). The following graph[8] clearly demonstrates the contrast in relative GHG emissions between coal and LNG:

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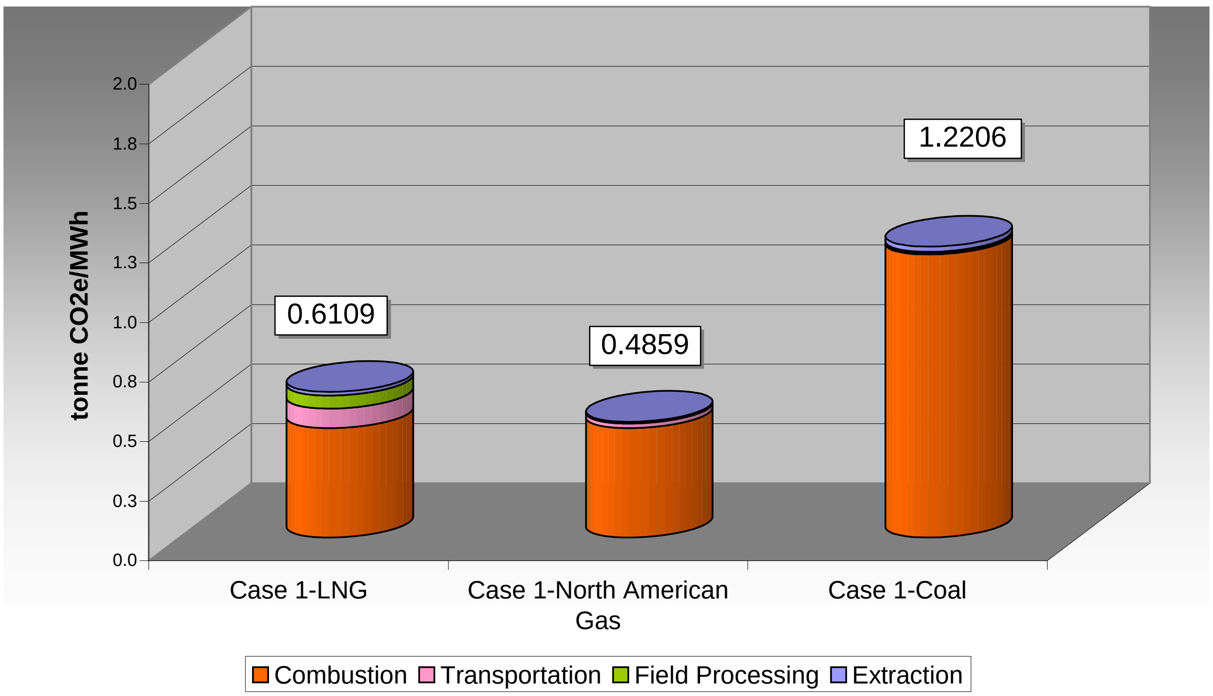
[6] See Energy Commission Committee Report in 08-GHG-OII-01 (Investigation regarding Greenhouse Gas Emission Impacts of Power Plants), *Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Applications*,(hereinafter "Committee CEQA GHG report") CEC-700-2009-004 (March 2009), available at: http://energy.ca.gov/2009publications/CEC-700-2009-004/CEC-700-2009-004.PDF, which at P. 20 states: "Unlike criteria air pollutants such as nitrogen oxides, where the effect is basin-specific, a molecule of GHG emitted in Montana (or China) has the same climate warming effect as a molecule of GHG emitted in California."

[7] See United Nations Framework Convention on Climate Change, Article 4 Sections 2(a) and (b) (1992), available at: http://unfccc.int/resource/docs/convkp/conveng.pdf

[8] PACE Presentation, *Comparative Life-Cycle Analysis of GHG Emissions from Select Hydrocarbon Fuels* (May 25, 2007), Slide 16, attached as Appendix 3.

Case 1 - Power Generation U.S. National Average Analysis Results



GHG emissions attributable to natural gas usage in California has been the subject of much analysis at the Energy Commission, particularly as to how GHG emissions should be addressed to fulfill the requirements of the California Environmental Quality Act ("CEQA"). Two reports have been released in 08-GHG-OII-01, and both have significant conclusions as to how GHG emissions should be addressed under CEQA when new power plants are sited.[9] The OII Committee CEQA GHG report concluded, in part, that "new gas-fired power plants are more efficient than older power plants, and they displace these older facilities in the dispatch order."[10] In other words, when one considers the electric system as a whole, the down-stream emissions attributable to natural gas usage by new power plants will result in a net-reduction of system-wide GHG emissions. To the extent that LNG supplies fuel to these newer, more efficient gas facilities, the State will see net-reductions in GHG emissions.

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[9] See Committee CEQA GHG report; See also, *MRW Consultant Report on Framework for Evaluating Greenhouse Gas Implication of Natural Gas-Fired Power Plants in California*, (hereinafter "MRW GHG Report") CEC-700-2009-009 (May 2009), available at: http://energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF.

[10] See Committee CEQA GHG Report at P. 21.

In addition, the State will have an increased need for natural gas facilities as the State pursues a 33% Renewable Portfolio Standard ("RPS"). The MRW GHG report provides strong analytical support for the notion that natural gas facilities are needed to provide back up generation to ensure reliability as the State increases the RPS.[11]

In sum, LNG offers far lower emissions than coal-fired generation. Further, the use of LNG as a natural gas supply source for power generation will in nearly all cases offset the use of another energy source and its environmental impacts, and will also facilitate the integration of renewable generation. As to up-stream sources of GHG emissions attributable to LNG, California regulators should take note that upstream emissions are accounted for and should avoid penalizing LNG imports by adopting rules that would double-count these emissions.

The IEPR Committee Should Consider An alternative Interpretation To Staff's Analysis Of The Kitimat LNG Project Announcements; The Kimitat Project Is Not Representative Of Significant Upheaval In The Natural Gas Markets.

The staff LNG report seems to view the announcements regarding the change in the Kitimat project as representative of a significant "upheaval" in the natural gas markets. We disagree. A quick analysis of the underlying forecasted price differentials between Asia and U.S. markets suggest considerable uncertainty with respect to whether the financial justification for export remains plausible.

Here is the current text:

> *Perhaps no single project on the West Coast has revealed the upheaval in natural gas market than Kitimat LNG. Kitimat LNG was originally proposed to be an LNG import facility on the west coast of Canada. The project received both local and federal approval and seemed poised to begin construction on the regasification terminal. Then in September 2008, the project sponsors decided that it would be in their best interest to convert the project to a liquefaction export terminal instead of an import facility. Kitimat would use natural gas from Canada's sedimentary basins to supply the liquefaction terminal. Mitsubishi has already signed onto the project with plans of bringing LNG to the Japanese market. The applicants gave the following reasons to go in this new direction:*
>
> > *"Fundamental changes altering the global natural gas market have made exporting LNG more economically viable than importing it…Rising gas demand in Asia, as well as rapidly increasing gas supplies in North America from non-traditional plays have led to significantly higher natural gas prices in Asia*

[11] See MRW Report at P. 8.

> *than North America, a compelling opportunity for companies looking to export LNG from North America to Asia."9*

Analysis: In September, 2008 Kitimat LNG dropped its import terminal proposal in favor of a 5.0 mmtpa LNG liquefaction project. The project received Canadian government approval in December and won approval from the British Columbia provincial government in January, 2009.

Recently, Kitimat has announced a Heads of Agreement with Mitsubishi and a Memorandum of Understanding with Kogas for interest in their plant. Neither non-binding agreement has been finalized, nor has a final investment decision been taken on the project.

Kitimat's approach is to allow a potential participant to access natural gas reserves in Western Canada, including newly discovered shale gas resources, to meet its LNG requirements. According to Kitimat, the new unconventional plays in the Horn River Basin and the Montney area of British Columbia are estimated to contain recoverable natural gas reserves of ~70 Tcf by themselves.

A merchant Liquefaction plant, guaranteed by tolling fees, is a novel business model. The rationale behind the project appears to be driven by the premise that the producer / toll holder of gas would achieve a higher netback by delivering LNG to Asian markets versus delivering piped gas to North American markets.

The project was conceived when (as a result of a shortage of LNG) spot prices for LNG in Asia were much higher than US/Canadian natural gas spot prices. (Asian spot cargoes US$15-20/MMBtu when Henry Hub ("HH") was US$10-13/MMBtu).

Since that time, Asian LNG demand has collapsed as a result of the recession, while Asian spot pricing is currently around US$3.50-$4.00 / MMBtu, slightly less than HH and EU pricing.

Asian long term pricing (20 year contracts), which is linked to oil, has also fallen to around US$8/MMBtu. It is also generally assumed that the world LNG market will be oversupplied for the next few years with new production coming online from Qatar, Sakhalin, Yemen, Australia and others.

The convergence of global gas prices may prove to be a challenge to a business model that is dependent on a global separation of prices.

In our view, for this project to work Kitimat needs to see a sustainable difference in gas prices of approximately $3.00-$4.00 / MMBtu between Asian and North American projects. Currently, prices do not support this difference and economic rationale does not appear to be plausible.

In summary, we believe that the staff LNG report should reflect the uncertainties that exist for this project similar to the other uncertainties identified with all natural gas infrastructure projects, rather than simply conclude that the Kitimat project is strongly representative of “upheaval” in natural gas markets.

Clearwater Port provides The Following Responses To Factors That Could Drive Increased LNG Imports To The U.S. West Coast

At the end of the LNG Uncertainties report, CEC staff posed a series of questions about the role of LNG in meeting future gas needs. These questions included:

- *What factors help to determine landed LNG prices in the United States, Europe, and Asia?*
- *How much LNG could be available to U.S. importers given the large price differences between the United States, European, and Asian markets?*
- *What other non-economic factors could drive the development of LNG?*

In response to staff questions, we have highlighted the following factors that will drive increased LNG imports:

- Historically, long term pricing for U.K., Japan and U.S. have tracked closely. Despite high spot prices in Asia in 2007/2008 resulting from supply shortfall, cumulative Asian prices have been consistent with North American gas pricing over the last decade.
- North American prices are projected to increase as a result of higher exploration and development costs of conventional and unconventional gas supplies.
- LNG is a price “taker” in North America, acting to increase supply reliability and reducing price volatility.
- LNG competes favourably in North America with prices around $4/ MMBTU, as evidenced by approximately 66 deliveries of LNG to the Gulf Coast and East Coast in the January through May 2009 timeframe. (During this same period average Henry Hub prices were $4.19 / MMBtu.
- The global supply of LNG is forecast to nearly double from 24.5 Bcfd in 2007 to 43.9 Bcfd in 2014.
- There is significant potential for North American markets to receive LNG supply (2013 to 2020) in the midterm, with over 70% of proposed liquefaction trains located within the Asia Pacific supply Basin.
- The global economic downturn favours increased LNG imports to the U.S.:
    - Asian LNG demand has been weakening and is expected to remain flat;

- There is an oversupply of LNG in the Asia Pacific ("AP") region;
- Supplier competition is increasing;
- The U.S. west coast provides liquidity which is critical for the launch of new supply projects; and
- There has been a strong reduction in key commodity prices over the past 12 months, increasing the cost competitiveness of new LNG supply projects and receiving terminals.

In summary, LNG remains a viable, competitive supply option for North America and in particular, the U.S. west coast, including natural gas markets in Mexico, California and the Pacific Northwest.

<u>Conclusion</u>

Clearwater Port thanks the IEPR Committee and CEC staff for their hard work and goals of providing the most accurate, up-to-date analysis of natural gas and LNG development in California and the West Coast. Clearwater Port requests that the Commission take into account the comments, data and analyses provided with this filing in the final IEPR report as it relates to natural gas infrastructure and the potential for LNG to meet California's future natural gas demand.

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APPENDIX 1

Bradwood Landing update
NW Energy Conference, June 2009

About NorthernStar Natural Gas Inc.

NorthernStar Natural Gas Inc.

- U.S.-owned and managed company established to develop, own and operate LNG importation terminals in strategic locations

Experienced Management Team

- Has developed over 50 energy infrastructure projects with total capital investment in excess of $15BN
- Involved in the development, construction or operation of nine LNG projects worldwide

Financial Capability

- Majority shareholder is MatlinPatterson ($9 BN private equity fund)
- Successfully completed a $100MM convertible bond offering in May 2006
- Successfully recapitalized company in May 2009

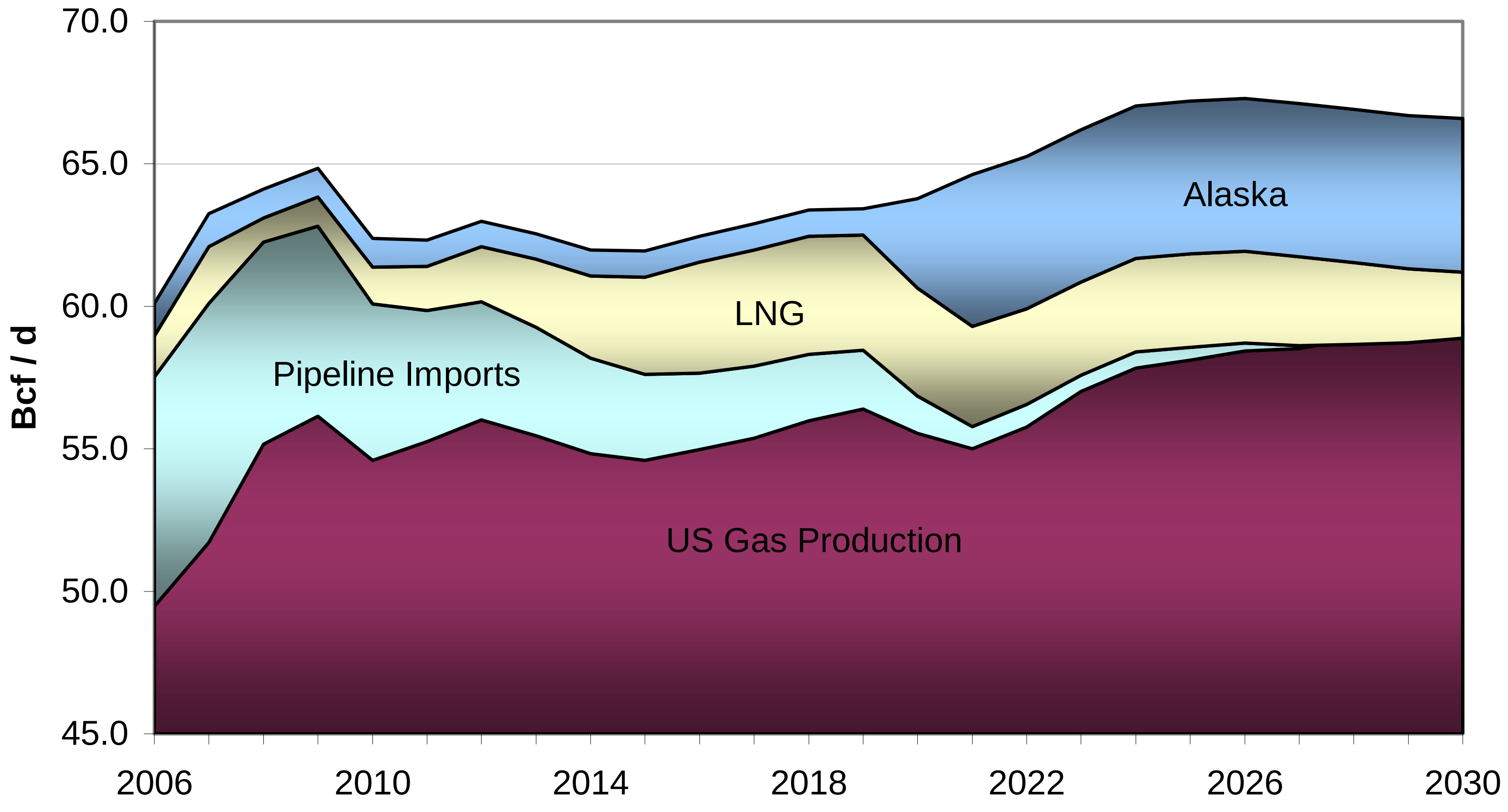
Bradwood Landing milestones

☑	Filed with OR FSEC	1Q 2005
☑	Pre-filed with FERC	2Q 2005
☑	Completed technical design	2Q 2006
☑	Submitted Application to FERC (terminal & pipeline)	2Q 2006
☑	Submission of Coastal Zone Management Act (CZMA) permit application	4Q 2006
☑	Positive Waterway Suitability Report (WSR) from USCG	1Q 2007
☑	Preliminary Biological Assessment (BA) from FERC	1Q 2007
☑	Issuance of Draft Environmental Impact Statement (DEIS)	3Q 2007
☑	CZMA deemed complete	4Q 2007
☑	Local County Commission Board Final Approval for Land Use (LUCS)	1Q 2008
☑	Final BA received from FERC	4Q 2008
☑	FERC Issuance of Final EIS (FEIS)	3Q 2008
☑	FERC Issuance of "certificate order" authorizing Terminal and/Pipeline	3Q 2008
☐	Receive State air & water, Army Corps, Biological Opinion and all other permits	1Q 2010

Bradwood Landing

- First and only U.S. West Coast LNG project approved by FERC (September 2008)
- Local land use approval received March 2008
- Deemed complete on major State permits
- Completed additional refinancing in tight credit markets to allow completion of development and start of construction
- On target to commence construction in 2010 and operations in 2014
- Executed a number of MOU's with major customers
- Only West Coast LNG project with labor union endorsement
- Lowest cost LNG import project on U.S. West Coast
- Expected to create between 5,000 – 20,000 new jobs in the Pacific Northwest

Imported natural gas is essential to meet growing U.S. demand

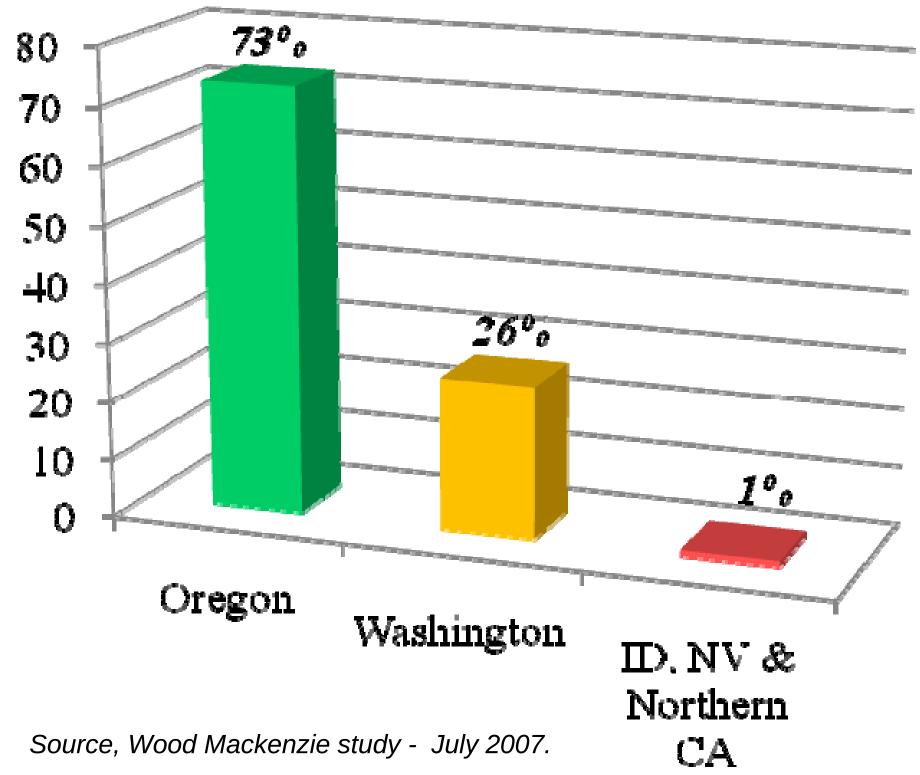


Even with forecasted increase in U.S. domestic production, LNG imports will be necessary to keep pace with growing gas demand.

Source: EIA, 2009

Bradwood Landing designed to deliver gas to Pacific Northwest market

- Oregon consumers would receive on average 73% of all LNG delivered to consumers from the Bradwood facility.
- Washington would receive 26% of all LNG delivered.
- Less than 1% on average would go to Idaho, Northern California and Nevada combined.

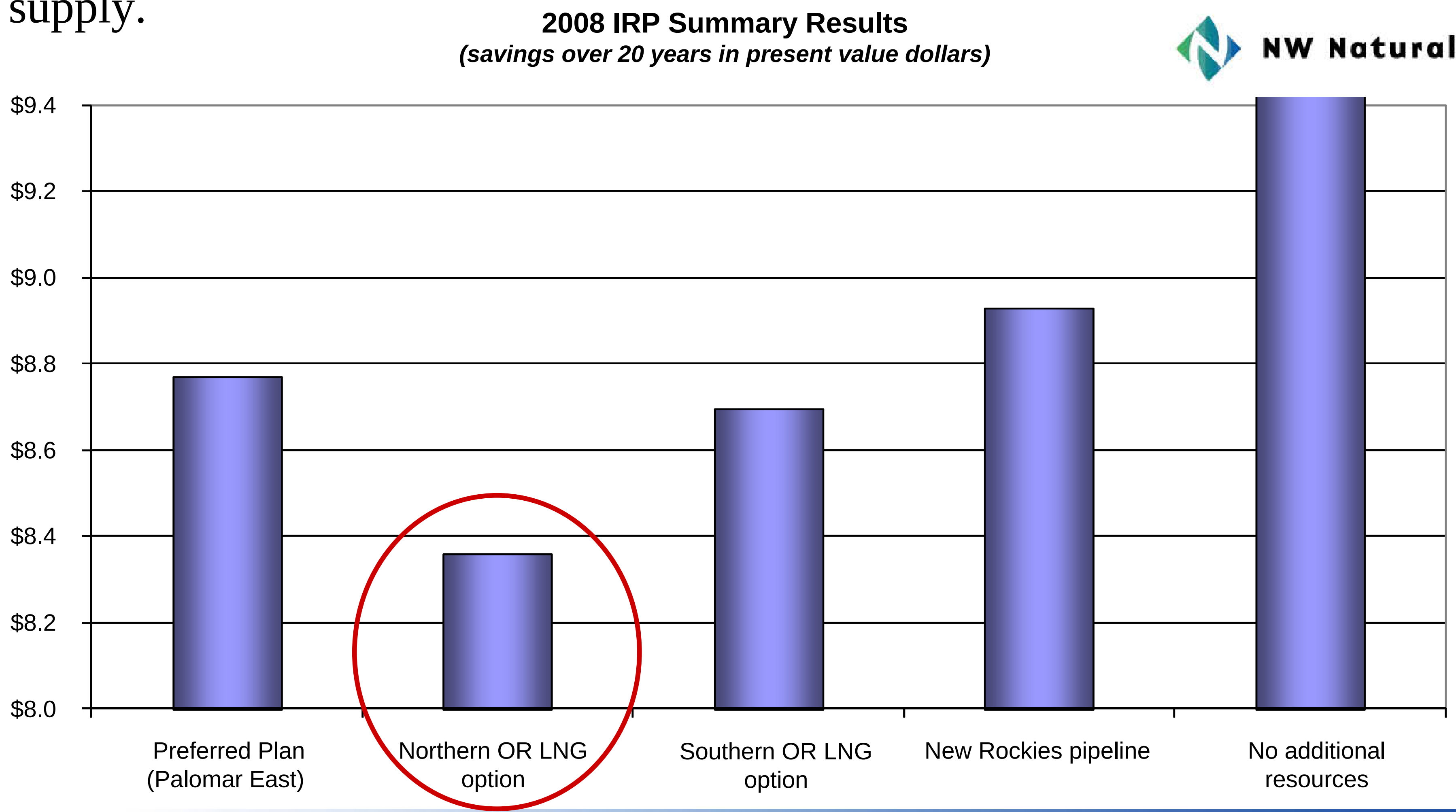


Source, Wood Mackenzie study - July 2007.

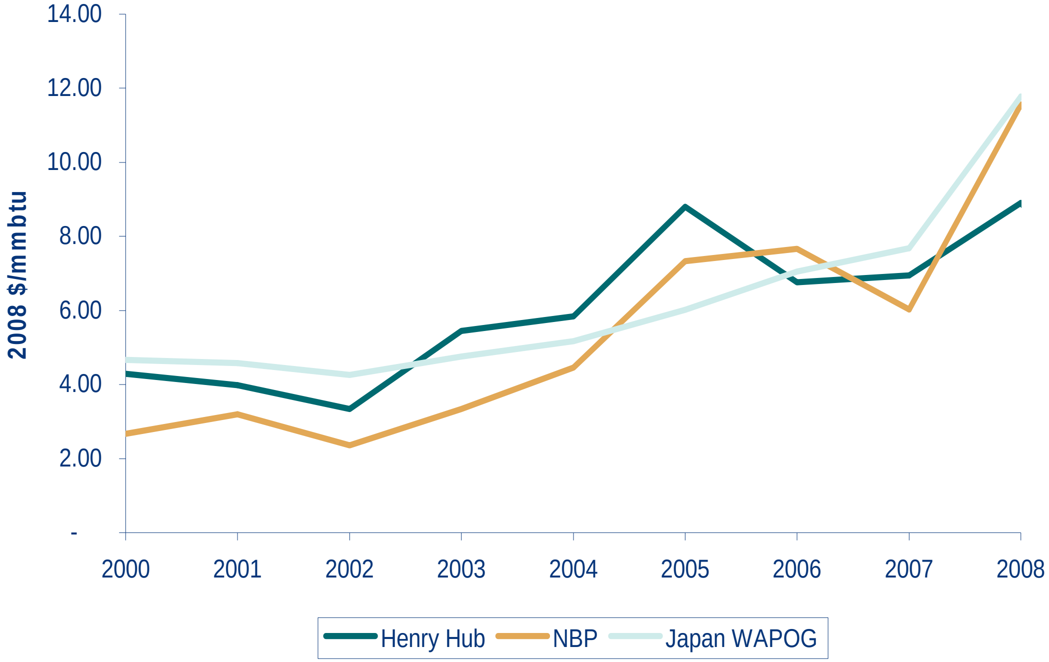
- An independent study by a University of Oregon economist shows that increased gas supply from Bradwood Landing will result in lower energy prices for Pacific Northwest consumers, creating between 5,000 and 20,000 new jobs

An LNG Terminal could provide significant savings to gas consumers

NW Natural's modeling shows that an LNG terminal could save consumers hundreds of millions of dollars in transportation-based cost savings from LNG supply.



Historically long term pricing for U.K., Japan and U.S. have tracked closely



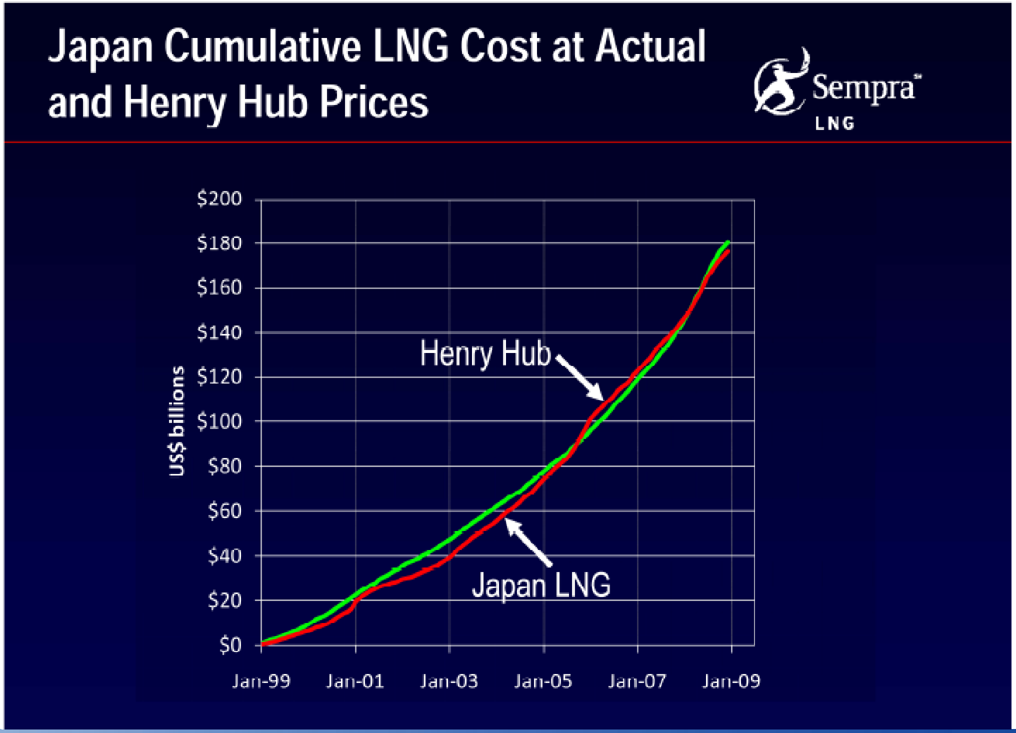
Source: Wood Mackenzie December 2008.

WAPOG = Weighted Average Price of Gas

Spot Prices - 2009

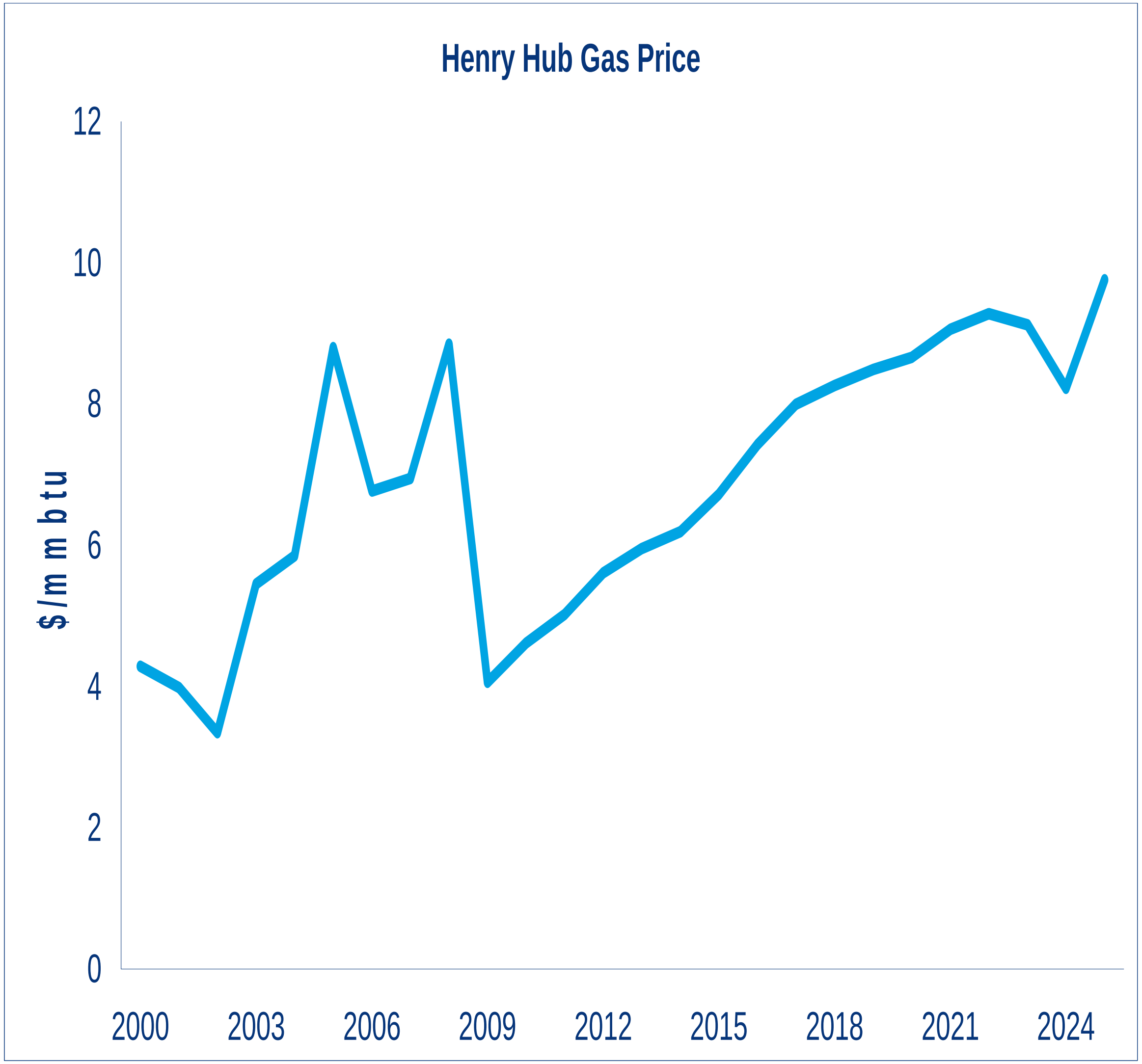
	July	August
Japan / Korea Marker	$4.00-$4.10	$4.15-$4.25
Henry Hub	$3.964	$4.078
National Balancing Point	$4.425	$4.704

Source: Platts LNG Daily 06/01/09



Despite high spot prices in Asia in 2007/8 resulting from supply shortfall, cumulative Asian prices are consistent with North America gas pricing over the last decade

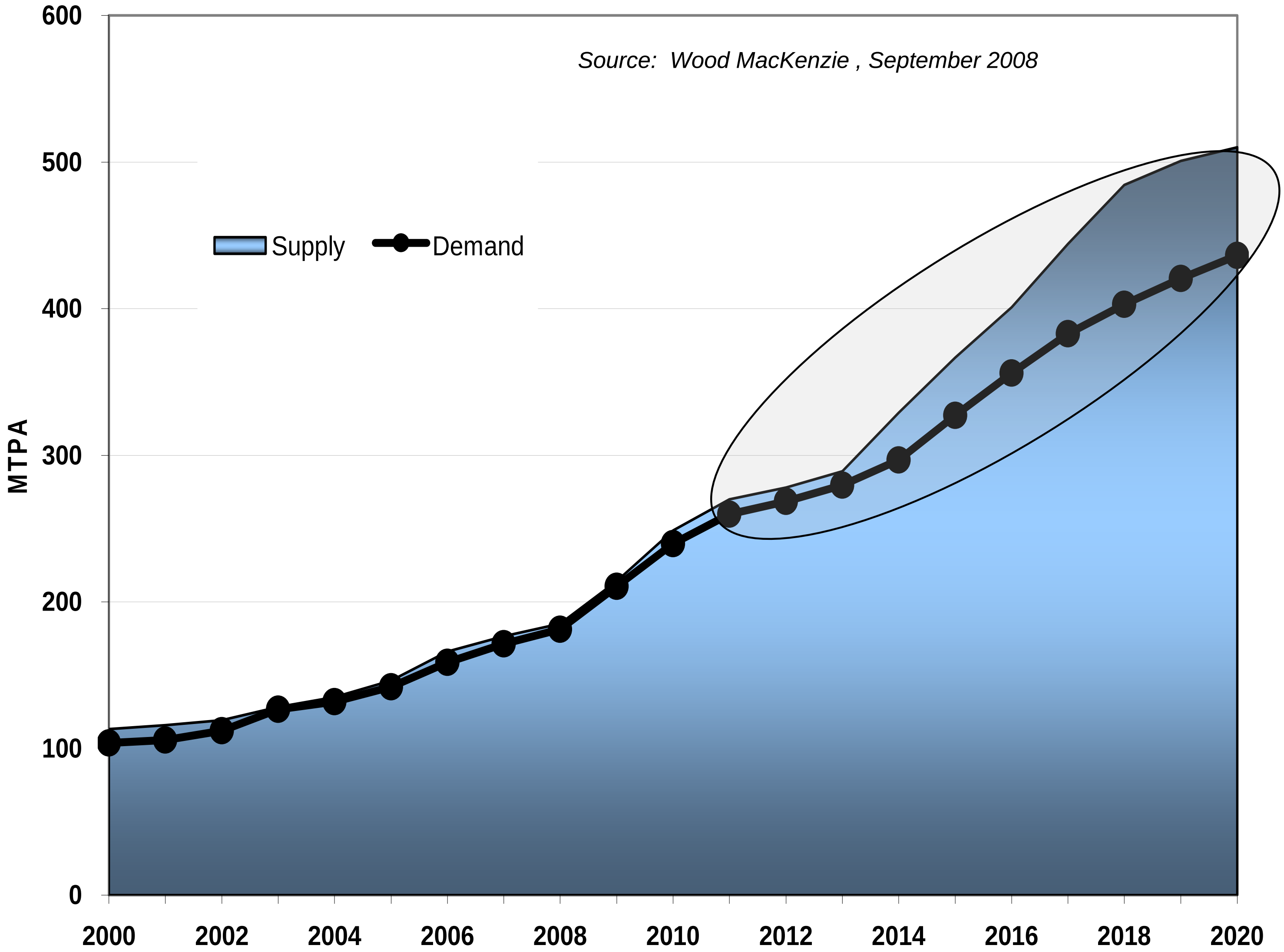
North American Gas Prices Rising



Source: *Wood Mackenzie May 2009.*

- North American prices are projected to increase as a result of higher exploration and development costs of conventional & unconventional gas supplies.
- LNG is a price “taker” in North America, acts to increase supply reliability and reduce price volatility.
- LNG competes favorably in North America with prices around $4/ MMBTU as evidenced by recent deliveries of LNG to the Gulf Coast (+/- 70 cargoes delivered YTD)

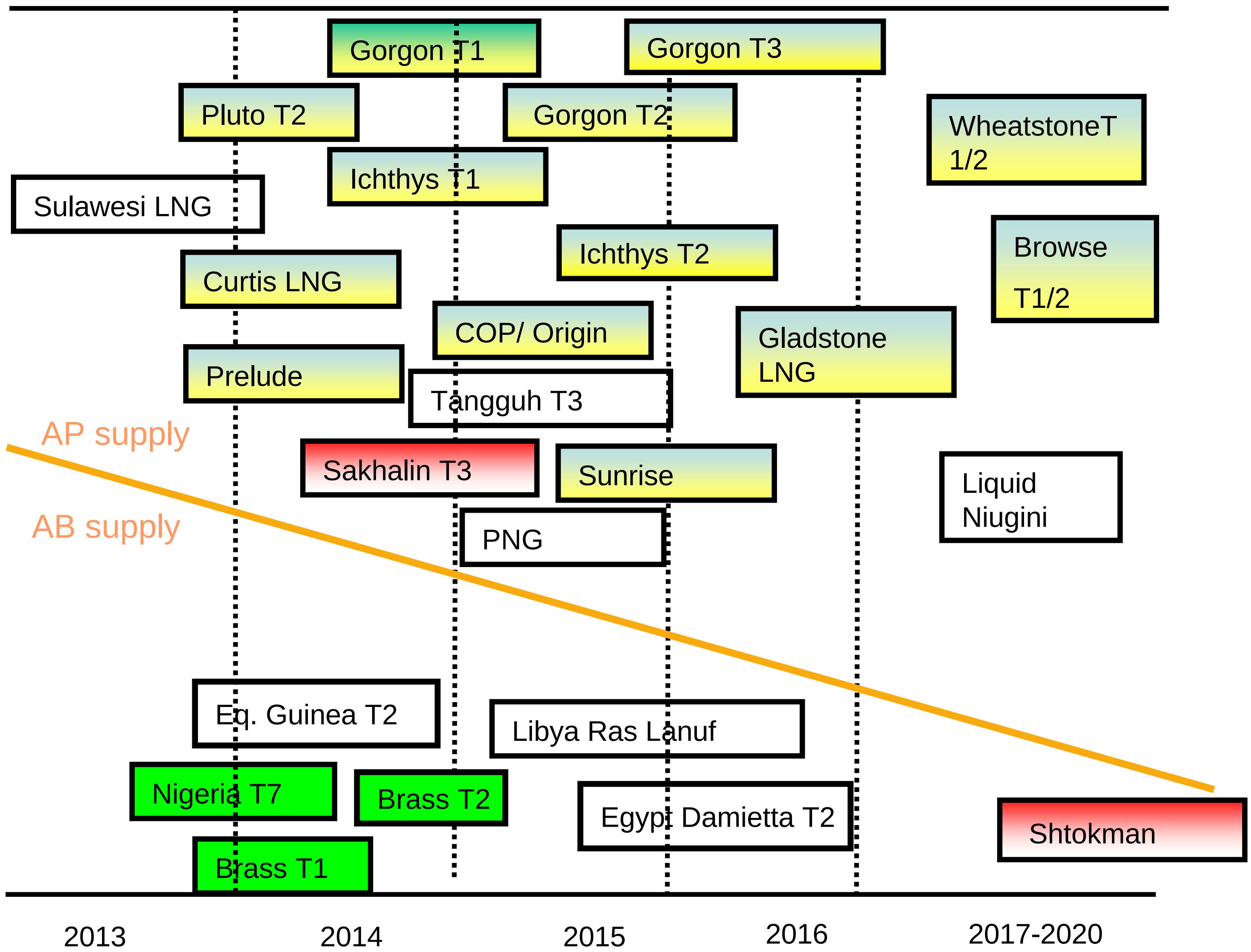
LNG Supply/Demand



The global supply of LNG is forecast to nearly double from 24.5 Bcfd in 2007 to 43.9 Bcfd in 2014.

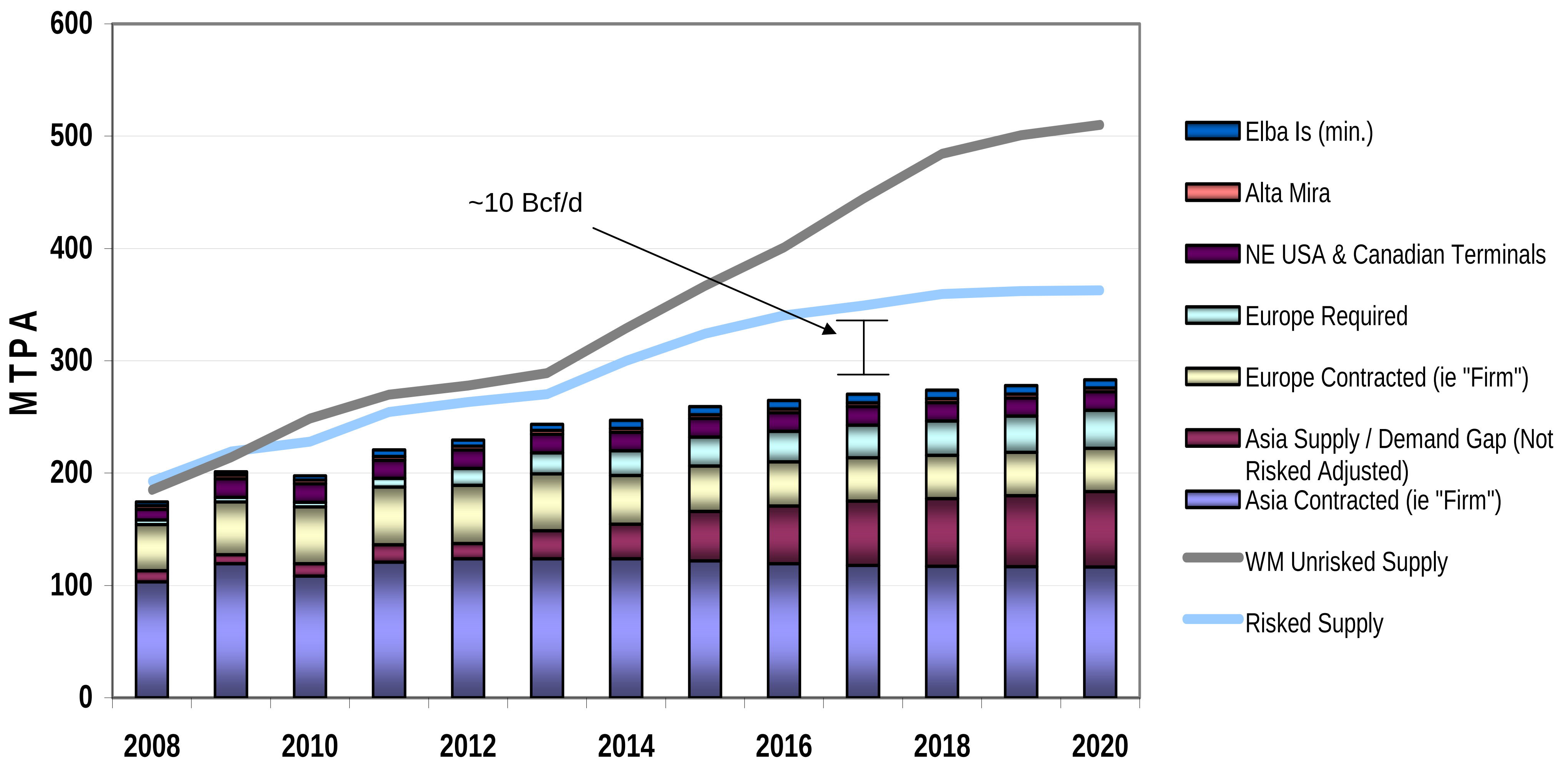
Potential North American LNG supply (2013 to 2020)

Over 70% of proposed liquefaction trains are located within the Asia Pacific supply Basin

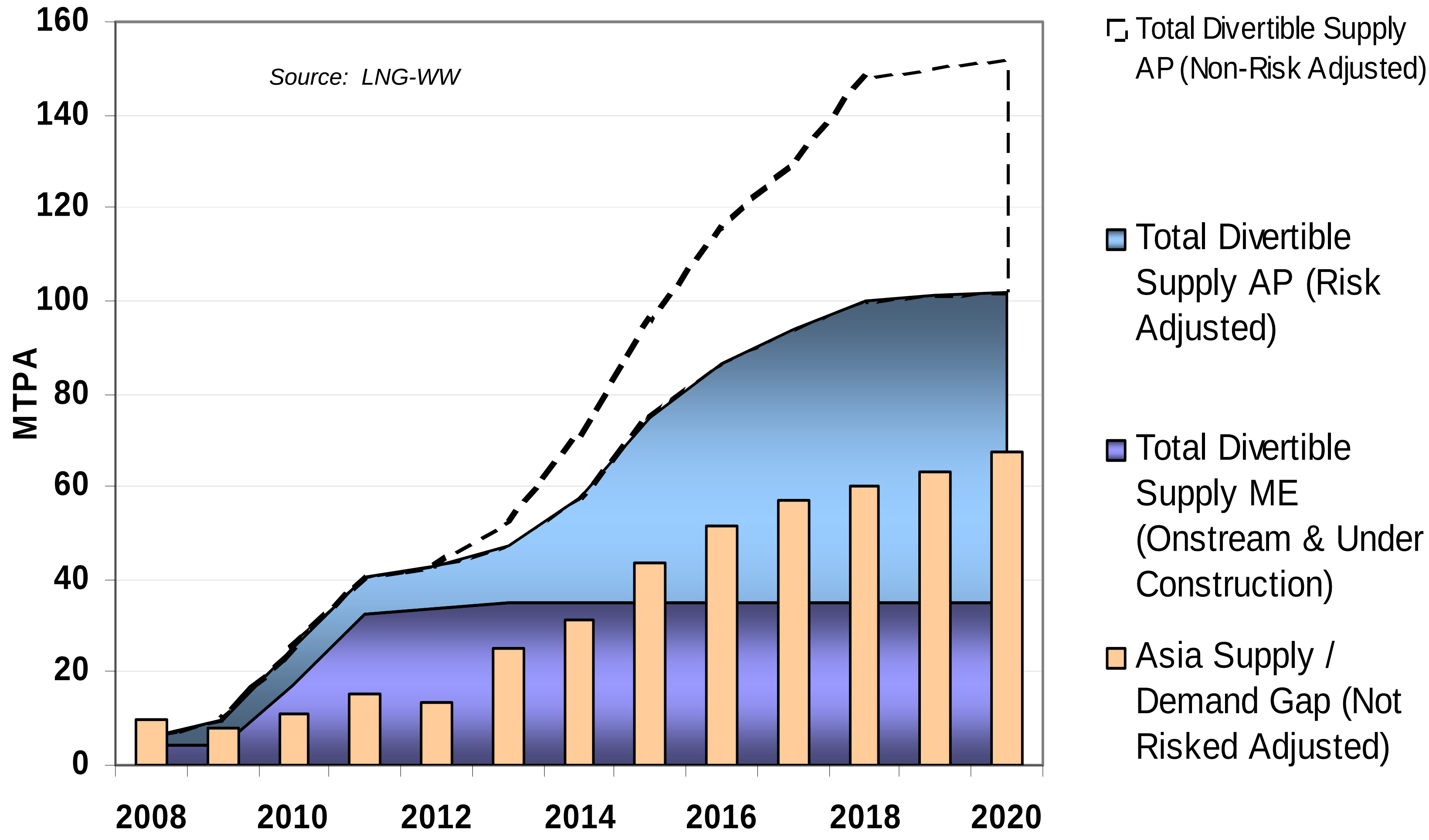


Source: LNG-WW

Risk Weighted LNG Supply Exceeds Non Risk Weighted Firm LNG demand

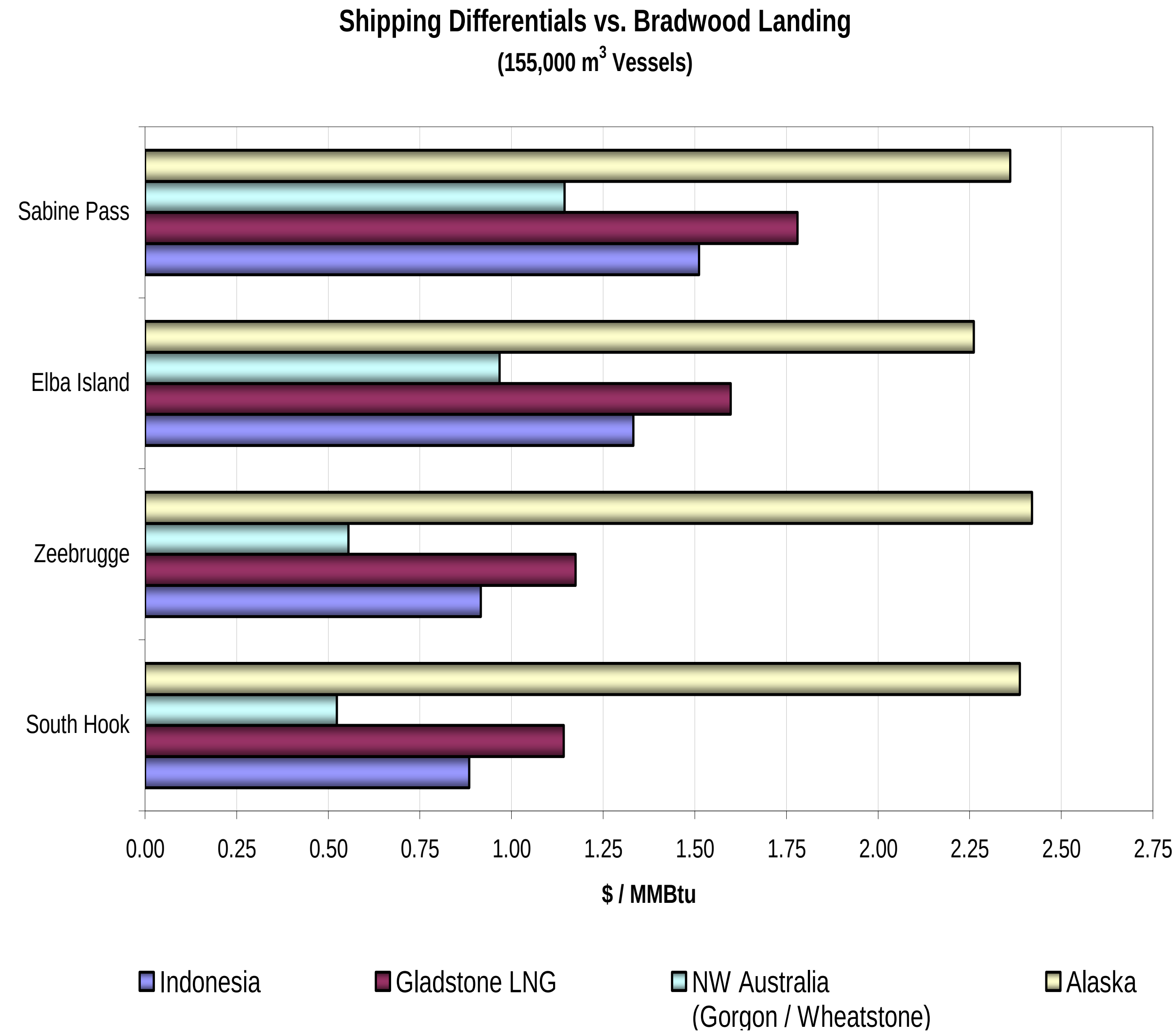


Risk weighted supply from Asia Pacific & existing Middle East projects exceeds <u>non</u> risk weighted Asia Pacific demand



Economic downturn moderates Asia Pacific demand, further increasing competition for launch markets for new Asia Pacific supply

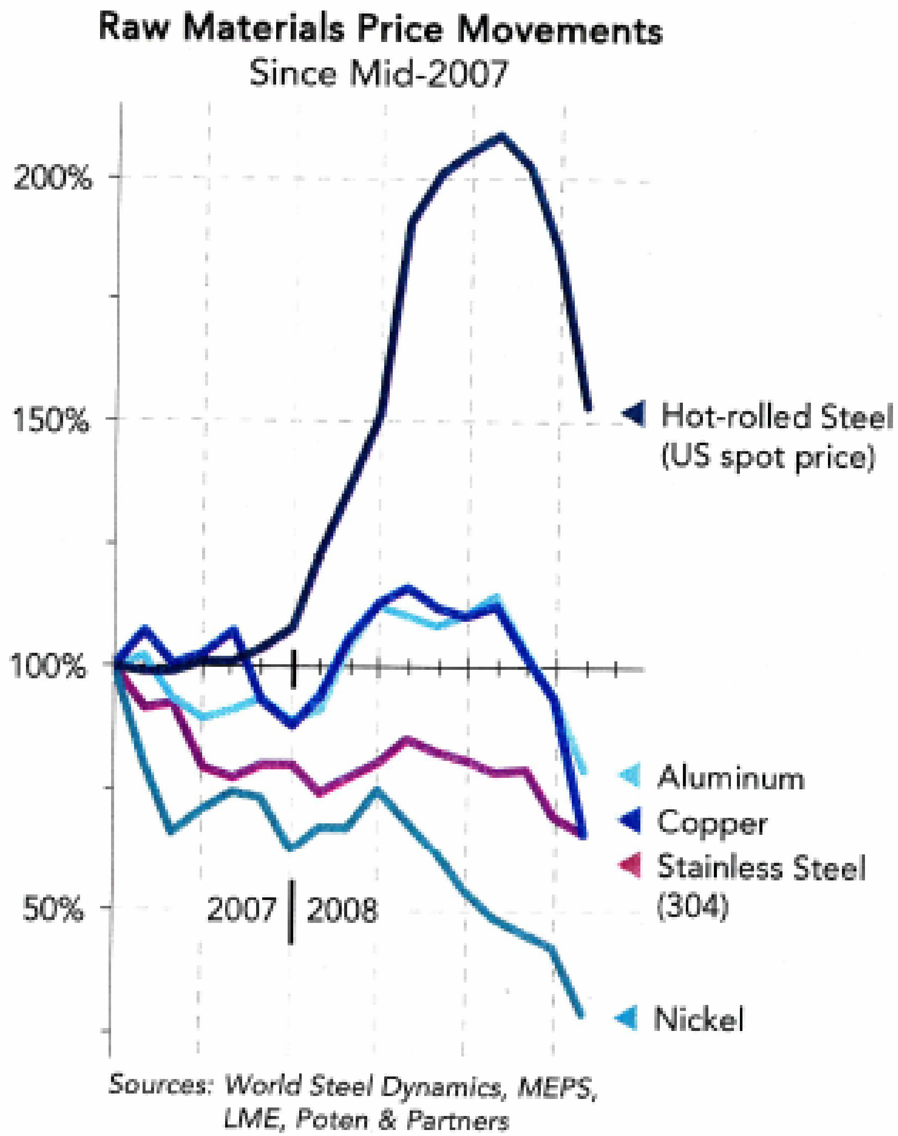
Bradwood is most attractive alternative market for Asia Pacific supply



Bradwood Landing enjoys significant shipping cost advantages increasing its attractiveness to Asia Pacific supply as an alternative market:

- $1.10 to $2.30 /MMBtu versus Gulf Coast locations
- $0.50 to $2.30 / MMBtu versus European locations

Global downturn - Implications



Asian LNG demand weakening and expected to remain flat:

- Oversupply of LNG in AP region (Buyers exercising DQT)
- Increased supplier competition
- Access to Bradwood Landing critical for launch of new supply projects

Strong reduction in key commodity prices over the past 12 months increases cost competitiveness of new LNG supply projects and Bradwood Landing.

More information

Bradwood Landing
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Astoria, OR 97103
(503) 325-3335
www.bradwoodlanding.com

platts
100 YEARS

www.platts.com

LNG Daily

Volume 6 / Number 103
Monday, June 1, 2009

As hurricane season begins, bears still in control

Houston—With fundamentals overwhelmingly bearish, nothing—save a catastrophic hurricane that wipes out significant Gulf of Mexico production, gas processing plants and pipeline capacity—should prevent US gas prices from falling even further this summer, several industry analysts and traders told Platts in interviews in the past week.

With the US hurricane season officially under way Monday, several storm forecasters have called for relatively normal activity in the Atlantic Basin—leaving market participants and observers resolutely bearish.

Between potentially record-setting storage inventories, an expected uptick in LNG imports and weak industrial demand, sources expect both New York Mercantile Exchange and cash prices to fall to less than $3/MMBtu and possibly test the $2/MMBtu-level later this summer.

When hurricanes Katrina and Rita made landfall in late summer 2005, the then-prompt-month NYMEX contract spiked by nearly $5/MMBtu. Two years

(continued on page 4)

Kogas signs MOU for 40% of Kitimat LNG output

Washington—Kitimat LNG has signed a non-binding memorandum of understanding with Korea Gas under which the state-owned South Korean gas monopoly would buy as much as 40% of Kitimat's planned LNG output from its proposed 5-million-mt/yr (640,000-Mcf/d) liquefaction plant in Western Canada, Kitimat said Monday.

Under the MOU, Kogas, the world's largest LNG importer, would buy as much as 2 million mt/yr for 20 years from the proposed plant in Kitimat, British Columbia. The total value of the deal would be more than $20 billion, the company added.

The proposed liquefaction plant received Canadian government approval in December and won approval from the British Columbia provincial government in January. The project would receive gas from the pipeline system in Western Canada for export to Asian markets.

The developer of the project, Calgary-based Galveston LNG, originally proposed building an LNG import terminal in Kitimat, but in September dropped that project in favor of the export project. Galveston LNG has said Kitimat LNG

(continued on page 6)

July JKM at $4.05/MMBtu as Adgas sells cargo

Singapore—Platts' July LNG Japan Korea Marker was assessed down 2.5 cents Monday at $4.05/MMBtu on reports that Abu Dhabi's Adgas sold a first-half July cargo at a free-on-board price of "close to $3.50/MMBtu,"a trading source said.

The cargo was sold to a "major client" with a "large international portfolio," the source said. The buyer "may not have decided where to take it yet, he added."

Current ship rates for LNG tankers are very weak, reportedly as low as $25,000/d, said several sources. With fuel oil prices at about $390/mt and assuming a journey time from Abu Dhabi to Japan of 14 days, freight costs for that distance could be about 50 cents/MMBtu. That would imply an ex-ship price from Abu Dhabi to Japan of $4/MMBtu for the first half of July.

Another said that if the buyer has regasification capacity in India, it might be able to get a higher resale price by delivering it in there, where there is reportedly some spot demand.

Adgas offered the cargo in a tender that closed last week. Several major international companies reportedly

(continued on page 3)

Platts Asia daily spot LNG

LNG DES Japan/Korea Marker (JKM) — $/MMBtu	
JKM (Jul) (a)	4.00-4.10
H1 Jul	3.95-4.05
H2 Jul	4.05-4.15
H1 Aug	4.15-4.25
JKM vs Henry Hub futures (Jul) (b)	0.086
JKM vs NBP futures (Jul) (b)	-0.375
JKM vs. Asian Dated Brent (ADB) crude oil (b)	-8.696

NG Futures and Related Assessments

	$/MMBtu	Pence/Therm
NYMEX Henry Hub (Jul)	3.964 (b)	
NYMEX Henry Hub (Aug)	4.078 (b)	
UK NBP (Jul)	4.425 (b)	27.00 (c)
UK NBP (Aug)	4.704 (b)	28.70 (c)

	$/MMBtu	$/barrel
ADB Crude Oil	12.75 (d)	67.05 (b)
Deviation cost of freight to Taiwan/China	-0.20	

(a) JKM Marker averages the assessments of the two half-months comprising the first full month of forward delivery. LNG assessments assessed at Asian market close 0830 GMT. **(b)** NYMEX Henry Hub futures, ICE NBP futures and Asian Dated Brent crude oil all assessed at Asian market close 0830 GMT. **(c)** ICE NBP futures converted from Pence/Therm to $/MMBtu. **(d)** Asian Dated Brent converted from $/barrel to $/MMBtu. Detailed assessment methodology is found on www.platts.com.

Key price benchmarks

Asia contract markers — $/bbl	
JCC crude oil (April)	47.39
Europe contract markers	
Platts UK next-month NBP gas — p/th	27.30
Platts UK next-month NBP gas — $/MMBtu	4.40
US contract markers — $/MMBtu	
Platts next-day Henry Hub	3.865
NYMEX Henry Hub (Jul) settlement	4.249

Feedstocks Scorecard ($/MMBtu)

Asia	
Japan JCC LNG (April)	8.18
Singapore fuel oil	10.52
Qinhuangdao coal	3.24
Minas crude oil	13.166
LSWR Mixed/Cracked FOB Indonesia	9.629
Fuel oil 180 CST FOB Singapore	10.136
Naphtha CFR Japan	14.269
Europe	
Northwest Europe fuel oil	9.55
ARA coal	2.86
US	
US Gulf Coast 3%S fuel oil	NA
New York Harbor 1%S fuel oil	NA

Japan JCC value shows latest available CIF price published by the Ministry of Finance, converted to US dollars per MMBtu. All other values reflect Platts most recent one-month forward assessments for each product in each region, converted to US dollars per MMBtu.

Australia's Santos to sell undeveloped Timor Sea gas fields: CEO

Darwin, Australia—Australian exploration and production company Santos has placed its undeveloped gas fields in the Timor Sea up for sale, CEO David Knox said Monday.

Santos previously considered using those fields for a liquefaction project. The fields hold LNG-scale gas resources of multiple trillion cubic feet, Knox said. The assets include Santos' Petrel, Tern, Evans Shoal and Caldita discoveries.

"We've had these fields for a long time and they've been sitting in our contingent resources," Knox said on the sidelines of the Australian Petroleum Production and Exploration Association's annual conference here. "We get no shareholder value for (the assets) ... because we haven't been able to demonstrate there's been a cash flow stream. We've been unable to combine them into a (proposed) Darwin second (liquefaction) train despite lots of working discussions—it hasn't happened."

Santos is an 11.4%-shareholder in the ConocoPhillips-operated 3.5-million-mt/yr (448,000-Mcf/d) Darwin LNG project. In recent years, the US company has been trying to secure gas resources to underpin an expansion of the Darwin plant, which started producing in February 2006.

"We've got lots of things to do in Santos, so we're looking around, (seeing) which fields could we monetize and which fields are better in other people's hands and worth more than they are in ours, and the Timor Sea fields fit into that (last category)," Knox said. "Obviously, we have a holding price and if we don't get that, then we will keep them because they are valuable fields, but if someone else wants them for a good price, I'd be happy to let them have a crack at them."—*Christine Forster*

Indonesia rejects Donggi-Senoro LNG feed gas deal

Jakarta—Indonesia's upstream regulator, BPMigas, has rejected Pertamina and Medco Energi Internasional's proposal to increase the price the companies would charge the proposed Donggi-Senoro LNG project for feed gas, with an official saying Monday it should be higher.

The two companies have proposed adjusting the oil-linked price formula to yield a gas price of $3.10/MMBtu at today's oil prices, up from $2.80/MMBtu in the current formula.

"The price is supposed to be $3.80/MMBtu," BPMigas Chairman R. Priyono said Monday. "It is related to the state's revenue."

BPMigas previously told Indonesia's state-owned Pertamina and privately owned Medco to revise the price formula for gas that would be supplied from the Donggi and Matindok blocks to the DS LNG consortium, in which the two companies are also partners. The Energy and Mines Ministry would not approve a gas-sales deal to the DS consortium if Pertamina and Medco don't increase the price sufficiently, Priyono has said.

DS LNG is led by Japan's Mitsubishi, which has a 51% stake. Pertamina holds 29% and Medco owns 20%. The consortium plans to build a 2-million-mt/yr (256,000-Mcf/d) LNG plant in Central Sulawesi. The estimated cost of the liquefaction project is $1.4 billion.

Pertamina and Medco signed gas-sales agreements with DS LNG in January to supply the consortium under a 15-year contract beginning in 2012, Iin Arifin Takhyan, former vice president of Pertamina, has said. The DS LNG project would buy 250,000 Mcf/d of gas from the Senoro block, which is equally owned by Pertamina and Medco, and 85,000 Mcf/d from the Matindok block, which is wholly owned by Pertamina.

DS LNG would be the first liquefaction project in Indonesia to have separate upstream and downstream development. The other three LNG projects in the country—Arun, Bontang and Tangguh—are integrated developments.—*Anita Nugraha*

platts *LNG Daily*

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Taiwan's April LNG imports drop 23% on month to 23 Bcf

Singapore—Taiwan's LNG imports saw a steep month-on-month decline in April, down 23% to 1.09 million kiloliters (495,152 mt or 23 Bcf), and down 36.7% from a year previously, when it imported 1.73 million kl, according to data recently released by the country's Energy Bureau.

In February and March, Taiwan saw monthly gains in the volume of LNG imports, after January imports fell to 800,802 kl, the lowest level since February 2006. But the recovery in imports proved to be short-lived.

The drop in LNG use seemed to be due to the non-power sectors. Figures from state-owned utility Taipower showed generation from LNG grew 23.8% in April, to 2.08 TWh from 1.68 TWh in March. The March figure was already an increase of 48.8% from February, when the company generated just 1.127 TWh of power from LNG.

That increase in part reflected an overall climb in power generation, with Taipower's total sales rising 10% month on month in March to 13.32 TWh, and then dipping just slightly, 0.22%, in April to 13.29 TWh. LNG-fired generation also grew at the expense of coal-fired power, which saw a drop of 5.44% month on month in April, to 4.78 TWh.

The fall in LNG use outside of power may have been due to an increase in costs. Overall, the cost of LNG imports to Taiwan grew 32.3% month on month, to $534.58/mt ($10.28/MMBtu), although that was down 16.6% from April 2008's figure. The monthly rise in average costs may have been partly due to the fact that Taiwan imported no LNG from Qatar in April, which in previous months had been the cheapest source of LNG for the island nation.

Instead, Taiwan brought in a single cargo from Australia, at $463.74/mt ($8.92/MMBtu), and two cargoes from Equatorial Guinea, at an average price of $677.62/mt ($13.03/MMBtu). In addition to halting imports from Qatar, Taiwan also brought in no LNG from Trinidad and Tobago in April, compared with the previous month's single cargo, which cost $479.24/mt ($9.27/mt). That may have been replaced by the Australian cargo, which was priced similarly to the previous month's Trinidad and Tobago cargo.

The UK's BG, which has production capacity in Trinidad and Tobago and has reportedly signed a medium-term deal with Taiwan's CPC, was said to have taken several cargoes offered by Australia's North West Shelf in a tender for 20 cargoes held earlier in the year. By using locally sourced LNG to supply its contracted buyers, rather than its supplies in the Atlantic Basin, BG would save on freight costs, and could use the Trinidad and Tobago cargoes to supply the US or Europe.

With overall Taiwanese imports down, the main suppliers that were impacted were Indonesia and Malaysia, who provide Taiwan with the bulk of its LNG. Imports from Indonesia were down 50% month on month to 269,600 kl and down 33.4% year on year. Supplies from Malaysia were down 46.3% month on month, to 270,700 kl (122,655 mt), and down 65.6% year on year.

Indonesian officials said in March that Taiwan asked to cut its term LNG offtake from Indonesia by six cargoes this year. Indonesia also faced similar requests for term volume reductions from other customers in South Korea and Japan, for a total cut of 18 cargoes, and in April signaled its willingness to consider allowing them to forgo 15. But later Indonesian officials said they would resume producing liquid petroleum gas at the Bontang liquefaction plant, and an industry observer said that likely meant Indonesia would not reduce the number of term cargoes it sells to Japan this year, but meet Japanese requests for fewer cargoes by selling cargoes with lower calorific values.—*Jonty Rushforth*

Taiwan LNG imports

	Apr-09		Apr-08			
	Vol (mt)	Cost ($/mt)	Vol (mt)	Cost ($/mt)	% vol chg	% cost chg
Indonesia	122,157	431.41	183,371	896.00	-33.38	-51.85
Malaysia	122,655	467.16	356,185	467.45	-65.56	-0.06
Australia	59,085	463.74	—	na	na	na
Nigeria	64,341	640.34	177,843	700.05	-63.82	-8.53
E. Guinea	126,914	677.62	65,247	712.68	94.51	-4.92
Total	495,152	534.58	782,646	641.16	-36.73	-16.62

July JKM at $4.05/MMBtu as Adgas sells cargo *(from page 1)*

participated. A source said BP, Royal Dutch Shell, Total and Vitol placed bids, adding there were no bids from "smaller buyers," unlike Adgas' previous tender for a cargo this month.

The cargo for this month was reportedly sold at an FOB price "in the low 3s," a source said.

The reported higher price for the July cargo may reflect improvement in US prices, with July New York Mercantile Exchange futures moving as high as $4.60/MMBtu last month. US futures were flat Monday morning Singapore time, with July at $3.964/MMBtu and August at $4.078/MMBtu.

But prices have also been firmer in the UK, at least in dollar-denominated terms. July futures for the National Balancing Point gas hub were at 27 pence/therm ($4.425/MMBtu) at 0830 GMT Monday, up 0.2 p from the same time Friday, but up 12.3 cents in dollar-denominated terms, due to a further strengthening of the pound. The pound gained about 10% against the dollar since early May, last month.—*Jonty Rushforth*

Spain's Gas Natural sells Enagas stake to Oman Oil

Barcelona—Spain's Gas Natural has sold its 5% stake in domestic natural gas grid owner Enagas to Oman Oil, the gas and power utility said Monday.

The divestiture, for which no value was provided, fulfills one of the conditions laid out earlier this year by Spain's National Competition Commission when it authorized the Eur16-billion ($23-billion) takeover of Spanish power producer Union Fenosa, a deal completed in April.

Gas Natural, which at one time owned 100% of Enagas, has been steadily reducing its stake in the gas grid owner since 2002, largely because of ever-increasing government restrictions on cross ownership in the energy sector.

Oman Oil, owned by the Sultanate of Oman, also owns 15% of the Saggas LNG import terminal in Spain's eastern Valencia region and 10% of Spanish oil products distributor CLH.

In addition to selling the Enagas stake, Spain's competition regulator required Gas Natural to sell various gas distribution networks with a total customer base of around 600,000 users, representing about 9% of domestic demand, and 2,000 MW of operational gas-fired, combined-cycle plants.

Additionally, Gas Natural cannot participate in management decisions relating to Spanish petroleum Cepsa, 5%-owned by Union Fenosa, and guarantee the independence of Union Fenosa Gas, which is 50% owned by the takeover target and 50% owned by Italy's Eni.—*Henry Cybulski*

As hurricane season begins, bears still in control

(from page 1)

later, the NYMEX fell after hurricanes Gustav and Ike knocked out substantial Gulf gas flow.

"We saw two big hurricanes last year … and it didn't even create a hiccup in natural gas' decline," said Schork Group analyst Stephen Schork. "We came into a winter, which was by virtually every measure colder than normal, and it wasn't even a speed bump in the NYMEX's decline."

Today, "the market is viewing demand, as compared to supply, to remain weak," Schork said, adding that he expects further softness on the NYMEX in the coming months even if the threat of Gulf storms increases.

He said it would require significant buying by funds acting on storm fears to reverse the NYMEX's downward direction.

"There's certainly that potential if you get enough money in the market," Schork said. "The only thing weighing on it is absolute lack of demand."

The United States Natural Gas Fund, which holds 25% of the July NYMEX contract's open interest, may be able to apply pressure on gas prices.

"We've seen a lot of money moving out of oil into gas, leading to that bump in May where the NYMEX went from $3.50/MMBtu to $4.50/MMBtu, then back to $3.50/MMBtu," Schork said.

Traders were divided as to the ability of a single fund to push the NYMEX higher, even on storm fears, but they did not discount short-lived price spikes if a Gulf hurricane threatens. But some physical traders said only a hurricane of Katrina-like proportions would cause a major blip in today's supply-rich market.

"There's more storage online now and a lot of pipes are full with gas," a Gulf trader said. "People are just looking for opportunities to offload now."

Mark Cook, principal at storage firm SGR Holdings, said, "There is an abundance of gas and there are new outlets for it. We certainly seem to be living in luxury with the storage that we have."

The US Energy Information Administration said Thursday that working gas in storage was 2.213 Tcf as of May 22, more than 30% above year-ago levels and more than 20% higher than the five-year average. In comparison, inventories were more than 500 Bcf lower than that—1.692 Tcf—during the same week of 2005; Katrina hit three months later.

According to Platts historical spot prices, Florida Gas Transmission zone 3 gained $6/MMBtu during the week Katrina made its Gulf approach and in its immediate aftermath, while Henry Hub prices jumped more than $3/MMBtu in the same period.

Ike had less of an impact. Florida zone 3 gained $1/MMBtu on average during the week of the storm, while Henry Hub tacked on about 20 cents/MMBtu.

Supply portfolio diversification provided by new pipelines delivering unconventional gas —such as the Rockies Express and Gulf Crossing—likely accounted for the lack of a price spike last year, some sources said.

George Lippman, president of Lippman Consulting, said the offshore area was producing volumes nearing 11.5 Bcf/d before Katrina. By October 2005, that stood at about 4.9 Bcf/d.

When Ike rolled onshore, flows were about 8.5 Bcf/d and were cut to 2.5 Bcf/d after the storm. Offshore Gulf output has yet to return to 8 Bcf/d.

"The Gulf is disappearing," Lippman said.

The market lost production following Ike "and there was no price impact," he said. "That tells you how important it was."

Gulf forward basis markets, meanwhile, have so far shown no hint of a fear premium. Instead, prices have been influenced by increased unconventional supplies, such as shale gas.

Florida Gas Transmission's zone 3 was assessed by Platts Friday at plus 17 cents and plus 19 cents/MMBtu for August and September packages, respectively. Platts forward full values assessed Friday indicate prices would not exceed the mid-$4.20s/MMBtu through summer.

Last year, Platts forward basis at that gas-hungry market topped out at plus $1.07/MMBtu for August, not because of hurricane fears, but because of a delay in the Southeast Supply Header construction that would have delivered 1 Bcf/d to Florida.

That surpassed 2007 levels when hurricanes Humberto and Dean actually threatened Gulf production in late summer. That year, Florida August and September basis topped out at plus 71.25 cents and plus 79.75 cents/MMBtu, respectively.

Forward data also shows the back of the summer curve in serious decline, largely because of the expected growth in LNG imports to the Gulf late this summer, sources said.

"We've got too much gas and not enough takeaway now," said a Gulf trader who represents producers. "I think we have front-row tickets to the train wreck."—*Adam Bennett, Samantha Santa Maria, Joshua Starnes*

US LNG Terminal Throughput (Dt/d)

	Point Capacity	May 26	May 27	May 28	May 29	May 30	May 31	Jun 1
COVE POINT, MD								
DOMINION COVE POINT LNG LP	1,800,000	351,062	590,106	641,436	447,145	443,136	444,639	604,776
ELBA ISLAND, GA								
SOUTHERN NATURAL GAS CO	952,593	681,903	890,860	859,424	383,866	0	0	436,065
EVERETT, MA								
ALGONQUIN GAS TRANSMISSION CO	275,200	121,084	121,374	147,551	118,918	118,953	129,023	125,823
TENNESSEE GAS PIPELINE CO	200,000	79,179	101,866	96,823	60,515	60,515	60,515	100,857
GULF GATEWAY								
BLUE WATER PIPELINE	694,299	0	0	0	0	0	0	0
SEA ROBIN PIPELINE CO	635,000	0	0	0	0	0	0	0
LAKE CHARLES, LA								
TRUNKLINE GAS CO LLC	1,800,000	10,070	7,904	5,733	46	6,826	38,451	16,412
NORTHEAST GATEWAY								
ALGONQUIN GAS TRANSMISSION CO	1,200,000	0	0	0	0	0	0	0
SABINE PASS								
CHENIERE CREOLE TRAIL PIPELINE CO	2,100,000	11,275	19,000	11,275	11,275	11,275	11,275	11,275
Total:		**1,254,573**	**1,731,110**	**1,762,242**	**1,021,765**	**640,705**	**683,903**	**1,295,208**

The volume in the column with today's date is what was scheduled to move on the pipeline as of 4 pm Central time. The volume listed for other dates is the final volume scheduled for that day.
Source: Platts data

US FERC grants Cheniere's request to re-export LNG from Sabine Pass

Washington—The US Federal Energy Regulatory Commission has approved Cheniere Energy's request to modify its Sabine Pass LNG import terminal in Cameron Parish, Louisiana, to allow it export foreign-sourced gas.

Cheniere said in its application to FERC last fall that its US customers would benefit from the ability to store imported LNG and then resell it when US gas prices drop below global market prices. LNG import terminals must import small amounts to keep their equipment cooled at proper temperatures, and the ability to re-export the majority of a cargo, after using a small amount for cooling, would make it easier to import those small amounts even if US gas prices are low, Cheniere has said.

"The proposal will help ensure that the Sabine Pass facility remains in operation even when US market prices are low," FERC said in an order issued late Friday. "To the extent that a domestic market for LNG does develop, the proposal will help ensure that a supply is present and available for delivery to domestic markets."

> The proposal will help ensure that the Sabine Pass facility remains in operation even when US market prices are low. To the extent that a domestic market for LNG does develop, the proposal will help ensure that a supply is present and available for delivery to domestic markets.
>
> **—US Federal Energy Regulatory Commission**

Cheniere has a pending application with the Department of Energy for authorization to export as much as 64 Bcf of LNG for a two-year period. To export the LNG, Sabine Pass would need to modify four 24-inch-diameter check valves at the terminal. The modified system could be used to move LNG from storage tanks to transfer lines and onto a tanker.

In its environmental review, FERC found no major reliability, operational or safety issues, but staff found that using the terminal for export would result in the additional discharge of ballast water when loading LNG carriers.

The Coast Guard has already ruled that it won't require Sabine Pass to submit a modified water-suitability assessment or a formal letter of intent explaining the terminal's use as an export facility.

The terminal can accommodate as many as 400 LNG vessels a year. Of those, as many as 20 or so cargoes are expected to be for the purpose of exporting gas.—*Joel Kirkland*

Russian gas output falls 16-18% through May

Moscow—Russian Energy Minister Sergei Shmatko said Monday he hopes European gas injection into storage this summer would compensate somewhat for a large drop in gas consumption so far this year.

"As of the end of May, we see that the decline will be some 16%-18%," Shmatko said on Russia's state-run Vesti channel. "But there are some optimistic expectations that we can compensate somewhat for the fall in gas output in the summer months, when gas consumers ... pump gas into underground storage facilities.

"We can expect that the decline in gas output will be narrowed," he said.

Russian gas output dropped 17.1% on the year to 197.7 billion cubic meters (6.98 Tcf) in the first quarter, mainly due to a drop in demand, the ministry said.

In early April, Russia's state-owned gas monopoly, Gazprom, said it expected its gas output to fall about 10% this year and remain down for four to five years, matching a drop in demand in Russia and the rest of Europe, the company's largest export market. But later that month, Gazprom Deputy CEO Alexander Ananenkov said the company's production this year could total 450-510 Bcm, indicating a decline of 7%-18% from last year's output of 549.7 Bcm.

Gazprom accounts for more than 80% of Russia's gas production. Russia by far has the world's largest gas reserves and provides about 25% of the gas consumed in Europe.

Gas demand at the end of last year and the start of this year dropped dramatically due to the deteriorating global economy, relatively mild weather and the record high price of Russian gas compared with cheaper fuel oil, according to Gazprom. Russian pipeline exports are indexed to the price of fuel oil, but with a time lag, creating a temporary situation in which gas prices were significantly higher than fuel oil prices, in terms of energy units, as the price of oil started to plummet last year.

Pipeline access bill

Separately, Shmatko said he expects a draft law that would secure access for associated gas producers to trunk pipelines operated by Gazprom would be submitted to the parliament for approval soon.

"The document will be submitted to the State Duma in the near future ... and I think that companies would start to submit their applications for (capacity) immediately after the law is approved," he said.

The move is part of an effort to reduce gas flaring in Russia, which now totals 15 Bcm/yr, or some 25% of total associated gas production, said Shmatko. Russian authorities are pushing oil producers to reduce gas flaring to a maximum 5% of output by 2012, but producers are finding it difficult to increase gas use, due to limited access to pipelines.

Under existing laws, Gazprom must accept other producers' gas into its pipelines only if there is spare capacity, and the vagueness of the wording allows Gazprom to restrict gas volumes available to other producers. Currently, if there is spare capacity, gas suppliers to municipal utilities have priority, Shmatko said. Producers of associated gas would now receive the same priority status, he said.

"There are no disagreements with Gazprom on the issue," he added.

In 2007, Russia flared 17 Bcm of associated gas, or 28% of the 61 Bcm of associated gas produced that year, according to then-Prime Minister Viktor Zubkov. Just 29% of the total associated gas was processed for industrial use, while the remaining volumes were used by oil producers for their own needs at fields.

The official statistics, however, may be inaccurate as most oil fields in Russia do not have gas-metering systems. Some experts believe the actual amount flared could be as high as 50-70 Bcm.—*Nadia Rodova*

Calendar of LNG events

June	
10-12	Small Scale LNG
	Stavanger, Norway
	http://www.tekna.no/
17-18	Contract Risk Management for LNG Supply & Purchase Agreements
	Seoul, South Korea
	http://www.iqpc.com
23-25	Global LNG Congress
	Istanbul, Turkey
	http://www.theenergyexchange.co.uk
29-Jul 1	Next Generation LNG
	Singapore
	http://asiapacific.cwclng.com/
July	
28-29	Commercializing FLNG Asia
	Singapore
	http://www.iqpc.com/
August	
4-6	SPE Asia Pacific Oil & Gas
	Jakarta, Indonesia
	http://www.spe.org/
10-11	Marcus Evans LNG World
	Perth, Australia
	www.marcusevansassets.com

Kogas signs MOU for 40% of Kitimat LNG output *(from page 1)*

would come online in 2013.

Canadian shipper Teekay and Merrill Lynch have formed a joint venture to liquefy onshore Western Canadian gas using a floating production vessel that would be moored off Kitimat. That project is slated to come online in 2012-13.

North America has one liquefaction plant, Alaska's Kenai LNG plant, which started operating in 1969. That 1.5-million-mt/yr facility, owned by ConocoPhillips (70%) and Marathon (30%), primarily exports to Japan.

Galveston LNG in January announced that Japanese conglomerate Mitsubishi agreed to acquire capacity and an equity stake in the planned liquefaction plant. Under that agreement, Mitsubishi committed to buy 1.5 million tons of annual terminal capacity and acquire a minority equity interest in the project. Financial terms were not disclosed.

Kitimat said Monday it is negotiating with other potential terminal users and investors for terminal capacity, off-take and equity.

"We welcome Kogas' participation in our project," said Kitimat LNG President Rosemary Boulton said in statement. "The addition of a strong international company and leading LNG buyer such as Kogas marks a significant milestone in the development of the Kitimat LNG terminal."

Kogas CEO Kangsoo Choo added, "Our agreement with Kitimat LNG is key to our ongoing efforts to ensure a secure supply of natural gas for Korea in the long-term. We are pleased to add natural gas from Canada to our portfolio and tap into the country's growing sources of supply."—*Jeff Barber*

ConocoPhillips eyes collaboration on Australian CSG-to-LNG plans

Darwin, Australia—The US' ConocoPhillips is among the companies looking for opportunities to collaborate with developers of rival coalseam gas-based LNG projects planned on Curtis Island, in the port of Gladstone in the eastern Australian state of Queensland, a senior company executive said Monday.

"Certainly we are looking to work with the other projects that are there from the upstream, the midstream and the downstream side of the business," Ryan Lance, ConocoPhillips' senior vice president of international exploration and production, told reporters on the sidelines of the Australian Petroleum Production and Exploration Association's annual conference here.

"There will be some natural collaboration that will make sense as we go forward," he said. "We're all looking for those opportunities."

ConocoPhillips made the world's largest oil-and-gas-sector acquisition last year by agreeing to pay Australian integrated energy company Origin Energy as much as nearly $8 billion for a 50% share in its proposed coalseam gas-based LNG project in Gladstone. The deal was the largest among other mergers and acquisitions centered on the Queensland coalseam gas sector, which has also attracted the interest of global players BG, Petronas and Royal Dutch Shell.

ConocoPhillips and Origin formed a joint venture, Asia Pacific LNG, to develop Australia's largest coalseam gas reserves base for liquefaction at a plant that would have as many as four 3.5-million-mt/yr (448,000-Mcf/d) trains. The companies plan to make a final investment decision next year, with first LNG targeted for 2014.

Australian exploration-and-production company Santos, which has teamed up with Malaysia's state-owned Petronas to pursue the planned Gladstone LNG project, which would initially produce 3.5 million mt/yr, has also indicated willingness to collaborate with rival projects. Although collaboration is typically difficult to pull off, it makes sense among the proposed coalseam-gas based LNG projects in eastern Australia because it would significantly cut costs and improve efficiency, Santos CEO David Knox said Monday.

"We have a project we can deliver without collaboration, but I would welcome it if it's possible," he said.

> Certainly we are looking to work with the other projects that are there from the upstream, the midstream and the downstream side of the business.
>
> **—Ryan Lance, Senior Vice President, International Exploration and Production, ConocoPhillips**

In addition to the Santos-Petronas and Origin-ConocoPhillips proposals, UK-based BG is developing a 7.4-million-mt/yr LNG project in Gladstone based on coalseam gas it acquired through recent takeovers of Queensland Gas and Pure Energy. Shell has also launched preliminary studies for its planned plant in Gladstone.

Shell has a joint venture with Arrow Energy to supply gas to its proposed plant. Arrow has also agreed to supply gas to a 1.5-million-mt/yr LNG plant proposed by Australia's Liquefied Natural Gas Ltd.

Meanwhile, Canada's LNG IMPEL has proposed an open-access liquefaction plant in Gladstone with as many as three trains, each with capacity of 700,000 to 1.3 million mt/yr.

"There are a lot of projects being talked about and, with the current economic recession and global downturn, folks are wondering is there enough demand for the LNG that's out there," ConocoPhillips' Lance said. "We believe there is ... and (that) once we come out of this economic recession, especially with the conversation around climate change and CO2 ... LNG will actually be a fuel for the future.

"As countries, specifically in Asia, make choices between coal-fired power generation, oil-fired power generation and generation from LNG, the demand will be there," he said. "We'll go through a bit of a lull for a while, but long term we think it's a good business."

Santos' negotiations with potential customers of its Gladstone project are "going well" although the proof would be a heads of agreement outlining a term deal, Knox said.

"We are in discussions with multiple parties and making good progress," he said. "We're seeing customers genuinely engaging."

He conceded that Japanese buyers are now going through tough economic times.

"To get them to sign (a non-binding heads of agreement) is not that straightforward right now," Knox said. "It's a matter of us presenting a good enough case and sufficient surety of FID next year and first delivery in 2014 to persuade them to do so."

The Gladstone LNG projects are among a number of liquefaction projects planned in the Australasia region. US companies Chevron and ExxonMobil lead planned projects in Western Australia's Gorgon region and Papua New Guinea, respectively. Australia's Woodside Petroleum is pursuing its Sunrise and Browse projects in northwestern Australia. Japan's Inpex plans to develop its Ichthys gas field off Western Australia to supply an LNG plant in Darwin.

Only three LNG projects are likely to make FIDs this year, FACTS Global Energy Chairman Fereidun Fesharaki told reporters on the sidelines of the conference.

He said those would be Gorgon, the ExxonMobil-led PNG LNG project and the Donggi-Senoro LNG project in Indonesia's Central Sulawesi. It is possible that FIDs would be made next year for Inpex's Ichthys project and one Gladstone coalseam gas-based plant, he said.

Among the Gladstone projects, which would be very dependent on oil prices, Fesharaki forecast that only two would proceed, and at a slow pace.—*Christine Forster*

APPENDIX 2

ISSUE Alert | MARCH 17, 2009

VanNess Feldman
ATTORNEYS AT LAW

Court Dismisses State Challenge to FERC Environmental Conditions

On March 13, 2009, the U.S. Court of Appeals for the D.C. Circuit dismissed for lack of standing a petition by the Delaware Department of Natural Resources and Environmental Control ("Delaware") challenging orders by the Federal Energy Regulatory Commission ("FERC" or the "Commission") that conditionally approved an application by Crown Landing LLC ("Crown Landing") under the Natural Gas Act ("NGA") to site, construct and operate a liquefied natural gas ("LNG") terminal at the mouth of the Delaware River. Delaware claimed that FERC had exceeded its statutory authority by conditionally approving the application *before* the requirements of the Coastal Zone Management Act ("CZMA") and Clean Air Act ("CAA") had been satisfied. The court held that Delaware had suffered no injury in fact and so lacked standing to challenge FERC's orders. *Delaware Department of Natural Resources and Environmental Control v. FERC*, No. 07-1007 (D.C. Cir. 2009).

REGULATORY BACKGROUND

Under the CZMA, any applicant for a Federal license to conduct activities affecting a "land or water use or natural resource" of a state's coastal zone must certify to the relevant state agency that the proposed activity complies with the enforceable policies of the affected state's coastal management plan. The state agency has six months to inform the Federal government whether it concurs with or objects to the applicant's consistency certification. An applicant may appeal a state's objection to the Secretary of Commerce, who can override the state's objection if the Secretary finds that the activity is consistent with the objectives of the CZMA or otherwise necessary in the interest of national security.

The Clean Air Act establishes a joint state and federal program to control air pollution in the United States. Section 109 requires the Environmental Protection Agency ("EPA") to establish National Ambient Air Quality Standards ("NAAQS") for certain pollutants, known as "criteria pollutants"(*e.g.*, ozone, sulfur dioxide, nitrogen dioxide, particulate matter, carbon monoxide, and lead). To meet these standards, section 110 requires each State to develop a state implementation plan or "SIP," subject to review and approval by EPA. For areas that presently do not meet the NAAQS or have not met the limits in the past, the CAA prohibits a federal agency from licensing any activity that fails to conform to a state plan that has been approved by the EPA to meet the NAAQS. For these areas, federal agencies must ensure that any proposed project conforms with the applicable state plan prior to approval of the project.

FACTS

On February 3, 2005, the Delaware Department of Natural Resources and Environmental Control issued a Coastal Zone Status Decision, which determined that the proposed LNG pier was prohibited by the state's Coastal Zone Act. This decision was affirmed by Delaware's Coastal Zone Industrial Control Board.

On June 20, 2006, the FERC issued an order approving Crown Landing's application, but conditioned the approval upon Crown Landing's obtaining state authorizations under the CZMA and CAA. Specifically, FERC's order provided that no construction could commence until the state authorizations were obtained.

On rehearing, Delaware argued that the Commission did not have authority to issue an approval order unless the Commission first ensured compliance with the state's environmental programs. Nevertheless, the Commission found that approving the Crown Landing project subject to the conditions imposed was consistent with case law, the Commission's conditioning authority, and relevant agency regulations.

THE D.C. CIRCUIT'S DECISION

Delaware argued that the CZMA unambiguously grants the state priority in the approval process. In considering whether Delaware had standing, the court said it would assume the validity of Delaware's merits argument, i.e., that FERC had violated the statutory scheme by issuing a conditional order, because Delaware had "a statutory right to go first". Nevertheless, the court said, it could not see how the "FERC's allegedly illegal action" caused Delaware any injury in light of the State's ability to veto the project. (In fact, as the court noted, Delaware had already rejected the project.)

The court was not persuaded by Delaware's argument that its rights were not protected adequately by FERC's conditional order, because Crown Landing could appeal any state objection to the CZMA consistency certification denial directly to the Secretary of Commerce. Because the Commission's order was conditioned on Delaware's approval, it would be unaffected by any subsequent action overriding Delaware's objection by the Secretary of Commerce. Such intervention by the Secretary of Commerce would require a new order by the Commission.

The court dismissed Delaware's concern that it would "face intense political pressure to acquiesce in FERC's conditional approval" saying that "Delaware is essentially asking us to prevent it from changing its own mind." Concerning the argument that Delaware had "suffered the loss of a statutory procedural right – the right to precede FERC and thereby prevent a FERC proceeding", the court found that the procedural injury did not confer standing because it did not affect a concrete substantive interest.

IMPLICATIONS

Although the D.C.Circuit's decision does not decide the merits of FERC's longstanding practice of issuing a certificate order conditioned on subsequent compliance with other Federal permitting requirements, it leaves that practice in place. Similar challenges have been made to FERC's conditioning authority under the NGA concerning other LNG and pipeline projects, as well as to FERC's authority to issue conditional licenses for hydrokinetic projects under the Federal Power Act ("FPA"). In fact, a similar challenge pending before the D.C. Circuit on FERC's issuance of a conditional hydrokinetic license is being held in abeyance, pending the outcome of this decision. Such challenges could also be raised to FERC authorizations under the FPA for siting transmission facilities.

The decision suggests that the standing doctrine could limit future challenges to FERC's approach of issuing conditional certifications, effectively precluding attacks on FERC's pragmatic approach to the timing of multiple permits required to construct energy infrastructure projects under its jurisdiction. Yet, two factors in this case might distinguish this case from others: the challenge here was being brought by the state itself, and the state already had denied the consistency determination under the CZMA. The decision, however, does not affect the ability of a state to delay or halt a project by denying a permit required by the CAA or CZMA.

FOR ADDITIONAL INFORMATION

For more information, please contact Bob Christin in our Washington, DC office at (202) 298–1987.

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued February 19, 2009 Decided March 13, 2009

No. 07-1007

DELAWARE DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

CROWN LANDING LLC AND STATOIL NATURAL GAS, LLC,
INTERVENORS

On Petition for Review of Orders
of the Federal Energy Regulatory Commission

Scott H. Angstreich argued the cause for petitioner. With him on the briefs were *David C. Frederick*, *Daniel G. Bird*, *Joseph R. Biden, III*, Attorney General, Attorney General's Office of the State of Delaware, *Kevin P. Maloney*, Deputy Attorney General, and *Philip Cherry*.

Samuel Soopper, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With him on the brief were *Cynthia A. Marlette*, General Counsel, and *Robert H. Solomon*, Solicitor.

Frederic G. Berner Jr. was on the brief for intervenor Crown Landing LLC.

Before: ROGERS, *Circuit Judge*, and SILBERMAN and WILLIAMS, *Senior Circuit Judges*.

Opinion for the Court filed by *Senior Circuit Judge* SILBERMAN.

SILBERMAN, *Senior Circuit Judge*: Petitioner Delaware seeks review of two FERC orders by which the Commission conditionally approved an application to site, construct, and operate a liquid natural gas terminal near the mouth of the Delaware River. We dismiss the petition for lack of jurisdiction: Delaware lacks standing because it has not suffered an injury-in-fact.

I

In September 2004, Crown Landing LLC, a wholly-owned subsidiary of BP America Production Company, filed an application with the Commission to site, construct, and operate a liquid natural gas import terminal at the mouth of the Delaware River. Onshore portions of the proposed project were to be located in New Jersey, but a pier designed for the unloading of tanker ships was planned to extend beyond New Jersey waters into that portion of the river which appertains to neighboring Delaware.[1]

[1]The First State's title to certain submerged lands within a twelve-mile radius of the New Castle courthouse was conclusively determined by the Supreme Court in *New Jersey v. Delaware*, 291 U.S. 361, 374 (1934).

Section 3 of the Natural Gas Act ("NGA"), 15 U.S.C. §717b(a) *et seq*., prohibits the importation of foreign natural gas without prior authorization by the Commission. As amended,[2] the NGA confers upon the Commission the authority to approve or deny applications for the "siting, construction, expansion, or operation of a [liquid natural gas] terminal." With certain limitations, irrelevant here, approval orders may be issued conditionally as the Commission deems necessary or appropriate.

The NGA specifically provides for the protection of rights granted to the states under the Coastal Zone Management Act of 1972 ("CZMA"), 16 U.S.C. § 1451 *et seq*., and the Clean Air Act ("CAA"), 42 U.S.C. § 7401 *et seq.* Although the mechanisms differ, both of these statutes mandate that federal licensing authorities ensure compliance by proposed projects with relevant state-based environmental programs.

The CZMA tasks the states with the development of coastal zone protection programs in exchange for federal funding incentives. Upon approval of such a program by the National Oceanic and Atmospheric Administration, any applicant for a federal license to conduct activities in a coastal zone must certify that the proposed activity complies with the program adopted by the affected state. A copy of this certification must be furnished to the relevant state agency, which must inform the federal government within six months whether or not it concurs with the certification. Ordinarily, no license may be granted absent state approval of this compliance certification.[3]

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[2] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[3] In the event that the state fails to inform the federal government of its decision within the allotted six month period, the state's

However, if the Secretary of Commerce concludes, whether on his own initiative or upon appeal by the applicant, that the project is consistent with the objectives of the CZMA or otherwise necessary on national security grounds, the state's pre-approval rights may be preempted and the project may proceed.

The CAA similarly requires each state to adopt a plan to implement, maintain, and enforce national air quality standards within the state. Once the Environmental Protection Agency has approved of a state plan, no department or agency of the federal government is authorized to license any activity that fails to conform with the plan. Federal agencies bear an "affirmative responsibility" to ensure that any proposed project conforms with the applicable state plan prior to approval. Under this statute, there is no provision permitting a federal official to override a state, but, on the other hand, there also does not appear to be any mechanism for the state specifically to disapprove a project.

Crown Landing did not file a CZMA certification with Delaware but did request a status decision from the state (we gather that a status decision is, in effect, a preliminary, yet preemptive, decision). On February 3, 2005, the Delaware Department of Natural Resources and Environmental Control, petitioner here, issued its decision and rejected the project. On appeal, Delaware's Coastal Zone Industrial Control Board unanimously affirmed that decision. Meanwhile, New Jersey filed an original action before the Supreme Court challenging Delaware's jurisdiction to regulate the Crown Landing terminal pursuant to its authority under the CZMA. The Supreme Court confirmed that Delaware indeed possesses this authority. *New Jersey v. Delaware*, 128 S. Ct. 1410, 1427-8 (2008).

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concurrence with the proposal is conclusively presumed.

On June 20, 2006, the Commission issued an order approving Crown Landing's application subject to some sixty-seven conditions precedent.[4] The Commission acknowledged that the Crown Landing proposal is subject to coastal zone consistency reviews in New Jersey, Delaware, and Pennsylvania and thus concluded that the company must obtain the concurrence of the relevant state agencies prior to Commission approval of the commencement of construction. *See* Conditional Approval Order at ¶ 62,391; *see also id*. at ¶ 62,386. Accordingly, *final* approval by the Commission is subject to the condition that documentation of concurrence by the state of Delaware evidencing the consistency of the project with the state's Coastal Management Program be submitted by the company "**prior to construction**." *Id*. App. A, at ¶ 20 (emphasis in original). The order contains a parallel condition requiring pre-construction submission of an air quality analysis specifically demonstrating conformity with applicable state implementation plans under the CAA. *Id*. App. A, at ¶ 22.

Delaware requested agency rehearing on the basis that the Commission had exceeded its statutory authority by approving the application under its NGA powers *before* the requirements of the CZMA and CAA had been satisfied. In Delaware's view, issuance of an approval order–conditionally or otherwise–is *ultra vires* conduct unless the Commission has first ensured compliance with relevant state environmental programs. Rehearing was denied. Order Denying Rehearing and Issuing Clarification, *Crown Landing LLC*, Docket No. CP04-411-001, 117 FERC ¶ 61,209 (Nov. 17, 2006). Delaware's petition for review before this Court, filed in January 2007, was held in

[4] Order Granting Authority Under Section 3 of the Natural Gas Act and Issuing Certificate, *Crown Landing LLC; Texas Eastern Transmission LP*, Docket Nos. CP04-411-000, CP-04-416-000, 115 FERC ¶ 61,348 (June 20, 2006) ("Conditional Approval Order").

abeyance pending resolution New Jersey's original action before the Supreme Court. Then the Commission, joined by Crown Landing, moved to dismiss Delaware's petition on grounds of non-justiciability and lack of standing. We ordered the case restored to the oral argument calendar, deferred the dismissal motions, and ordered the parties to revisit their merits briefs in light of the Supreme Court's intervening decision.

II

As noted, FERC, along with intervenor Crown Landing, challenges Delaware's standing, asserting that the state lacks an injury-in-fact, because FERC's order is explicitly conditioned on state approval under the CZMA (and CAA). Indeed, the state has already exercised its CZMA authority to reject the project, which has received the imprimatur of the Supreme Court. *See New Jersey*, 128 S. Ct. at 1427-28. Delaware responds that it has suffered an injury because it was entitled under both statutes to block the project before FERC even proceeded to consider the matter. In other words, FERC lacked statutory authority to issue a conditional order, even if that condition preserved Delaware's right to veto the project.

Delaware argues that the CZMA unambiguously grants the state priority in the approval process. The statute reads in relevant part: "[n]o license or permit shall be granted by the Federal agency until the state or its designated agency has concurred with the applicant's certification." 16 U.S.C. § 1456(c)(3)(A). The CAA contains similar language. 42 U.S.C. § 7506(c)(1). The merits therefore depend upon whether FERC's conditional approval order constitutes a "license or permit" within the meaning of these statutes.

Of course, in considering standing, we must assume the validity of Delaware's merits argument, *i.e.*, that FERC violated the statutory scheme by going ahead and issuing a conditional order, because Delaware had a statutory right to go first (*i.e.*, Alphonse ahead of Gaston). *See Warth v. Seldin*, 422 U.S. 490, 500 (1975); *see also Emergency Coalition to Defend Educational Travel v. Dep't of Treas.*, 545 F.3d 4, 10 (2008); *Parker v. District of Columbia*, 478 F.3d 370, 377 (D.C. Cir. 2007), *aff'd without reaching standing issue sub nom. District of Columbia v. Heller*, 128 S. Ct. 2783 (2008); *City of Waukesha v. EPA*, 320 F.3d 228, 235 (D.C. Cir. 2003); *Am. Fed'n of Gov't Employees, AFL-CIO v. Pierce*, 697 F.2d 303, 305 (D.C. Cir. 1982).

Still, we are unable to see how FERC's allegedly illegal procedure causes Delaware any injury in light of FERC's acknowledgment of Delaware's power to block the project. Delaware is apparently concerned that it will face intense political pressure to acquiesce in FERC's conditional approval and reverse its own status decision–pressure it would somehow avoid were FERC not to have acted at all. We could hardly recognize this conjectural political dynamic as representing a concrete injury or, indeed, any sort of legally-cognizable injury. Delaware essentially is asking us to prevent it from changing its own mind.

To be sure, Delaware mentioned in its brief and stressed at oral argument that, under the CZMA, Crown Landing could potentially appeal any Delaware denial directly to the Secretary of Commerce. It is argued, therefore, that Delaware is not adequately protected by FERC's conditions. But as we read FERC's order, this is not so. The Commission conditioned its approval on Delaware's approval–which would be unaffected by any subsequent action by the Secretary of Commerce. FERC's counsel dispelled any doubt on this score by unequivocally assuring us at oral argument that any modification of the

Commission's position–including to recognize an intervention by the Secretary–would require a new order.[5]

That leaves Delaware with the argument that it was injured because it has suffered the loss of a statutory procedural right–the right to precede FERC and thereby prevent a FERC proceeding. Delaware's difficulty is that an alleged procedural injury does not confer standing unless the procedure affects a concrete substantive interest. *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 573 n.8 (1992). In its reply brief, arguing in the alternative that the case is moot (and hence that FERC's order should be vacated), Delaware contends that because Crown Landing has "announced publicly that it is 'stopping work on the project,'" the controversy has gone away. But this statement implicitly concedes the obvious: that Delaware's substantive interest is the preventing of the construction of the project. Its alleged procedural injury has no bearing on that interest, because under FERC's order the project cannot be resurrected without Delaware's approval.

Delaware points to two cases to support its statutory procedural right claim–one is ours and one the Fifth Circuit's. In *Zivotofsky v. Secretary of State*, 444 F.3d 614 (D.C. Cir.

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[5] It is not apparent that even if FERC allowed construction to move forward based on a secretarial decision, Delaware would have standing based only on their procedural (Alphonse-Gaston) theory, but, of course, Delaware would then have standing to challenge FERC's order and the Secretary's decision as an interpretation of the substantive statutes (including the APA). In any event, this scenario–which was not raised in Delaware's opening brief–hardly presents a ripe controversy now.

2006), we recognized that a child born in Jerusalem had standing to insist that his U.S. passport record his birthplace as Israel. But there the plaintiff claimed that the State Department had violated a statutory right to receive this precise passport alteration upon request; he did *not* assert a procedural injury at all, nor was the alleged harm limited to speculative future psychological effects, as the government argued. Rather, the right to a proper listing of the child's birthplace was a substantive right conferred by Congress.

At first glance, *Texas v. United States*, 497 F.3d 491 (5th Cir. 2007), seems more supportive of Delaware. Texas argued that it had been subjected to an "invalid administrative process" devised by the Secretary of the Interior to deal with approval of Indian gaming activities. But the key to the court's conclusion that Texas had suffered an injury-in-fact was that Texas had been deprived of an alleged statutory procedural protection–a court finding on whether Texas had negotiated in bad faith–that bore on the likelihood of an ultimate concrete injury, *i.e.*, the Secretary's approval of an Indian gaming proposal. In that regard, the case is no different from a failure to issue an environmental impact statement that can affect whether or not a project injurious to the plaintiff will be built. *Lujan*, 504 U.S. at 573 n.7. *See also Summers v. Earth Island Inst.*, 555 U.S. __, No. 07-463, slip op. at 8-9 (Mar. 3, 2009).[6]

[6] Delaware heavily relies on the Supreme Court's statement in *Massachusetts v. EPA* that state petitioners are "entitled to special solicitude in [courts'] standing analysis." 127 S. Ct. 1438, 1454-55 (2007) (quotation marks omitted). This special solicitude does *not* eliminate the state petitioner's obligation to establish a concrete injury, as Justice Stevens' opinion amply indicates. Indeed, the opinion devotes a full section to the "harms associated with climate change," *id*. at 1455, on its way to holding in the state's favor.

In sum, because FERC's order–as it stands now–cannot possibly authorize Crown Landing's project absent the approval of Delaware, the state has suffered no injury-in-fact, and thus lacks standing.

For the foregoing reasons, the petition for review is dismissed.

So ordered.

APPENDIX 3

Study on Natural Gas Needs and Alternatives as they may be met by the Jordan Cove Energy Facility at Coos Bay

Revised Draft on Task 1 – Natural Gas and Electricity Supply/Demand Projections

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Chapter 1

Executive Summary for Task 1

I.1 Introduction

ICF was retained by the Jordan Cove Energy Project (JCEP) in February 2008 to provide an assessment of the outlook for natural gas consumption in the Pacific Northwest over the 2008 to 2030 period. This assessment is based on a review of publicly available information and forecasts, and is summarized in this report.

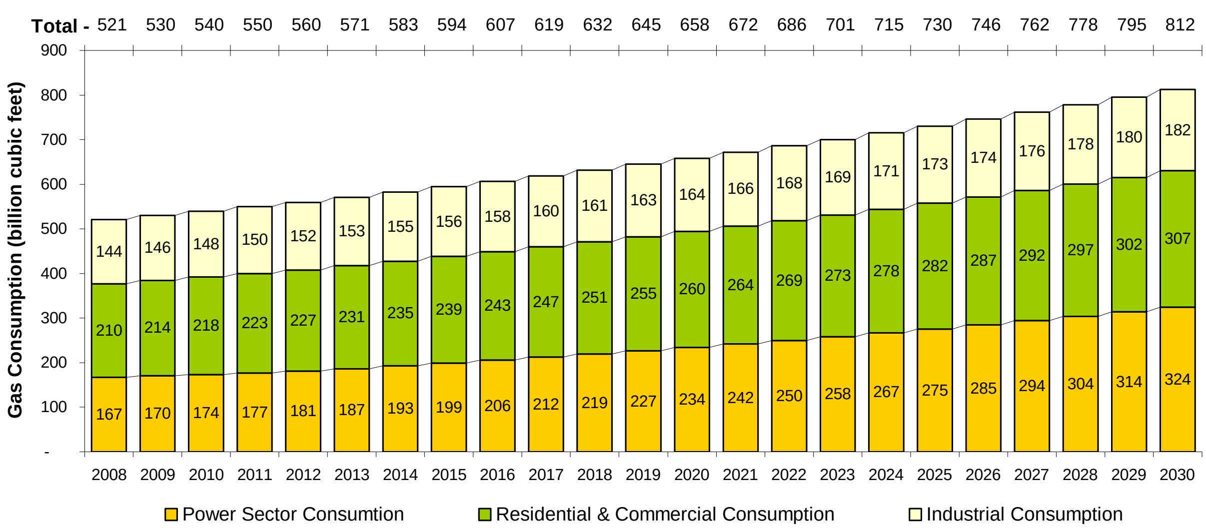
The Base Case projection will be used as a starting point for scenario analysis in a study of the potential impacts of Jordan Cove LNG imports into the Pacific Northwest. Task 2 of this study is a comprehensive analysis of LNG and the Pacific Northwest gas market.

I.2 Outlook for Natural Gas Consumption in the Pacific Northwest

Historically, i.e. in the 1990s, the industrial sector was the largest consumer of natural gas in Oregon and Washington. However, in recent years, the power sector is emerging as the increasingly dominant consumer class, and in Oregon, the power sector has now eclipsed the industrial sector as the largest natural gas end-user. This trend is expected to continue, with gas consumption from the power sector expected to increase at a more rapid pace than other sectors.

Exhibit 1-1 summarizes our Base Case projection for gas consumption for key sectors between 2008 and 2030. The overall growth rate is projected to be approximately 2 percent on average. This is nearly identical to the historical market growth rate from 1997 to 2006, although there are differences among individual sector growth rates. The growth rate is projected to be highest for the power sector at approximately 3.1 percent on average, and lowest for the industrial sector at 1.1 percent on average. Natural gas consumption in the commercial and residential sectors (referred to in this report as the "CORE" sector) is projected to grow at an annual average rate of 1.7 percent, consistent with recent historical trends. Modest industrial gas consumption is consistent with a growing economy.

Exhibit 1-1
Summary of Base Case Pacific Northwest (OR+WA) Gas Consumption Forecast



I.3 Gas Consumption from the Power Sector

Historically, hydroelectric generation has been the dominant form of electric generation in the Pacific Northwest; on average, hydro has contributed around 70 percent to the overall generation mix. Other generation requirements have been met through a combination of natural gas, coal, nuclear, and a small amount of renewable resources. Going forward, however, due to environmental constraints and limited resources, the region has limited potential to bring additional hydroelectric capacity into service and in fact, may be facing decreasing hydroelectric capacity and generation over time.

Amid growing concerns about climate change and associated opposition to coal-fired generation (particularly vocal in the Pacific Northwest and California), options for incremental sources of energy are thus limited to nuclear, natural gas and renewables. In the Pacific Northwest, there are currently no announced plans for development of nuclear facilities and hence the practical alternatives for the foreseeable future appear to be natural gas fired capacity and renewable capacity. While renewable sources have the potential to play an increasing role, especially in light of Renewable Portfolio Standard (RPS) requirements in both Oregon and Washington, they have clear constraints and limitations associated; intermittent availability, interconnection problems, and in some cases, prohibitively high cost (e.g. solar). The intermittent nature of renewable sources, such as wind, poses concern for system reliability, particularly when capacity of such sources in the overall system increases. While the hydro system has some capacity for providing the rapid response generation (i.e. operating reserves) in the event of sudden and unanticipated decreases in wind output, natural gas generation is normally the source of such generation in the US and is not likely to be impacted by tightening environmental controls. Furthermore, seasonal variations in renewable output may increase the overall variability of supply when combined with the large variability of the region's hydroelectric system.

As the region of the country most reliant on hydroelectric generation from legacy dams, the variability of hydroelectric supplies can greatly increase the importance of natural gas generation very rapidly. The range of hydroelectric output is plus or minus 12% when expressed on a capacity factor or generation basis,[1] which is the equivalent of 226,000 MMCf per year (approximately 45 percent of annual gas consumption) assuming natural gas generation makes up the entire difference.[2] This is of course an extreme example but illustrates the potential for a significant increase in natural gas consumption in order to backfill any shortfall in hydroelectric generation. Indeed, a contributing factor to the western energy crisis of 2000-2001 (and the increase in gas consumption from the power sector) was the Pacific Northwest's hydroelectric shortfall. Additionally, any increase in hydrological variability due to climatic changes further increases the importance of natural gas as a "swing fuel".

The key role of natural gas generation in meeting incremental demand has important implications due to the potential for significant electricity demand growth. The Pacific Northwest has seen a steady increase in electricity demand growth over the long-term on average, with the exception of the significant decrease in demand levels in Oregon and Washington in 2001 (associated with the western energy and economic crisis, the extremely high wholesale power prices that resulted in the closing of many industrial facilities in the northwest). Since then, peak and energy demand have been growing robustly at an average rate of 3.8% and 2.3%, respectively (over the 2001 to 2006 period). To the extent this recovery in demand growth is more indicative of the future of the Pacific Northwest, the potential for increased demand for natural gas is greater.

Thus, natural gas fired generation is expected to play a strong role going forward as it can not only provide reliable, continuous power to meet incremental demand needs, but can also act as a supplemental resource to address the variability and intermittent nature of generation from hydro and wind resources. Natural gas consumption from the power sector is accordingly expected to increase at a strong pace as well.

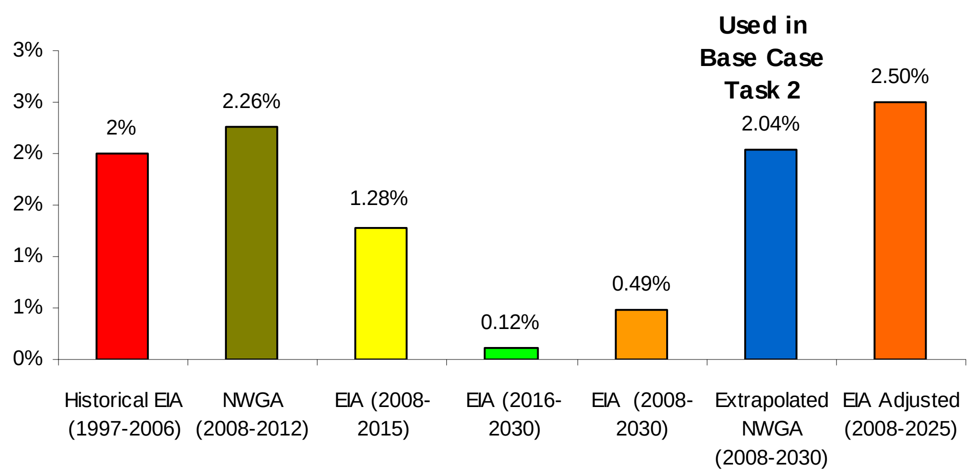
[1] The average capacity factor over the 1995 to 2006 period was 44.5%, the maximum was 56% and the lowest annual level was 31%.

[2] 31,000 GWh hydro generation variability substituted with 7500 Btu/kWh heat rate gas fired generation results in 233,000,000 equivalent MMBtu (226,00 MMCfd) of gas consumption

I.4 Comparison of Base Case Projections for Gas Use

As can be seen in Exhibit 1-2, our Base Case projection for natural gas consumption is similar to the historical experience in the region (on average across all sectors). As our Base Case projection is derived largely from an extrapolation of NWGA projections, it is also very similar to the 2008-2012 NWGA projections on average. The Base Case projection is considerably higher than the EIA projections, but as we discuss in this report, we believe the EIA projections for natural gas consumption are considerably understated as they are predicated on a view that incremental power generation in the Pacific Northwest (and California) are going to be predominantly met through increased coal-fired generation. We believe this to be an unreasonable assumption considering (i) present opposition to new coal plants in the Pacific Northwest, including recent decisions in Oregon rejecting new coal projects, (ii) the small share of existing coal power plant capacity in the region in the overall capacity mix, (iii) the paucity of local coal production, (iv) the history of remote coal generation in coal-producing regions in Utah, Wyoming and Montana being complicated by the need for new transmission, (v) likely forthcoming national green house gas (GHG) emissions cap regulations (not embedded in EIA's base case), and (vi) the significant increase in new coal plant construction costs. When the EIA projection is revised to assume that incremental coal-fired generation will be met by a combination of natural gas and renewables generation, the EIA adjusted projection exceeds our Base Case projection.

Exhibit 1-2
Pacific Northwest Annual Average Gas Consumption Growth Rates for All Sectors



Acronyms
EIA: Energy Information Administration (part of the Department of Energy)
NWGA: NorthWest Gas Association

Sources
EIA Annual Energy Outlook 2007 for forecasted information
EIA Natural Gas, US Data for historical information
NWGA Northwest Gas Outlook For Years 2007-2012, published fall 2007
EIA Adjusted reflects ICF's adjustment of the EIA 2008-2025 forecast as described previously and in chapter 4

Chapter 2

Background on the Power and Natural Gas Sectors in the Pacific Northwest

II.1 Introduction

This chapter provides an overview of the supply/demand profile for both the electric power and natural gas sectors in Oregon and the Pacific Northwest more broadly (including Washington). The first section focuses on the electric supply/demand profile, with discussion on the historical capacity and generation mix, followed by a discussion of historical peak and energy demand trends. The second section focuses on the natural gas sector, with discussion of historical gas consumption by sector (and in aggregate), supply sources and international/interstate gas imports and exports for Oregon and the Pacific Northwest.

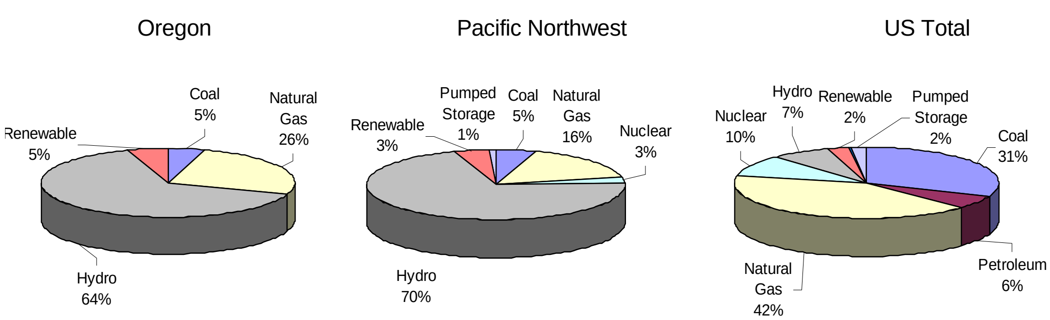
II.2 Electric Supply/Demand Profile

II.2.1 Capacity and Generation Mix

Historically, the capacity and generation mix in Oregon and the Pacific Northwest has been dominated by hydro generating units, considerably more so than almost all other regions across the US. In 2006, hydroelectric units accounted for about 64 percent of total installed capacity in Oregon and 70 percent in the Pacific Northwest more broadly (see Exhibit 2-1). This contrasts with 7 percent for the US as a whole. Generation levels are even higher, with hydro accounting for 71, 74, and 7 percent of the overall 2006 generation mix in Oregon, the Pacific Northwest, and the US, respectively (see Exhibit 2-2). Hydroelectric units have negligible variable costs (as there are no fuel costs) and hence they are always dispatched to the maximum extent available. Availability is in turn driven by the hydrological and weather conditions prevailing at the time, but is also a function of any environmental or other constraints limiting water flow and hydro generation.

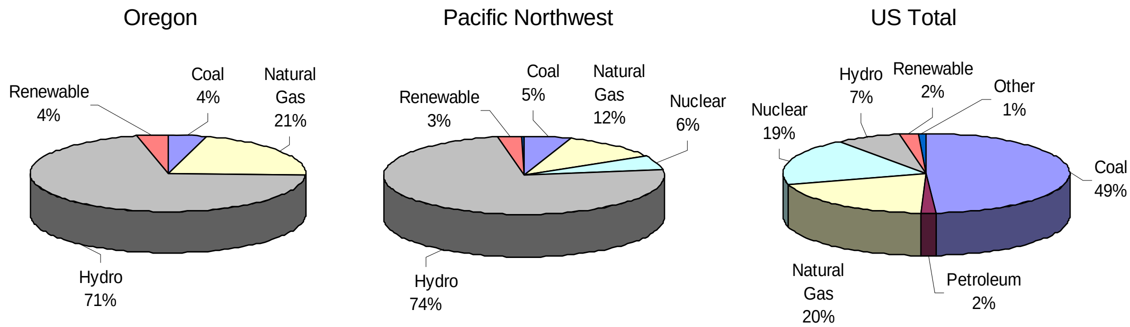
Natural gas capacity is the next most important resource in the Pacific Northwest capacity and generation mix, accounting for 16 and 12 percent of the capacity and generation mix, respectively. The remainder of generation comes from a combination of nuclear, coal, and renewable capacity.

Exhibit 2-1
Capacity Mix of Oregon, Pacific Northwest and US total - 2006



Source: EIA

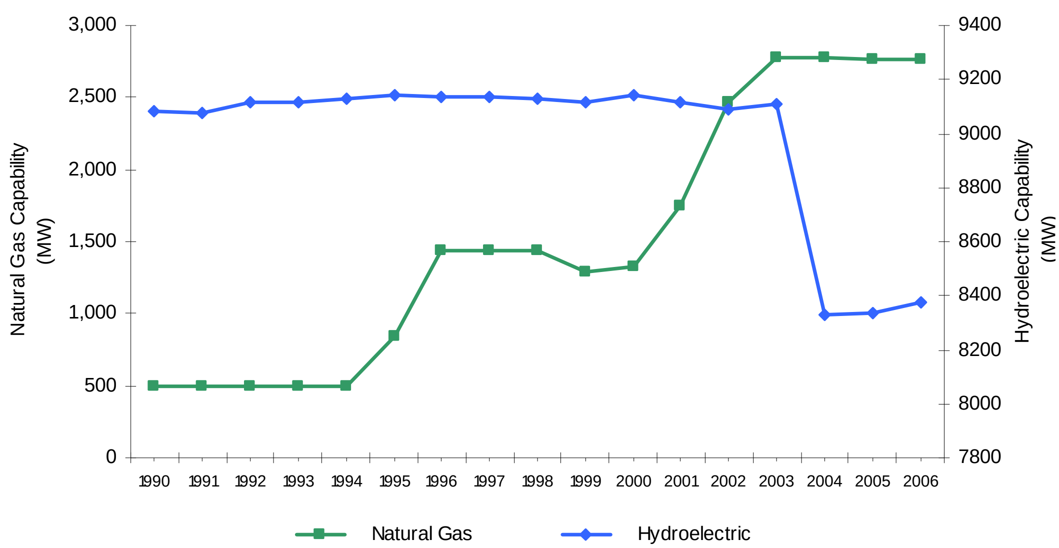
Exhibit 2-2
Generation Mix of Oregon, Pacific Northwest and US Total - 2006



Source: EIA

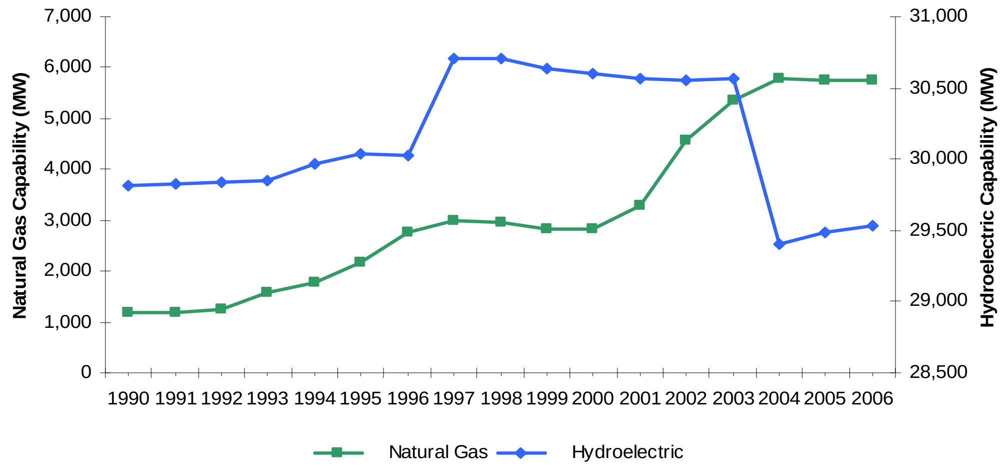
Natural gas capacity has been the most dynamic aspect of the capacity mix over the past two decades. Specifically, gas-fired capacity in Oregon has increased from 500 MW in 1990 to roughly 2,800 MW in 2006. In Washington, gas fired capacity has increased from 700 MW to roughly 3,000 MW in the same period and will further increase to approximately 3,900 MW by end of 2008. In contrast, in Oregon, hydro capacity has remained virtually static over the past 15 years except in 2004 when there was a decline from 9,100 MW to 8,300 MW, due to a revision in the operating norms for hydro units. In Washington, similarly, hydro capacity has remained largely static since 1997 except in 2004 when there was a small decline in capacity, from 21,450 MW to 21,100 MW. Exhibits 2-3 and 2-4 summarize Oregon and Pacific Northwest natural gas and hydro capacity over the 1990 to 2006 period.

Exhibit 2-3
Oregon Natural Gas and Hydroelectric Capability 1990-2006



Source: EIA

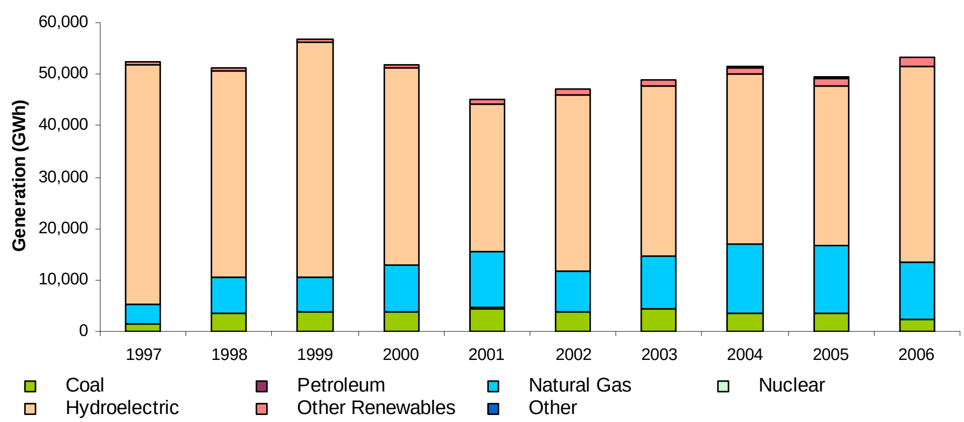
Exhibit 2-4
Pacific Northwest Natural Gas and Hydroelectric Capability 1990-2006



Source: EIA

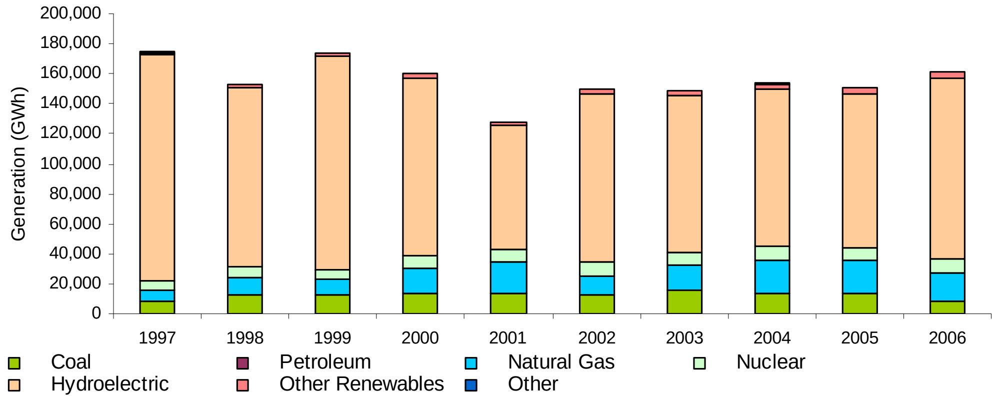
The multi-year trend of increasing reliance on natural gas to meet electricity demand growth rather than building new hydro-electric dams co-exists with year-by-year variation in hydroelectric conditions which can be quite significant. Since gas generation effectively fills in for hydroelectric shortfalls, gas-fired generation is inversely correlated with hydro generation, all else being equal (see chapter 3 for additional discussion). But, on a weather normal basis, since hydro capacity has not increased (and rather decreased slightly) in the past ten years, incremental energy requirements are being met largely through increased gas-fired generation (and secondarily, through increased renewable generation). For example, increasing energy requirements and poor hydro conditions increased gas-fired generation considerably in the 2000 to 2001 period, while increasing energy requirements over time and hydro capacity contraction has led to increased gas-fired generation on average over the 1997 to 2006 period. It should be noted that the 2000 and 2001 shortfalls in hydroelectric generation coincided with the California energy crisis.

Exhibit 2-5
Historical Oregon Generation Mix



Source: EIA

Exhibit 2-6
Historical Pacific Northwest (OR+WA) Generation Mix



Source: EIA

II.2.2 Peak and Energy Demand

Both Oregon and Washington are winter peaking, with 2006 peak demand of 9.3 GW and 16.5 GW respectively, for a total of 25.8 GW.[3] This represents approximately 3 percent of the total US peak demand of 790 GW in 2006. Total Oregon and Washington energy demand in 2006 was 148,541 GWh, reflecting a 66 percent load factor[4]. The Pacific Northwest is the only major US region in which the annual peak demand occurs during the winter; all other major regions peak during the summer air conditioning season. The Pacific Northwest has also had among the lowest average generation costs and the lowest retail electricity prices facilitating significant electric heating. This diversity has affected many aspects of the power industry, including diversity in power trading and extensive transmission interconnections with neighboring summer peaking regions.

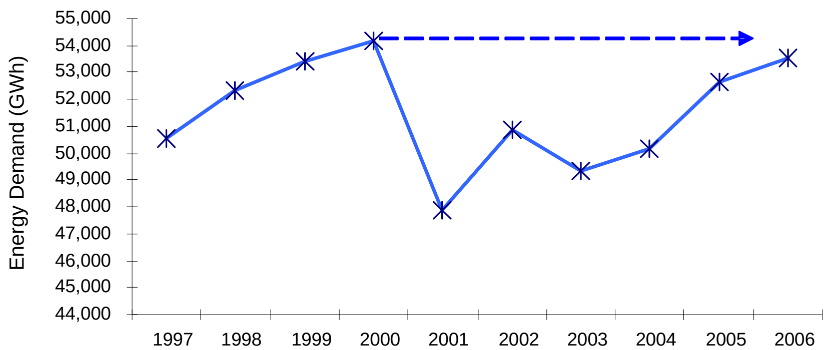
The 10-year rolling average peak and energy demand growth is 0.5 and 0.9 percent, respectively, over the 1986-2006 period. For context, average peak and energy demand growth across the US was 2.5 and 2.6 percent over this period. These low peak and energy demand growth rates in the Pacific Northwest can be explained in part by one or two periods of contraction in demand, associated with the western energy and economic crisis, which in turn resulted in the closing of many industrial facilities in the northwest, significantly reducing electricity demand. For example, in 2001, peak and energy demand across both Oregon and Washington decreased by approximately 10 to 12 percent.

The significant decrease in electricity demand in this period and the associated western energy crisis reflects a relatively unique confluence of events and factors, both fundamental and structural. The period leading up to the 2001 crisis evidenced excess capacity in the west in the early 1990s followed by a period of deregulation, during which virtually no capacity was added while demand continued to grow. This resulted in eroding reserve margins[5], which when compounded with a period of very low hydro availability in 2000 and 2001 (the second driest hydro period in 73 years), resulted in a shortage of generation capacity, which in turn resulted in explosively high wholesale power prices. In addition to shortages, wholesale market structure issues and some degree of market manipulation also prevailed. This combination of factors including high wholesale power prices and retail price caps precipitated utility bankruptcies and financial distress, federal and state government intervention, and litigation. The resultant explosive power prices also had traumatic effects on the industrial sector, with practical annihilation of the aluminum industry.

[3] Source: NERC ES&D 2007 for NWPP scaled to estimate Oregon and Washington demand based on historical information from EIA and information from GE MAPS; Oregon summer peak in 2006 was 8.7 GW and Washington summer peak was 15.5 GW
[4] Load factor is a ratio of annual energy demand and peak demand for 8760 hours
[5] Reserve margin is a measure of system reliability and expresses a ratio of available net capacity less peak demand, to peak demand. This is indicative of excess capacity available over peak demand. As reserve margins approach a 13-18% target level, high prices tend to result reflective of shortage or near-shortage conditions.

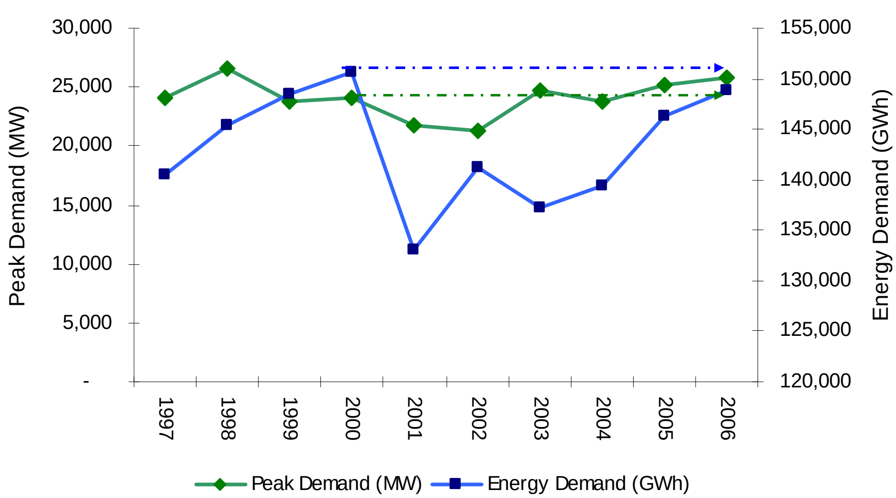
Since 2001, however, peak and energy demand have been growing robustly at an average rate of 3.8% and 2.3%, respectively (over the 2001 to 2006 period). 2006 peak demand has surpassed the 2000 peak demand, while 2006 energy demand is still below, but approaching 2000 levels (see Exhibits 2-7 through 2-9). With the dramatic reduction in industrial load in 2001, generation previously utilized for industrial purposes became available for residential and commercial sectors.

Exhibit 2-7
Oregon Historical Energy Demand 1997-2006



Source: NERC ES&D 2007 for NWPP scaled to estimate Oregon demand based on historical information from EIA and information from GE MAPS; specifically, Oregon demand is 22% of total NWPP demand

Exhibit 2-8
Pacific Northwest (OR+WA) Historical Peak and Energy Demand 1997-2006



Source: NERC ES&D 2007 for NWPP scaled to estimate Pacific Northwest (OR+WA) demand based on historical information from EIA and information from GE MAPS NWPP demand

Exhibit 2-9
Pacific Northwest Historical Electricity Demand Growth 1997-2006

Year	Energy Demand (GWh)	Peak Demand (MW)	%Growth in GWh	%Growth in MW
1997	140,491	24,078	-2.4%	1.6%
1998	145,440	26,617	3.5%	10.5%
1999	148,513	23,838	2.1%	-10.4%
2000	150,616	24,101	1.4%	1.1%
2001	133,057	21,705	-11.7%	-9.9%
2002	141,299	21,292	6.2%	-1.9%
2003	137,178	24,770	-3.0%	16.3%
2004	139,406	23,842	1.6%	-3.8%
2005	146,281	25,175	4.9%	5.6%
2006	148,825	25,806	1.7%	2.5%
Average (1997-2006)			0.8%	1.1%
Average (2001-2006)			2.3%	3.8%

Source: NERC ES&D 2007 for NWPP

II.2.3 Imports and Exports

Historically, the Pacific Northwest has been a net exporter of energy to California and Canada, largely due to the abundance of low variable cost hydroelectricity, but also due to varying seasonal requirements in the northern areas vs. the southern areas. Going forward, as excess capacity across the West diminishes, available capacity in the Pacific Northwest, notable gas-fired capacity may be called on to operate increasingly not only to meet local demand but potentially for exports as well.

Washington has consistently been a net exporter, with net exports totaling roughly 11 percent of local generation (see Exhibit 2-10). In contrast, Oregon has been a net importer in some years and a net exporter in other years and generally at lower levels. On average, over the 1997-2006 period, Oregon was a very small net importer, at a level less than 1 percent of total local generation (see Exhibit 2-11). As such, to some degree, Oregon can be considered a transit point for energy flowing between Washington and California. Additionally, as mentioned earlier, Oregon and Washington imports and exports are dictated in part by varying seasonal requirements. Western Canada and the Pacific Northwest are winter peaking while California and most of the rest of the US are summer peaking. Hence imports may flow north in the winter and south during the summer.

The large role of power imports and exports highlights the significant interaction that other regions have with the Pacific Northwest. Thus, the effects of relatively small shortfalls in supply can have a magnified effect if they are reinforced by trends elsewhere in the western US. In fact, as discussed earlier, one of the factors contributing to the western energy crisis was supply shortages in the Pacific Northwest due to low hydro generation combined with supply shortages elsewhere in the WECC. Note that Washington has consistently been a net interstate exporter of energy, with the notable exception of 2001 when the western energy crises occurred (see Exhibit 2-10).

Exhibit 2-10
Washington Historical Net Trades 1997-2006

Washington					
Year	Net International Trade (GWh)	Net Interstate Trade (GWh)	Net Trade (GWh)	Generation (GWh)	Net Trade as % of Local Generation
1997	-3,632	27,068	23,436	122126	19%
1998	-2,467	1,943	-524	102159	-1%
1999	-1,809	11,262	9,453	117084	8%
2000	1,133	2,365	3,498	108237	3%
2001	5,058	-8,627	-3,569	83049	-4%
2002	1,187	17,460	18,647	102765	18%
2003	1,957	12,786	14,743	100095	15%
2004	4,848	11,430	16,278	102165	16%
2005	3,004	8,996	12,000	101966	12%
2006	8,656	8,465	17,121	108203	16%
Average	1,794	9,315	11,108	104,785	11%

Note: Negative values indicate net imports and positive values indicate net exports

Exhibit 2-11
Oregon Historical Net Trades 1997-2006

Oregon					
Year	Net International Trade (GWh)	Net Interstate Trade (GWh)	Net Trade (GWh)	Generation (GWh)	Net Trade as % of Local Generation
1997	-773	486	-287	52413	-1%
1998	-591	1,029	438	51148	1%
1999	-310	5,498	5,188	56848	9%
2000	-153	-2,738	-2,891	51790	-6%
2001	-140	-3,955	-4,095	45052	-9%
2002	-1,468	-226	-1,694	47099	-4%
2003	-3,115	3,600	485	48966	1%
2004	-2,446	4,616	2,170	51381	4%
2005	-3,842	2,255	-1,587	49325	-3%
2006	14	269	283	53341	1%
Average	-1282	1083	-199	50736	-0.4%

Note: Negative values indicate net imports and positive values indicate net exports

II.3 Natural Gas Supply / Demand Profile

II.3.1 Gas Consumption Profile

Up until the 1990s, the industrial sector was the largest consumer of natural gas in Oregon and Washington. However, in recent years, the power sector has emerged as the increasingly dominant consumer class, and in Oregon, the power sector has now eclipsed the industrial sector as the largest natural gas end-user. This is consistent with the aforementioned lack of investment in new hydro-electric facilities and the heavy reliance on natural gas generation as the marginal power source.

Specifically, as can be seen in Exhibit 2-12, gas consumption in the industrial sector in Oregon declined at an average rate of -2% in the 1997-2007 period. However, much of this decline was concentrated in the two-year period from 1999 to 2001. Industrial demand, which had been rising steadily through the 1990s, subsequently decreased in response to increases in natural gas prices. The sharp drop in 2000 and 2001 corresponds to the California Energy crisis. Oregon's industrial gas consumers reduced their gas use by 35 percent from 108 Bcf in 1999 to less than 70 Bcf in 2001.

In contrast, natural gas use in the power sector in Oregon dramatically increased at an average growth rate of close to 20 percent annually over the 1997 to 2006 period. Of course, these large growth rates (particularly in the early part of this period) can be partially explained by increases from a low starting level of gas consumption in this sector.

Residential and commercial consumers (referred to as the "CORE" sector in aggregate) have also seen increased gas consumption over the past few years (albeit at a more moderate pace), with an average growth rate of 2.0 percent, over this same period. Year-to-year growth in the CORE gas consuming sector is not readily apparent from historical consumption levels. Since this sector consumes gas mainly for space and water heating, weather has a significant influence. Population growth is the dominant driver for this sector. During this time period, Oregon population grew at an average annual rate of 1.3 percent. Historically, technological efficiency gains balance increases in average square footage per person and the CORE sector gas consumption, when adjusted for weather, trends near population growth.

The trends are similar in Washington, with a decline in the industrial gas consumption levels and a rapid increase in power gas consumption levels. Exhibit 2-13 summarizes historical growth trends for the Pacific Northwest region in aggregate. Overall, gas consumption levels have grown at an average rate of 2.9 percent in Oregon, 1 percent in Washington, and 1.7 percent in the Pacific Northwest in aggregate over the 1997 to 2006 period. Growth rates would have been higher were it not for the large decrease experienced in 2002.

The power sector increase in gas consumption is primarily driven by increased gas-fired capacity installation and increasing electricity demand requirements largely being met by incremental generation from these natural gas power plants. As discussed earlier in section II.2, due to hydroelectric availability variations year-to-year and natural gas generation's role in supplementing hydro generation, gas consumption profiles for the power sector can also vary considerably year to year, despite a generally increasing trend. For example, gas consumption from the power sector was at its highest level in 2000 and 2001, corresponding to years of particularly low hydroelectric generation (see Chapter 3 for additional discussion on this topic).

Exhibits 2-14 through 2-17 provide additional graphical summaries of historical gas consumption by sector in Oregon and the Pacific Northwest.

Exhibit 2-12
Oregon and Washington Historical Gas Consumption Growth by Sector 1997-2006

	Oregon				Washington			
Year	Core sector	Industrial	Power Sector	All Sectors	Core sector	Industrial	Power Sector	All Sectors
1997								
1998	4.2%	13.7%	118.6%	25.2%	-0.9%	19.7%	45.6%	13.6%
1999	11.0%	5.1%	-6.0%	4.0%	13.9%	-6.6%	-19.2%	-0.5%
2000	0.3%	-29.4%	39.9%	-5.2%	-0.2%	-32.7%	127.9%	0.3%
2001	-1.7%	-8.4%	18.8%	2.6%	15.8%	-10.4%	15.8%	8.0%
2002	0.6%	0.9%	-32.3%	-11.7%	-15.4%	-9.7%	-54.1%	-25.0%
2003	-4.8%	-4.2%	33.2%	6.4%	-0.7%	-2.7%	46.3%	6.9%
2004	2.1%	6.2%	19.3%	9.7%	0.4%	2.9%	14.1%	4.3%
2005	4.2%	-2.8%	-0.8%	0.0%	3.3%	-1.4%	-0.4%	1.1%
2006	2.2%	0.6%	-14.6%	-4.8%	2.8%	5.8%	-10.7%	0.1%
Average	2.0%	-2.0%	19.6%	2.9%	2.1%	-3.9%	18.4%	1.0%

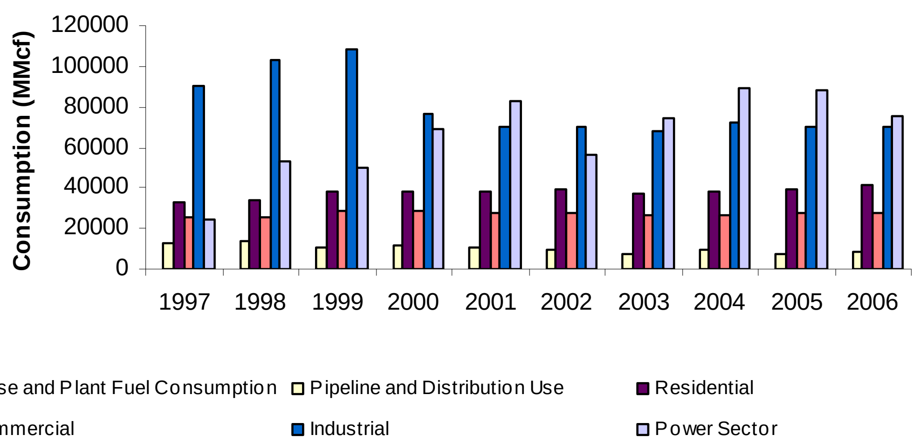
Source: EIA

Exhibit 2-13
Pacific Northwest Historical Gas Consumption Growth by Sector 1997-2006

Pacific Northwest (OR+WA)				
Year	Core Sector	Industrial	Power Sector	Total
1997				
1998	0.8%	17.0%	79.6%	18.3%
1999	12.9%	-1.5%	-11.7%	1.4%
2000	0.0%	-31.1%	74.8%	-2.1%
2001	9.6%	-9.5%	17.3%	5.7%
2002	-10.3%	-4.6%	-43.5%	-19.4%
2003	-2.2%	-3.5%	38.7%	6.7%
2004	1.0%	4.6%	17.0%	6.8%
2005	3.6%	-2.1%	-0.6%	0.6%
2006	2.5%	3.2%	-12.9%	-2.2%
Average	2.0%	-3.1%	17.6%	1.7%

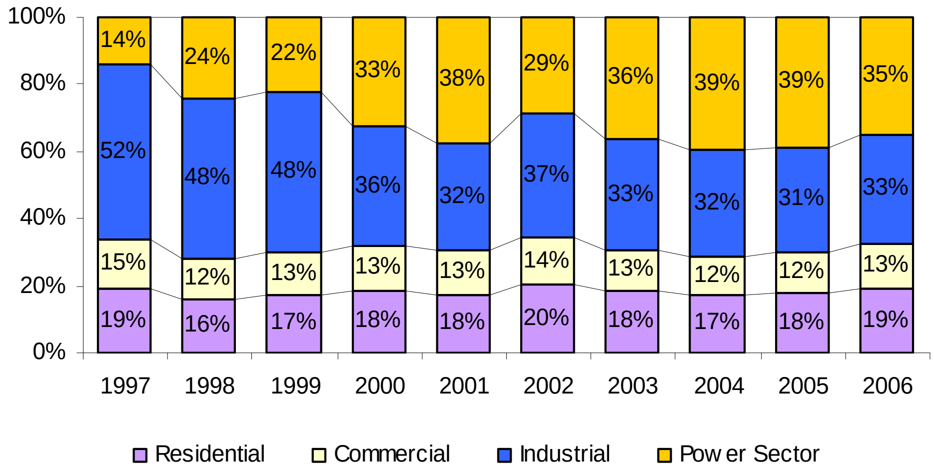
Source: EIA

Exhibit 2-14
Oregon Historical Gas Consumption by Sector 1997-2006



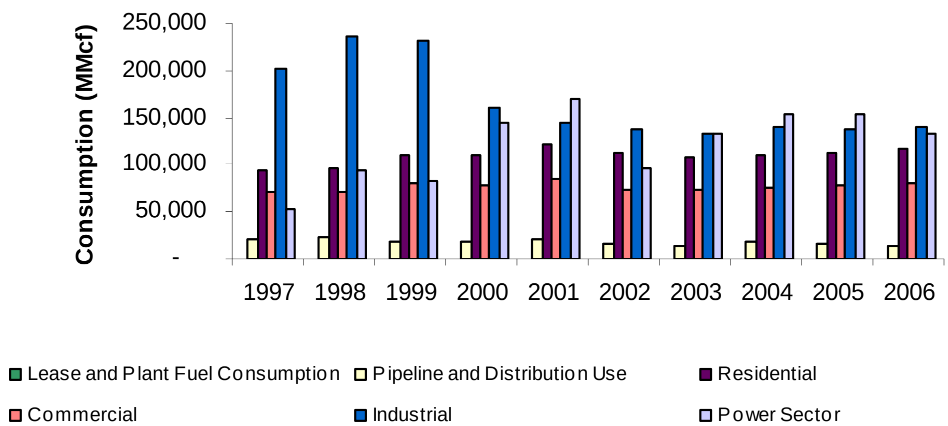
Source: EIA

Exhibit 2-15
Oregon Historical Gas Consumption by Sector 1997-2006



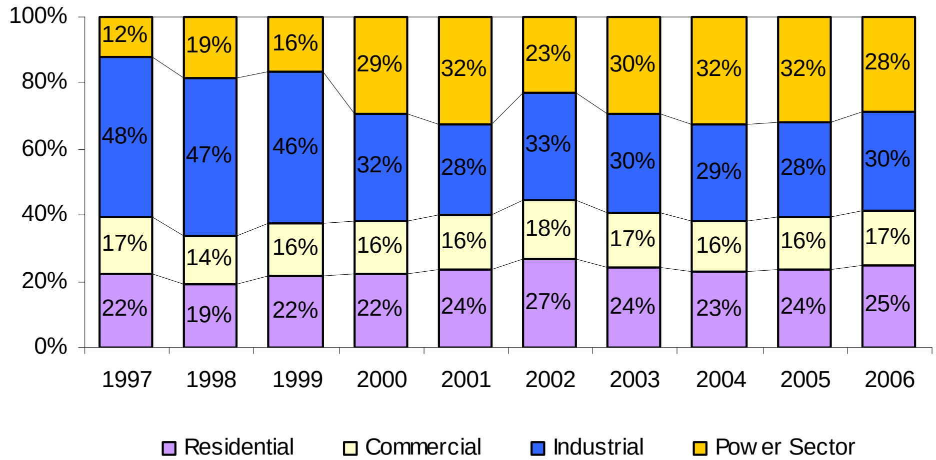
Source: EIA

Exhibit 2-16
Pacific Northwest (OR + WA) Historical Gas Consumption by Sector 1997-2006



Source: EIA

Exhibit 2-17
Pacific Northwest (OR + WA) Historical Gas Consumption by Sector 1997-2006



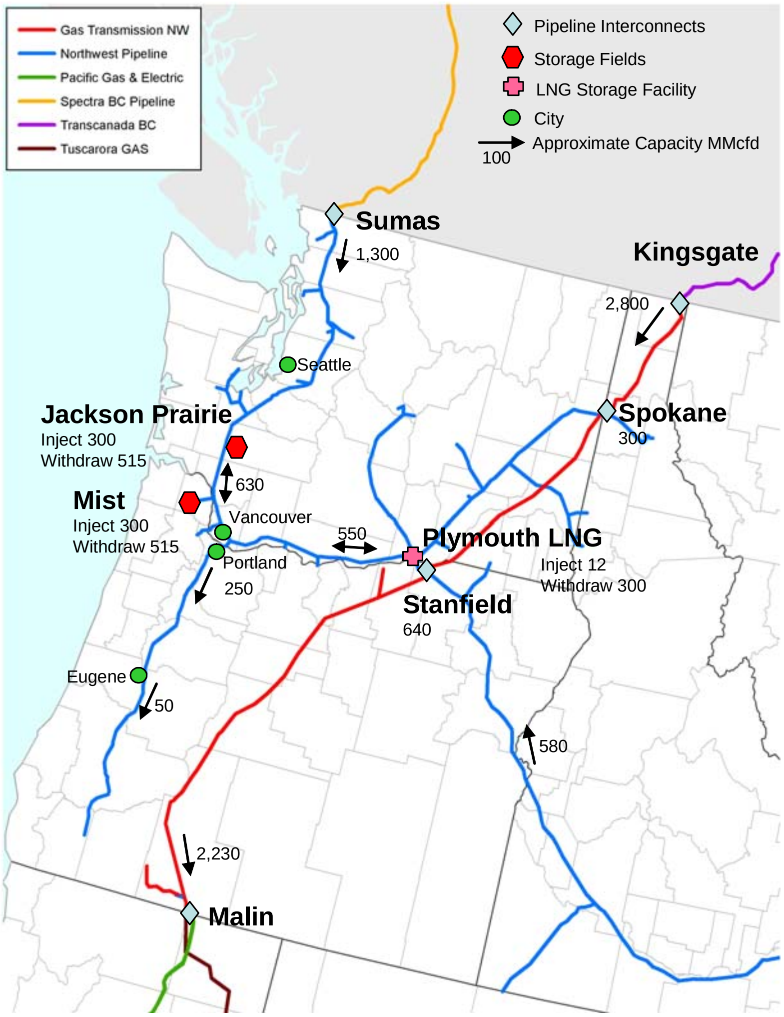
Source: EIA

II.3.2 Pacific Northwest Imports (Supply) and Exports

The Pacific Northwest has negligible gas production and must rely on natural gas produced outside the region. Historically, Oregon and Washington has depended on gas from the Western Canada Sedimentary Basin (WCSB) and the U.S. Rockies. The Pacific Northwest is also a transit point for gas supplies to California and Nevada.

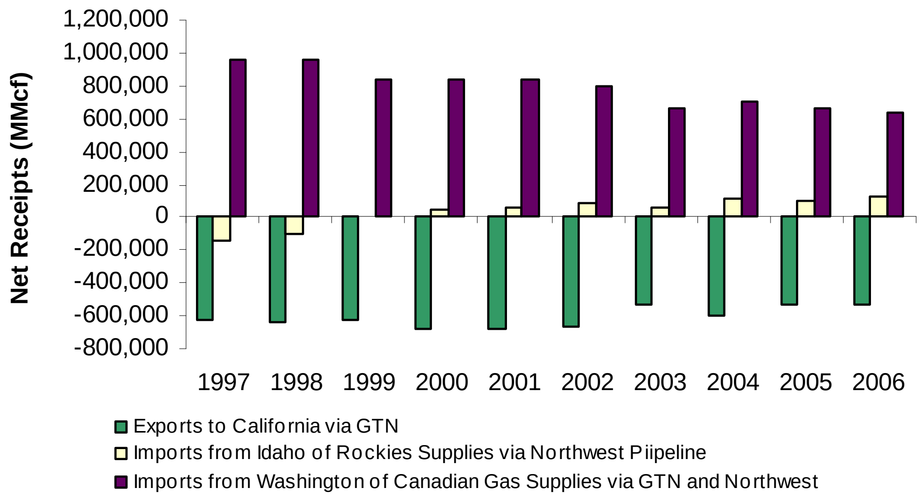
Washington imports natural gas from Canada via Gas Transmission Northwest (GTN) and Northwest Pipeline (Exhibit 2-18). Much of the gas imported into Washington on GTN flows through Oregon to serve markets in California and Nevada. Exhibits 2-19 through 2-21 are for summaries of gas import and export receipts for Oregon, the Pacific Northwest, and California.

Exhibit 2-18
Pacific Northwest Pipeline Infrastructure



In the last 10 years, annual imports of Canadian gas supplies entering Oregon from the state of Washington declined by roughly one-third from over 950 Bcf in 1997 to under 635 Bcf in 2006 (Exhibit 2-19). As mentioned earlier, increasing internal gas demand in Canada has resulted in reduced exports to the Pacific Northwest, impacting gas supplies for the whole region. During the same time period, exports to California from Oregon declined by only 100 Bcf. The natural gas shortfall was balanced by increasing supplies from the Rocky Mountains, a growing production area. Prior to 1999, Canadian gas supplies would be exported from Oregon to serve Idaho markets. However, after 2000, the net annual flow has reversed resulting in net imports from Idaho to Oregon. Currently, southern Idaho (and some Northern Nevada markets) is being served almost exclusively by Rockies supplies with the balance flowing to the Pacific Northwest. According to the Northwest Pipeline electronic bulletin board (EBB), in the past two years, flow out of Wyoming at the Kemmerer Compressor station (in southwestern Wyoming) is nearly always at the maximum pipeline capacity, limiting additional imports of Rockies gas supplies into the region. Additional Rocky Mountain gas supplies into Oregon cannot be achieved without incremental pipeline capacity.

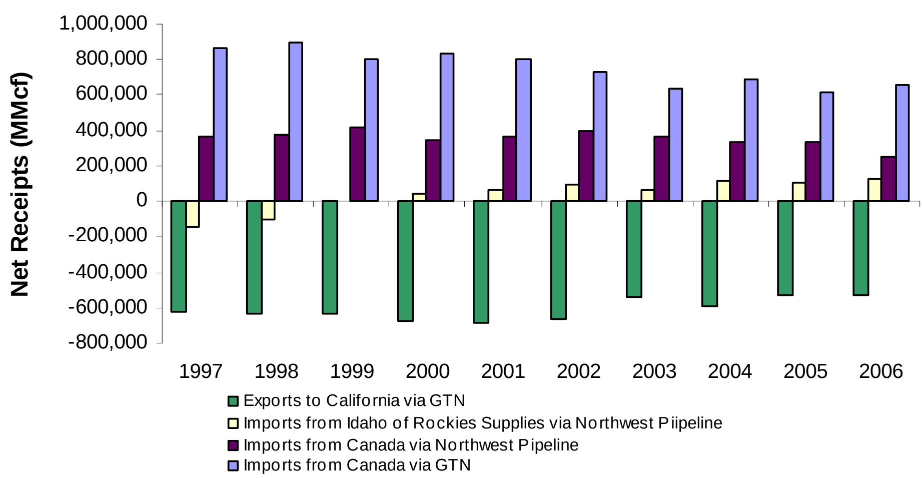
Exhibit 2-19
Oregon Historical Gas Import and Export Receipts



Source: EIA international and Interstate Movements of Natural Gas by State

The natural gas import and export picture for the Pacific Northwest as a whole is similar to Oregon's individual balance (see Exhibit 2-20). From 1997 to 2000, Canadian imports have declined by over 300 Bcf per year. Two thirds of the decline or 200 Bcf has been on GTN while the remaining third was reduced imports on Northwest Pipeline. Exports to California and imports from southern Idaho are the same as the Oregon balance since the entry and exit points are along the Oregon border. Rocky Mountain gas supplies that began entering the region after 2000 serve both Washington and Oregon markets, mainly via Northwest pipeline.

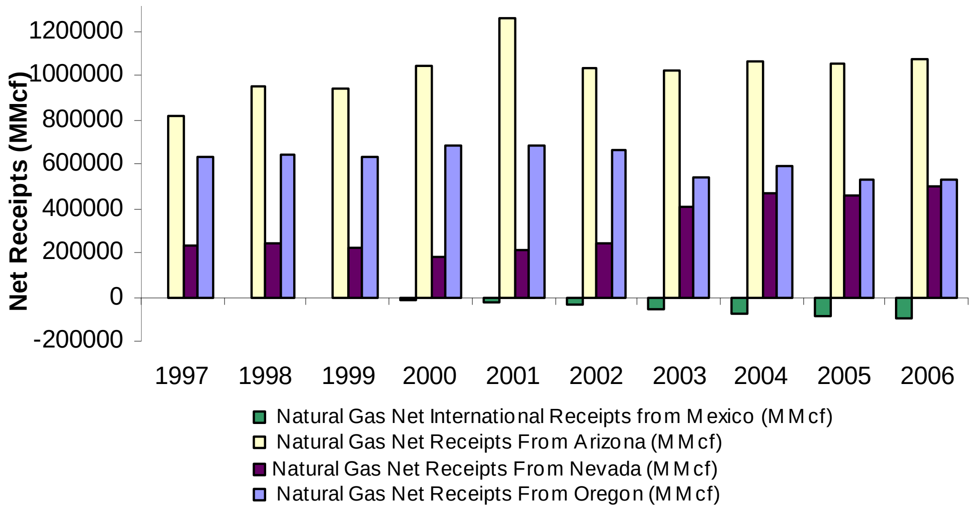
Exhibit 2-20
Pacific Northwest (OR+WA) Historical Gas Import and Export Receipts



Source: EIA international and Interstate Movements of Natural Gas by State

Historical California imports and exports are shown in Exhibit 2-21. With the decline of Canadian gas supply via the Pacific Northwest, California increased imports via other sources. Rocky Mountain gas supplies from Nevada increased in 2003 after a Kern River Gas Transmission pipeline expansion. But similar to the Pacific Northwest, additional Rocky Mountain gas supplies are limited by pipeline capacity. California gas consumption growth and the availability of other gas supplies will determine the California's demand for Canadian gas imports via Oregon.

Exhibit 2-21
California Historical Gas Import and Export Receipts



Source: EIA international and Interstate Movements of Natural Gas by State

Chapter 3

Role of Natural Gas in a Diversified Power Generation Mix

III.1 Introduction

This chapter provides an overview of the role of natural gas in the power sector in the Pacific Northwest. It begins with a brief discussion of terminology commonly used to describe power systems, namely capacity and generation. The following section provides a discussion of hydroelectricity's role in the Pacific Northwest as this is an important determinant of the role of natural gas. The next section provides an overview of historical hydro and natural gas generation in the region. The fifth section discusses projections of electricity demand growth, and the last section discusses the potential capacity and generation profile in the region going forward.

III.2 Power System Capacity vs. Generation

As an introduction to a discussion of power systems and generation requirements, it is useful to distinguish between a plant's capacity and generation. Each unit has a maximum power output measured in MW and this is referred to as the plant's capacity, and is equal to the energy delivered per second. A modification to the definition can be appropriate for hydroelectric and other plants limited by the available energy input (e.g. water flow or wind availability). In some cases, the capacity level is decreased (or "de-rated") to account for this limitation.[6] In considering availability to meet system reliability requirements, particularly during peak load periods, the level of total available capacity (or de-rated capacity for intermittent resources) is assessed relative to peak demand and reserve requirements.

Most power plants do not actually produce energy at the maximum potential in every hour of the year for a number of reasons including unexpected or forced outages, planned outages to permit maintenance, lack of demand[7], lack of storage, and competition from lower cost units. Generation is the sum of actual output across a period of time and is measured in units of energy or MWh, and capacity factor[8] is an expression of actual generation relative to maximum potential generation over a given period. Generation levels need to be sufficient to meet system energy requirements and transmission losses.

A region may have excess capacity in a given time period for purposes of meeting peak demand and reserve requirements, but would still require incremental generation (typically from existing facilities) to meet growing energy needs. As such, it is likely that gas generation or gas consumption will be growing even in the face of "excess capacity", particularly if other existing non-gas facilities are already being utilized close to their maximum potential level.

III.2 Role of Hydroelectricity in the Pacific Northwest

The Pacific Northwest is blessed with abundant hydroelectricity and relies heavily on hydroelectric power to meets its energy needs. However, due to environmental constraints and limited resources, the region (and the US as a whole) has limited potential to bring additional hydroelectric capacity into service and in fact, may be facing decreasing hydroelectric capacity and generation over time.

- The Biennial Monitoring Report on the Fifth Power Plan from NWPCC (January 5, 2007) states that new hydro sites may yield about 480 MW of additional hydropower

[6] For example, in contrast to a fossil unit's contribution to reserve margin of 100%, hydro units' or wind units' contribution to reserve requirements may be considerably less than 100%
[7] Demand and supply must always be in balance even as demand varies
[8] Capacity factor is sometimes expressed as capacity utilization

capacity with roughly 200 average MW[9] of generation by 2025. However, this report also states that new hydroelectric development would unlikely offset loss of capacity and energy associated with expected removal of several older "environmentally damaging" hydro projects. Specifically, damage to waterway and ecological systems is sometimes attributable to hydro dam projects. Hydro dams are also considered the drivers of near-extinction of Pacific Northwest salmon fish species and are also blamed for blocking water needed for healthy river systems.

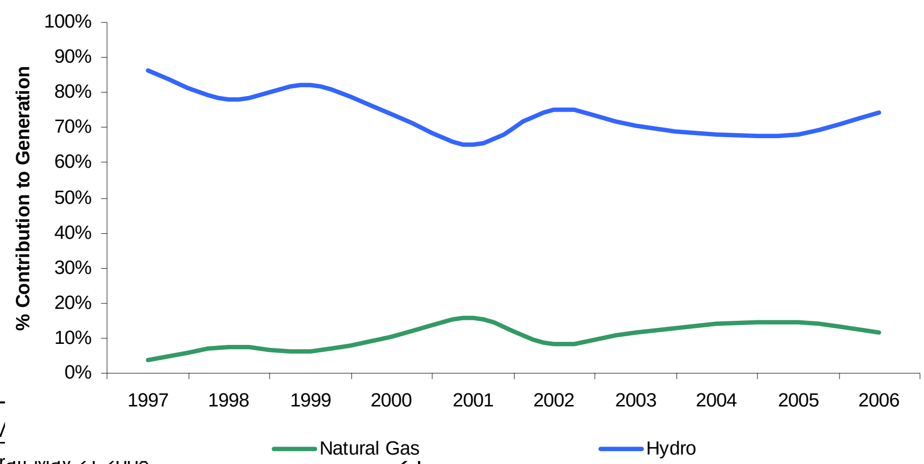
- Of the approximately 2,600 MW of new capacity that has come on-line or will come on-line in the 2006 to 2009 period (i.e. is recently operational or is currently under construction), only 15 MW (or less than 1 percent) is hydro capacity.
- Of the approximately 7,000 MW of new capacity that has been planned or proposed, less than 90 MW comprises hydro capacity, or approximately 1 percent.
- Moreover, the hydro regulations which specify project operations for fish, such as seasonal flow augmentations, minimum flow level for fish, spills for juvenile fish passage, reservoir drawdown limitations and turbine operations efficiency requirement, have greatly reduced the ability of hydro energy production to meet firm loads. Any future norms for fishery operations may further decrease the flexibility of the hydro system operations and hence may result in further lowering of hydro generation and capability.
- As an example of increasing pressure from environmental concerns, Portland General Electric recently started disassembling the 22 MW Bull Run Hydroelectric Project at Marmot Dam (one of the largest dams of Oregon). This will be followed by disassembly of the Little Sandy Dam on its namesake river in the summer of 2008. These removals will create unimpeded salmon and steelhead passage from the southwest slopes of Mt. Hood to the Pacific Ocean.

As such, hydroelectric generation is likely to remain, at best, at historical average levels, and increasing electricity demand will have to be met by other sources.

III.3 Historical Hydro and Natural Gas Generation Profile

Historically, natural gas generation has played an important role in the system to address hydro variability, particularly during periods of low hydroelectric generation. As such, it can be considered an important "swing" resource. This can be observed by the inverse correlation between hydroelectric generation and natural gas generation over the 1997 to 2006 period (see exhibits 3-1 and 3-2). There is also important seasonal variation in demand for natural gas. Hydroelectric generation is concentrated in the spring during the period of runoff associated with snow melt. As the storage capacity of the region's hydro-electric system does not allow water to be sufficiently stored, it is not possible to avoid hydro generation concentration in the spring. This results in lesser demand for fossil energy in this period. As the summer demand season begins, demand for natural gas increases as hydroelectric output decreases.

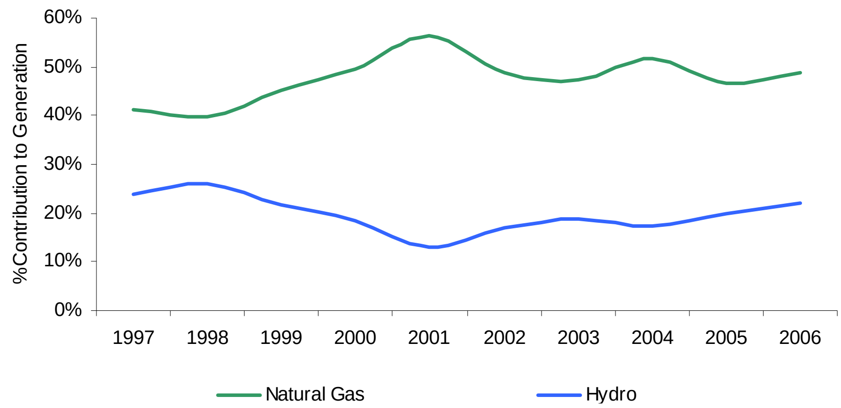
Exhibit 3-1
Historical Hydro and Gas Fired Generation in the Pacific Northwest (OR+WA)



[9] 1 average M

Source: EIA

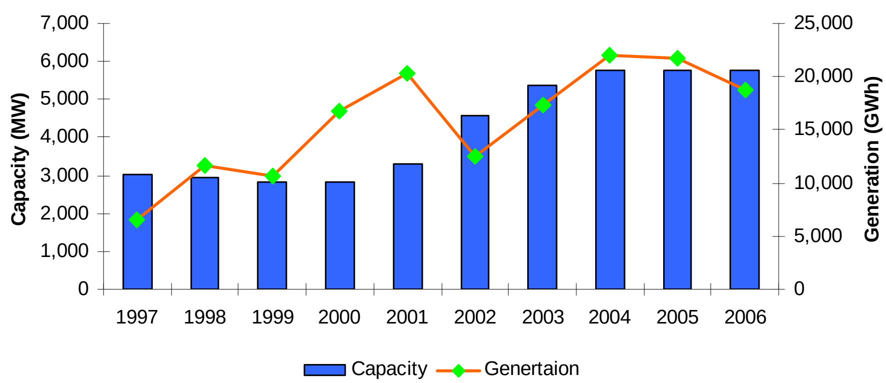
Exhibit 3-2
Historical Hydro and Gas Fired Generation in California



Source: EIA

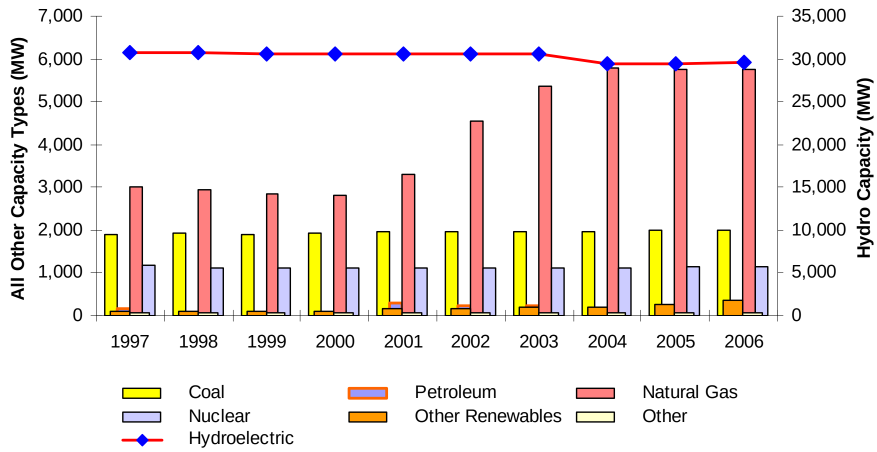
Furthermore, over the past several years, Oregon and Pacific Northwest incremental capacity and generation requirements have been mainly satisfied through natural gas based capacity and generation. Specifically, natural gas capacity in Oregon and Washington has nearly doubled from approximately 3000 MW in the 1997 to 2000 period to approximately 5800 MW in 2006. Other capacity types have either decreased or remained unchanged during this period, excluding a small incremental expansion of renewable capacity (see Exhibits 3-3 and 3-4).

Exhibit 3-3
Pacific Northwest Historical Gas-Fired Capacity and Generation Profile



Source: EIA

Exhibit 3-4
Pacific Northwest Historical Capacity Additions Compared to Hydro Capacity



Source: EIA

III.4 Electric Demand Growth Outlook

Electricity demand growth is the primary driver for increased generation and capacity expansion. Publicly available projections of electricity demand growth for the Pacific Northwest range from 1.2 to 1.5 percent for peak demand and 1.1 to 1.6 percent for energy demand. These forecasts are generally higher than long-term historical experience in the region, largely due to the significant decrease in demand in the early part of this decade, associated with the energy crisis and the closure of industrial plants, notably aluminum smelter plants (as discussed in greater detail in chapter 2). We do note, however, that all the official projections are lower than recent historical experience in the 2001 to 2006 period. Exhibits 3-5 and 3-6 summarize the projections from the various sources.

Exhibit 3-5
Electricity Demand Growth Projections from Various Sources

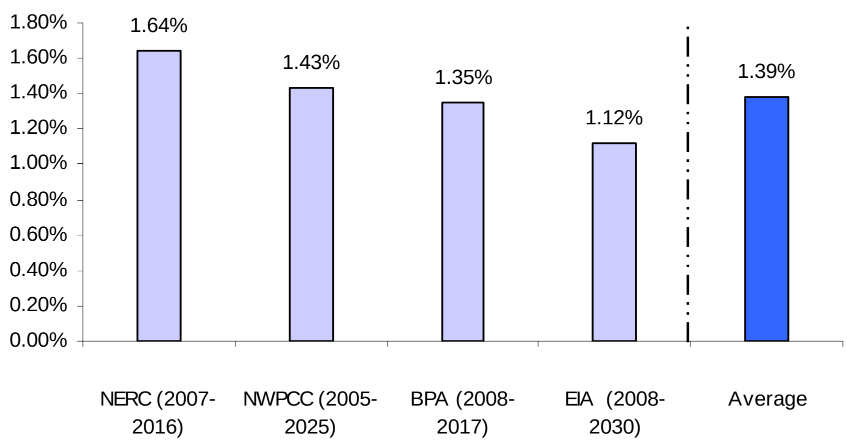
Source	Planning Study	Forecast Period	Regions Covered	Average Annual Peak Demand Growth	Average Annual Energy Demand Growth
NERC	2007 Long Term Reliability Assessment	2007-2016	NWPP (comprises of WA, OR, ID, WY, MT, and UT; a small portion of Northern California; and the Canadian provinces of BC and Alberta.)	1.54%	1.64%
NWPCC	Fifth Power Plan	2005-2025	Includes OR, WA, ID, and MT west of the continental divide, as well as the portions of NV, UT, and WY that lie within the U.S Columbia river basin; excludes Federal demand		1.43%
BPA	2007 Pacific Northwest Loads and Resources Study	2008-2017	Includes OR, WA, ID, and MT west of the continental divide, as well as the portions of NV, UT, and WY that lie within the U.S Columbia river basin	1.15%	1.35%
EIA	Energy Outlook 2007	2008-2030	NWPP (comprises of WA, OR, ID, WY, MT, and UT; a small portion of Northern California; and the Canadian provinces of BC and Alberta.)		1.12%
Average				1.35%	1.39%

BPA's projections include retail load consumption as well as long-term and multi-year import and export contracts. NWPCC projections reflect long-term forecasts of demand for individual consuming sectors such as residential, commercial, and industrial, but excludes demand associated with Federal load and firm exports to other regions. NWPCC projections reflect an assumption of recovery from economic recession of early 2000, although somewhat dampened by the permanent effects of higher electricity prices and lasting efficiency improvements achieved during the economic crisis.

In contrast to the BPA and NWPCC projections which are focused on the Pacific Northwest, the EIA projections and NERC projections are for a larger geographic region, namely all of the Northwest Power Pool. Sub-regional detail is not available from these sources. The EIA projections are provided by sector, with the commercial sector projected to experience the highest rate of growth.

Overall, as can be seen, NERC projects the highest level of demand growth at 1.5% and 1.6% annually on average for peak and energy, while EIA projects the lowest level of demand growth at 1.1% annually on average for energy. The average annual demand growth across sources is approximately 1.4% for both peak and energy.[10] For purposes of our analysis, we utilize this average growth rate, but do note that NERC and utility projections across most regions have consistently understated actual demand growth in most periods.

Exhibit 3-6
Electric Energy Demand Growth Projections from Various Sources



Sources:

NERC ES&D 2007: North American Electric Reliability Corporation Electric Supply & Demand 2007
NWPCC 5th Power Plan: Northwest Power and Conservation Council Fifth Power Plan
EIA AEO 2007: Energy Information Administration Annual Energy Outlook 2007

[10] Note that these projections for the Pacific Northwest are lower than US average historical growth rates which have been in the 2% to 2.5% range on average over the last two decades. They are also lower than US-wide projections from NERC. Additionally, EIA's Pacific Northwest forecast is lower than its US forecast as a whole. Additionally, we believe that both Washington and Oregon have already been active in pursuing demand side management and energy efficiency and that these may be reflected in recent historical levels and projections going forward. For example, based on EIA data for 2004, Washington was the 5th highest state in terms of energy efficiency spending and the 3rd best state in terms of energy efficiency savings in the US. Oregon ranks 8th for both metrics.

III.5 Electric Capacity and Generation Outlook

Incremental generation is required immediately to meet growing electrical energy demand. Assuming an annual average energy demand growth rate of 1.4 percent (the average across public forecasts referenced in the previous section), approximately 2000 to 2500 GWh of incremental generation would be required annually to meet incremental local energy requirements, with a cumulative increase in incremental generation requirements of approximately 54,000 GWh over the 2008-2030 period. This reflects a 36 percent increase over 2006 generation levels.[11]

The increase in generation requirements in some years could be greater even if the average growth trend does not change. One critical source of this variability is the region's dependence on its very large hydroelectric system. Fossil and nuclear generation can generally be controlled by system operators (i.e. with the exception of forced outages, they can determine if, when, and how much to run the facilities); in contrast hydroelectric generation is largely a function of hydrological conditions outside the control of system operators. Thus, the Pacific Northwest has the greatest variability in annual electric generation outside the control of system operators, and natural gas (as the key swing fuel) generation and consumption could vary greatly around a steady trend line. Furthermore, the upswings in gas generation have in some case coincided with grid-wide problems such as the 2000/2001 western energy crisis.

The potential for increased utilization of natural gas generation is further emphasized by observing historical capacity factor levels and their potential to increase over time. As mentioned earlier, capacity factor is a measure of actual generation relative to potential maximum generation. In Oregon, for example, capacity factors have been in the 36 to 56 percent range over the 2002 to 2006. They have been even lower in Washington in the 26 to 33 percent range. These plants can generally operate as high as 90 percent. In contrast, hydroelectric, nuclear and coal facilities already generally operate close to their maximum potential, and thus have very limited room to increase further.

Incremental generation requirements could be higher if net exports increased over time and would be lower if net exports decreased over time (or net imports increased over time). There is potential that buyers from outside the region might seek to access the generation capacity of the region's gas plants through upgrades in transmission, additional contracting, etc. This is related to temporary availability of capacity in the region as discussed below. Any sales from plants that would otherwise be operating to meet local demand would have to be made up by other plants, increasing total gas generation and consumption.

While the region will be relying on natural gas as the key marginal source of generation, there is some excess total generation capacity at the peak when one includes the most costly capacity. Most public sources indicate that no significant capacity expansion is required in the immediate future, even though increased generation is required. Indeed, when only local system coincident seasonal peak demand and maximum expected capacity are considered, Oregon and Washington combined have a summer reserve margin of approximately 40 percent in 2008 and a winter reserve margin of approximately 31.5 percent. This reflects a summer peak of approximately 25 GW, a winter peak of approximately 26.5 GW, and capacity of approximately 35 GW.[12]

Of course, the Pacific Northwest is part of the larger, highly interconnected Western Electric Coordinating Council (WECC) grid and hence capacity additions and generation levels are dictated not only by local requirements but the requirements of the larger grid as well. Other parts of the western grid are expected to require additional capacity as soon as 2009-2010. This can be expected to create demand for power from the Pacific Northwest. Historically, the Pacific Northwest has imported energy from western Canada and exported energy to California, with the region being a net exporter of energy overall (see Chapter 2 for more discussion on historical flows). However, as discussed earlier in chapter 2, import and export patterns vary during the course of the year, due to varying load profiles (with Western Canada and the Pacific Northwest peaking in the winter and the

[11] 2006 generation was around 162,000 GWh

[12] Source: Peak Demand from NERC ES&D 2007 for NWPP scaled to estimate Pacific Northwest (Oregon + Washington) demand based on historical information from EIA and information from GE MAPS; capacity information from ICF and assumes a hydro contribution to reserves at around 70 to 80 percent of total rated capacity.

rest of the US dominantly peaking in the summer) and due to varying hydro and other conditions year by year.
Assuming an annual average peak demand growth rate of 1.35 percent, approximately 500 to 600 MW of incremental capacity would be required annually once the system is in supply/demand balance or equilibrium (i.e. that peak demand and reserve requirements are at or above existing capacity levels). Assuming equilibrium in approximately 2015,[13] close to 7.5 GW of incremental capacity would be required between 2016 and 2030. However, the potential for retirement of older capacity including hydroelectric capacity, and an acceleration of peak demand growth bringing the region closer to the national average cannot be ruled out, and flexible planning is required to handle uncertainty in future conditions.

Again, it is important to recognize that even with the assumption that no new capacity is required in the Pacific Northwest for several years (which may be optimistic in light of the potential for greater demand growth, exports, retirements, etc.), incremental generation is required immediately to meet growing energy requirements and to supplement intermittent hydro and renewable resources.

III.5.1 Limited Alternatives to Meet Incremental Capacity and Generation Requirements

As discussed in chapter 2, the current capacity and generation mix comprises hydro, coal, natural gas, nuclear, and renewable resources[14], with the vast majority coming from hydroelectric resources. While the potential universe of incremental capacity and generation could include all these resources, from a practical perspective, future capacity additions will likely be dominated by natural gas and renewables.

Incremental hydro capacity is extremely unlikely in any significant amount as most of the feasible sites have already been developed. The remaining opportunities are, for the most part, small-scale and relatively expensive. Additionally, environmental considerations may limit any significant new development and there may be potential for some level of hydro resource contraction. Hydro generation is thus likely to remain at historical average levels for the foreseeable future (or to decrease slightly over time).

Amid growing concerns about climate change and associated opposition to coal-fired generation (particularly vocal in the Pacific Northwest and California), options for alternative sources of energy are limited to nuclear, natural gas and renewable. In the Pacific Northwest, there are no announced plans for development of nuclear facilities and hence the practical alternatives for the foreseeable future appear to be natural gas fired capacity and renewable capacity. While renewable sources have the potential to play an increasing role, especially in light of Renewable Portfolio Standard requirements in both Oregon and Washington, they have clear constraints and limitations associated intermittent availability, interconnection problems, and in some cases, prohibitively high cost (e.g. solar). The effective “fuel” used by wind units for generation is wind flow and as the wind profile varies by time of day and season, with a significant degree of unpredictability, it is difficult for system operators to control and depend on this resource as it might fossil resources with respect to system reliability. This intermittent nature of renewable sources, such as wind, poses more concern for system reliability, particularly when capacity of such sources in the overall system increases, and this variability is combined with hydro variability. Additionally, wind resources are often located distantly from load, and hence interconnection with the grid can be a bottle neck in their expansion. Solar technology is still in early stages of development and as such, cost per MW of solar technology is very high and the capital cost recovery of solar plant through market based economic components is still very difficult to achieve. As such, natural gas fired generation is expected to play a strong role going forward as it can not only provide reliable, continuous power but can also act as a supplemental

[13] Note that public projections for when new capacity will be required for the Pacific Northwest region are limited. The NERC 2007 Long-Term Reliability Assessment indicates that the Northwest Power Pool (NWPP) as a whole may not need incremental capacity until after its forecast horizon which terminates in 2016. However, hydro availability during system peaks is a critical issue in making this determination and other factors such as the potential for retirements, higher demand growth, etc. could easily accelerate any stated need.
[14] For the context of this report, renewable resources are defined as including wind, biomass, solar and geothermal resources.

resource to address the variability and intermittent nature of generation from hydro and wind resources.

While there has been a tremendous resurgence in the interest of nuclear power plant development across the US over the last couple of years, none of this interest appears concentrated in the Pacific Northwest. Despite the announcement of potential licensing and development of 23 facilities with over 40 GW across the US, none of these are located in the Pacific Northwest. As such, it is extremely unlikely that any new nuclear capacity will be coming on-line in this region before 2020, and possibly 2025. Nuclear generation is thus likely to remain at historical average levels for the foreseeable future.

There are only two coal plants in the Pacific Northwest, namely Boardman and Centralia, totaling approximately 2 GW in capacity. As mentioned above, the region experiences considerable public opposition to development of new coal-fired facilities. Even in the absence of national CO_2 regulations, Oregon has promulgated a state law on carbon dioxide emission standards, reflective of strong anti-coal sentiments.[15] Washington has also promulgated a law that would make it difficult for new coal plants to get built.[16] Consistent with this, there are no announced conventional coal plants for either Oregon or Washington. There are, however, three IGCC coal plants announced with a combined capacity of approximately 1800 MW in Oregon and Washington. However, development of two of the three projects have been effectively stalled and/or ceased. Specifically:

- Energy Northwest's proposed 680 MW Pacific Mountain Energy Center in Kamala appears to violate the recent Washington law on CO_2 emissions and carbon sequestration.
- The Wallula Energy Resource Center IGCC power plant sponsors recently withdrew their request for the Potential Site Study[17] and indicated that they do not intend to re-apply for site certification anytime in the near future.

Hence, new coal or IGCC plant development appears to have very limited potential in the Pacific Northwest and coal generation is likely to remain at historical levels, which are generally close to maximum availability.[18]

III.5.2 Renewable and Natural Gas Generation Expected to Play Important Role in the Capacity and Generation Mix

In light of the limited potential for incremental hydro, nuclear, and coal development, incremental generation and capacity needs are likely to be fulfilled primarily through the increased utilization and development of gas-fired and renewables capacity.

There are explicit renewable portfolio standard (RPS) requirements for both Washington and Oregon that would dictate the addition of renewable capacity. RPS's require that a certain percentage of total electric energy consumed in a given region (usually a state) comes from eligible renewable generation technologies. Key aspects of RPSs differ from state to state, including percentage of energy required, eligibility of generators by technology, location (in-state vs. out-of-state), or vintage, usage of credit trading for compliance, and alternate compliance mechanisms, and affected load serving entities (LSE's). That said, most RPSs include wind, solar, biomass (closed-loop), geothermal, and landfill gas, and occasionally small hydro (<25 MW) as eligible technologies. At present, RPS goals are 15%

[15] In 1997, as part of HB 3283, the Oregon legislature gave the Energy Facility Siting Council the authority to set carbon dioxide emissions standards for new energy facilities. For base load gas plants and non-base load plants, the standard sets the net emissions rate at 0.675 lb/kWh CO_2. Additionally, the following Oregon greenhouse gas emission goals were put into state law in the 2007 session: (i) arrest growth of emissions by 2010; (ii) 10 percent below 1990 levels by 2020; and (iii) 75 percent below 1990 levels by 2050.
[16] The SB6001 Bill establishes a greenhouse gas performance standard for all new, long-term base load electric power generation. Under the standard, all base load generation for which utilities enter into long-term contracts must meet a greenhouse gas emissions standard of 1,100 pounds of less per megawatt-hour beginning in July 2008.
[17] Press release dated March 25, 2008
[18] Historical coal capacity factors have ranged from 70 to 85 percent for Boardman and 68 to 89 percent for Centralia over the 2001 to 2005 period. Capacity factors for both plants were lower in 2006 due to extended outage conditions. Maximum average availability is likely to be approximately 85 percent and hence there is some potential for increased generation to this level, unless environmental or other constraints prohibit this.

of demand by 2020 in Washington and 25% of demand by 2025 in Oregon. There remains some uncertainty as to whether these requirements need to be fulfilled within the states or can be fulfilled within the broader WECC. Nonetheless, it is anticipated that there will be significant renewable capacity development and generation to meet these requirements.[19]

Additionally, incremental generation requirements for the near-term are likely to be met by increased utilization of existing gas-fired facilities as existing non-gas resources have approached or will soon approach their availability limits. As mentioned earlier, coal capacity factors are approaching maximum availability with capacity factors for the Pacific Northwest as a whole in the 72 to 89 range between 2001 and 2005. Hydrological conditions are unlikely to change for the better and hence long-term average historical generation levels are likely to be repeated at best. Nuclear capacity factors have been in the 78 to 93 percent range over the 2002 to 2006 period, already close to maximum availability in the 90 to 93 percent range. In contrast, natural gas capacity factors[20] have been modest (in the 36 to 56 percent range for Oregon and in the 26 to 33 percent range for Washington over the 2002 to 2006 period), and these plants could be utilized at considerably greater levels (up to approximately 90 percent) to meet incremental needs. Furthermore, with the expectation of significant renewable resource additions, natural gas generation will be critical to supplement wind to address its intermittent and variable nature.

The projection that natural gas and renewable capacity and generation will dominate capacity expansion is consistent with the make-up of power plants recently added or currently under construction, as well as with the announced power plants for potential development. When looking at plants operational in 2006, 2007 and 2008 and under construction for operation in 2008 and 2009, gas capacity comprises 51 percent and renewable capacity comprises 48 percent. When looking at the combination of firm and announced builds for 2008 and onwards, gas capacity comprises 33 percent, wind capacity comprises 43 percent, other renewables comprise an additional 5 percent, and IGCC builds comprise 12 percent (still listed despite recent setbacks). Exhibit 3-7 summarizes firm and announced builds by type.

Exhibit 3-7
Firm and Announced builds in the Pacific Northwest (OR+WA)

Plant	Firm Capacity (MW)					Announced Capacity (MW)			Total Firm + Announced	
Type	2006	2007	2008	2009	Total	Planned	Proposed	Total	MW	% of Total
Wind	329	666	164	0	1159	32	2943	2975	4134	43%
Hydro	14	0	1	0	15	1	88	89	103	1%
IGCC	0	0	0	0	0	0	1126	1126	1126	12%
Coal	0	0	0	0	0	0	0	0	0	0%
Biomass	14	50	3	16	83	20	22	42	125	1%
Natural gas	0	685	650	0	1335	0	1833	1833	3168	33%
Tidal current	0	0	0	0	0	0	19	19	19	0%
Wave	0	0	3	0	3	3	202	205	208	2%
Geothermal	0	0	0	0	0	0	87	87	87	1%
Petroleum[2]	0	0	0	0	0	0	600	600	600	6%
Solar	0	0	0	0	0	1	0	1	1	0%
Total	357	1401	821	16	2595	57	6920	6977	9571	100%

Source: Power Plant Development Activity in the Pacific Northwest 2002-Present (dated Feb 2008)

[19] There are additional incentives for renewable generation. The Oregon Business Energy Tax Credit was established in 1979 to provide 35% tax credits to businesses that initiate projects to invest in energy conservation, renewable energy resources, recycling, and less polluting transportation fuels. This credit was recently increased to 50% for businesses that install renewable energy systems. In addition, manufacturers of renewable energy systems and components that construct new facilities in Oregon are eligible for the increased tax credit. The maximum eligible cost for renewable projects has also increased from $10 million to $20 million per project.

[20] Capacity factors express generation as a percentage of potential maximum generation

The NWPCC Fifth Plan projections also anticipate significant renewable and natural gas capacity expansion and generation. The Fifth plan assumes 6000 additional MW of wind potential and projects the need for even more gas fired capacity than identified prior to the Fifth plan, in part to maintain system reliability, and regulation and load following capability for the integration of wind power.[21] The Plan anticipates the potential for 480 MW of hydro expansion but this is expected to be offset (or more than offset) by contraction of existing hydro resource.

Additionally, the Northwest Wind Integration Action Plan (March 2007) report indicates that gas fired generation will play a role as flexibility augmentation technology to provide system reliability in an environment of increasing wind generation and capacity in the system.[22] It should also be noted that, in some cases, renewable resources cannot be located near load, especially in the western-most parts of the region. To the extent that transmission capacity is not forthcoming, natural gas will have the additional advantage of being located close to load.

III.5.3 Potential Natural Gas Generation Outlook

Pacific Northwest energy demand was approximately 149,000 GWh in 2006. Assuming 1.39% annual average growth (the average growth rate across four public projections as discussed in section III.3), incremental generation requirements would be approximately 54,000 GWh over the 2008 to 2030 period (see Exhibit 3-8). In the extreme, if all these incremental requirements were to be met through local gas-fired generation in the Pacific Northwest (existing and new capacity), incremental gas consumption from the power sector would be approximately 385,000 MMcf, representing a 5.65% annual average increase of gas consumption in the power sector between 2008 and 2030.[23] It is of course unlikely that all incremental needs would be met through gas-fired generation and more likely that they would be met primarily through a combination of gas-fired and renewable generation.

If half the incremental needs were met through gas-fired generation, then the resultant increase in gas consumption from the power sector would be approximately 192,000 MMcf or a 3.8% annual increase over the 2008-2030 period. For context, if one were to assume a 35% capacity factor level for all renewable projects (firm and proposed) and a conservative 50% average capacity factor level for all gas projects, the firm and announced build mix implies very similar levels of generation from both natural gas and renewables, each at around 32 percent of the overall total (or close to 40 percent if IGCC announcements were to be excluded). Exhibit 3-8 summarizes potential incremental gas consumption requirements from the power sector under varying scenarios of incremental gas generation. This assessment is provided for illustrative purposes only. Furthermore, generation requirements could be lower or higher if the net import / export profile were to change going forward.

Exhibit 3-8
Potential Power Sector Gas Consumption Scenarios 2008-2030

Sensitivity Cases of Power Sector Demand Growth for Pacific Northwest (OR + WA)			
Historical 2006 energy demand (GWh)	148,825		
Average annual energy demand growth 2007-2030 (%)	1.39%		
Expected energy demand 2008 (GWh)	152991		
Expected energy demand 2030 (GWh)	207,280		
Incremental energy demand and generation 2008-2030 (GWh)	54,289		
	Case-I	**Case-II**	**Case-III**
Incremental % generation from gas	25%	50%	100%
Historical gas consumption 2006 (MMCf)[1]	133,985		
Total gas demand 2030 (MMcf)	237,559	341,134	548,282
Incremental gas requirement[1] 2008-2030 (MMcf)	96,192	192,385	384,770

[21] Biennial Monitoring Report on the Fifth Power Plan, Jan 5, 2007, page G-4
[22] Northwest Wind Integration Action Plan March, 2007, pages D1 and D4
[23] This calculation assumes an average heat rate for gas-fired units of 7300 Btu/kWh, reflecting a mix of dominantly combined cycle capacity (which has heat rates in the 6900 to 7100 Btu/kWh range for recent technology) and some less efficient gas-fired capacity.

Average annual gas demand growth 2008-2030 (%)	2.39%	3.84%	5.65%

[1] Assumes 7300 btu/kWh heat rate (weighted average) for gas plants in the region during this period

III.6 EIA Projections for Capacity Expansion and Generation

The EIA 2007 Annual Energy Outlook (AEO) is the only publicly available forecast (that we are aware of) that provides long-term projections of capacity expansion and generation through 2030. As mentioned earlier, the projections are not provided by state but rather for aggregate regions. EIA's 2007 AEO projects significant new coal fired capacity and incremental coal-fired generation to meet future requirements (indeed almost all future requirements) of the Northwest Power Pool. EIA projects that coal-fired capacity would increase from 11 GW in 2008 to 20 GW by 2030 (with expansion commencing in 2016) and generation would increase from 9 average GW to 16 average GW over the same period. EIA projects natural gas capacity to increase from 9 GW to 13 GW in the same period (with expansion commencing in 2019), but projects gas-fired generation to decrease from 3 average GW to 1 average GW in this period. This results in a decrease in natural gas consumption between 2008 and 2030, or more specifically, between 2015 and 2030.

These EIA projections appear extremely unlikely considering (i) present opposition to new coal plants in the Pacific Northwest, including recent decisions in Oregon rejecting new coal projects, (ii) the small share of existing coal power plant capacity in the region in the overall capacity mix, (iii) the paucity of local coal production, (iv) the history of remote coal generation in coal-producing regions in Utah, Wyoming and Montana being complicated by the need for new transmission, (v) likely forthcoming national GHG emissions cap regulations (not embedded in EIA's base case), and (vi) the significant increase in new coal plant construction costs.[24]

If EIA projections were to be adjusted to assume (i) limited incremental coal-fired generation (keeping generation for the 2016 to 2025 period at 2015 levels) due to CO_2 regulations and other factors as mentioned above, (ii) incremental energy demand during the 2016-2025 period would be met through renewable generation sufficient to meet a hybrid RPS standard (20% of energy demand by 2025), and (iii) gas-fired generation to meet residual incremental energy needs, projected gas consumption levels would be considerably higher. Specifically, the annual average growth rate would be 4.9% rather than a negative growth rate. Note that beyond 2025, there is the potential that new nuclear capacity in the region may be viable and hence the gas consumption growth rate for the 2025 to 2030 period may be lesser in this scenario. This adjustment reflects a simplistic analysis and is provided only to illustrate the potentially significant implications on natural gas consumption projections.

[24] EIA's AEO 2007 assumes an all-in coal construction cost of approximately $1290/kW (2005$). However, costs have escalated significantly in the past 2 years with increases in commodity costs, labor costs, etc., and these increases have not been reflected in EIA's projections. At present, coal construction costs are generally estimated in excess of $2,500/kW. As an example, in April 2008, Midland City Council in Michigan approved a plan for a $2530/kW coal plant and Consumers Energy announced a plan for $2,875/kW coal plant. Other plants have been announced including Turk in Arkansas, Edwardsport in Indiana, Cliffside in North Carolina, and Little Gypsy in Louisiana. All these plants' estimated costs range from $2000/kW to $2900/kW. It is important to note that construction cost increases are not limited to coal plants, but extend to natural gas plants and wind plants as well. However, on a $/kW basis, the increase in coal plant costs are generally the highest.

Chapter 4

Natural Gas Demand Projections

IV.1 Introduction

This chapter provides a discussion on the outlook for natural gas consumption in the region. This assessment is based on publicly available information.

IV.2 Summary of Publicly Available Forecasts

There are limited public forecasts available for natural gas consumption going forward. As can be seen in Exhibit 4-1, the Northwest Gas Association (NWGA)[25] has a region-specific forecast for the Pacific Northwest, but the 2007 outlook only goes out to 2012. EIA provides projections for natural gas consumption through 2030, but the smallest relevant region is the "Pacific", which includes not only Oregon and Washington, but also California, Alaska, and Hawaii. Hence, Pacific Northwest specific projections are not directly available from EIA and are limited to NWGA.

Exhibit 4-1
Natural Gas Consumption Projections from Various Sources

Source	Forecast Period	Region	Gas Consumption Annual Average Growth Rate by Sector (%)			
			Power	**Core**	**Industrial**	**All Sectors**
NWGA 2007 Gas Outlook	2008-2012	OR, WA, and North ID	3.5	2.0	1.3	2.3
EIA AEO 2007	2008-2015	Pacific (OR, WA, CA, HI, and Alaska)	2.8	1.4	-0.6	1.3
	2016-2030		-3.1	1.0	1.6	0.1
	2008-2030		-12.1	1.1	0.9	0.5

Exhibit 4-2 provides additional detail on the NWGA 2007 Outlook projections for natural gas consumption by state and by sector within the Pacific Northwest. In this report, the Pacific Northwest is defined as Oregon and Washington. NWGA defines the Pacific Northwest more broadly to also include British Columbia and Idaho but provides information into sub-regions and therefore allows Oregon and Washington gas consumption to be broken out separately In the NWGA report, Washington gas consumption values also include some limited gas consumption in the Northern Idaho panhandle[26].

As can be seen, Washington has slightly higher gas consumption levels as compared with Oregon. Over the NWGA forecast horizon, Washington accounts for approximately 58% of the total Pacific Northwest gas consumption, with Oregon representing the remaining 42%. Washington is also projected to increase its gas consumption at a higher rate of approximately 2.6 percent as compared with Oregon at an annual average growth rate of 1.8 percent. Core sector gas consumption growth rates, which are driven by population growth, are similar between the two states. However, gas

[25] The NWGA consists of six major natural gas distribution and three pipeline companies that operate in the region.
[26] Avista Utilities serves both the Spokane, Washington area and localities across the state line in Idaho. Historical data and forecasts are provided by individual distribution companies and therefore the northern Idaho gas consumption numbers was grouped into the western Washington subregion.

consumption for the Washington industrial and power sectors are 1.5 and 2.5 times higher respectively.

Exhibit 4-2
Natural Gas Consumption Projections from NWGA 2007 Outlook (Bcf per year)

	Core (Residential and Commercial)	Industrial	Power	All Sectors
Oregon Annual Gas Consumption				
2008-2009	73.7	76.9	84.0	234.6
2009-2010	74.5	79.5	85.7	239.6
2010-2011	75.9	80.0	87.9	243.8
2011-2012	78.1	79.1	90.3	247.5
Average	79.0	79.1	93.4	251.5
Washington Annual Gas Consumption (Includes portions of northern Idaho)				
2008-2009	145.4	81.2	85.4	312.0
2009-2010	147.8	85.6	96.6	330.0
2010-2011	151.4	87.2	96.8	335.4
2011-2012	156.9	87.4	99.8	344.1
Average	158.3	87.3	100.4	346.0
Total Pacific Northwest Annual Gas Consumption				
2008-2009	219.1	158.1	169.4	546.6
2009-2010	222.3	165.1	182.3	569.7
2010-2011	227.3	167.2	184.7	579.2
2011-2012	235.0	166.5	190.1	591.6
Average	237.3	166.4	193.8	597.5

Exhibit 4-3
Natural Gas Consumption Growth Rate Projections from NWGA 2007 Outlook

	Core (Residential and Commercial)	Industrial	Power	All Sectors
Oregon Annual Gas Consumption Growth Rates				
2008-2009	2.1%	3.4%	2.1%	2.1%
2009-2010	3.1%	0.7%	2.6%	1.7%
2010-2011	3.9%	-1.1%	2.7%	1.5%
2011-2012	2.3%	0.0%	3.5%	1.6%
Average	2.9%	0.7%	2.7%	1.8%
Washington Annual Gas Consumption Growth Rates				
2008-2009	2.3%	5.4%	13.1%	5.8%
2009-2010	3.2%	1.8%	0.2%	1.6%
2010-2011	4.2%	0.2%	3.1%	2.6%
2011-2012	1.5%	-0.1%	0.6%	0.5%
Average	2.8%	1.8%	4.2%	2.6%
Total Pacific Northwest Annual Gas Consumption Growth Rates				
2008-2009	2.3%	4.4%	7.6%	4.2%
2009-2010	3.2%	1.3%	1.3%	1.7%
2010-2011	4.1%	-0.4%	2.9%	2.1%
2011-2012	1.7%	-0.1%	2.0%	1.0%

Average	2.8%	1.3%	3.5%	2.3%

The NWGA forecasts are generally consistent, on an average basis and an all-sector basis with historical growth in the 1997 to 2006 period. As discussed in chapter 2, historical gas consumption grew at an annual average rate of 1.7 percent in the 1997-2006 period, but at a higher annual average rate of 3.0 percent in the 2002 to 2006 period. The lower growth rate of gas consumption for the longer historical period can be explained by destruction of demand during the energy crisis from the industrial sector.

When comparing projections to historical experience by sector, a number of observations can be made. The NWGA projections are considerably lower for the power sector. The robust growth averaging over 18.5% per year is not expected to continue at the same rapid pace. However, power sector gas consumption growth is still expected to be the fastest growing sector at an average annual growth rate of 3.5%. NWGA gas consumption projections for heating load in the core sector are projected to increase at 2.0 percent essentially equaling historical trends.

The NWGA does not expect gas consumption to decrease in the industrial sector. The industrial sector experienced negative growth in the 2000-2003 period, contributing to average negative growth of the 1997-2006 period. NWGA projections do not anticipate a repeat of this experience; however, the projected growth is modest, at 1.3% annually. Most likely, the most gas sensitive industries have ceased operations in the region (as well as other parts of the U.S.), and the NWGA projects modest growth from the remaining industrial gas consumers consistent with a growing regional economy.

Total gas consumption growth in the EIA forecast is lower than the NWGA forecast for the near-term (2008-2015), at an annual average rate of 1.3 percent across all sectors as compared to NWGA's forecast of 2.3% for all sectors over the 2008-2012 period. Sector specific growth is also lower for all sectors. ICF does not believe that the EIA forecast should be given significant weight for a number of reasons:

(1) The applicable geographic region is much broader including the states of California, Hawaii, and Alaska. This biases the forecast to events projected to occur in California.

(2) EIA has significantly reduced their natural gas consumption projections in recent years. For example, total U.S. 2015 gas consumption in the reference 2008 AEO forecast is 17 percent below the vintage 2005 AEO forecast.

(3) EIA projections for demand growth for the power sector and gas consumption associated with the power sector have been understated in recent years.

(4) EIA's reference case (for which the greatest detail is available), does not consider existing or potential future national CO_2 regulations. With CO_2 regulations, natural gas generation and gas consumption more broadly is likely to increase considerably.

(5) Not only does EIA's reference case project a significant increase in coal capacity and generation in the Northwest Power Pool, but also in California. EIA's reference case projects increase in coal capacity of roughly 20 GW and an increased in coal- fired generation of approximately 150,000 GWh from 2004 to 2030 with an average annual growth of approximately 7.3% for both coal capacity and generation for California. This significant increase in California seems to be unrealistic considering the region's dearth of existing coal capacity, its opposition to coal capacity, its early adoption of aggressive RPS targets of 20% by 2010, and its announced plans to adopt state specific GHG emissions regulations in the event national regulations are not enforced by 2012.

(5) EIA reference case modeling is based on 2005 assumptions and data inputs, which may be dated when considering changed market dynamics since than, most notably, an almost-certain GHG emissions cap regime, which would replace much of envisaged coal capacity with renewable, gas and other lesser carbon emitting technologies, but also other factors such as dramatic increases in the costs of new power plant construction.

IV.3 Approach to the Assessment of Gas Consumption for the 2008-2030 Period

In order to provide a base projection of gas consumption levels for the 2008 to 2030 period, ICF utilized:

(1) EIA data for actual gas consumption for the most recent year available for Oregon and Washington as a base year starting point of consumption by sector;
(2) NWGA forecasted growth rates for gas consumption for 2008 to 2012 for Oregon and Washington; and
(3) Extrapolations of NWGA forecasted growth rates for 2008 to 2012 for the Pacific Northwest, applied to the 2013 to 2030 period.

NWGA defines the Pacific Northwest as including Oregon, Washington, British Columbia, and Idaho, i.e. broader that our definition for purposes of this assessment as including Oregon and Washington alone. However, NWGA provides additional detail for the following sub-regions:

- West Oregon
- East Oregon
- West Washington
- East Washington & North Idaho
- BC Lower Mainland & Vancouver Island
- BC Interior
- South Idaho

As mentioned earlier and summarized in Exhibit 4-2, we compiled gas consumption growth rate information for Oregon and for Washington, with Washington including portions of northern Idaho. However, since the base year of 2006 was normalized to EIA's gas consumption levels of Washington alone, the impact of including portions of northern Idaho was reduced.

IV.3.1 Gas Consumption Outlook for the Power Sector

The methodology, as applied to Oregon, is as follows, resulting in an annual average 3.2 percent growth rate in gas consumption for the power sector from 2008 to 2030:

(1) Oregon gas consumption of 75,180 MMcf in 2006 (data from EIA)
(2) Power sector average growth rate of 2.7 percent from 2006 to 2012 (based on the average NWGA projection for Oregon for the 2008-2012 period)
(3) Power sector average growth rate of 3.3 percent from 2013 to 2030 (based on the base case NWGA projection for the Pacific Northwest for the 2008-2012 period)

The methodology, as applied to Washington, is as follows, resulting in an annual average 2.9 percent growth rate from 2008 to 2030:

(1) Washington gas consumption of 58,800 MMcf in 2006 (data from EIA)
(2) Power sector average growth rate of 8.3 percent from 2006-2012 based on several factors:
    a. NWGA projects a significant increase in gas consumption in 2008 and 2009, presumably due to the addition of new gas plants; ICF factors this in by adjusting 2007 and 2008 gas consumption to reflect the Mint Farm 286 MW power plant coming on-line in 2007 and the Grays Harbor 650 MW power plant coming on-line in 2008; this results in a 15.3 percent growth rate from 2006 to 2007 and a 29.4 percent growth rate from 2007 to 2008; by way of reference, the NWGA average growth rate for 2008-2009 is 13.1 percent.
    b. Power sector average growth rate of 1.3 percent from 2009 to 2012 (based on the average NWGA projection for Washington for the 2009-2012 period)
(3) Power sector average growth rate of 3.3 percent from 2013-2030 (based on the base case NWGA projection for the Pacific Northwest for the 2008-2012 period)

These average growth rates of 2.9 and 3.2 percent are generally consistent with EIA's forecast for gas consumption for the power sector for 2008-2015 (at 2.8 percent), but as discussed earlier, considerably higher than EIA's longer term forecast. These growth rates are, however, considerably lower than the historical power sector gas consumption growth rate in the Pacific Northwest of the past decade.

For context, the projected growth rate of 3.1 percent on average for natural gas consumption in the Pacific Northwest implies that approximately 30 to 35 percent of incremental generation requirements will be met through local natural gas-fired generation. This is roughly consistent with the percentage of gas-fired capacity announced as a fraction of overall capacity expansion, and may be considered conservative in light of the fact that gas-fired power plant capacity factors are likely to be higher than renewable plant capacity factors on average.

IV.3.2 Gas Consumption Outlook for Other Sectors and in Aggregate

We applied a similar methodology for determining gas consumption from the other sectors, namely the CORE (commercial and residential) and industrial sectors. The projection assumes that CORE sector gas consumption will follow recent trends. This implies that population growth, space and water heating equipment efficiency increases, and changes in square footage per household and commercial space continue to follow current trends. Industrial sector gas consumption growth at 1.3% is less than half of the projected GDP growth of 3.0%.

Specifically, CORE sector growth projections are derived by summing up the commercial and residential sector gas consumptions. The methodology for Oregon and Washington CORE sector growth, resulting in an annual average 1.7 percent growth from 2008 to 2030, is as follows:

(1) EIA total commercial and residential gas consumption of 71,882 MMcf and 133,844 MMcf for Oregon and Washington in 2007[27]
(2) CORE sector annual average growth rate of 1.7 percent for Oregon and 2.2 percent for Washington from 2007 to 2012 (based on NWGA average growth rates for the commercial and residential sectors from 2008 to 2012)
(3) CORE sector annual average growth of 1.7 percent from 2013 – 2030 (based on NWGA base case weighted average growth from 2008-2012 for the Pacific Northwest)

The industrial sector growth rate averages 1.0 percent and 1.2 percent for Oregon and Washington, respectively, from 2008 to 2030:

(1) EIA industrial gas consumption of 68,836 MMcf and 73,387 MMcf for Oregon and Washington, respectively, in 2007
(2) Industrial sector annual average growth of 0.9 percent for Oregon and 1.8 percent for Washington from 2007 to 2012 (based on NWGA average growth rates from 2008 to 2012 for the industrial sector)
(3) Industrial sector annual average growth of 1.0 percent from 2013 to 2030 (based on NWGA base case average growth from 2008 to 2012 for the Pacific Northwest)

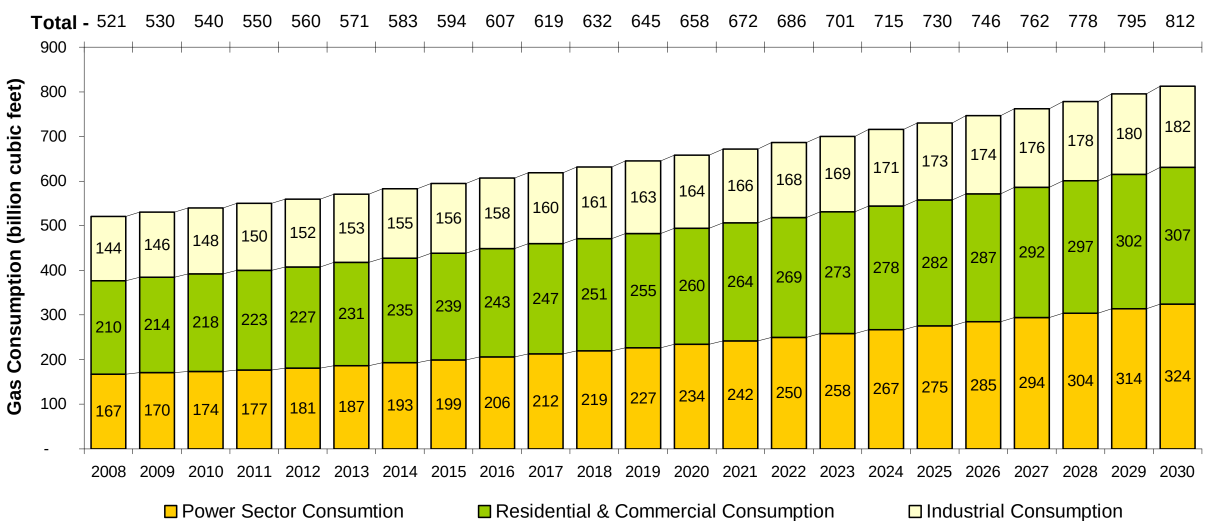
The resultant projections for 2008 to 2030 are summarized in Exhibits 4-3 and 4-4.

[27] Note 2007 data from EIA was available for all sectors except the power sector at the beginning of this study; hence 2006 actual values were used as the basis for power sector projections and 2007 actual values were used as the basis for all other sector projections.

Exhibit 4-4
Natural Gas Consumption Projections for the Power Sector with Adjusted and Extrapolated NWGA Growth Rates

	Power	CORE	Industrial	All Sectors
OR				
2006-2012[28]	2.7%	1.7%	0.9%	1.8%
2013-2030	3.3%	1.7%	1.0%	2.2%
2008-2030	3.2%	1.7%	1.0%	2.1%
WA				
2006-2012[28]	8.3%	2.2%	1.8%	3.9%
2013-2030	3.3%	1.7%	1.0%	2.0%
2008-2030	2.9%	1.8%	1.2%	2.0%
Pacific Northwest				
2006-2012[28]	5.2%	2.0%	1.3%	2.9%
2013-2030	3.3%	1.7%	1.0%	2.1%
2008-2030	3.1%	1.7%	1.1%	2.0%

Exhibit 4-5
Natural Gas Consumption Projections for All Sectors



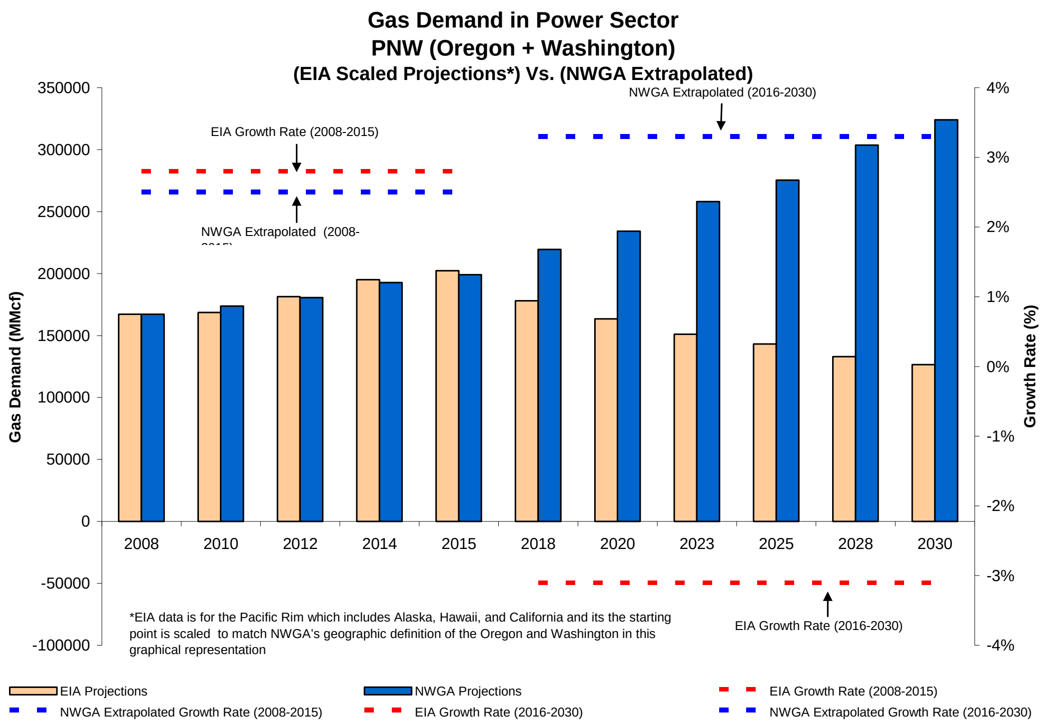
Source: ICF base projection based on publicly available information

IV.3.2 EIA Gas Consumption Outlook

As discussed earlier, the EIA Energy Outlook 2007 projects gas demand for power, residential, commercial and industrial sectors from 2008 to 2030 but for a larger Pacific region which includes California, Alaska and Hawaii. Ignoring the mismatch in regional focus, the EIA projects a similar (albeit slightly lower) rate of growth in gas consumption in the power sector for 2008 to 2015, but a decrease in gas consumption in the power sector from 2016 to 2030, in turn a function of an assumption of decreasing gas fired generation from 2016 onwards (see Exhibit 4-6).

[28] CORE and Industrial sector growth are average from 2007-2012

Exhibit 4-6
EIA vs. NWGA Projections for Gas Demand from the Power Sector



EIA projects that from 2016 onwards, all increasing energy demand requirements will be met by bringing on new coal capacity and increasing coal-fired generation. As noted earlier, this assumption of meeting all increasing energy demand for the Pacific region (including California) from coal-fired generation seems extremely unlikely and impractical considering the present opposition to coal plants, the focus on controlling GHG emissions and the promotion of renewable generation. Therefore, we believe a significant adjustment to the EIA projections is warranted. For illustrative purposes, we constructed a scenario whereby we made an adjustment to the projections by replacing incremental coal-fired generation from 2016 to 2025 with renewable and gas-fired generation, sufficient to meet a hybrid RPS standard. The resultant gas consumption growth rates are summarized in Exhibit 4-7. As can be seen, this scenario results in increasing the gas consumption annual average growth rate from 0.5% to 2.5%, exceeding the growth rate implied by NWGA projections. Alternative scenarios are of course possible, but we believe this scenario illustrates the significant impact of changing a single key assumption (coal generation growth) to one that is more reasonable and likely.

Exhibit 4-7
EIA Annual Gas Consumption Growth Rates – Reference Case and Adjusted

	Power Sector	Core Sector	Industrial Sector	All Sectors
EIA 2007 Outlook Base Case (2008-2030)	-1.21%	1.12%	0.88%	0.49%
EIA Outlook Adjusted (2008-2025)	4.88%	1.20%	0.77%	2.50%
ICF / NWGA Base Case (2008-2030)	3.10%	1.70%	1.10%	2.00%

Exhibits 4-8 to 4-10 compare projected sector growth rates among: the historical period 1997 to 2006, the NWGA forecast, the EIA forecast for different time periods, the NWGA extrapolated forecast, and the EIA adjusted forecast which makes adjustments for coal capacity in the power sector. Exhibit 4-11 is a comparison of projected growth rates for all end-use sectors combined. ICF used extrapolated growth rates from the NWGA report to create a Base Case forecast to 2030 of Pacific Northwest gas consumption. This Base Case was used as a starting point for scenario analysis in a study of the potential impacts of Jordan Cove LNG imports into the Pacific Northwest; Task 2 in a comprehensive analysis of LNG and the Pacific Northwest gas market.

ICF believes that the Base Case projection is reasonable. Gas consumption in the power sector although robust, is well below recent historical growth rates and below the EIA projection when adjusted for coal-fired capacity additions. Since the power sector is the highest growth rate sector, it has the highest impact of the growth in the market as a whole. CORE consumption of space and water heating load customers are projected near historical trends. Industrial gas consumption is projected to increase modestly although consumption levels had decreased in recent years. ICF believes that industries most susceptible to higher gas prices have adjusted or shut-down. Modest gas consumption growth in the industrial sector is consistent with a growing economy. For all sectors in the Base Case, the projected average annual natural gas growth rate to 2030 in the Pacific Northwest is 2%, almost identical to the overall market growth rate from 1997 to 2006.

Exhibit 4-8
Pacific Northwest Annual Average Growth Rates for the Power Sector

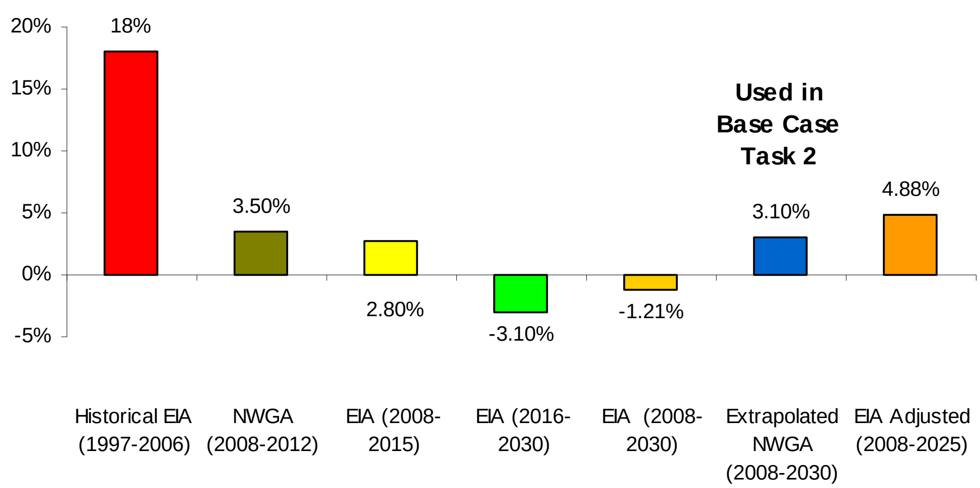
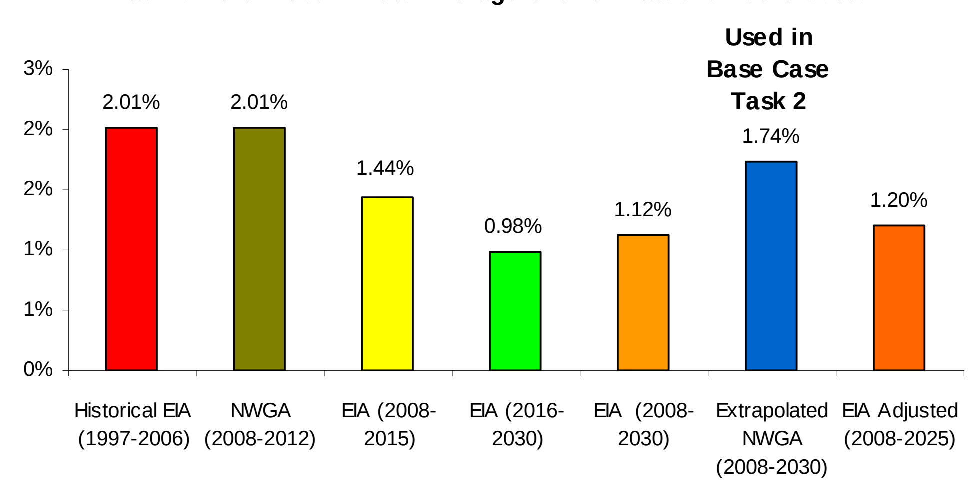


Exhibit 4-9
Pacific Northwest Annual Average Growth Rates for Core Sector[29]



[29] Note: the EIA Adjusted case only went to 2025 due to data availability. Gas consumption in the EIA case and the EIA Adjusted case are identical for all sectors except the power sector.

Exhibit 4-10
Pacific Northwest Annual Average Growth Rates for Industrial Sector

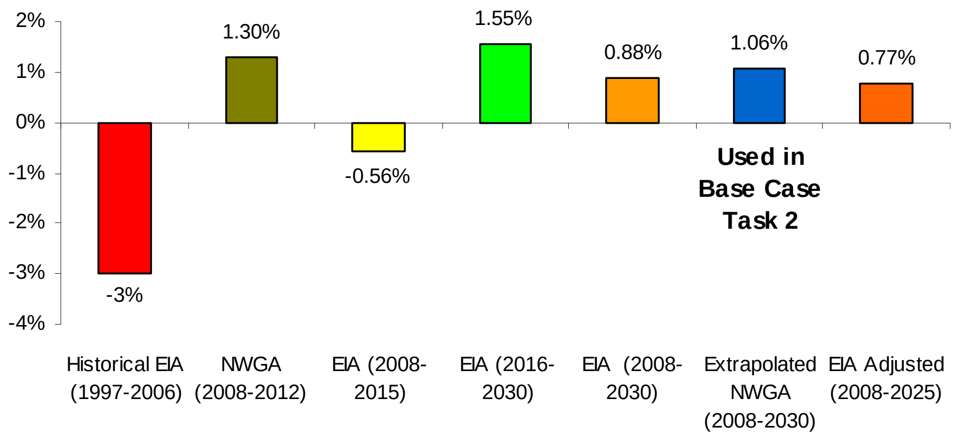
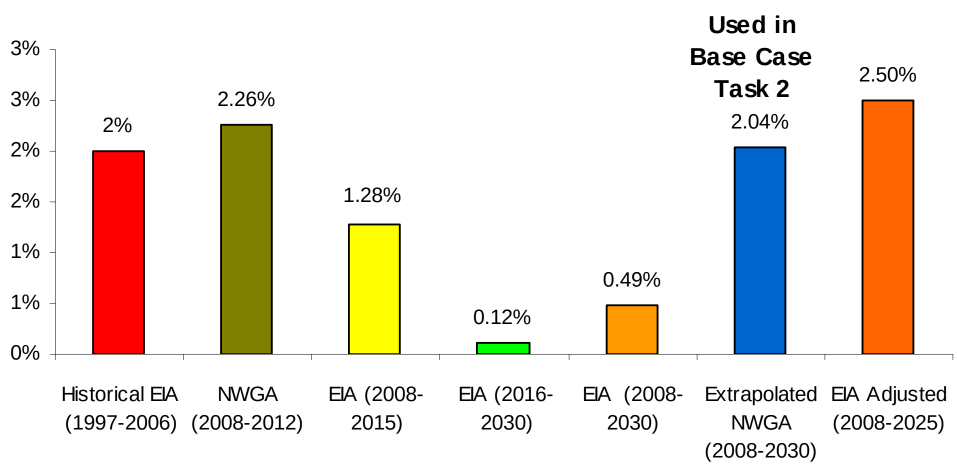


Exhibit 4-11
Pacific Northwest Annual Average Growth Rates for All Sectors



PACE | Global Energy Services

Comparative Life-Cycle Analysis

of GHG Emissions from

Select Hydrocarbon Fuels

May 25, 2007

Introduction

Introduction

- The purpose of this life-cycle analysis is to compare Greenhouse Gas (GHG) emissions associated with each and every process required to generate power from the following hydrocarbon-based fuels:
  - North American Natural Gas
  - LNG
  - Coal
- This life-cycle analysis examines the common processes required for consumption of the selected fuels, including:
  - Extraction
  - Processing
  - Transportation
  - Combustion

Why a Comparative Life-Cycle Analysis?

- Post-combustion emissions alone do not capture the full impacts of fuel consumption.
  - For example, upstream emissions (extraction and processing) and mid-stream emissions (transportation), although significantly lower than end-use combustion emissions, are notable on a relative scale and create GHG emissions that can impact / cause concern in different geographic areas of the life-cycle.
- It is therefore imperative to know, and have documented support of, the projected cumulative emissions for each fuel throughout their respective supply chain.
- Moreover, the fuels in the analysis have different molecular structures and undergo different processes associated with energy consumption, from extraction all the way to combustion.
- As a result, a life-cycle analysis is necessary to ensure commonality of not only GHG emissions for the combustion of each fuel, but to document the cumulative impact of GHG emissions associated with each process in energy consumption.

Life-Cycle Analysis:

Structure and Defined Terms

Structure of Life-Cycle Analysis

- The structure of this life-cycle analysis centers on the subject fuels (North American Natural Gas, LNG, and Coal) and common processes required for consumption:
  - Extraction
  - Processing
  - Transportation
  - Combustion

- The analysis applies two cases to the common processes:
  - Case One (1) compares GHG emissions associated with each process of the most likely scenario for the life cycle of fuel consumed to generate power in the U.S.:
    - North American Natural Gas
    - LNG
    - Coal
  - Case Two (2) compares GHG emissions associated with each process of the most likely scenario for the life cycle of fuel consumed to generate power in the Pacific Northwest:
    - Natural Gas
    - LNG
    - Coal

Life-Cycle Analysis: Defined Terms.

- To ensure comparable results, this life-cycle analysis examines the common processes required for consumption of the selected fuels, including:

	Extraction	Processing	Transportation	Combustion
N. American Natural Gas	Compression-related and fugitive emissions from supply wells	Processing plant activities	Gathering lines, compressor stations, and main line transportation losses.	Post-combustion GHG emissions: - Carbon Dioxide CO_2 - Methane CH_4 - Nitrous Oxide N_2O
LNG	Compression-related and fugitive emissions from supply wells	Processing plant activities, liquefaction, and regasification.	Tanker shipments plus gathering lines, compressor stations, and main line transportation losses.	Post-combustion GHG emissions: - Carbon Dioxide CO_2 - Methane CH_4 - Nitrous Oxide N_2O
Coal	Methane release from coal mines	Methane and carbon dioxide release from crushing, handling, etc.	From supply basin to end-use plant, including rail, barge and / or truck.	Post-combustion GHG emissions: - Carbon Dioxide CO_2 - Methane CH_4 - Nitrous Oxide N_2O

Life-Cycle Analysis: Defined Terms, Continued.

- GHG emissions:
  - Includes only the three major anthropogenic gases associated with hydrocarbon-based energy consumption:
    - Carbon Dioxide (CO_2)
    - Methane (CH_4)
    - Nitrous Oxide (N_2O)
- Carbon Dioxide Equivalent (CO_2e):
  - CO_2e is a metric to commonly report emissions from various GHGs and their respective warming properties or Global Warming Potentials (GWPs).
  - One unit of CO_2e is equivalent to one unit of carbon dioxide emissions.
- Global Warming Potential (GWP):
  - A measure of how much a given mass of a GHG, if released, would contribute to ambient warming.
  - GWP is calculated over a specific time interval (generally, 100 years), and represented in terms of CO_2e.

Life-Cycle Analysis: Key Factors and Inputs

- Unless otherwise noted, the same methodology and analysis is applied in Case 1 and Case 2.
- Emissions attributable to the various processes of consumption are presented in terms of generation output (MWh) to provide a direct comparison.
- Note construction and decommissioning related emissions are excluded from this analysis due to lack of available documentation of past construction activities and uncertainties associated with infrastructure life-expectancy and available technology at the time of decommissioning.
- Pace Global relied upon various sources and published emissions factors for this study.

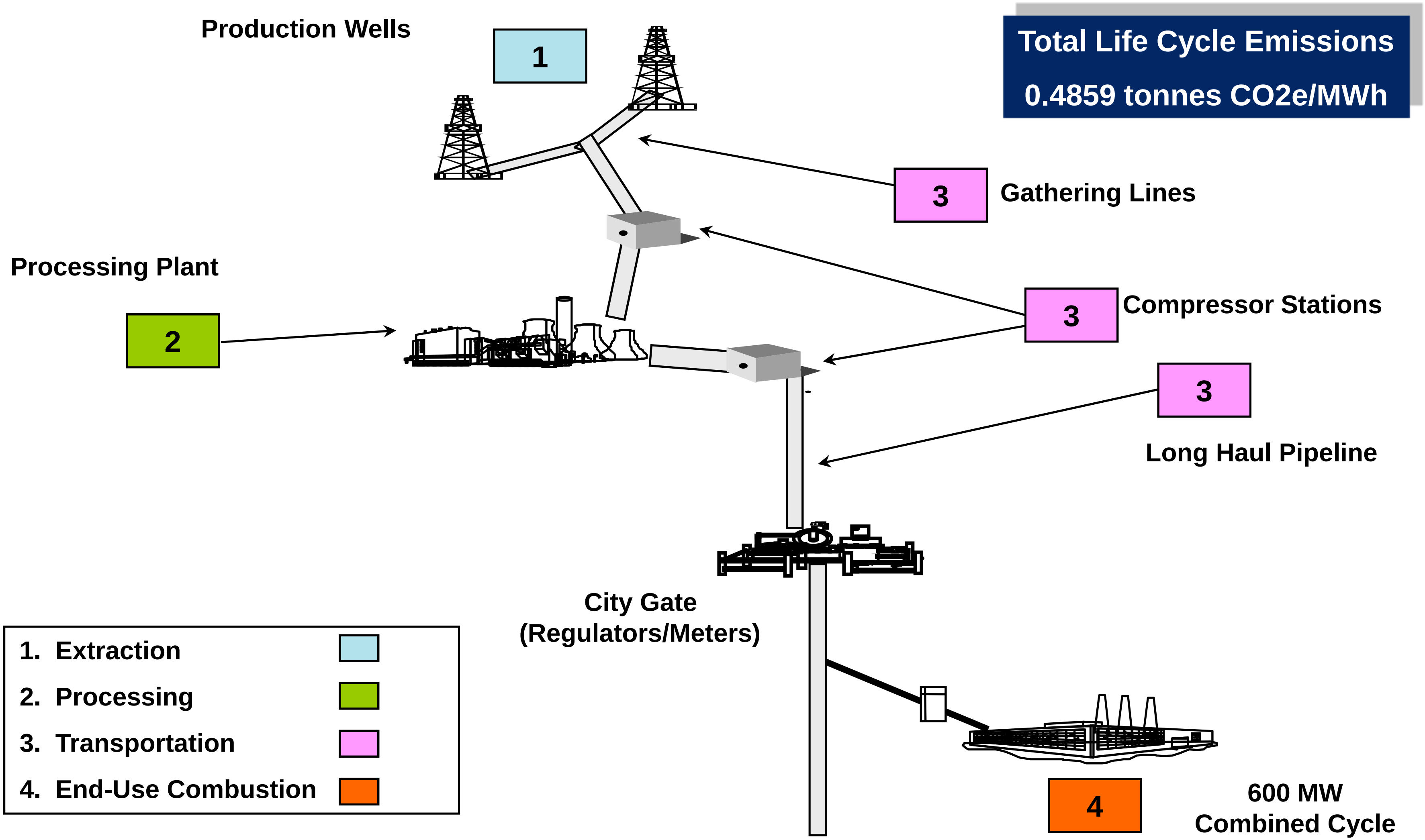
Life-Cycle Analysis:

Case 1

Case 1: Definition & Assumptions

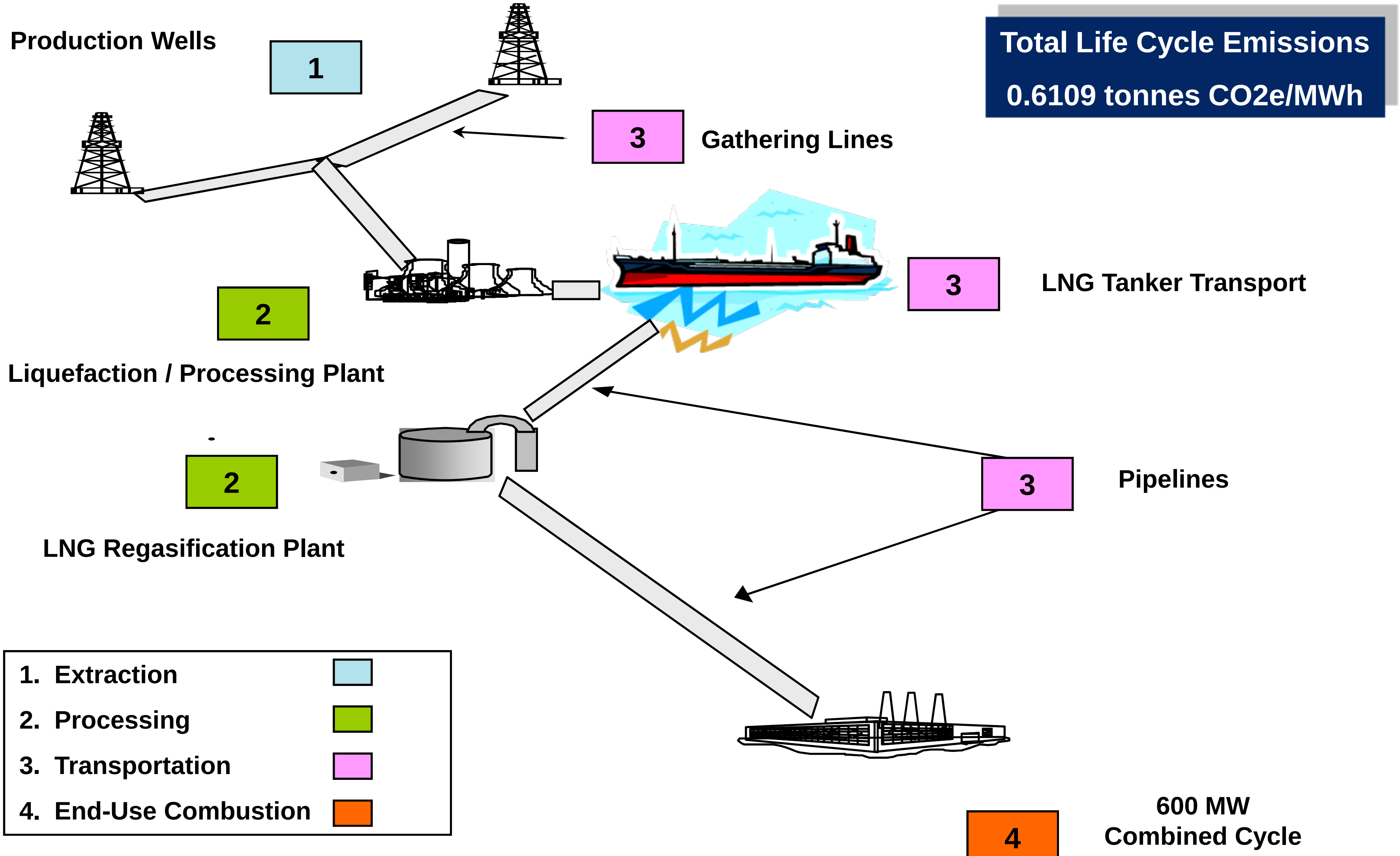
- Case 1 compares the life cycle GHG emissions of fuels consumed for power generation in the U.S., most likely scenario.
- Pace Global relied upon various sources and published emissions factors for this study, including:
  - US EPA *AP 42* Emission Factors by technology and fuel
  - Pace Global rail costing model & other internal assumptions
  - U.S. Department of Energy
  - Publicly available studies
  - EIA Form 860 data

Case 1: North American Natural Gas



Source: American Gas Association and Pace Global

Case 1: LNG

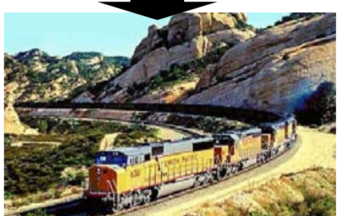


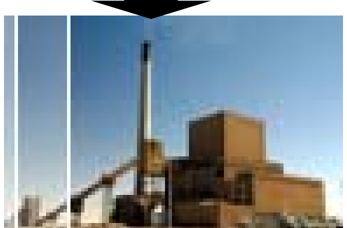
Source: American Gas Association and Pace Global

Case 1: Coal

Total Life Cycle Emissions

1.2206 tonnes CO2e/MWh





Extraction:

PRB Surface Mine

- **10,065 Btu/lb weighted average U.S. coal consumed**
- **Extraction/Mining Process Emissions**
    - **Methane release extraction – 0.021 tonnes CO2e/MWh**
    - **Handling/crushing – 0.007 tonnes CO2e/MWh power produced**

Processing Plant

Transportation

- **National average assume 70% rail transport and 30% barge/truck - CO2 emissions from diesel powered engines**
- **Weighted average haul distance1,530 miles**
- **12,200 tons coal per round trip**
- **11,800 gallons diesel fuel consumed per roundtrip**
- **0.004 tonnes CO2e/MWh power produced**

Combustion:

600 MW Plant

- **Stack emissions from coal fired generation, weighted average heat rate U.S. fleet of 10,920**
    - **CO2 and trace amounts of CH4 and N2O**
- **1.189 tonnes CO2e/MWh**

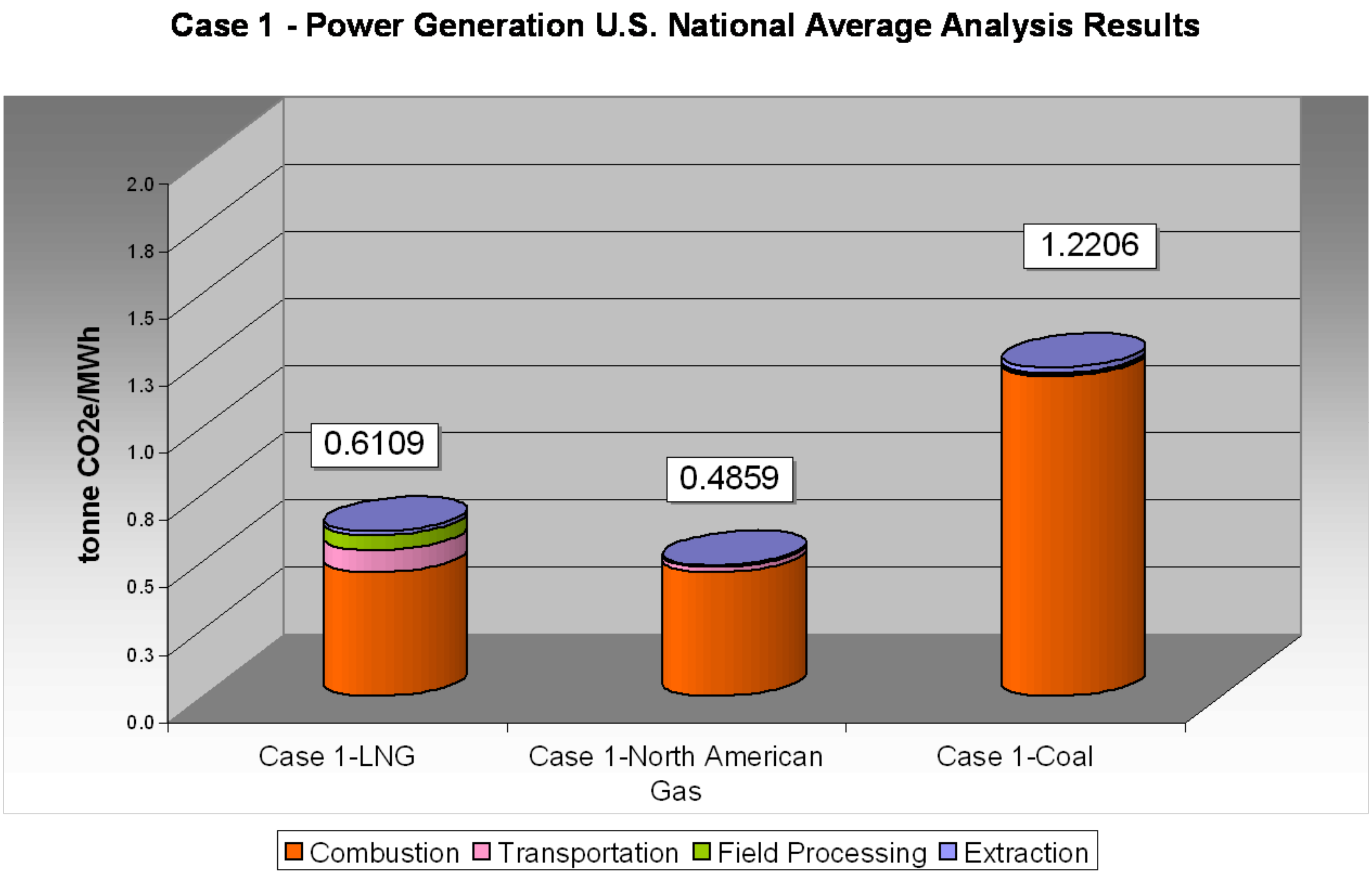
Source: Pace Global

Case 1 – Total GHG Emissions Summary (CO2e / MWh)

	Case 1: Natural Gas	Case 1: LNG	Case 1: Coal
Extraction	0.0048	0.0147	0.0211
Processing	0.0024	0.0548	0.0069
Transportation	0.0195	0.0823	0.0042
Pre-Combustion Total	0.0268	0.1518	0.0321
Combustion	0.4591	0.4591	1.1885
Life Cycle Total	0.4859	0.6109	1.2206

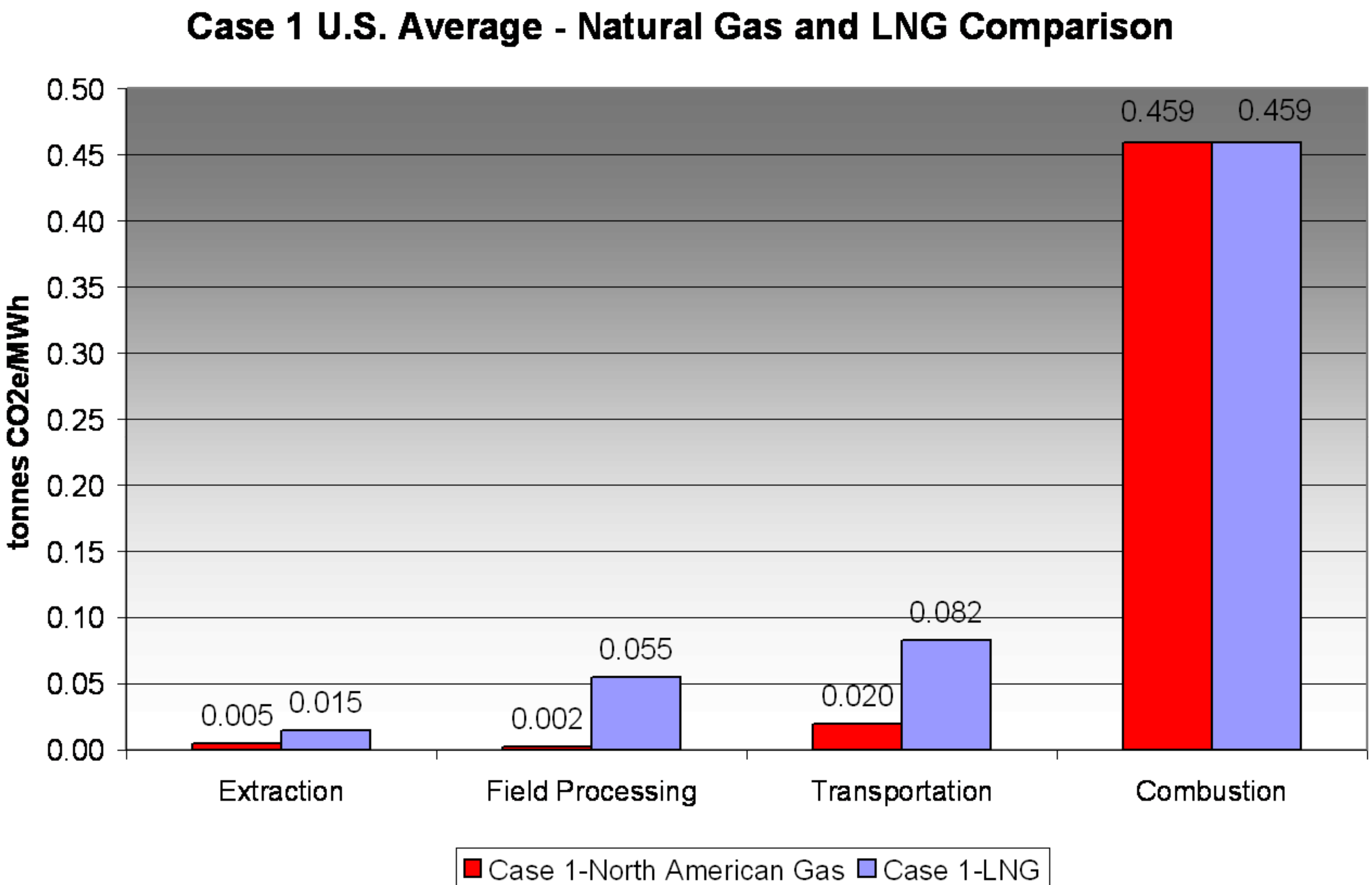
Source: Pace Global

Case 1 – Total GHG Emissions Summary (CO2e / MWh)



Source: Pace Global

Case 1 – Natural Gas versus LNG (CO2e / MWh)



Source: Pace Global

Life-Cycle Analysis:

Case 2

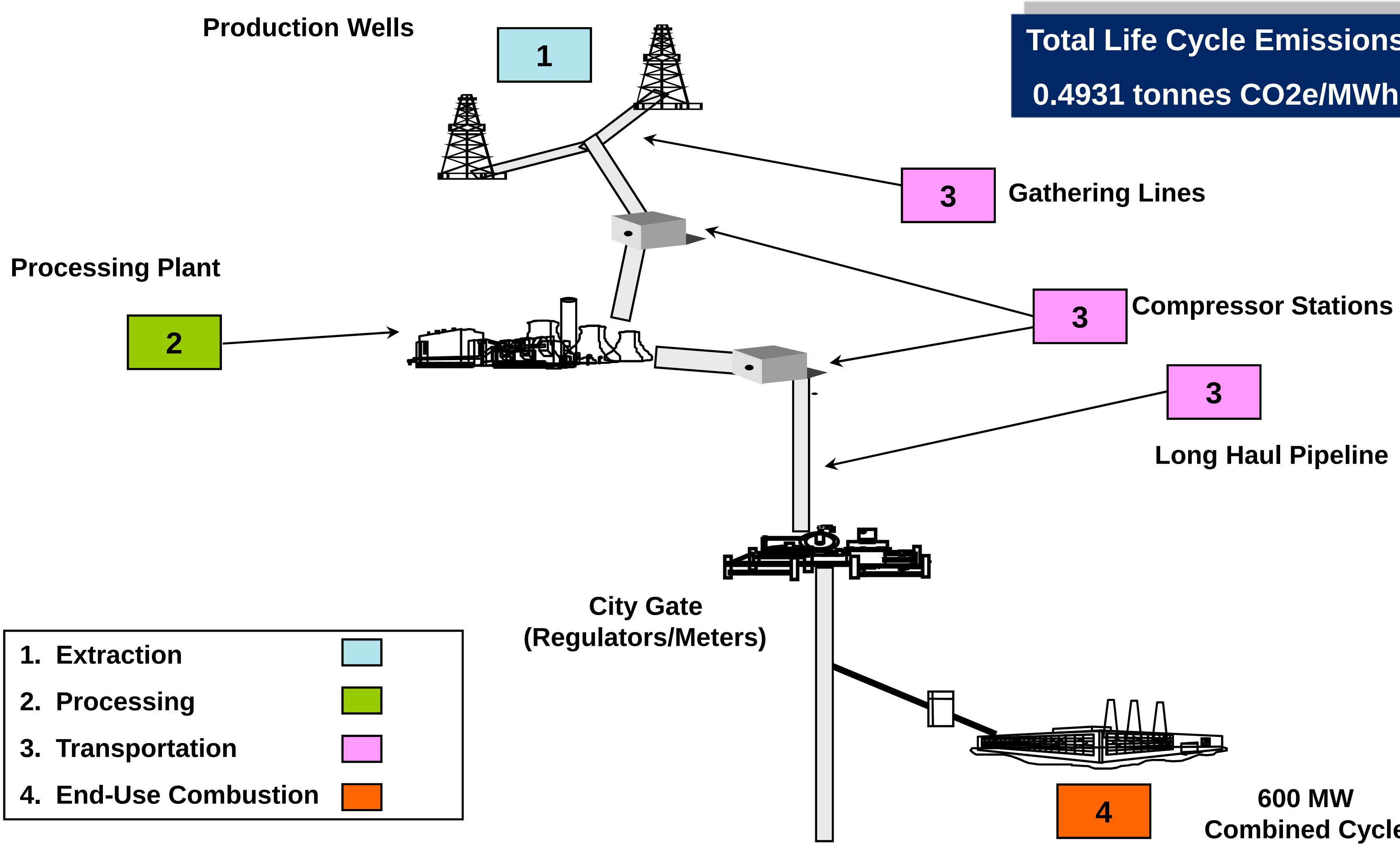
Case 2: Definition & Assumptions

- Case compares the life cycle GHG emissions of fuels consumed for power generation in the Pacific Northwest, most likely scenario.
- Pace Global relied upon various sources and published emissions factors for this study, including:
  – US EPA *AP 42* Emission Factors by technology and fuel
  – Pace Global rail costing model & other internal assumptions
  – U.S. Department of Energy
  – Publicly available studies
  – EIA Form 860 data

Case 2: North American Natural Gas

Total Life Cycle Emissions

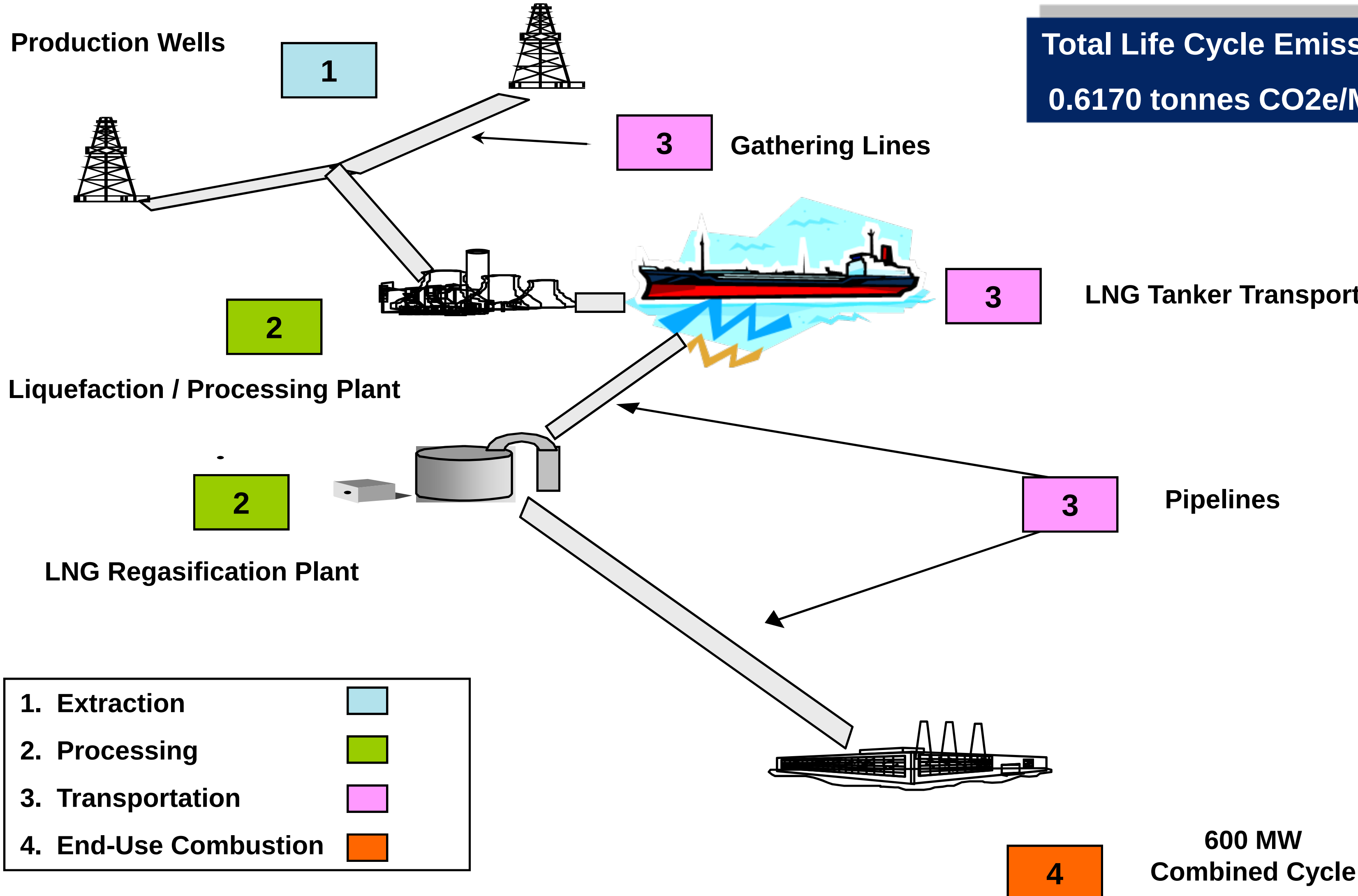
0.4931 tonnes CO2e/MWh



1. Extraction
2. Processing
3. Transportation
4. End-Use Combustion

Source: American Gas Association and Pace Global

Case 2: LNG



Total Life Cycle Emissions

0.6170 tonnes CO2e/MWh

1. Extraction
2. Processing
3. Transportation
4. End-Use Combustion

Source: American Gas Association and Pace Global

Case 2: Coal

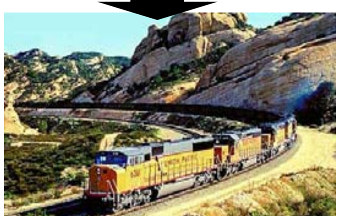
Total Life Cycle Emissions

1.3338 tonnes CO2e/MWh

Extraction:
PRB Surface Mine

Processing Plant

- 8,400 Btu/lb PRB coal
- Extraction/Mining Process Emissions
  - Methane release extraction – 0.0022 tonnes CO2e/MWh
  - Coal handling/crushing - 0.0047 tonnes CO2e/MWh



Transportation

- Rail transport CO2 emissions from diesel powered locomotive
- 3,080 Miles per round trip
- 13,800 tons coal per round trip
- 25,500 gallons diesel fuel consumed per roundtrip
- 0.0113 tonnes CO2e/MWh power produced

Combustion:
600 MW Plant

- Stack emissions from coal fired generation
  - CO2 and trace amounts of CH4 and N2O
- 1.316 tonnes CO2e/MWh power produced

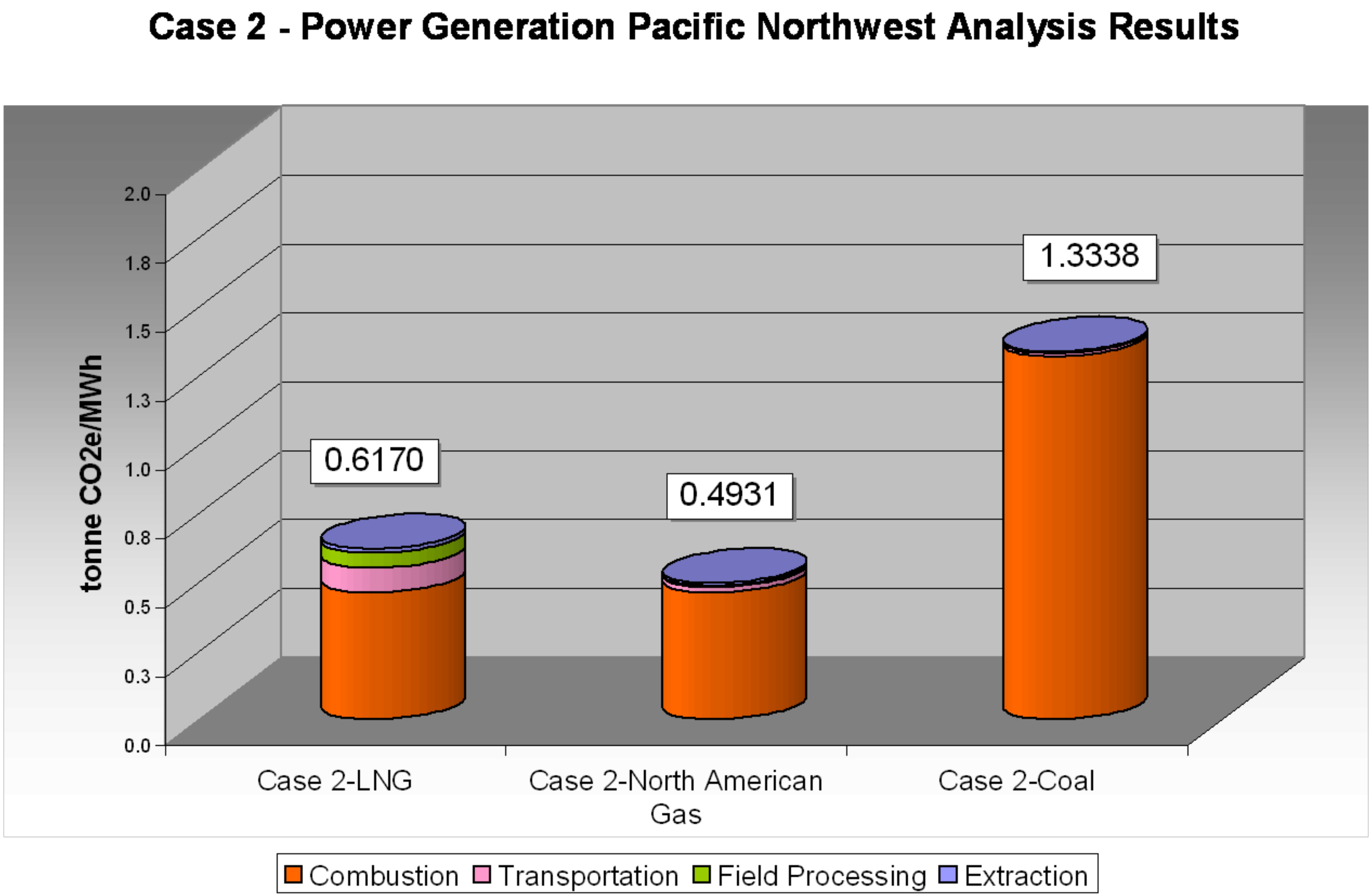
Source: Pace Global

Case 2 – Total GHG Emissions Summary (CO2e / MWh)

	Case 2: Natural Gas	Case 2: LNG	Case 2: Coal
Extraction	0.0096	0.0147	0.0022
Processing	0.0049	0.0548	0.0047
Transportation	0.0195	0.0884	0.0113
Pre-Combustion Total	0.0340	0.1579	0.0183
Combustion	0.4591	0.4591	1.3156
Life Cycle Total	0.4931	0.6170	1.3338

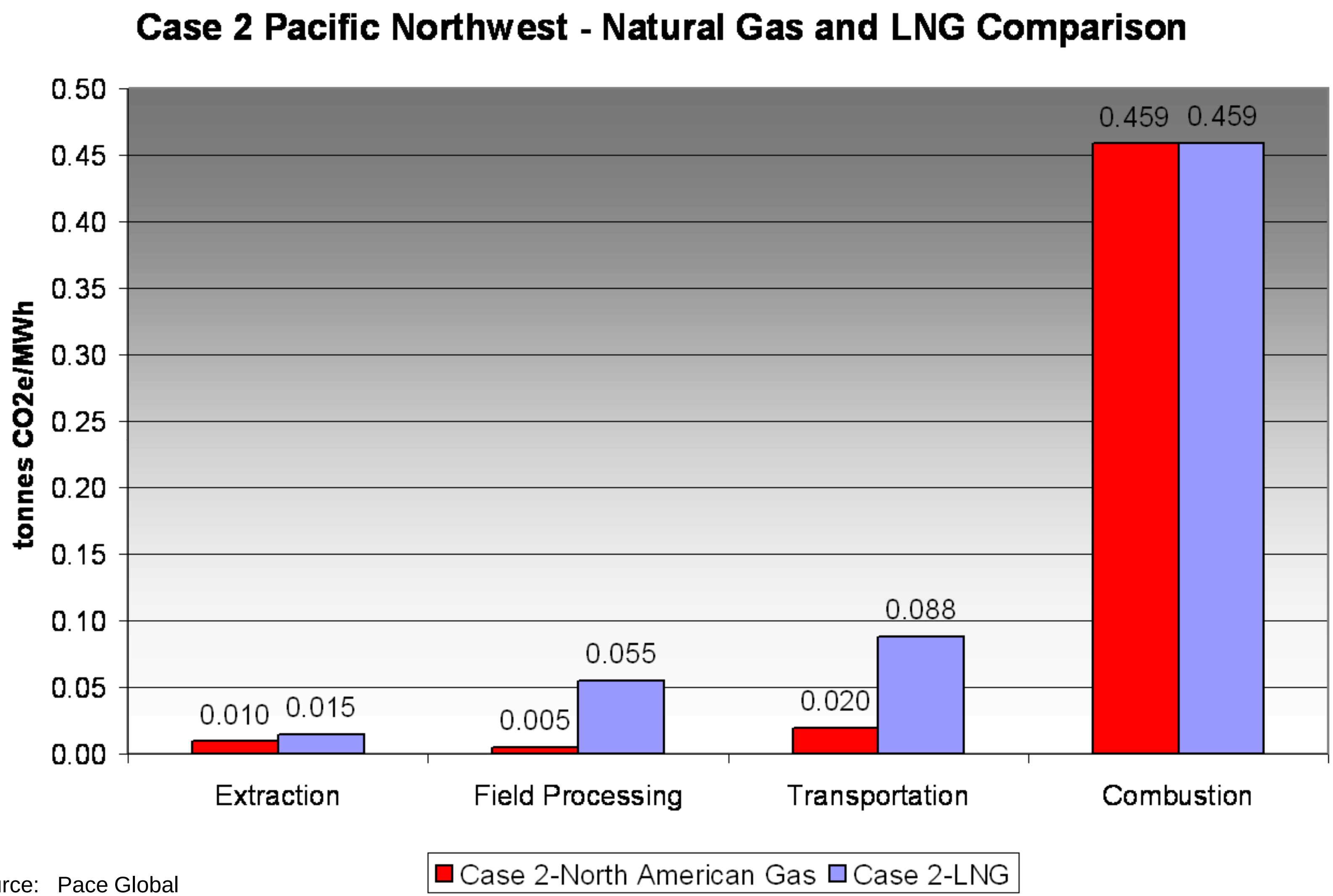
Source: Pace Global

Case 2 – Total GHG Emissions Summary (CO2e / MWh)



Source: Pace Global

Case 2 – Natural Gas versus LNG (CO2e / MWh)



Source: Pace Global

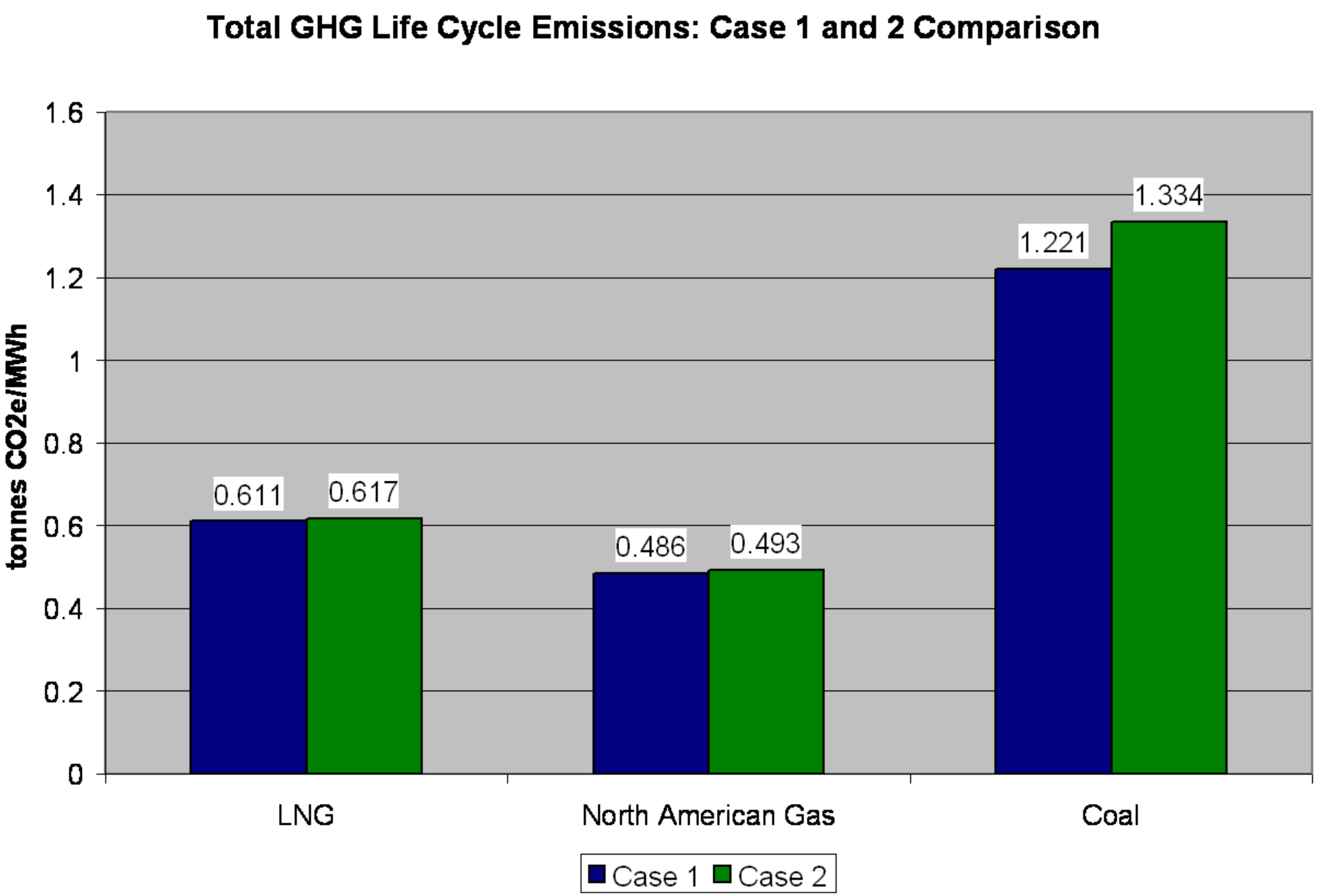
Life-Cycle Analysis:

Summary Comparison

Case 1 & Case 2: Total GHG Emissions Summary (CO2e / MWh)

	Case 1: Gas	Case 2: Gas	Case 1: LNG	Case 2: LNG	Case 1: Coal	Case 2: Coal
Extraction	0.0048	0.0096	0.0147	0.0147	0.0211	0.0022
Processing	0.0024	0.0049	0.0548	0.0548	0.0069	0.0047
Transportation	0.0195	0.0195	0.0823	0.0884	0.0042	0.0113
Pre-Combustion Total	0.0268	0.0340	0.1518	0.1579	0.0321	0.0183
Combustion	0.4591	0.4591	0.4591	0.4591	1.1885	1.3156
Life Cycle Total	0.4859	0.4931	0.6109	0.6170	1.2206	1.3338

Case 1 & Case 2: Total GHG Emissions Summary (CO2e / MWh)



Source: Pace Global

Case 1 & Case 2: Summary

- Variation in North American natural gas and LNG cases are due to differences in transportation distances and pathways.
- Variation in coal cases are due to:
  - – The inclusion of some underground coal in the national weighted average of coal use increases total carbon emissions from extraction and processing (methane release) phases in Case 1.
  - – Case 2 assumes a lower generating facility heat rate characteristic of Pacific Northwest facilities and longer transportation haul. The incremental carbon emissions attributable to the transportation and generation processes make Case 2 total emissions overall greater than Case 1.

Critical Findings

- Both Case 1 and Case 2 demonstrate the following:
- Natural gas produced in North America is the lowest Life-Cycle producer of GHG.
- In terms of GHG Life-Cycle emissions, LNG is the incredibly close to Natural Gas.
- Coal is produces the highest GHG Life-Cycle emissions
- LNG is therefore the next best option to Natural Gas in terms of GHG Life-Cycle emissions, market timing, and feasibility.