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18 May 2009

DOCKET	
09-IEP-1J	
DATE	May 18 2009
RECD.	May 18 2009

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 09-IEP-1J
1516 Ninth Street
Sacramento, CA 95814-5512

To whom it may concern,

I am writing from Pacific Environment, an organization that is working to keep California's Clean Energy Promise. This letter is in regards to "natural gas activities" in the 2009 IEPR. As facilitators of the coalition Ratepayers for Affordable Clean Energy (RACE), we have long viewed any imports of Liquefied Natural Gas (LNG) as entirely inappropriate for the state. We maintain that position, and find the analysis of the greenhouse gas impacts as written in the report "Liquefied Natural Gas Uncertainty Issues" to be deeply flawed.

Page 2 of the report states that, "There appears to be a growing consensus that the carbon footprint of LNG, on a lifecycle basis, is smaller than that of coal-fired generation." It then cites two studies on the subject, one from Carnegie Mellon University, and another funded by Sempra Energy.

In California, however, the debate is not between LNG and coal. We use relatively little coal in the state for electricity generation, and SB1368 forbids the utilities from buying power from coal power plants. There are no plans to shut down any out of state coal plant as a result of the opening of the Costa Azul LNG terminal.

What LNG does displace is domestic natural gas, as well as investment into renewables. For these energy sources, there is no doubt that LNG emits far more greenhouse gases. Even in the lowest case, LNG emits far more greenhouse gas emissions than domestic natural gas. As was covered by several experts at the IEPR workshop on May 14, 2009, there is no shortage of domestic natural gas in North America. Coal is simply not at issue here.

The lifecycle calculation is somewhat complicated by the fact that not all natural gas is the same. For instance, natural gas from both Indonesia and Australia has a much higher carbon content that that from Russia. But at its base, all imported LNG requires overseas shipping, as well as an energy-intensive liquefaction process, leading to at least a 15 percent increase over domestic natural gas. When high carbon content is added in (LNG from Indonesia or Australia, for instance), that can result in about another 10 percent add on. Either way, LNG comes out to be significantly more of a greenhouse gas than domestic natural gas.

251 Kearny Street, Second Floor ▪ San Francisco, CA 94104
tel. 415.399.8850 ▪ fax. 415.399.8860 ▪ www.pacificenvironment.org

Measuring the lifecycle emissions of coal is complicated, but it's also irrelevant in the case of California.

Below are brief summaries of three studies that, for the most part, agree with each other, even though each takes a look at it from a different angle. While the CEC report cites this issue as an "uncertainty," among these three reports there is strong consensus that the lifecycle of LNG is anywhere from 15 to 25 percent greater than that of domestic natural gas.

-The first is the Carnegie Mellon study (Griffin), a comparison between different LNG technologies and different coal technologies. It finds that the highest emitting LNG lifecycle emits a bit more than the best available coal technology. (As you've already cited this, I am not including it as an attachment.)

-The second study is by Richard Heede of Climate Mitigation Services, who analyzed the lifecycle emissions of LNG coming from Australia to a proposed (and rejected) LNG terminal near Oxnard.

-The third study is by Bill Powers of Powers Engineering, done for the RACE Coalition. It is part of a larger set of comments sent to CARB last July (which also summarizes the other studies). Section V examines an LNG supply line from Indonesia to Sempra's Costa Azul LNG terminal.

The industry-supported PACE study does not agree with this consensus, which is not surprising considering the client. It's short on detail, and leaves out some important factors. It should not be used to influence California's climate policy.

The problems with the PACE study include:

(1) Massive CO_2 venting at the source is not factored in. Since Sempra intends to import gas from Tangguh to Costa Azul, the recent information about Tangguh's carbon problems should be considered. The BBC recently reported that Tangguh's operator, BP, has reneged on its carbon sequestration commitment at Tangguh. Natural gas there has a very high CO_2 content: 12 percent.

BP's promise to sequester that carbon is now inoperative, and the CO_2 is going to vent. Sempra now plans to import Tangguh LNG from the plant to Mexico/California when the first train comes on line this summer. That CO_2 is not a factor in the "assumptions" used by PACE, and if it were accurately assessed it would dramatically skew the PACE conclusions downward.

(2) The PACE study assumes the liquefaction trains are at the site of the extraction. Not so at Sakhalin, Russia, the world's largest LNG export facility. How much GHG is emitted in a leaky 500 mile pipeline, a facility that is well known to be shoddily built and certainly prone to spills and attendant GHG

discharge? Until this question is answered, this assumption cannot be taken seriously.

(3) The PACE study (on page 5) states its Life Cycle Analysis (LCA) assumes two fundamentally-contradictory things:

"The LCA examined the entire life cycle of the fuels including extraction (of fuel from already-developed wells and mines), processing, transportation, and combustion."

"The LCA boundary included only process and operation-related emissions and did not include emissions from the construction or decommissioning of infrastructure, such as construction of power plants, trains, ships, etc. The LCA only included emissions from the operation of infrastructure directly attributable to the fuel combusted in the end-use power plant."

These are not divorceable. Emissions attributable to the ancillary uses of the gas and the production process, that are proximately caused by the infrastructure that would not be built or operated independently of the LNG project, cannot be discarded.

There will be considerable energy expenses in exploration, construction and ancillary activities. The amount of steel to be smelted for pipes and ships, for example, is enormous. The amount of waste gas to be emitted in the construction and exploration process is enormous.

Again the main points of this letter that should be included in the IEPR:

- That LNG is, in some cases, less emitting than coal is beside the point. LNG will displace domestic natural gas, and even in the best case scenario is more highly polluting than domestic natural gas.

- The PACE study on LNG is flawed and inaccurate, and lacking in the detail and rigor of three other studies on the subject.

Please feel free to contact me if you have questions.

Yours,

Rory Cox
California Program Director
Ph: 415.399.8850 x302

LNG Supply Chain Greenhouse Gas Emissions for the Cabrillo Deepwater Port: Natural Gas from Australia to California

By Richard Heede

Climate Mitigation Services

7 May 2006

Climate Mitigation Services
Principal Investigator: Richard Heede
heede@climatemitigation.com
1626 Gateway Road
Snowmass, CO 81654 USA
970-927-9511 office
970-404-1144 mobile

to Pam-e for her red-headed wisdom

Report commissioned by Environmental Defense Center
Santa Barbara, California
www.edcnet.org
805-963-1622
Linda Krop, Chief Counsel

Contents

Cover: *Puteri Firus* sailing for Shell International Trading & Shipping, Alstom/Chantiers, shipbuilder, www.marine.alstom.com

LNG Supply Chain Greenhouse Gas Emissions,

In which natural gas from BHP Billiton's Scarborough offshore field is extracted, transported by subsea pipeline to the proposed Pilbara LNG plant near Onslow, Western Australia, where the gas is liquefied, shipped by LNG carrier to Cabrillo Deepwater Port offshore Ventura County, and finally combusted by SoCalGas' end-use customers in southern California.

Introduction

This report summarizes an analysis of greenhouse gas emissions from the entire supply chain as identified by BHP Billiton, the project's applicant, as the likely source of natural gas delivered as LNG to the Cabrillo Deepwater Port receiving terminal offshore Los Angeles, Malibu, and Oxnard, California. BHP has presented and the California State Lands Commission (CSLC) has reviewed what appear to be reliable estimates of most of the greenhouse gas emissions arising from start-up and yearly operation of the Cabrillo facility. No attempt was made by BHP or by the CSLC to include emissions from other critical links in the delivery chain from the production of natural gas in Australia through to its consumption by California gas customers. This interpretation of what constitutes greenhouse gases emissions arising from a proposed energy project is too narrow.

Climate Mitigation Services was commissioned by the Environmental Defense Center on behalf of the California Coastal Protection Network to fill this analytical gap. The Cabrillo Deepwater Port, as this analysis will show, is the source of only 1.5 percent of the full range of emissions from the supply chain summarized in this report.

What follows is an identification of the major segments of the supply chain as described by BHP in its *Construction Permit Application* and by the CSLC in its *Revised Draft Environmental Impact Report*. The report quantifies the pertinent emissions of greenhouse gases from each of these segments.

Study Objectives

This study's objective is to take a comprehensive view of a proposed new source of natural gas to southern California customers — the Cabrillo Deepwater Port — and estimate total emissions of greenhouse gases from the production of the delivered gas to its combustion by end-users. The Liquefied Natural Gas (LNG) receiving and re-gasification terminal is intended to supply 800 million cubic feet of natural gas per day (equal to the energy contained in ~7 million gallons of gasoline per day), according to BHP Billiton, the Australian multi-national energy and minerals company proposing to build the Cabrillo facility 14 miles offshore Ventura County.

BHP has estimated greenhouse gas emissions from the operation of the Cabrillo Deepwater Port as part of its permit application to the U.S. Coast Guard and the State of California. While the BHP application also estimates impacts on air quality, water discharges, land use, ocean bottom disturbances, etc., the purpose of the present analysis is to estimate emissions of greenhouse gases across the entire supply chain of natural gas — from its production platform offshore Western Australia and across the Pacific Ocean to California, including liquefaction and other significant emissions sources. Emissions from the combustion of the delivered natural gas by

California gas customers are also included (after deducting for minor non-fuel uses of natural gas). This allows a meaningful comparison of total supply chain emissions to those from the Cabrillo Port estimated by BHP Billiton in its *Construction Permit Application*.

Each emissions source and the methodology used to quantify them are fully documented in the appended spreadsheets. This report summarizes the major segments of the supply chain, the main sources of greenhouse gases in each segment, and quantifies emissions from each link in the chain that may, if BHP is successful, connect California's gas power plants and water heaters to a natural gas field offshore Western Australia.

This summary report cannot substitute for the details contained in the attached spreadsheets and their cell notes. CMS relies on BHP-supplied data when feasible, and upon industry practice and reasonable (and fully documented) performance indicators when estimating emissions beyond the limited scope of BHP's own estimates. Nonetheless, it is important to state clearly that the results summarized herein are *estimates* and are made without access to detailed engineering analyses only available to BHP, and in many cases are merely in the early planning stages.

It is not our purpose to attribute the entirety of the supply chain emissions to BHP. Rather, the purpose is to fully account for all the emissions attributable to the proposed project from start to finish, from production to combustion. Cabrillo is not isolated from the rest of the supply: it relies on Australian gas that has to be liquefied and shipped at considerable environmental and capital cost, and the gas supplied by the Cabrillo regasification plant will be burned in appliances and turbines in California. State agency officials and the California public cannot make an adequate assessment of the pros and cons of the proposed project without information on the broader scope. This study does *not* evaluate alternative means of delivering energy resources to California, and no recommendations for or against this project will be made.[1]

Both "high" and "low" estimates are calculated and fully documented in the attached set of worksheets and tables; we generally report the average of high and low in this summary. Note: CMS reports LNG and emissions in metric tonnes (1 tonne = 1.1023 short tons).

Boundary definition

This study identifies and quantifies all significant sources of greenhouse gas emissions inherently linked to BHP's delivery of natural gas to southern California. The boundary commences both temporally and geographically with the production of natural gas offshore Western Australia. Energy-related combustion and process emissions across the supply chain are within the boundary. The chain ends with the combustion of the delivered gas by California gas customers. The gases included in the inventory are carbon dioxide and methane from combustion sources, process emissions, and fugitive and/or vented sources.

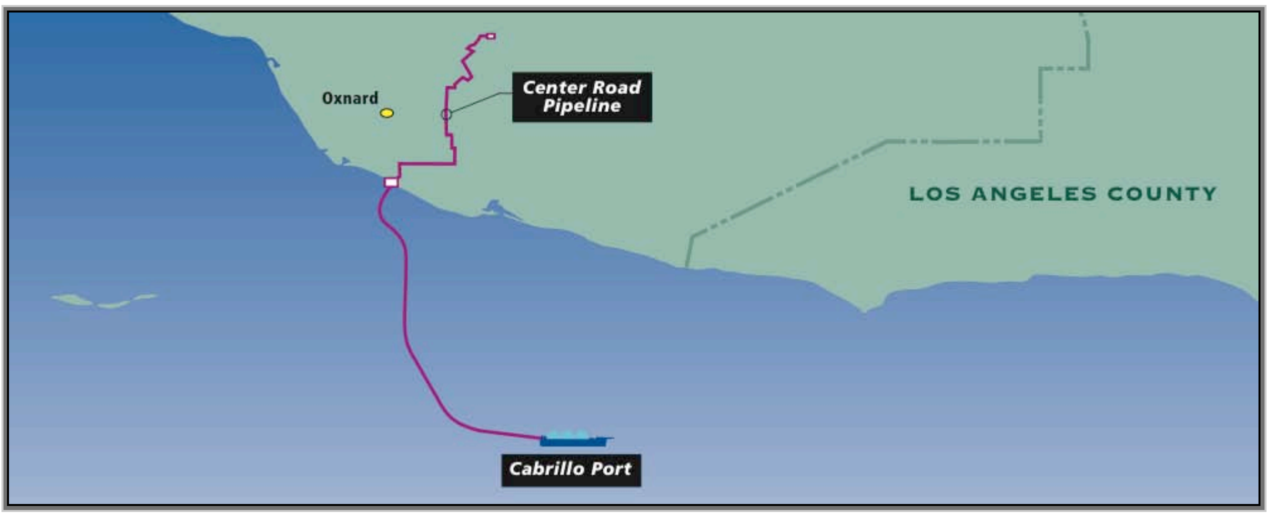
Nitrous oxide and halocarbon emissions sources are *not* included, except for a minor amount of N_2O from the liquefaction plant.[2] Also excluded are emissions from the materials embodied in

[1] The uses of BHP's delivered gas are numerous, and a detailed assessment would need to be done to adequately compare options such as domestic natural gas, hydrogen, renewable energy, end-use efficiency, or alternate sources of LNG. Interested readers might start with Hunt et al (2006) *Does California Need Liquefied Natural Gas?*

[2] Potential emissions of halocarbon leakage or off-gassing during the manufacture, installation, and use of insulation materials in cryogenic storage tanks, pipelines, and LNG carriers have not been quantified. The value chain contains on the order of 10^5 m^3 of insulation material. These include rigid foams (polystyrene, polyurethane, and phenolic resins) and bulk zeolites. Liquefaction plants typically use propane and/or mixed refrigerants; van de Graaf (2006).

the supply chain, such as the ~600,000 tonnes of steel built into production platforms, pipelines, liquefaction plant, fleet of LNG carriers, storage tanks, and the offshore Cabrillo facility.[3]

Energy consumption and emissions from shipyards, engine manufacturers, and the offices of naval architects and plant engineers are similarly outside the boundary, even though these emissions are at least partially attributable to the creation of the supply chain in question. Nor is travel by BHP managers from Perth included, or commuting to work by hundreds of Cabrillo Port construction workers (except for emissions from fuel used by crew boats). The emissions from manufacturing and towing the 200,000-tonne Cabrillo Port to its offshore site, or mooring it to the seafloor, are also excluded. Although omitted by BHP, CMS has estimated emissions from the construction of the pipeline connecting the Cabrillo facility to onshore gas utilities.



Location of the Cabrillo Deepwater Port facility. Source: California State Lands Commission (2006).

Supply chain description

In brief, the delivery of gas to southern California markets via the proposed Cabrillo Floating Storage and Regasification Unit (FSRU) is accomplished by transporting the gas produced from the offshore Scarborough natural gas field by a production platform on (yet to be built) through a 170-mile (280-km) subsea pipeline (yet to be built) to a large gas processing plant being planned near Onslow, Western Australia (population of 800).

This plant (yet to be built) would remove impurities and liquefy nearly 8 million tonnes of natural gas per year by chilling the gas, now mostly methane, to minus 259 ºF. At this point it is liquefied natural gas (hereafter LNG), and its volume has decreased by a factor of 600, enabling it to be economically shipped in a fleet of LNG carriers (yet to be built) across the Pacific Ocean to California, where it will be re-gasified by adding heat to the LNG in the Cabrillo FSRU (yet to be built), and piped to shore in a planned pair of 24-inch pipelines. The LNG business is not new; in fact Japan has imported LNG for power generation and heating needs for decades, including from an LNG plant in Kenai, Alaska.

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[3] CMS does *not* include the roughly estimated 700,000 tonnes of CO_2 from the fabrication of 570,000 tonnes of steel at ~1.24 tonne CO_2 per tonne of steel. Emission factor from Delucchi (2003b). See Table 10 in the worksheet folio.

Where do emissions come from? Carbon dioxide, the principal greenhouse gas, is released as an essential byproduct of combustion: it's the high-temperature combination of hydrocarbons in the fuel — natural gas is mostly methane (CH_4), which is three-quarters carbon and one-quarter hydrogen by weight — with oxygen in the air that releases carbon dioxide and additional heat. Carbon dioxide comprises 94 percent of the total supply chain's emissions — nearly all of the CO_2 from fuel combustion — with methane the remaining six percent.

Every segment of the supply chain emits greenhouse gases. Liquefaction plants use enormous amounts of energy to generate power and run compressors that chill the natural gas to below its boiling point. Production platforms, pipelines, and the Cabrillo FSRU's re-gasification units are all energy-intensive, which essentially means that large quantities of fuels (mostly natural gas) are converted into CO_2 and emitted to the atmosphere. Production platforms and gas processing facilities routinely flare some of the throughput gas, or flash gas, chiefly for safety reasons, and the CO_2 from flares are estimated. Also, CO_2 is typically produced with natural gas, although the gas from Scarborough is reportedly very low in CO_2 (~1 percent).[4] Most of this CO_2 must be removed from the natural gas feed at the liquefaction plant and is vented to the atmosphere along with nitrogen, sulfur, helium, and other contaminants.[5] LNG carriers use marine diesel fuel and/or LNG boil-off gas for propulsion, with substantial CO_2 emissions for the trade route across the Pacific Ocean. Each of these supply chain segments will be described and quantified below.

Carbon dioxide represents 84 percent of total U.S. greenhouse gas (GHG) emissions, methane emissions comprise 9 percent, and nitrous oxide and various halocarbon gases the remaining 7 percent. Methane is important in the supply chain insofar as methane routinely leaks from gas pipelines, storage tanks, compressors, valves, flanges, and seals; methane is also directly vented from the gas processing plant. While routine leaks and vents are not large in terms of mass flow, methane is a greenhouse gas 23 times more powerful than CO_2 per unit mass. Finally, not all of the methane is fully combusted when gas is burned, and these quantities must also be counted.

Overall results

BHP adequately estimated emissions of greenhouse gases arising from the start-up and operation of the proposed Cabrillo Deepwater Port, the energy and emissions from the unloading of ~2.2 LNG carrier berthings per week, emissions from fuel used by the Cabrillo receiving terminal's tugs, tenders, and crew boats, and the main emissions source at Cabrillo: natural gas used in the FSRU's re-gasification units. BHP's estimate totals 261 tonnes of CO_2 per year, including a small amount of methane from incomplete fuel combustion.[6]

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[4] BHP has indicated that Indonesia is an alternate source of natural gas. The gas field has not been identified, nor has the gas been characterized. Thus it cannot be ascertained if the source gas is higher in carbon dioxide content than the gas from Scarborough. CMS has not modeled the supply chain emissions from this secondary source.

[5] CO_2 can be captured and re-injected into oil or gas field for re-pressurization and enhanced recovery, or otherwise sequestered away from the atmosphere. BHP has not, to our knowledge, investigated such opportunities to reduce project emissions anywhere along the supply chain. Nor do we know if BHP has signed a Greenhouse Challenge Co-operative Agreement with the Commonwealth Government. Western Australia does require an emissions mitigation plan, and greenfield projects such as Pilbara are subject to environmental and emissions guidelines. See Chiu (2002), Office of Environment and Heritage (2003), and BHP Billiton Petroleum (2005).

[6] BHP omits estimating methane leakage from the FSRU ("since fugitive leaks from the FSRU process equipment will be composed of primarily methane, they are not regulated by permit or source-specific requirements," and are thus excluded, BHP (2005), section 3.6). The BHP permit application also omits emissions from fuel consumed in construction of the mooring facilities and laying the pipeline from the FSRU to onshore natural gas infrastructure. CMS has made a rough estimate of fuel consumed and added the resulting emissions to the Cabrillo start-up and annualized into the supply chain operating emissions with a 25-year time horizon.

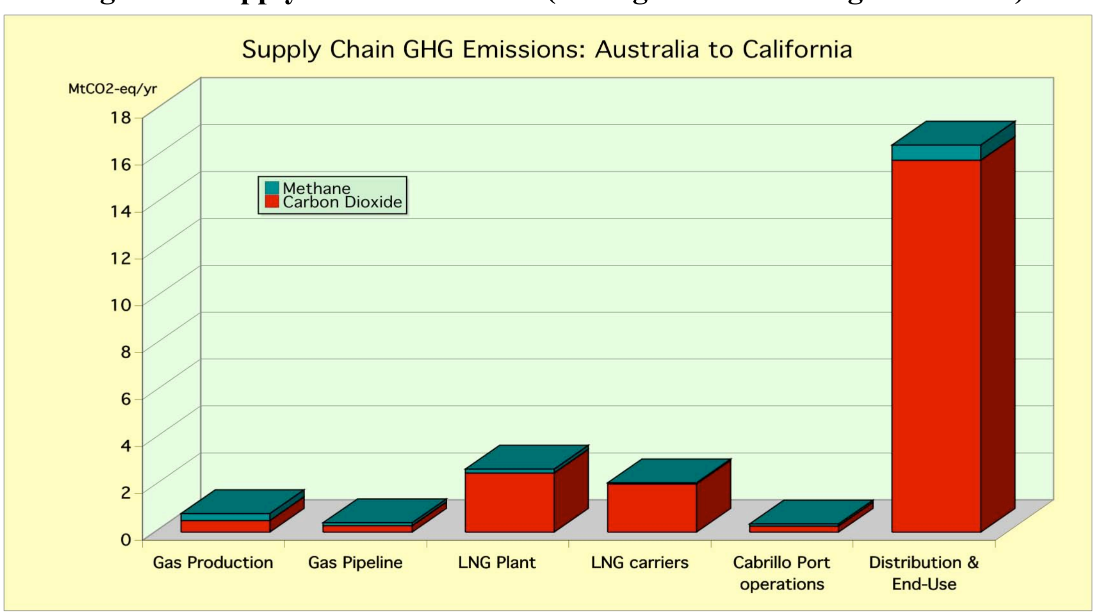
Table 1: Supply Chain emissions (average of low and high estimates)[7]

Supply-chain segment	Methane	Carbon Dioxide	Total	Percent
	thousand tonnes of CO_2-eq			
Gas production (Scarborough)	297	494	791	3.5
Gas pipeline to Pilbara LNG	135	264	399	1.7
Liquefaction plant at Onslow	175	2,512	2,687	11.8
LNG carrier fleet, Australia ↣ California	47	2,048	2,095	9.2
Cabrillo Deepwater Port Operations	85	261	346	1.5
Cabrillo Start-Up (annualized, 25 yrs)	negl	0.4	0.4	0.0
Ultimate gas distribution & combustion	650	15,852	16,502	72.3
Total supply-chain GHG emissions	1,389	21,434	22,823	100.0
Percent	6.1	93.9	100.0	

Note: BHP Billiton's estimate of annual emissions at Cabrillo totals 261 thousand tonnes CO_2-eq (288 thousand tons CO_2-eq). Note that the table is in metric tonnes (1 tonne = 1.1023 tons).

BHP's estimate of emissions from the Cabrillo Deepwater Port operations represents 1.5 percent of the supply chain emissions as estimated by Climate Mitigation Services (Table 1). Emissions from Cabrillo operations are significant, especially in terms of local air quality if not global warming, but clearly pale in comparison (by a factor of 66 to 1) to emissions from the other elements of the supply chain required for gas delivery to southern California. The major component is, not surprisingly, combustion of the delivered fuel. Compared to the emissions from end-use combustion of the gas — which is a common measure of the global warming contribution of natural gas — the rest of the supply chain emits an additional 44 percent.[8] Methane is 6.1 percent of the total. The energy-intensive liquefaction plant and the LNG carrier "pipeline" across the Pacific emit ~twelve and nine percent of total emissions, respectively.

Figure 1: Supply Chain Emissions (average of low and high estimates)



[7] CMS has estimated each supply chain segment in a range. The table averages the high and low estimates.
[8] This fraction is derived as follows: the supply chain total divided by CO_2 from "Gas distribution & combustion:" 22.82 million tonnes of CO_2-eq ÷ 15.85 $MtCO_2$ = 1.440, or 44 percent "adder" to end-use combustion alone.

SUPPLY CHAIN SEGMENTS AND EMISSIONS ESTIMATES

Natural gas production at Scarborough offshore gas field

According to BHP's plans as stated in its *Construction Permit Application*, natural gas will be produced from the Scarborough subsea gas field 270-km northwest of the Pilbara Coast of Western Australia. The field is jointly owned by BHP and ExxonMobil, lies at depth of 900 m, was discovered in 1979, is shut-in (that is, there is no production facilities in place), and contains an estimated 8 trillion cubic feet (Tcf) of gas reserves. This reserve estimate is under review.[9]

All of the elements of the proposed supply chain between Scarborough and Cabrillo will use natural gas to fuel pipeline compressors, run generators at liquefaction plants, fuel engines onboard the LNG carriers, re-heat the cryogenic fluid in the Cabrillo re-gasification units, etc. Since BHP proposes to deliver 800 million cubic feet (0.8 Bcf)[10] per day to SoCalGas, our first task is to estimate the total amount of gas production required. This detailed analysis is summarized in Table 2 below. Suffice it to say here that the total annual production is not 292 billion cubic feet (800 million cf/day times 365 days per yr) but 379 Bcf/year in order to cover the delivery rate and the supplementary gas requirements. While it may be the case that BHP's production plans cannot satisfy this 30 percent higher production rate, this is not really material. The objective is to estimate total emissions, and whether it is produced at Scarborough or elsewhere matters less than the total quantity involved.[11]

Table 2. Total gas production required for each segment and supply chain total

Segment	Million cf/day	Billion cf/yr	Million tonnes/yr
Production at Scarborough	21	8	0.17
Pipeline to Pilbara	13	5	0.10
LNG plant	103	37	0.81
LNG Carrier fleet	88	32	0.69
Cabrillo Deepwater Port ops	13	5	0.10
Gas deliveries to SoCalGas	800	292	6.28
Total supply chain	1,038	379	8.15

Natural gas in million tonnes or the equivalent in LNG. Also see attached worksheets, Table 1.

[9] Exxon previously put Scarborough's recoverable gas reserves at 5 trillion cubic feet and "insufficient to sustain a world-scale LNG project." BHP recently completed an extensive reserve evaluation, and BHP and Exxon are now in closer agreement as to the field's reserves. An Exxon spokesperson stated that the company does not necessarily agree that "BHP's LNG plans [are] the best way to develop the reservoir." Wilson (2006); also see Freed (2006).

[10] The U.S. convention is to use mmcf for thousand thousand cubic feet. CMS adopts "M" as million, and "B" as billion, hence $MtCO_2$ for million tonnes CO_2 and Bcf for billion cubic feet. However, CMS avoids the use of both mmcf and Mcf, preferring to write it out to avoid confusion.

[11] That said, other gas sources might contain higher fractions of CO_2 (and vented to the atmosphere). Or it might require supplemental LNG shipments from other liquefaction plants, which would alter the LNG carrier propulsion estimates and perhaps the fleet size. Or BHP could buy LNG on the spot market. This analysis is based on the project as described in the BHP permit application. However, as we will discuss with the LNG plant below, BHP's plans are not adequate to supply the required amount of LNG to propel the requisite delivery rate to California.

The total production quantity determines each subsequent step, since emissions estimates are tied to, say, flaring rates at production platforms, or energy inputs to liquefaction, or the amount of LNG that has to be loaded and transported annually. This parasitic energy consumption drives emissions as well plant capacities and, for that matter, BHP's opportunities to improve plant efficiencies and profitability while also reducing the climate impact of its operations.

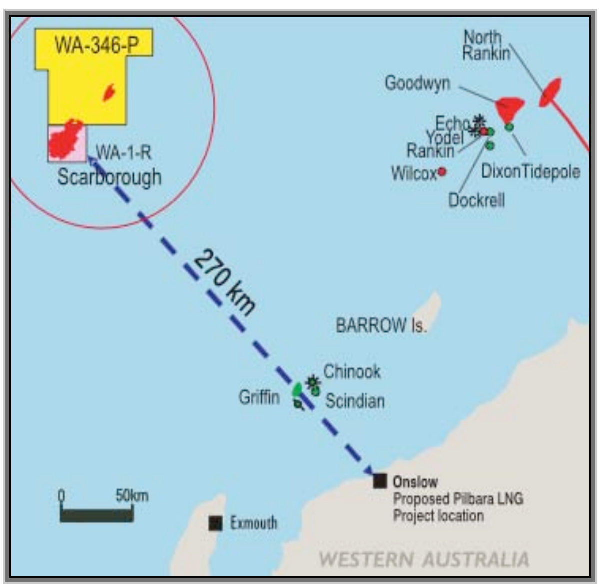
Emissions from gas production include gas flaring, methane leaks, platform energy requirements for compressors, power generation, heating loads, lighting, and hotel loads (for accommodation requirements such as hot water, ventilation, cooking, waste handling, and so forth).

Emissions related to gas production totals 0.79 million tonnes CO_2-eq ($MtCO_2$-eq), with 0.49 $MtCO_2$ of the total as combusted and vented carbon dioxide and 0.30 $MtCO_2$-eq as methane.

CMS' emissions estimates are based on reasonable and transparent protocols. Uncertainties are inevitable, in no small measure because these facilities have neither been designed nor built. CMS did not have access to BHP engineering data other than the scant information published in the permit application. CMS has assumed industry best-practice or, in some cases, improvements over standard practice or industry benchmarks. The assumption made throughout this analysis is that BHP will adopt the best-available technology and low-emission designs within economic and regulatory pressures. CMS makes low and high emissions estimates for each supply chain segment, and uses the average of the two in this summary report.

Natural gas transportation by subsea pipeline

The Scarborough subsea pipeline will transport about 370 Bcf of gas annually to Onslow, Western Australia, where BHP has selected a site to build its proposed Pilbara LNG plant (see the illustration on page 10). CMS estimates that 0.21 to 0.37 million tons of CO_2-eq will be emitted for pipeline energy needs, plus fugitive methane from leaky seals, compressors, and so forth. Methane leakage rates are based on U.S. data for gas production and transmission rates per Bcf of throughput. Since it is a subsea pipeline except for the production compressor station and onshore facilities, CMS reduced the industry gas transmission leakage rate by a factor of ten to five (low and high estimates, respectively).



Map of Scarborough natural gas field offshore Western Australia. BHP Billiton *Petroleum Review 2005*.

Pipeline compressor energy is the source of about half of the total pipeline emissions. CMS uses a conservative range in the pipeline energy estimate: forty and sixty percent *below* the U.S. industry average for the high and low estimates, respectively, since Scarborough is closer to the LNG plant than typical distances in the U.S. The industry rate is ~2.5 percent of gas throughput consumed for pipeline energy. If CMS had applied the common performance factor, 9.4 billion cubic feet of gas would be consumed for gas transportation, rather than the estimated 4.8 Bcf.

Gas liquefaction: proposed LNG plant at Onslow

Liquefaction is the preferred method for reducing the volume of natural gas in order to "economically" enable its long-distance transportation. Liquefaction also requires purification of the feed gas to remove natural gas liquids, CO_2, sulfur, and other contaminants that could corrode the steel tanks or impede liquefaction or otherwise not meet U.S. natural gas standards. Natural gas liquefies at a temperature of 259 degrees Fahrenheit below zero (-161 ºC). Once liquefied, it has to be stored in heavily insulated tanks to minimize the heat transfer that would lead to excessive "boil off" — gasification or volatization — of the LNG. Liquefaction plants are typically built near shipping terminals, since most LNG is produced for international markets in Asia and Europe and, increasingly, the United States.

Unidentified LNG storage facility, presumably for peaking purposes. Source: US DOE (2005).

BHP North West Shelf natural gas processing plant. BHP Billiton *Petroleum Review 2005*.

CMS estimated the amount of LNG sufficient to (a) account for LNG boil-off during the 17-day trans-Pacific voyage and any additional propulsion or power generation requirements, including each vessel's return trip to Pilbara, (b) the amount of natural gas needed to operate the Cabrillo Deepwater Port, and (c) deliver the indicated amount of natural gas to SoCalGas. These estimates are shown in Table 2 above. If the Pilbara plant is sized to account for these parasitic loads and sufficient to deliver 292 Bcf of gas (equivalent to 6.28 million tonnes of LNG), the required plant size has to be increased from the 6 Mt/yr announced by BHP to 7.1 Mt/yr.[12]

BHP may elect to acquire additional quantities of LNG from other suppliers on the emerging spot market in order to satisfy its indicated delivery rate rather than increase the productive capacity of the Pilbara plant. This uncertainty is relatively immaterial to our principal objective, however, which is to estimate the supply chain emissions of greenhouse gases. Another plant may emit less or more CO_2 and methane, the feed gas may have a higher CO_2 content, but these are unknowns, and we have based our estimates on the most likely chain of events. This includes BHP's plans to construct an LNG plant at Onslow, use natural gas from Scarborough, and ship the LNG in a fleet of carriers to Cabrillo in southern California.[13]

BHP Billiton has not issued any design specifications on the proposed LNG plant. CMS thus does not have plant-specific emissions estimates to draw upon, nor are the selected liquefaction or electric generation or compressor technologies known. BHP has not yet issued a Feasibility report nor prepared an Environmental Impact Assessment. A sketch of the proposed plant based on BHP's site-selection study is reproduced below.

An artist's sketch of the proposed Pilbara LNG plant at Onslow. Source: BHP *Pilbara News*.

In lieu of actual process and technology specifications, CMS used emissions factors for a state-of-the-art facility operated by ConocoPhillips at Darwin, Australia. The Darwin plant uses the Phillips Cascade Process for liquefying natural gas, is a single-train 3.24 Mt/yr plant with one large cryogenic storage tank, and emits an estimated 1.4 million tonnes of carbon dioxide and methane per annum.[14] The CMS methodology for using Darwin's emissions rates involved several steps, each detailed in the attached worksheets:

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[12] The Pilbara plant will consume ~37 Bcf of gas from Scarborough in the process of liquefying 7.1 Mt/yr of LNG. While many LNG plants use propane and other natural gas liquids contained in the feed gas, BHP has not provided an analysis of the Scarborough, and CMS has converted the LNP plant's energy requirements to equivalent gas.

[13] Due to the trans-Pacific voyage, BHP will need a fleet of 11 LNG carriers. Assumptions: 138,000 m^3 carriers, gas mode on 60,000 HP Wärtsilä 50DF engines (consuming 6,740 m^3 one way), 7,900 nautical miles each way, vessel speed of 19.5 knots, and a 24-hour turn-around at each terminal. A current cost of $160+ million per carrier suggests a "pipeline" investment of $1.76 billion. Diesel-only fuel mode would increase net deliverable LNG by 13,500 m^3 per trip (assuming full re-liquefaction of boil off gas) and reduce the fleet size by one carrier and $160 million.

[14] The Darwin plant delivers LNG to Tokyo Electric and other Japanese project partners. The first shipment to equity partners Tokyo Electric and Tokyo Gas occurred in Feb06. Emissions are based on estimates (with planned mitigation measures), not measurements, and are drawn from ConocoPhillips (2005) *Operations Env. Mngt Plan*.

1. Scale Darwin's emissions by a factor based on actual LNG requirements for Pilbara, which was in turn increased from BHP's estimated plant size (6.0 Mt/yr) to CMS' estimate that 7.07 Mt/yr of capacity is required in order to deliver 800 million cubic feet of gas to Cabrillo. The resulting scaling factors is thus: Darwin = 3.24 Mt/yr and Pilbara = 7.07 Mt/yr for a ratio of 1:2.18;[15]
2. The scaling factor was applied to Darwin's emissions rates per tonne of LNG produced, except for two important adjustments: (a) Darwin's feed gas (from the Baya-Undan gas field 500 km offshore) contains six times more CO_2 than BHP's Scarborough gas, (b) the electricity required to operate acid gas venting process is thus also reduced. Both of these factors are accounted for;
3. The Pilbara "low" emissions estimate is based on Darwin's emissions rates multiplied by the scaling factor between the two plants (and adjusted for the lower carbon content of gas feed, as noted above);
4. The Pilbara "high" estimate is based on a blended emissions factor, averaging Darwin's unusually low emissions rate (0.43 tonnes CO_2-eq per tonne of LNG produced) and the recently completed Train #4 at Atlantic LNG Company of Trinidad and Tobago (0.81 tCO_2-eq/tLNG). This higher emissions factor is again adjusted for Scarborough's lower CO_2 content feed gas.
5. Also, in the Pilbara "high" estimate, the methane venting rate has been increased from Darwin's rate to that of U.S. natural gas industry average in 2004.[16]

CMS estimates both "high" and "low" emissions for the scaled-up Pilbara LNG plant for refrigeration compressors (which, due to their very large size and constant operation, require enormous inputs of site-generated power), other plant electricity demands, acid gas venting (removal of carbon dioxide from the feed gas prior to liquefaction), nitrogen rejection units, flaring from numerous sources at the LNG plant, terminal, and loading operations), methane vented directly to the atmosphere, and minor amounts of nitrous oxide emissions. The "low" estimate totals 1.97 million tonnes of CO_2-eq per year, the "high" estimate totals 3.41 MtCO_2-eq/yr, and an average of 2.69 Mt MtCO_2-eq/yr. Methane from venting and incomplete combustion is 5.6 to 7.0 percent of total LNG plant emissions.

The Darwin LNG plant, 3.24 Mt/yr, *left*, & the Atlantic 4-train LNG plant, 15 Mt/yr, *right*.

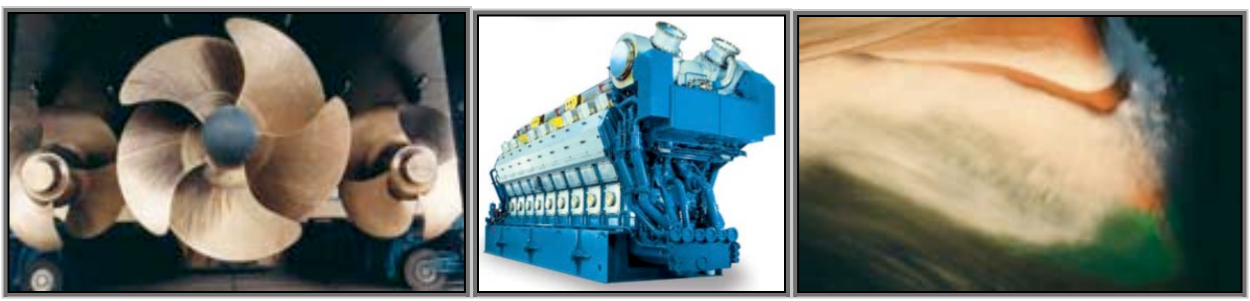
[15] This assumes that BHP adopts the ConocoPhillips design, liquefaction process, state-of-the-art technology, and mitigation efforts. CMS cannot ascertain that BHP will select these technologies, nor meet or exceed the Darwin plant's emissions reduction initiatives — such as high-efficiency aero-derivative gas-fired turbines to power refrigeration compressors, waste heat recovery, ship vapor recovery, efficient pumps and motors, and cascading emissions benefits from smart design and technology.

[16] ConocoPhillips (2005) *Darwin OEMP*, note to Table 5.2: "A routine venting operation. .... The methane emission rate is 268.8 kg/h with duration of venting assumed to be 7,671 hours per year." CMS has updated the GWP factor from 21 to 23xCO_2, per IPCC's *TAR* report (2001), p. 388. Using the scaling factor applied to compressors (based on the Atlantic Train #4 relative to the Darwin emissions rate) results in a methane emissions estimate of 6,604 tonnes of CH_4. CMS instead applies the methane emissions rate of the US natural gas processing industry (Table 11 in the attached worksheets), namely 28.22 tonnes of CH_4 per Bcf of natural gas consumption, which, in the case of the scaled-up Pilbara plant, totals 366 Bcf per year (see worksheet Table 1).

LNG shipping via fleet of LNG carriers

LNG carriers are traditionally powered by steam turbines burning marine diesel or heavy fuel oil. The new generation of LNG carriers are increasingly installing diesel-electric propulsion systems in which two to four large engines generate electricity that power electric drives. Dual-fueled engines, such as those made by Wärtsilä that CMS has based its propulsion and emissions estimates upon, can burn either marine diesel/heavy fuel oil and/or natural gas — the source of which is the boil-off gas from the cargo. Emissions from this segment of the LNG supply chain are the result of converting propulsion fuel into carbon dioxide (plus some methane).

CMS based its fuel consumption estimates on statements in the CSLC (2006) *Revised Draft EIR*. Although BHP has "not finalized design specifications for LNG carriers" or determined (to our knowledge) the size, propulsion type, or fuel preference, CMS used the lower end of the vessel size (138,000 m^3) cited, modeled emissions and fuel consumption for three scenarios (low, medium, and high), and derived total annual trips based upon the same basic criterion followed throughout this exercise: the delivery of 800 million cubic feet of gas daily (292 Bcf/yr) to southern California markets.[17]



Propellers, 50DF dual-fueled engine, and a bulbous bow plowing through pacific waters. www.wartsila.com

The BHP permit application cites a power rating of 60,000 HP (44.7 MW), and while this is higher than the propulsion rating of other ships of similar size,[18] CMS has used the BHP-supplied data for the calculations.[19] Furthermore, CMS assumed the use of Wärtsilä 50DF duel-fuel engines as power plants, with CO_2 emission rates of 430 to 630 grams of CO_2 per kWh, depending on fuel type.

[17] CSLC (2006) *Rev Draft EIR*, p. 2-21: "LNG carriers would have a capacity ranging from 36.5 to 55.5 million gallons (138,000 to 210,000 m^3). Of this volume, an estimated 4 million gallons (15,100 m^3) would be consumed by the carrier while in transit for fuel and for maintaining the cold tanks; the remaining 32.5 or 51.5 million gallons (123,000 or 195,000 m^3) would be transferred to the FSRU. LNG carriers would be powered by natural boil-off gas from their LNG cargo, as agreed with the U.S. Environmental Protection Agency (USEPA) (Klimczak 2005). The Applicant has not finalized design specifications for LNG carriers; therefore, the diesel storage capacity for LNG carriers cannot be estimated at this time."

[18] Küver et al (2002) "Evaluation of Propulsion Options for LNG Carriers," show the predicted power requirement — albeit for propulsion only — of a state-of-the-art LNG carrier of 145,000 m^3 size cruising at 19.5 knots (as we assume here) as ~25 MW, not the 44.74 MW used by BHP. Küver also models the boil-off rate (0.15% BOG/d) vs fuel requirement for a 142,000 m^3 carrier, which consumes its full boil-off rate of 100 tonnes/day at 19.5 knots, thus requiring no re-liquefaction and no supplementary diesel fuel consumption.

[19] Either BHP is including high auxiliary power requirements — for other ship functions, hotel loads, and possibly powering re-liquefaction compressors so as to deliver the maximum cargo to Cabrillo as opposed to using the boil-off gas as engine fuel — or BHP will reduce the expected ships' power rating, or increase the vessel size. Resolving this conflicting information may justify a re-calculation of the fuel type and quantity for the LNG trade route. Note: If BHP was planning to use the next-generation carrier size (up to 250,000 m^3), its fleet would to make fewer than the stated ~"2.5 deliveries per week" (BHP, p. 3-5).

Assuming Scarborough/Pilbara as the origination of the gas and LNG, CMS estimates a trade route of 9,100 miles, or 7,908 nautical miles, each way. LNG carriers recently delivered from shipyards typically achieve 19.5 knots (though this will vary by trade route).[20] means a voyage of 406 hours, or almost 17 days en route. CMS modeled three fuel scenarios as follows:

1. Gas-only mode that used LNG boil-off gas plus an additional quantity of vaporized natural gas sufficient to fuel the engines: 430 gCO_2/kWh times 18.1 million kWh for each one-way trip = 7,800 tonnes of CO_2, consuming 6,740 m^3 of LNG en route;
2. Duel-fuel mode that burned boil-off gas at the normal rate supplemented with diesel fuel at 630 gCO_2/kWh, which means a blended rate of 529 gCO_2/kWh ⇨ 9,590 tonnes of CO_2 and the consumption of 3,420 m^3 of LNG en route (of which the boil-off gas, at 0.15 percent per day, would supply approximately 54 percent of the required fuel);[21]
3. Diesel-only mode at 630 gCO_2/kWh resulting in 11,430 tonnes of CO_2 for each one-way trip, with zero LNG consumption. Note: this assumes re-liquefaction of the boil-off gas,[22] which requires on-board compressors and a power requirement of up to 3.5 MW (Roger Courtay, quoted in *Naval Architect*, Nov03). Ship design aside, BHP's blue-water fuel option will most likely be driven by fuel costs versus the value of the additional deliverable cargo, not emissions.[23]

These three options become the "low," "medium," and "high" emissions scenarios. Annual low emissions totals 1.80 million tonnes of CO_2-eq ($MtCO_2$-eq), with 112 loads of LNG delivered (2.2 berthings per week). The medium estimate totals 2.09 $MtCO_2$-eq, and 107 berthings per year. The high emissions estimated totals 2.37 $MtCO_2$-eq, with 101 berthings per year. CMS based its gas production estimate at Scarborough plus the Pilbara liquefaction capacity on the gas-only propulsion fuel mode cited in the CSLC *Draft EIR* (p. 2-21, quoted above) and its reference to consuming a large quantity of LNG boil-off gas en route. The quantity of natural gas consumed for the LNG carrier operations totals 32 Bcf per annum, which is equivalent to 0.69 million tonnes of LNG per year. (See Table 2 above and the attached worksheet Tables 1, 7, 8 and 9 for details, calculations, assumptions, documentation, and results.)

An LNG carrier with Moss spherical tanks shown in BHP literature.

[20] Colton, Maritime Business Strategies (2006), www.coltoncompany.com

[21] As noted in footnotes on the previous page, BHP is probably in error in citing a 60,000 HP vessel. Küver et al (2002) show that a 142,000 m^3 carrier with diesel-electric propulsion will theoretically consume its BOG at 19.5 knots (albeit, for propulsion only). CMS estimates may be revised with updated or more complete BHP data.

[22] In the high emissions scenario the LNG is reliquefied onboard in order to maximize the amount of LNG delivered. See Lunde (2005). Hamworthy is a leading proponent and systems vendor for this concept. www.hamworthy.com

[23] BHP has stated that its LNG carriers will burn only natural gas while in Federal waters. CLSC *Revised Draft EIR,* pp. 4.6-15, 16, 34, states that the LNG tankers will run "primarily on natural gas" within 25 miles of shore.

LNG terminal: Cabrillo Deepwater Port

Next, CMS used BHP-supplied data on the amount of natural gas needed to operate the Cabrillo Deepwater Port, including gas used to generate electricity on board the LNG carriers that power pumps to transfer 57,000 to 63,000 tons of LNG from the carrier to the FSRU (at a design rate of 65,000 gallons per minute). CMS also included fuel consumption for tenders, tugs, and crew boats, and natural gas burned in the four (of eight) constantly operating 115 million Btu/hr vaporization units on the FSRU.[24] Electricity also has to be generated to run the FSRU's cranes and booms, waste transfer pumps, water pumps as well as hotel loads such as water heating, ventilation, cooking (for a crew of 30 to 50 persons), lighting, and electronic equipment. Other emissions sources include methane from incomplete combustion of fuel.

The generating capacity onboard the FSRU totals 25 MW and is to be provided by four Wärtsilä 9L50DF duel-fuel generators.[25] BHP's own emissions estimate from the sources listed above totals 0.26 million tonnes CO_2-equivalent per annum (including 39 tonnes of methane). BHP also estimated Start-Up emissions for the break-in phase of the Cabrillo Port totaling 0.01 milllion tonnes of CO_2-eq.

Sketch of the Cabrillo Deepwater Port Floating Storage and Regasification Unit (FSRU). Source: BHP.

CMS adopts BHP's emissions estimate as the "low" estimate. The CMS "high" estimate totals 0.43 $MtCO_2$-eq for the annual operating emissions (plus 0.02 $MtCO_2$-eq for Start-Up) by adding fugitive methane from the FSRU operations (note: BHP estimated methane from incomplete combustion but did not estimate fugitive methane; CMS applies BHP's cited methane rate [0.39 gCH_4/HP-hr] to BHP's trans-Pacific LNG carrier trade route). Since there is growing pressure on operators and engineers to reduce both flaring and venting at FPSOs and FSRUs, CMS lowers the benchmark methane emission rate by applying one-half of the average U.S. gas industry

[24] This is an impressively large operation. The FSRU is 970 feet long and covers about four acres (see image above). The LNG re-gasification units have a combined heat rate of 460 million Btu/hr — sufficient capacity to heat the homes in a mid-sized mountain town in winter — in order to heat and vaporize ~800 tons/hour of the cryogenic liquid from -259ºF to 41ºF.

[25] Three Wärtsilä gen-sets of 8.3 MW plus one back-up generator; each will typically be fueled with natural gas but capable of running on diesel whenever required, e.g., in emergency natural gas curtailment situations. BHP (2005), section 2.2.

leakage rate for gas processing facilities. Presumably, BHP's FSRU will achieve a lower rate than typical gas processing facilities, but BHP supplies no estimates of its own and CMS does not have access to measured data from such facilities. CMS applies a reasonable estimate in lieu of BHP- or CSLC-published estimates.[26]

In addition, CMS estimates that the six-month FSRU construction phase will consume ~1.1 million gallons of diesel and marine diesel fuel and emit 0.01 MtCO_2-eq for pipelaying and related construction activities. This involves a flotilla of pipe-laying vessels and barges and tenders and crew boats for the construction of the twin 24-inch subsea natural gas pipelines connecting the FSRU to onshore gas networks, as well as an armada of trucks and trenchers and dozers and backhoes for the pipelines' shore crossing and utility-connections. Construction emissions are added to Cabrillo's Start-Up phase, and both the "low" and "high" emissions estimates for Start-Up are added to Cabrillo's operational emissions by annualizing Start-Up over a 25-year period.[27]

Anchor handling tug *Primus* of Antigua, left, and pipelaying vessel *Solitaire* of Panama, right.
Source: Maritimephoto.com, with permission.

Ultimate consumption of the gas delivered to California customers

The largest component of the supply chain emissions is, not surprisingly, the combustion of the natural gas delivered to SoCalGas and distributed to the utility's customers. While a common benchmark is to estimate carbon dioxide from complete combustion of the natural gas delivered, CMS makes two adjustments. First, we deduct small amounts of gas diverted to other, non-fuel uses, and are consequently sequestered into other products rather than combusted to CO_2 and emitted to the atmosphere; secondly, we deduct a small fraction to account for the small

[26] BHP has estimated emissions of methane from incomplete combustion of natural gas used in the equipment categories listed in Table 10 of the attached worksheets. The BHP estimate, as far as we can ascertain, does not include fugitive emissions of methane from leaky pipes, valves, flanges, tanks, seals, and other fuel containment systems. CMS has not evaluated the legal requirement to estimate additional methane emissions, nor can CMS make an engineering estimate of such emissions. CMS does attribute one-half of the emissions rate from natural gas processing (0.5 * 28.22 tonnes CH_4/Bcf) plus one-tenth of methane emissions from gas distribution and storage (0.1 * 105.73 tonnes CH_4/Bcf) as an indicator that a Cabrillo-specific emissions estimate must be made. These rates are applied to total natural gas throughput (292 Bcf delivered to SoCalGas plus 5 Bcf required for Cabrillo operations).

[27] While a 25-year time horizon may be shorter than total anticipated project lifetime (40 years is mentioned in the CLSC *Draft EIR*), it is close to the 21.1-year life-expectancy of Scarborough gas field, assuming that the identified 8.0 trillion cubic feet of reserves are produced at an annual rate of 379 Bcf/yr detailed Table 2 above. This annual production rate accounts for the gas delivered to SoCalGas by BHP as well as the gas consumed at the Scarborough gas platform, in the 270-km subsea pipeline to the Pilbara LNG plant, for liquefaction and LNG plant use, gas consumption by LNG carriers, and gas requirements of the Cabrillo FSRU. Without these adjustments, the 800 million cf of gas per day deliverable to SoCalGas equals 292 Bcf/yr, or a simple 27-yr depletion schedule.

proportion of the fuel that is not combusted into CO_2. The first calculation is based on U.S. non-fuel uses of natural gas, although southern California's end-use gas consumption patterns likely differ somewhat from the nation as a whole, whereas the second is based on default values used by the U.S. EPA and the IPCC inventory protocols.

Non-fuel uses of natural gas are chiefly for fertilizer and methanol production and averages about three percent of total U.S. natural gas consumption. An analysis by CMS shows that the actual sequestration rate must also account for the proportion of non-fuel uses that is relatively quickly returned to the atmosphere as greenhouse gases; methanol, for example, is used in transportation, and fertilizer production emits both nitrous oxide and CO_2. Once adjusted, the sequestration rate is reduced from 3.05 to 0.3 percent of total natural gas consumption.

According to EPA and IPCC inventory guidelines, 0.5 percent of natural gas in the combustion stream is not combusted to CO_2. Finally, a methane leakage rate is applied to gas distribution based on typical leakage rates in the natural gas industry. See the worksheet Table 12 for details.

The "low" and "high" estimates are numerically close, given the small variability applied to combustion emissions minus "sequestered non-fuel uses" and "non-combusted" fractions. The emissions estimates range from 15.82 to 15.89 $MtCO_2$ plus 0.58 to 0.72 $MtCO_2$-eq of methane for an average total "gas distribution and combustion" estimate of 16.50 $MtCO_2$-eq per year.

Cyclone Glenda satellite image hours after it pummeled Onslow, Western Australia (site of BHP's proposed Pilbara LNG plant) with 176-mph winds on 30Mar06, left; bulk carrier *Graham* facing a cyclone at sea, 2002, right.

Summary

A full accounting of emissions of greenhouse gases arising from the supply chain linked to BHP Billiton's proposed LNG receiving terminal has been presented. Contrary to BHP's submitted emissions estimates — which included only emissions from the Cabrillo Deepwater Port operations — CMS has included emissions from the natural gas production platform offshore Western Australia, transportation by subsea pipeline to the emissions-intensive onshore liquefaction plant, followed by shipping in a fleet of LNG carriers across 7,900 nautical miles of Pacific Ocean, receiving and regasification at the Cabrilllo terminal 14 miles offshore Ventura and Los Angeles Counties, and finally combusted by gas customers in southern California. All of these steps are required to deliver the quantity of natural gas premised in the BHP *Construction Permit Application* filed with Federal agencies and the State of California Lands Commission.

Table 3: Supply Chain emissions: low estimate

Supply-chain segment	Methane	Carbon Dioxide	Total	Percent
	thousand tonnes of CO_2-eq			
Gas production (Scarborough)	254	400	654	3.1%
Gas pipeline to Pilbara LNG	90	211	301	1.4%
Liquefaction plant at Onslow	110	1,855	1,965	9.2%
LNG carrier fleet, Australia → California	44	1,755	1,799	8.4%
Cabrillo Deepwater Port Operations	0.9	261	261	1.2%
Cabrillo Start-Up (annualized, 25yrs)	negl	0.4	0.4	0.0%
Ultimate gas distribution & combustion	578	15,815	16,393	76.7%
Total supply-chain GHG emissions	1,078	20,300	21,378	100.0%
Percent	5.0%	95.0%	100.0	

Table 4: Supply Chain emissions: high estimate

Supply-chain segment	Methane	Carbon Dioxide	Total	Percent
	thousand tonnes of CO_2-eq			
Gas production (Scarborough)	339	589	928	3.8%
Gas pipeline to Pilbara LNG	181	317	497	2.1%
Liquefaction plant at Onslow	239	3,169	3,409	14.1%
LNG carrier fleet, Australia → California	49	2,320	2,369	9.8%
Cabrillo Deepwater Port Operations	169	261	431	1.8%
Cabrillo Start-Up (annualized, 25yrs)	negl	0.4	0.5	0.0%
Ultimate gas distribution & combustion	722	15,888	16,610	68.5%
Total supply-chain GHG emissions	1,699	22,548	24,248	100.0%
Percent	7.0%	93.0%	100.0	

Note: BHP Billiton's estimate of annual emissions at Cabrillo totals 261 thousand tonnes CO_2-eq.
Note: Tables 3 and 4 are in metric tonnes (1 tonne = 1.1023 short tons).

Conclusions

The supply chain emissions analysis summarized in this report provides a superior measure of the proposed Cabrillo Deepwater Port's impact on the global climate. No energy supply project of the scale proposed by BHP Billiton is without substantial emissions of greenhouse gases in every critical link of the supply chain.

There is no satisfactory rationale for ignoring emissions arising from the proposed supply chain — without which the project is infeasible — in an environmental impact report.

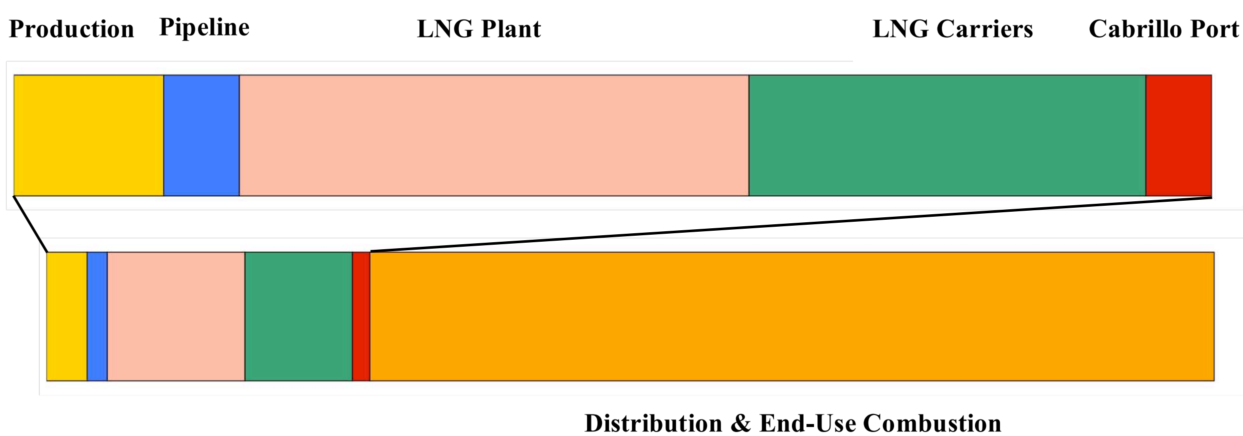
The accuracy of CMS's estimates can be improved with contributions and data-sharing by both the proponent and the State of California Lands Commission. CMS uses conservative estimation procedures, performance benchmarks, and emissions factors, and each step of the calculations is fully documented and transparent. Considerable uncertainties are unavoidable in an analysis with so many unknowns. BHP's documentation of the planned supply chain is sparse, and BHP only estimated emissions the Cabrillo Deepwater Port segment.

Moreover, technological change is rapid in the fast-growing LNG sector: operators are under pressure to market stranded natural gas from offshore fields. Also, public and regulatory pressures increasingly mandate emissions mitigation measures, especially regarding the transport, storage, and processing of LNG. The private sector can profit handsomely from increasing efficiency and trading emissions. Finally, the Cabrillo Port and its requisite supply segments will not be completed until 2011 or later. All of these factors suggest considerable evolution of the technologies deployed along the entire supply chain. Given these uncertainties, the CMS estimates of emissions from the BHP supply chain must be regarded as preliminary and subject to improvement with access to better engineering data as the project matures.

The BHP estimate, echoed by California State Land Commission's *Revised Draft Environmental Impact Report*, concludes that the project's emissions of greenhouse gases are "insignificant" and "represent less than 0.06 percent of the ... emissions produced in California in 2002."[28]

CMS results show a different picture, with the supply chain emissions from production through end-use of the delivered natural gas equal to 4.3 to 4.9 percent of California's total GHG emissions, and 5.3 to 5.9 percent of CO_2 emissions using Energy Information Administration state emissions data.[29] Broadening the comparison — again accounting for emissions from production in Australia to combustion of the gas delivered to end-use customers in California — shows that emissions from BHP's proposed LNG project are equivalent to 0.30 to 0.34 percent of total U.S. emissions (using EIA data for 2004). BHP's estimated emissions from its operation of the Cabrillo Deepwater Port comprises a mere 1.5 percent of emissions from the entire supply chain. This relationship is shown in Figure 2, with the Cabrillo emissions in red.

Figure 2. Bars showing relative emissions contributed by each supply chain segment



[28] CSLC, p. 4-20: "Project operations would cause annual CO_2 emissions of 0.29 million tons per year (MMtons/yr). Project start-up and construction activities would result in one-time CO_2 emissions of 0.010 MMtons and 0.017 MMtons, respectively. These emissions represent less than 0.06 percent of the 543 MMtons of CO_2-equivalent greenhouse gas emissions produced in California in 2002 (CEC 2005). The greenhouse gas emissions from the Project would be insignificant alone, but could exacerbate, in combination of existing greenhouse gases, global warming effects."

[29] Using the cited CEC emissions data for all greenhouse gases in 2002. Supply chain CO_2 emissions comprise 5.27 to 5.84 percent of California's CO_2 emissions in 2001 (EIA data).

Another notable result of the CMS study is that the supply chain adds 35 to 53 percent to the common way of measuring emissions from natural gas consumption, namely the combustion of the gas itself, disregarding the supply chain emissions. This is the LNG supply chain "adder," although it must be emphasized that we have not estimated ancillary emissions from other natural gas supply alternatives — such as the Long Beach or Baja Mexico LNG proposals, sources of domestic gas by pipeline from Texas or Colorado, or, for that matter, coal-fired electric generation, renewable electricity options, or end-use efficiency of any and all uses of natural gas in California.[30]

Consequently, the results presented in this report do not argue for or against the proposed LNG project. Instead, the objective has simply been to fill the analytical gap left by BHP Billiton's and CSLC's omission of estimating the emissions from the remainder of the required natural gas supply chain.

[30] See, for example, Hunt et al (2006), Lovins et al (2004), and Lovins et al (forthcoming late 2006).

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Conversions[31]

Table of conversions		
1 tonne LNG	**46,467**	cubic feet gas
1 cubic meter LNG	**21,189**	cubic feet gas
1 cubic meter LNG	**0.4560**	tonne LNG
1 tonne LNG	**2.1930**	cubic meter LNG
1 tonne LNG	**51.1138**	million Btu
1 cubic meter LNG	**23.3079**	million Btu
1 million cubic feet gas	**21.5206**	tonnes LNG
1 million cubic feet gas	**47.1943**	cubic m LNG
1 nautical mile	**1.1508**	statute miles
1 horsepower (HP)	**0.7457**	kW
1 kW	**1.3410**	horsepower (HP)
1 million cf gas per day	**7,885**	tonnes LNG per yr
1 tonne	**1.1023**	short (US) tons
1 kg	**2.2046**	lb
1 cubic meter	**35.3147**	cubic feet
Combustion of 1 Bcf	**54,602**	tonnes CO2
1 tonne CO2	**18,314**	cubic feet gas
Combustion of 1 m^3 LNG	**1.1570**	tonnes CO2
Combustion of 1 tonne LNG	**2.5372**	tonnes CO2

[31] Conversion sources: U.S. Dept of Energy (2005) *Liquefied Natural Gas: Understanding the Basic Facts*, p. 9; miscellaneous engineering sources; and calculations by CMS.

A portion of the LNG trade route from NW Australia to southern California,
around the edge of Earth's disk at ~2 o'clock.

Notes

LNG Supply Chain GHG Emissions: Australia to California

Folio of worksheets

Richard Heede
Climate Mitigation Services
Snowmass, Colorado, USA 81654
heede@climatemitigation.com

All emissions estimates are annual

Table 1	**Total gas production required to deliver 800 million cf/day**
Table 2	**Emissions from gas production at Scarborough platform**
Table 3	**Emissions from transporting produced gas to Pilbara LNG plant**
Table 4	**Emissions from liquefaction at the proposed LNG plant**
Table 5	**Upsizing the Pilbara LNG plant to that required for delivery**
Table 6	**Comparing production and GHG emissions from several LNG trains**
Table 7	**Shipping details: distance, vessel speed, and journey duration**
Table 8	**Emissions for each LNG carrier from Onslow to Cabrillo (one way)**
Table 9	**Emissions from BHP's presumed LNG carrier fleet, per annum**
Table 10	**Emissions from Cabrillo Deepwater Port, including regasification**
Table 11	**Methane emissions rate from the US natural gas industry**
Table 12	**Emissions from gas distribution and combustion (net of seq.)**
Table 13	**LNG Supply-Chain Emissions Summary - Low Estimate**
Table 14	**LNG Supply-Chain Emissions Summary - High Estimate**
Table 15	**Average of Low and High Supply-Chain Emissions**
Table 16	**Comparing total LNG Supply-Chain to US and California emissions**

Tables 1-16 on four sheets, with cell comments, sources, formulae, caveats, and discussion on the following sixteen pages.

Notes

LNG Supply-Chain Emissions Study: natural gas from Western Australia to Cabrillo Deepwater Port

Richard Heede
Climate Mitigation Services
Snowmass, Colorado
heede@climatemitigation.com / 970-927-9511
File started: 5 April 2006
Last modified: 5 May 2006

These estimates of supply chain emissions from fuel consumption, venting of CO_2, flaring, and methane leakage are based on published BHP data to the extent possible. Reasonable and documented default values, emissions coefficents, and industry averages are also used in order to present as complete an inventory of the full range of emissions associated with BHP Billiton's Cabrillo Deepwater Port and the indicated quantities of natural gas sent out to SoCalGas company. This inventory encompasses emissions from the proposed source of the natural gas offshore Western Australia to ultimate combustion by SoCalGas' customers in California.

Annual Emissions

Table of contents

Table 1	Scarborough Gas Production		
Total gas production	milllion cf per day	Bcf/yr	tonnes of gas (or LNG)
Offshore gas production platform	21	8	166,355
Pipeline to Pilbara LNG	13	5	103,945
LNG plant requirements	103	38	808,019
LNG carrier fleet requirements	88	32	691,770
Cabrillo Deepwater Port ops	13	5	102,447
Gas deliveries to SoCalGas	800	292	6,284,030
Total	1,038	379	8,156,565

Table of conversions

1 tonne LNG	46,467	cubic feet gas
1 cubic meter LNG	21,189	cubic feet gas
1 cubic meter LNG	0.4560	tonne LNG
1 tonne LNG	2.1930	cubic meter LNG
1 tonne LNG	51.1138	million Btu
1 cubic meter LNG	23.3079	million Btu
1 million cubic feet gas	21.5206	tonnes LNG
1 million cubic feet gas	47.1943	cubic m LNG
1 nautical mile	1.1508	statute miles
1 horsepower (HP)	0.7457	kW
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Combustion of 1 Bcf	54,602	tonnes CO2
1 tonne CO2	18,314	cubic feet gas
Combustion 1 m^3 LNG	1.1570	tonnes CO2
Combust'n 1 tonne LNG	2.5372	tonnes CO2

Table 2	CO2 venting	Gas flaring	Methane	Methane	Platform energy	Prod'n Emissions
Gas production emissions	tonnes CO2/yr	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq/yr	tonnes CO2/yr	tonnes CO2-eq/yr
Total (low estimate)	31,042	31,042	11,054	254,242	337,533	653,859
Total (high estimate)	41,390	41,390	14,746	339,159	506,299	928,237
		CH4, % of gas prod'n	0.181%	Gas equiv. (average):	7.73	Bcf/yr

Table 3	Pipeline energy	Pipeline CH4	Pipeline CH4	Pipeline Emissions
Gas transportation	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq/yr	tonnes CO2-eq/yr
Pipeline to Pilbara LNG (low est.)	211,087	3,926	90,288	301,375
Pipeline to Pilbara LNG (high est.)	316,631	7,851	180,576	497,207
Gas equivalent (average of low & high):	4.83	Bcf/yr		

	A	B	C	D	E	F	G	H	I	J	K	L	M
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LNG Supply-Chain Emissions Study, folio 2

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Annual Emissions

Table 4	Darwin LNG (3.24 Mt/yr)			Pilbara LNG (7.07 Mt/yr) (low estimate)			Pilbara LNG (7.07 Mt/yr) (high estimate)		
Liquefaction plant	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq/yr	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq
Refrigeration compressors	615,106		615,106	1,343,785		1,343,785	2,508,292		2,508,292
Power generation turbines (disc)	106,615		106,615	174,686		174,686	326,068		326,068
Acid gas venting (discounted)	574,350		574,350	209,125		209,125	209,125		209,125
Flaring	59,485		59,485	129,953		129,953	129,953		129,953
Venting (methane)		2,172	49,958		4,745	109,141		10,343	237,887
Other plant emissions (N2O)		2	474		3	1,035		5	1,448
Purchased electricity (not estimated)				(not estimated)			(not estimated)		
Total liquefaction plant (high & low)	1,355,556	2,174	1,405,988	1,857,549	4,749	1,967,724	3,173,438	10,348	3,412,773

Gas equiv (low est.): 30.19 Bcf/yr | Gas equiv (high est): 54.29 Bcf/yr

Estimated natural gas demand, LNG liquefaction (discounted average of low & high estimate 37.55 Bcf/yr

Emissions from BHP's proposed Pilbara LNG plant are estimated on the basis of ConocoPhillips' Darwin LNG facility. The Darwin plant adopted several emissions reduction initiatives, such as high-efficiency aero-derivative gas-fired turbines to power refrigeration compressors, waste heat recovery, ship vapor recovery, efficient pumps and motors, and cascading emissions benefits from smart design and technology. The Darwin plant likely emits far fewer greenhouse gases per unit of LNG produced than other LNG plants around the world, and may exceed the emissions performance of BHP's Pilbara plant designs.

BHP's proposed Pilbara LNG plant at Onslow, Western Australia, has been up-sized to meet BHP's estimated quantity of re-gasified LNG delivered to Cabrillo, namely 800 million cubic feet per day. Since the LNG carriers will consume LNG en route from Pilbara to Cabrillo, Pilbara must be scaled up from 6.0 to 7.08 Mt/yr in order to deliver the indicated LNG to Cabrillo. See the tables below for details.

Note: BHP's Pilbara gas feed is <1 percent CO2, compared to Darwin's more typical 6+ percent CO2. CMS has adjusted for Pilbara's low acid venting factor.

Table 5	Darwin	Pilbara
Scaling LNG plant	(Mt/yr)	(Mt/yr)
Delivery capacity	na	6.39
Gross production	3.24	7.08
Scale of Pilbara over Darwin:		**2.185**

Table 6	LNG production	GHG emissions	Emissions rate
Plant comparison	Mt/yr	MtCO2-eq/yr	tCO2-eq/tLNG
Darwin	3.24	1.41	0.43
Pilbara (low estim.)	7.08	1.97	0.28
Pilbara (high estim.)	7.08	3.41	0.48
Atlantic train 1	1.00	1.00	1.00
Atlantic train 2	2.23	2.03	0.91
Atlantic train 4	1.80	1.46	0.81
Total or average	22.43	11.27	0.50
		Atlantic #4/Darwin factor:	**1.867**

	A	B	C	D	E	F	G	H	I	J	K	L	M
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LNG Supply-Chain Emissions Study, folio 3

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Climate Mitigation Services

Annual Emissions

Table 7	Onslow, Australia to Cabrillo		Vessel speed	Trip duration (one way)		Gas delivery rate at Cabrillo				
Shipping details	Miles	Nautical miles	Knots	Hours	Days	Million cf (gas)/day		m^3 LNG per day	m^3 LNG per year	tonnes LNG per year
(each LNG carrier, one way)	9,100	7,908	19.5	405.5	16.9	813		38,371	14,005,400	6,386,477

Table 8	Engine power		Emissions rate	Trip energy	Trip emissions			Equiv Gas	Equiv LNG	
Per LNG carrier emissions	brake HP	total kW	gCO2/kWh	kWh	kgCO2	tonnes CO2		million cf	tonnes	cubic meters
Low estimate (gas only mode)	60,000	44,742	430	18,144,180	7,801,997	7,802		143	3,075	6,743
Medium estimate (gas & diesel mode)	60,000	44,742	529	18,144,180	9,589,374	9,589		73	1,560	3,422
High estimate (diesel only mode)	60,000	44,742	630	18,144,180	11,430,833	11,431		na	zero	zero
Per LNG carrier emissions										
Methane, low estimate	grams CH4/HP-hr	0.35		kgCH4 per trip:	8,540			tonnes CO2-eq/trip	196	
Methane, high estimate	grams CH4/HP-hr	0.43		kgCH4 per trip:	10,438			tonnes CO2-eq/trip	240	

Table 9	Carrier capacity	LNG delivered	LNG carriers	Round trip emissions				Annual LNG Fleet operations		
LNG carrier fleet emissions	m^3 LNG	m^3 LNG	Landings per year	tonnes CO2	tonnes CH4	tonnes CO2-eq		tonnes CO2	CH4 in tonnes CO2-eq	tonnes CO2-eq
Low estimate (gas only mode)	138,000	124,513	112.48	15,604	17	393		1,755,160	44,189	1,799,349
Medium estimate (gas & diesel mode)	138,000	131,156	106.78	19,179	19	437		2,047,989	46,613	2,094,602
High estimate (diesel only mode)	138,000	138,000	101.49	22,862	21	480		2,320,194	48,731	2,368,925
						Gas equivalent (gas-mode):		32.14	Bcf/yr	

Table 10	Equipment	Carbon dioxide	Methane	Methane	Total Cabrillo Ops	Cabrillo Start-Up
Cabrillo Deepwater Port	rating (each)	tons CO2/yr	tons CH4/yr	tons CO2-eq/yr	tonnes CO2-eq/yr	tonnes CO2-eq
4 Wartsila 9L50DF generators	8,250 kW	54,752	20.9		50,107	9,267
4 submerged cmbust'n vaporizers	115 million Btu/hr	215,271	3.5		195,365	na
2 tug boats	15,000 BHP	12,006	12.9		11,161	?
1 crew boat	1,500 BHP mains	332	0.4		309	?
LNG carrier (LNG offloading)	60,000 BHP total	4,492	4.8		4,175	na
Miscellaneous sources		372	0.4		346	356
Cabrillo operations, low estimate		287,225	43	986	261,463	9,623
Additions: construction: methane			35	805	730	730
Additions: methane FSRU operations			8,075	185,726	168,489	
Additions to BHP: vessels & equip. (CO2)	1.06 million glns diesel					10,800
Additions: electricity & misc (not est.)					na	na
Additions: project materials (not est.)	700,000	tonnes CO2 from steelmaking: not included			na	na
Cabrillo operations, high estimate					430,682	21,153
	Gas equivalent:	4.76	Bcf/yr			
	Equivalent LNG	102,699	tonnes/yr			

Table 11	US methane 2004	Methane rate
Methane rate	million tonnes CH4	tonnes CH4/Bcf
US consumption (Bcf)	22,321	
Gas production	1.86	83.33
Gas processing	0.63	28.22
Transmission, storage	2.36	105.73
Gas distribution	1.79	80.19
Incomplete combust'n	0.02	0.93
Total gas industry	6.66	298.40

	A	B	C	D	E	F	G	H	I	J	K	L	M
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LNG Supply-Chain Emissions Study, folio 4

Richard Heede

Climate Mitigation Services

Annual Emissions

Table 12	Gas delivered to SoCalGas		Methane leakage: gas distribution & combustion			Non-fuel uses		Non-combusted	Total combusted	Total emissions
Gas delivery & combustion	Million cf (gas)/day	Billion cf per year	Rate: tonnes CH4/Bcf	tonnes CH4	tonnes CO2-eq	tonnes CO2 sequestered		tonnes CO2 sequestered	tonnes CO2/yr	tonnes CO2-eq/yr
Low estimate	800	292	86	25,124	577,862	48,629		79,719	15,815,494	16,393,356
High estimate	800	292	108	31,406	722,327	24,314		31,888	15,887,640	16,609,968
			CH4 leakage of total del	0.39%						

Table 13	LNG Supply-Chain Emissions Summary - Low Estimate							Average of Low & High Estimates			
	Carbon Dioxide	Methane	Methane	Total GHG	Total GHG			Carbon Dioxide	Total GHG	Total GHG	
Emissions Sum (Low est.)	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq/yr	tonnes CO2-eq/yr	US tons CO2-eq/yr	Percent of low:		tonnes CO2/yr	tonnes CO2-eq/yr	US tons CO2-eq/yr	% ave
Gas production (Scarborough)	399,617	11,054	254,242	653,859	720,749	3.1%	Pn	494,348	791,048	871,973	3.5%
Gas transportation	211,087	3,926	90,288	301,375	332,206	1.4%	Pl	263,859	399,291	440,138	1.7%
Liquefaction plant	1,857,549	4,749	110,176	1,967,724	2,169,023	9.2%	Liq	2,515,493	2,690,249	2,965,461	11.8%
LNG carrier fleet	1,755,160	1,921	44,189	1,799,349	1,983,422	8.4%	LNG	2,047,989	2,094,602	2,308,879	9.2%
Cabrillo Deepwater Port Ops	260,569	39	894	261,463	288,210	1.2%	Cb	260,569	346,072	381,475	1.5%
Cabrillo Start-Up (annualized, 25yrs)	373	1	12	385	424	0.0%	Su	410	438	483	0.0%
Customers of BHP-delivered gas	15,815,494	25,124	577,862	16,393,356	18,070,397	76.7%	En	15,851,567	16,501,662	18,189,782	72.3%
Total Supply Chain emissions	20,299,849	46,813	1,077,663	21,377,512	23,564,431	100%	Tt	21,434,235	22,823,362	25,158,192	100%

Percent of total relative to combustion of the natural gas: 135.2%

Total relative to combustion: 144.0%

CH4/total (low): 5.0%

CH4/total (average): 6.1%

Table 14	LNG Supply-Chain Emissions Summary - High Estimate							Average of Low & High Estimates		
	Carbon Dioxide	Methane	Methane	Total GHG	Total GHG			Methane	Methane	Methane
Emissions Sum (High est.)	tonnes CO2/yr	tonnes CH4/yr	tonnes CO2-eq/yr	tonnes CO2-eq/yr	US tons CO2-eq/yr	Percent of high		tonnes CO2-eq/yr	US tons CO2-eq/yr	Percent of total CH4
Gas production (Scarborough)	589,079	14,746	339,159	928,237	1,023,196	3.8%	Pn	296,700	327,053	21.37%
Gas transportation	316,631	7,851	180,576	497,207	548,071	2.1%	Pl	135,432	149,286	9.75%
Liquefaction plant	3,173,438	10,348	239,335	3,412,773	3,761,900	14.1%	Liq	174,755	192,633	12.58%
LNG carrier fleet	2,320,194	2,119	48,731	2,368,925	2,611,266	9.8%	LNG	46,613	51,381	3.36%
Cabrillo Deepwater Port Ops	260,569	7,357	169,219	430,682	474,741	1.8%	Cb	85,057	93,758	6.13%
Cabrillo Start-Up (annualized, 25yrs)	447	2	44	491	541	0.0%	Su	28	31	0.00%
Customers of BHP-delivered gas	15,887,640	31,406	722,327	16,609,968	18,309,168	68.5%	En	650,095	716,599	46.81%
Total Supply Chain emissions	22,547,997	73,829	1,699,392	24,248,283	26,728,883	100%	Tt	1,388,680	1,530,741	100.00%

Percent of total relative to combustion of the natural gas: 152.6%

CH4/total (high): 7.0%

Carbon Dioxide	Carbon Dioxide	Carbon Dioxide
tonnes CO2/yr	US tons CO2/yr	Percent of total CO2
494,348	544,920	2.31%
263,859	290,852	1.23%
2,515,493	2,772,828	11.74%
2,047,989	2,257,498	9.55%
260,569	287,225	1.22%
410	452	0.00%
15,851,567	17,473,183	73.95%
21,434,235	23,626,958	100.00%

Table 15	Comparing total supply-chain emissions to US and California emissions					
	Total US GHG	LNG supply chain (this study)		Total Calif. CO2	LNG supply chain (this study)	
Emissions Sum	tonnes CO2-eq/yr	tonnes CO2-eq/yr	tonnes CO2-eq/yr	tonnes CO2/yr	tonnes CO2 only	tonnes CO2 only
	2004	low estimate	high estimate	CO2 only	low estimate	high estimate
		21,377,512	24,248,283	2001	20,299,849	22,547,997
		percent of US	percent of US		percent of California	percent of California
	7,122,100,000	0.300%	0.340%	383,100,000	5.30%	5.89%

	A	B	C	D	E	F	G	H	I	J	K	L	M
224													

Cell: B23
Comment: Rick Heede:
Table 1 estimates the total quantity of natural gas production necessary to supply (a) the 800 million cubic feet BHP has indicated it will provide to SoCalGas, (b) the additional natural gas required for gas production platforms, pipeline fuel, for combustion equipment at the Pilbara liquefaction plant, as LNG carrier propulsion fuel, and gas consumed by the Cabrillo FSRU for regasification and other uses.

Cell: E23
Comment: Rick Heede:
Total gas production is not based on the productive capacity of BHP Billiton's & ExxonMobił's jointly owned Scarborough natural gas field. The purpose is to estimate the total amount of natural gas required for the entire supply chain IF the objective is to deliver 800 million cubic feet of natural gas to SoCalGas via the proposed LNG plant at Pilbara using gas from Scarborough and shipped to Cabrillo for regasification and delivery in California. CMS has estimated both high and low natural gas demand for major elements of this supply chain, which, of course, requires additional natural gas to be produced at Scarborough and sent down the supply chain. We have averaged the high and low demand estimates in this total Bcf production column in order to enable downstream estimates to use one datum for aggregate natural gas required. This analysis is based on Scarborough and Pilbara since BHP has indicated these facilities as likely sources of gas and LNG, respectively.

This is an approximation of the quantity of Scarborough natural gas production required per annum (and per day), based on a delivery of 800 million cubic of gas regasified at Cabrillo per day, and accounting for the the amounts of natural gas (or their equivalent in natural gas liquids or purchased energy) used at the Scarborough offshore production platform, to run pipeline compressors for the 280-km subsea pipeline to the onshore Pilbara LNG plant near Onslow, Western Australia. Also included are the natural gas requirements to fuel the LNG carrier fleet, which uses boil-off gas and vaporized LNG during the trans-Pacific crossing, and, finally, natural gas used to power generators and produce heat for the vaporizers at the Cabrillo Deepwater Port. The amount of natural gas that BHP indicates will be delivered to SoCalGas (and comprises the design basis for the Cabrillo FSRU engineering) totals 292 billion cubic feet (Bcf) per annum. The parasitic loads mentioned above add 84 Bcf/yr, or nearly 29 percent to the quantity proposed to be delivered.

BHP may elect to acquire natural gas from another field in Australia, or to contract for LNG delivery from Indonesia or another LNG plant. For that matter, we cannot ascertain whether BHP's plans for Scarborough and/or Pilbara LNG will be sufficient to meet the estimated total demand. This uncertainty is immaterial, really. What is important is to estimate the total natural gas requirement and the associated emissions of greenhouse gases. Of course, gas fields differ in terms of carbon dioxide content of the feed gas delivered to LNG plants, and the efficiency and emissions of LNG plants also vary significantly. Indeed, the emissions rates as modeled for this analysis are significantly below world averages for two principal reasons:

(1) Scarborough natural gas contains ~one percent carbon dioxide (meaning that less CO2 has to be removed prior to liquefaction; removed CO2 is typically vented to the atmosphere).

(2) the emissions rate -- measured as tonnes of CO2-equivalent per tonne of LNG produced -- of ConocoPhillips' Darwin LNG plant on which we base the proposed Pilbara plant's performance is significantly below world average.

Cell: E24
Comment: Rick Heede:
The gross amount of natural gas produced at Scarborough includes a quantity of gas consumed at the production platform and for pipeline propulsion as shown in Tables 2 and 3. While this gas usage emits carbon dioxide, it does not require additional liquefaction capacity at Pilbara. This column shows total gas consumption in tonnes.

Cell: L31
Comment: Rick Heede:
Conversion sources:
U.S. Dept of Energy (2005) Liquefied Natural Gas: Understanding the Basic Facts, p. 9;
miscellaneous engineering sources;
and calculations by CMS.

Cell: B37
Comment: Rick Heede:
Table 2 estimates emissions from venting, flaring, and natural gas consumption at production platforms such the Scarborough gas field. Since Scarborough is shut in, and no production platform has been deployed, we industry standards to estimate emissions. Our estimates are based on total gas production required to deliver the quantity cited by BHP in its Permit Application, anmely 800 million cf per day; this estimate is derived in Table 1.

Cell: C37

Comment: Rick Heede:
We assume a CO2 gas venting rate of 0.15 percent (low estimate) to 0.25 percent (high estimate) at the Scarborough gas production platform. Formula = Total gas production *0.0025 * tonnes CO2/Bcf combusted.

Note: a similar calculation for CO2 venting emissions from sour gas processing is made in API (2001) Compendium of Greenhouse Gas Estimation Methodologies, p. 4-32.

Cell: D37
Comment: Rick Heede:
We assume a gas flaring rate of 0.15 percent (low estimate) to 0.20 percent (high estimate) of throughput. While probably conservative, gas flaring data in natural gas production is scarce. EIA data show a total flaring rate of 0.451 percent (91 Bcf flared of 20,198 Bcf marketed), but this is an industry total, not merely gas production. Note: gas flaring rates have declined sharply as markets and technology have improved: 29 percent in 1920, 12.8 percent in 1950, 0.81 percent in 1980, etc. Source: Heede (2003), spreadsheet on Venting and Flaring, cell note F11. Note also that global flaring rates remain quite high: Oak Ridge CDIAC data show total emissions from flaring equal to 2.0 percent of emissions from gas combustion (28 MtC of 1,348 MtC in 2002); this, however, is flaring from both gas and oil operations.

Note: A much wider range of gas production platfform flaring is suggested by : “Of ten Norwegian platforms the percentage of the gas production flared varied from 0.04 to 15.9. The volume of gas flared is usually higher on an oil production platform than on a gas production platform, since it is preferred to sell the gas rather than to flare it if there is a choice. Generally, the volume flared is higher on new platforms than on the old because the elder have had time to develop better procedures, have fewer shut downs and practice more direct venting of the gas.”Source: European Environment Agency (2005) Emission Inventory Guidebook: Section B926: Flaring in Gas & Oil Extraction, EMEP/CORINAIR, http://reports.eea.eu.int/EMEPCORINAIR4/en.

Cell: E37
Comment: Rick Heede:
Routine and fugitive emissions of methane is common at production platforms, and average 83.33 tonnes of CH4 per Bcf of gas produced, according to US EIA data. Since methane is a greenhouse gas 23 times more potent than carbon dioxide (100-year time horizon), even modest quantities will result in large relative emissions. We conservatively apply one-half (low estimate) to two-thirds (high estimate) of the average US methane emissions rate for natural gas production facilities -- that is, 83.33 tonnes of methane per 1 Bcf of gas production * 0.50 and 0.667, respectively.

EPA (2006) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004, Appendix G: Methodology for Estimating CH4 Emissions from Natural Gas Systems, shows 1,467 Gg (1.467 million tonnes) of methane from natural gas production for 19.4 Tcf produced in 2001, or a rate of 75.62 tonnes of CH per Bcf produced. Table G-1 shows activity data,# but it cannot be aggregated in any meaningful sense to show typical emissions per offshore production platform.

#: blowdowns, pressure relief valves, mishaps, compressors, peneumatic device vents, etc.

Source: European Environment Agency (2005) Emission Inventory Guidebook: Section B521: Table 8.24 (p. 19) suggests that large gas production platforms incorporate 8,300 gas connectors, 3,000 valves, 65 pressure relief devices, and 560 other components.

Another source: API (2001), p. 4-67: Table 4-21. Facility-Level Average Fugitive Emission Factors shows 16.25 lb CH4 per million Scf of natural gas production at offshore platforms. This means, for Scarborough’s production level, 16.25 lb CH4/million Scf * 1,031 million Scf/day * 365 day/yr = 3,057.6 tons of CH4 per year (2,773.8 tonnes/yr). This is substantially lower than the EIA approach applied above. API’s facility-level methane emissions rate is 40.63 lb CH4 per million Scf produced onshore.

BHP will be in a position to correct or refine -- as well as publish -- the Scarborough fugitive emissions estimate made here once the platform designs are complete.

In view of the lower API emission factors for offshore gas production platforms CMS has adjusted the EIA factors by multiplying both the low and high estimates described above by 0. 7; that is, reduce each factor by 30 percent.

Cell: G37
Comment: Rick Heede:
We conservatively assume that 0.5 *3.262 percent (low estimate) to 0.75 * 3.262 percent (high estimate) of gross gas production is used to fuel generators, hotel loads, heating requirements, and other platform energy demand such as lighting and pumps and compressors.

Data for the U.S natural gas industry shows 3.262 percent for 2004 (Natural Gas Consumption by End Use, 1997-2005, EIA): Lease gas consumption = 731.56 Bcf, of Total gas consumption of 22,430.23 Bcf = 3.262 percent.

Cell: B47
Comment: Rick Heede:
This table estimates energy use and emissions from the subsea pipeline linking the Scarborough natural gas field to the onshore Pilbara LNG facility at Onslow, Western Australia.

Cell: C47
Comment: Rick Heede:
Compressors to pressurize gas pipelines use large quantities of energy. A typical gas pipeline moves gas at approximately 50 km per hour, and deploy compressors every 80 to 96 km along its length with power ratings of about 4,000 to 10,000 HP.

BHP has not published pipeline engineering specifics for the proposed BHP/ExxonMobil pipeline from Scarborough to onshore facilities at Pilbara. CMS instead uses EIA gas industry data and assumes 0.4 * 2.5495 percent (low estimate) to 0.6 * 2.5495 percent (high estimate) of the throughput energy for BHP's 270-km proposed subsea link between the Scarborough gas field and the LNG plant at Onslow, Western Australia. That is, forty to sixty percent of the total amount of natural gas consumed by pipeline compressors and related uses in the US (see below). Some of the remainder will be applied to SoCalGas gas distribution, whereas this fraction is applied to gas transportation between Scarborough and Pilbara LNG plant.

Data for the U.S natural gas industry shows 2.55 percent for 2004 (Natural Gas Consumption by End Use, 1997-2005, EIA): Pipeline and distribution use = 571.85 Bcf, of Total gas consumption of 22,430.23 Bcf = 2.5495 percent. This is supported by an analysis by Rose (1979): "Gas pipelines are also more energy-intensive, using about 2.5 percent of the energy transported or five to six times as much as for oil or oil-product pipelines."Rose cites statistics from J. N. Hooker of ORNL of gas pipelines using 2,000 Btu per ton-mile, compared to oil pipelines using 320-360 Btu/ton-mile (stats from late 1960s-early 1970s).

Cell: D47
Comment: Rick Heede:
Methane emissions (routine leakage through seals, valves, joints, and related infrastructure) for gas transmission and storage average 105.7 tonnes of CH_4 per Bcf of gas consumed in the United States (2004, EIA data). Since the Scarborough to Pilbara LNG plant is a subsea pipeline, and "only" 280-km in length, we apply a leakage rate of ten percent (low estimate) to twenty percent (high estimate) of this US average.

API (2001) Compendium, Table 4-21 Facility-level Average Fugitive Emissoin Factors, p. 4-67, show 1,259,400 lb CH_4 per gas transmission compressor station-year, or 630 tons (571 tonnes) of methane per compressor-year. We do not know how many equivalent compressors will be required for the 280-km subsea pipeline from Scarborough to Pilbara. The American Gas Association notes that there is typically (on land, at least) one compressor station every 50 to 60 miles (80.5 to 96.6 km). The Scarborough to Pilbara pipeline would thus require the equivalent of 2.9 to 3.5 such compressors. Further research may suggest a more appropriate methane emissions factor for the Scharborough pipeline to onshore facilities; such research, however, is beyond the scope of this simple analysis made without access to BHP design criteria.

Cell: B51
Comment: Rick Heede:
We estimate the gas consumption in Bcf of pipeline energy used to transport gas by subsea pipeline from the offshore Scarborough gas field to Pilbara LNG plant. See "pipeline energy" for details.

Cell: E67
Comment: Rick Heede:
ConocoPhillips published (per Australian law) an Environmental Management Plan for its 10 million tonne per year LNG facility near Darwin, Australia. While the facility may be expanded to 10 Mt/yr, Table 5.3 shows "Darwin LNG Plant Projected Normal Operations Air Emissions for 3.24 Mt/yr Nominal Annual Average Production Rate," p. 5-10. This is data for Darwin's first LNG train. These emissions estimates are summarized for the Darwin plant below and used as the baseline for BHP's emissions for its LNG facility at Pilbara near Onslow, Western Australia. Darwin's baseline emissions rates are scaled up to Pilbara's larger plant size in Table 5.

ConocoPhillips Petroleum Company (2005) Darwin LNG: Operations Environmental Management Plan, DLNG/HSE/PLN/001, rev.1, www.darwinlng.com/Environment/Index.htm

Darwin LNG report Table 5.2 shows "Estimated Annual Hydrocarbon Flaring and Venting Volumes for the 3.24 Mtpa Normal Operations Case," (p. 5-7). It details routine and expected non-routine flaring volumes, plus venting of methane in the plant's nitrogen rejection units (NRU) and acid gas venting. The NRU data shows methane component only (at 2.887 million Nm^3 per year), whereas the acid gas venting is chiefly CO_2 (99.85 percent of 7.235 million Nm^3/yr) and a small (0.13 percent) of methane.

Cell: H67

Comment: Rick Heede:
BHP is in the pre-feasibility phase of evaluating its proposed Pilbara LNG plant. The preferred site is a few km outside Onslow, Western Australia. The proposal includes the construciton of a 280-km subsea pipeline from BHP/ExxonMobil's Scarborough natural gas field to the Pilbara onshore site. Scarborough is shut in, and has been evaluated to contain 8 trillion cubic feet (Tcf) of recoverable natural gas.

While the pre-feasibility study shows the Pilbara plant at 6.0 million tonnes of LNG per year, its capacity will, in actuality, have to be somewhat larger if it is to produce sufficient quantities of LNG as required by the company's estimated natural gas delivery rate of 800 million cubic feet per day to SoCalGas via Cabrillo. And Pilbara's gross capacity must be larger still to account for the LNG consumed by its fleet of LNG carriers en route to and return from Cabrillo. This scaling calculation is shown in Table 5.

Note: this calculation also accounts for LNG (whether boil-off or re-gasified) required for FSRU operations, shown in Table 10 "Cabrillo Deepwater Port."

Note: Since the power demand associated with acid gas removal is also reduced due to lower CO2 content in Pilbara's feedgas, we assume that emissions from power generation turbines are decreased by 0.25 of the scale-up factor shown in Table 5 (that is, scaled up by 75 percent rather than 100 percent).

Cell: L67
Comment: Rick Heede:
The low estimate for BHP's proposed (but uncharacterized) liquefaction plant is simply the emissions rate (in tonnes of CO2 per tonne of LNG) of the Darwin high-efficiency / low-emission faciltiy amply characterized in ConocoPhillip's reports, albeit pre-operational estimates of emissions.

In this high emissions estimate of the Pilbara LNG plant we assume the same low acid gas venting rate (since feed gas from Scarborough is only ~1.0 percent CO2), but average the emissions rates from Darwin and the Atlantic Train 4 (the newest plant installed at this Trinidad facility, which emissions are estimated in Diocee et al, 2004). Assuming Atalntic Train #4's emissions coefficient increases Pilbara's emissions from energy use in compressors from 0.434 tCO2/tLNG to 0.81 tCO2/tLNG, or by a factor of 86.64 percent. While this a broad range, it conforms to the spread of emissions factors for recently-built LNG facilities, and both Darwin and Atlantic use high-efficiency equipment. Also, so as to make the comparison valid, the Atlantic Train #4 emissions also exclude acid gas venting.

In sum, the formula for compressor and generation emissions are (Pilbara low estimate) * 1.867.

Cell: B69
Comment: Rick Heede:
ConocoPhillips has installed six aero-derivative LM2500 gas-fired turbines. The company estimates total six-pack emissions of 615,106 tonnes of CO2 per year.

Cell: B70
Comment: Rick Heede:
ConocoPhillips uses three Solar Taurus 60s and two Solar Taurus 60 dual-fuel turbines for power generation. The company estimates emissions for both ship-loading and other power demands totaling 106,615 tonnes of CO2 per year.

Pilbara's emissions from power generation turbines are discounted (by 25 percent from the scale-up formula) in order to account for decreased energy requirements for acid gas venting of Pilbara's low carbon dioxide content Scarborough feed gas.

Cell: B71
Comment: Rick Heede:
Natural gas processing facilities -- including LNG plants -- vent CO2 contained in the feed gas. (While carbon sequestration programs are being engineered and installed at several oil and gas production sites, we are not aware of any efforts to re-injector otherwise sequester CO2 emissions from gas processing plants.)

In Darwin's case, the gas comes from the Bayu-Undan field 500 km west of Darwin via a 26-inch subsea gas line. This gas contains about 6 percent CO2, which is considerably higher than the feed gas from BHP's Scarborough field (reportedly 1.0 percent or less). This feed gas difference argues for reducing the scaling factor applied to compressor and flaring emissions with respect to BHP's proposed Pilbara development by about 6+ relative to ~1 percent, say by 1:6, or from 2.17 to 2.17/6 = 0.361.

Yates (2004) puts Darwin's feed gas at "over 6% carbon dioxide," p. 8.

Cell: B72

Comment: Rick Heede:
The Darwin Environmental Management Plan also details emissions estimates for the numerous flares common at gas processing facilities, such as flash gas, marine flares, condensate flares, and so on. These total 59,485 tonnes of CO2 per year.

Cell: B73
Comment: Rick Heede:
ConocoPhillips's (2005) Darwin EMS, note to Table 5.2, states: "A routine venting operation. Only the methane vented volumes are presented, because other gases are neither greenhouse gases nor air pollutants. The methane emission rate is 268.8 kg/h with duration of venting assumed to be 7,671 hours per year." 268.8 kg/h times 7,671 hr/yr = 2,062 tonnes of methane. On its Table 5.3, annual "TOC/CH4 venting totals 2,172.1 tonnes.

CMS has updated the GWP factor from 21 to 23xCO2, per IPCC's TAR report (2001), p. 388.

Cell: K73
Comment: Rick Heede:
Using the scaling factor applied to compressors (based on the Atlantic Train #4 relative to the Darwin emissions rate) results in a methane emissions estimate of 6,604 tonnes of CH4. CMS instead applies the methane emissions rate of the US natural gas processing industry (Table 11), namely 28.22 tonnes of CH4 per Bcf of natural gas consumption, which, in the case of the scaled-up Pilbara plant, totals 366 Bcf per year (see Table 1).

Cell: B74
Comment: Rick Heede:
ConocoPhillips included emissions of nitrous oxide, chiefly from stationary combustion sources. 1.6 tonnes of N2O is cited; CMS has updated their GWP factor to 296xCO2, per IPCC's TAR report (2001), p. 388.

Cell: B75
Comment: Rick Heede:
An entity may elect to sets its emissions boundaryto include emissions from power plants providing electricity to the site. Since the Darwin LNG plant EIS is following Australian reporting guidelines (which, of course, focus on new facility emissions), no such emissions are included. CMS cannot estimate the quantity of power purchased by either Darwin or the proposed Pilbara plant, and all required power is assumed to be generated onsite. If Pilbara will require grid-connected power purchases, future supply-chain emissions estimates should quantify associated CO2 emissions.

Cell: E77
Comment: Rick Heede:
LNG compressors and power generators at LNG plants are sometimes fueled with natural gas liquids. To our knowledge, BHP has not published the composition of Scarborough gas, and we assume that the proposed Pilbara LNG plant will use natural gas to run the energy-intensive liquefaction and related systems. In practice, an LNG plant may also use entrained natural gas liquids to fuel some plant equipment. CMS calculates the equivalent quantity of natural gas required to run BHP's proposed Pilbara plant. This calculation estimates the amount of natural gas combusted in power generation equipment equal to the emissions estimates for those same functions at ConocoPhillips' Darwin plant -- even though BHP may build an LNG facility with less efficient combustion and process systems. The gas consumption estimate also adds flaring emissions and gas used in power generation turbines (which itself discounted for lower CO2 content in the gas feed than at Darwin). The estimate excludes emissions from acid gas venting.

Cell: J79
Comment: Rick Heede:
This averages the high and low estimates of gas consumption for liquefaction, including compressors, power generation turbines (discounted, as explained above, for lower power demand based on low CO2 content of the Scarborough feed gas), and flaring. It excludes emissions from acid gas venting (other than the power required to do so). While Pilbara may well use natural gas liquids for part of its energy supply, rather than relying exclusively on "parasitic" use of its natural gas, we do not have any data showing NGL content of Scarborough gas. However, we discount this average to account for some NGL usage: formula: (low + high)/2.25

Cell: B95
Comment: Rick Heede:
The detailed estimate made of ConocoPhillips' Darwin LNG plant emissions must be scaled to each plant's LNG production capacity. The Darwin emissions are based on a facility producing 3.24 million tonnes of LNG per year (Mt/yr, or Mtpa) by the completion of its first liquefaction train in early 2006. Emissions vary plant by plant based on a numberof variables, the most important being technology selection (gas turbines, steam, or electric compressors), feed gas, facility age, and environmental regulations.

Since BHP's Pilbara pre-feasibility study has not been published a site-specific emissions estimate cannot be made in lieu of BHP's own forthcomng estimates. We can, however, scale up the estimated Darwin emissions based on a LNG train capacity of 3.24 Mt/yr to Pilbara's anticipated capacity. We assume that the Darwin facility is subject to the same Federal regulations facing BHP in Onslow, Western Australia, and that both facilities will employ modern technology and be required to mitigate process and energy-related emissions. Pilbara's feed gas is expected to come from Scarborough natural gas field 280 km northwest of Onslow, and that gas has a carbon dioxide content of less than 1.0 percent, per BHP data.

BHP has stated that Pilbara LNG plant will be a 6 million tonne per year facility. This, however, is not sufficient to deliver the promised amount of LNG to Cabrillo (being short by ~1.07 Mt/yr), given that 800 million cf per day of natural gas is projected to be re-gasified at Cabrillo and delivered to SoCalGas (total gas production is derived in Table 1).

As shown in the "LNG carrier fleet emissions" table below, such a delivery projection translates to 13.99 m^3 of LNG per year once the FSRU's own gas requirements of approximately 12 million cf/day are added, and once the fuel requirement of each LNG trans-Pacific round-trip is accounted for (6,743 m^3 one-way), each LNG carrier will depart with 138,000 m^3 and deliver 124,513 m^3 of LNG. This ratio drives the estimated scale-up of the Pilbara plant from 6.38 Mt/yr to 7.07 Mt/yr. (These numbers are subject to change.)

Rather than increase the planned size of Pilbara, BHP may instead elect to contract for LNG from another plant -- in Indonesia, for example -- or buy LNG on the emerging spot market. But our intention here is to estimate total emissions from a LNG supply chain that delivers 800 million cf/day to Cabrillo (plus Cabrillo's gas usage), regardless of the eventual source of the LNG.

In sum, we estimate Pilbara emissions of carbon dioxide and methane on the basis of scaling Darwin's emissions by a factor of 2.18 to reflect Pilbara's 118 percent larger capacity requirement.

Cell: I95
Comment: Rick Heede:
To the best of our knowledge, this table compares the emissions performance of several LNG plants and/or trains using the same measurement criteria and sources. That is, acid gas venting is not included, although the emissions from generating electricity (including power requirements of CO2 removal). Nonetheless, uncertainties remain, and these comparisons could be greatly improved by access to company data. Also, data from other LNG plants and liquefaction trains would be extremely useful, particularly those using different technology.

Cell: D116
Comment: Rick Heede:
Approximate; estimated on the basis of air travel distance between Los Angeles and Perth (9,310 miles), minus 210 miles. Or LAX to Darwin (7,870 miles) plus ~1,240 miles for Onslow to Darwin.

1 nautical mile = 1.151 statute miles.

Cell: E116
Comment: Rick Heede:
Assumed vessel speed is based on published data on new LNG shipbuilding orders. Maritime Business Strategies's (Tim Colton) "LNG Carrier Construction Activity in 2006" lists Basin of operation, owner, yards, sizes (the average size of 23 new orders is 209,000 dwt). The Pacific Eurus (owned by LNG Marine Transport and serving Tokyo Electric's run between Darwin Australia [ConocoPhillips' Darwin LNG] and Japan) is 137,000 m^3, cost $180 million, has four Moss tanks, flies a Bahama flag, and cruises at 19.0 knots.

Source: www.coltoncompany.com/shipbldg/worldsbldg/gas/lngactivity2006.htm

Cell: G116
Comment: Rick Heede:
Simple division of estimated nautical miles of route (one way) by average vessel speed.

Cell: H117
Comment: Rick Heede:
"The Project will have a capability of regasifying up to a maximum capacity of 1.5 Bcf/day, with a normal rate of between 0.6 Bcf/day and 0.9 Bcf/day, or about 800 million cubic feet per day." BHP, p. 1-3.

BHP emissions estimates are indeed based on FSRU throughput of 800 million cf per day, 365 days per year, total 292 billion cf per year. BHP Permit, Appendix A, Table FSRU 9, Submerged combustion vaporizer emissions summary.

We thus add 800 million cf per day to estimated gas requirements for FSRU regasification and other "parasitic" gas loads (gas to run generators, hotel loads, and other loads identified by BHP. These total 12.2

million cf per day and are estimated at the bottom of Table 10 by converting BHP's estimated FSRU emissions of 287,225 tons of CO2 into equivalent natural gas (4.46 Bcf).

Cell: D123
Comment: Rick Heede:
We assume propulsion by Wartsila 18V50DF dual-fueled engines with emissions of diesel mode: 630 gCO2/kWh (100% load); gas mode: 430 gCO2/kWh (100% load). The Wartsila 18V50DF generates 17,100 kW (950 kW per cylinder).

Cell: F123
Comment: Rick Heede:
Trip energy is calculated by multiplying total LNG carrier propulsion plant (60,000 HP, according to BHP), which equals 44.74 MW, times transit time (in total trip hours) as estimated in a table above.

Cell: H123
Comment: Rick Heede:
It is typical for gas-powered engines to use the boil-off gas (BOG). Under normal conditions this averages 0.12 to 0.15 percent of the carrier's capacity per day of operation. In the case of an LNG carrier with 138,000 m^3 capacity, 0.15 percent per day means a boil-off of 207 m^3 of LNG per day, or, for a 7,908 nmile transit of 16.9 days, a total of 3,422 m^3. This amount is roughly half (54.2 percent) of the fuel consumption of the Wartsila engines operating in gas mode across the Pacific Ocean, and additional LNG will have to be vaporized in transit (see the discussion below using Kuver et al data). While the Wartsila 50DF engines are dual-fueled and the carriers are expected to carry marine diesel fuel onboard, we have NOT assumed any diesel operation mode fo the low estimate.

For the medium emissions estimate, however, we estimate as follows:
Use the boil-off rate as priority fuel input, and supplement with diesel as required. In practice (in this thought experiment), this means that 3,422 m^3 of boil-off LNG is consumed, plus diesel makes up the difference. The result is that less LNG is consumed, more LNG is delivered, and, presumably, more money is made. Total emissions are higher by approximately 17 percent. Küver et al (2002) "Evaluation of Propulsion Options for LNG Carriers," p. 12, shows an example of a 142,000 m3 LNG carrier with boil-off rate of 0.15 percent per day compared to the vessel's LNG requirements at various speeds. A speed of 19.5 knots consumes all BOG, requiring no re-liquefaction and, indeed, no supplementary marine diesel. While this conflicts with our calculation based on BHP-supplied datum of its LNG carrier with a power rating of of 60,000 HP (44.7 MW), we do not correct BHP's assumption and make no adjustments to our calculation.

The high emissions estimate assumes diesel-only mode at an emissions rate of 630 gCO2/kWh, which converts to 11,431 tonnes of CO2 for the 7,908 nm trip and zero net consumption of LNG (assuming that the boil-off gas will be re-liquified or compressed en route).

BHP has stated in its permit application that its carriers will operate in gas-mode to reduce emissions while in Federal waters. The bluewater fuel option will, most likely, be made on financial rather than environmental grounds.

Note: the CSLC's (2006) Revised Draft EIR, p. 2-21: "LNG carriers would have a capacity ranging from 36.5 to 55.5 million gallons (138,000 to 210,000 m 3). Of this volume, an estimated 4 million gallons (15,100 m3) would be consumed by the carrier while in transit for fuel and for maintaining the cold tanks; the remaining 32.5 or 51.5 million gallons (123,000 or 195,000 m 3) would be transferred to the FSRU. LNG carriers would be powered by natural boil-off gas from their LNG cargo, as agreed with the U.S. Environmental Protection Agency (USEPA) (Klimczak 2005). The Applicant has not finalized design specifications for LNG carriers; therefore, the diesel storage capacity for LNG carriers cannot be estimated at this time."

This CSLC and/or BHP estimate is approximately 12 percent higher than calculated here. The CMS estimate for round-trip LNG consumption is 2 * 6,743 m^3 = 13,486 m^3, versus 15,100 m^3 in the CSLC Draft EIR, p. 2-21.

Note: in the "high emissions" example above, the LNG is reliquefied onboard in order to maximise the amount of LNG delivered. See Tore Lunde in the attached report's list of references and Hamworthy, Ltd at www.hamworthy.com. Hamworthy is a leading proponent and systems vendor for this concept. Also see Kuver et al (2002), Larsen & Thorkildsen (2005), and Harper (2002).

Cell: C124
Comment: Rick Heede:
BHP (2005) Cabrillo Permit Application, p. 1-3, Table 1.3-2 and Appendix Table FW-8 (LNG Carrier Vessel Emission Summary, PDF page 112), which cites teh presumed vessel's power rating as 60,000 Brake HP (also, coincidentally, BHP) datum as "from BHP estimates." The BHP calculations only include emissions within US Federal waters. CMS estimates fuel and emissions for the trans-Pacific route.

We take BHP's word for an LNG carrier's power rating (60,000 HP, which converts to 44.74 MW), but this is substantially higher than other similarly-sized LNG vessels recently completed by Mitsubishi, Daewoo, and Samsung, which are in the 137 to 147,000 m^3 range and are powered by 29,000 to 39,500 HP engines. See www.coltoncompany.com/shipbldg/worldsbldg/gas/lngactivity2006.htm

Indeed, any revision to this shipping emissions estimate should anticipate the likelihood that BHP's datum of 60,000 HP either refers to a larger LNG carrier than assumed here, or is in error. Indeed, Kuver et al (2002) "Evaluation of Propulsion Options for LNG Carriers," show the predicted power requirement -- albeit for propulsion only -- of a state-of-the-art LNG carrier of 145,000 m^3 size cruising at 19.5 knots (as we assume here) as ~25 MW, not the 44.74 MW used by BHP.

Cell: D124
Comment: Rick Heede:
1 HP = 0.74570 kW.

Cell: E124
Comment: Rick Heede:
While the BHP permit application does not specify (to our knowledge) the yet-to-be ordered LNG carriers, the document does specify a Wartsila dual-fuel engine for the FSRU. Wartsila supplies power plants to a growing number of LNG shipbuilding orders. These engines are designed to run either or both on natural gas and marine diesel fuel, and can quickly switch fuels. (Even in gas-mode, the engines use about 1 percent diesel fuel for ignition purposes.) The engines -- typically four engines to a large LNG carrier -- generate electricity that power an electric propulsion system. We assume all-gas mode for the trans-Pacific route for the following low emissions estimate, even though it is reasonable to expect considerable use of the higher-emission (but cheaper) diesel fuel mode. All-diesel mode comprises the high estimate, and a mixed-fuel mode determines the medium estimate.

The emission rate for the 50DF series of engines is typically 430 grams of CO2 per kWh (in gas mode; 630 g/kWh in diesel mode); each cylinder generates 950 kW; a typical specification is for three or four 50DFs at each 8,550 to 11,400 kW; the engine series is built in 6 to 18-cylinder models. Note that emissions rates vary by fuel composition, heating value, load, and other factors: we have best-guessed an unspecified ship configuration for illustrative but reasonable circumstances.

See Wartsila 50DF engines at www.wartsila.com, Vaasa, Finland.

Note: the medium estimate assumes that all available boil-off gas is consumed, which supplies approx 54.2 percent of total energy required. The emissions rate shown below is thus a proportional mix of fuel modes.

Cell: H124
Comment: Rick Heede:
Emissions are based on Wartsila engine specifications for the 50DF series (see emissions rate) and total trip energy.

Note: Low emissions estimate is based on gas-only mode, consuming all of the boil-off gas plus additional LNG must be vaporized.

Medium estimate assumes gas plus diesel mode (using all of the boil-off gas), and additional fuel consumed is diesel. Note: ~54 of the required energy is supplied by boil-off gas at 0.15 percent of total LNG carrier capacity per day. See cell notes under "Equiv LNG."

High estimate assumes all diesel fuel mode, with boil-off gas re-liquefied or compressed and stored for delivery. Neither option may be likely, but the purpoe here is to estimate vessel emissions with diesel fuel, regardless of the disposition of the LNG boil-off gas.

Cell: K124
Comment: Rick Heede:
1 tonne of LNG equals 46,467 cf (0.046467 million cf).

Cell: L124
Comment: Rick Heede:
1 tonne of LNG is 2.193 m^3;
1 m^3 of LNG = 0.4560 tonne (I.e, 0.456 the density of water at STP).

Cell: B126
Comment: Rick Heede:

See notes under “Emissions rate” and “Trip emissions” for calculation procedure.

Cell: L126
Comment: Rick Heede:
This figure is lower for the high emissions estimate because only the boil-off gas is used, and the additional fuel requirements are provided by diesel fuel. Hence the higher emissions and “minimum” LNG consumption.

Cell: B130
Comment: Rick Heede:
BHP’s estimate of LNG carrier “reactive hydrocarbons (ROC) as CH4” emissions references US EPA AP-42, Table 3-2-2, and cites an emissions rate of 0.39 grams per brake HP-hr, presumably as uncombusted methane in the fuel stream. We take 90 percent of BHP’s cited emissions factor as the low estimate and 110 percent of BHP’s cited emissions factor as the high estimate.

This row estimates kg of methane per LNG carrier trip from Pilbara LNG plant to Cabrillo Deepwater Port (one way only), and also shows total trip emissions in CO2-equivalent. We use the IPCC GWP factor of CH4 = 23xCO2 (100-year time horizon).

Cell: D137
Comment: Rick Heede:
LNG carrier capacity (assumed as 138,000 m^3) minus the LNG converted to gas and used as propulsion fuel in the Wartsila engines en route to Cabrillo. Naturally, the ship needs to retain approximately an equal amount of LNG aboard for the return trip. In actual operations the carrier will likely carry a larger amount of LNG for the return in order to keep the Moss tanks cold for the re-fill at Onslow, Western Australia. Also, we have not included any LNG or gas consumption while the carrier is being off-loaded -- which takes an estimated 20 hours, including deberthing and turn-around, according to BHP.

This CSLC and/or BHP estimate is approx 12 percent higher than calculated here. The CMS estimate for round-trip LNG consumption is 2 * 6,743 m^3 = 13,486 m^3, versus 15,100 m^3 in the CSLC Draft EIR, p. 2-21. See cell note under Table 8 “Equiv LNG” Cubic meters consumed per one-way trip.

Cell: J137
Comment: Rick Heede:
This summarizes our estimate of total annual emissions of carbon dioxide from BHP’s fleet of LNG carriers serving its proposed Onslow to Cabrillo Deepwater Port project. The emissoins are chiefly from LNG used as fuel in a set of Wartsila 50DF dual-fueled gas engines used to power a vessel’s propulsion drive, plus other ship-board loads such as refrigeration compressors, navigation systems, hotel loads, pumps, motors, lights, heating, hot water, etc. The estimate uses BHP published factors (e.g., the LNG carrier total power rating of 60,000 HP). We also estimate the number of annual berthings by an LNG carrier with nominal capacity of 138,000 cubic meters (and delivering 125,373 m^3): 112 berthings per year, or 2.1 landings per week.

Given the ~7,908 route nautical miles from Onslow, Western Australia, to Cabrillo, at ~19.5 knots, each trip takes 405 hours, or 16.9 days, and consumes 3,075 tonnes of LNG one way, emitting 7,802 tonnes of CO2 per journey (0.987 tonnes of CO2 per nmile). See the calculations and cell notes for details.

Cell: K137
Comment: Rick Heede:
This cell is a sum of estimated emissions of fugitive methane -- in units of carbon dioxide-eqiuvalent per year-- from BHP’s LNG carrier fleet delivering 13.78 million cubic meters of LNG to Cabrillo in a year. See the calculation and cell notes above for details.

Cell: I141
Comment: Rick Heede:
We quantified the amount of natural gas equivalent to the energy inputs to the Pilbara LNG plant in Table 3. Here we estimate the similar natural gas required to fuel the LNG carrier fleet per year. Note that this is an estimate of maximum gas consumption based on the presumption (supported by BHP indications, though not made explicit) that the LNG carriers wiil use LNG boil off gas and indeed operate in all-gas mode in both Federal waters and for the trans-Pacific crossing. As we have stated elsewhere, BHP’s decision will likely be based on minimizing costs, not emissions, and may thus dictate partial diesel mode beyond Federal waters. This would then REDUCE the amount of natural gas used as propulsion fuel, increase total emissions, reduce the number of vessel landings per year (and thus round trips) because more LNG can be delivered per vessel landing. The result is that even fewer trips required by diesel + gas LNG carrier propulsion is not enough to reduce overall shipping emissions.Finally, the total quantity of natural gas produced at Scarborough and liquefied at Pilbara will also be reduced, with cascading savings throughout the supply chain. These considerations have been taken into account to the extent feasible in this brief operational analysis. A more thorough analysis of environmental dispatch would reduce several sources of uncertainty as well as identify numerous opportunties to reduce overall supply-chain emissions while also improving long-term profitability.

Cell: E146
Comment: Rick Heede:
BHP excludes emissions of methane from pipeline leakage (BHP, section 3.6). Tellingly, BHP states that “since fugitive leaks from from the FSRU process equipment will be composed of primarily methane, they are not regulated by permit or source-specific requirements.” This suggests a reason for BHP’s low emissions levels from the FSRU, namely that they apply factors to fuel combustion equipment, such as tug boats and the large power generators, for uncombusted fuel, i.e., natural gas released to the atmosphere. Thus, natural gas leakage from seals, valves, and other LNG and natural gas handling systems are NOT included.

Note: This omission is estimated in “additions, construction (CH4)” as our high estimate below.

The CSLC Draft Revised EIR (section 4.6.1.4) states that “direct releases of boil-off gas to the atmosphere would take place only during an upset condition.” This leaves fugitive methane releases from leaking natural gas handling systems unestimated. It is also possible that such leaks can be brought to zero at an LNG receiving and re-gasification facility.

BHP permit application makes reference to EPA’s AP-42 tables, but does not cite specific emissions rates for methane for each combustion source and the EPA default values for methane releases (presumable from uncombusted natural gas).

Also see American Petroleum Institute (2001) Compendium Of Greenhouse Gas Emissions Estimation Methodologies For The Oil And Gas Industry, p. 4-14.

Cell: F146
Comment: Rick Heede:
Methane emissions in tons of methane converted to tons of CO2-equivalent. Note that we use short tons here since we are chiefly listing BHP data.

Cell: G146
Comment: Rick Heede:
This duplicates BHP’s (2005) operating emissions summary for the Cabrillo Deepwater operations. We only deduct half of methane emissions from LNG carrier operations as explained in the “LNG carrier” line item below. BHP data are converted to metric tonnes.

Cell: H146
Comment: Rick Heede:
Cabrillo FSRU Startup emissions. BHP estimated emissions from fuel consumption by Wartsila 9L50DF generators and emergency fire pump generator. No emissions are estimated from tug boat operations or use of crew boat. A total of 12.9 tons of methane is included. BHP unit in tons converted to metric tonnes.

Note: Startup emissions are amortized over a 25-year period. See Summary Tables for details.

Note: BHP has not estimated emissions from fuel used in pipelaying and construction activities. CMS does estimate such emissions, albeit quite roughly, given the lack of data. See “Additions to BHP: Vessels and equipment (CO2)” below. This, added to BHP’s identified Startup emissions, comprises our high estimate. Note also that we do not include emissions from materials (cement, steel, pipe, copper, petrochemicals) manufacture, assembly, or transportation. We do make a preliminary estimate of emissions from the quantity of steel required for the supply-chain plant (see “Additions: project materials (not included)”, but such emissions are too tentative to include in this inventory. Atlantic Train #4 required 14.5 million work-hours (Rick Cape, Atlantic LNG website).

Cell: B147
Comment: Rick Heede:
The FSRU will be 296 m long, 65 m wide, and 50 m high, with a displacement of 200,000 dwt. Moored to a depth of 2,900 feet. Send out pipelines: two 24-inch lines to existing SoCalGas on-shore system. … “The total LNG transfer rate, through the starboard side loading arms, will be approximately 65,000 gallons per minute (gpm). Each LNG carrier berthing, unloading, and de-berthing event will last approximately 20 hours and will occur approximately two to three times per week.” The FSRU will host three 56 m diameter (91,000 m^3) spherical Moss tanks with a total storage capacity of 273,000 m^3.

BHP (2005), p. 2-1, 2-2, and 2-3.

Cell: G147
Comment: Rick Heede:
Note: BHP units are in short tons. CMS has converted BHP’s emissions to metric tonnes.

Cell: J147
Comment: Rick Heede:
Here we calculate the emissions of methane in the US natural gas industry as a function of total US natural gas consumption for the four major gas industry segments as shown below. Emissions are from EIA (2005a) and (2005b). Year 2004 for both emissions and consumption. These emissions rates are, of course, general, and do not specifically apply to SoCalGas or its customers, or to BHP's supply chain components -- although these factors do help fill in some data gaps in lieu of company data.

Note: CMS applies these methane emission rates in order to estimate supply chain emissions at BHP's Scarborough gas field (using the EIA gas production sector rate) and for emissions related to distributing the gas to SoCalGas customers. Emissions from gas processing and gas transmissions are based on BHP estimates or other metrics shown in the above tables.

Cell: B148
Comment: Rick Heede:
BHP (2005), p. 3-2: "The four lean-burn Wartsila 9L50DF main generator engines will supply the electricity to operate the facility. The Wartsila 9L50DF is a four-stroke lean-burn spark-ignited gas engine. The primary fuel for these engines is natural gas with a small (1%) amount of diesel burned as a pilot fuel. Each of the four units will have power output of 8,250 kilowatts (kW) with an annual estimated operation of 26,280 hours, for a total power plant generating capacity of approximately 25 megawatts (MW)."

Cell: B149
Comment: Rick Heede:
These devices, of which the FSRU operate four units, re-gasify LNG by heating the chilled liquid at a design rate of 115 million Btu/hr. Total annual fuel consumption (though not estimated in the pertinent table, BHP permit, Apppendix A, FSRU Table 9) is 8760 hrs/yr times 115 million Btu/hr with gas at 1007.6 Btu/cubic foot: total gas combusted equals 0.114 million cf per day = 0.9998 billion cf (Bcf) per device, or 4 Bcf in total. This gas consumption (along with other FSRU gas requirements) is entered in Table 1 in order to feed enough gas or LNG through the supply chain to effectively deliver 292 Bcf per year to SoCalGas.

Cell: B150
Comment: Rick Heede:
BHP (2005), p. 3-4: "The crewboat will conduct approximately 2.5 round trips per week. The tug/supply boat will operate once a week to bring supplies to the FSRU and haul black waste from the FSRU back to shore for disposal, and will conduct approximately 2.5 LNG carrier berthings per week. The primary fuel for these vessels will be gasified LNG."

Cell: B152
Comment: Rick Heede:
BHP estimates LNG carrier emissions for ~2.5 vessels arriving (and departing) per week, but only for transit through US Federal waters. Since we estimated LNG carrier emissions for their trans-Pacific voyages, we only include 50 percent of BHP's emissions estimate in order to account for the carriers' energy and emissions during offloading LNG at berth.

Cell: B153
Comment: Rick Heede:
BHP identified small sources, e.g., 3 freefall lifeboats, emergency firepump, etc. BHP also lists a 145,000 gallon diesel fuel storage tank, -- from which no fugitive methane leakage is estimated.

BHP (2005) p. 3-4: "Diesel Storage Tank. Some breathing losses and small amounts of working losses of VOCs will occur from the diesel storage tank. The tank will be kept full but will not be utilized after commissioning except for emergency diesel engine fueling and provision of pilot fuel to the Wartsila engines. The diesel fuel tank will have a capacity of approximately 144,500 gallons."

Cell: J153
Comment: Rick Heede:
Methane emissions from "stationary sources" (in EIA's lingo) refers to fugitive emissions from incomplete combustion of natural gas, chiefly residential and commercial boilers and appliances. Original units in CO2-equivalent, hence our datum (0.476 million tonnes) is divided by 23.

Cell: J154
Comment: Rick Heede:
In the U.S. (2004), methane emissions from natural gas industry -- production, processing, transmission, and distribution -- accounted for 6.64 million tonnes of methane. Using a conversion factor of 0.04228 lb/cf (= 0.019178 kg/cf = 19.178 g/cf); thus 6.64 million tonnes = 346.23 Bcf, which is 1.551 percent of 2004 US natural gas consumption (22,321 Bcf; EIA AER, Table 6.1).

Cell: B155
Comment: Rick Heede:
Emissions of ROCs (reactive organic compounds) are listed in the CSLC Draft EIR (Table 4.6-11) but are not added to the project's construction-phase emissions. It appears that none of BHP's construction fuel-consumption is estimated by either BHP or CSLC (in the latter case, CSLC methane ("ROC") emissions are esimated in the section 4.6.1.3 Regulated Air Pollutant Emissions. CMS thus includes these estimate here as GHG emissions.

These emissions are chiefly from construction activities: primarily from pipelaying, trenching, and related activities using combustion equipment. See the following line item ("Additions to BHP: vessels and equipment").

Cell: E155
Comment: Rick Heede:
CMS adds the methane emissions (listed as ROCs) estimated in CSLC's Table 4.6-11 "Total Air Pollutant Emissions from Project Construction Activities" and a total project emissions of 35 tons of methane.

Cell: B156
Comment: Rick Heede:
BHP has estimated emissions of methane from incomplete combustion of natural gas (derived from re-gasified LNG) used in the equipment categories listed in Table 10. This estimate, as far as we can ascertain, does not include fugitive emissions of methane from leaky pipes, valves, flanges, tanks, seals, and other fuel containment and regasification systems. CMS has not evaluated the legal requirement to estimate additional methane emissions, nor can CMS make an engineering estimate of such emissions without access to company engineering data.

While it is common for conventional natural gas receiving terminals and related systems to leak methane from numerous (non-combustion) sources, both routine venting and fugitive emissions standards are being tightened for FSRUs and FPSOs. BHP has published no data on non-combustion methane emissions from the Cabrillo FSRU.

BHP states that "since fugitive leaks from from the FSRU process equipment will be composed of primarily methane, they are not regulated by permit or source-specific requirements." (BHP permit application, section 3.6).

CMS therefore attributes only one-half of the emissions rate from natural gas processing (0.5 * 28.22 tonnes CH4/Bcf) plus one-tenth of methane emissions from gas distribution and storage (0.1 * 105.73 tonnes CH4/Bcf) as an indicator that a Cabrillo-specific emissions estimate should be made. These emissions rate are applied to total natural gas throughput (292 Bcf delivered to SoCalGas plus 4 Bcf required for Cabrillo operations). The result is shown in US tons to match the BHP presentation units.

In the absence of estimated fugitive methane by BHP and the CSLC, CMS uses the above factors as a preliminary estimate. BHP and/or CSLC may be able to refine this preliminary estimate.

Cell: E156
Comment: Rick Heede:
Emissions of methane from FSRU operations as described in coulmn B: not estimated by BHP.

Cell: B157
Comment: Rick Heede:
CMS estimates additional emissions of carbon dioxide from fuel used during construction of the offshore FSRU , the natural gas pipeline connecting the FSRU to onshore gas utilities, etc.

CMS also estimates emissions of methane from FSRU operations; see line item above. We do not include methane emitted from incomplete combustion of the fuel consumed byconstruction vessels and pieplaying equipment. If CMS had done so, it would be approximately 0.0081 lb CH4 per million Btu (for large-bore diesel engines >600HP), and 0.036 lb CH4 per million Btu (for smaller IC diesel engines). Assuming, roughly, 0.016 lb CH per million Btu and diesel fuel at 128,700 Btu per gallon (LHV; 138,700 at HHV), thus approx. (1.064 million gallons*0.1287 million Btu/gallon) = 0.1369 trillion Btu, and 0.1369 trillion Btu * 0.016 lb CH4 per million Btu = 2,190 lb CH4, i.e., barely 1 ton of methane, and negligible.

Cell: C157
Comment: Rick Heede:
The roughly estimated quantity of carbon dioxide emissions from diesel fuel used in construction vessels and ground equipment (11,905 tons of CO2 (= 10,800 tonnes CO2)) converts to 1.064 million gallons of diesel fuel at 22.384 lbs CO2 per gallon.

Cell: H157
Comment: Rick Heede:

Both the BHP Permit Application and the CSLC Draft EIR present information on a virtual flotilla of dynamically positioned pipelaying vessels (25,000 HP), two anchor handling towing/supply vessels (30,000 HP), crew boat (1,500 HP), a tug and pipe barge (4,000 HP), a construction barge (8,000 HP), a tug (6,500 HP), oceangoing tub (25,000 HP), an exit hole barge tug (4,000 HP), and other smaller vessels. This equipment is anticipated to be operational at various percent loads for days to weeks. Also, for shore crossing and pipeline trenching operations, there will be an armada of forklifts, trenchers, backhoes, dozers, pipebending equipment, dewatering pumps, cement equipment, as well as dump and water and utility and pipestringing trucks.

Source: CSLC (2006), Table 4.6-2 through 4.6-9, Section 4 (Air Quality).

Neither BHP nor CLSC has estimated emissions of greenhouse gases from this equipment's fuel consumption. CMS estimates fuel and emissions very crudely and tentatively as follows:

Assume an average of 50,000 HP of various equipment for an average of 60 days of 12 hrs each.

Estimate emissions by assuming (conservatively) an emissions rate of 500 gCO2/HP-hr.

Crudely, we have 30,000 * 60 * 12 = 21.6 million HP-hrs, * 0.5 kgCO2/HP-hr = 10.8 million kgCO2, or 10,800 tonnes of CO2.

Cell: B158
Comment: Rick Heede:

Consumption of electricity in pipelaying and shore facilities will probably be relatively small and have not been estimated by either BHP or CMS.

Other emissions sources related to the planning, design, construction, and operation of the Cabrillo Deepwater Port -- but not estimated by BHP or CMS -- include air travel from Australia to the US (or shipyards in Asia), commuting to work by construction and operations crews (other than by crew boats, which are included), transportation of pipeline materials, concrete (both cement process and transport), and towing of the FSRU from the shipyard (in Asia?).

Cell: B159
Comment: Rick Heede:

The operational emissions flowing from the processing, freezing, and transportation of 8.1 to 6.4 million tonnes of natural gas annually, depending on where in the supply chain one looks. Emissions related to the mining, smelting, fabrication, assembly, and transportation of millions of tonnes of materials such as cement, aluminum, copper, steel, nickel, insulation, and petrochemicals are not included. CMS considers such emissions potentially part of the full accounting of environmental impacts from the construction and operation of the supply chain, but are not included.

Take steel, for example.
A gas production platform might contain on the order of 20,000 tonnes of steel (and Scarborough is at a depth of 900 meters), a gas pipeline contains ~500 kg per meter (140,000 tonnes from Scarborough to Pilbara), each LNG carrier approx 30,000 tonnes (330,000 tonnes for an 11-vessel fleet), the FSRU about 35,000 tonnes, and a large liquefaction plant embodies on the order of 40,000 tonnes (in cables, pipelines, structural steel, pylons, jetties, tanks, etc). All told, on the order of 0.57 million tonnes of steel. Note: this is a very rough and preliminary approximation.

Delucchi (2003) Appendix H: "The Lifecycle of Materials," p. 84-85, estimates CO2 emissions per tonne of virgin steel at 1,498 kgCO2/tonne (2,996 lb/ton) and recycled steel at 978 kgCO2/tonne (1,956 lb/ton). This includes both process and manufacturing emissions. If we average virgin and recycled emissions we get 1,238 kg of CO2 per tonne of steel, or 1.24 tCO2/tonne. Times 0.57 million tonnes of steel = 0.70 million tonnes of CO2 for steel fabrication. This, of cource, excludes transportation of steel, shipbuilding, platform construction, or pipe manufacturing.

Cell: C161
Comment: Rick Heede:

We quantified the amount of natural gas equivalent to the energy inputs to the Pilbara LNG plant in Table 3 and that required to fuel the LNG fleet in Teble 8. Here we estimate the similar parasitic natural gas required to fuel the Cabrillo regasifaction equipment plus FSRU generators plus tug boats plus the carriers' own generators (to run pumps and hotel loads, etc).

Cell: C162
Comment: Rick Heede:

Total annual natural gas consumed at the Cabrillo FSRU and other equipment converted to tonnes of LNG.

Cell: H173
Comment: Rick Heede:
Not all natural gas made available to the US economy is combusted to carbon dioxide. In 2004, 3.35 percent of total gas supplies were used in non-fuel uses such as fertilizer manufacture, methanol production, and similar end-uses. An analysis of such non-combustion uses reveals that ~90 percent of this carbon is relatively quickly re-emitted to the atmosphere -- but through different pathways and/or with some delay. For example, the produced methanol is burned, and much of the natural gas used in fertilizer production is converted to nitrous oxide via the volatization of nitrogen in fertilizers; N2O is another greenhouse gas.

EIA(2004) Documentation for Emissions of Greenhouse Gases in the United States 2002, p. 29-30:

Natural gas used for nonfuel purposes include feedstocks for nitrogenous fertilizer production (ammonia NH3) and other chemical products, especially methanol.

EIA data show half of natural gas used for nonfuel purposes is for fertilizer production and half for other uses. The carbon coefficient is 14.47 kgC/million Btu.

EIA states that the use of natural gas feedstocks to make nitrogenous fertilizers "is considered a non-sequestering use, because the underlying chemical is ammonia (NH3), which is manufactured by steam reforming of natural gas and reacting the synthesis gas with atmospheric nitrogen, literally leaving the carbon in the feedstock `up in the air.'" Other pathways, e.g., recovering the carbon for urea production, only delays the carbon's release to the atmosphere.

In sum, our analysis concludes that 0.305 percent of total natural gas supply is actually sequestered. This factor is used to estimate the amount of natural gas removed from the combustion pathway and thus NOT emitted to the atmosphere, hence the term "tonnes CO2 sequestered." The high estimate assumes half the above sequestration rate: 0.305 percent * 0.5.

The formula (low estimate) is thus: total gas delivered to SoCalGas in Bcf/yr * 54.6 tCO2 per Bcf * 0.00305

The formula (high estimate) is thus: total gas delivered to SoCalGas in Bcf/yr * 54.6 tCO2 per Bcf * 0.00305 * 0.5

Cell: J173
Comment: Rick Heede:
Per IPPC and US EIA emissions inventory guidelines, the default value for the fraction of natural gas in combustion equipment that is typically not combusted to carbon dioxide is 0.5 percent. This factor is used to estimate the fraction of natural gas sequestered from the atmosphere.

The formula (low estimate) is: total gas delivered to SoCalGas in Bcf/yr * 54.6 tCO2 per Bcf * 0.005

The formula (high estimate) is: total gas delivered to SoCalGas in Bcf/yr * 54.6 tCO2 per Bcf * 0.005 * 0.4 (That is, we reduce the uncombusted fraction by 60 percent (from 0.5 to 0.2 percent)).

Cell: K173
Comment: Rick Heede:
After removing the small factors for sequestered non-fuel uses of natural gas and gas not combusted to carbon dioxide, this cell shows the total amount of carbon dioxide emitted by gas consumers in southern California from combustion of the natural gas annually delivered to SoCalGas from LNG regasified at BHP's proposed Cabrillo Deepwater Port. (This formula has been verified.)

Procedural note: This is based on the following: EIA and EPA data on carbon content of natural gas (14.47 kgC per million Btu -- usually expressed as 14.47 TgC/QBtu: 14.47 million tonnes of carbon per quadrillion (10^15 Btu)).

We use the heat content of "marketed" natural gas at 1,030 Btu per cubic foot.

Formula: 14.47 kgC/million Btu * 1.03 million Btu/1000 cf * 3.664191 CO2 per C = 54.602 tonnes of CO2 per Bcf.

Cell: L173
Comment: Rick Heede:
Emissions of carbon dioxide plus methane in CO2-eq units.

Cell: B174
Comment: Rick Heede:
Table 12 estimates emissions from SoCalGas and the gas utility's customers through: (a) fugitive methane from transmissions and distribution pipelines and related systems, and (b) the combustion of the natural gas marketed (minus the small amounts not fully combusted to carbon dioxide or sequestered through non-fuel uses of natural gas, such as fertilizer production). Since more than 99 percent of the marketed natural gas is converted to carbon dioxide, this item represents the largest single source of supply chain emissions.

Cell: C174
Comment: Rick Heede:
BHP indicates that average LNG re-gasification rate will make 800 million cubic feet of natural gas per day available to SoCalGas.

Cell: D174
Comment: Rick Heede:
Million cubic feet per day times 365 days per year.

Cell: E174
Comment: Rick Heede:
Average methane emissions rates in the US natural gas industry are shown in Table 11. Fugitive methane for major industry sectors are also shown so that emissions rates -- in tonnes of methane per billion cubic feet (Bcf) consumed in the U.S. in 2004 -- can be estimated foreach sector of interest.

The low estimate adds 20 percent of the methane emission rate for transmission and storage, 80 percent of gas distribution, and 80 percent of incomplete combustion, and we apply the resulting 86 tonnes of methane per Bcf to the total amount of gas marketed to SoCalGas customers.

The high estimate adds 25 percent of the methane emission rate for transmission and storage, 100 percent of gas distribution, and 100 percent of incomplete combustion, and we apply the resulting 108 tCH4/Bcf to the total amount of gas marketed to SoCalGas customers.

Cell: F174
Comment: Rick Heede:
Bcf of natural gas delivered by BHP to SoCalGas times the methane leakage rate = total tonnes of associated methane leakage. Note: this is a generalized estimate. The SoCalGas pipelines and gas handling systems may be less leaky than the US average.

Cell: G174
Comment: Rick Heede:
Total CH4 leakage times methane's GWP of 23xCO2, per IPCC TAR, p. 388.

Cell: E177
Comment: Rick Heede:
As a check on the reasonableness of our methane leakage estimate above we calculate the quantity of methane leakage as a percent of the quantity delivered to SoCalGas. 0.48 percent is one-third of the U.S. total methane leakage, which was 1.55 percent in 2004, or 346 Bcf leaked of 22,321 Bcf consumed.

Cell: G183
Comment: Rick Heede:
1 metric tonne = 1.1023 short tons.

Cell: L183
Comment: Rick Heede:
1 metric tonne = 1.1023 short tons.

Cell: B189
Comment: Rick Heede:

Startup emissions do NOT include significant emissions from FSRU materials fabrication, assembly, or transportation on the rationale that such emissions are beyond the defined emissions boundary and are not required to be included by the relevant regulatory rules. The FSRU weighs in at 200,000 dwt (BHP, p. 2-2). CMS has made a very preliminary estimate of steel inputs to the supply chain and related carbon emissions, but CMS not included this estimate in this analysis (see Table 10, line item on “Project materials”).

BHP does address construction emissions in section 3.1, and identify pipelaying vessel energy, assist boats, and onshore drilling rig and trenching equipment. However, these emissions estimates are not quantified in BHP’s application. CMS does so in Table 10, line item “Additions to BHP: vessels & equip. (CO2)” which estimates the emissions (again, very roughly), chiefly from the consumption of 1.06 million gallons of diesel fuel in construction vessels, pipelaying vessels, trenching for pipelaying, and so forth.

Startup emissions are annualized for a 25-year period. While this may be shorter than total anticipated project lifetime (40 years is mentioned in the CLSC Draft EIR), it is close to the 21.2-year life-expectancy of Scarborough gas field, assuming that the identified 8.0 trillion cubic feet of reserves are produced at an annual rate of 377 billion cf per year detailed in our Table 1. This annual production rate accounts for the gas delivered to SoCalGas by BHP as well as the gas consumed at the Scarborough gas platform, in the 280-km subsea pipeline to the proposed Pilbara LNG plant, for liquefaction and plant use, gas consumption by LNG carriers (boil-off gas), and gas requirements of the Cabrillo FSRU. Without all of these adjustments, the 800 million cubic feet of gas per day deliverable to SoCalGas equals 292 Bcf per year.

Cell: D191
Comment: Rick Heede:
The CMS aggregate methane emissions estimate is 46 percent of the total emissions of methane if solely based on the US CH4 rate (298 tonnes CH4/Bcf * 377 Bcf = 112,500 tonnes of CH4). EIA data; see Table 11 above.

Cell: G200
Comment: Rick Heede:
1 metric tonne = 1.1023 short tons.

Cell: B206
Comment: Rick Heede:
Startup emissions are annualized over a 25-year period. See “Cabrillo Start-Up” in Table 13 for details.

Cell: D208
Comment: Rick Heede:
As with the low methane emissions estimate, this high estimate is considerably lower than methane emissions from the US natural gas industry. The CMS estimate is 73 percent of the total emissions of methane if based on the US CH4 rate (298 tonnes CH4/Bcf * 377 Bcf = 112,500 tonnes of CH4).

Cell: C216
Comment: Rick Heede:
Energy Information Administration (2005a) Emissions of Greenhouse Gases in the United States in 2004, p. x.

Cell: F216
Comment: Rick Heede:
EIA, undated and uncited. Table C3: Summary of State Energy-related Carbon Dioxide Emissions, 1990-2001), milloin metric tonnes of CO2.

Cell: H218
Comment: Rick Heede:
Supply chain emissions of CO2 divided by state of California CO2 (data for 2001).

AB32 Scoping Plan Comments

California Air Resources Board - Electricity and Natural Gas Sector

Submitted by Ratepayers for Affordable Clean Energy

Submitted on 31 July, 2008

Contact:
Rory Cox, Coalition Coordinator
Ph: 415.399.8850 x302
Email: rcox@pacificenvironment.org

I. Introduction – Ratepayers for Affordable Clean Energy (RACE) is a partnership of over 30 organizations working towards a clean energy future for the West Coast of North America. We envision that in the coming years, the West Coast's energy supply will be increasingly clean, efficient, and affordable for all. RACE works to develop progressive energy policies, supports grassroots campaigns, analyzes state and local energy policies, and works to influence lawmakers to make the best choices on energy issues. Our members represent communities from Baja California, Mexico, to British Columbia, Canada, though most of our partners are located in California and Oregon. A complete list of our partners is at the end of this comment letter.

We applaud the State of California for its leadership in reducing global warming, and are grateful to live in a state that has recognized the reduction of carbon emissions as one of the most important public policy challenges our society faces. As California has a large and influential economy and populace, what happens here has global implications.

II. The Case for Urgency – The case for urgency was made most clear by simply breathing in much of California on the day of the release of the Draft Climate Change Draft Scoping Plan (Draft Plan). On that day, June 26, 2008, countless brush and forest fires were burning out of control throughout the state. The scale of this year's fire season is yet to be fully comprehended as it is still on-going as this is being written. But what is clear is that the severity, quantity, and the earliness of the fires are unprecedented in recorded history. The full impacts and costs to public health, to essential natural resources, and to property from these fires are yet to be known, but it is likely to be very high. While fires rage in California, much of the Mid West is recovering from unprecedented flooding which has damaged a large volume of crops. This is contributing to the rising price of food staples that Californians are now enduring.

On page 6 of the Draft Plan, the current and projected impacts of global warming are outlined. The summer of '08 fires in California, as well as floods in the Mid West, are an illustration that these impacts have begun, and they will take a significant toll on our state's quality of life and economy. This underscores the critical importance of getting the implementation of AB32 right. Given that the impacts of global warming are here, and by all accounts will get worse, it is critical that California's agencies realize that there is no room for error in this endeavor to reduce greenhouse gas emissions from one of the largest economies in the world. Action on global warming needs to be swift, decisive and real. There is simply no time for half-measures, creative accounting of carbon emissions, or any measure that is experimental or unproven.

III. Lifecycle Emissions in the Electricity Sector – In its decision 07-01-039, the California Public Utilities Commission issued its order institute rulemaking regarding greenhouse gas emissions standards in the electricity sector. This was issued in January of 2007. In response to an argument made by the Community Environment Council, the CPUC denied the Council's request for a preliminary "lifecycle" analysis of net emissions for natural gas plants that may use liquefied natural gas (LNG). The CPUC went on to argue that there was no reason to single out LNG, writing in a footnote,

"…the lifecycle emissions concept could encompass the process for extracting fuel (e.g., uranium for nuclear powerplants), transportation of fuel to the powerplant, as well as the fabrication of the generation facility (e.g., the wind turbine, photovoltaic cells, etc.) that produces the electric power and any associated fuel disposal processes. We have no record in Phase 1 on the various approaches and methods for conducting a lifecycle analysis of GHG emissions to consider in making this determination."[1]

These comments will outline why this approach to lifecycle emissions is flawed and, given the impacts on the climate of uncounted emissions, dangerous. We will outline another sector where the state does count lifecycle emissions, as well as science-based policies and statements that indicate that other agencies and one of the state's utilities have acknowledged that these emissions do indeed warrant regulation.

IV. New scholarship reveals full lifecycle impacts: When AB32, and the accompanying law SB1368, were being written, the scientific body of work for evaluating LNG's full impacts was still unfolding. In fall of 2007, however, researchers at Carnegie-Mellon University released a rigorous study on the lifecycle emissions of LNG. As the authors state, "If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from (LNG) imports, emissions from these steps in the fuel cycle could influence the total fuel cycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate."[2]

In the report, the authors detail different scenarios of natural gas and coal production, and find that indeed, there is a significant energy penalty which adds in the range of 15 to 25 percent extra emissions to the production and combustion of domestic natural gas (see figure 1). Once these are accounted for, LNG becomes comparable to coal on a lifecycle basis.

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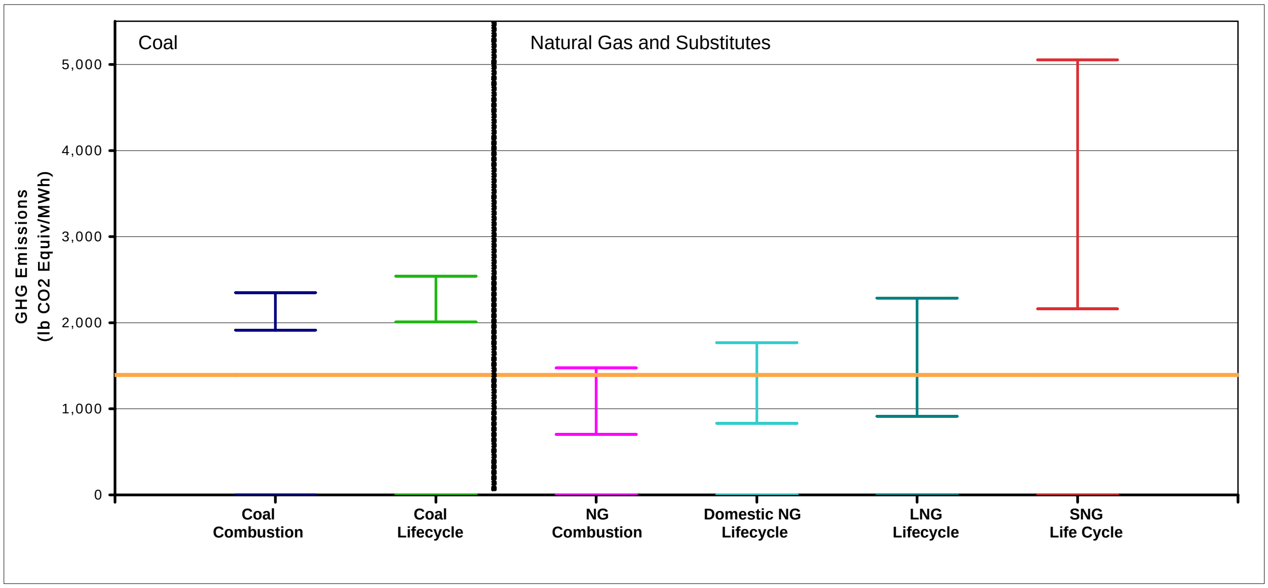
[1] California Public Utilities Commission. "Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies." Decision 07-01-039, January 25, 2007

[2] Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews. Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation. Carnegie-Mellon University. 2007

Figure 1: Fuel Combustion and Life Cycle GHG Emissions for Current Power Plants[3]

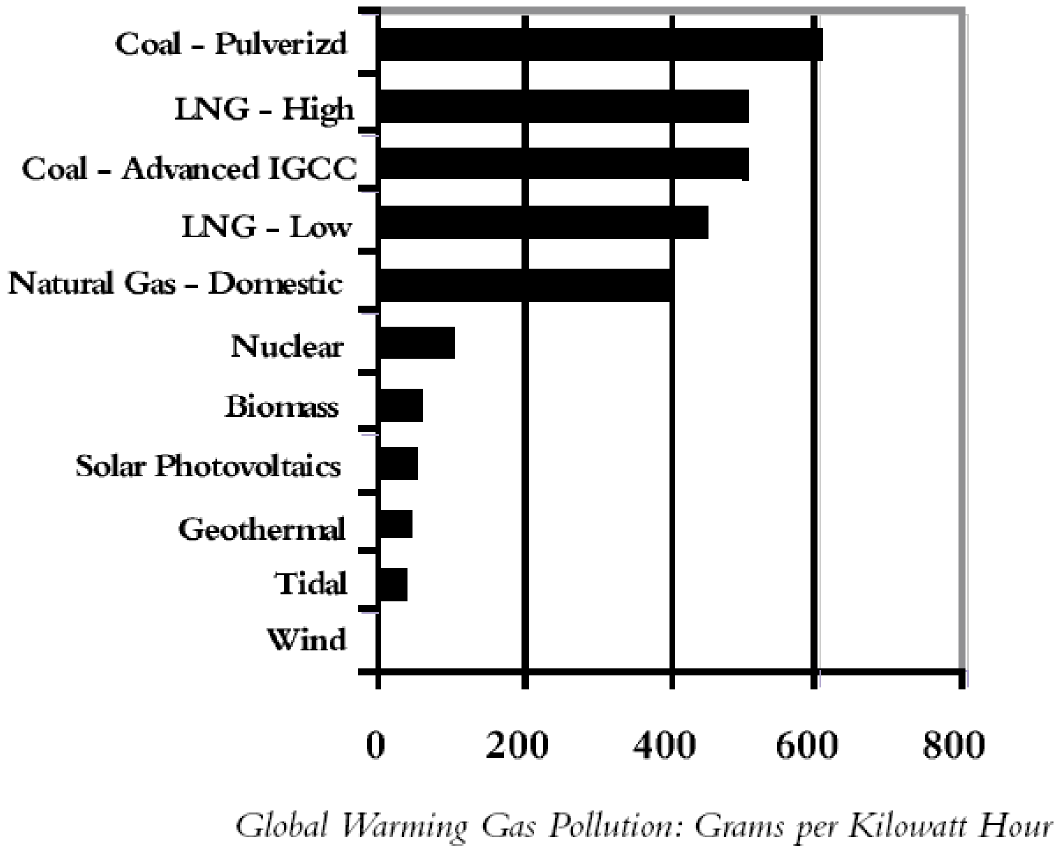


The Carnegie Mellon study reinforced conclusions reached by Richard Heede, who in 2006 analyzed the supply chain of LNG from Australia to a since-rejected terminal located off the coast of Southern California. Heede found that all aspects of the supply chain combined (liquefaction, transport and consumption of LNG) would have resulted in approximately 25 million tons of greenhouse gas emissions per year. About 20 percent of that, or about 5 million tons, would have been from the additional processing and transportation needed for an LNG supply chain. *This is roughly the emissions equivalent of 1 million cars per year for one LNG project, a significant volume of emissions that will not be accounted for if the lifecycle emissions are not considered in the implementation of the new greenhouse gas laws.*

The chart (Figure 2) below illustrates how various energy sources, including renewables, compare on a lifecycle basis. While the CPUC dismisses the task of evaluating all sources of electricity on a lifecycle basis, we believe that the only way to uphold the intent and spirit of AB32 is to do so.

[3] Ibid. Page 9.

Figure 2: Comparison of Lifecycle Greenhouse Gas Emissions in Electricity Production[4]



V. Costa Azul Case Study: An analysis of Sempra's Costa Azul LNG terminal illustrates why the high lifecycle GHG emissions of LNG make it incompatible with the state's Energy Action Plan and AB 32, the Global Warming Solutions Act. As stated in Energy Action Plan II:[5]

Governor Schwarzenegger signed Executive Order S-3-05 on June 1, 2005, clearly establishing California's leadership in and commitment to the fight against climate

[4] Sources include: Jaramillo, Paulina; Griffin, W. Michael ; Matthews, H.Scott. *Comparitive Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG and SNG for Electricity Generation.* Carnegie Mellon University. 2007. Heeded, Richard. *LNG Supply Chain Greenhouse Gas Emissions for the Cabrillo Deepwater Port: Natural Gas from Australia to California.* Climate Mitigation Services. May 7, 2006; Orkustofnon – http://www.os.is/page/english; *IAE Greenhouse Gas R&D Program*; Powers Engineering, June 1, 2004. Global LNG Summit Presentation. Parliamentary Office of Science and Technology Postnote. *Carbon Footprint of Electricity Generation.* October 2006.

[5] CEC/CPUC, *Energy Action Plan II – Implementation Roadmap for Energy Policies*, September 21, 2005, p. 12.

change. The Executive Order establishes greenhouse gas (GHG) emission reduction targets that call for a reduction of GHG emissions to 2000 levels by 2010; to 1990 levels by 2020; and to 80 percent below 1990 levels by 2050.

Climate change is the most serious threat to our environmental future, and demands immediate action. Its symptoms are already evident in California.

AB 32 now mandates the GHG reduction targets established in Executive Order S-3-05 and referenced in Energy Action Plan II.

The CPUC now requires California investor-owned utilities (IOUs) to conduct GHG modeling of long-term procurement plan (LTPP) scenarios. The CPUC issued its final decision on the IOU's 2006 LTPPs in R.06-02-013 on December 20, 2007. The CPUC issued Decision D.07-12-052 by unanimous vote. The primary focus of D.07-12-052 is to determine whether the LTPPs will ensure that the IOUs are "procuring preferred resources as set forth in the Energy Action Plan" and are appropriately responding to "policies that promote the reduction of greenhouse gases, especially in the production and delivery of electric resources by the regulated utilities."[6]

Using Sempra's Costa Azul LNG project as an example, imported LNG carries a GHG burden in that project that is approximately 25 percent greater than domestic natural gas.[7] Sempra will import LNG from British Petroleum's (BP) Tangguh, Indonesia LNG liquefaction plant.[8] The additional GHG burden is related to the high CO_2 content (10 percent) of the Indonesian raw gas that will be removed during gas processing and the energy necessary to: 1) cryogenically liquefy natural gas into LNG, 2) transport the LNG across the Pacific in a specially-designed tankers, and 3) regasify the LNG back to

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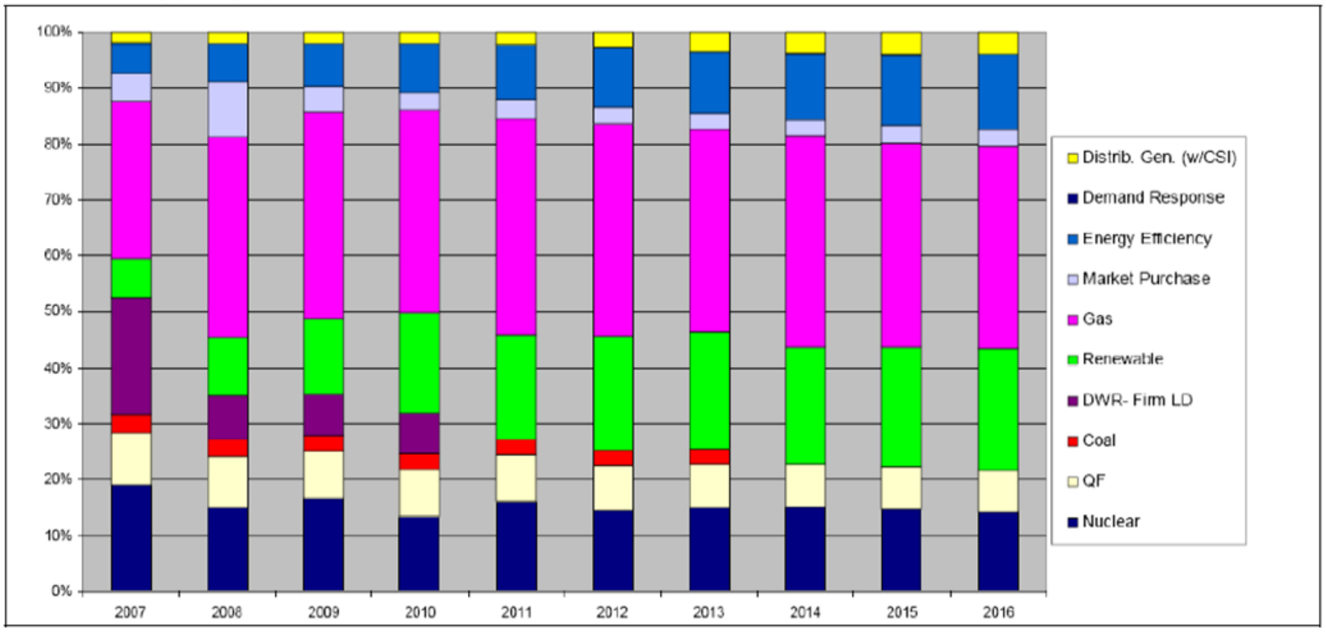
[6] R.06-04-009, Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, *Opening Comments of the Center for Energy Efficiency and Renewable Technologies on E3 Modeling Methodology and Staff Workpaper on Emission Reduction Measures*, January 7, 2008.

[7] P. Jaramillo, Carnegie-Mellon University, *Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, Environmental Science & Technology, published online July 25, 2007, and "Supporting Information" document. All CO2 emission factors listed in this footnote are from the "Supporting Information" document. Assume the LNG is shipped from BP liquefaction plant in Tangguh, Indonesia, 7,500-mile tanker roundtrip to Sempra LNG regasification terminal in Baja California. The raw gas feeding the Tangguh liquefaction plant contains 10 percent CO2 which will be vented to atmosphere at the plant (source: BP Indonesia webpage http://www.bp.com/sectiongenericarticle.do?categoryId=9004748&contentId=7008786). This is equivalent to a CO2 emission rate of 12 lbs CO2 per MMBtu, per the Carnegie-Mellon estimate of 120 lbs CO2 per MMBtu of natural gas combusted. Assume average CO2 generation from liquefaction (14 lb CO2 per MMBtu without considering CO2 content in raw gas). 7,500 miles is the same distance as Oman to the Everett, Massachusetts LNG terminal route cited in report, which generates 8 lb CO2 per MMBtu in transport CO2 emissions. Assume CO2 generation from LNG regasification and storage is low due to use of seawater heating to regasify the LNG (1 lb CO2 per MMBtu). Domestic natural gas emits a maximum of 140 lb CO2 per MMBtu. Total additional CO2 associated with LNG from Tangguh, Indonesia is 35 lb CO2 per MMBtu. Incremental lifecycle CO2 emissions associated with LNG imported from Tangguh are 35 lb CO2 ÷ 140 lb CO2 = 0.25, or a 25 percent increase in lifecycle CO2 emissions.

[8] See Attachment A.

gaseous form at Sempra's receiving terminal in Baja California. All of the power sold by SDG&E in 2016 that produces CO_2 emissions will be generated by power plants burning natural gas. (See Figure 3.)

Figure 3: SDG&E Projection of Power Generation Sources to be Used to Meet Electricity Demand, 2007 – 2016.



Approximately 50 percent of the natural gas sold by SDG&E is used in electric generation plants.[9] The remaining 50 percent is used primarily by commercial and residential customers for space heating, water heating, and cooking and related uses.

Neither the CPUC nor the state's electric or gas utilities are currently forecasting the negative GHG emissions impact of switching from domestic sources of natural gas to LNG imports. However, to be consistent with/to follow state climate change reduction laws and policies, the IOUs and the CPUC must factor in/analyze/compare/consider all GHG emissions caused by changing from domestic natural gas to LNG sources for electricity production, heating, or other IOU natural gas requirements.

For example, SDG&E forecasts a 20 percent reduction in GHG emissions between 2007 and 2016 in its Dec. 11, 2006 LTPP submitted to the CPUC.[10] However, the SDG&E forecast does not account for the GHG impact of the reversal of flow on the SDG&E

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[9] 2006 California Natural Gas Report, SDG&E Tabular Data, pp. 98-100. In 2010, electric generation consumes 175 mmcfd of 333 mmcfd total natural gas demand. In 2015, electric generation consumes 175 mmcfd of 348 mmcfd total demand. All other non-electric power generation combustion sources will consume 173 mmcfd in 2015.

[10] SDG&E 2007-2016 Long-Term Procurement Plan, December 11, 2006, p. 207.

natural gas pipeline system in 2009 to move imported LNG from Sempra's Costa Azul LNG import terminal in Baja California to San Diego.

All of the natural gas consumed in SDG&E territory will become natural gas derived from imported LNG if flow is permanently reversed on the SDG&E pipeline system in 2009. The 1,000 million cubic feet per day (mmcfd) Costa Azul LNG import terminal went on line in April 2008.[11] Sempra has preliminary approval from the CPUC to reverse flow on the SDG&E natural gas pipeline system to move this LNG from the Costa Azul LNG terminal directly into the San Diego market.[12] The CEC forecasts that this flow reversal will occur in 2009.[13,14] The forecast also does not address the cost of reversing flow on the SDG&E pipeline system, which will add at least $200 million in costs to ratepayers to move the gas from the LNG terminal to users north of the U.S.– Mexico border.[15]

The lifecycle GHG emissions from natural gas fired power plants in SDG&E service territory, and those served by the Baja California natural gas pipeline system which is interconnected with the Costa Azul LNG terminal, will increase by approximately 25 percent in 2009. As noted, all GHG emitting power generation sources identified in the 2016 SDG&E forecast are natural gas-fired. Therefore, all CO_2 emissions forecast for 2016 shown in Figure 3 are from natural gas-fired sources. The result of the additional GHG associated with the lifecycle GHG burden of imported LNG will be to increase the SDG&E basecase CO_2 emission estimates for power generation shown in Figure 3 by 25 percent from 2009 forward. See the adjusted CO_2 estimate (red line) in Figure 4. This will nullify the decline in GHG emissions from 2007 to 2016 currently projected by SDG&E.

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[11] Sempra LNG website, Energia Costa Azul – Project Overview. www.sempralng.com

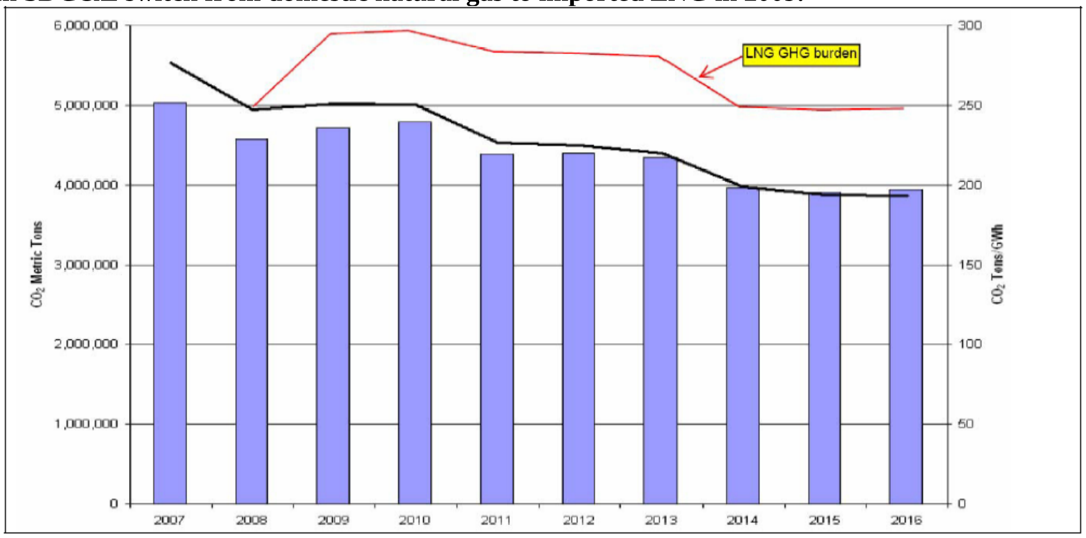
[12] CPUC Decision 04-09-022, *Rulemaking 04-01-025 to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, Phase I, Sept. 2, 2004. Findings of Fact (p. 89): 38. There is potential California customer access to LNG supplies through Otay Mesa, Ehrenberg/Blythe, Oxnard and Long Beach. 39. Designating OtayMesa as a common receipt point for both the SoCalGas and SDG&E systems will send a signal to potential LNG suppliers that the gas they provide will have access to the utilities' systems.

[13] California Energy Commission, *Natural Gas Market Assessment – Preliminary Results*, staff draft report, in support of CEC 2007 Integrated Energy Policy Report, CEC-200-2007-009-SD, May 2007, p. 23. "*Major findings regarding natural gas supply are: Importation of LNG is expected from Mexico into San Diego through the Transportadora De Gas Natural De Baja California (TGN) pipeline beginning in 2009. Gas imported from Costa Azul is projected to grow from zero to more than 1,500 MMcf per day by 2017*."

[14] J. Fore - CEC Natural Gas Unit, *2007 IEPR Natural Gas Forecast – Revised Reference Case*, PowerPoint presentation, August 16, 2007. Graphic on p. 26 shows natural gas from Costa Azul LNG terminal coming northward through Otay Mesa receipt point to San Diego at rate of 350 million cubic feet per day (mmcfd) in beginning in mid-2009. This flowrate is greater than the average daily natural gas demand forecast by SDG&E for 2010 of 333 mmcfd (see footnote 3). The revised August 16, 2007 LNG flow forecast shows LNG imports rising to 400 mmcfd through Otay Mesa in 2016, significantly less than the initial June 2007 reference case forecasting 1,000 mmcfd of LNG imports by 2016 (this case is also shown in the graphic on p. 26 of the PowerPoint).

[15] CPUC Decision 04-09-022, *Rulemaking 04-01-025 to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, Phase I, Sept. 2, 2004.

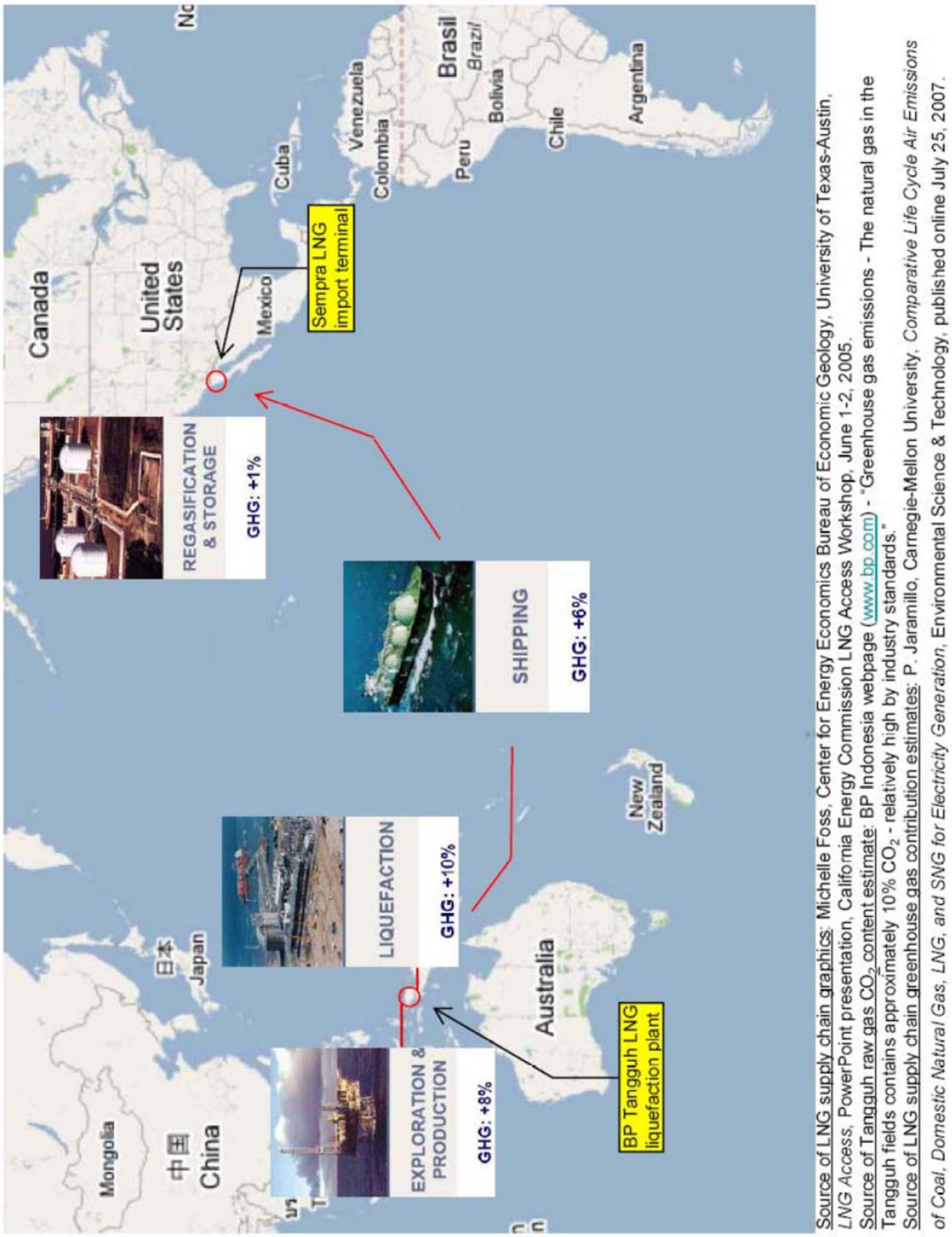
Figure 4. SDG&E projection of greenhouse gas emissions trends, 2007-2016, and Powers Engineering adjustment that reflects the lifecycle CO2 increase (from electric power generation only) resulting from SDG&E switch from domestic natural gas to imported LNG in 2009.



The lifecycle GHG emissions associated with imported LNG will eliminate the GHG reduction benefits of reaching 20 percent renewable energy generation by 2010 as mandated by AB 107. AB 32 requires a return to the 1990 GHG emission level by 2020. This is an estimated GHG reduction of 25 percent by 2020. The post-2020 phase of AB 32 is even more ambitious, targeting an 80 percent reduction in GHG by 2050. It is unlikely that SDG&E can achieve the 2020 AB 32 target if there is no net lifecycle reduction in GHG emissions from natural gas-fired combustion sources in SDG&E service territory in the 2007-2016 timeframe. Thus, the CPUC is willfully allowing the intent and spirit of AB32 to be violated by not accounting for the full emissions impact in electricity generation.

Figure 5 shows a graphic of the route from the liquefaction plant to Sempra's LNG import terminal near Ensenada, Baja California. Figure 4 also shows a breakdown of the 25 percent increase in lifecycle GHG emissions from each stage in the LNG process, from production of raw gas near Tangguh, processing and liquefaction of this gas, transport 7,500 miles to the LNG receiving terminal in Baja California, and regasification of the LNG for pipeline delivery to SDG&E service territory.

Figure 5. LNG versus domestic natural gas: +25% increase in lifecycle greenhouse gas emissions.



VII. Precedents For the Consideration of Lifecycle Emissions – While the CPUC refuses to recognize lifecycle emissions for electricity production in the emissions performance standards for California's new greenhouse gas laws, other agencies in California and Oregon, as well as a utility with an interest in an LNG project have all recognized the impact that the lifecycle emissions that LNG has on the climate, as well as on new laws to curb greenhouse gases.

- AB1007, the Alternative Fuels law signed into law in 2007, is intended to diversify transportation fuel in the state in order to reduce oil dependency and pollution. According to the law, the evaluation of any fuel for transportation must be measured on a lifecycle basis in order to understand the full impact of the fuel. This requirement is explicit in the law.

- In April, 2007, the Cabrillo Port LNG project proposed near Oxnard, California was rejected by both the California State Lands and Coastal Commissions. Among the reasons given by both agencies were the questionable wisdom of such a project in the face of a new, unfolding regulatory regime regarding greenhouse gas emissions. State Lands Commissioner John Chiang, in his rejection statement, said, "We all know that the Governor and the Legislature have enacted statutes to reduce California's carbon footprint and move us away from fossil fuels toward cleaner, renewable alternatives. I do not think this is something that carries out the promise of our new, groundbreaking laws."

- The CPUC is currently considering the nature of contracts between LNG suppliers and utilities. In comments filed at the CPUC on January 24, 2008 in regards to this proceeding, PG&E writes, "PG&E acknowledges that LNG imports raise environmental issues which should be addressed as part of the determination for the need for West Coast LNG supplies. In particular, further review may be necessary to quantify the carbon footprint associated with *liquefaction, transportation, and regasification* and identify strategies that can help mitigate environmental impacts associated with West Coast LNG supplies."[16] We find that, given the amount of research already done, there is no need for further review. However, it is worth noting that this utility, which is a partner in a proposed LNG project in Southern Oregon, explicitly acknowledges LNG's lifecycle emissions, including the LNG stages which add to the emissions over domestic natural gas.

- In May 2008, the Oregon Department of Energy (ODOE) responded to a request by Governor Ted Kulongoski with an assessment of the need and impacts for LNG in Oregon. The ODOE writes, "Liquefied natural gas supplied to Oregon would have significantly more life cycle CO2 costs than North American natural gas, because of the large transportation distances involved in shipping LNG to Oregon and because of the processes used to liquefy and to re-gasify the natural

[16] Posted by Pacific Gas & Electric at http://docs.cpuc.ca.gov/Published/proceedings/R0711001.htm on January 24, 2008.

> gas….It is likely that CO_2 emissions from regasification at an LNG terminal in Oregon would be included in a regional or national cap-and-trade system. This could adversely affect Oregon's ability to meet its CO_2 reduction targets under state law passed in 2007 (House Bill 3543) and under the Western Climate Initiative. It is possible that liquefaction and transport emissions of LNG will be included in future international agreements as well."

Conclusion – AB32 demonstrated that California leads in the fight against global warming. But the CPUC's implementation plan threatens to undermine that effort, and compromise the state's leadership on the issue. The amount of emissions that will not be counted is in the millions of tons, a highly significant amount. As such, we find it absolutely critical that the implementation of AB32 cover all of the emissions generated by electricity production from all fuels, measured on a lifecycle basis.

Comments prepared by:

Rory Cox
California Program Director
Pacific Environment
311 California Street, Suite 650
San Francisco, CA 94104
Ph: 415.399.8850 x302
Email: rcox@pacificenvironment.org

Bill Powers
Chair, Border Power Plant Working Group
4452 Park Blvd., Suite 209
San Diego, California 92116
Ph: 619-295-2072
Email: bpowers@powersengineering.com

Ratepayers for Affordable Clean Energy partners:

- Amazon Watch
- Border Power Plant Working Group
- California Alternative Energies Corporation
- Californians for Renewable Energy - CARE
- Central Coast Alliance United for a Sustainable Economy (CAUSE)
- Center for Biological Diversity
- Citizens Against LNG (Coos Bay)
- Coalition for a Safe Environment
- Energy Options
- Environment California
- Environmental Protection Information Center (EPIC)
- Friends of Living Oregon Waters (FLOW)
- Green Guerrillas Against Greenwash
- Greenpeace

Ratepayers for Affordable Clean Energy

- Local Power
- Long Beach Citizens for Utility Reform
- Marin Clean Alternative Energy Now
- No LNG Community Alliance (Oxnard)
- Northcoast Environmental Center
- Pacific Environment
- Public Citizen
- Renewables 100 Policy Institute
- Rivervision
- Saviers Road Design Team
- Stewards of the Earth
- Texada Action Now
- Vallejo Community Planned Renewal (VCPR)
- Ventura LNG Task Force
- Wildcoast
- Women's Energy Matters