
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission File No. 001-16383

CHENIERE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of incorporation or organization)

700 Milam Street, Suite 800
Houston, Texas
(Address of principal executive offices)

95-4352386
(I.R.S. Employer Identification No.)

77002
(Zip code)

Registrant's telephone number, including area code: **(713) 375-5000**

Securities registered pursuant to Section 12(b) of the Act:

None

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, \$ 0.003 par value
(Title of Class)

American Stock Exchange
(Name of each exchange on which registered)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or smaller company filer. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately \$1,735,000,000 as of June 29, 2007.

48,605,369 shares of the registrant's Common Stock were outstanding as of February 15, 2008.

Documents incorporated by reference: The definitive proxy statement for the registrant's Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant's fiscal year) is incorporated by reference into Part III.

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**CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS**

This annual report contains certain statements that are, or may be deemed to be, “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements, other than statements of historical facts, included herein or incorporated herein by reference are “forward-looking statements.” Included among “forward-looking statements” are, among other things:

- statements relating to the construction and operation of each of our proposed liquefied natural gas (“LNG”) receiving terminals or our proposed natural gas pipelines, or expansions or extensions thereof, including statements concerning the completion or expansion thereof by certain dates or at all, the costs related thereto and certain characteristics, including amounts of regasification and storage capacity, the number of storage tanks and docks, pipeline deliverability and the number of pipeline interconnections, if any;
- statements that we expect to receive an order from the Federal Energy Regulatory Commission (“FERC”) authorizing us to construct and operate proposed LNG receiving terminals or proposed pipelines by certain dates, or at all;
- statements regarding future levels of domestic natural gas production, supply or consumption; future levels of LNG imports into North America; sales of natural gas in North America; and the transportation, other infrastructure or prices related to natural gas, LNG or other energy sources or hydrocarbon products;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions, whether on the part of Cheniere or at the project level;
- statements regarding any terminal use agreement (“TUA”) or other commercial arrangements presently contracted, optioned, marketed or potential arrangements to be performed substantially in the future, including any cash distributions and revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total LNG regasification capacity that are, or may become, subject to TUAs or other contracts;
- statements regarding counterparties to our TUAs, construction contracts and other contracts;
- statements regarding any business strategy, any business plans or any other plans, forecasts, projections or objectives, including potential revenues and capital expenditures, any or all of which are subject to change;
- statements regarding legislative, governmental, regulatory, administrative or other public body actions, requirements, permits, investigations, proceedings or decisions;
- statements regarding our anticipated LNG and natural gas marketing activities; and
- any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as “achieve,” “anticipate,” “believe,” “estimate,” “expect,” “potential,” “forecast,” “plan,” “project,” “propose,” “strategy” and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this annual report.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in “Risk Factors.” All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. These forward-looking statements are made as of the date of this annual report.

DEFINITIONS

In this annual report, unless the context otherwise requires:

- *Bbl* means 42 US gallons of oil or condensate;
- *Bcf* means billion cubic feet;
- *Bcf/d* means billion cubic feet per day;
- *EPC* means engineering, procurement and construction;
- *EPCM* means engineering, procurement, construction and management;
- *IPA* means indexed purchase agreement;
- *LNG* means liquefied natural gas;
- *Mcf* means thousand cubic feet;
- *Mcfe* means Mcf equivalents with barrels of oil or condensate converted to Mcf at 1 barrel = 6 Mcf;
- *MMcf/d* means million cubic feet per day;
- *MMBtu* means million British thermal units; and
- *TUA* means terminal use agreement.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, in the energy business generally. As used in this annual report, the terms “Cheniere”, “we”, “us” and “our” refer to Cheniere Energy, Inc. and its subsidiaries, including our publicly traded subsidiary partnership, Cheniere Energy Partners, L.P. (“Cheniere Partners”). We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals and natural gas pipelines, and we are also developing a business to market LNG and natural gas, primarily through our wholly-owned subsidiary, Cheniere Marketing, Inc. (“Cheniere Marketing”). To a limited extent, we continue to be engaged in oil and natural gas exploration and development activities in the Gulf of Mexico.

Our common stock has been publicly traded since July 3, 1996 and is currently traded on the American Stock Exchange under the symbol “LNG”. Our principal executive offices are located at 700 Milam Street, Suite 800, Houston, Texas 77002, and our telephone number is (713) 375-5000. Our internet address is <http://www.cheniere.com>. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the Securities and Exchange Commission (“SEC”) under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes, nor is it incorporated by reference into this Form 10-K.

Cheniere Energy Partners

In March and April 2007, we and Cheniere Partners completed a public offering of 15,525,000 Cheniere Partners common units. Cheniere Partners received \$98.4 million of net proceeds, after deducting the underwriting discount and structuring fees, upon issuance of 5,054,164 common units to the public in the

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offering. Cheniere Partners invested the \$98.4 million of net proceeds that it received from the offering in U.S. treasury securities to fund a distribution reserve. As part of the offering, we, as a selling unitholder, received \$203.9 million of net proceeds in connection with the sale of 10,470,836 of our Cheniere Partners common units to the public. In connection with the offering and in exchange for Cheniere Partners common and subordinated units, we contributed the equity interests in the entity owning the Sabine Pass LNG receiving terminal to Cheniere Partners. As a result of the offering, our ownership interest in Cheniere Partners is approximately 90.6%.

Business Segments

Our business activities are conducted by four reporting segments for which we provide information in our financial statements for the years ended December 31, 2007, 2006 and 2005 as required under Statement of Financial Accounting Standards (SFAS) No. 131, "*Disclosures about Segments of an Enterprise and Related Information*." These four segments are our:

- LNG receiving terminal business,
- natural gas pipeline business,
- LNG and natural gas marketing business, and
- oil and gas exploration and development business.

Overview of the LNG Industry

LNG is natural gas that, through a refrigeration process, has been reduced to a liquid state, which represents approximately 1/600th of its gaseous volume. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to justify economically the use of LNG. LNG is transported using large oceangoing LNG tankers specifically constructed for this purpose. LNG receiving terminals offload LNG from LNG tankers, store the LNG prior to processing, heat the LNG to return it to a gaseous state and deliver the resulting natural gas into pipelines for transportation to market.

Our Business Strategy

We are pursuing a business strategy with the following primary components:

- complete the development of our Sabine Pass LNG receiving terminal currently under construction in western Cameron Parish, Louisiana on the Sabine Pass Channel with an aggregate designed regasification capacity of approximately 4 Bcf/d;
- complete the development and construction of our two additional LNG receiving terminals, Corpus Christi LNG and Creole Trail LNG, upon, among other things, achieving acceptable commercial arrangements, with an aggregate designed regasification capacity of up to 6 Bcf/d;
- the development and construction of natural gas pipelines and other infrastructure within North America;
- develop an LNG and natural gas marketing business, including: natural gas and LNG trading activities, purchasing LNG on a short- and long-term basis, LNG shipping, natural gas storage, buying and selling domestic natural gas and entering into swaps, futures and physical and financial options in support of our trading and marketing activities;
- pursue other energy business initiatives, including participating in projects that own or are developing foreign natural gas reserves that could be converted into LNG and investing in LNG shipping businesses; and
- engage in limited oil and gas exploration and development activities generally.

On February 25, 2008, we announced that we are evaluating strategic options to enhance shareholder value, including options to optimize the value of the Sabine Pass LNG receiving terminal and the regasification capacity at the facility held under a long-term TUA by Cheniere Marketing.

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LNG Receiving Terminal Business

We began developing our LNG receiving terminal business in 1999 and, since then, have been among the first companies to secure sites and commence development of new LNG receiving terminals in North America. We have focused our development efforts on the following three LNG receiving terminal projects: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. Our ownership interest in the Sabine Pass LNG receiving terminal is held through Cheniere Partners, in which we hold an approximate 90.6% interest. In turn, Cheniere Partners owns a 100% interest in Sabine Pass LNG, L.P. ("Sabine Pass LNG"), which is currently constructing the Sabine Pass LNG receiving terminal. We currently own 100% interests in the both the Corpus Christi and Creole Trail LNG receiving terminal projects. In addition, we own a 30% interest in a fourth LNG receiving terminal project, Freeport LNG, located on Quintana Island near Freeport, Texas.

Sabine Pass LNG Receiving Terminal

Development

We are constructing the Sabine Pass LNG receiving terminal in western Cameron Parish, Louisiana, on the Sabine Pass Channel. In 2003, we formed Sabine Pass LNG to own, develop and operate the Sabine Pass LNG receiving terminal. We have entered into leases for three tracts of land consisting of 853 acres in Cameron Parish, Louisiana for the project site. The Sabine Pass LNG receiving terminal was designed, and permitted by the FERC, with an initial regasification capacity of approximately 2.6 Bcf/d and three LNG storage tanks with an aggregate LNG storage capacity of approximately 10.1 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. In June 2006, Sabine Pass LNG received approval from the FERC to increase the regasification capacity of the Sabine Pass LNG receiving terminal from approximately 2.6 Bcf/d to 4.0 Bcf/d (with peak capacity of 4.3 Bcf/d) and increase the aggregate LNG storage capacity from approximately 10.1 Bcf to 16.8 Bcf by adding up to three additional LNG storage tanks, additional vaporizers and related facilities.

Construction

In March 2005, the FERC issued an order authorizing Sabine Pass LNG to commence construction of the Sabine Pass LNG receiving terminal, subject to certain ongoing conditions. Sabine Pass LNG expects its EPC contractor, Bechtel Corporation, to complete construction and commissioning of the first three tanks, approximately 2.6 Bcf/d of regasification capacity, and associated facilities necessary to achieve initial commercial operations during the second quarter of 2008.

In June 2006, Sabine Pass LNG received authorization from the FERC to commence construction activities for the expansion of the Sabine Pass LNG receiving terminal, subject to certain ongoing conditions. The first stage of the expansion includes the addition of the fourth and fifth LNG storage tanks, and additional regasification capacity of approximately 1.4 Bcf/d. Sabine Pass LNG expects to complete the construction and commissioning of this stage of its expansion during the third quarter of 2009.

We estimate that the aggregate cost to complete construction of the Sabine Pass LNG receiving terminal will be approximately \$1.4 billion, before financing costs. Our cost estimates are subject to change due to such items as cost overruns, change orders, increased component and material costs, escalation of labor costs and increased spending to maintain our construction schedule.

Customers

The entire capacity of approximately 4.0 Bcf/d at the Sabine Pass LNG receiving terminal has been contracted under two 20-year, firm commitment TUAs with third parties, and one with our wholly-owned subsidiary Cheniere Marketing. Each of the customers at the Sabine Pass LNG receiving terminal must make the

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full contracted amount of capacity reservation fee payments under its TUA whether or not it uses any of its reserved capacity. Provided the Sabine Pass LNG receiving terminal has achieved commercial operation, which we expect will occur during the second quarter of 2008, capacity reservation fee TUA payments will be made by the Sabine Pass LNG customers as follows:

- Total LNG USA, Inc. (“Total”) has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$125 million per year for 20 years commencing April 1, 2009. Total, S.A. has guaranteed Total’s obligations under its TUA up to \$2.5 billion, subject to certain exceptions.
- Chevron U.S.A., Inc. (“Chevron”) has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$125 million per year for 20 years commencing not later than July 1, 2009. Chevron Corporation has guaranteed Chevron’s obligations under its TUA up to 80% of the fees payable by Chevron.
- Our wholly-owned subsidiary, Cheniere Marketing, has reserved approximately 2.0 Bcf/d of regasification capacity, and is entitled to use any capacity not utilized by Total and Chevron. Cheniere Marketing has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$250 million per year for at least 19 years commencing January 1, 2009, plus capacity payments of \$5 million per month during an initial commercial operations ramp-up period in 2008. Cheniere has guaranteed Cheniere Marketing’s obligations under its TUA.

Under each of these TUAs, Sabine Pass LNG is also entitled to retain 2% of the LNG delivered for the customer’s account, which Sabine Pass LNG will use primarily as fuel for revaporation and self-generated power at the Sabine Pass LNG receiving terminal.

Each of Total and Chevron has paid us \$20 million in nonrefundable advance capacity reservation fees, which will be amortized over a 10-year period as a reduction of each customer’s regasification capacity fees payable under its TUA.

Corpus Christi LNG Receiving Terminal

We are also developing the Corpus Christi LNG receiving terminal near Corpus Christi, Texas. We formed Corpus Christi LNG, L.P. (“Corpus Christi LNG”) in May 2003 to develop the terminal. The Corpus Christi LNG receiving terminal is located on 612 leased acres and was designed, and permitted by the FERC, with a regasification capacity of approximately 2.6 Bcf/d, three LNG storage tanks with an aggregate LNG storage capacity of approximately 10.1 Bcf and two unloading docks capable of handling the largest LNG carriers currently being operated or built. In December 2005, the FERC issued an order authorizing Corpus Christi LNG to commence initial construction of the Corpus Christi LNG receiving terminal, subject to satisfaction of certain conditions specified by the FERC. In order to accelerate the timing of its development of the Corpus Christi LNG receiving terminal, Corpus Christi LNG commenced in April 2006 preliminary site work, which has since been completed. Engineering and design work on the LNG receiving terminal is ongoing. We will contemplate making a final investment decision to complete construction of the Corpus Christi LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements.

Creole Trail LNG Receiving Terminal

We are also developing an LNG receiving terminal at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. We formed Creole Trail LNG, L.P. (“Creole Trail LNG”) in December 2004 to develop the terminal. We have options to lease tracts of land comprising 1,750 acres in Cameron Parish, Louisiana for the project site. The Creole Trail LNG receiving terminal was designed, and permitted by the FERC, with a regasification capacity of 3.3 Bcf/d, four LNG storage tanks with an aggregate LNG storage capacity of 13.5 Bcf and two unloading docks capable of handling the largest LNG carriers currently being

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operated or built. In June 2006, the FERC authorized Creole Trail LNG to site, construct and operate the Creole Trail LNG receiving terminal. We will contemplate making a final investment decision to commence construction of the Creole Trail LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements.

Other LNG Receiving Terminal Sites

We continue to evaluate, and may develop, additional sites that we believe may be commercially desirable locations for LNG receiving terminals.

Other LNG Receiving Terminal Interests—Freeport LNG

We own a 30% limited partner interest in Freeport LNG Development, L.P. (“Freeport LNG”), which is constructing an LNG receiving facility on Quintana Island near Freeport, Texas. The first phase of the project includes regasification capacity of 1.75 Bcf/d, one dock, two LNG storage tanks with an aggregate LNG storage capacity of 6.7 Bcf, and a 9.4-mile, 42-inch diameter pipeline through which natural gas will be transported to customer redelivery points at Stratton Ridge, Texas. We currently expect that the first phase of the Freeport LNG receiving terminal project will commence operations in the second quarter of 2008. The proposed second phase, which has received FERC approval, includes additional regasification capacity of up to 2.25 Bcf/d, a second dock, and a third LNG storage tank. Freeport LNG is also currently constructing 7.5 Bcf of underground salt cavern storage at Stratton Ridge which is expected to be completed and integrated with the LNG receiving terminal operations in the first quarter of 2011.

Freeport LNG has entered into TUAs with three customers: The Dow Chemical Company for approximately 500 MMcf/d of regasification capacity; ConocoPhillips Company for approximately 900 MMcf/d of regasification capacity; and MC Global Gas Corporation, a wholly owned subsidiary of Mitsubishi Corporation, for approximately 150 MMcf/d of regasification capacity. We believe that Freeport LNG has obtained sufficient financing to fund the first phase of the project and a portion of the proposed second phase; as a result, we do not anticipate that any capital calls will be made upon us as a limited partner in Freeport LNG in the foreseeable future.

LNG Receiving Terminal Competition

New supplies to meet North America’s natural gas demand could be developed from a combination of the following sources:

- existing producing basins in the United States, Canada and Mexico;
- frontier basins in Alaska, northern Canada and offshore deepwater;
- areas currently restricted from exploration and development due to public policies, such as areas in the Rocky Mountains and offshore Atlantic, Pacific and Gulf of Mexico coasts; and
- imported LNG.

In addition, demand for energy currently met by natural gas could alternatively be met by other energy forms such as coal, hydroelectric, oil, wind, solar and nuclear energy. LNG will face competition from each of these energy sources.

We compete with other companies to construct LNG receiving terminals in economically desirable locations. According to the FERC, as of January 14, 2008, there were six existing LNG receiving terminals in North America, including one offshore facility for receiving natural gas regasified from LNG onboard

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specialized LNG vessels, and other new LNG receiving terminals or expansions approved or proposed to be constructed. To the extent that we may desire to sell regasification capacity in our proposed LNG receiving terminals or resell some of our contracted regasification capacity, we will compete with other proposed third-party LNG receiving terminals or existing terminals having uncommitted capacity.

In addition, in connection with obtaining LNG for commissioning of the Sabine Pass LNG receiving terminal, Sabine Pass LNG must compete in the world LNG market to purchase and transport cargoes of LNG. Sabine Pass LNG may purchase and transport such cargoes at costs that may result in losses upon resale of the regasified LNG.

LNG Receiving Terminal Governmental Regulation

Our LNG receiving terminal operations are subject to extensive regulation under federal, state and local statutes, rules, regulations and other laws. Among other matters, these laws require that we engage in consultations with certain federal and state agencies and that we obtain certain permits and other authorizations before commencement of construction and operation of LNG receiving terminals. This regulatory burden increases the cost of constructing and operating the LNG receiving terminals, and failure to comply with such laws could result in substantial penalties.

FERC

In order to site and construct our proposed LNG receiving terminals, we must receive and are required to maintain authorization from the FERC under Section 3 of the Natural Gas Act of 1938 (“NGA”). The FERC permitting process includes:

- initial public notice and public meetings;
- data gathering and analysis at the FERC’s request;
- issuance of a Draft Environmental Impact Statement by the FERC;
- additional public meetings, as warranted;
- issuance of a Final Environmental Impact Statement by the FERC; and
- the FERC order authorizing construction.

In addition, orders from the FERC authorizing construction of an LNG receiving terminal are typically subject to specified conditions that must be satisfied throughout the construction, commissioning and operation of terminals. Those conditions require us to:

- appoint third-party environmental inspectors to monitor compliance with the FERC’s conditions;
- submit any material changes to the design or construction of the facility for FERC approval;
- submit an implementation plan for compliance with the FERC-ordered mitigation measures;
- submit monthly construction reports and weekly environmental reports detailing construction progress and ongoing compliance efforts;
- file plans regarding the installation, implementation and operation of various safety measures and comply with those plans.

In addition, throughout the life of our LNG receiving terminals, they will be subject to regular reporting requirements to the FERC and the Department of Transportation regarding the operation and maintenance of the facilities.

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Other Federal Governmental Permits, Approvals and Consultations

In addition to the FERC authorization under Section 3 of the NGA, our construction and operation of LNG receiving terminals are also subject to additional federal permits, approvals and consultations required by certain other federal agencies, including: Advisory Counsel on Historic Preservation, U.S. Army Corps of Engineers, U.S. Department of Commerce, National Marine Fisheries Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency and U.S. Department of Homeland Security.

Our LNG receiving terminals will also be subject to U.S. Department of Transportation siting requirements and regulations of the U.S. Coast Guard relating to facility security. Moreover, our LNG receiving terminals will also be subject to local and state laws, rules and regulations.

Energy Policy Act of 2005

In 2005, the Energy Policy Act of 2005 (“EPAAct”) was signed into law. The EPAAct gave the FERC exclusive authority to approve or deny an application for the siting, construction, expansion or operation of an LNG receiving terminal. The EPAAct also amended the NGA to prohibit market manipulation and the NGA and the Natural Gas Policy Act of 1978 (“NGPA”) to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of the FERC up to \$1 million per day per violation. The FERC issued a final rule making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC’s jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud.

LNG Receiving Terminal Environmental Regulation

Our LNG receiving terminal operations are subject to various federal, state and local laws and regulations relating to the protection of the environment. In some cases, these laws and regulations require us to obtain governmental permits and authorizations before we may conduct certain activities. These environmental laws and regulations may impose substantial penalties for noncompliance and substantial liabilities for pollution. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial liabilities for non-compliance or for pollution or releases of hazardous substances, materials or compounds or otherwise require additional costs or changes in operations that could have a material adverse effect on our business, results of operations, financial condition and prospects. Failure to comply with these laws and regulations may also result in substantial civil and criminal fines and penalties. As with the industry generally, our operations will entail risks in these areas, and compliance with these laws and regulations increases our overall cost of business. While these laws and regulations affect our capital expenditures and earnings, we believe that these laws and regulations do not affect our competitive position in the industry because our competitors are similarly affected. Environmental laws and regulations have historically been subject to frequent revision and reinterpretation. Consequently, we are unable to predict the future costs or other future impacts of environmental regulations on our future operations.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

CERCLA, also known as the “Superfund” law, imposes liability, without regard to fault, on certain classes of persons who are considered to be responsible for the spill or release of a hazardous substance into the environment. Potentially liable persons include the owner or operator of the site where the release occurred and persons who disposed or arranged for the disposal of hazardous substances at the site. Under CERCLA, responsible persons may be subject to joint and several liability for:

- the costs of cleaning up the hazardous substances that have been released into the environment;
- damages to natural resources; and
- the costs of certain health studies.

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In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances. Although CERCLA currently excludes petroleum, natural gas, natural gas liquids and LNG from its definition of “hazardous substances,” this exemption may be limited or modified by the U.S. Congress in the future.

Clean Air Act (CAA)

Our LNG receiving terminal operations are subject to the federal CAA and comparable state and local laws. We may be required to incur certain capital expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing other air emission-related issues. We do not believe, however, that our operations will be materially adversely affected by any such requirements.

The U.S. Supreme Court has ruled that the Environmental Protection Agency (“EPA”) has authority under existing legislation to regulate carbon dioxide and other heat-trapping gases in mobile source emissions. In addition, Congress is currently considering proposed legislation directed at reducing “greenhouse gas emissions.” It is not possible at this time to predict how future regulations or legislation may address greenhouse gas emissions and impact our business. However, future regulations and laws could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Clean Water Act (CWA)

Our LNG receiving terminal operations are also subject to the federal CWA and analogous state and local laws. Pursuant to certain requirements of the CWA, the EPA has adopted regulations concerning discharges of wastewater and storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under an EPA general permit.

Resource Conservation and Recovery Act (RCRA)

The federal RCRA and comparable state statutes govern the disposal of “hazardous wastes.” In the event any hazardous wastes are generated in connection with our LNG receiving terminal operations, we are subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes.

Endangered Species Act

Our LNG receiving terminal operations and planned construction activities may also be restricted by requirements under the Endangered Species Act, which seeks to ensure that human activities do not jeopardize endangered or threatened animal, fish and plant species nor destroy or modify their critical habitats.

Natural Gas Pipeline Business

We formed Cheniere Pipeline Company, a wholly-owned subsidiary, to develop natural gas pipelines that will provide access to North American natural gas markets for customers of our Sabine Pass and proposed Corpus Christi and Creole Trail LNG receiving terminals. We are also developing other pipeline projects not primarily related to our LNG receiving terminals. Our pipeline systems that are being developed in conjunction with our LNG receiving terminals will interconnect with multiple interstate pipelines, providing a means of delivering revaporized natural gas from our LNG receiving terminals to various North American natural gas markets. Our other projects are market focused, seeking to connect natural gas supplies to growing markets. Our ultimate decisions regarding pipeline connections to our facilities will depend upon future events, including, in particular, customer preferences and general market demand for natural gas from a particular LNG receiving terminal.

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Creole Trail Pipeline

Development

In October 2007, the FERC approved an application to merge our Sabine Pass Pipeline into our Creole Trail Pipeline, thereby creating an integrated pipeline system of approximately 150 miles in length. The Creole Trail Pipeline is being constructed in two phases. Phase 1, which is currently nearing completion of construction, consists of 94 miles of natural gas pipeline connecting with the Sabine Pass LNG receiving terminal and running easterly along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines in southwest Louisiana. Phase 2, once constructed, will consist of approximately 59 miles of natural gas pipeline running from the terminus of Phase 1 east to a terminus near Rayne, Louisiana.

Construction

Construction of Phase 1 of the Creole Trail Pipeline commenced in the second quarter of 2007, and we anticipate that a portion of Phase 1 will be available for operations in the first quarter of 2008, with the remaining portion anticipated to be available for operations in the second quarter of 2008. We will contemplate making a final investment decision to construct Phase 2 of the Creole Trail Pipeline upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements. The total anticipated cost to construct Phase 1 of the Creole Trail Pipeline is approximately \$550 million, before financing costs. Our cost estimates are subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs and escalation of labor costs.

Customers

We offered our Creole Trail Pipeline capacity to potential customers through a formal open season process, and awarded Cheniere Marketing all of the capacity in the Creole Trail Pipeline. Cheniere Marketing has entered into a firm transportation agreement for transportation at a negotiated rate for the transport and sale of revaporized natural gas that it derives from its own imported LNG or LNG that it purchases from other importers for sale into North American markets. See “—LNG and Natural Gas Marketing Business” below. Cheniere Marketing’s capacity rights and obligations under the transportation precedent agreements may be assigned to unaffiliated customers with whom we enter into TUAs for our LNG receiving terminals capacity and who may also desire to enter into agreements for the transportation of revaporized gas on the Creole Trail Pipeline. Furthermore, we expect that other unaffiliated third-party shippers of domestic natural gas may desire transportation services in the Creole Trail Pipeline on at least an interruptible basis.

Corpus Christi Pipeline

We formed Cheniere Corpus Christi Pipeline, L.P., a wholly-owned subsidiary of Cheniere, to develop a 24-mile, 48-inch interstate natural gas pipeline that is designed to transport 2.6 Bcf/d of regasified LNG, from the Corpus Christi LNG receiving terminal northwesterly along a corridor that will allow for interconnection points with various interstate and intrastate natural gas transmission pipelines. The FERC issued an order in April 2005 authorizing us to construct, own and operate the Corpus Christi Pipeline, subject to specified conditions that must be satisfied. We will contemplate making an investment decision to commence construction of the Corpus Christi Pipeline upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements to build the Corpus Christi LNG receiving terminal.

Other Pipelines

We continue to evaluate, and may develop, additional pipelines that we believe may be commercially desirable based on customer preferences and general market demand for natural gas. Currently, we are evaluating the following pipeline projects.

Cheniere Southern Trail Pipeline

Cheniere Partners conducted a non-binding open season to gauge interest from prospective shippers in the proposed Cheniere Southern Trail Pipeline. Negotiations with open season respondents are ongoing. As currently

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contemplated, the Cheniere Southern Trail Pipeline would involve the construction of approximately 350 miles of up to 42-inch diameter pipeline that is currently estimated to cost approximately \$1.5 billion, before financing costs. We will contemplate making a final investment decision to commence construction of the Cheniere Southern Trail Pipeline upon, among other things, entering into acceptable commercial arrangements, receiving FERC authorization to construct and operate the pipeline and obtaining adequate financing to construct the Cheniere Southern Trail Pipeline.

Frontera Pipeline

In September 2007, we entered into an equity purchase agreement with Tidelands Oil & Gas Corporation and acquired an 80% interest in Frontera Pipeline, LLC, an entity which owns 100% of Sonora Pipeline and Terranova Energia, and which together are developing the Burgos Hub Project. The Burgos Hub Project is a proposed integrated pipeline project traversing the United States and Mexico border and the potential construction of a related underground natural gas storage facility in Mexico. The aggregate cost to construct the project is currently estimated to be approximately \$700 million to \$800 million, before financing costs. Our cost estimate is subject to change due to such items as cost overruns, change orders, delays in construction, increased component and material costs, escalation of labor costs and increased spending to maintain our construction schedule. We will contemplate making a final investment decision in the Burgos Hub Project upon, among other things, receiving all required authorizations to construct and operate the pipeline and storage facility, arranging appropriate financing and entering into acceptable commercial arrangements for the pipeline and storage facility.

Natural Gas Pipeline Competition

Our proposed pipelines will compete with intrastate and other interstate pipelines throughout our service territory. The principal elements of competition among pipelines are rates, terms of service, access to supply and flexibility and reliability of service. In addition, the FERC's continuing efforts to increase competition in the natural gas industry are increasing the natural gas transportation options of a pipeline's traditional customers.

Our pipelines will face competition from other intrastate and/or interstate pipelines that connect with our LNG receiving terminals. In particular, our Creole Trail Pipeline will compete with the proposed Kinder Morgan Louisiana Pipeline owned by Kinder Morgan Energy Partners, L.P. ("Kinder Morgan"). Kinder Morgan has announced that it is building a 3.2 Bcf/d take-away pipeline system from the Sabine Pass LNG receiving terminal. Total and Chevron have both announced agreements with Kinder Morgan securing 100% of the initial capacity on the Kinder Morgan Louisiana Pipeline for 20 years.

Natural Gas Pipeline Governmental Regulation

Interstate Natural Gas Pipelines

Under the NGA, the FERC is granted authority to set "just and reasonable rates" for the transmission or sale of natural gas in interstate commerce. It also gives FERC the authority to grant certificates allowing construction and operation of facilities used in interstate gas transmission and authorizing the provision of services. Under the FERC's regulations, their jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale. However, FERC's jurisdiction does not extend to the production, gathering, or local distribution of natural gas.

In general, the FERC's authority to regulate interstate natural gas pipelines and the services that they provide includes:

- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;

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- the extension and abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

Failure to comply with the NGA can result in the imposition of administrative, civil and criminal remedies, including civil and criminal penalties which were recently increased under the EPCRA.

The natural gas industry historically has been regulated since 1938. Among other things, the FERC regulates the transportation rates and terms and conditions of service of interstate natural gas pipelines. See “—Rates” below. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines; however, the FERC may or may not continue this approach in the future.

We have received authorization from the FERC to provide firm and interruptible transportation services, as well as parking and lending services, for our pipelines based on cost of service rates. Beginning in the mid-1980s, the FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985), which requires open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988), which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction;
- Order No. 636 (1992), which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to “unbundle” or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies whether purchased from the pipeline or from other merchants such as marketers or producers. Order No. 636 also permitted pipeline customers to release all or part of their firm transportation capacity to third parties. Order No. 636 has been affirmed in all material respects upon judicial review; and
- Order No. 637 (2000), which, among other things, required pipelines to implement imbalance management services; restricted the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and implemented new pipeline reporting requirements.

In November 2003, the FERC issued a series of orders adopting revised Standards of Conduct (Order No. 2004) that apply uniformly to interstate natural gas pipelines. These Standards of Conduct were designed to govern relationships between the pipeline and any energy affiliate, rather than governing conduct between the pipeline and its marketing affiliate. However, in 2006, Order No. 2004, as applied to natural gas pipelines, was vacated by a federal court, and the FERC issued an interim rule which expressly states that the Standards of Conduct do not govern the relationship between natural gas pipelines and our marketing employees. We have established the required policies and procedures to comply with the Standards of Conduct, and are subject to audit by the FERC to review compliance, policies and our training programs.

Our pipelines that interconnect with our LNG receiving terminals will be interstate natural gas pipelines requiring us to obtain authorization from the FERC pursuant to Section 7 of the NGA to construct and operate these pipeline facilities. The rates that we charge will be subject to the FERC’s regulation under Section 4 of the NGA. Our interstate pipelines will also be subject to the FERC’s open access requirements and the FERC’s Standards of Conduct as discussed above. The FERC’s exercise of jurisdiction over interstate natural gas pipelines is substantially broader than its exercise of jurisdiction over LNG receiving terminals.

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Natural Gas Pipeline Safety

Louisiana and Texas administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal remedies.

The Pipeline Safety Improvement Act of 2002 (“PSIA”), which is administered by the U.S. Department of Transportation Office of Pipeline Safety, governs the areas of testing, education, training and communication. The PSIA requires pipeline companies to perform extensive integrity tests on natural gas transmission pipelines that exist in high population density areas designated as “high consequence areas.” Pipeline companies are required to perform the integrity tests on a seven-year cycle. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. In December 2003, the Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs for gas transportation pipelines. The final rule requires pipeline operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline, as necessary; and implement preventive and mitigation actions. This rule incorporates the requirements of the PSIA.

Energy Policy Act of 2005

The EPA Act contains numerous provisions relevant to the natural gas industry and to interstate pipelines. See “—LNG Receiving Terminal Business Governmental Regulation—Energy Policy Act of 2005.”

Rates

Under the NGA, rates charged for the interstate transportation of natural gas must be just and reasonable and not unduly discriminatory or preferential. Amounts collected by the pipeline that the FERC finds unlawful are subject to refund with interest.

Natural Gas Pipeline Environmental Regulation

Our natural gas pipeline business is subject to the same federal, state and local laws and regulations relating to the protection of the environment that are applicable to our LNG receiving terminals. See “—LNG Receiving Terminal Business—LNG Receiving Terminal Environmental Regulation” above.

LNG and Natural Gas Marketing Business

Our wholly-owned subsidiary, Cheniere Marketing, is developing a natural gas and LNG marketing and trading business. Its principal asset is a TUA at the Sabine Pass LNG receiving terminal. We intend to build a portfolio of long-term and short-term and spot LNG purchase agreements from foreign suppliers, pursuant to which LNG will be delivered to either our LNG receiving terminals or other terminals with whom we will trade on the supplier’s vessels, or on vessels that we contract for our own use. In order to facilitate the importation of LNG into the U.S., we are also developing a portfolio of downstream natural gas sales agreements with major local distribution companies, power generators, industrial users and other gas marketing firms. We will also purchase domestic natural gas to satisfy our sales commitments during times that we elect to divert contracted supplies away from the U.S., or during times that we are not able to obtain LNG supplies.

In the course of engaging in the foregoing commercial activities, Cheniere Marketing has entered into, and will in the future enter into, various commercial transactions. These transactions include natural gas purchases

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and sales and options on natural gas purchases and sales, generally using master contracts promulgated by the North American Energy Standards Board (“NAESB contracts”) or the International Swap Dealers Association (“ISDA contracts”); short- and long-term natural gas transportation contracts with various domestic transporters, including firm, interruptible, capacity release and “parking and loan” agreements; short- and long-term natural gas storage agreements; natural gas processing agreements; financial derivatives agreements, generally using ISDA contracts; and futures and options on futures cleared on the NYMEX exchange through our brokerage agreements. Our marketing activities may also include the use of derivative transactions in order to take market positions or manage and hedge exposure to price, volume, timing, location, quality and credit risk associated with the marketing of LNG and natural gas. We have developed risk management policies, procedures and systems, which are reviewed regularly, to assist us in controlling and managing our marketing activities.

As a result of our acquisition of the remaining equity interest in J & S Cheniere S.A. (“J & S Cheniere”), we have acquired a 100% interest in time charter agreements for two LNG vessels. We plan to utilize these LNG tankers to transport LNG from foreign suppliers or merchants to LNG receiving terminals in the U.S. or to international markets if more favorable economic conditions exist in those markets.

LNG and Natural Gas Marketing Competition

Our LNG purchase efforts compete for supplies of LNG with:

- large, multinational and national companies with longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources; and
- oil and gas producers who sell or control LNG derived from their international oil and gas properties.

Additionally, we compete for supplies against purchasers located in other countries, in which prevailing market prices can be substantially different, and frequently higher, than those in the U.S.

Our natural gas marketing efforts compete for sales of natural gas with a variety of competitors including:

- major integrated marketers who have large amounts of capital to support their marketing operations and offer a full-range of services and market numerous products other than natural gas;
- producer marketers who sell their own natural gas production or the production of their affiliated natural gas production company;
- small geographically focused marketers who focus on marketing natural gas for the geographic area in which their affiliated distributor operates; and
- aggregators who gather small volumes of natural gas from various sources, combine them and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately.

LNG and Natural Gas Marketing Governmental Regulation

In 1992 and 1993, the FERC concluded that sellers of short-term or long-term natural gas supplies would not have market power over the sale for resale of natural gas. The FERC established light-handed regulation over sales for resale of natural gas and adopted regulations granting blanket certificates to allow entities selling natural gas to make interstate sales for resale at negotiated rates. In 2003, the FERC amended the blanket marketing certificates to require that all sellers adhere to a code of conduct with respect to natural gas sales. The code of conduct addresses such matters as natural gas withholding, manipulation of market prices, communication of accurate information and record retention.

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The EPCRA contains provisions intended to prohibit the manipulation of the natural gas markets and is applicable to our marketing business as well. See “—LNG Receiving Terminal Business Governmental Regulation—Energy Policy Act of 2005.”

The prices at which we will sell natural gas are not regulated, insofar as the interstate market is concerned and, for the most part, are not subject to state regulation. We are permitted to domestically make sales of natural gas for resale in interstate commerce pursuant to a blanket marketing certificate automatically granted by the FERC. Our sales of natural gas will be affected by the availability, terms and cost of pipeline transportation. As noted above, under “—Natural Gas Pipeline Business—Natural Gas Pipeline Governmental Regulation,” the price and terms of access to pipeline transportation are subject to extensive federal and state regulation.

Oil and Gas Exploration and Development Business

Although our focus is primarily on development of LNG-related businesses, we continue to be involved to a limited extent in oil and gas exploration, development and exploitation. Our historical oil and gas exploration activities have existed through active interpretation of our seismic data and generation of prospects, through participation in the drilling of wells, and through farm-out arrangements and back-in interests (see below) whereby the capital costs of such activities are borne primarily by industry partners. Our current oil and gas exploration and development activities have been focused on two areas: the Cameron Project, which covers an area of approximately 230 square miles extending roughly three to five miles on either side of the westernmost 28 miles of Louisiana coastline; and the Offshore Texas Project Area, which covers approximately 6,800 square miles in the shallow waters offshore Texas and the West Cameron Area of offshore Louisiana.

Oil and Gas Exploration and Development Prospects

Our exploration team generated, captured, sold or caused to be drilled 11 prospects during 2005, 2006 and 2007. We retained interests in the form of working interests, overriding royalty interests (a share of the hydrocarbons produced from an oil and gas property, free of the expense of production) and back-in working interests (an agreement whereby we retain a reversion right to a working interest in a well at payout but bear none of the cost of drilling the initial well). Our overriding royalty interests ranged from 0.63% up to 5.0%, and back-in working interests ranged from 15.0% up to 20.0%. We also participated in the drilling of wells with cost-bearing working interests of 5.0% up to 25.0%. In the wells where we participated with a cost-bearing working interest, we also retained an overriding royalty interest prior to payout and a back-in working interest after payout. All 11 of the above-mentioned prospects were drilled by our industry partners.

Oil and Gas Exploration and Development Drilling Activities

During 2005, we participated directly in the drilling of two wells; in 2006, we participated directly in the drilling of four wells; and in 2007, we did not participate directly in the drilling of any wells. Our industry partners drilled three wells, seven wells and one well in 2005, 2006 and 2007, respectively, on prospects that we generated. During 2005, one well was a discovery; during 2006, five wells were discoveries and during 2007, one well was a discovery. For the discoveries drilled in the years 2005 through 2007, four of the wells were producing, one was awaiting development and two were deemed temporarily abandoned.

At December 31, 2007, we had working interests of 5.0% to 25.0% in three wells and overriding royalty interests (ranging from 0.63% to 5.0%) in eighteen other wells. Of the 21 wells in which we had an interest as of December 31, 2007, eleven were productive, one was awaiting development, two were deemed non-commercial, and seven were shut in waiting for plugging and abandonment. All seven of the wells waiting for plugging were wells in which we had only an overriding royalty interest and therefore, we have no liability for abandonment costs.

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Oil and Gas Exploration and Development Production and Sales

The following table presents certain information with respect to our oil and natural gas production, average sales prices received and average production costs during 2005, 2006 and 2007.

	Year Ended December 31,		
	2007	2006	2005
Production:			
Oil (Bbl)	8,908	3,295	2,167
Gas (Mcf)	609,714	319,112	396,284
Gas equivalents (Mcf)	663,162	338,882	409,286
Average sales prices:			
Oil (per Bbl)	\$ 70.38	\$ 61.97	\$ 48.64
Gas (per Mcf)	\$ 7.79	\$ 6.60	\$ 7.32
Selected data per Mcfe:			
Average sales price	\$ 8.11	\$ 6.82	\$ 7.34
Production costs	\$ 0.54	\$ 0.70	\$ 0.58
Oil and gas depreciation, depletion and amortization excluding impairments (1)	\$ 1.11	\$ 0.61	\$ 0.09

- (1) Amounts reported for the year ended December 31, 2005 have been adjusted to reflect the change in our method of accounting for investments in oil and gas properties from the full cost method to the successful efforts method.

Oil and Gas Exploration and Development Acreage

The following table sets forth certain information with respect to our developed and undeveloped leased acreage as of December 31, 2007.

	Developed Acres		Undeveloped Acres (1)	
	Gross	Net	Gross	Net
Texas	960	240	40,320	12,096
Total	960	240	40,320	12,096

- (1) We have 6,048 net lease acres expiring in 2008.

Oil and Gas Reserves

All of the information herein regarding estimates of our proved reserves, related future net revenues and PV-10 as of December 31, 2007 is taken from the report generated by Sharp Petroleum Engineering, Inc., an independent petroleum engineer, in accordance with the rules and regulations of the SEC. The independent engineer's estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data that we provided.

	December 31, 2007 Proved Reserves			
	Oil (Bbl)	Gas (Mcf)	Mcf	PV-10 (1)
Offshore Texas	7,251	1,117,514	1,161,020	\$ 4,306,119
Offshore Louisiana	1,618	142,419	152,127	\$ 855,418
Proved Reserves	8,869	1,259,933	1,313,147	\$ 5,161,537
Proved Developed Reserves	8,869	1,259,933	1,313,147	\$ 5,161,537

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- (1) The PV-10 amount (present value of estimated pre-tax future net revenues discounted at 10%) is calculated using year-end prices of \$92.63 per barrel of oil and \$6.215 per Mcf of gas.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and future amounts and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, geologic success and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, our reserves may be subject to downward or upward revision based upon production history, purchases or sales of properties, results of future development, prevailing oil and gas prices and other factors. Therefore, the present value shown above should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties.

In accordance with SEC guidelines, the estimates of future net revenues from our proved reserves and the present value thereof are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. We may receive amounts different than the estimates for a number of reasons, including changes in prices. See Supplemental Information to Consolidated Financial Statements. Estimates of our proved oil and gas reserves were not filed with or included in reports to any other federal authority or agency other than the SEC during the fiscal year ended December 31, 2007.

Oil and Gas Exploration and Development Experience

We have built a technical and management team that is experienced in the Gulf of Mexico and in various technical specialties required for our exploration program. The technical staff averages over 30 years of experience exploring for oil and gas in the Gulf Coast. We believe that this experienced team allows us to be very productive in the generation and acquisition of prospects.

Oil and Gas Exploration and Development Competition and Markets

The availability of a ready market for and the price of any hydrocarbons that we produce will depend on many factors beyond our control, including:

- the extent of domestic production and imports of foreign oil;
- the marketing of competitive fuels, the proximity and capacity of natural gas pipelines;
- the availability of transportation and other market facilities;
- the demand for hydrocarbons;
- the political conditions in international oil-producing regions;
- the effect of federal and state regulation of allowable rates of production;
- taxation; and
- the conduct of drilling operations and federal regulation of natural gas.

In addition, the restructuring of the natural gas pipeline industry has eliminated the gas purchasing activity of traditional interstate gas transmission pipeline buyers. Producers of natural gas, therefore, have been required to develop new markets among gas marketing companies, end-users of natural gas and local distribution companies. All of these factors, together with economic factors in the marketing area, generally may affect the supply and/or demand for oil and gas and thus the prices available for sales of oil and gas.

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Competition in the industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. We compete with independent producers of varying sizes, all of which are engaged in the exploration, development and acquisition of producing and non-producing properties.

Oil and Gas Exploration and Development Governmental Regulation

Our oil and gas exploration, development and related operations are subject to extensive federal, state and local statutes, rules, regulations and other laws. Failure to comply with such laws can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability.

MMS Regulations

We conduct certain activities on federal oil and gas leases which the Minerals Management Service (“MMS”), administers. The MMS grants leases through competitive bidding. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to The Outer Continental Shelf Lands Act (“OCSLA”). For example, for offshore operations, we must comply with the following MMS requirements:

- obtain MMS approval of exploration plans prior to the commencement of exploration operations;
- obtain MMS approval of development and production plans prior to the commencement of such operations;
- obtain an MMS permit prior to the commencement of drilling (in addition to permits which may be required from other agencies, such as the Coast Guard, the Army Corps of Engineers and the EPA);
- comply with stringent MMS engineering and construction specifications applicable to offshore production facilities located on the Outer Continental Shelf (“OCS”);
- comply with MMS prohibitions or restrictions on the flaring or venting of natural gas, liquid hydrocarbons and oil; and
- comply with MMS regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities.

Bonding and Financial Responsibility Requirements

In connection with our ownership or operation of oil and gas leases, we are required by governmental agencies, including the MMS, to obtain bonding or otherwise demonstrate financial responsibility at varying levels. These bonds may cover such obligations as plugging and abandonment of wells, removal and closure of related exploration and production facilities, and pollution liabilities. The costs of such bonding and financial responsibility requirements can be substantial, and we may not be able to obtain such bonds and/or otherwise demonstrate financial responsibility in all cases.

Regulation of Production

Our oil and gas production operations are subject to state conservation laws and regulations, including:

- laws relating to the unitization or pooling of oil and gas properties;
- laws establishing the maximum rates of production from wells;
- laws regulating the spacing of wells;
- laws regulating the plugging and abandonment of wells; and
- laws which otherwise regulate the operation of, and production from, both oil and gas wells.

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Such laws may restrict the rate at which the wells in which we have an interest may produce oil or gas, with the result that the amount or timing of our revenues could be adversely affected.

Oil and Gas Exploration and Development Environmental Regulation

Our oil and gas exploration, development and related operations are subject to the same federal, state and local laws and regulations relating to the protection of the environment that are applicable to our LNG operations. See “—LNG Receiving Terminal Business Environmental Regulation” above. In addition, our oil and gas exploration, development and related operations are subject to the following regulations.

The disposal of wastes containing Naturally Occurring Radioactive Material, which are commonly generated during oil and gas production, is regulated under state law. Typically, wastes containing naturally occurring radioactive material can be managed on site or disposed of at facilities licensed to receive such waste at costs that are not expected to be material.

The federal Oil Pollution Act of 1990 (“OPA”) requires owners and operators of facilities that could be the source of an oil spill into waters of the U.S. (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any such oil spill. OPA also requires affected facility owners and operators to demonstrate that they have at least \$35 million in financial resources to pay the costs of cleaning up an oil spill and to compensate any parties damaged by an oil spill. Such financial assurances may be increased to as much as \$150 million if a formal assessment indicates such an increase is warranted.

Financial Information about Segments

During the last three fiscal years, substantially all of our revenues have resulted from our oil and gas exploration and development activities. For information about our segments’ revenues, profits and losses and total assets, see Note 26—“Business Segment Information” of our Notes to Consolidated Financial Statements.

Subsidiaries

Our assets are generally held by or under our operating subsidiaries. We conduct most of our operations through these subsidiaries, including our operations relating to the development of our LNG receiving terminal business, the development of our pipeline business and our marketing business.

Employees

We had 378 full-time employees as of February 15, 2008.

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ITEM 1A. RISK FACTORS

The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, results of operation, financial condition and prospects.

Risks Relating to Our Financial Matters

We have not been profitable historically, and we are currently experiencing negative operating cash flow. Our ability to achieve profitability and generate positive operating cash flow in the future is subject to significant uncertainty.

From our inception, we have generally incurred operating losses, and we will likely continue to incur operating losses and experience negative operating cash flow through at least 2008. We have incurred, and continue to incur, significant capital and operating expenditures while we develop our planned LNG receiving terminals and pipelines. Although we plan to commence commercial operations of the Sabine Pass LNG receiving terminal during 2008, we do not expect to generate positive operating cash flow from our LNG receiving terminal segment until 2009 at the earliest. Our current oil and gas exploration activities, which are limited in scope, will not generate sufficient funds to cover our 2008 expenditures.

Any delays beyond the expected development periods for our planned LNG receiving terminals or pipelines would prolong, and could increase the level of, our operating losses and negative operating cash flow. Our future liquidity may also be affected by the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and by the anticipated timing of receipt of cash flow under TUAs and other sales of capacity in relation to the incurrence of projected project operating expenses. However, many factors (including factors beyond our control) could result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements. Our ability to generate positive operating cash flow and achieve profitability in the future is dependent on our ability to successfully complete our Sabine Pass LNG receiving terminal and other development projects as well as our ability to commercially exploit Cheniere Marketing's reserved capacity at the Sabine Pass LNG receiving terminal. Our ability to accomplish these objectives is subject to a number of risks, including those discussed below.

Our ability to develop our planned LNG receiving terminals and pipelines is contingent on our ability to obtain funding. If we are unable to do so, we may be unable to implement or complete our business plan, and our business may ultimately be unsuccessful.

As of December 31, 2007, we had \$296.5 million in cash and cash equivalents and \$770.2 million in restricted cash and cash equivalents and treasury securities, including \$420.4 million in restricted cash to be used to complete construction of the Sabine Pass LNG receiving terminal. We will need substantially more financing to complete all of our proposed LNG receiving terminals and natural gas pipelines. In addition, the continued development of our marketing business will require significant credit support and funding. To fund these development projects, we plan to pursue a variety of sources of funding, including some or all of the following:

- debt and/or equity financing at the project level;
- debt and/or equity financing by Cheniere or its subsidiaries; and
- asset sales, to the extent permitted, and joint venture arrangements by Cheniere and/or its subsidiaries.

Our ability to obtain these or other types of financing will depend, in part, on factors beyond our control, such as the status of various debt and equity markets at the time financing is sought and such markets' view of our industry and prospects at such time. In particular, currently tight lending conditions in the U.S. credit markets

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may make it more time consuming and expensive for us to obtain financing, if we can obtain financing at all. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all, even if our development projects are otherwise proceeding on schedule. In addition, our ability to obtain some types of financing may be dependent upon our ability to obtain other types of financing. For example, project-level debt financing is typically contingent upon a significant equity capital contribution from the project sponsor. As a result, even if we are able to identify potential project-level lenders, we may still have to obtain another form of external financing for us to fund an equity capital contribution to the project subsidiary. Any project-level debt financing would likely be conditioned upon our prior receipt of commitments for a portion of projected regasification capacity under long-term TUAs, as well as our achievement of additional milestones. A failure to obtain financing at any point in the development process of any of our projects could cause us to delay or fail to complete our business plan, which could cause our business to be unsuccessful.

Even if we are able to obtain financing, the terms required may adversely affect our business.

In order to obtain many types of financing, we may have to accept terms that are disadvantageous to us or that may have an adverse impact on our current or future business, operations or financial condition. For example:

- borrowings or debt issuances may subject us to certain restrictive covenants, including covenants restricting our ability to raise additional capital or cross-defaults to our other indebtedness;
- borrowings or debt issuances at the project level may subject the project entity to restrictive covenants, including covenants restricting its ability to make distributions to us or limiting our ability to sell our interests in such entity;
- additional sales of interests in our LNG projects would reduce our interest in future revenues once the LNG receiving terminals commence operations;
- the prepayment of terminal use fees by, or a business development loan from, prospective customers would reduce future revenues once the LNG receiving terminals commence operations;
- offerings of our equity securities would cause dilution for holders of our common stock;
- our ability to borrow funds under some project financing arrangements will likely be subject to our satisfying the conditions and covenants in the financing and the construction schedule agreed to at the time we enter into such arrangement. If circumstances change, we may need to seek waivers of conditions or covenants under our financing arrangements to prevent defaults thereunder and acceleration thereof, which we might not be able to obtain on a timely basis, or at all; and
- we may be required to make equity contributions before we can borrow under certain financing arrangements.

Our substantial indebtedness could adversely affect our ability to operate our business.

As of December 31, 2007, we had approximately \$2.8 billion of indebtedness. Our substantial indebtedness could have important consequences, including:

- limiting our ability to obtain additional financing to fund our capital expenditures, working capital, acquisitions, debt service requirements or liquidity needs for general business or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service debt, including indebtedness that we may incur in the future;
- limiting our ability to compete with other companies who are not as highly leveraged;
- limiting our ability to react to changing market conditions in our industry and in our customers' industries and to economic downturns;
- limiting our flexibility in planning for, or reacting to, changes in our business and future business opportunities;

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- making us more vulnerable than a less leveraged company to a downturn in our business or in the economy;
- limiting our ability to attract customers; and
- resulting in a material adverse effect on our business, results of operations and financial condition if we are unable to service our indebtedness or obtain additional financing, as needed.

Our substantial indebtedness and the restrictive covenants contained in our debt agreements may not allow us the flexibility that we need to operate our business in an effective and efficient manner and may prevent us from taking advantage of strategic and financial opportunities that would benefit our business.

Our ability to satisfy our obligations will depend upon our future operating performance. Prevailing economic conditions and financial, business and other factors, many of which are beyond our control, will affect our ability to make payments on our debt obligations. If we are not able to generate sufficient cash from operations to meet our other obligations, we may need to refinance all or a portion of our indebtedness on or before maturity. We may not be able to refinance any of our indebtedness on commercially reasonable terms or at all.

We may experience cost overruns and delays in the completion of our Sabine Pass and other proposed LNG receiving terminals and pipelines as well as difficulties in obtaining funding for any additional costs, which could have a material adverse effect on our financial condition and results of operations.

Our construction costs for Sabine Pass and/or other proposed LNG receiving terminals and pipelines may be significantly higher than our current estimates as a result of cost overruns, change orders under existing or future construction contracts, increased component and material costs, escalating labor costs, limited availability of labor, delays in construction and increased spending to maintain construction schedules. As of February 14, 2008, change orders for \$172.7 million had been approved under the EPC agreements with Bechtel and other contractors for the Sabine Pass LNG receiving terminal. We have limited experience constructing LNG receiving terminals.

Furthermore, in order to cover increased construction costs we may need to obtain additional funding. If we fail to obtain sufficient funding, our business plan could fail. Our ability to obtain debt or equity financing that may be needed to provide additional funding to cover increased construction costs will depend, in part, on factors beyond our control, such as the status of various capital and industry markets at the time financing is sought. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have a material adverse effect on our current or future business, results of operations, financial condition and prospects.

Our existing level of cash resources, negative cash flow and limited ability to obtain additional financing could cause us to defer or limit development of our business.

We are dependent upon our existing cash resources, and the availability of additional debt or equity financing, in order to fund our negative operating cash flow and to provide the capital required for the continued development of our business. Prevailing economic and market conditions, as well as other factors, may adversely affect the availability and cost of additional financing, which could require us to defer or limit expenditures we would otherwise make in developing our business. Such deferrals or limitations in the development of our business could be significant and could adversely affect our ability to pursue our business strategy, which in turn could adversely affect our results of operations, financial condition and business prospects.

Risks Relating to Our LNG Receiving Terminal Business

Our inability to timely construct and commission our LNG receiving terminals would prevent us from commencing operations when anticipated and would delay or prevent us from realizing anticipated cash flows.

We are currently constructing the Sabine Pass LNG receiving terminal. We may not complete the Sabine Pass LNG receiving terminal, and our other LNG receiving terminals, in a timely manner, or at all, due to numerous factors, some of which are beyond our control. Factors that could adversely affect our planned completion include:

- failure by Bechtel or the other contractors to fulfill their obligations under their construction contracts, or disagreements with them over their contractual obligations;
- our failure to enter into satisfactory additional agreements with contractors for construction of any portion of any LNG receiving terminal;
- shortages of materials or delays in delivery of materials;
- cost overruns and difficulty in obtaining sufficient debt or equity financing to pay for such additional costs;
- difficulties or delays in obtaining LNG for commissioning activities necessary to achieve commercial operability of the LNG receiving terminals;
- cost overruns due to difficulties or delays in obtaining LNG for commissioning our LNG receiving terminals at acceptable cost;
- failure to obtain and retain all necessary governmental and third-party permits, licenses and approvals for the construction and operation of the LNG receiving terminals;
- weather conditions, such as hurricanes, and other catastrophes, such as explosions, fires, floods and accidents;
- difficulties in attracting and maintaining a sufficient skilled and unskilled workforce, increases in the level of labor costs and the existence of any labor disputes;
- resistance in the local community to the development of the LNG receiving terminals due to safety, environmental or security concerns; and
- local and general economic and infrastructure conditions.

Our inability to timely complete the Sabine Pass LNG receiving terminal and our other LNG receiving terminals, as a result of any of the foregoing factors, could prevent us from commencing operations when anticipated, which could delay payments under the TUAs. As a result, we may not receive our anticipated cash flows on time or at all.

We are dependent on Bechtel and other contractors for the successful completion of our LNG receiving terminals.

We have limited experience constructing LNG receiving terminals and working with EPC contractors, including Bechtel, and with other construction contractors. Timely and cost-effective completion of our proposed LNG receiving terminals in compliance with agreed specifications is central to our business strategy and is highly dependent on our contractors' performance under their agreements with us. Our contractors' ability to perform successfully under their contracts is dependent on a number of factors, including their ability to:

- design and engineer our proposed LNG receiving terminals to operate in accordance with specifications;
- engage and retain third-party subcontractors and procure equipment and supplies;
- respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control;

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- attract, develop and retain skilled personnel, including engineers;
- post required construction bonds and comply with the terms thereof;
- manage the construction process generally, including coordinating with other contractors and regulatory agencies; and
- maintain their own financial condition, including adequate working capital.

Although some of our EPC contracts provide for liquidated damages, if the contractor fails to perform in the manner required with respect to certain of its obligations, the events that trigger a requirement to pay liquidated damages may delay or impair the operation of the applicable LNG receiving terminal, and any liquidated damages that we receive may not be sufficient to cover the damages that we suffer as a result of any such delay or impairment. In addition, each contractor's liability for liquidated damages is subject to a cap. Each of our material agreements with contractors is also subject to termination by the contractor prior to completion of construction under certain circumstances, including extended delays (of 100 days or more) caused by *force majeure* events and our insolvency, breach of material obligations not subject to adjustment by change order, or failure to pay undisputed amounts.

Furthermore, we may have disagreements with our contractors about different elements of the construction process, which could lead to the assertion of rights and remedies under their contracts and increase the cost of the project or result in a contractor's unwillingness to perform further work on the project. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor. This would likely result in significant project delays and increased costs.

To commission our LNG receiving terminals, we must purchase and process LNG. We have not previously purchased or processed any LNG.

Our LNG receiving terminals must undergo a commissioning process for their storage tanks and other equipment before commencement of commercial operation. The commissioning process will require a substantial quantity of LNG as well as access to adequate LNG tankers to deliver the LNG.

Our construction cost estimates include the costs of acquiring this LNG (a minor portion we refer to as "heel" LNG) at our LNG receiving terminals. Our actual cost to obtain LNG for the commissioning process could exceed our estimates, and the overrun could be significant.

We face several principal risks associated with this required purchase of LNG, including the following:

- we may be unable to enter into a contract for the purchase of the LNG needed for commissioning and may be unable to obtain tankers to deliver such LNG on terms reasonably acceptable to us or at all;
- we will bear the commodity price risk associated with purchasing the LNG, holding it in inventory for a period of time and selling the regasified LNG; and
- we may be unable to obtain financing for the purchase and shipment of the LNG on terms that are reasonably acceptable to us or at all.

Our failure to obtain LNG, or our inability to finance the purchase of LNG needed for commissioning, would impede commencement of commercial operation at our LNG receiving terminals, which could delay the date on which our TUA customers are required to begin making payments to us. This delay in payments could have a material adverse effect on our business, results of operations, financial condition and prospects.

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Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development of our LNG receiving terminals could impede completion of the terminals and have a material adverse effect on us.

The design, construction and operation of LNG receiving terminals are all highly regulated activities. The FERC's approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to construct and operate our proposed LNG receiving terminals. Although we have obtained NGA Section 3 authorization to construct and operate our LNG receiving terminals, such authorization is subject to ongoing conditions imposed by the FERC. We also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed LNG receiving terminals, including several under the Clean Air Act and the Clean Water Act from the U.S. Army Corps of Engineers and the Louisiana Department of Environmental Quality. We have no control over the outcome of the review and approval process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any existing or potential interventions or other actions by third parties will interfere with our ability to obtain and maintain such permits or approvals. Failure to obtain and maintain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

After our LNG receiving terminals are placed in service, their businesses will involve significant operational risks.

If we are successful in completing our LNG receiving terminals, we will still face risks associated with operating the facilities. These risks will include, but will not be limited to, the following:

- the facilities' performing below expected levels of efficiency;
- breakdown or failures of equipment or systems;
- operational errors by vessel or tug operators or others;
- operational errors by us or any contracted facility operator or others;
- labor disputes; and
- weather-related interruptions of operations.

We may be required to purchase natural gas to provide fuel at our LNG receiving terminals, which would increase operating costs and could have a material adverse effect on our results of operations.

The TUAs for regasification capacity at the Sabine Pass LNG receiving terminal provide for an in-kind deduction of 2% of the LNG delivered to the Sabine Pass LNG receiving terminal, which will be used primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. There is a risk that this 2% in-kind deduction will be insufficient for these needs and that we will have to purchase additional natural gas from third parties. Sabine Pass LNG has no arrangements in place to obtain any such natural gas and will bear the risk of changing prices with respect to additional natural gas that it may need to purchase for fuel.

We face competition in the LNG receiving terminal business from competitors with far greater resources, as well as potential overcapacity in the LNG receiving terminal marketplace.

Many companies have secured access to, or are pursuing the development or acquisition of LNG import infrastructure to serve the U.S. gas market including major energy corporations (e.g., BG, BP, ExxonMobil, Occidental and ConocoPhillips), industrial corporations, domestic and foreign utilities, and several smaller entrants such as ourselves. Almost all of these competitors have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing

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resources and access to LNG supply than we and our affiliates do. The superior resources that these competitors have available for deployment could allow them to compete successfully against us, if and when our TUAs terminate or expire, and/or against Cheniere Marketing, which could have a material adverse effect on us.

Some industry analysts have predicted substantial excess LNG receiving capacity in North America for at least several years based on terminals currently in operation or under construction. This could have a material adverse effect on Cheniere Marketing or on us in the event we have to replace our TUAs, and on our business, results of operations, financial condition and prospects.

We may have difficulty obtaining enough customers for regasification capacity at our proposed LNG receiving terminals to implement and complete our business plan. We may change our business strategy as to how and when we market our capacity.

Our current marketing strategy calls for us to enter into long-term TUAs for a portion of the regasification capacity at our LNG receiving terminals, including a commitment to pay capacity reservation fees, prior to the commencement of construction of each facility. The portion of our total regasification capacity that we plan to commit under such long-term TUAs has changed in the past and may change in the future for various reasons, including responding to market factors or perceived opportunities that we believe may be available to us. Our ability to obtain project-level financing for each LNG receiving facility may be contingent on our ability to enter into commercial agreements in advance of the commencement of construction. As of the date of this filing, we do not have any third-party agreements in place for either our proposed Corpus Christi LNG receiving terminal or our proposed Creole Trail LNG receiving terminal, nor do we have any third-party contracts in place for the use of our pipelines.

We may experience difficulty attracting additional customers because we are a small, developing company with no operating history in the LNG business. In order to succeed, we must convince additional potential customers, among other things, that we will be able to secure adequate financing for the construction of the LNG receiving terminals and natural gas pipelines that we are developing and that they will be approved by appropriate governmental agencies. We may also change our strategy due to our inability to enter into agreements with additional customers prior to construction and based on our views regarding future prices, demand and supply of natural gas and regasification capacity. If these efforts are not successful, our business, results of operations, financial condition and prospects could be materially adversely affected.

Our TUAs are subject to termination by our contractual counterparties under certain circumstances, and we are generally dependent on the performance of those counterparties under the TUAs.

Sabine Pass LNG has entered into long-term third-party TUAs with Total and Chevron. Each of the TUAs contains various termination rights. For example, each counterparty may terminate its TUA if the Sabine Pass LNG receiving terminal experiences a force majeure delay for longer than 18 months, fails to deliver a specified amount of natural gas redelivery nominations or fails to receive or unload a specified number of LNG cargoes. Sabine Pass LNG may not be able to replace these TUAs on desirable terms, or at all, if they are terminated. In the case of each of these TUAs, Sabine Pass LNG is dependent on the respective counterparty's continued willingness and ability to perform its obligations under the TUAs. If either of these counterparties fails to perform its obligations under its respective TUA, our business, results of operations, financial condition and prospects could be materially adversely affected, even if Sabine Pass LNG were ultimately successful in seeking damages from that counterparty or its guarantor for a breach of the TUA.

Risks Relating to Our Natural Gas Pipeline Business

Expanding our business by constructing pipelines subjects us to risks.

The construction of a new pipeline involves numerous regulatory, environmental, political and legal uncertainties beyond our control and requires the expenditure of significant amounts of capital that we will be required to finance through borrowings, through the issuance of additional equity or from operating cash flow. If

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we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. Whenever we build a new pipeline, the construction may occur over an extended period of time, and we will not receive any revenues until the pipeline has been completed and customers pay for transportation service on the pipeline. Moreover, we may construct pipelines to capture anticipated future growth in a region in which such growth does not materialize. As a result, our pipelines may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. The success of our pipeline construction project may depend upon the level of LNG import activity in the areas proposed to be serviced by the project as well as our ability to obtain commitments from LNG suppliers and other customers to utilize the newly constructed pipelines.

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development of our pipelines would have a detrimental effect on us and our LNG projects.

The design, construction and operation of natural gas pipelines and the transportation of natural gas are all highly regulated activities. FERC approval under Section 7 of the NGA, as well as several other material state governmental and regulatory approvals and permits, is required in order to construct and operate our proposed pipelines. We also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed pipelines, including several under the Clean Air Act and the Clean Water Act from the U.S. Army Corps of Engineers and the Louisiana Department of Environmental Quality. We have no control over the timing of the review and approval process nor can we predict the outcome of the process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any third parties will attempt to interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, we may not be able to recover our investment in the projects. Failure to obtain and maintain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our proposed pipelines, including their FERC gas tariffs, will be subject to FERC regulation.

Our FERC tariffs contain pro forma transportation agreements, which must be filed and approved by the FERC. Before we enter into a transportation agreement with a shipper that contains a term that materially deviates from our tariff, we must seek FERC approval. The FERC may approve the material deviation in the transportation agreement; however, in that case, the materially deviating terms must be made available to our other similarly-situated customers. If we fail to seek FERC approval of a transportation agreement that materially deviates from our tariff, or if FERC audits our contracts and finds deviations that appear to be unduly discriminatory, the FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the recently enacted Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1 million per day for each violation.

The FERC could change its current ratemaking policies, and those changes could have adverse effects on our proposed pipelines.

Any reduction in the capacity of, or the allocations to, interconnecting, third-party pipelines could cause a reduction of volumes transported in our proposed pipelines, which would adversely affect our revenues and cash flow.

We will depend upon third-party pipelines and other facilities that will provide delivery options to and from our proposed pipelines. If any pipeline connection were to become unavailable for volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to continue shipping natural gas to

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end markets could be restricted, thereby reducing our revenues. Any permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our proposed pipelines could have a material adverse effect on our business, results of operations and financial condition.

Our pipeline business could be materially adversely affected if we lose the right to situate our proposed pipelines on property owned by third parties.

We do not anticipate owning the land on which our proposed pipelines will be constructed, and we are subject to the possibility of increased costs to obtain and retain necessary land use. We anticipate obtaining the right to construct and operate our pipelines on land owned by third parties for a period of time. If we were to lose these rights or be required to relocate our pipelines, our business could be materially adversely affected.

Pipeline safety integrity programs and repairs may impose significant costs and liabilities on us.

The federal Office of Pipeline Safety has issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and to take additional measures to protect pipeline segments located in what the rule refers to as “high consequence areas” where a leak or rupture could potentially do the most harm. The final rule requires operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

We will be required to initiate pipeline integrity testing programs that are intended to assess pipeline integrity. The rule, or an increase in public expectations for pipeline safety, may require additional reporting and more frequent inspection or testing of our proposed pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should we fail to comply with the Office of Pipeline Safety’s rules and related regulations and orders, we could be subject to penalties and fines.

Because our proposed pipelines will be dependent upon a few customers, including an affiliate, for a significant portion of the revenues anticipated to be generated by our pipeline business, our business may be materially and adversely affected if we lose any one of these customers.

We do not currently have any third-party customers for our pipelines. Customers with whom we enter into TUAs for our LNG receiving terminals may enter into agreements for the transportation of revaporized gas on our proposed pipelines. However, the number of such customers is anticipated to be limited, and we anticipate being substantially dependent on them for a significant percentage of the revenues generated by our pipeline business. In addition, the largest customer of our proposed pipelines is anticipated to be our affiliate, Cheniere Marketing, which does not have any arrangements for any supplies of LNG or any unconditional commitments from customers for the purchase of natural gas. The loss of any customers, a decline in their creditworthiness, the failure of Cheniere Marketing to obtain LNG or customers for regasified LNG, or a substantial reduction in customers’ shipments on our proposed pipelines could have a material adverse effect on our business, results of operations and financial condition.

Risks Relating to Our LNG and Natural Gas Marketing Business

We are in the early stages of developing our LNG and natural gas marketing business.

We have recently begun developing our LNG and natural gas marketing business. To date, the business has been unprofitable and has a limited operating history upon which to evaluate our business strategy or the future prospects of the business. Since inception, our LNG and natural gas marketing business has had net operating

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losses. The ability of our LNG and natural gas marketing business to generate revenues in the future will depend upon whether we can successfully develop and implement our business strategy and make the transition from a development stage business to an operating business. We may encounter many expenses, delays, problems and difficulties that we have not anticipated and for which we have not planned in developing and operating our LNG and natural gas marketing business.

Our use of hedging arrangements may adversely affect our future results of operations or liquidity.

To reduce our exposure to fluctuations in the price, volume, timing, location, quality and credit risk associated with the marketing of LNG and natural gas, we use futures, swaps and option contracts traded or cleared on NYMEX and over-the-counter options and swaps with other natural gas merchants and financial institutions. Hedging arrangements would expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Our hedging arrangements may also limit the benefit that we would receive from increases in the prices for natural gas. The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices change.

The limited operating history of, and limited capital resources and credit available to, our LNG and natural gas marketing business limit our ability to develop that business.

We have limited the amount of capital available to our LNG and natural gas marketing business. The business currently has limited access to third-party sources of financing. Other investment-grade marketing companies have greater financial, technical and marketing resources and access to LNG supply than we do. Our LNG and natural gas marketing business is in its early stages of development and may not generate sufficient revenues and cash flows to cover the significant fixed costs of the business. The limited capital and credit available to our LNG and natural gas marketing business, along with a lack of cash flows, may inhibit our ability to develop that business.

If we do not attract and retain qualified personnel for our developing LNG and natural gas marketing business, our operations could be adversely affected.

Our success in developing and operating an LNG and natural gas marketing business will be, in part, dependent upon the number and quality of personnel that we can hire and our ability to maintain good relationships with them. If we are unable to retain qualified employees and then successfully maintain good relationships with them, our results of operations may be adversely affected.

Our exposure to the performance and credit risks of counterparties under agreements that we have entered into with them may adversely affect our future results of operations and liquidity.

Our LNG and natural gas marketing business enters into purchase and sale, hedging, and other transactions with numerous third parties (commonly referred to as “counterparties”). In such arrangements, we are exposed to the performance and credit risks of our counterparties, including the risk that one or more counterparties fails to perform its obligation to make deliveries of commodities and/or to make payments. These risks may increase during periods of commodity price volatility. Defaults by suppliers and other counterparties may adversely affect our working capital and/or financial results and our access to third-party financing.

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Risks Relating to Our LNG Businesses in General

The inability to import LNG into the United States could materially adversely affect our third-party LNG receiving terminal customers and our business plans and results of operations.

Operation of our LNG receiving terminals and natural gas pipelines will be dependent upon the ability of third-party customers and Cheniere Marketing to import LNG supplies into the United States. Political instability in foreign countries that have supplies of natural gas, or strained relations between such countries and the United States, may impede the willingness or ability of LNG suppliers and merchants in such countries to export LNG to the United States. Such foreign suppliers and merchants may also be able to negotiate more favorable prices with other LNG customers around the world than with customers in the United States, thereby reducing the supply of LNG available to be imported into the United States market. Furthermore, some foreign suppliers of LNG may have economic or other reasons to direct their LNG to non-U.S. markets or to competitors' LNG receiving terminals in the U.S. Any significant impediment to the ability to import LNG into the United States generally or to our LNG terminals specifically could have a material adverse effect on us, on our third-party LNG receiving terminal customers and on our business, results of operations, financial condition and prospects. In addition, the quality of LNG available for importation may not meet the quality specifications of our pipelines or the pipelines interconnected with or downstream of our proposed LNG receiving terminals.

Failure of sufficient LNG liquefaction capacity to be constructed worldwide could adversely affect the performance by our third-party LNG receiving terminal customers and Cheniere Marketing of obligations under TUAs and could reduce our operating revenue and cause us operating losses.

Commercial development of an LNG liquefaction facility takes a number of years and requires substantial capital investment. Many factors could negatively affect continued development of LNG liquefaction facilities, including:

- increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of LNG and natural gas, which might decrease the expected returns relating to investments in LNG projects;
- the inability of project owners or operators to obtain governmental approvals to construct or operate LNG facilities;
- political unrest in exporting countries or local community resistance in such countries to the siting of LNG facilities due to safety, environmental or security concerns; and
- any significant explosion, spill or similar incident involving an LNG liquefaction facility or LNG carrier.

If sufficient LNG liquefaction capacity is not constructed, our LNG and natural gas marketing business, demand for and development of the assets of our LNG receiving terminal and natural gas pipeline businesses, and our financial performance could each be adversely affected. In addition, our third-party LNG receiving terminal customers may find it difficult to obtain sufficient utilization of their capacity at our LNG receiving terminals to support their obligations under their TUAs.

There may be a shortage of LNG tankers worldwide, which could adversely affect our and our customers' ability to import LNG into North America and, therefore, inhibit our growth and cause us operating losses.

The construction and delivery of LNG vessels requires significant capital and long construction lead times, and the availability of the vessels could be delayed to our detriment because of:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;

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- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances at the shipyards;
- bankruptcy or other financial crisis of shipbuilders;
- quality or engineering problems;
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and
- shortages of or delays in the receipt of necessary construction materials.

Failure of imported LNG to become a competitive source of energy in North America could adversely affect our ability to develop our LNG receiving terminal and natural gas pipeline businesses, our ability to import LNG into North America and our ability to develop our LNG and natural gas marketing business, which could inhibit our growth and cause us operating losses.

In North America, due mainly to a historically abundant supply of natural gas, imported LNG has not historically been a major energy source. Our business plan is based, in part, on the belief that LNG can be produced and delivered at a lower cost than the cost to produce some domestic supplies of natural gas, or other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered in North America, which could further increase the available supply of natural gas and could result in natural gas being available at a lower cost than imported LNG. In addition to natural gas, LNG also competes in North America with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy. In addition, other continents have a longer history of importing LNG and, due to their geographic proximity to LNG producers and limited domestic natural gas supplies, may be willing and able to pay more for LNG, thereby reducing or eliminating the supply of LNG available in North American markets. As a result of these and other factors, LNG may not become a competitive source of energy in North America. The failure of LNG to become a competitive supply alternative to domestic natural gas, oil and other import alternatives could adversely affect our ability to enter into additional TUAs with customers and could also impede the ability to import LNG into North America on a commercial basis and our ability to develop our LNG and natural gas marketing business, which could inhibit our growth and cause us operating losses.

Decreases in the price of natural gas could lead to reduced development of LNG projects worldwide, which could adversely affect our ability to enter into TUAs and natural gas sale contracts with customers, which could inhibit our growth and cause us operating losses.

The development of domestic LNG receiving terminals and LNG projects generally is based on assumptions about the future price of natural gas and the availability of imported LNG. Natural gas prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to one or more of the following factors:

- relatively minor changes in the supply of, and demand for, natural gas;
- political conditions in international natural gas producing regions;
- the extent of domestic production and importation of natural gas in relevant markets;
- the level of consumer demand;
- weather conditions;
- the competitive position of natural gas as a source of energy compared with other energy sources; and
- the effect of government regulation on the production, transportation and sale of natural gas.

The willingness of potential customers to contract for regasification capacity would be negatively impacted and, once facilities are in operation, LNG throughput volumes would likely decline if the price of natural gas in North America is, or is forecast to be, lower than the cost to produce and deliver LNG to North American

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markets. Any significant decline in the price of natural gas could cause the cost of natural gas produced from imported LNG to be higher than domestically produced natural gas. As a result, we and our customers may not be able to procure supplies of LNG or customers for regasified LNG, which may inhibit our growth and cause us operating losses.

Cyclical or other changes in the demand for LNG regasification capacity may adversely affect our ability to enter into TUAs and natural gas sale contracts with customers, which could inhibit our growth and cause us operating losses.

The economics of our planned LNG terminals, natural gas pipelines and LNG and natural gas marketing operations could be subject to cyclical swings, reflecting alternating periods of under-supply and over-supply of LNG importation capacity and available natural gas, principally due to the combined impact of several factors, including:

- significant additions in regasification capacity in North America, Europe, Asia and other markets, which could divert LNG from our proposed LNG receiving terminals;
- reduced demand for natural gas, which could suppress demand for LNG;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- insufficient LNG production worldwide, which may limit the LNG traded worldwide;
- cost improvements that allow competitors to offer LNG regasification services at reduced prices;
- insufficient LNG tanker supplies, which may limit the ability to import LNG;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported LNG, natural gas or alternative energy sources, which may reduce the demand for imported LNG and/or natural gas;
- changes in relative demand for LNG in North America and other markets, which may decrease LNG imports into North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

Changes in the economics of our planned LNG receiving terminals, natural gas pipelines and LNG and natural gas marketing operations could materially adversely affect our and our customers' ability to procure supplies of LNG to be imported into North America and to procure customers for regasified LNG at economical prices, or at all, which could reduce our operating revenues and cause us operating losses.

We may experience increased labor costs, and the unavailability of skilled workers or our failure to retain key personnel could hurt the ability to construct and operate our proposed LNG receiving terminals and pipelines.

Companies in our industry, including us, are dependent upon the available labor pool of skilled employees. We compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct our proposed LNG receiving terminals and pipelines and, upon commencement of commercial operation, to provide our customers with the highest quality service. A shortage in the labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult for us to attract and retain personnel and could require an increase in the wage and benefits packages that we offer, thereby increasing our operating costs. For example, in the aftermaths of Hurricanes Katrina and Rita, Bechtel and certain subcontractors temporarily experienced a shortage of available skilled labor necessary to meet the requirements of the Sabine Pass LNG receiving terminal construction plan. As a result, we agreed to change orders with Bechtel concerning additional activities and

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expenditures to mitigate the hurricanes' effects on the construction of the Sabine Pass LNG receiving terminal. Any increase in our operating costs could materially adversely affect our business, results of operations, financial condition and prospects.

Risks Relating to Our Oil and Gas Exploration and Development Business

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and future net cash flows.

Numerous uncertainties, including those beyond our control, are inherent in estimating quantities of proved oil and gas reserves. Information included herein for 2007 relating to estimates of our proved reserves is based on reports prepared by Sharp Petroleum Engineering, Inc. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows may vary considerably from the actual results because of a number of variable factors and assumptions involved, including the following:

- historical production from the area compared with production from other producing areas;
- the effects of regulation by governmental agencies;
- future oil and gas prices;
- operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Therefore, the estimates of the quantities of oil and gas and the expected future net cash flows computed by different engineers or by the same engineers (but at different times) may vary significantly. The actual production, revenues and expenditures related to our reserves may vary materially from the engineers' estimates. In addition, we may make changes to our estimates of reserves and future net cash flows, which may be based on production history, results of future development, oil and gas prices, performance of counterparties under agreements to which we are a party and operating and development costs.

Do not interpret the PV-10 values included in this Form 10-K as the current market value of our properties' estimated oil and gas reserves. According to the SEC, the PV-10 is generally based on prices and costs as of the date of the estimate. In contrast, the actual future prices and costs may be materially higher or lower. Actual future net cash flows may also be affected by the following factors:

- the amount and timing of actual production;
- the supply of, and demand for, oil and gas;
- the curtailment or increases in consumption by natural gas purchasers; and
- the changes in governmental regulations or taxation.

The timing in producing and the costs incurred in developing and producing oil and gas will affect the timing of actual future net cash flows from proved reserves. Ultimately, the timing will affect the actual present value of oil and gas. In addition, the SEC requires that we apply a 10% discount factor in calculating PV-10 for reporting purposes. This is not necessarily the most appropriate discount factor to apply because it does not take into account the interest rates in effect, the risks associated with us and our properties, or the oil and gas industry in general.

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Risks Relating to Our Business in General

We have a limited operating history in the LNG businesses that we are developing. Our business plans are contingent on our ability to manage successfully our anticipated expansion and transition to operating these businesses.

We had net losses of \$181.8 million and \$145.9 million for the years ended December 31, 2007 and 2006, respectively. We expect to continue to incur operating losses and experience negative operating cash flow through at least 2008 and to incur significant capital expenditures through completion of development of the Sabine Pass LNG receiving terminal. Any delays beyond the expected development periods for the Sabine Pass LNG receiving terminal would prolong, and could increase the level of, our operating losses and negative operating cash flows.

We have never managed the construction, operation or maintenance of an LNG facility. We have limited experience in the construction, and no experience in the operation, of LNG receiving terminals or pipelines or the marketing of LNG or natural gas, and, as a result, we will be forced to rely to a significant extent on the new employees we hire to perform these functions. As our operations expand, we will also have to expand our administrative staff. If we are not able to successfully manage the expansion of our business, our business, results of operation, financial condition and prospects could be materially adversely affected.

Our initiatives to pursue downstream and upstream opportunities as part of our overall energy business strategy may not be successful and, even if successful, could expose us to greater and unanticipated risks.

We have little or no prior experience in some of the downstream opportunities that we are pursuing, such as natural gas pipeline development or natural gas marketing. We also have limited experience in some of the upstream opportunities that we are pursuing, such as investment in LNG shipping businesses and oil and gas exploration, development and transportation. Similarly, we have little or no prior experience in other upstream opportunities that we are pursuing, such as securing foreign LNG supply arrangements and developing foreign natural gas reserves that could be converted into LNG and imported into either domestic or international markets. We may not be successful in our efforts to pursue any or all of these initiatives. If we are successful in pursuing one or more of these downstream or upstream opportunities, we will likely incur greater risks than we expect to incur in our LNG receiving terminal business, and some of those risks we will not be able to anticipate.

We are subject to significant operating hazards and uninsured risks, one or more of which may create significant liabilities for us.

The construction and operation of our proposed LNG receiving terminals and pipelines will be subject to the inherent risks often associated with these types of operations, including explosions, pollution, release of toxic substances, fires, hurricanes and adverse weather conditions and other hazards, each of which could result in a significant delay in the timing of commencement of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations face possible risks associated with acts of aggression or terrorism on our facilities and the facilities and tankers of third parties on which our operations are dependent.

In accordance with customary industry practices, we maintain and intend to maintain insurance against some, but not all, of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our business, results of operations, financial condition and prospects.

Existing and future governmental regulation could result in increased compliance costs or additional operating costs and restrictions.

Our business is and will be subject to extensive federal, state and local laws and regulations that regulate the discharge of natural gas, hazardous substances, materials and other compounds into the environment or otherwise relate to the protection of the environment. Many of these laws and regulations, such as the Comprehensive Environmental Response, Compensation and Liability Act, the Clean Air Act, the Oil Pollution Act and the

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Clean Water Act, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our LNG receiving terminals and pipelines. Releases in violation of these regulations can lead to substantial liabilities for non-compliance or for pollution or releases of hazardous substances, materials or compounds or otherwise require additional costs or changes in operations that could have a material adverse effect on our business, results of operations, financial condition and prospects. Failure to comply with these laws and regulations may also result in substantial civil and criminal fines and penalties.

Existing environmental laws and regulations may be revised or reinterpreted or new laws and regulations may be adopted or become applicable to us. For example, the adoption of frequently proposed legislation implementing a carbon tax on energy sources that emit carbon dioxide into the atmosphere may have a material adverse effect on the ability of our customers: (i) to import LNG, if imposed on them as importers of potential emission sources, or (ii) to sell regasified LNG, if imposed on them or their customers as natural gas suppliers or consumers. In addition, as we consume retainage gas at the LNG receiving terminals, this carbon tax may also be imposed on us directly. Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to our LNG receiving terminals through navigable waterways, could cause additional expenditures, restrictions and delays in our business and to the planned construction of our LNG receiving terminals, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating costs and restrictions could have a material adverse effect on our business, results of operations, financial condition and prospects.

Hurricanes or other disasters could result in a delay in the completion of our LNG receiving terminals and pipelines, higher construction costs and the deferral of the dates on which our TUA counterparties are obligated to begin making payments to us.

In August and September of 2005, Hurricanes Katrina and Rita and related storm activity, including windstorms, storm surges, floods and tornadoes, caused extensive and catastrophic damage to coastal and inland areas located in the Gulf Coast region of the U.S. (parts of Texas, Louisiana, Mississippi and Alabama) and certain other parts of the southeastern U.S. Construction at the Sabine Pass LNG receiving terminal site was temporarily suspended in connection with Hurricane Katrina, as a precautionary measure. Approximately three weeks after the occurrence of Hurricane Katrina, the terminal site was again secured and evacuated in anticipation of Hurricane Rita, the eye of which made landfall to the east of the site. As a result of these 2005 storms and related matters, the Sabine Pass LNG receiving terminal experienced construction delays and increased costs totaling approximately \$36.4 million.

Future similar storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, delays or cost increases in construction of, or interruption of operations at, our LNG receiving terminals, pipelines or related infrastructure.

Terrorist attacks or military campaigns may adversely impact our business.

A terrorist incident involving an LNG facility or LNG carrier may result in delays in, or cancellation of, construction of new LNG facilities, including our proposed LNG receiving terminals and related natural gas pipelines, which would increase our costs and decrease our cash flows and could delay commencement of commercial operations. A terrorist incident may also result in temporary or permanent closure of existing LNG facilities, which, after commencement of commercial operations at our LNG receiving terminals, could increase our costs and decrease our cash flows, depending on the duration of the closure. Operations at our LNG receiving terminals could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost to us. In addition, the threat of terrorism and the impact of military campaigns may lead to continued volatility in prices for natural gas that could adversely affect Cheniere Marketing and our customers, including their ability to satisfy their obligations to us under their TUAs.

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We depend on key personnel, and we could be seriously harmed if we lost their services.

We depend on our executive officers for various activities. We do not maintain key person life insurance policies on any of our personnel. Although we have arrangements relating to compensation and benefits with certain of our executive officers, we do not have any employment contracts or other agreements with key personnel binding them to provide services for any particular term. The loss of the services of any of these individuals could seriously harm us. In addition, our future success will depend in part on our ability to attract and retain additional qualified personnel.

Some of our economic value is derived from our ownership of a minority interest in an entity over which we exercise no day-to-day control.

We own a 30% limited partner interest in Freeport LNG. Some of our value is attributable to this investment. In this annual report, we may use the words “our,” “we” or “us” in describing this investment or its assets and operations; however, we do not exercise control over Freeport LNG. The management team of Freeport LNG could make business decisions without our consent that could impair the economic value of our investment in Freeport LNG. Any such diminution in the value of our investment could have an adverse impact on our business, results of operations, financial condition and prospects.

We may have to take actions that are disruptive to our business strategy to avoid registration under the Investment Company Act of 1940.

The Investment Company Act of 1940, or Investment Company Act, requires registration for companies that are engaged primarily in the business of investing, reinvesting, owning, holding or trading in securities. Registration as an investment company would subject us to restrictions that are inconsistent with our fundamental business strategy.

A company may be deemed to be an investment company if it owns investment securities with a value exceeding 40% of the value of its total assets (excluding government securities and cash items) on an unconsolidated basis, unless an exemption or safe harbor applies. Securities issued by companies other than majority-owned subsidiaries are generally counted as investment securities for purposes of the Investment Company Act. We own minority equity interests in Freeport LNG which could be counted as an investment security. We generally plan to invest our liquid assets in commercial paper or other assets that may be considered investment securities in order to achieve higher yields from our available funds than investments in government securities and money market or similar cash investments would provide. Based on our board of directors’ determination of the value of our subsidiaries, we estimate that less than 40% of our assets consist of investment securities. However, in the event we acquire additional investment securities in the future, or if the value of our interests in companies that we do not control were to increase relative to the value of our controlled subsidiaries, we might be required to invest some portion of our liquid assets in government securities or cash items that yield lower returns than our proposed investments, or, in the alternative, we might be required to divest some of our non-controlled business interests, or take other action, in order to avoid being classified as an investment company.

We engage in operations and may make substantial commitments and investments outside the United States, which would expose us to political, governmental and economic instability and foreign currency exchange rate fluctuations.

Conducting operations or making commitments and investments outside of the United States will cause us to be affected by economic, political and governmental conditions in the countries where we engage in business. Any disruption caused by these factors could harm our business. Risks associated with operations, commitments and investments outside of the United States include risks of:

- currency fluctuations;

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- war;
- expropriation or nationalization of assets;
- renegotiation or nullification of existing contracts;
- changing political conditions;
- changing laws and policies affecting trade, taxation and investment;
- multiple taxation due to different tax structures; and
- the general hazards associated with the assertion of sovereignty over certain areas in which operations are conducted.

Because our reporting currency is the United States dollar, any of our operations conducted outside the United States would face additional risks of fluctuating currency values and exchange rates, hard currency shortages and controls on currency exchange. We would be subject to the impact of foreign currency fluctuations and exchange rate changes on our reporting for results from those operations in our financial statements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are, and may in the future be, involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management and legal counsel, as of December 31, 2007, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET PRICE FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock has traded on the American Stock Exchange under the symbol LNG since March 24, 2003. The table below presents the high and low daily closing sales prices of the common stock, as reported by the American Stock Exchange, for each quarter during 2006 and 2007.

	<u>High</u>	<u>Low</u>
Three Months Ended		
March 31, 2006	\$41.32	\$ 37.71
June 30, 2006	43.93	33.27
September 30, 2006	37.90	28.74
December 31, 2006	31.70	24.85
Three Months Ended		
March 31, 2007	\$32.50	\$ 27.08
June 30, 2007	41.23	31.45
September 30, 2007	41.60	34.64
December 31, 2007	41.73	31.87

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As of February 15, 2008, we had 48,605,369 million shares of common stock outstanding held by approximately 1,137 record owners.

We have never paid a cash dividend on our common stock. We currently intend to retain earnings to finance the growth and development of our business and do not anticipate paying any cash dividends on the common stock in the foreseeable future. Any future change in our dividend policy will be made at the discretion of our board of directors in light of our financial condition, capital requirements, earnings, prospects and any restrictions under any financing agreements, as well as other factors the board of directors deems relevant.

Issuer Purchases of Equity Securities

On May 31, 2007, we announced that we notified Credit Suisse International (“Credit Suisse”) of our irrevocable commitment to exercise, on one or more occasions on or before July 23, 2007, all of our options to purchase from Credit Suisse an aggregate of 9,175,595 shares of our common stock for \$35.42 per share. Our option to purchase the shares was part of the issuer call spread entered into in July 2005 by us and Credit Suisse in connection with our issuance of \$325.0 million of Convertible Senior Unsecured Notes. As of December 31, 2007, we had acquired 9,175,595 shares of our common stock for a cash price of \$35.42 per share under the call options.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data set forth below are derived from our audited Consolidated Financial Statements for the periods indicated. The financial data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and our Consolidated Financial Statements and Notes thereto included elsewhere in this report.

	Year Ended December 31,				
	(in thousands, except per share data)				
	2007	2006	2005 (4)	2004 (4)	2003 (4)
		(as adjusted)	(as adjusted)	(as adjusted)	(as adjusted)
Revenues	\$ 647	\$ 2,371	\$ 3,005	\$ 1,998	\$ 658
LNG terminal and pipeline development expenses	34,656	12,099	22,020	17,166	6,705
Exploration costs	1,116	3,138	2,839	2,662	1,604
Depreciation, depletion and amortization	6,393	3,131	1,325	507	308
General and administrative expenses	122,046	58,012	29,145	12,476	2,542
Loss from operations	(163,940)	(75,874)	(52,561)	(30,930)	(10,501)
Equity in net loss of limited partnership	(191)	—	(1,031)	(1,346)	(4,471)
Gain on sale of investment in unconsolidated affiliate (1)	—	—	20,206	—	—
Gain on sale of LNG assets	—	—	—	—	4,760
Reimbursement from limited partnership investment	—	—	—	2,500	—
Loss on early extinguishment of debt (2)	—	(43,159)	—	—	—
Derivative gain (loss) (2)	—	(20,070)	837	—	—
Interest expense, net	(104,557)	(53,968)	(17,373)	(4)	(88)
Interest income	82,635	49,087	17,520	501	3
Minority interest	3,425	—	97	2,862	3,015
Net loss	(181,777)	(145,853)	(29,538)	(24,876)	(6,440)
Net loss per share (basic and diluted) (3)	\$ (3.60)	\$ (2.68)	\$ (0.56)	\$ (0.64)	\$ (0.22)
Weighted average shares outstanding (basic and diluted) (3)	50,537	54,423	53,097	38,895	29,543

	December 31,				
	(in thousands, except per share data)				
	2007	2006	2005 (4)	2004 (4)	2003 (4)
		(as adjusted)	(as adjusted)	(as adjusted)	(as adjusted)
Cash and cash equivalents	\$ 296,530	\$ 462,963	\$ 692,592	\$ 308,443	\$ 1,258
Restricted cash and cash equivalents	228,085	176,827	122,217	—	—
Working capital	427,511	588,034	770,797	305,752	155
Non-current restricted cash and cash equivalents	478,225	1,071,722	55,844	—	—
Non-current restricted treasury securities	63,923	—	—	—	—
Property, plant and equipment, net	1,645,112	748,818	280,106	2,643	2,095
Debt issuances costs, net	44,005	41,545	43,008	1,302	—
Goodwill	76,844	76,844	76,844	—	—
Total assets	2,962,299	2,604,488	1,290,147	315,330	6,662
Long-term debt	2,757,000	2,357,000	917,500	—	—
Deferred revenue	40,000	41,000	41,000	23,000	1,000
Total liabilities	3,264,413	2,461,241	1,021,606	28,966	5,452
Total stockholders' equity	(302,114)	143,247	268,541	286,364	1,210

(1) Effective January 1, 2003, we began accounting for this investment in Gryphon Exploration Company using the cost method of accounting. In 2005, Gryphon Exploration Company was sold to Woodside Energy (USA), generating net cash proceeds and a gain to Cheniere of \$20.2 million.

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- (2) Amounts in 2006 primarily relate to losses on the termination of the Sabine Pass Credit Facility and the Term Loan in November 2006 and related hedge transactions. See Note 17—"Long-Term Debt and Credit Facility" of our Notes to Consolidated Financial Statements.
- (3) Net loss per share and weighted average shares outstanding have been restated to reflect a two-for-one stock split that occurred on April 22, 2005.
- (4) Amounts reported for the years ended December 31, 2005, 2004 and 2003 have been adjusted to reflect the change in our method of accounting for investments in oil and gas properties from the full cost method to the successful efforts method.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

Introduction

The following discussion and analysis presents management's view of our business, financial condition and overall performance and should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data." This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future. Our discussion and analysis include the following subjects:

- Overview of Business
- Overview of 2007 Events
- Liquidity and Capital Resources
- Contractual Obligations
- Results of Operations
- Off-Balance Sheet Arrangements
- Inflation and Changing Prices
- Summary of Critical Accounting Policies and Estimates
- Recently Issued Accounting Standards Not Yet Adopted

Overview of Business

We are engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals and natural gas pipelines, and we are also developing a business to market LNG and natural gas. To a limited extent, we continue to be engaged in oil and natural gas exploration and development activities in the Gulf of Mexico. We operate four segments: LNG receiving terminal business, natural gas pipeline business, LNG and natural gas marketing business, and oil and gas exploration and development business. The three LNG receiving terminals under development by us have an aggregate designed regasification capacity of approximately 10.1 Bcf/d, subject to expansion.

LNG Receiving Terminal Business

We have focused our LNG receiving terminal development efforts on the following three projects: the Sabine Pass LNG receiving terminal in western Cameron Parish, Louisiana on the Sabine Pass Channel; the Corpus Christi LNG receiving terminal near Corpus Christi, Texas; and the Creole Trail LNG receiving terminal at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana.

Our ownership interest in the Sabine Pass LNG receiving terminal is held through Cheniere Energy Partners, L.P. ("Cheniere Partners"), a Delaware limited partnership, in which we hold an approximate 90.6% interest as a result of the completion of an initial public offering of common units in Cheniere Partners (including

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the exercise by the underwriters of their over-allotment option). In turn, Cheniere Partners owns a 100% interest in Sabine Pass LNG, L.P. ("Sabine Pass LNG"), which is constructing the Sabine Pass LNG receiving terminal. We currently own 100% interests in the proposed Corpus Christi and Creole Trail LNG receiving terminals. In addition, we own a 30% limited partner interest in a fourth LNG receiving terminal project, Freeport LNG, located on Quintana Island near Freeport, Texas. The three LNG receiving terminals under development by us have an aggregate designed regasification capacity of approximately 10.1 Bcf/d, subject to expansion. Sabine Pass LNG has entered into long-term TUAs with Total, Chevron and our wholly-owned subsidiary, Cheniere Marketing, for regasification capacity at the Sabine Pass LNG receiving terminal.

Construction of the Sabine Pass LNG receiving terminal commenced in March 2005, and we anticipate commencing commercial operation during the second quarter of 2008 with initial send out capacity of approximately 2.6 Bcf/d and storage capacity of approximately 10.1 Bcf. We anticipate achieving full operability of the Sabine Pass LNG receiving terminal with a total send out capacity of approximately 4.0 Bcf/d and total storage capacity of approximately 16.8 Bcf during the third quarter of 2009. We will contemplate making final investment decisions to complete construction of the Corpus Christi LNG receiving terminal and to commence construction of the Creole Trail LNG receiving terminal upon, among other things, entering into acceptable commercial arrangements and entering into acceptable financing arrangements.

Natural Gas Pipeline Business

We are developing natural gas pipelines to provide access to North American natural gas markets from our LNG receiving terminals, and to serve growing natural gas markets with diverse new sources of natural gas supplies. We have focused our natural gas pipeline development efforts on the following three projects: the Creole Trail Pipeline originating at the Sabine Pass LNG receiving terminal to points of interconnection with multiple interstate and intrastate natural gas pipelines throughout southern Louisiana; the Corpus Christi Pipeline originating at the Corpus Christi LNG receiving terminal to points of interconnect with interstate and intrastate natural gas pipelines in South Texas; and the Cheniere Southern Trail Pipeline originating in southern Louisiana to a point of interconnect with the Florida Gas Transmission Pipeline in Western Florida. We have also purchased an 80% interest in the Frontera Pipeline, a combined transportation and storage project designed to serve industrial and power generation customers in Northeastern Mexico.

In October 2007, the Federal Energy Regulatory Commission ("FERC") approved an application to merge our Sabine Pass Pipeline into our Creole Trail Pipeline, thereby creating an approximately 150-mile integrated pipeline system, which we refer to as the Creole Trail Pipeline. Initial construction of Phase 1 of the Creole Trail Pipeline (consisting of 94 miles of natural gas pipeline) commenced in the second quarter of 2007, and we anticipate that it will be available for operations in the second quarter of 2008.

The Corpus Christi Pipeline will be developed in conjunction with the Corpus Christi LNG receiving terminal when we have entered into acceptable commercial arrangements and entered into acceptable financing arrangements.

Cheniere Partners has recently completed a non-binding open season to gauge third-party shipper interest in the Cheniere Southern Trail Pipeline project. The pipeline would interconnect with multiple takeaway pipelines from four LNG receiving terminals in Southwestern Louisiana, plus a fifth being developed in Mississippi. The Cheniere Southern Trail Pipeline may also interconnect with multiple onshore pipelines to serve conventional basins in the Gulf of Mexico, and with new developments transporting natural gas from the unconventional shale plays in Texas and Arkansas. The Cheniere Southern Trail Pipeline would supply Florida with natural gas needed to supply the anticipated growth in natural gas-fired generation capacity in the state over the next ten to fifteen years. This pipeline would provide LNG suppliers with access to new natural gas markets, while providing alternative access to conventional gas supplies, to improve gas supply security for Florida and the remainder of the Southeastern U.S.

In September 2007, we entered into an equity purchase agreement with Tidelands Oil & Gas Corporation and acquired an 80% interest in Frontera Pipeline, LLC, an entity which owns 100% of Sonora Pipeline and Terranova Energia, and which together are developing the Burgos Hub Project. The Burgos Hub Project in an

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integrated pipeline project traversing the United States and Mexico border and the construction of a related subterranean storage facility in Mexico. We will contemplate making a final investment decision in the Burgos Hub Project, among other things, receiving all required authorizations to construct and operate the pipeline and storage facility, entering into acceptable commercial arrangements and entering into acceptable financing arrangements for the pipeline and storage facility once operations commence.

LNG and Natural Gas Marketing Business

We are developing a natural gas and LNG marketing and trading business, with a TUA at the Sabine Pass LNG receiving terminal being our principal asset. We intend to build a portfolio of long-term and short-term and spot LNG purchase agreements from foreign suppliers, pursuant to which LNG will be delivered to either our LNG receiving terminals or other terminals with whom we will trade on the supplier's vessels, or on vessels that we contract for our own use. In order to facilitate the importation of LNG into the U.S., we are also developing a portfolio of downstream natural gas sales agreements with major local distribution companies, power generators, industrial users and other gas marketing firms. We will also purchase domestic natural gas to satisfy our sales commitments during times that we elect to divert contracted supplies away from the U.S., or during times that we are not able to obtain LNG supplies.

As we develop our marketing business, we are engaging in domestic natural gas purchases and sales, transportation and storage transactions, and physical and financial derivative transactions. Through a capacity option agreement, we have obtained the right to deliver LNG to the United Kingdom. In addition, we have contracted for the use of two LNG vessels to transport LNG.

Oil and Gas Exploration and Development Business

Although our focus is primarily on the development of LNG-related businesses, we continue to be involved to a limited extent in oil and gas exploration, development and production activities in the shallow waters of the Gulf of Mexico.

Overview of 2007 Events

Our significant accomplishments during 2007, some of which may also impact future years, include the following:

- the construction of the Sabine Pass LNG receiving terminal continued to progress and within budget estimates. The commissioning of the Sabine Pass LNG receiving terminal is expected to begin in early 2008 with a target for a second quarter 2008 start-up;
- construction of the initial phase of the Creole Trail Pipeline (consisting of 94 miles of natural gas pipeline) commenced in the second quarter of 2007 and it is expected to be operational in the second quarter of 2008;
- all required operational and maintenance personnel for the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline had been hired as of December 2007;
- we executed an option agreement with Gaz de France International Trading S.A.S. ("GdF"), which gives GdF the right to sell us LNG in 2008 for a predetermined price, and provides us access to the United Kingdom market from 2009 for at least 15 years;
- we have continued our efforts to increase our presence in the U.S. domestic natural gas trading and marketing markets increasing our average monthly physical volume from zero as of December 31, 2006 to approximately 185,000 MMBtu per day as of December 31, 2007, and have executed over 100 master agreements for the purchase and sale of domestic natural gas with a variety of counterparties, as well as entering into numerous other enabling agreements on pipelines and at storage facilities;
- we acquired 100% ownership in J&S Cheniere and with it the ability to control two LNG tanker ships to be delivered in 2008;

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- we entered into a credit facility that provides for up to \$35.0 million of borrowings and up to \$100.0 million of letters of credit for our natural gas marketing business;
- we completed an initial public offering of Cheniere Partners and raised \$302.3 million from the sale of 9.4% of Cheniere Partners to the public; and
- we entered into a \$400.0 million credit agreement, using a portion of the proceeds to repurchase 9,175,595 shares of our common stock for a cash price of \$35.42 per share under the call options acquired in connection with our July 2005 issuance of \$325.0 million of Convertible Senior Unsecured Notes.

Liquidity and Capital Resources

Overview

We are primarily engaged in LNG-related business activities. Most of our revenues will be directly related to our ability to successfully exploit our maritime, LNG receiving terminal, and pipeline assets. As our Creole Trail Pipeline is designed to provide transportation services for our Sabine Pass LNG facility and all of that facility's throughput capacity is currently contracted for under long-term TUAs, we are dependent on our LNG and natural gas marketing business to provide a significant portion of our revenue until we begin receiving payments under the TUAs with Total and Chevron beginning in 2009. Our LNG and natural gas marketing business activities are not expected to begin to generate significant revenues before the second quarter of 2008, at the earliest.

In March 2007, we formed a publicly traded partnership that includes 100% of Sabine Pass LNG and completed a public offering of common units in the partnership as described below under the caption Cheniere Energy Partners, L.P. We retain a combined general and limited partnership interest of 90.6% in the partnership which is consolidated in our financial statements. As of December 31, 2007 we had \$770.2 million in Restricted Cash and Cash Equivalents and U.S. Treasury Securities, including \$420.4 million for the remaining construction costs of the Sabine Pass LNG receiving terminal, \$212.8 million for interest payments through May 2009 related to the Senior Notes and \$75.7 million for cash distributions by Cheniere Partners through the distribution made in respect of the quarter ending June 2009. An additional \$61.3 million is restricted under loan and bank guarantee arrangements. We receive unrestricted cash from the partnership through quarterly distributions which are determined by the partnership's distributable cash balance and are dependent upon our compliance with certain covenants.

We have obtained financing and approval of our board of directors to construct the Sabine Pass LNG receiving terminal and the Creole Trail Pipeline, as more fully described below.

As of December 31, 2007, we had an unrestricted Cash and Cash Equivalents balance of \$296.5 million. To execute our current business plan, we will need additional financing in the next 12 months, which we expect to obtain from issuing debt or equity securities, or conducting asset sales or obtaining credit support. However, we may not be able to obtain such financing on terms that are acceptable to us, if at all. See Item 1A. "Risk Factors—Risks Relating to Our Financial Matters."

Cheniere Energy Partners, L.P.

On March 26, 2007, Cheniere Partners and Cheniere LNG Holdings, LLC ("Holdings"), our wholly-owned subsidiary, completed a public offering of 13,500,000 Cheniere Partners common units (the "Cheniere Partners Offering"). Cheniere Partners received \$98.4 million of net proceeds upon the issuance of 5,054,164 common units to the public in the Cheniere Partners Offering, and Holdings received \$164.5 million of net proceeds in connection with its sale of 8,445,836 common units of Cheniere Partners. In April 2007, the underwriters of the Cheniere Partners Offering exercised their over-allotment option with Holdings for the purchase of an additional 2,025,000 common units. Holdings received \$39.4 million of net proceeds from such sale. The \$203.9 million of

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net proceeds received by Holdings was unrestricted as to its use by us while the \$98.4 million received by Cheniere Partners was restricted and is invested in U.S. Treasury Securities to fund a distribution reserve. As a result of these transactions, our combined general partner and limited partner ownership interest in Cheniere Partners was reduced to approximately 90.6%.

For each calendar quarter through June 30, 2009, Cheniere Partners will make quarterly cash distributions of \$0.425 per unit on all outstanding common units, as well as related distributions to its general partner, using cash and earned interest from the distribution reserve that was funded with the \$98.4 million of net proceeds that it received from the Cheniere Partners Offering. From the date of the Cheniere Partners Offering through June 30, 2009, based on our current holdings of approximately 41% of the common units (10,891,357 common units) and 100% of the general partner units (3,302,045 general partner units), we anticipate receiving \$4.8 million per quarter out of the total \$11.4 million quarterly distribution. After June 30, 2009, the distribution reserve is expected to have been depleted, and Cheniere Partners will rely on the receipt of operating revenues from Sabine Pass LNG's various TUsAs to fund future quarterly cash distributions to us and other unitholders.

In addition to 10,891,357 common units, Holdings, through a wholly-owned subsidiary, also holds 100% of the 135,383,831 subordinated units of Cheniere Partners. These subordinated units were pledged as collateral under the 2007 Term Loan. Holdings' common, general partner and subordinated units represent an aggregate 90.6% ownership interest in Cheniere Partners. During the subordination period, however, the subordinated units will not be entitled to receive any distributions until the common units have received the initial quarterly distributions plus any arrearages on the initial quarterly distribution from prior quarters. The subordinated units do not accrue arrearages. The subordination period generally will end if:

- Cheniere Partners has earned and paid at least \$0.425 on each outstanding common unit, subordinated unit and general partner unit for each of the three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2010; or
- if Cheniere Partners has earned and paid at least \$0.638 (150.0% of the initial quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for any four consecutive quarters ending on or after June 30, 2008.

In addition to the 3,302,045 general partner units, representing a 2.0% ownership interest, held by the general partner of Cheniere Partners, a wholly-owned subsidiary of Holdings, the general partner also owns incentive distribution rights, which entitle it to increasing percentages (up to a maximum of 50.0%) of the cash that Cheniere Partners distributes in excess of \$0.489 per unit per quarter.

Our LNG Receiving Terminal Projects

Sabine Pass LNG Receiving Terminal

As discussed above, the Sabine Pass LNG receiving terminal is 100% owned by Cheniere Partners. The Sabine Pass LNG receiving terminal is being constructed with regasification capacity of approximately 4.0 Bcf/d and five LNG storage tanks with an aggregate LNG storage capacity of 16.8 Bcf. We estimate that the aggregate cost to construct the Sabine Pass LNG receiving terminal will be approximately \$1.4 billion, before financing costs. Our cost estimates are subject to change due to such items as cost overruns, change orders, increased component and material costs, escalation of labor costs and increased spending to maintain our construction schedule. We are funding the construction period capital resource requirements of the Sabine Pass LNG receiving terminal from a portion of the \$2,032.0 million in gross proceeds received from Sabine Pass LNG's issuance in November 2006 of senior secured notes (the "Senior Notes"). As of December 31, 2007, we had incurred \$1.0 billion of construction costs, not including financing costs. We believe that we have sufficient funds from the restricted cash and cash equivalents of \$420.4 million designated to complete the construction of the Sabine Pass LNG receiving terminal.

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Beginning in 2009, each of the customers at the Sabine Pass LNG receiving terminal must make the full contracted amount of capacity reservation fee payments under its TUA whether or not it uses any of its reserved capacity. Provided the Sabine Pass LNG receiving terminal has achieved commercial operation, which we expect will occur during the second quarter of 2008, capacity reservation fee TUA payments will be made by the following Sabine Pass LNG customers:

- Total has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$125 million per year for 20 years commencing April 1, 2009. Total, S.A. has guaranteed Total's obligations under its TUA up to \$2.5 billion, subject to certain exceptions; and
- Chevron has reserved approximately 1.0 Bcf/d of regasification capacity and has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$125 million per year for 20 years commencing not later than July 1, 2009. Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.
- Our wholly-owned subsidiary, Cheniere Marketing, has reserved the remaining 2.0 Bcf/d of regasification capacity, and is entitled to use any capacity not utilized by Total and Chevron. Cheniere Marketing has agreed to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$250 million per year for at least 19 years commencing January 1, 2009, plus capacity payments of \$5 million per month during an initial commercial operations ramp-up period in 2008. Cheniere has guaranteed Cheniere Marketing's obligations under its TUA.

Under each of these TUAs, Sabine Pass LNG is also entitled to retain 2% of the LNG delivered for the customer's account, which Sabine Pass LNG will use primarily as fuel for reevaporation and self-generated power at the Sabine Pass LNG receiving terminal.

Each of Total and Chevron has paid us \$20 million in nonrefundable advance capacity reservation fees, which will be amortized over a 10-year period as a reduction of each customer's regasification capacity fees payable under its TUA.

From the time of commercial operations until Total and Chevron's TUA payments commence, all regasification capacity at the Sabine Pass LNG receiving terminal will be available to Cheniere Marketing. Once Total and Chevron's TUA payments commence, the remaining 2.0 Bcf/d of regasification capacity will be available to Cheniere Marketing. In addition, Cheniere Marketing is entitled to use any capacity not utilized by Total and Chevron.

Corpus Christi LNG Receiving Terminal

In order to accelerate the timing of its development of the Corpus Christi LNG receiving terminal, Corpus Christi LNG elected in April 2006 to commence preliminary site work and entered into an engineering, procurement and construction services agreement for such preliminary work which has since been completed. We will contemplate making a final investment decision to complete construction of the Corpus Christi LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements. As of December 31, 2007, we had incurred \$33.1 million in construction costs, which were funded from cash and cash equivalents.

Creole Trail LNG Receiving Terminal

We will contemplate making a final investment decision to commence construction of the Creole Trail LNG receiving terminal upon, among other things, achieving acceptable commercial arrangements and entering into acceptable financing arrangements.

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Freeport LNG Receiving Terminal

We have a 30% limited partner interest in Freeport LNG. Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG's own cash flows, borrowings or other sources, and with capital contributions by the limited partners. We did not receive any capital calls, and made no capital contributions, in 2007, nor do we anticipate any capital calls in the foreseeable future.

Our Pipeline Projects

Creole Trail Pipeline

We currently expect to fund the remaining costs of the pipeline project approved by our board of directors from existing cash and cash equivalent balances. We estimate the total cost to construct Phase 1 of the Creole Trail Pipeline to be approximately \$550 million, before financing costs. This estimate includes the costs to construct the pipeline and costs related to interconnections with third-party pipelines and to right-of-ways. As of December 31, 2007, we had incurred, before financing costs, \$422.2 million of costs for Phase 1 of the Creole Trail Pipeline and believe we have adequate financial resources available to complete construction of this phase of Creole Trail Pipeline.

Corpus Christi Pipeline

Construction of the Corpus Christi Pipeline is contingent upon our decision to complete construction of the Corpus Christi LNG receiving terminal.

Cheniere Southern Trail Pipeline

Cheniere Partners conducted a non-binding open season to gauge interest from prospective shippers in the proposed Cheniere Southern Trail Pipeline. Negotiations with open season respondents are ongoing. As currently contemplated, the Cheniere Southern Trail Pipeline would involve the construction of approximately 350 miles of up to 42-inch diameter pipeline that is currently estimated to cost approximately \$1.5 billion, before financing costs. We will contemplate making a final investment decision to commence construction of the Cheniere Southern Trail Pipeline upon, among other things, entering into acceptable commercial arrangements, receiving FERC authorization to construct and operate the pipeline and obtaining adequate financing to construct the Cheniere Southern Trail Pipeline.

Our LNG and Natural Gas Marketing Business

We will need funds to develop our LNG and natural gas marketing business, including capital or credit facilities required to satisfy any creditworthiness requirements under contracts and to develop the systems necessary to implement our business strategy. As of December 31, 2007, we had committed \$60.0 million to our marketing activities, in addition to funding overhead costs and capital expenditures. In September 2007, Cheniere Marketing entered into a secured working capital facility to provide letter of credit support for current marketing activities in the U.S. natural gas markets. Cheniere Marketing expects to amend that working capital facility to increase its size and to additionally permit the issuance of letters of credit in support of LNG purchases and other related LNG and natural gas marketing activities.

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Sources and Uses of Cash

The following table summarizes the sources and uses of our cash and cash equivalents for the years ended December 31, 2007, 2006 and 2005. The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals that are referred to elsewhere in this document. Additional discussion of these items follows the table (in thousands).

	<u>2007</u>	<u>2006</u>	<u>2005</u>
Sources of cash and cash equivalents:			
Use of restricted cash and cash equivalents	\$ 527,043	\$ —	\$ —
Borrowings from debt	400,000	2,415,400	925,000
Proceeds from sale of common units in partnership	203,946	—	—
Proceeds from issuance of common units in partnership	98,442	—	—
Sale of common stock	3,158	1,953	2,972
Sales of investment in unconsolidated affiliate	—	—	20,206
Other	1,048	—	47
Total sources of cash and cash equivalents	1,233,637	2,417,353	948,225
Uses of cash and cash equivalents:			
LNG terminal and pipeline construction-in-process	(788,517)	(440,367)	(229,705)
Purchase of treasury shares	(325,101)	—	—
Investment in treasury securities	(98,442)	—	—
Operating cash flow	(84,291)	(80,426)	(18,956)
Purchases of intangible and fixed assets, net of sales	(41,684)	(10,527)	(5,811)
Advances under long-term contracts, net of transfers to construction-in-process	(38,617)	(7,101)	(8,087)
Distributions to minority interest	(13,631)	—	—
Investment in restricted cash and cash equivalents	—	(1,070,713)	(177,385)
Repayment of debt	—	(981,900)	(1,500)
Debt issuance costs	(9,787)	(43,796)	(42,124)
Purchase of issuer call spread	—	—	(75,703)
Oil and gas property additions, net of sales	—	(3,687)	(2,064)
Other	—	(8,465)	(2,741)
Total uses of cash and cash equivalents	(1,400,070)	(2,646,982)	(564,076)
Net increase (decrease) in cash and cash equivalents	(166,433)	(229,629)	384,149
Cash and cash equivalents at end of year	\$ 296,530	\$ 462,963	\$ 692,592

Use of restricted cash and cash equivalents

Under the indenture governing the Senior Notes, a portion of the proceeds from the Senior Notes is required to be used for scheduled interest payments through May 2009 and to fund the cost to complete construction of the Sabine Pass LNG receiving terminal. Due to these restrictions imposed by the indenture, the proceeds are not presented as cash and cash equivalents, and therefore, when proceeds from the Senior Notes are used they are presented as a source of cash and cash equivalents. In 2007, the \$527.0 million of restricted cash and cash equivalents were used primarily to pay for construction activities at the Sabine Pass LNG receiving terminal.

Borrowings from debt

Our borrowings from debt were \$400.0 million, \$2.4 billion and \$925.0 million in 2007, 2006 and 2005, respectively. During 2007, we received \$400.0 million from borrowings under the 2007 Term Loan, which was used primarily to repurchase shares of our common stock under the call option acquired in the issuer call spread

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purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. During 2006, we received \$2.0 billion in proceeds from the issuance of the Senior Notes and \$383.4 million in borrowings under the amended Sabine Pass credit facility. During 2005, we received proceeds in the amounts of \$600.0 million and \$249.3 million (net of \$75.7 million for the issuer call spread) from the Term Loan and the issuance of our Convertible Senior Unsecured Notes, respectively.

Proceeds from sale of common units in partnership

In conjunction with the Cheniere Partners Offering, we sold to the public a portion of the Cheniere Partners common units held by us, realizing net proceeds of \$203.9 million, which included \$39.4 million of net proceeds realized once the underwriters exercised their option to purchase an additional 2,025,000 common units from us. These net proceeds are being used for corporate and general purposes.

Proceeds from issuance of common units in partnership

Through the Cheniere Partners Offering, Cheniere Partners received \$98.4 million in net proceeds for the issuance of common units to the public. Cheniere Partners used all of the net proceeds to purchase U.S. treasury securities to fund a distribution reserve for payment of initial quarterly distributions through the quarter ending June 30, 2009.

Sales of investment in unconsolidated affiliate

On August 31, 2005, Gryphon Exploration Company was sold for \$283 million, plus assumption of \$14 million of net debt in a merger with Woodside Energy (USA). We received net cash proceeds of \$20.2 million for our interest in Gryphon, and because our investment balance was zero, we recognized a gain in 2005 equal to the net cash proceeds amount.

LNG terminal and pipeline construction-in-process

Capital expenditures for our LNG receiving terminals and pipeline projects were \$788.5 million, \$440.4 million and \$229.7 million in 2007, 2006 and 2005, respectively. The 79.0% increase in 2007 resulted primarily from our continued construction expenditures on the Sabine Pass LNG receiving terminal which commenced construction in the first quarter of 2005 and the Creole Trail Pipeline which commenced initial construction in the second quarter of 2007.

LNG terminal and pipeline construction-in-process capital expenditures in 2006 increased 91.7% compared to 2005 primarily due to increased expenditures related to the Sabine Pass LNG receiving terminal.

Investment in treasury securities

As mentioned above, through the Cheniere Partners Offering, Cheniere Partners received \$98.4 million in net proceeds from the issuance of common units to the public. Cheniere Partners used all of the net proceeds to purchase U.S. treasury securities to fund a distribution reserve for payment of initial quarterly distributions through the quarter ending June 30, 2009.

Operating cash flow

Net cash used in operations was \$84.3 million, \$80.4 million and \$19.0 million in 2007, 2006 and 2005, respectively. Net cash used in operations in 2005 through 2007 related primarily to the continued development of our LNG receiving terminals and related activities, including increased employee support costs. In addition, in 2006 we incurred prepayment penalties and a cash derivative loss related to the termination of our interest rate swaps upon the early termination of the Sabine Pass credit facility and the Term Loan, and in 2005, the net cash used in operations was partially offset by advance LNG terminal capacity reservation fees of \$18.0 million.

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Purchases of intangible and fixed assets, net of sales

Purchases of fixed assets were \$41.7 million, \$10.5 million and \$5.8 million in 2007, 2006 and 2005, respectively. The increase in fixed assets from 2005 through 2007 resulted primarily from the expansion of our business. In addition, in December 2007, we purchased the remaining 51% ownership in J & S Cheniere from Mercuria for approximately \$15.0 million, and allocated the purchase price primarily to two LNG time charter agreements that J & S Cheniere had entered into.

Advances under long-term contracts, net of transfer to construction-in-process

We have entered into certain contracts and purchase agreements related to the construction of our Sabine Pass LNG receiving terminal that require us to make payments to fund costs that will be incurred or equipment that will be received in the future. Advances made under long-term contracts on purchase commitments are carried at face value and transferred to property, plant, and equipment as the costs are incurred or equipment is received.

Distributions to minority interest

During 2007, we distributed \$13.6 million to non-affiliated common unitholders of Cheniere Partners.

Debt issuance costs

Our debt issuance costs were \$9.8 million, \$43.8 million and \$42.1 million in 2007, 2006 and 2005, respectively. The debt issuance costs in 2007 were primarily related to the \$400.0 million 2007 Term Loan. Debt issuance costs in 2006 were primarily related to the amended Sabine Pass credit facility and the Senior Notes. Debt issuance costs in 2005 were primarily related to the Sabine Pass credit facility, the Convertible Senior Unsecured Notes and the Term Loan.

Investment in restricted cash and cash equivalents

Investment in restricted cash and cash equivalents was zero, \$1.1 billion and \$177.4 million in 2007, 2006 and 2005, respectively. Investments in restricted cash and cash equivalents are cash and cash equivalents that have been legally restricted to be used for a specific purpose. Between 2005 and 2007, the changes in investments in restricted cash and cash equivalents were related to borrowings that were contractually restricted to be used for the construction of our Sabine Pass LNG receiving terminal and for interest payments on the Senior Notes.

Repayment of debt

In 2006, we repaid borrowings under the amended Sabine Pass credit facility and Term Loan with a portion of the proceeds obtained from the \$2.0 billion issuance of the Senior Notes.

Purchase of issuer call spread

Concurrent with the issuance of the Convertible Senior Unsecured Notes, we also entered into hedge transactions in the form of an issuer call spread. During 2007, we exercised the call spread and purchased 9.2 million shares of our common stock for an aggregate purchase price of \$325.0 million.

Debt Agreements

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of \$325.0 million aggregate principal amount of Convertible Senior Unsecured Notes due 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The notes bear interest at a rate of 2.25% per year. The notes are convertible at any time into our

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common stock under certain circumstances at an initial conversion rate of 28.2326 per \$1,000 principal amount of the notes, which is equal to a conversion price of approximately \$35.42 per share. As of December 31, 2007, no holders had elected to convert their notes.

We may redeem some or all of the notes on or before August 1, 2012, for cash equal to 100% of the principal plus any accrued and unpaid interest if in the previous 10 trading days the volume-weighted average price of our common stock exceeds \$53.13, subject to adjustment, for at least five consecutive trading days. In the event of such redemption, we will make an additional payment equal to the present value of all remaining scheduled interest payments through August 1, 2012, discounted at the U.S. Treasury rate plus 50 basis points. The indenture governing the notes contains customary reporting requirements.

Sabine Pass LNG Senior Secured Notes

In November 2006, Sabine Pass LNG issued an aggregate principal amount of \$2,032.0 million of Senior Notes, consisting of \$550.0 million of 7.25% Senior Secured Notes due 2013 and \$1,482.0 million of 7.50% Senior Secured Notes due 2016. Interest on the Senior Notes is payable semi-annually in arrears on May 30 and November 30 of each year. The Senior Notes are secured on a first-priority basis by a security interest in all of Sabine Pass LNG's equity interests and substantially all of its operating assets.

Under the indenture governing the Senior Notes, except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied. The indenture requires that Sabine Pass LNG apply its net operating cash flow (i) first, to fund with monthly deposits its next semiannual payment of approximately \$75.5 million of interest on the Senior Notes, and (ii) second, to fund a one-time, permanent debt service reserve fund equal to one semiannual interest payment of approximately \$75.5 million on the Senior Notes. Distributions will be permitted only after phase 1 target completion of the Sabine Pass LNG receiving terminal, as defined in the indenture governing the Senior Notes, or such earlier date as project revenues are received, upon satisfaction of the foregoing funding requirements, after satisfying a fixed charge coverage ratio test of 2:1 and after satisfying other conditions specified in the indenture.

2007 Term Loan

In May 2007, Cheniere Subsidiary Holdings, LLC ("Cheniere Subsidiary"), a newly formed wholly-owned subsidiary of Cheniere, entered into a \$400.0 million credit agreement ("2007 Term Loan"). Borrowings under the 2007 Term Loan generally bear interest at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the 2007 Term Loan outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. The 2007 Term Loan will mature on May 31, 2012. The net proceeds from the 2007 Term Loan were \$391.7 million and are being used for general corporate purposes, including the repurchase, completed in July 2007, of approximately 9.2 million shares of our outstanding common stock pursuant to the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. The 2007 Term Loan is secured by a pledge of our subordinated units in Cheniere Partners and our equity interests in the entities that own our 30% interest in Freeport LNG.

Marketing Credit Facility

In September 2007, Cheniere Marketing entered into a credit facility ("Marketing Credit Facility") that provides up to \$35.0 million of borrowings and up to \$100.0 million of letters of credit and is secured by the "borrowing base" composed of cash or cash equivalents, receivables, broker margin deposits and inventory of Cheniere Marketing meeting certain criteria. Cheniere Marketing may only use the letters of credit and the proceeds of loans only for financing, securing or guaranteeing the performance of its obligations related to the purchase, sale, storage, transfer or exchange of natural gas and other products, to support Cheniere Marketing's obligations under commodity contracts and derivative contracts related to such products, and to fund the working

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capital requirements of Cheniere Marketing. Borrowings mature on the earlier of two months after such borrowings and September 12, 2008. The unpaid principal balance of each borrowing generally bears interest at a variable rate equal to LIBOR plus 1.50%. The Marketing Credit Facility is secured by a pledge of Cheniere Marketing's accounts receivables, inventory and other assets. As of December 31, 2007, we had no borrowings and \$66.5 million of letters of credit outstanding under the Marketing Credit Facility.

Issuances of Common Stock

During 2007, 2006 and 2005, we raised \$3.2 million, \$2.0 million and \$3.0 million, respectively, net of offering costs, from the exercise of stock options, the exchange or exercise of warrants, a public equity offering of common stock and the sale of Cheniere common stock to accredited investors pursuant to Regulation D.

During 2007, we issued a total of 1,717,467 shares of our common stock. A total of 415,637 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of \$3.2 million. In addition, 272,612 shares were issued in satisfaction of cashless exercises of options to purchase 316,033 shares of common stock. In January 2007, we issued 630,396 shares having three-year graded vesting to our employees and executive officers in the form of non-vested stock awards related to our performance in 2006. In May 2007, we issued 30,574 shares having a one-year graded vesting to our directors. In June 2007 and November 2007, we issued 149,929 shares as retention grants to certain employees vesting 50% on December 1, 2008, 30% on December 1, 2009, and 20% on June 1, 2010. In the year ended December 31, 2007, we issued an additional 249,819 shares of non-vested stock having three or four-year graded vestings primarily to new employees.

During 2007, we purchased 9,175,595 shares of our common stock for a cash price of \$35.42 per share under the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. As of December 31, 2007, these shares had not been cancelled and remained as treasury stock on our Consolidated Balance Sheet.

During 2006, we issued a total of 710,685 shares of our common stock. A total of 309,734 shares of our common stock were issued pursuant to the exercise of stock options, resulting in net cash proceeds of \$2.0 million. In addition, 76,534 shares were issued in satisfaction of cashless exercises of options to purchase 97,801 shares of our common stock. A total of 78,671 shares were issued in 2006 to executive officers in the form of non-vested restricted stock awards related to our performance in 2005, and we issued 241,240 shares of non-vested restricted stock to new employees. We paid federal payroll withholding taxes of \$1.0 million in exchange for 25,733 shares of our common stock, which related to common stock previously awarded to officers that vested during 2006. These shares were initially recorded as treasury shares, at cost, but were subsequently retired. In December 2006, 30,239 shares were issued to outside directors in the form of non-vested (restricted) stock awards related to their services provided in 2006.

Contractual Obligations

We are committed to making cash payments in the future on certain of our contracts. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2007 (in thousands).

	Payments Due for Years Ending December 31,				
	Total	2008	2009-2010	2011-2012	Thereafter
Long-term debt—					
Convertible Senior Unsecured Notes (1)	\$ 325,000	\$ —	\$ —	\$ 325,000	\$ —
2007 Term Loan (1)	400,000	—	—	400,000	—
Senior Notes (1)	2,032,000	—	—	—	2,032,000
Operating lease obligations (2)(4)	524,166	57,237	114,334	114,342	238,253
Construction and purchase obligations (3)(5)	456,619	395,734	45,064	6,008	9,813
Other obligations (6)	29,387	2,404	6,078	5,785	15,120
Total	\$ 3,767,172	\$ 455,375	\$ 165,476	\$ 851,135	\$ 2,295,186

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- (1) A discussion of these obligations can be found at Note 17 of our Notes to Consolidated Financial Statements.
- (2) A discussion of these obligations can be found at Note 7 of our Notes to Consolidated Financial Statements.
- (3) A discussion of these obligations can be found at Note 23 of our Notes to Consolidated Financial Statements.
- (4) Minimum lease payments have not been reduced by a minimum sublease rental of \$4.3 million due in the future under noncancelable subleases.
- (5) Represents construction contracts and obligations to purchase long-lead equipment and materials for our LNG receiving terminals and natural gas pipelines.
- (6) Includes obligations for natural gas storage transportation contracts, telecommunication services and software licensing.

In addition, in the ordinary course of business, we maintain letters of credit and have certain cash and cash equivalents restricted in support of certain performance obligations of our subsidiaries. Restricted cash and cash equivalents and outstanding letters of credit totaled approximately \$770.2 million at December 31, 2007. For more information, see Note 6—“Restricted Cash and Cash Equivalents and Treasury Securities” of our Notes to Consolidated Financial Statements.

Results of Operations

Overall Operations

2007 vs. 2006

Our consolidated net loss was \$181.8 million in 2007, a 25% increase over our 2006 net loss, as described below. The increase in the loss was primarily due to our increase in employee headcount in anticipation of commencing operations in early 2008, additional LNG receiving terminal development expenses and an increase in the amount of DD&A recognized in part due to our increase in asset infrastructure being placed in service. In addition, a significant portion of our loss is attributable to the recognition of non-cash, share-based payments accounted for under SFAS No. 123R, *Share-Based Payments*, which requires all non-cash, share-based compensation be recognized in the financial statements based on fair value at the date of grant. As a result of our issuance of non-cash, share-based payments to employees, we recorded \$56.6 million of non-cash compensation expense in 2007. Not including the impact of this non-cash expense in 2007, our net loss would have been \$125.2 million, or \$2.48 net loss per common share—basic and diluted.

2006 vs. 2005

Our consolidated net loss was \$145.9 million in 2006, a 394% increase over our 2005 net loss, as described below. The increase in the loss was due primarily to a \$43.2 million loss recorded from the early extinguishment of debt, a \$20.1 million derivative loss related to the termination of our interest rate swaps associated with the early termination of debt, an increase in G&A related to the expansion of our business, offset by a \$20.2 million gain on the sale of our investment in Gryphon in 2005. As a result of our issuance of non-cash, share-based payments to employees, we recorded \$20.2 million of non-cash compensation expense related to these share-based payments in 2006. Not including the impact of this non-cash expense in 2006, our net loss would have been \$125.7 million, or \$2.31 net loss per common share—basic and diluted.

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LNG Receiving Terminal and Pipeline Development Expenses

Our LNG receiving terminal and pipeline development expenses include primarily professional costs associated with front-end engineering and design work, obtaining orders from the FERC authorizing construction of our facilities and other required permitting for our planned LNG receiving terminals and natural gas pipelines. Additional discussion of these items follows the tables below: (in thousands)

2007 vs. 2006

	2007	2006
Salaries and benefits	\$15,468	\$ 5,733
Non-cash compensation	5,417	4,874
Public relations	4,977	940
Professional and technical services	1,165	9,424
Regulatory pipeline asset	—	(12,343)
Sabine Pass LNG receiving terminal site rental	1,523	1,435
Other	6,106	2,036
Total LNG receiving terminal and pipeline development expenses	\$34,656	\$ 12,099

Salaries and benefits—LNG receiving terminal and pipeline development expenses include expenses of our employees directly involved in development activities. Employees' salaries and benefits are charged to development expense when they are engaged directly in LNG receiving terminal and pipeline activities that meet capitalization criteria. The increase in salaries and benefits from 2006 to 2007 was due to an increase in the average number of employees engaged in LNG receiving terminal and pipeline activities from 68 in 2006 to 138 in 2007.

Public relations—The increase in public relations in 2007 was primarily due to our participation in Hurricane Rita relief in Johnson Bayou, Louisiana. Specifically, we participated in building the Johnson Bayou Rural Health Clinic that will be operated by West Calcasieu Cameron Hospital Group to assist the local community in its rebuilding efforts from the effects of Hurricane Rita.

Professional and technical services—The decrease from 2006 was primarily due to a decreases in engineering, legal and other technical and professional services directly related to the Corpus Christi and Creole Trail LNG receiving terminals. We continue to evaluate making an investment decision in both the Corpus Christi and Creole Trail LNG receiving terminals.

Regulatory pipeline asset—In the second quarter of 2006, we recognized as regulatory assets, as prescribed by SFAS No. 71, *Accounting for Effects of Certain Types of Regulations*, amounts that had previously been expensed as pipeline development expenses. The impact of recording these regulatory assets reduced pipeline development expense for the year ended 2006 by \$12.3 million.

Sabine Pass LNG receiving terminal site rental—As required by Financial Accounting Standards Board ("FASB") Staff Position ("FSP") 13-1, *Accounting for Rental Costs Incurred During a Construction Period*, which became effective January 1, 2006, we expense our Sabine Pass LNG site lease.

2006 vs. 2005

	2006	2005
Professional and technical services	\$ 9,424	\$14,372
Salaries and benefits	5,733	5,140
Non-cash compensation	4,874	1,235
Sabine Pass LNG receiving terminal site rental	1,435	2
Other	2,976	1,271
Regulatory pipeline asset	(12,343)	—
Total LNG receiving terminal and pipeline development expenses	\$ 12,099	\$22,020

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Professional and technical services—The decrease from 2005 is primarily due to decrease in engineering, legal and other technical and professional services directly related to the Corpus Christi and Creole Trail LNG receiving terminals. We continue to evaluate making an investment decision in both Corpus Christi and Creole Trail LNG receiving terminals.

Salaries and benefits—LNG receiving terminal and pipeline development expenses include expenses of our employees directly involved in development activities. Employees' salaries and benefits are charged to development expense when they are engaged directly in LNG receiving terminal and pipeline activities that meet capitalization criteria. The slight increase in 2006 compared to 2005 related to an increase in employee headcount.

Non-cash compensation—Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R, which requires recognition of compensation expense for all share-based payments granted after January 1, 2006 and prior to, but that have not yet vested as of January 1, 2006 using valuation models to determine the expense. As a result of our adoption of SFAS No. 123R, non-cash compensation increased \$3.6 million from 2005 to 2006.

Sabine Pass LNG receiving terminal site rental—As required by FSP FAS 13-1, *Accounting for Rental Costs Incurred During a Construction Period*, which became effective January 1, 2006, we expense our Sabine Pass LNG site lease.

Regulatory pipeline asset—In the second quarter of 2006, we recognized as regulatory assets, as prescribed by SFAS No. 71, *Accounting for Effects of Certain Types of Regulations*, amounts that had previously been expensed as pipeline development expenses. The impact of recording these regulatory assets reduced pipeline development expense for the year ended 2006 by \$12.3 million.

General and Administrative Expenses

2007 vs. 2006

The increase in G&A expenses by \$64.0 million in 2007 compared to 2006 primarily resulted from the expansion of our business (including increases in our corporate and LNG and natural gas marketing staff from an average of 111 employees in 2006 to an average of 187 employees in 2007). Included in G&A expenses in 2007 and 2006 was non-cash compensation of \$51.2 million and \$16.6 million, respectively. Excluding the impact of non-cash compensation, G&A for 2007 and 2006 would have been \$70.8 million and \$41.4 million, respectively.

2006 vs. 2005

The increase in G&A expenses by \$28.9 million in 2006 compared to 2005 primarily resulted from the expansion of our business (including increases in our corporate staff from an average of 47 employees in 2005 to an average of 95 employees in 2006). Included in G&A expenses in 2006 was an increase in non-cash compensation of \$11.1 million resulting primarily from stock option expense. Corporate employee-related costs in 2006 and 2005, including non-cash compensation, were \$27.0 million and \$12.6 million, respectively.

Gain on Sale of Investment in Unconsolidated Affiliate

In 2005, we recognized \$20.2 million from the sale of Gryphon Exploration Company ("Gryphon"), an unconsolidated affiliate of which we owned approximately 9.3%. Gryphon was sold for \$283.0 million, plus assumption of \$14.0 million of net debt, in a merger with Woodside Energy (USA). This sale generated net cash proceeds of \$20.2 million to us, and because our investment balance was zero at the closing of the transaction, we recognized a gain in 2005 equal to the cash proceeds amount.

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Loss on Early Extinguishment of Debt

In connection with the issuance of the Senior Notes in November 2006, we terminated an amended Sabine Pass credit facility and term loan. As a result, we recorded a \$43.2 million loss on the early extinguishment of debt related to the expensing of debt issuance costs.

Derivative Gain (Loss)

In connection with the issuance of the Senior Notes in November 2006, we terminated an amended Sabine Pass credit facility and term loan. As a result, we recorded a \$20.1 million derivative loss primarily as a result of terminating related interest rate swaps.

Interest Expense, net

2007 vs. 2006

Interest expense, net of amounts capitalized, increased \$50.6 million in 2007 compared to 2006. The increase was caused primarily by interest expense recognized on the Sabine Pass notes issued for the construction of the Sabine Pass LNG receiving terminal. In addition, in May 2007, we entered into the 2007 Term Loan which increased our debt and correspondingly increased our interest expense, net of amounts capitalized.

2006 vs. 2005

Interest expense, net of amounts capitalized, increased \$36.6 million in 2006 compared to 2005. The increase related primarily to the issuance of the Senior Notes in November 2006. The issuance of the Senior Notes represented a significantly larger debt obligation compared to borrowings under the Sabine Pass credit facility in existence in 2005, and resulted in greater interest expense that was not subject to capitalization.

Interest Income

2007 vs. 2006

Interest income increased \$33.5 million in 2007 compared to 2006 because of the higher average invested cash balances resulting from the November 2006 issuance of Senior Notes.

2006 vs. 2005

Interest income increased \$31.6 million in 2006 compared to 2005. The increase primarily related to the increase in average invested cash balances in 2006.

Off-Balance Sheet Arrangements

As of December 31, 2007, we had no “off-balance sheet arrangements” that may have a current or future material affect on our consolidated financial position or results of operations.

Inflation and Changing Prices

During 2007, 2006 and 2005, inflation and changing commodity prices have had an impact on our revenues but have not significantly impacted our results of operations. However, we experienced escalated steel prices relating to the construction of our Sabine Pass LNG receiving terminal as a result of global market conditions and increased labor and materials costs in connection with the collateral effects of the 2005 hurricanes.

Summary of Critical Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. In preparing our financial statements in conformity with U.S. generally accepted accounting principles (“GAAP”), we make every effort to comply properly with all applicable rules on or before their adoption, and we believe that the proper implementation and consistent application of the accounting rules are critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them. Additional information about our critical accounting policies is included in Note 2—“Summary of Significant Accounting Policies” of our Notes to Consolidated Financial Statements.

Change in Method of Accounting for Investments in Oil and Gas Properties

Effective January 1, 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties. While our primary focus is the development of our LNG-related businesses, we have continued to be involved, to a limited extent, in oil and gas exploration and development activities in the U.S. Gulf of Mexico. We determined that, in light of our level of exploration and development activities in 2005, the successful efforts method of accounting provided a better matching of expenses to the period in which oil and gas production was realized. As a result, we determined that the change in accounting method at that time was appropriate. The change in accounting method constituted a “Change in Accounting Principle,” requiring that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from our inception. The cumulative effect of the change in accounting method as of December 31, 2006 and 2005 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by \$18.0 million and \$18.2 million, respectively. The change in accounting method resulted in a decrease in the net loss of \$0.3 million and an increase in the net loss of \$0.3 million for the years ended December 31, 2006 and 2005, respectively, and had no impact on earnings per share (basic and diluted) for these respective periods (see Note 19—“Adjustment to Financial Statements—Successful Efforts” of our Notes to Consolidated Financial Statements). The change in method of accounting had no impact on cash or working capital.

Accounting for LNG Activities

We begin capitalizing the costs of our LNG receiving terminals and related pipelines once the individual project meets the following criteria: (i) regulatory approval has been received, (ii) financing for the project is available and (iii) management has committed to commence construction. Prior to meeting these criteria, most of the costs associated with a project are expensed as incurred. These costs primarily include professional fees associated with front-end engineering and design work, costs of securing necessary regulatory approvals, and other preliminary investigation and development activities related to our LNG receiving terminals and related natural gas pipelines.

Costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land costs, costs of lease options and the cost of certain permits which are capitalized as intangible LNG assets. The costs of lease options are amortized over the life of the lease once it is obtained. If no lease is obtained, the costs are expensed. Site rental costs and related amortization of capitalized options have been capitalized during the construction period through the end of 2006. Beginning in 2006, such costs have been expensed as required by FSP 13-1.

During the construction periods of our LNG receiving terminals and related pipelines, we capitalize interest and other related debt costs in accordance with SFAS No. 34, *Capitalization of Interest Cost*, as amended by SFAS No. 58, *Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method—an Amendment of FASB Statement No. 34*. Upon commencement of operations, capitalized interest, as a component of the total cost, will be amortized over the estimated useful life of the asset.

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Revenue Recognition

LNG regasification capacity fees are recognized as revenue over the term of the respective TUAs. Advance capacity reservation fees are initially deferred.

Successful Efforts Method of Accounting

We have elected to follow the successful efforts method of accounting for our oil and gas properties. Under this method, production costs, geological and geophysical costs (including the cost of seismic data), delay rentals, costs of unsuccessful exploratory wells, and internal costs directly related to our exploration and development activities are charged to expense as incurred. The costs of property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are initially capitalized when incurred. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures and a risk-adjusted discount rate. Individually significant unproved properties are also periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Depreciation, depletion and amortization of proved oil and gas properties is determined on a field-by-field basis using the unit-of-production method over the life of the remaining proved reserves.

We account for the retirement of our tangible long-lived assets in accordance with SFAS No. 143 *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires us to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and a corresponding increase in the carrying amount of the related long-lived assets. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using the unit-of-production method used to depreciate oil and gas properties under the full cost method of accounting.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently uncertain, and our reserve data are only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate. At least annually, our reserves are estimated by an independent petroleum engineer.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of natural gas and crude oil that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

The present value of future net cash flows does not necessarily represent the current market value of our estimated proved natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

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Our rate of recording depreciation, depletion and amortization (“DD&A”) is dependent upon our estimate of proved reserves. If the estimate of proved reserves declines, the rate at which we record DD&A expense increases thereby reducing net income. Such a decline may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields.

Regulated Natural Gas Pipelines

Our developing natural gas pipeline business is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we have determined that certain of our pipeline systems to be constructed have met the criteria set forth in SFAS No. 71, *Accounting for the Effects of Certain Types of Regulations*. Accordingly, we have applied the provisions of SFAS No. 71 to the affected pipeline subsidiaries beginning in the second quarter of 2006.

Our application of SFAS No. 71 is based on the current regulatory environment, our current projected tariff rates, and our ability to collect those rates. Future regulatory developments and rate cases could impact this accounting. Although discounting of our maximum tariff rates may occur, we believe that the standards required by SFAS No. 71 for its application are met and the use of regulatory accounting under SFAS No. 71 best reflects the results of future operations in the economic environment in which we will operate. Regulatory accounting requires us to record assets and liabilities that result from the rate-making process that would not be recorded under generally accepted accounting principles for non-regulated entities. We will continue to evaluate the application of regulatory accounting principles based on on-going changes in the regulatory and economic environment. Items that may influence our assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the rate-making process and the FERC proceedings;
- excess capacity;
- increased competition and discounting in the markets we serve; and
- impacts of ongoing regulatory initiatives in the natural gas industry.

Natural gas pipeline costs include amounts capitalized as an Allowance for Funds Used During Construction (“AFUDC”). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service.

Cash Flow Hedges

We have used, and may in the future use, derivative instruments to limit our exposure to variability in expected future cash flows. As defined in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, cash flow hedge transactions hedge the exposure to variability in expected future cash flows (i.e., in our case, the variability of floating interest rate exposure). In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the balance sheet prior to settlement), and any changes in the fair value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable, such as a movement in interest rates, has been effectively fixed so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement or else a one-sided net impact on earnings will be

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reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of other comprehensive income, to the extent that the hedge is effective. We assess both at the inception of each hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. On an on-going basis, we monitor the actual dollar offset of the hedges' market values compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges will be reflected in earnings. Ineffectiveness is the amount of gains or losses from derivative instruments that are not offset by corresponding and opposite gains or losses on the expected future transaction.

Goodwill

Goodwill is accounted for in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*. We perform an annual goodwill impairment review in the fourth quarter of each year, although we may perform a goodwill impairment review more frequently whenever events or circumstances indicate that the carrying value may not be recoverable. See Note 13—"Goodwill" of our Notes to Consolidated Financial Statements.

Share-Based Compensation Expense

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R using the modified prospective transition method, and therefore have not restated the results of prior periods. Under this method, we recognize compensation expense for all share-based payments granted after January 1, 2006 and prior to, but not yet vested as of, January 1, 2006, in accordance with SFAS 123R using the Black-Scholes-Merton option valuation model. Under the fair value recognition provisions of SFAS 123R, we recognize share-based compensation net of an estimated forfeiture rate and only recognize compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award. Prior to the adoption of SFAS 123R, we accounted for share-based payments under Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees*, and accordingly, did not recognize compensation expense for options granted that had an exercise price greater than or equal to the market value of the underlying common stock on the date of grant.

Determining the appropriate fair value model and calculating the fair value of share-based payment awards require the input of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. We believe that implied volatility, calculated based on traded options of our common stock, combined with historical volatility is an appropriate indicator of expected volatility and future stock price trends. Therefore, expected volatility for the year ended December 31, 2007 was based on a combination of implied and historical volatilities. The assumptions used in calculating the fair value of share-based payment awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our share-based compensation expense could be materially different in the future. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, the share-based compensation expense could be significantly different from what we have recorded in the current period. See Note 21—"Share-Based Compensation" of our Notes to Consolidated Financial Statements for a further discussion on share-based compensation.

Recently Issued Accounting Standards Not Yet Adopted

In September 2006, FASB issued SFAS 157, *Fair Value Measurements* ("SFAS No. 157"), which defines fair value, establishes a new framework for measuring that value and expands disclosures about fair value measurements. Broadly, SFAS No. 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or

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liability in an orderly transaction between market participants on the measurement date. SFAS No. 157 established market or observable inputs as the preferred source of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. SFAS No. 157 will require, among other things, expanded disclosure about fair value measurements that have a significant portion of the value determined using unobservable inputs (level 3 measurements). The standard applies prospectively to new fair value measurements performed after the required effective dates, which are as follows: on January 1, 2008, the standard applied to our measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities; on January 1, 2009, the standard will apply to all remaining fair value measurements, including non-recurring measurements of non-financial assets and liabilities such as measurement of potential impairments of goodwill, other intangible assets and other long-lived assets. It also will apply to fair value measurements of non-financial assets acquired and liabilities assumed in business combinations. In January 2008, the FASB issued proposed FASB Staff Position (FSP) FAS 157-c, Measuring Liabilities under Statement 157, which will modify the definition of fair value by requiring an estimation of the proceeds that would be received if the entity were to issue the liability at the measurement date. Further revisions to the measurement guidance are possible, and we are monitoring emerging interpretations and developments. SFAS No. 157 will not have a material adverse effect on our financial position, results of operations and cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value for Financial Assets and Financial Liabilities* (“SFAS No. 159”), which permits entities to choose to measure financial assets and liabilities, with certain exceptions, at fair value at specified election dates. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. A business entity shall report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning October 1, 2008. We are currently evaluating the impact of SFAS No. 159 on our financial position, results of operations and cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* (“SFAS No. 160”), which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 is effective for fiscal years beginning October 1, 2009. We are currently evaluating the impact SFAS No. 160 will have on our financial position, results of operations and cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Prices

We produce and sell natural gas, crude oil and condensate. As a result, our financial results can be affected as these commodity prices fluctuate widely in response to changing market forces. We have not entered into any derivative transactions related to our oil and gas producing activities.

Cash Investments

We have cash investments that we manage based on internal investment guidelines that emphasize liquidity and preservation of capital. Such cash investments are stated at historical cost, which approximates fair market value on our consolidated balance sheet.

Marketing and Trading Commodity Price Risk

Through Cheniere Marketing, we conduct natural gas marketing and trading activities accounted for as derivatives. We use value at risk (“VaR”) and other methodologies for market risk measurement and control purposes. For the year-ended December 31, 2007, the one-day VaR with a 95% confidence interval of our marketing and trading derivative positions averaged \$0.2 million. At December 31, 2007, the one-day VaR of our marketing and trading derivative positions was \$0.1 million.

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ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

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MANAGEMENT’S REPORTS TO THE STOCKHOLDERS OF CHENIERE ENERGY, INC.

Management’s Report on Internal Control Over Financial Reporting

As management, we are responsible for establishing and maintaining adequate internal control over financial reporting for Cheniere Energy, Inc. and its subsidiaries (“Cheniere”). In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, we have conducted an assessment, including testing using the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cheniere’s system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2007, based on criteria in *Internal Control—Integrated Framework* issued by the COSO.

Management’s Certifications

The certifications of Cheniere’s Chief Executive Officer and Chief Financial Officer required by the Sarbanes-Oxley Act of 2002 have been included as Exhibits 31 and 32 in Cheniere’s Form 10-K.

CHENIERE ENERGY, INC.

/s/ CHARIF SOUKI

/s/ DON A. TURKLESON

By: _____

By: _____

Charif Souki
Chief Executive Officer

Don A. Turkleson
Senior Vice President
and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.

We have audited the accompanying consolidated balance sheet of Cheniere Energy, Inc. and subsidiaries as of December 31, 2007, and the related consolidated statements of operations, stockholders' (deficit) equity, and cash flows for the year ended December 31, 2007. Our audit also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit. The financial statements of Cheniere Energy, Inc. for the years ended December 31, 2006 and 2005, were audited by other auditors whose report dated February 27, 2007, except for financial statement schedule I as to which the date is February 26, 2008, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2007 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cheniere Energy, Inc. and subsidiaries at December 31, 2007, and the consolidated results of their operations and their cash flows for the year ended December 31, 2007, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cheniere Energy, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 26, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

ERNST & YOUNG LLP

Houston, Texas
February 26, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.

We have audited Cheniere Energy, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Cheniere Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cheniere Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Cheniere Energy, Inc. and subsidiaries as of December 31, 2007, and the related consolidated statements of operations, stockholders' (deficit) equity, and cash flows for the year ended December 31, 2007 and our report dated February 26, 2008 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

ERNST & YOUNG LLP

Houston, Texas
February 26, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of Cheniere Energy, Inc.:

We have audited the accompanying consolidated balance sheet of Cheniere Energy, Inc. and subsidiaries (the "Company"), as of December 31, 2006, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2006. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule I. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cheniere Energy, Inc. and subsidiaries at December 31, 2006, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for investments in oil and gas properties. As also discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for stock-based compensation.

/s/ UHY LLP

UHY LLP

Houston, Texas
February 27, 2007 except for
financial statement schedule I as to which the
date is February 26, 2008

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CHENIERE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(in thousands, except share data)

	December 31,	
	2007	2006
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 296,530	\$ 462,963
Restricted cash and cash equivalents	228,085	176,827
Interest receivable	6,084	6,642
Accounts receivable	42,702	1,299
Derivative assets	1,056	—
Prepaid expenses and other	26,155	2,242
	<u>600,612</u>	<u>649,973</u>
Total current assets	600,612	649,973
NON-CURRENT RESTRICTED CASH AND CASH EQUIVALENTS	478,225	1,071,722
NON-CURRENT RESTRICTED TREASURY SECURITIES	63,923	—
PROPERTY, PLANT AND EQUIPMENT, NET	1,645,112	748,818
DEBT ISSUANCE COSTS, NET	44,005	41,545
GOODWILL	76,844	76,844
INTANGIBLE LNG ASSETS	20,402	4,331
ADVANCES UNDER LONG-TERM CONTRACTS	28,497	7,101
OTHER	4,679	4,154
	<u>2,962,299</u>	<u>2,604,488</u>
Total assets	\$ 2,962,299	\$ 2,604,488
LIABILITIES AND STOCKHOLDERS' (DEFICIT) EQUITY		
CURRENT LIABILITIES		
Accounts payable	\$ 6,620	\$ 3,659
Accrued liabilities	164,917	58,280
Derivative liabilities	1,564	—
	<u>173,101</u>	<u>61,939</u>
Total current liabilities	173,101	61,939
LONG-TERM DEBT	2,757,000	2,357,000
MINORITY INTEREST	285,675	—
DEFERRED REVENUE	40,000	41,000
OTHER NON-CURRENT LIABILITIES	8,637	1,302
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' (DEFICIT) EQUITY		
Preferred stock, \$.0001 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, \$.003 par value		
Authorized: 120,000,000 shares at both December 31, 2007 and 2006, respectively		
Issued and outstanding: 47,730,869 and 55,212,771 shares at December 31, 2007 and 2006, respectively	143	166
Treasury stock: 9,192,529 and no shares, respectively, at cost	(325,039)	—
Additional paid-in-capital	451,705	390,256
Accumulated deficit	(428,918)	(247,141)
Accumulated other comprehensive loss	(5)	(34)
	<u>(302,114)</u>	<u>143,247</u>
Total stockholders' (deficit) equity	(302,114)	143,247
Total liabilities and stockholders' (deficit) equity	\$ 2,962,299	\$ 2,604,488

The accompanying notes are an integral part of these financial statements.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2007	2006	2005
			(As Adjusted)
Revenues			
Oil and gas sales	\$ 5,376	\$ 2,310	\$ 3,005
Marketing and trading gain (loss)	(4,729)	61	—
Total revenues	647	2,371	3,005
Operating costs and expenses			
LNG receiving terminal and pipeline development expenses	34,656	12,099	22,020
Exploration costs	1,116	3,138	2,839
Oil and gas production costs	358	237	237
Impairment of fixed assets	18	1,628	—
Depreciation, depletion and amortization	6,393	3,131	1,325
General and administrative expenses	122,046	58,012	29,145
Total operating costs and expenses	164,587	78,245	55,566
Loss from operations	(163,940)	(75,874)	(52,561)
Derivative gain (loss)	—	(20,070)	837
Gain on sale of investment in unconsolidated affiliate	—	—	20,206
Equity in net loss of limited partnership	(191)	—	(1,031)
Loss on early extinguishment of debt	—	(43,159)	—
Interest expense, net	(104,557)	(53,968)	(17,373)
Interest income	82,635	49,087	17,520
Other income	851	176	722
Loss before income taxes and minority interest	(185,202)	(143,808)	(31,680)
Income tax (provision) benefit	—	(2,045)	2,045
Loss before minority interest	(185,202)	(145,853)	(29,635)
Minority interest	3,425	—	97
Net loss	\$ (181,777)	\$ (145,853)	\$ (29,538)
Net loss per common share—basic and diluted	\$ (3.60)	\$ (2.68)	\$ (0.56)
Weighted average number of common shares outstanding—basic and diluted	50,537	54,423	53,097

The accompanying notes are an integral part of these financial statements.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS' (DEFICIT) EQUITY
(in thousands)

	Common Stock		Treasury Stock		Additional Paid-In Capital	Deferred Compensation	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' (Deficit) Equity
	Shares	Amount	Shares	Amount					
Balance—December 31, 2004 (as adjusted)	50,919	\$ 153	—	\$ —	\$364,504	\$ (6,543)	\$ (71,750)	\$ —	\$ 286,364
Issuances of stock	3,427	10	—	—	80,115	—	—	—	80,125
Issuances of restricted stock	175	1	—	—	6,662	(6,663)	—	—	—
Amortization of deferred compensation	—	—	—	—	—	3,522	—	—	3,522
Expenses related to offerings	—	—	—	—	(27)	—	—	—	(27)
Purchase of issuer call spread	—	—	—	—	(75,703)	—	—	—	(75,703)
Comprehensive loss:									
Interest rate swaps, net of income tax	—	—	—	—	—	—	—	3,798	3,798
Net loss	—	—	—	—	—	—	(29,538)	—	(29,538)
Balance—December 31, 2005 (as adjusted)	54,521	164	—	—	375,551	(9,684)	(101,288)	3,798	268,541
Issuances of stock	386	1	—	—	1,995	—	—	—	1,996
Issuances of restricted stock	350	1	—	—	(1)	—	—	—	—
Forfeitures of restricted stock	(18)	—	18	—	—	—	—	—	—
Reversal of deferred compensation	—	—	—	—	(9,684)	9,684	—	—	—
Share-based compensation expense	—	—	—	—	23,371	—	—	—	23,371
Treasury stock acquired	(26)	—	26	976	(976)	—	—	—	—
Treasury stock retired	—	—	(44)	(976)	—	—	—	—	(976)
Comprehensive loss:									
Interest rate swaps	—	—	—	—	—	—	—	(3,798)	(3,798)
Foreign currency translation	—	—	—	—	—	—	—	(34)	(34)
Net loss	—	—	—	—	—	—	(145,853)	—	(145,853)
Balance—December 31, 2006	55,213	166	—	—	390,256	—	(247,141)	(34)	143,247
Issuances of stock	688	2	—	—	3,155	—	—	—	3,157
Issuances of restricted stock	1,029	2	—	—	(2)	—	—	—	—
Forfeitures of restricted stock	(20)	—	20	—	—	—	—	—	—
Share-based compensation	—	—	—	—	58,331	—	—	—	58,331
Treasury stock acquired	(9,179)	(27)	9,179	(325,101)	27	—	—	—	(325,101)
Treasury stock retired	—	—	(7)	62	(62)	—	—	—	—
Comprehensive loss:									
Foreign currency translation	—	—	—	—	—	—	—	29	29
Net loss	—	—	—	—	—	—	(181,777)	—	(181,777)
Balance—December 31, 2007	47,731	\$ 143	9,192	\$(325,039)	\$451,705	\$ —	\$(428,918)	\$ (5)	\$(302,114)

The accompanying notes are an integral part of these financial statements.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2007	2006	2005
			(As Adjusted)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	\$ (181,777)	\$ (145,853)	\$ (29,538)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	6,393	3,131	1,325
Impairment of unproved properties and dry hole expense	785	2,089	1,410
Amortization of debt issuance costs	6,320	3,958	—
Non-cash compensation	56,638	21,768	3,583
Use of restricted cash and cash equivalents	103,043	—	—
Restricted interest income on restricted cash and cash equivalents	(53,327)	—	—
Gain on sale of investment in unconsolidated affiliate	—	—	(20,206)
Deferred tax provision	—	2,045	(2,045)
Loss on early extinguishment of debt	—	37,136	—
Minority interest	(3,425)	—	(97)
Other	230	1,797	2,017
Changes in operating assets and liabilities:			
Accounts and interest receivable	(41,654)	(5,842)	(320)
Prepaid expenses	(23,928)	(1,522)	(280)
Deferred revenue	—	—	18,000
Deferred rent	4,404	—	—
Regulatory assets	—	(12,343)	—
Accounts payable and accrued liabilities	42,007	13,210	7,195
NET CASH USED IN OPERATING ACTIVITIES	(84,291)	(80,426)	(18,956)
CASH FLOWS FROM INVESTING ACTIVITIES:			
LNG terminal and pipeline construction-in-process	(788,517)	(440,367)	(229,705)
Use of (investment in) restricted cash and cash equivalents	526,318	(1,070,713)	(177,385)
Investments in restricted treasury securities	(98,442)	—	—
Purchases of intangible and fixed assets, net of sales	(41,684)	(10,527)	(5,811)
Investment in limited partnership	—	—	(2,102)
Oil and gas property, net of sales	17	(3,687)	(2,064)
Proceeds from sale of investment in unconsolidated affiliate	—	—	20,206
Advances under long-term contracts, net of transfers to construction-in-process	(38,617)	(7,101)	(8,087)
Other	1,031	(7,533)	(639)
NET CASH USED IN INVESTING ACTIVITIES	(439,894)	(1,539,928)	(405,587)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuances of Senior Notes	—	2,032,000	—
Proceeds from sale of common units in partnership	203,946	—	—
Proceeds from issuance of common units to minority owners in partnership	98,442	—	—
Distributions to minority interest	(13,631)	—	—
Issuance of Convertible Senior Unsecured Notes	—	—	325,000
Proceeds from Term Loan	—	—	600,000
Proceeds from 2007 Term Loan	400,000	—	—
Repayment of Term Loan	—	(598,500)	(1,500)
Borrowings under Sabine Pass Credit Facility	—	383,400	—
Repayment of Sabine Pass Credit Facility	—	(383,400)	—
Purchase of issuer call spread	—	—	(75,703)
Debt issuance costs	(9,787)	(43,796)	(42,124)
Sale of common stock	3,158	1,953	2,972
Purchase of treasury shares pursuant to an issuer call spread	(325,101)	—	—
Use of restricted cash and equivalents	725	—	—
Other	—	(932)	47
NET CASH PROVIDED BY FINANCING ACTIVITIES	357,752	1,390,725	808,692
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(166,433)	(229,629)	384,149
CASH AND CASH EQUIVALENTS—BEGINNING OF YEAR	462,963	692,592	308,443
CASH AND CASH EQUIVALENTS—END OF YEAR	\$ 296,530	\$ 462,963	\$ 692,592

The accompanying notes are an integral part of these financial statements.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, in the energy business generally, including our publicly traded subsidiary partnership, Cheniere Energy Partners, L.P. (“Cheniere Partners”). As used in these Notes to Consolidated Financial Statements, the terms “Cheniere”, “we”, “us” and “our” refer to Cheniere Energy, Inc. and its subsidiaries. We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals and natural gas pipelines, and we are developing a business to market LNG and natural gas primarily through our wholly-owned subsidiary, Cheniere Marketing, Inc. (“Cheniere Marketing”). To a limited extent, we continue to be engaged in oil and natural gas exploration and development activities in the Gulf of Mexico.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Cheniere Energy, Inc. and its majority-owned subsidiaries. We also hold ownership interests in entities that are accounted for under the equity method of accounting. All significant intercompany accounts and transactions have been eliminated in consolidation.

Certain reclassifications have been made to conform prior period information to the current presentation, including a \$179.0 million reclassification between current Restricted Cash and Cash Equivalents and Non-Current Restricted Cash and Cash Equivalents on our December 31, 2006 Consolidated Balance Sheet. The reclassification had no effect on our overall consolidated financial position, results of operations or cash flows.

All references to issued and outstanding shares, weighted average shares, and per share amounts in the accompanying consolidated financial statements have been retroactively adjusted to reflect our two-for-one stock split that occurred on April 22, 2005.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of our LNG receiving terminals and related pipelines once the individual project meets the following criteria: (i) regulatory approval has been received, (ii) financing for the project is available and (iii) management has committed to commence construction. Prior to meeting these criteria, most of the costs associated with a project are expensed as incurred. These costs primarily include professional fees associated with front-end engineering and design work, costs of securing necessary regulatory approvals, and other preliminary investigation and development activities related to our LNG receiving terminals and related pipelines.

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land costs, costs of lease options and the costs of certain permits, which are capitalized as intangible LNG assets. The costs of lease options are amortized over the life of the lease once obtained. If no lease is obtained, the costs are expensed. Site rental costs and related amortization of capitalized options were capitalized during the construction period through the end of 2005. Beginning in 2006, such costs have been expensed as required by the Financial Accounting Standards Board (“FASB”) Staff Position (“FSP”) 13-1, *Accounting for Rental Cost Incurred During a Construction Period*.

During the construction periods of our LNG receiving terminals, we capitalize interest and other related debt costs in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 34, *Capitalization of Interest Cost, as amended by SFAS No. 58, Capitalization of Interest Cost in Financial Statements That Include*

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Investments Accounted for by the Equity Method—an Amendment of FASB Statement No. 34 Upon commencement of operations, capitalized interest, as a component of the total cost, will be amortized over the estimated useful life of the asset.

Regulated Operations

Our developing natural gas pipeline business is subject to the jurisdiction of the Federal Energy Regulatory Commission (“FERC”) in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we have determined that certain of our pipeline systems to be constructed have met the criteria set forth in SFAS No. 71, *Accounting for the Effects of Certain Types of Regulations*. Accordingly, we began applying the provisions of SFAS No. 71 to the affected pipeline subsidiaries in the second quarter of 2006.

Our application of SFAS No. 71 is based on the current regulatory environment, our current projected tariff rates and our ability to collect those rates. Future regulatory developments and rate cases could impact this accounting. Although discounting of our maximum tariff rates may occur, we believe the standards required by SFAS No. 71 for its application are met and the use of regulatory accounting under SFAS No. 71 best reflects the results of future operations in the economic environment in which we will operate. Regulatory accounting requires us to record assets and liabilities that result from the rate-making process that would not be recorded under generally accepted accounting principles (“GAAP”) for non-regulated entities. We will continue to evaluate the application of regulatory accounting principles based on on-going changes in the regulatory and economic environment. Items that may influence our assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the rate-making process and the FERC proceedings;
- excess capacity;
- increased competition and discounting in the markets we serve; and
- impacts of ongoing regulatory initiatives in the natural gas industry.

Natural gas pipeline costs include amounts capitalized as an Allowance for Funds Used During Construction (“AFUDC”). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service.

Change in Method of Accounting for Investments in Oil and Gas Properties

Effective January 1, 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties. While our primary focus is the development of our LNG-related businesses, we have continued to be involved, to a limited extent, in oil and gas exploration and development activities in the U.S. Gulf of Mexico. We determined that, in light of our current level of exploration and development activities, the successful efforts method of accounting provides was better matching of expenses to the period in which oil and gas production was realized. As a result, we determined that the change in accounting method was appropriate. The change in accounting method constituted a “Change in Accounting Principle,” requiring that all prior period financial statements be adjusted to reflect the results and balances that would have been reported had we been following the successful efforts method of accounting from

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

our inception. The cumulative effect of the change in accounting method as of December 31, 2006 and 2005 was to reduce the balance of our net investment in oil and gas properties and retained earnings at those dates by \$2.9 million and \$18.0 million, respectively. The change in accounting method for the years ended December 31, 2006 and 2005 resulted in a decrease in the net loss of \$15.0 million and \$0.3 million, respectively. The cumulative effect of the change in accounting method increased earnings per share (basic and diluted) \$0.28 for the year ended December 31, 2006, but had no impact on earnings per share (basic and diluted) for the year ended December 31, 2005 (see Note 19 —“Adjustment to Financial Statements—Successful Efforts”). The change in method of accounting had no impact on cash or working capital.

Successful Efforts Method of Accounting

We have elected to follow the successful efforts method of accounting for our oil and gas properties. Under this method, production costs, geological and geophysical costs (including the cost of seismic data), delay rentals, costs of unsuccessful exploratory wells, and internal costs directly related to our exploration and development activities are charged to expense as incurred. The costs of property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are initially capitalized when incurred. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is written down to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures and a risk-adjusted discount rate. Individually significant unproved properties are also periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Depreciation, depletion and amortization of proved oil and gas properties are determined on a field-by-field basis using the unit-of-production method over the life of the remaining proved reserves.

Capitalized Exploratory Well Costs

In April 2005, the FASB issued FSP No. FAS 19-1, *Accounting for Suspended Well Costs*, which amends SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*. Under the provisions of FSP No. FAS 19-1, exploratory well costs continue to be capitalized after the completion of drilling when (i) the well has found a sufficient quantity of reserves to justify completion as a producing well and (ii) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FSP No. FAS 19-1 provides several indicators that can assist an entity in demonstrating that sufficient progress is being made when assessing the reserves and economic viability of the project.

At December 31, 2007, we had not capitalized any suspended well costs for wells on which drilling was completed more than one year ago. In addition, there were no suspended well costs charged to expense for the year ended December 31, 2007.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Asset Retirement Obligations

We account for the retirement of our tangible long-lived assets in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires us to record the fair value of a liability for legal obligations associated with the retirement of tangible long-lived assets and a corresponding increase in the carrying amount of the related long-lived assets. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense based on the useful life of the applicable asset.

Revenue Recognition

LNG regasification capacity fees are recognized as revenue over the term of the respective terminal use agreement (“TUA”). Advance capacity reservation fees are initially deferred.

Revenues from the sale of oil and gas production are recognized upon passage of title, net of royalty interests. When sales volumes differ from our entitled share, an underproduced or overproduced imbalance occurs. To the extent an overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. At December 31, 2007 and 2006, we had no gas imbalances.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction activities, major renewals and betterments are capitalized, while expenditures for maintenance and repairs and general and administrative activities are charged to expense as incurred. Interest costs incurred on debt obtained for the construction of property, plant and equipment are capitalized as construction-in-process over the construction period or related debt term, whichever is shorter. Once placed into service, the LNG terminal construction-in-process costs will be depreciated using the straight-line depreciation method. Depreciation of computer and office equipment, computer software, leasehold improvements and vehicles is computed using the straight-line method over the estimated useful lives of the assets, which range from two to ten years. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed from the account, and the resulting gains or losses are recorded in operations.

In accordance with SFAS No. 144, management reviews property, plant and equipment for impairment periodically and whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. No such impairment was recorded for the years ended December 31, 2007, 2006 or 2005.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements. Deferred tax assets and liabilities are included in the consolidated financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled as prescribed in SFAS No. 109, *Accounting for Income Taxes*. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the current period’s provision for income taxes. A valuation allowance is provided for deferred tax assets if it is more likely than not that such asset will not be realizable.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Cash Flow Hedges

As defined in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, cash flow hedge transactions hedge the exposure to variability in expected future cash flows (i.e., in our case, the variability of floating interest rate exposure). In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the balance sheet prior to settlement), and any changes in the fair value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable, such as a movement in interest rates, has been effectively fixed so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement or else a one-sided net impact on earnings will be reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of other comprehensive income, to the extent that the hedge is effective. We assess both at the inception of each hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. On an on-going basis we monitor the actual dollar offset of the hedges' market values compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges will be reflected in earnings. Ineffectiveness is the amount of gains or losses from derivative instruments that are not offset by corresponding and opposite gains or losses on the expected future transaction.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make certain estimates and assumptions that affect the amounts reported in the consolidated financial statements and the accompanying notes. Actual results could differ from the estimates and assumptions used.

Depletion of oil and gas properties is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves. Similarly, total reserves to be discovered through our exploration program are subject to numerous uncertainties including estimates of future recoverable reserves and commodity price outlook.

Other items subject to estimates and assumptions include, but are not limited to, the carrying amount of property, plant and equipment, and goodwill; valuation allowances for income tax assets; and the fair value of share-based payments. Actual results could differ significantly from those estimates.

Cash Equivalents

We classify all investments with original maturities of three months or less as cash equivalents. Our investments are primarily in commercial paper and are made in accordance with corporate policy, which, among other things, stipulates minimum acceptable credit ratings of commercial paper issuers.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, restricted cash and cash equivalents, restricted certificates of deposit, accounts receivable, and accounts payable approximate fair value because of the short maturity of those instruments. We use available market data and valuation methodologies to estimate the fair value of debt.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Commodity Price Risk

We produce and sell natural gas, crude oil and condensate. As a result, our financial results can be affected as these commodity prices fluctuate widely in response to changing market forces. We had not entered into any commodity hedging transactions as of December 31, 2007.

Concentration of Credit Risk

All of our oil and gas revenues are attributable to properties operated by five companies. These companies sell our share of production for us, pay the associated severance taxes, and remit the balance to us. Our products are commodities and have a readily available market for sale.

We maintain funds in bank accounts that exceed the limit insured by the Federal Deposit Insurance Corporation (“FDIC”). Accounts are guaranteed by the FDIC up to \$100,000. The risk of loss attributable to these uninsured balances is mitigated by depositing funds only in commercial banks with minimum Standard & Poor’s and Moody’s Investor Service ratings of A and Aa3, respectively. We have not experienced any losses in such accounts.

We have entered into certain long-term TUAs with unaffiliated third parties for regasification capacity at our proposed Sabine Pass LNG receiving terminal. We are dependent on the respective counterparties’ creditworthiness and their willingness to perform under their respective TUAs. We have mitigated this credit risk by securing TUAs with creditworthy third-party customers with a minimum Standard & Poor’s rating of AA.

Goodwill

As further described in Note 13—“Goodwill”, we account for goodwill in accordance with the provisions of SFAS No. 142 *Goodwill and Other Intangible Assets*. Under the provisions of that statement, we are required to perform an annual review of goodwill for impairment. This review is required to be done at the reporting unit level, which we have determined to be our LNG receiving terminals business, which is a component of our LNG receiving terminal development business segment. We perform the annual review for possible impairment in the fourth calendar quarter of each year. If an event or change in circumstances indicates the fair value of a reporting unit may be below its carrying value, an impairment test would be performed sooner than the annual review date.

Debt Issuance Costs

Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees and printing costs. These costs are capitalized and are being amortized to interest expense over the term of the related debt facility.

Share-Based Compensation Expense

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123R, *Share-Based Payments*, using the modified prospective transition method, and therefore have not restated the results of prior periods. Under this method, we recognize compensation expense for all share-based payments granted after January 1, 2006 and prior to, but not yet vested as of, January 1, 2006, in accordance with SFAS No. 123R using the Black-Scholes-Merton option valuation model. Under the fair value recognition provisions of SFAS No. 123R, we recognize share-based compensation net of an estimated forfeiture rate and only recognize compensation cost for those shares expected to vest on a straight-line basis over the requisite service period of the award. Prior to the adoption of SFAS No. 123R, we accounted for share-based payments under Accounting Principles Board (“APB”) Opinion 25, *Accounting for Stock Issued to Employees*, and accordingly, did not recognize compensation expense for options granted that had an exercise price greater than or equal to the market value of the underlying common stock on the date of grant.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Determining the appropriate fair value model and calculating the fair value of share-based payment awards requires the use of highly subjective assumptions, including the expected life of the share-based payment awards and stock price volatility. We believe that implied volatility, calculated based on traded options of our common stock, combined with historical volatility is an appropriate indicator of expected volatility and future stock price trends. Therefore, the expected volatility for the year ended December 31, 2007 used in our fair value model was based on a combination of implied and historical volatilities. The assumptions used in calculating the fair value of share-based payment awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. As a result, if factors change and we use different assumptions, our share-based compensation expense could be materially different in the future. In addition, we are required to estimate the expected forfeiture rate and only recognize expense for those shares expected to vest. If our actual forfeiture rate is materially different from our estimate, future share-based compensation expense could be significantly different from what we have recorded in the current period (see Note 21—“Share-Based Compensation” for further discussion on share-based compensation).

Net Loss Per Share

Net loss per share (“EPS”) is computed in accordance with the requirements of SFAS No. 128, *Earnings Per Share*. Basic EPS excludes dilution and is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted EPS reflects potential dilution and is computed by dividing net income by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued. Basic and diluted EPS for all periods presented are the same since the effect of our options, warrants and unvested stock is anti-dilutive to our net loss per share under SFAS No. 128. Stock options, warrants and unvested stock representing securities that could potentially dilute basic EPS in the future that were not included in the diluted computation because they would have been anti-dilutive for the years 2007, 2006 and 2005 were 5.8 million, 5.7 million and 5.7 million, respectively. In addition, common shares of 9.2 million, 9.2 million and 4.0 million on a weighted average basis, issuable upon conversion of the Convertible Senior Unsecured Notes (described in Note 17—“Long-Term Debt and Credit Facility”), were not included in the computation of diluted net loss per share for 2007, 2006 and 2005, respectively, because the computation of diluted net loss per share utilizing the “if-converted” method would be anti-dilutive. No adjustments were made to reported net loss in the computation of EPS.

New Accounting Pronouncements

In September 2006, FASB issued SFAS 157, *Fair Value Measurements*, which defines fair value, establishes a new framework for measuring that value and expands disclosures about fair value measurements. Broadly, SFAS No. 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. SFAS No. 157 established market or observable inputs as the preferred source of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. SFAS No. 157 will require, among other things, expanded disclosure about fair value measurements that have a significant portion of the value determined using unobservable inputs (level 3 measurements). The standard applies prospectively to new fair value measurements performed after the required effective dates, which are as follows: on January 1, 2008, the standard applied to our measurements of the fair values of financial instruments and recurring fair value measurements of non-financial assets and liabilities; on January 1, 2009, the standard will apply to all remaining fair value measurements, including non-recurring measurements of non-financial assets and liabilities such as measurement of potential impairments of goodwill, other intangible assets and other long-lived assets. It also will apply to fair value measurements of non-financial

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

assets acquired and liabilities assumed in business combinations. In January 2008, the FASB issued proposed FASB Staff Position (FSP) FAS 157-c, Measuring Liabilities under Statement 157, which will modify the definition of fair value by requiring an estimation of the proceeds that would be received if the entity were to issue the liability at the measurement date. Further revisions to the measurement guidance are possible, and we are monitoring emerging interpretations and developments. SFAS No. 157 will not have a material adverse effect on our financial position, results of operations and cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value for Financial Assets and Financial Liabilities*, which permits entities to choose to measure financial assets and liabilities, with certain exceptions, at fair value at specified election dates. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. A business entity shall report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning October 1, 2008. We are currently evaluating the impact of SFAS No. 159 on our financial position, results of operations and cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51*, which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 is effective for fiscal years beginning October 1, 2009. We are currently evaluating the impact SFAS No. 160 will have on our financial position, results of operations and cash flows.

NOTE 3—INITIAL PUBLIC OFFERING OF CHENIERE ENERGY PARTNERS, L.P.

On March 26, 2007, Cheniere Energy Partners, L.P. (“Cheniere Partners”) and Cheniere LNG Holdings, LLC (“Holdings”), our wholly-owned subsidiary, completed a public offering of 13,500,000 Cheniere Partners common units (the “Cheniere Partners Offering”). Cheniere Partners is a Delaware limited partnership formed by us to develop, own and operate the Sabine Pass liquefied natural gas (“LNG”) receiving terminal. Upon the closing of the Cheniere Partners Offering, the following transactions occurred:

- Holdings contributed its ownership interests in the entities that directly or indirectly own the Sabine Pass LNG receiving terminal to Cheniere Energy Investments, LLC, a wholly-owned subsidiary of Cheniere Partners;
- Cheniere Partners issued 21,362,193 common units, 135,383,831 subordinated units, 3,302,045 general partner units (representing a 2% general partner interest) and certain general partner incentive distribution rights to wholly-owned subsidiaries of Cheniere;
- Cheniere Partners issued 5,054,164 common units to the public and received net proceeds of \$98.4 million; and
- Holdings initially sold 8,445,836 common units to the public and received net proceeds of \$164.5 million, after which Cheniere and the public owned 89.8% and 8.2% limited partner interests in Cheniere Partners, respectively. Holdings also granted the underwriters an option to purchase an additional 2,025,000 of its Cheniere Partners’ common units to cover over-allotments in connection with the Cheniere Partners Offering.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Cheniere Partners used all of the net proceeds of \$98.4 million it received from the sale of its common units to purchase U.S. treasury securities to fund a distribution reserve for payment of initial quarterly distributions of \$0.425 per common unit, as well as related quarterly distributions to its general partner, through the quarterly distribution to be made in respect of the quarter ending June 30, 2009.

On April 16, 2007, the underwriters of the Cheniere Partners Offering exercised their over-allotment option to purchase 2,025,000 additional common units, which resulted in net proceeds of approximately \$39.4 million to Holdings as the selling unitholder.

The net proceeds of \$164.5 million from the initial sale of the common units by Holdings and the net proceeds of \$39.4 million that it received from the subsequent exercise of the underwriters' option to purchase additional common units from Holdings are not assets of Cheniere Partners, and therefore are unrestricted as to our use and are available for corporate and general business purposes.

As of December 31, 2007, our combined general partner and limited partner ownership interest in Cheniere Partners was approximately 90.6%. As of such date, we held 135,383,831 subordinated units, 10,891,357 common units and 3,302,045 general partner units of Cheniere Partners. During the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the initial quarterly distribution plus any arrearages on the initial quarterly distribution from prior quarters. Our subordinated units do not accrue arrearages. The subordination period generally will end if:

- Cheniere Partners has earned and paid at least \$0.425 on each outstanding common unit, subordinated unit and general partner unit for each of the three consecutive, non-overlapping four-quarter periods ending on or after June 30, 2010; or
- Cheniere Partners has earned and paid at least \$0.638 (150% of the initial quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for any four consecutive quarters ending on or after June 30, 2008.

The portion of the common units held by the public is presented as a minority interest on our Consolidated Balance Sheet. Losses attributable to the minority interest are presented separately on our Consolidated Statement of Operations based upon the minority interest's share of Cheniere Partners' losses calculated in accordance with Cheniere Partners' partnership agreement.

NOTE 4—MINORITY INTEREST

We have consolidated certain joint ventures and partnerships because we have a controlling interest in these ventures. Therefore, the entities' financial statements are consolidated in our consolidated financial statements and the other entities equity is recorded as minority interest. The following table sets forth the components of our minority interest balance attributable to third-party investors' interest (in thousands):

Net proceeds from Cheniere Partners' issuance of common units (1)	\$ 98,442
Net proceeds from Holdings' sale of Cheniere Partners common units (2)	203,946
Distributions to Cheniere Partners' minority interest	(13,631)
Minority interest share of loss of Cheniere Partners	(3,425)
Minority interest in Frontera (3)	343
	<hr/>
Minority interest at December 31, 2007	\$285,675

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- (1) Through the Cheniere Partners Offering, Cheniere Partners received \$98.4 million in net proceeds from the issuance of its common units to the public. Securities and Exchange Commission (“SEC”) Staff Accounting Bulletin (“SAB”) No. 51, *Accounting for Sales of Stock by a Subsidiary*, provides guidance on accounting by the parent for issuances of a subsidiary’s common equity to unaffiliated parties. Under SAB No. 51, a company may elect an accounting policy of recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the parent’s investment. Upon the conversion of all of our subordinated units in Cheniere Partners to common units, we will evaluate whether to recognize a gain through earnings at that time.
- (2) In conjunction with the Cheniere Partners Offering, Holdings sold a portion of the Cheniere Partners common units held by it to the public, realizing proceeds net of offering costs of \$203.9 million, which included \$39.4 million of net proceeds realized once the underwriters exercised their option to purchase an additional 2,025,000 common units from Holdings. Due to the subordinated distribution rights on our subordinated units, we have recorded those proceeds as a minority interest. Upon the conversion of all of our subordinated units in Cheniere Partners to common units, we will evaluate whether to recognize a gain through earnings at that time.
- (3) In September 2007, Cheniere acquired an 80% interest in Frontera Pipeline LLC (“Frontera”) from Tidelands Oil and Gas Corporation (“Tidelands”) for \$1.0 million, providing Cheniere with an 80% ownership stake in the Burgos Hub Project. This project involves the development and construction of an integrated pipeline project traversing the United States and Mexico border and the construction of a related subterranean storage facility in Mexico. As of December 31, 2007, Tidelands’ proportionate interest in the net assets of Frontera was \$0.3 million.

NOTE 5—TREASURY STOCK

During the second and third quarters of 2007, we purchased 9.2 million shares of our common stock through the exercise of call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes (see Note 17—“Long-Term Debt and Credit Facility”). These purchases completed the acquisition of our common stock under the call option, bringing our total stock purchased under the issuer call spread to 9.2 million shares with an aggregate purchase price of approximately \$325.0 million. These shares were held as treasury stock at December 31, 2007.

NOTE 6—RESTRICTED CASH AND CASH EQUIVALENTS AND TREASURY SECURITIES

Restricted cash and cash equivalents and treasury securities are composed of cash that has been contractually restricted as to usage or withdrawal, as follows:

Sabine Pass LNG Receiving Terminal Construction Reserve

In November 2006, Sabine Pass LNG, L.P., our wholly-owned subsidiary (“Sabine Pass LNG”), consummated a private offering of an aggregate principal amount of \$2 billion of Senior Secured Notes consisting of \$550 million of 7 1/4% Senior Secured Notes due 2013 (the “2013 Notes”) and \$1.5 billion of 7 1/2% Senior Secured Notes due 2016 (the “2016 Notes”) and collectively with the 2013 Notes, the “Senior Notes”) (see Note 17—“Long-Term Debt and Credit Facility”). Under the terms and conditions of the Senior Notes, we were required to fund a cash reserve account for approximately \$887 million to pay the remaining costs to complete the Sabine Pass LNG receiving terminal. The cash accounts are controlled by a collateral trustee, and therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheet. As of December 31, 2007 and 2006, \$40.2 million and \$16.5 million related to accrued construction costs had been classified as part of current restricted cash and cash equivalents, and \$380.2 million and \$803.6 million related to remaining construction costs had been classified as a non-current asset on our Consolidated Balance Sheet, respectively.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Senior Notes Debt Service Reserve

As described above, Sabine Pass LNG consummated a private offering of an aggregate principal amount of \$2 billion Senior Notes (see Note 17—“Long-Term Debt and Credit Facility”). Under the terms and conditions of the Senior Notes, we were required to fund a cash reserve account for \$335.0 million related to future interest payments on the Senior Notes through May 2009. The cash accounts are controlled by a collateral trustee, and therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheet. As of December 31, 2007 and 2006, \$151.0 million and \$159.8 million related to the payment of interest due within twelve months had been classified as part of current restricted cash, and \$61.8 million and \$179.0 million related to the remaining payments of interest through May 2009 had been classified as non-current restricted cash, respectively.

Cheniere Partners Distribution Reserve

At the closing of the Cheniere Partners Offering, Cheniere Partners funded a distribution reserve of \$98.4 million, which was invested in U.S. treasury securities (see Note 3—“Initial Public Offering of Cheniere Energy Partners, L.P.”). The distribution reserve, including interest earned thereon, will be used to pay quarterly distributions of \$0.425 per common unit for all common units, as well as related distributions to Cheniere Partners’ general partner, through the distribution made in respect of the quarter ending June 30, 2009. The U.S. treasury securities were acquired at a discount from their maturity values equal to an average of approximately 4.87% per year. As of December 31, 2007, we classified the \$63.9 million balance of U.S. treasury securities as Non-Current Restricted Treasury Securities on our Consolidated Balance Sheet, as these securities had original maturities greater than three months.

Other Restricted Cash and Cash Equivalents

As of December 31, 2007 and 2006, \$36.9 million and \$0.5 million related to various other contractual restrictions had been classified as part of current restricted cash and cash equivalents, and \$36.2 million and \$89.1 million had been classified as a non-current asset on our Consolidated Balance Sheet, respectively.

NOTE 7—LEASES

Future Annual Minimum Lease Payments

Future annual minimum lease payments are as follows (in thousands):

<u>Year Ending December 31,</u>	<u>Operating Leases (2)</u>
2008	57,237
2009	57,188
2010	57,146
2011	57,144
2012	57,198
Thereafter (1)(2)	238,253
Total	\$ 524,166

(1) Thereafter includes certain lease option renewals as they were reasonably assured, as defined in SFAS No. 13, *Accounting for Leases*.

(2) Future annual minimum lease payments do not include \$4.3 million expected to be recovered through sublease agreements for our Texas Avenue office lease in Houston, Texas.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Tug Boat Agreements

Sabine Pass TUG Services, LLC, our wholly owned subsidiary, entered into a Marine Services Agreement (the “Tug Agreement”) for the use of tug boats and marine services for the Sabine Pass LNG receiving terminal. The term of the Tug Agreement commenced in January 2008 for a period of 10 years, with an option to renew two additional, consecutive terms of five years each. In accordance with EITF 01-08, *Determining Whether an Arrangement Contains a Lease*, we have determined that the Tug Agreement contains a lease for the tugs specified in the Tug Agreement. In addition, we have concluded that the tug boat lease contained in the Tug Agreement is an operating lease as defined in SFAS No. 13, and as such, the equipment component of the Tug Agreement will be charged to expense over the term of the Tug Agreement as it becomes payable.

LNG Vessel Time Charters

In December 2007, we acquired the remaining 51% equity interest in J & S Cheniere S.A. (“J & S Cheniere”), which had entered into time charter party agreements. The agreements provide us with LNG vessels, for the purpose of carrying LNG cargos, for a minimum period of five years with an option to extend for an additional five years with the same terms and conditions as the original charter period.

LNG Site Leases

Our obligations under LNG site options are renewable on an annual or semiannual basis. We may terminate our obligations at any time by electing not to renew or by exercising the options.

In January 2005, we exercised our options and entered into three land leases for the site of the Sabine Pass LNG receiving terminal. The leases have an initial term of 30 years, with options to renew for six 10-year extensions with similar terms as the initial term. In February 2005, two of the three leases were amended, thereby increasing the total acreage under lease to 853 acres and increasing the annual lease payments to \$1.5 million. The annual lease payments will be adjusted for inflation based on a consumer price index, as defined in the lease agreements, every five years. We recognized \$1.5 million of site lease expense on the Consolidated Statement of Operations for 2007 and 2006.

NOTE 8—ADVANCES UNDER LONG-TERM CONTRACTS

We have entered into certain engineering, procurement and construction (“EPC”) contracts and purchase agreements related to the construction of our Sabine Pass LNG receiving terminal that require us to make payments to fund costs that will be incurred or equipment that will be received in the future. Advances made under long-term contracts on purchase commitments are carried at face value and transferred to Property, Plant and Equipment as the costs are incurred or equipment is received. As of December 31, 2007 and 2006, our Advances Under Long-term Contracts were \$28.5 million and \$7.1 million, respectively.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 9—PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of LNG terminal construction-in-process expenditures, LNG site and related costs, investments in oil and gas properties, and fixed assets, as follows (in thousands):

	December 31,	
	2007	2006
LNG TERMINAL COSTS		
LNG terminal construction-in-process	\$ 1,169,695	\$ 684,008
LNG site and related costs, net	1,991	1,467
Total LNG terminal costs	\$ 1,171,686	\$ 685,475
NATURAL GAS PIPELINE COSTS		
Natural gas pipeline construction-in-process	\$ 425,038	\$ 45,615
Pipeline right-of-ways	15,751	2,134
Total natural gas pipeline costs	\$ 440,789	\$ 47,749
OIL AND GAS PROPERTIES, successful efforts method		
Proved	\$ 2,526	\$ 2,343
Unproved	—	779
Accumulated depreciation, depletion and amortization	(653)	(263)
Total oil and gas properties, net	\$ 1,873	\$ 2,859
FIXED ASSETS		
Computers and office equipment	\$ 8,195	\$ 5,352
Furniture and fixtures	5,008	1,310
Computer software	12,268	8,043
Leasehold improvements	11,247	2,206
Projects-in-process	2,147	1,724
Other	1,072	123
Accumulated depreciation	(9,173)	(6,023)
Total fixed assets, net	\$ 30,764	\$ 12,735
PROPERTY, PLANT AND EQUIPMENT, net	\$ 1,645,112	\$ 748,818

LNG Terminal Costs

Once an LNG receiving terminal is placed into service, the related LNG terminal construction-in-process costs will be depreciated using the straight-line depreciation method. The identifiable components of the Sabine Pass LNG receiving terminal with similar estimated useful lives have a depreciable range between 10 and 50 years. Depreciation will begin once construction is complete.

Costs associated with the construction of the Sabine Pass LNG receiving terminal have been capitalized as construction-in-process since the date the project satisfied our criteria for capitalization. For the years ended December 31, 2007, 2006 and 2005, we capitalized \$66.2 million, \$24.9 million and \$5.3 million of interest expense related to the construction of the Sabine Pass LNG receiving terminal, respectively. In March 2006, our Corpus Christi LNG receiving terminal satisfied the criteria for capitalization. Accordingly, costs associated with the initial site work for the Corpus Christi LNG receiving terminal have been capitalized as construction-in process since that time. For the years ended December 31, 2007 and 2006, we capitalized \$2.1 million and \$0.5 million, respectively, of interest expense related to this construction project.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Natural Gas Pipeline Costs

Our developing natural gas pipeline business is subject to the jurisdiction of the Federal Energy Regulatory Commission (“FERC”) in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we have determined that our pipelines to be constructed have met the criteria set forth in SFAS No. 71. Accordingly, we began applying the provisions of SFAS No. 71 to the affected pipeline subsidiaries in the third quarter of 2006. Natural gas pipeline costs also include amounts capitalized as Allowance for Funds Used During Construction (“AFUDC”). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service. For the years ended December 31, 2007 and 2006, we capitalized \$15.1 million and \$1.1 million, respectively, of AFUDC to our natural gas pipeline projects.

Oil and Gas Properties

In the first quarter of 2006, we converted from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties; therefore, our oil and gas property balance presented above has been adjusted to reflect this change (see Note 19—“Adjustment to Financial Statements—Successful Efforts”).

Fixed Assets

Our fixed assets are recorded at cost and are depreciated on a straight-line method based on estimated lives of the individual assets or groups of assets. Depreciation expense related to our property, plant and equipment totaled \$5.7 million, \$2.9 million and \$1.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

In the third quarter of 2006, we impaired certain leasehold improvement costs related to our office space under the Texas Avenue office lease in accordance with FASB Technical Bulletin No. 79-15, *Accounting for Loss on a Sublease Not Involving the Disposal of a Segment*. The impairment was the result of signing our new office lease for space under the Pennzoil office lease (see Note 23—“Commitments and Contingencies”), and the belief that we would not recover or realize a benefit from the leasehold improvement costs in the future. The impact of this impairment in property, plant and equipment was to increase accumulated depreciation by \$1.6 million and recognize an impairment of fixed assets by the same amount in our Consolidated Statement of Operations.

NOTE 10—INTANGIBLE ASSETS

The fair values, net book values and estimated useful lives of our intangible assets as of December 31, 2007 and 2006 are presented in the following tables.

	As of December 31, 2007			
	Fair value	Amortization Period	Accumulated Amortization	Net book value
Amortizable intangible assets	\$ 14,228	5 years	\$ —	\$ 14,228
Intangible assets not subject to amortization	6,174	—	—	6,174
	\$20,402		\$ —	\$ 20,402

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

As of December 31, 2006

	Fair value	Amortization Period	Accumulated Amortization	Net book value
Intangible assets not subject to amortization	4,331	—	—	4,331
	<u>\$ 4,331</u>		<u>\$ —</u>	<u>\$ 4,331</u>

Amortizable Intangible Assets

We assigned \$14.2 million and zero to intangible assets acquired either individually or with a group of assets that are subject to amortization as of December 31, 2007 and 2006, respectively. The weighted average amortization period for these assets is 5 years. For the years ended December 31, 2007 and 2006, we had not recognized amortization expense.

Intangible Assets Not Subject to Amortization

We assigned \$6.2 million and \$4.3 million to intangible assets acquired either individually or with a group of assets that are not subject to amortization as of December 31, 2007 and 2006, respectively.

NOTE 11—DEBT ISSUANCE COSTS

We have incurred debt issuance costs in connection with our long-term debt. These costs are capitalized and are being amortized over the term of the related debt. As of December 31, 2007, we had capitalized \$44.0 million of costs directly associated with the arrangement of debt financing, net of accumulated amortization, as follows (in thousands):

Long-term Debt	Debt Issuance Costs	Amortization Period	Accumulated Amortization	Net Costs
2013 Senior Notes	\$ 9,352	7 years	\$ (1,591)	\$ 7,761
2016 Senior Notes	25,199	10 years	(3,065)	22,134
2007 Term Loan	8,450	5 years	(982)	7,468
Senior Unsecured Convertible Notes	9,542	7 years	(3,344)	6,198
Marketing Credit Facility	612	1 years	(168)	444
	<u>\$ 53,155</u>		<u>\$ (9,150)</u>	<u>\$44,005</u>

Scheduled amortization of these debt issuance costs for the next five years is estimated to be \$33.1 million.

NOTE 12—INVESTMENT IN LIMITED PARTNERSHIP

We account for our 30% limited partnership investment in Freeport LNG Development, L.P. ("Freeport LNG") using the equity method of accounting. As of December 31, 2007 and 2006, we had unrecorded cumulative suspended losses of \$19.8 million and \$13.0 million, respectively, related to our investment in Freeport LNG as the basis in this investment had been reduced to zero. We did not record our share of the losses of the partnership for all of 2007 and 2006 and a portion of 2005 because we did not guarantee any obligations and had not been committed to provide any further financial support since December 2005.

We recorded zero, zero and \$1.0 million for the years ended December 31, 2007, 2006 and 2005, respectively, related to net losses of Freeport LNG.

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The financial position of Freeport LNG at December 31, 2007 and 2006 and the results of Freeport LNG's operations for the years ended December 31, 2007, 2006 and 2005 are summarized as follows (in thousands):

	December 31,	
	2007	2006
Current assets	\$ 120,580	\$ 274,399
Construction-in-process	863,977	594,191
Fixed assets, net, and other assets	47,906	30,132
Total assets	\$ 1,032,463	\$ 898,722
Current liabilities	\$ 34,477	\$ 38,621
Notes payable	1,063,984	903,369
Deferred revenue and other deferred credits	5,478	5,666
Partners' capital	(71,476)	(48,934)
Total liabilities and partners' capital	\$ 1,032,463	\$ 898,722

	Year Ended December 31,		
	2007	2006	2005
Revenue	\$ —	\$ —	\$ —
Loss from continuing operations	(16,677)	(16,631)	(16,238)
Net loss	(22,542)	(30,162)	(16,663)
Cheniere's 30% equity in net loss from limited partnership (1)	\$ (6,763)	\$ (9,049)	\$ (4,999)

- (1) During 2007, 2006 and 2005, we did not record \$6.8 million, \$9.0 million and \$4.0 million of the net losses for such periods, respectively, as the basis in this investment had been reduced to zero and because we did not guarantee any obligations and had not been committed to provide any further financial support since December 2005.

NOTE 13—GOODWILL

In February 2005, we acquired the minority interest in Corpus Christi LNG, L.P. ("Corpus Christi LNG"), through the acquisition of BPU LNG, Inc. ("BPU"), in exchange for 2.0 million restricted shares of our common stock. BPU held as its sole asset the 33.3% limited partner interest in Corpus Christi LNG. As a result of this transaction, we own 100% of the limited partner interests in Corpus Christi LNG. This transaction was accounted for using the purchase method of accounting as prescribed by SFAS No. 141, *Accounting for Business Combinations*, and was valued at \$77.2 million, including direct transaction costs. Of this amount, \$76.8 million has been recorded as goodwill and will be accounted for in accordance with SFAS No. 142. The goodwill is the difference between the deemed value of the shares conveyed and the historical carrying value of the minority interest under GAAP plus direct transaction costs. For the calculation of federal income taxes, none of this goodwill amount will be deductible.

We performed annual goodwill impairment reviews in the fourth quarter of 2007 and 2006. These impairment reviews consisted of comparing the carrying value, including goodwill, of the reporting unit under review to the estimated fair value of the reporting unit. Had the carrying value exceeded the estimated fair value of the reporting unit, an impairment of the reporting unit would have been recognized, resulting in an impairment charge to earnings. A reporting unit is defined as a business segment or component of a business segment that has similar economic characteristics. For our impairment reviews, we have designated our LNG receiving terminal business as the reporting unit under review due to similar economic characteristics. Our reviews indicated that no impairment of goodwill was necessary.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 14—DERIVATIVE INSTRUMENTS

Interest Rate Derivative Instruments

In connection with the closing of the Sabine Pass Credit Facility in February 2005, we entered into swap agreements (“Sabine Swaps”). Under the terms of the Sabine Swaps, we were able to hedge against rising interest rates, to a certain extent, with respect to drawings under the Sabine Pass Credit Facility, up to a maximum amount of \$700 million. The Sabine Swaps had the effect of fixing the LIBOR component of the interest rate payable under the Sabine Pass Credit Facility with respect to hedged drawings under the Sabine Pass Credit Facility up to a maximum of \$700 million at 4.49% from July 25, 2005 through March 25, 2009 and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the Sabine Swaps was March 25, 2012.

The Sabine Pass Credit Facility was amended and restated in July 2006, increasing the amount available to Sabine Pass LNG from \$822 million to \$1.5 billion. In connection with the closing of the amended Sabine Pass Credit Facility in July 2006, we entered into additional interest rate swap agreements (the “Amended Sabine Swaps” and collectively with the Sabine Swaps, the “Swaps”). The Swaps had the combined effect of fixing the LIBOR component of the interest rate payable on borrowings up to a maximum of \$1.25 billion at a blended rate of 5.26% from July 25, 2006 through July 1, 2015.

In connection with the closing of the Term Loan on August 31, 2005, Cheniere LNG Holdings entered into interest rate swap agreements (“Term Loan Swaps”) to hedge against rising interest rates. Under the terms of the Term Loan Swaps, Cheniere LNG Holdings hedged an initial notional amount of \$600 million. The notional amount declined in accordance with anticipated principal payments under the Term Loan. The Term Loan Swaps had the effect of fixing the LIBOR rate component of the interest rate payable under the Term Loan at 3.75% from August 31, 2005 to September 27, 2007, at 3.98% from September 28, 2007 to September 27, 2008, and at 5.98% from September 28, 2008 to September 30, 2010. The final termination date of the Term Loan Swaps was September 30, 2010.

In conjunction with the termination of the amended Sabine Pass Credit Facility and the Term Loan in November 2006, we terminated the Swaps and the Term Loan Swaps, and recognized a loss of \$20.1 million. In accordance with EITF 00-9, *Classification of a Gain or Loss from a Hedge of Debt That Is Extinguished*, the loss recognized as the result of early termination of the Swaps and the Term Loan Swaps is presented on the Consolidated Statement of Operations as a Derivative loss.

Accounting for Hedges

SFAS No. 133, as amended and interpreted by other related accounting literature, establishes accounting and reporting standards for derivative instruments. Under SFAS No. 133, we are required to record derivatives on our balance sheet as either an asset or liability measured at their fair value, unless exempted from derivative treatment under the normal purchase and normal sale exception. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met. These criteria require that the derivative is determined to be effective as a hedge and that it is formally documented and designated as a hedge.

We determined that the Swaps and the Term Loan Swaps qualified as cash flow hedges within the meaning of SFAS No. 133 and designated them as such. We assessed both at the inception of each of the Swaps and the Term Loan Swaps and on an on-going basis, whether the Swaps and the Term Loan Swaps that were used in our hedging transactions were highly effective in offsetting changes in cash flows of the hedged items. At inception, we determined the hedging relationship of the Swaps and the Term Loan Swaps and the underlying debt to be

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

highly effective. On an on-going basis, we monitored the actual dollar offset of the market values of the Swaps and the Term Loan Swaps compared to hypothetical cash flow hedges. Any ineffective portion of the cash flow hedges was reflected in earnings. We continued to assess the hedge effectiveness of the Swaps and the Term Loan Swaps on a quarterly basis in accordance with the provisions of SFAS No. 133 until they were terminated in November 2006. Ineffectiveness is the amount of gains or losses from derivative instruments which are not offset by corresponding and opposite gains or losses on the expected future transaction.

SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of accumulated other comprehensive income (“AOCI”) and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. In our case, the impact on earnings was a reduction of interest expense of zero and \$7.2 million for the years ended December 31, 2007 and 2006, respectively. The ineffective portion of the gain or loss on the derivative instruments, if any, must be recognized currently in earnings. For the years ended December 31, 2007 and 2006, we have recognized a net derivative loss of zero and loss of \$20.1 million, respectively. If the forecasted transaction is no longer probable of occurring, the associated gain or loss recorded in AOCI is recognized currently in earnings.

NOTE 15—ACCRUED LIABILITIES

As of December 31, 2007 and 2006, accrued liabilities consisted of the following (in thousands):

	December 31,	
	2007	2006
LNG terminal construction costs	\$ 39,574	\$ 16,334
Accrued interest expense and related fees	16,159	24,861
Pipeline construction costs	47,266	7,039
Natural gas purchases	40,607	—
Debt issuance costs	—	783
Payroll	16,143	5,512
IT projects-in-process	—	1,067
Other accrued liabilities	5,168	2,684
Accrued liabilities	\$ 164,917	\$ 58,280

NOTE 16—DEFERRED REVENUE

As of December 31, 2007 and 2006, we had recorded \$40.0 million and \$41.0 million as deferred revenue, respectively, related to advance capacity reservation fee payments.

In November 2004, Total LNG USA, Inc. (“Total”) paid Sabine Pass LNG a nonrefundable advance capacity reservation fee of \$10.0 million in connection with the reservation of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. An additional advance capacity reservation fee payment of \$10.0 million was paid by Total to Sabine Pass LNG in April 2005. The advance capacity reservation fee payments will be amortized over a 10-year period after operations commence as a reduction of Total’s regasification capacity fee under its TUA. As a result, we recorded the advance capacity reservation fee payments that we received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

In November 2004, we entered into a TUA to provide Chevron U.S.A., Inc. (“Chevron”) with approximately 0.7 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. In December 2005, Chevron exercised its option to increase its reserved capacity by approximately 0.3 Bcf/d to approximately 1.0 Bcf/d and paid Sabine Pass LNG an additional \$3.0 million advance capacity reservation fee. As of December 31, 2007, Chevron USA had made advance capacity reservation fee payments to Sabine Pass LNG totaling \$20.0 million. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron’s regasification capacity fee under its TUA. As a result, we recorded the advance capacity reservation payments that we received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

NOTE 17—LONG-TERM DEBT AND CREDIT FACILITY

As of December 31, 2007 and 2006, our long-term debt consisted of the following (in thousands):

	December 31,	
	2007	2006
Senior Notes	\$ 2,032,000	\$ 2,032,000
Convertible Senior Unsecured Notes	325,000	325,000
2007 Term Loan	400,000	—
Total Long-Term Debt	\$ 2,757,000	\$ 2,357,000

Below is a schedule of future principal payments that we are obligated to make on our outstanding long-term debt at December 31, 2007 (in thousands):

	Payments Due for Years Ended December 31,				
	Total	2008	2009 to 2010	2011 to 2012	Thereafter
Senior Notes	\$ 2,032,000	\$ —	\$ —	\$ —	\$ 2,032,000
Convertible Senior Unsecured Notes	325,000	—	—	325,000	—
2007 Term Loan	400,000	—	—	400,000	—
Total	\$ 2,757,000	\$ —	\$ —	\$ 725,000	\$ 2,032,000

Sabine Pass LNG Senior Notes

In November 2006, Sabine Pass LNG issued an aggregate principal amount of \$2,032.0 million of Senior Notes, consisting of \$550.0 million of the 2013 Notes and \$1,482.0 million of the 2016 Notes. Interest on the Senior Notes is payable semi-annually in arrears on May 30 and November 30 of each year. The Senior Notes are secured on a first-priority basis by a security interest in all of Sabine Pass LNG’s equity interests and substantially all of its operating assets.

Under the indenture governing the Senior Notes, except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied. The indenture requires that Sabine Pass LNG apply its net operating cash flow (i) first, to fund with monthly deposits its next semiannual payment of approximately \$75.5 million of interest on the Senior Notes, and (ii) second, to fund a one-time, permanent debt service reserve fund equal to one semiannual interest payment of approximately \$75.5 million on the Senior Notes. Distributions from Sabine Pass LNG will be permitted only after phase 1 target completion, as defined in

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

the indenture governing the Senior Notes, or such earlier date as project revenues are received, upon satisfaction of the foregoing funding requirements, after satisfying a fixed charge coverage ratio test of 2:1 and after satisfying other conditions specified in the indenture.

Convertible Senior Unsecured Notes

In July 2005, we consummated a private offering of \$325.0 million aggregate principal amount of Convertible Senior Unsecured Notes due 2012 to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (“Securities Act”). The notes bear interest at a rate of 2.25% per year. The notes are convertible at any time into our common stock under certain circumstances at an initial conversion rate of 28.2326 shares per \$1,000 principal amount of the notes, which is equal to a conversion price of approximately \$35.42 per share. As of December 31, 2007, no holders had elected to convert their notes.

We may redeem some or all of the notes on or before August 1, 2012, for cash equal to 100% of the principal plus any accrued and unpaid interest if in the previous 10 trading days the volume-weighted average price of our common stock exceeds \$53.13, subject to adjustment, for at least five consecutive trading days. In the event of such a redemption, we will make an additional payment equal to the present value of all remaining scheduled interest payments through August 1, 2012, discounted at the U.S. Treasury rate plus 50 basis points. The indenture governing the notes contains customary reporting requirements.

Concurrently with the issuance of the Convertible Senior Unsecured Notes, we also entered into hedge transactions in the form of an issuer call spread (consisting of a purchase and a sale of call options on our common stock) with an affiliate of the initial purchaser of the notes, having a term of two years and a net cost to us of \$75.7 million. These hedge transactions were entered into to offset potential dilution from conversion of the notes. The net cost of the hedge transactions was recorded as a reduction to Additional Paid-in-Capital in accordance with the guidance of Emerging Issues Task Force (“EITF”) Issue 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company’s Own Stock*. Net proceeds from the offering were \$239.8 million, after deducting the cost of the hedge transactions, the underwriting discount and related fees.

As of December 31, 2007, we had repurchased 9.2 million shares of our common stock through the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes at a cash price of \$35.42 per share, for an aggregate purchase price of approximately \$325.0 million.

2007 Term Loan

In May 2007, Cheniere Subsidiary Holdings, LLC (“Cheniere Subsidiary”), a newly formed wholly-owned subsidiary of Cheniere, entered into a \$400.0 million credit agreement (“2007 Term Loan”). Borrowings under the 2007 Term Loan generally bear interest at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the 2007 Term Loan outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. The 2007 Term Loan will mature on May 31, 2012. The net proceeds of \$391.7 million from the 2007 Term Loan are being used for general corporate purposes, including our repurchase, completed during the year ended December 31, 2007, of approximately 9.2 million shares of our outstanding common stock pursuant to the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes. The 2007 Term Loan is secured by a pledge of our subordinated units in Cheniere Partners and our equity interests in the entities that own our 30% interest in Freeport LNG.

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Marketing Credit Facility

In September 2007, Cheniere Marketing entered into a credit facility (“Marketing Credit Facility”) that provides up to \$35.0 million of borrowings and up to \$100.0 million of letters of credit and is secured by the “borrowing base” composed of cash or cash equivalents, receivables, broker margin deposits and inventory of Cheniere Marketing meeting certain criteria. Cheniere Marketing may only use the letters of credit and proceeds of loans for financing, securing or guaranteeing the performance of its obligations related to the purchase, sale, storage, transfer or exchange of natural gas and other products, to support Cheniere Marketing’s obligations under commodity contracts and derivative contracts related to such products, and to fund the working capital requirements of Cheniere Marketing. Borrowings mature on the earlier of two months after such borrowings and September 12, 2008. The unpaid principal balance of each borrowing generally bears interest at a variable rate equal to LIBOR plus 1.50%. The Marketing Credit Facility is secured by a pledge of Cheniere Marketing’s accounts receivables, inventory and other assets. As of December 31, 2007, we had no borrowings and \$66.5 million letters of credit outstanding under the Marketing Credit Facility.

Sabine Pass Credit Facility

In February 2005, we entered into the \$822 million Sabine Pass Credit Facility which was subsequently amended and restated in July 2006. The amended Sabine Pass Credit Facility increased the amount of the loans available to us from \$822 million to \$1.5 billion to finance the costs of constructing and placing into operations of the Sabine Pass LNG receiving terminal. In connection therewith, we entered into the Swaps to hedge the LIBOR interest rate component of the Sabine Pass Credit Facility. The Swaps had the combined effect of fixing the LIBOR component of the interest rate payable on borrowings up to a maximum of \$1.25 billion at a blended rate of 5.26% from July 25, 2006 through July 1, 2015 (see Note 14—“Derivative Instruments”).

Borrowings under the amended Sabine Pass Credit Facility bore interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varied from 0.875% to 1.125% during the term of the amended Sabine Pass Credit Facility. Interest was calculated on the unpaid principal amount outstanding and was payable semi-annually in arrears. A commitment fee of 0.50% per annum on the daily, undrawn portion of the lenders’ commitment was required. Administrative fees were also paid annually to the agent and the collateral agent. During 2006, borrowings under the amended Sabine Pass Credit Facility totaled \$383.4 million. Total interest expense recognized for the years ended December 31, 2006 and 2005 was \$13.7 million and \$5.3 million before capitalization of \$13.0 million and \$5.3 million, respectively.

In November 2006, as discussed above, borrowings under the amended Sabine Pass Credit Facility were repaid, and the facility was terminated in conjunction with the closing of the Senior Notes.

Term Loan

In August 2005, Holdings entered into a \$600 million Term Loan. The Term Loan interest rate equaled LIBOR plus a 2.75% margin with a termination date of August 30, 2012. In connection with the closing, Holdings entered into the Term Loan Swaps to hedge the LIBOR interest rate component of the Term Loan. The blended rate of the Term Loan Swaps on the Term Loan resulted in an annual fixed interest rate of 7.25% (including the 2.75% margin) for the first five years (see Note 14—“Derivative Instruments”). Quarterly principal payments of \$1.5 million were required through June 30, 2012, and a final principal payment of \$559.5 million was required on August 30, 2012.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

At December 31, 2005, principal repayments on the Term Loan of \$6.0 million were due within the next twelve months and were classified on the Consolidated Balance Sheet as a current liability. Total interest expense recognized for the years ended December 31, 2006 and 2005 was \$35.7 million and \$14.4 million before interest capitalization of \$3.5 million and \$603,000, respectively.

In November 2006, as discussed above, the amount outstanding under the Term Loan was repaid, and the Term Loan was terminated in conjunction with the issuance of the Senior Notes.

NOTE 18—FINANCIAL INSTRUMENTS

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, restricted cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term nature. We use available marketing data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*, and does not impact our financial position, results of operations or cash flows.

Financial Instruments (in thousands):

	Year Ended December 31, 2007		Year Ended December 31, 2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
2013 Notes (1)	\$ 550,000	\$ 525,250	\$ 550,000	\$ 547,250
2016 Notes (1)	1,482,000	1,404,195	1,482,000	1,478,295
2.25% Convertible Senior Unsecured Notes (2)	325,000	338,611	325,000	334,750
2007 Term Loan (3)	400,000	400,000	—	—
Restricted treasury securities (4)	63,923	66,984	—	—

- (1) The fair value of the Senior Notes is based on quotations obtained from broker-dealers who made markets in these and similar instruments as of December 31, 2007 and December 29, 2006.
- (2) The fair value of our Convertible Senior Unsecured Notes is based on the closing trading prices on December 31, 2007 and December 29, 2006.
- (3) The 2007 Term Loan bears interest at a fixed rate; therefore, the estimated fair value is expected to vary with changes in market interest rates. At December 31, 2007, the fair value of the debt instrument was stated at its carrying amount due to it being a non-trading instrument with no liquid market.
- (4) The fair value of our Restricted Treasury Securities is based on quotations obtained from broker-dealers who made markets in these and similar instruments as of December 31, 2007.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 19—ADJUSTMENT TO FINANCIAL STATEMENTS—SUCCESSFUL EFFORTS

As a result of our election to change our method of accounting for investments in oil and gas properties as discussed in Note 2—“Summary of Significant Accounting Policies”, adjustments have been made to the financial statements of prior periods as required by SFAS No. 154, *Accounting Changes and Error Corrections*. The effects of the change as it relates to financial data for the periods presented are displayed below (in thousands, except per share data):

Statement of Operations

	Year Ended December 31, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
Revenues	\$ 3,005	\$ 3,005	\$ —
Operating costs and expenses:			
LNG receiving terminal and pipeline development expenses	22,020	22,020	—
Exploration costs	—	2,839	2,839
Oil and gas production costs	237	237	—
Depreciation, depletion and amortization	3,702	1,325	(2,377)
General and administrative expenses	29,145	29,145	—
Total operating costs and expenses	55,104	55,566	462
Loss from operations	(52,099)	(52,561)	(462)
Non-operating income	20,159	20,881	722
Loss before income taxes and minority interest	(31,940)	(31,680)	260
Minority interest	97	97	—
Income tax benefit	2,045	2,045	—
Net loss	\$ (29,798)	\$ (29,538)	\$ 260
Net loss per share—basic and diluted	\$ (0.56)	\$ (0.56)	\$ —

Statement of Cash Flows

	Year Ended December 31, 2005		
	As Originally Reported	As Reported Under Successful Efforts	Effect of Change
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	\$ (29,798)	\$ (29,538)	\$ 260
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	3,702	1,325	(2,377)
Dry hole expense	—	809	809
Impairment of unproved properties	—	601	601
Other adjustments	(16,893)	(16,748)	145
Changes in operating assets and liabilities	24,595	24,595	—
NET CASH USED IN OPERATING ACTIVITIES	(18,394)	(18,956)	(562)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property additions, net of sales	(3,861)	(3,299)	562
Other cash flows from other investing activities	(402,288)	(402,288)	—
NET CASH USED IN INVESTING ACTIVITIES	(406,149)	(405,587)	562
NET CASH PROVIDED BY FINANCING ACTIVITIES	808,692	808,692	—
NET INCREASE IN CASH AND CASH EQUIVALENTS	384,149	384,149	—
CASH AND CASH EQUIVALENTS—BEGINNING OF PERIOD	308,443	308,443	—
CASH AND CASH EQUIVALENTS—END OF PERIOD	\$ 692,592	\$ 692,592	\$ —

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 20—INCOME TAXES

Income tax (provision) benefit included in our reported net loss consisted of the following (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Current federal income tax expense	\$ —	\$ —	\$ —
Deferred federal income tax (provision) benefit	—	(2,045)	2,045
Total income tax (provision) benefit	\$ —	\$(2,045)	\$2,045

From our inception, we have reported net operating losses for both financial reporting purposes and for federal and state income tax reporting purposes. Accordingly, we are not presently a taxpayer and have not recorded a net liability for federal, state or international income taxes in any of the years included in the accompanying financial statements. Our Consolidated Statement of Operations for the years ended December 31, 2006 and 2005 included a deferred income tax provision of \$2.0 million and a deferred income tax benefit of \$2.0 million, respectively. The deferred income tax provision and benefit recorded for the years ended December 31, 2006 and 2005 were recorded in accordance with the guidance in paragraph 140 of SFAS No. 109 and EITF Abstracts, Topic D-32, which, in certain circumstances, require items reported in AOCI to be considered in the realization of the tax benefit associated with a loss from continuing operations. In our situation, the specific circumstance relates to pre-tax Other Comprehensive Income (“OCI”) of \$5.8 million recorded for the year ended December 31, 2005 related to our interest rate swaps (see Note 14—“Derivative Instruments” and Note 22—“Comprehensive Loss” for additional discussions). The \$2.0 million deferred income tax benefit included in our 2005 Consolidated Statement of Operations represents the portion of the change in our tax asset valuation account that is allocable to the deferred income tax on items reported in OCI in our 2005 Consolidated Statement of Stockholders’ Equity. For the year ended 2006, however, primarily due to the termination of our interest rate swaps, we recorded a pre-tax OCI loss of \$5.8 million, and as a result recorded a deferred income tax provision of \$2.0 million. Such deferred income tax provision was limited to the amount of the deferred income tax benefit reported in the prior year.

Deferred tax assets and liabilities reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities at December 31, 2007 and 2006 are as follows (in thousands):

	Year Ended December 31,	
	2007	2006
Deferred tax assets		
Net operating loss carryforwards	\$ 38,560	\$ 54,381
Stock grant compensation expense	21,199	5,658
Advance payments—terminal use agreements	—	14,000
Start-up costs and construction-in-process associated with LNG, pipeline and marketing activities	8,051	18,727
Oil and gas properties and fixed assets (1)	2,137	2,248
Investment in limited partnership	90,600	1,538
Unrealized mark-to-market gains and losses	178	—
	\$ 160,725	\$ 96,552

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	Year Ended December 31,	
	2007	2006
Deferred tax liabilities		
Other items—deductible for tax	\$ (1,318)	\$ —
	(1,318)	—
Net deferred tax assets	159,407	96,552
Less: tax asset valuation allowance	(159,407)	(96,552)
	\$ —	\$ —

- (1) The change in the deferred tax asset valuation allowance in 2006 included \$6.3 million that related to the deferred tax asset created as a result of our conversion from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties effective January 1, 2006.

We believe that a substantial portion of the Sabine Pass LNG receiving terminal assets qualify for the 50% bonus depreciation allowance enacted by the Gulf Opportunity Zone Act of 2005. These accelerated deductions are based on the Sabine Pass qualifying additions that were treated as placed-in-service in 2007 under the applicable Internal Revenue Service (“IRS”) guidelines. The accelerated tax depreciation deduction offsets a substantial portion of the tax gain realized in the first quarter of 2007 that resulted from the Cheniere Partners Offering.

New Accounting Pronouncement

In July 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement No. 109*. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This new standard also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition rules.

The Company adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, on January 1, 2007. On the date of adoption, we determined that all of the material tax positions taken in our income tax returns and the positions we expect to take in our future income tax filings meet the more likely-than-not recognition threshold prescribed by FIN No. 48. During 2007, we determined that approximately \$70.5 million of deferred tax benefits for current year tax positions related to the accelerated recovery of certain capital costs for which the ultimate deductibility is highly certain, but for which there is some uncertainty related to the timing of the related current and future tax deductions. Under SFAS No. 109, the disallowance of an accelerated recovery period would not affect our annual reported effective income tax rate but would most likely result in the acceleration of cash income tax payments to the relevant taxing authorities. Adjustments that would affect our current year taxable income would generally be offset by our available net operating loss (“NOL”) carryovers, and therefore, the potential underpayment interest and penalties have not been accrued with respect to this liability.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

It is reasonably likely that the amount of our unrecognized tax benefits associated with the additions based on tax positions related to the 2007 reporting period will decrease significantly within the next twelve months, but the amount of the decrease cannot be reasonably estimated at this time. To date, the adoption of FIN No. 48 has had no impact on our financial position, results of operations or cash flows. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

Balance as January 1, 2007	\$ —
Additions based on tax positions related to current year	70,530
Additions for tax positions of prior years	—
Reductions for tax positions of prior years	—
Settlements	—
	<hr/>
Balance at December 31, 2007	\$ 70,530

(1) We have a request pending with the IRS to enter into a formal Pre-Filing Agreement for us to resolve the uncertain tax positions associated with the accelerated recovery of certain of our 2007 capital costs, and the timing of the related current and future tax deductions. We expect to finalize the agreement with the IRS early in 2008.

Our federal consolidated income tax returns filed to date have not been audited by the Internal Revenue Service; we have not been notified of any pending federal, state or international income tax audits. We have not entered into any agreements with any taxing authorities to extend the period of time in which they may assert or assess additional income tax, penalties or interest. However, because we are presently in an NOL carryover position and have been since our inception, under the applicable Internal Revenue Service guidelines, in the event of an audit, our available federal NOL carryover amount is subject to adjustment until the normal three-year federal statute of limitations closes for the year in which the NOL is fully utilized. The Texas Comptroller's office recently completed an audit of Cheniere's Texas franchise tax returns for the three-year period ended December 31, 2004; the Louisiana Department of Revenue recently completed an income and franchise audit of Cheniere and one of our wholly-owned affiliates for the two-year period ended December 31, 2003. We expect that all of our significant operating affiliates will be audited by the States of Texas and Louisiana for annual tax reporting periods ended on or after December 31, 2004. To date, all of the state-level income tax audits that have been settled favorably and without changes. None of our foreign affiliates have been audited by any foreign taxing authorities and none have been notified of any pending income tax audits.

As discussed above, we have not previously recorded a liability for international, federal or state income taxes and therefore we have not been subject to any penalties or interest expense related to any income tax liabilities. In future reporting periods, if any interest or penalties are imposed in connection with an income tax liability, we expect to include both of these items in the our income tax provision.

In accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our net operating loss ("NOL") carryforwards and other deferred tax assets. The change in the deferred tax asset valuation allowance was \$62.9 million and \$56.2 million for the years ended December 31, 2007 and 2006, respectively. The \$56.2 million change in the deferred tax asset valuation allowance in 2006 includes \$6.3 million that relates to the deferred tax asset created as a result of our conversion from the full cost method to the successful efforts method of accounting for our investments in oil and gas properties effective January 1, 2006 (see Note 2—"Summary of Significant Accounting Policies").

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

As discussed in Note 21—“Share-Based Compensation”, we adopted SFAS No. 123R effective January 1, 2006. For companies like Cheniere that have NOL carryforwards, SFAS No. 123R affects the manner in which share-based compensation tax deductions are treated for financial reporting purposes. We may claim share-based compensation deductions in our federal corporate income tax returns in an amount equal to the related income that is included in our employees’ reported federal taxable income subject to any other applicable limitations. Under SFAS No. 123R, tax benefits generated in 2006 and subsequent reporting periods related to the excess of tax deductible share-based compensation over the amount recognized for financial accounting purposes, may not be recorded to additional paid-in-capital (“APIC”) for financial reporting purposes until the share-based compensation deductions actually reduce our cash income tax liability. Any tax benefits attributable to these deductions will not be recorded to APIC for financial reporting purposes until such time as all existing and future NOL carryforwards have been fully utilized. As a result of the provisions of SFAS No. 123R, at December 31, 2007, we had excluded \$32.5 million of share-based compensation deductions from our NOL carryforwards for financial reporting purposes. At December 31, 2007, our NOL carryforwards for financial reporting purposes were \$110.2 million compared to NOL carryforwards for federal income tax reporting purposes of \$344.1 million.

Our federal NOL carryforwards expire starting in 2012 extending through 2027. Certain of our NOLs which were previously subject to annual utilization limitations under the Internal Revenue Code (“IRC”) Section 382 change of ownership regulations are now available for utilization due to annual increases in the allowed NOL utilization amounts provided for in IRC Section 382. The NOL carryforward amounts include approximately \$11.7 million as of December 31, 2007, of excess tax benefits recognized in 2005 and prior years related to the exercise of non-qualified employee stock options and vested stock awards. The full amount of the related federal income tax benefits are included in our deferred tax asset valuation allowance.

The reconciliation of the federal statutory income tax rate to our effective income tax rate follows:

	Year Ended December 31,		
	2007	2006	2005
U.S. statutory tax rate	35 %	35 %	35 %
Non-deductible executive share-based compensation expense (1)	0 %	(2)%	0 %
Deferred tax asset valuation reserve (2)	(35)%	(35)%	(24)%
State income tax expense (net of federal benefit) (3)	0 %	0 %	(5)%
All other	0 %	0 %	0 %
Effective tax rate as reported	0 %	(2)%	6 %

- (1) As discussed above, effective January 1, 2006, we began accounting for share-based compensation in accordance with SFAS No. 123R. The amount of share-based compensation deductions for financial reporting purposes included amounts subject to limitations under IRC Section 162(m) which limits, under certain circumstances, the amount of compensation that is deductible for federal income tax reporting purposes for certain covered officers. In cases where the limitations under section 162(m) apply, it results in share-based compensation expenses being recognized for financial reporting purposes for which a tax benefit will not be realized in either the current or future tax reporting periods.
- (2) As discussed above, in accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the federal and state deferred tax benefits related to our NOL carryforwards and other deferred tax assets. Prior to January 1, 2006, we elected to account for share-based compensation in accordance with APB Opinion No. 25. For federal income tax reporting purposes, we are generally allowed to claim federal income tax deductions based on the fair market value of the underlying securities on the date of vesting for vested stock awards and on the date of exercise for stock options. Because the share-based compensation expense that was required to be included in our reported annual operating losses was significantly less than the amounts that have been included in

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

our employees' taxable incomes, the associated excess tax benefits will be charged to equity upon the reversal of the associated valuation allowances. As discussed above, as of December 31, 2005, approximately \$11.7 million of deferred excess tax benefits related to the exercise of non-qualified employee stock options and vested stock awards in 2005 and prior reporting periods are included in our financial and federal income tax NOL carryforward amounts. For the year ended December 31, 2007, there was no change in the \$11.7 million of deferred excess tax benefits.

- (3) SFAS No. 109 requires us to measure our deferred income tax assets and liabilities separately for each tax jurisdiction that imposes an income tax on our operations (principally federal and state income taxes). In periods prior to 2005, our reported effective tax rate included amounts for certain expected deferred state income tax benefits related to our Texas and Louisiana exploration and development operations. In 2005, we determined that we do not expect to realize such future state income tax benefits; therefore, our 2005 reported effective tax rate includes an adjustment to eliminate the related deferred state income tax benefits.

NOTE 21—SHARE-BASED COMPENSATION

We have granted options to purchase common stock to employees, consultants and non-employee directors under the Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan ("1997 Plan") and the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan ("2003 Plan"). Prior to January 1, 2006, we accounted for grants made under the 1997 Plan and 2003 Plan using the intrinsic value method under the recognition and measurement principles of APB Opinion No. 25, and applied SFAS No. 123, *Accounting for Stock-Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure*, for disclosure purposes only. Under APB Opinion No. 25, share-based compensation cost related to stock options was not recognized in net income because the options granted under those plans had exercise prices greater than or equal to the market value of the underlying stock on the date of grant.

Effective January 1, 2006, we adopted SFAS No. 123R, which revised SFAS No. 123 and superseded APB No. 25. SFAS No. 123R requires that all share-based payments to employees be recognized in the financial statements based on their fair values at the date of grant. The calculated fair value is recognized as expense (net of any capitalization) over the requisite service period, net of estimated forfeitures, using the straight-line method under SFAS No. 123R. The statement was adopted using the modified prospective method of application, which requires compensation expense to be recognized in the financial statements for all unvested stock options beginning in the quarter of adoption. No adjustments to prior periods have been made as a result of adopting SFAS No. 123R. Under this transition method, compensation expense for share-based awards granted prior to January 1, 2006, but not yet vested as of January 1, 2006, and not previously amortized through the pro forma disclosures required by SFAS No. 123, are recognized in our financial statements over their remaining service period. The cost was based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123. As allowed by SFAS No. 123, compensation cost associated with forfeited options was reversed for disclosure purposes in the period of forfeiture. As required by SFAS No. 123R, compensation expense recognized in future periods for share-based compensation granted prior to adoption of the standard are adjusted for the effects of estimated forfeitures.

For the years ended December 31, 2007, 2006 and 2005 the total share-based compensation expense recognized in our net loss was \$58.3 million, \$21.8 million and \$3.6 million, respectively. As required by SFAS No. 123R, the effect of a change in estimated forfeitures is recognized through a cumulative adjustment included in share-based compensation cost in the period of change in estimate. We consider many factors when estimating expected forfeitures, including types of awards, employee class and historical experience. For the year ended December 31, 2007, the cumulative adjustment recognized in our compensation expense was \$4.8 million. For the years ended December 31, 2007 and 2006, the total share-based compensation cost capitalized as part of the cost of capital assets was \$1.7 million and \$1.6 million, respectively.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The impact of adopting SFAS No. 123R on our results of operations for the year ended December 31, 2006 was an increase in expenses of \$17.3 million, with a corresponding increase in our loss from operations, loss before income taxes and minority interest, and net loss resulting from the first-time recognition of compensation expense associated with employee stock options. The impact on our basic and diluted net loss per common share was an increase in per share net loss of \$0.32.

The total unrecognized compensation cost at December 31, 2007 relating to non-vested share-based compensation arrangements granted under the 1997 Plan and 2003 Plan, before any capitalization, was \$103.6 million. That cost is expected to be recognized over 4.25 years, with a weighted average period of 1.35 years.

Tax deductions are generally available to us in an amount equal to the share-based compensation income included in the taxable income of our employees, to the extent our corporate-level tax deductions are not otherwise limited by Section 162(m) of the Internal Revenue Code. As previously discussed in Note 20—"Income Taxes", SFAS No. 123R specifically provides that tax benefits associated with share-based payments to employees may not be recognized unless or until the corresponding tax deductions have reduced current taxes payable. As a result of our cumulative NOL carryovers and resulting valuation allowance, the tax benefits associated with deductions related to share-based payments to employees will not be recognized for financial reporting purposes until such time as all existing and future NOLs have been utilized.

The adoption of SFAS No. 123R had no effect on our net cash flow. Had we been a taxpayer, we would have recognized cash flow resulting from tax deductions in excess of recognized compensation cost as a financing cash flow. We received total proceeds from the exercise of stock options of \$3.2 million, \$2.0 million and \$2.5 million in the years ended December 31, 2007, 2006 and 2005, respectively.

The following table illustrates the pro forma net income and earnings per share that would have resulted in the year ended December 31, 2005 from recognizing compensation expense associated with accounting for employee share-based awards under the provisions of SFAS No. 123. The reported and pro forma net income and earnings per share for the years ended December 31, 2007 and 2006 are provided for comparative purposes only, as share-based compensation expense is recognized in the financial statements under the provisions of SFAS No. 123R (in thousands, except per share data).

	Years Ended December 31,		
	2007	2006	2005
Net loss as reported	\$ (181,777)	\$ (145,853)	\$ (29,538) (As Adjusted)
Add: Share-based employee compensation included in net loss (1)	58,331	21,768	3,583
Deduct:			
Total share-based employee compensation expense determined under fair value method for all awards, net of related income tax (1)(2)	(58,331)	(21,768)	(16,567)
Pro forma net loss	\$ (181,777)	\$ (145,853)	\$ (42,522)
Net loss per share			
Basic—as reported	\$ (3.60)	\$ (2.68)	\$ (0.56)
Diluted—as reported	\$ (3.60)	\$ (2.68)	\$ (0.56)
Basic—pro forma	\$ (3.60)	\$ (2.68)	\$ (1.09)
Diluted—pro forma	\$ (3.60)	\$ (2.68)	\$ (1.09)

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- (1) Year ended 2005 is conformed to 2006 and 2007 presentation.
- (2) Fair value of stock options computed using Black-Scholes option pricing model and the value of non-vested stock based on intrinsic value in accordance with SFAS No. 123R and SFAS No. 123.

Phantom Stock

In May 2007, the Company established the 2007 Incentive Compensation Plan (“2007 Plan”) and the 2008-2010 Incentive Compensation Plan (“2008-2010 Plan”) covering executive officers and other key employees for the performance periods of 2007, 2008, 2009 and 2010. A total of 537,000 and 1,611,000 shares of phantom stock were granted under the 2007 and 2008-2010 Plans, respectively, which will be payable in shares of our common stock if stock price hurdles established by the plans are achieved. At its sole discretion, the Compensation Committee of our Board of Directors may elect to settle all or part of the phantom stock in cash. As of December 31, 2007, the 2007 stock price hurdle was achieved and was granted as common stock in January 2008. Using a Monte Carlo simulation, fair values of \$18.4 million, \$16.2 million, \$13.4 million and \$11.1 million were calculated for the performance periods 2007, 2008, 2009 and 2010, respectively. A projected earnings date was also forecasted on which the stock price hurdle will be achieved for the award related to each performance period. The fair value of the award for each performance period will be amortized as compensation expense ratably from the date of plan approval to the date it is expected to be earned. In December 2007, an additional grant of 36,000 shares of phantom stock was made under the 2008-2010 Plan. Using the Monte Carlo simulation, fair values of \$0.2 million, \$0.2 million, and \$0.1 million were calculated for the additional shares for the performance periods 2008, 2009 and 2010, respectively. For the year ended December 31, 2007, a total of \$28.6 million was recognized as compensation expense relating to all phantom stock awards.

Stock Options

During 2007, we issued options to purchase 20,000 shares of our common stock under the 2003 Plan to employees as hiring incentives, having an exercise price equal to the stock price on the date of grant, graded vesting over four years, and a 10-year contractual life.

During 2006, we issued options to purchase 501,220 shares of our common stock under the 2003 Plan. This included options to purchase 131,220 shares, granted to employees primarily as hiring incentives, having an exercise price equal to the stock price on the date of grant, graded vesting over four years, and a 10-year contractual life; an option to purchase 300,000 shares granted to our Chairman of the Board and Chief Executive Officer having an exercise price of \$90.00, graded vesting over three years beginning in March 2010, and a 10-year contractual life; fully vested options to purchase a total of 50,000 shares granted to two of our directors having an exercise price equal to the stock price on the date of grant and a 10-year contractual life; and an option to purchase 20,000 shares having an exercise price equal to the stock price on the date of grant, graded vesting over two years, and a five-year contractual life granted to a consultant in exchange for services. These options are being accounted for in accordance with the guidance in SFAS No. 123R, with the exception of the consultant grant, which is being accounted for in accordance with the relevant accounting guidance for equity instruments granted to a non-employee.

We estimate the fair value of stock options under SFAS No. 123R at the date of grant using a Black-Scholes valuation model, which is consistent with the valuation technique we previously utilized to value options for the footnote disclosures required under SFAS No. 123. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The expected term (estimated period of time outstanding) of options granted in 2006 is based on the “simplified” method of estimating expected term for “plain vanilla” options allowed by Securities and Exchange Commission (“SEC”) Staff Accounting Bulletin No. 107 and varies based on the vesting period

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

and contractual term of the option. Prior to 2006, the expected term was based on our historical experience and estimate of future behavior of employees. Expected volatility for options granted in 2007 and 2006 is based on an equally weighted average of the implied volatility of exchange traded options on our common stock expiring more than one year from the measurement date and historical volatility of our common stock for a period equal to the option's expected life. Prior to 2006, estimated volatility was based solely on the historical volatility of our common stock for a period equal to the option's expected life. We have not declared dividends on our common stock.

The table below provides a summary of option activity under the combined plans as of December 31, 2007, and changes during 2007:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)			(in thousands)
Outstanding at January 1, 2007	5,187	\$ 34.25		
Granted	20	36.12		
Exercised	(731)	6.45		
Forfeited or Expired	(34)	34.51		
Outstanding at December 31, 2007	4,442	\$ 38.84	6.3	\$ 15,510
Exercisable at December 31, 2007	1,204	\$ 22.68	3.6	\$ 13,721

The weighted average grant-date fair value of options granted during the years ended December 31, 2007, 2006 and 2005 was \$19.44, \$23.07 and \$20.16, respectively. The total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was \$19.3 million, \$12.0 million and \$28.0 million, respectively.

Effective March 28, 2007, 69 employee stock option grants were amended to provide for acceleration of vesting upon termination under certain circumstances, within one year of a change of control event, or upon the death or disability of the stock option holder. This amendment did not have an impact on our assessment of stock options ultimately expected to vest, and, therefore, resulted in no change in their valuation of our forfeiture assumptions.

Stock and Non-Vested Stock

We have granted stock and non-vested (restricted) stock to employees, executive officers, outside directors and one consultant under the 2003 Plan. Prior to January 1, 2006, we accounted for grants of non-vested stock using the intrinsic value method under the recognition and measurement principles of APB No. 25 and recognized the computed value of the non-vested stock in stockholders' equity as an increase in additional paid-in-capital and a corresponding reduction in stockholders' equity attributable to deferred compensation. The balance in deferred compensation was amortized ratably over the vesting period to non-cash compensation expense (before any capitalization) with a corresponding decrease in the deferred compensation balance.

Under SFAS No. 123R, grants of non-vested stock are accounted for on an intrinsic value basis. No recognition of deferred compensation is made in stockholders' equity. Instead, the amortization of the calculated value of non-vested stock grants is accounted for as a charge to non-cash compensation and an increase in

CHENIERE ENERGY, INC. AND SUBSIDIARIES
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additional paid-in-capital over the requisite service period. With the adoption of SFAS No. 123R, we offset the remaining unamortized deferred compensation balance (\$9.7 million at December 31, 2005) in stockholders' equity against additional paid-in-capital. Amortization of the remaining unamortized balance will continue under SFAS No. 123R as described above.

In January 2007, 630,396 shares having three-year graded vesting were issued to our employees and executive officers in the form of non-vested stock awards related to our performance in 2006. In May 2007, 30,574 shares having a one-year graded vesting were issued to our directors. In June 2007 and November 2007, 149,929 shares were issued as retention grants to certain employees vesting 50% on December 1, 2008, 30% on December 1, 2009, and 20% on June 1, 2010. In the year ended December 31, 2007, an additional 249,819 shares of non-vested stock having three or four-year graded vestings were issued primarily to new employees.

On May 25, 2007, the Compensation Committee of our Board of Directors approved a bonus plan covering substantially all employees not otherwise included in the 2007 Plan. This plan provides covered employees the ability to earn bonuses based on the achievement of established annual performance goals as well as a stock price appreciation goal. For some employees, part of the bonus will be paid in restricted stock that has graded vesting in three equal amounts over a three-year period. For the restricted stock granted in January 2008 for the 2007 performance period, a fair value of \$14.0 million was estimated by analysis of the likelihood of plan goals being achieved, Monte Carlo simulation of our projected stock price appreciation, and the target bonus available to each covered employee. The fair value will be recalculated at each balance sheet date until the total number of restricted shares to be granted, if any, has been determined. Because of the existence of the stock price appreciation goal, which is a market condition, the restricted stock is not eligible for amortization under the straight-line method, and each vesting tranche is being amortized separately. For the year ended December 31, 2007, a total of \$3.1 million was recognized as compensation expense relating to the restricted stock to be awarded in January 2008 for 2007 performance under the bonus plan.

During 2006, 30,239 and 78,671 shares having three-year graded vesting were issued to our directors and certain of our executive officers, respectively. During the year ended December 31, 2006, a total of 241,240 shares of stock having four-year graded vesting were issued primarily to new employees.

The table below provides a summary of the status of our non-vested shares under the 2003 Plan as of December 31, 2007, and changes during 2007 (in thousands except for per share information):

	Non- Vested Shares	Weighted Average Grant- Date Fair Value Per Share
Non-vested at January 1, 2007	555	\$ 33.97
Granted	1,060	31.99
Vested	(240)	31.21
Forfeited	(20)	14.78
Non-vested at December 31, 2007	1,355	\$ 32.74

The weighted average grant-date fair values of non-vested stock granted during the years ended December 31, 2007, 2006 and 2005 were \$31.99, \$35.60 and \$37.98, respectively. The total grant-date fair values of shares vested during the years ended December 31, 2007, 2006 and 2005 were \$7.8 million, \$5.4 million and \$3.4 million, respectively.

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Share-based Plan Descriptions and Information

Our 1997 Plan provided for the issuance of stock options to purchase up to 5.0 million shares of our common stock, all of which have been granted. Non-qualified stock options were granted to employees, contract service providers and outside directors. Option terms for the remaining unexercised options are five years with vesting that generally occurs on a graded basis over three years.

Awards providing for the issuance of up to an aggregate of 11.0 million shares of our common stock may be made under our 2003 Plan. These awards may be in the form of non-qualified stock options, incentive stock options, purchased stock, restricted (non-vested) stock, bonus (unrestricted) stock, stock appreciation rights, phantom stock and other share-based performance awards deemed by the Compensation Committee to be consistent with the purposes of the 2003 Plan. To date, the only awards made by the Compensation Committee have been in the form of non-qualified stock options, restricted stock, bonus stock and phantom shares. Beginning in 2005, stock options granted to employees as hiring incentives have been granted at the money with 10-year terms and graded vesting over four years. Prior to that time, stock options granted as hiring incentives were granted at the money with five-year terms and graded vesting over three years. Retention grants made to employees provide for exercise prices at or in excess of the stock price on the grant date, 10-year terms and graded vesting over three years, which commence on the fourth anniversary of the grant date. Restricted stock that has been granted as a hiring incentive vests over three or four years on a graded basis, while restricted stock granted from a bonus pool vests over three years. Shares issued under the 2003 Plan are generally newly issued shares.

401(k) Plan

In 2005, we established a defined contribution pension plan (“401(k) Plan”). The 401(k) Plan allows eligible employees to contribute up to 100% of their compensation up to the Internal Revenue Service maximum. We match each employee’s salary deferrals (contributions) up to six percent of compensation and may make additional contributions at our discretion. Effective January 1, 2007, employees are immediately vested in the contributions made by us. Our contributions to the 401(k) Plan were \$1.8 million, \$0.9 million and \$0.5 million for the years ended December 31, 2007, 2006, and 2005, respectively. We have made no discretionary contributions to the 401(k) Plan to date.

NOTE 22—COMPREHENSIVE LOSS

The following table is a reconciliation of our net loss to our comprehensive loss for the periods shown (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Net loss	\$(181,777)	\$(145,853)	\$ (29,538) (As Adjusted)
Other comprehensive (loss) income items:			
Cash flow hedges, net of income tax	—	(3,798)	3,798
Foreign currency translation	29	(34)	—
Comprehensive loss	\$(181,748)	\$(149,685)	\$ (25,740)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 23—COMMITMENTS AND CONTINGENCIES

LNG Terminal Commitments and Contingencies

Obligations under LNG TUAs

Sabine Pass LNG has entered into third-party TUAs with Total and Chevron to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the Sabine Pass LNG receiving terminal.

Freeport LNG

Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG's own cash flows, borrowings or other sources, and, up to a pre-agreed total amount, with capital contributions by the limited partners. In December 2005, Freeport LNG announced that it had closed a \$383.0 million private placement of notes, which would be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and development of underground salt cavern gas storage. As a result of such financing being obtained, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future. Capital calls may be made upon us and the other limited partners in Freeport LNG and in the event of each such future capital call, we will have the option either to contribute the requested capital or to decline to contribute. If we decline to contribute, the other limited partners could elect to make our contribution and receive back twice the amount contributed on our behalf, without interest, before any Freeport LNG cash flows are otherwise distributed to us. We currently expect to evaluate Freeport LNG capital calls on a case-by-case basis and to fund additional capital contributions that we elect to make using cash on hand or funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

Under a settlement agreement dated as of June 14, 2001, we agreed to pay a royalty, which we refer to as the Crest Royalty. This Crest Royalty is calculated based on the volume of natural gas processed through covered LNG facilities. The Freeport LNG and Sabine Pass LNG receiving terminals are covered facilities. The Crest Royalty is subject to a maximum of approximately \$11.0 million per production year at throughput of approximately 1.0 Bcf/d and a minimum of \$2.0 million, beginning when natural gas is first commercially processed through a covered LNG facility. Freeport LNG has assumed the obligation to pay the Crest Royalty based on natural gas processed at Freeport LNG's receiving terminal. Freeport LNG has entered into TUAs for approximately 1.55 Bcf/d of terminal throughput capacity with ConocoPhillips Company and The Dow Chemical Company, which commence when the Freeport LNG receiving terminal begins commercial operations, as well as a subsidiary of Mitsubishi Corporation, which starts at the beginning of 2009. The ConocoPhillips TUA is for approximately 0.9 Bcf/d. The Dow TUA is for approximately 0.5 Bcf/d. Freeport LNG has announced that it expects to commence commercial operations in the second quarter of 2008.

LNG Terminal EPC Agreements

In December 2004, we entered into a lump-sum turnkey EPC agreement with Bechtel Corporation ("Bechtel") pursuant to which Bechtel is providing services for the engineering, procurement and construction of the initial phase of the Sabine Pass LNG receiving terminal with send-out capacity of 2.6 Bcf/d. Sabine Pass LNG agreed to pay Bechtel a contract price of \$646.9 million plus certain reimbursable costs. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. Payments under the EPC agreement will be made in accordance with the payment schedule set forth in the EPC agreement. The contract price and payment schedule, including milestones, may be amended only by change order. Bechtel will be liable to Sabine Pass LNG for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a scheduled bonus of \$12.0 million, or

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a lesser amount in certain cases, if on or before April 3, 2008, Bechtel completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sustained sendout at a significant rate for a preagreed period of time (currently provided to be a rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours). Bechtel is also entitled to receive an additional bonus of up to \$67,000 per day (up to a maximum of \$6.0 million) for each day that commercial operation is achieved prior to April 1, 2008. As of February 14, 2008, change orders for \$171.3 million had been approved, increasing the total contract price of the initial phase to \$818.2 million.

In July 2006, Sabine Pass LNG entered into an engineering, procurement, construction and management (“EPCM”) Agreement with Bechtel for engineering, procurement, construction and management of construction services in connection with our 1.4 Bcf/d expansion at the Sabine Pass LNG receiving terminal. Under the terms of the EPCM agreement, Bechtel will be paid on a cost reimbursable basis, plus a fixed fee in the amount of \$18.5 million. A discretionary bonus may be paid to Bechtel at Sabine Pass LNG’s sole discretion upon completion of the expansion.

In July 2006, Sabine Pass LNG entered into an EPC unit rate soil improvement contract with Remedial Construction Services, L.P. (“Remedial”) for engineering, procurement, and construction of soil improvement work. Work includes, but is not limited to, design, surveying, estimating, procurement and transportation of materials, equipment, labor, supervision and construction activities necessary to satisfactorily complete work on the 1.4 Bcf/d expansion, unless otherwise set forth in the soil contract. Progress payments will be paid based on quantities of work performed at unit rates, minus 10% retainage that will be paid upon final completion as well as any credits and early payment discounts applicable.

In July 2006, Sabine Pass LNG entered into an EPC LNG Tank Contract with Diamond LNG LLC (“Diamond”) and Zachry Construction Corporation (“Zachry” and collectively with Diamond, the “Tank Contractor”) for the construction of two LNG storage tanks in connection with the 1.4 Bcf/d expansion. Milestone payments for work incurred, minus a 5% retainage that will be paid upon final completion, will be based on a lump-sum, fixed price, subject to adjustments based on fluctuations in the cost of labor and change orders.

Pipeline EPC Agreements

In February 2006, CCTP (formerly known as Cheniere Sabine Pass Pipeline, L.P.), our wholly-owned subsidiary, entered into an EPC contract with Willbros Engineers, Inc. (“Willbros”). Under the EPC contract, Willbros will provide CCTP with services for the management, engineering, material procurement, construction and construction management in connection with the Creole Trail Pipeline. Progress payments will be paid based on quantities of work performed, minus 5% retainage on construction work that will be paid upon final completion. Such preliminary site work commenced during the second quarter of 2006. As of December 31, 2007, change orders for \$0.9 million had been approved, increasing the total contract price to \$68.5 million. CCTP may, at any time, terminate the agreement at its convenience, subject to payments on work performed prior to termination and reasonable direct close-out costs. Such work is expected to be fully complete in the second quarter of 2008.

In January 2007, CCTP entered into a construction agreement with Sheehan Pipe Line Construction Company (“Sheehan”) for the construction of approximately 36 miles of the Creole Trail Pipeline. Under the terms of the agreement, Sheehan will provide CCTP with equipment, labor, inspection, manufacture, fabrication, installation, delivery, transportation, storage, assembly and construction services in connection with the Creole Trail Pipeline. As of December 31, 2007, change orders for \$14.7 million had been approved, increasing the total estimated contract price to \$80.3 million. Progress payments will be paid based on quantities of work performed,

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

minus 5% retainage on construction work that will be paid upon final completion. CCTP may at any time terminate, for convenience, Sheehan's performance effective upon receipt of a written notice by Sheehan and payment for items provided or services performed prior to termination. Such work is expected to be fully complete in the second quarter of 2008.

In January 2007, CCTP entered into an agreement with Sunland Construction, Inc. ("Sunland") for the construction of approximately 23 miles of the Creole Trail Pipeline. Under the terms of the agreement, Sunland will provide CCTP with equipment, labor, inspection, manufacture, fabrication, installation, delivery, transportation, storage, assembly and construction services in connection with the Creole Trail Pipeline. As of December 31, 2007, change orders for \$9.7 million had been approved, increasing the total estimated contract price to \$79.8 million. Progress payments will be paid based on quantities of work performed, minus 5% retainage on construction work that will be paid upon final completion. CCTP may at any time terminate, for convenience, Sunland's performance effective upon receipt of a written notice by Sunland and payment for items provided or services performed prior to termination. The agreement is subject to a cancellation fee not to exceed 5% of the estimated contract price. Such work is expected to be fully complete in the second quarter of 2008.

In March 2007, CCTP entered into an agreement with Sunland for the construction of approximately 18 miles of the Creole Trail Pipeline. Under the terms of the agreement, Sunland will provide CCTP with equipment, labor, inspection, manufacture, fabrication, installation, delivery, transportation, storage, assembly and construction services in connection with the Creole Trail Pipeline. Change orders totaling approximately \$15.0 million are presently under negotiation, increasing the total estimated contract price to \$57.5 million. Progress payments will be paid based on quantities of work performed, minus 5% retainage on construction work that will be paid upon final completion. CCTP may at any time terminate, for convenience, Sunland's performance effective upon receipt of a written notice by Sunland, payment for items provided or services performed prior to termination. The agreement is subject to a cancellation fee not to exceed 2% of the estimated contract price. Such work is expected to be fully complete in the second quarter of 2008.

LNG Marketing and Transportation Guarantees

Cheniere has entered into guarantees in favor of third parties on account of Cheniere Marketing's LNG marketing and transportation activities. In connection with these guarantees, Cheniere has guaranteed obligations with various expiration dates which may arise out of Cheniere Marketing's non-performance. The maximum amount of exposure related to these guarantees was \$35.1 million at December 31, 2007.

Restricted Net Assets

At December 31, 2007, our restricted net assets of consolidated subsidiaries were approximately \$188.4 million.

Other Commitments

In the ordinary course of business, we have issued surety bonds related to our offshore oil and gas operations and entered into certain multi-year licensing and service agreements, none of which are considered material to our financial position.

Legal Proceedings

We are, and may in the future be, involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management and legal counsel, as of December 31, 2007, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 24—GAIN ON SALE OF INVESTMENT IN UNCONSOLIDATED AFFILIATE

In October 2000, Cheniere and Warburg, Pincus Energy Partners, L.P. formed Gryphon Exploration Company (“Gryphon”) to fund an oil and gas exploration program in the Gulf of Mexico. Effective January 1, 2003, our investment (effective 9.3% ownership) in Gryphon was accounted for under the cost method of accounting, and our investment basis was zero. On August 31, 2005, Gryphon was sold for \$283.0 million, plus assumption of \$14.0 million of net debt in a merger with Woodside Energy (USA). The transaction generated net cash proceeds of \$20.2 million to us, and because our investment balance was zero at the closing of this transaction, we recognized a gain in our Consolidated Statement of Operations for the year ended December 31, 2005 equal to the net cash proceeds amount.

NOTE 25—BUSINESS SEGMENT INFORMATION

We have four business segments: LNG receiving terminal business, natural gas pipeline business, LNG and natural gas marketing business, and oil and gas exploration and development business. These segments reflect lines of business for which separate financial information is produced internally and are subject to evaluation by our chief operating decision makers in deciding how to allocate resources.

Our LNG receiving terminal business segment is in various stages of developing three LNG receiving terminal projects along the U.S. Gulf Coast at the following locations: Sabine Pass LNG, approximately 90.6% owned (at December 31, 2007), in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG, 100% owned, near Corpus Christi, Texas; and Creole Trail LNG, 100% owned, at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% limited partner interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas.

Our natural gas pipeline business segment is in various stages of developing natural gas pipelines to provide access to North American natural gas markets.

Through our LNG and natural gas marketing business segment, we are developing a natural gas and LNG marketing and trading business, with a TUA at the Sabine Pass LNG receiving terminal being our principal asset. We intend to build a portfolio of long-term and short-term and spot LNG purchase agreements from foreign suppliers, pursuant to which LNG will be delivered to either our LNG receiving terminals or other terminals with whom we will trade on the supplier’s vessels, or on vessels that we contract for our own use. In order to facilitate the importation of LNG into the U.S., we are also developing a portfolio of downstream natural gas sales agreements with major local distribution companies, power generators, industrial users and other gas marketing firms. We will also purchase domestic natural gas to satisfy our sales commitments during times that we elect to divert contracted supplies away from the U.S., or during times that we are not able to obtain LNG supplies. As we develop our marketing business, we are engaging in domestic natural gas purchases and sales, transportation and storage transactions, and physical and financial derivative transactions. Through a capacity option agreement, we have obtained the right to deliver LNG to the United Kingdom. In addition, we have contracted for the use of LNG vessels to transport LNG.

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Our oil and gas exploration and development business segment conducts and participates in exploration, development and production activities in the shallow waters of the Gulf of Mexico.

	Segments					Total Consolidated
	LNG Receiving Terminal	Natural Gas Pipeline	LNG & Natural Gas Marketing	Oil & Gas Exploration and Development	Corporate and Other (1)	
(in thousands)						
As of or for the Year Ended December 31, 2007						
Revenues	\$ —	\$ —	\$ (4,729)	\$ 5,376	\$ —	\$ 647
Depreciation, depletion and amortization	235	—	891	734	4,533	6,393
Non-cash compensation	4,937	2,019	13,617	—	37,758	58,331
Income (loss) from operations	(37,390)	(4,835)	(39,356)	3,007	(85,366)	(163,940)
Interest expense, net	(69,419)	(4)	(502)	—	(34,632)	(104,557)
Interest income	52,273	—	2,476	3	27,883	82,635
Goodwill	76,844	—	—	—	—	76,844
Total assets	2,041,894	443,421	157,601	2,403	316,980	2,962,299
Expenditures for additions to long-lived assets	\$ 488,373	\$ 393,159	\$ 5,294	\$ (463)	\$ 13,604	\$ 899,967
As of or for the Year Ended December 31, 2006						
Revenues	\$ —	\$ —	\$ 61	\$ 2,310	\$ —	\$ 2,371
Depreciation, depletion and amortization	137	—	107	227	2,660	3,131
Non-cash compensation expense	5,726	603	1,265	1,349	12,825	21,768
Income (loss) from operations (2)	(28,392)	8,255	(6,915)	(3,187)	(45,635)	(75,874)
Loss on early extinguishment of debt (3)	(43,159)	—	—	—	—	(43,159)
Derivative loss (3)	(20,070)	—	—	—	—	(20,070)
Interest expense	(35,990)	(256)	—	—	(17,722)	(53,968)
Interest income	15,871	—	208	—	33,008	49,087
Income tax provision	—	—	—	—	(2,045)	(2,045)
Goodwill	76,844	—	—	—	—	76,844
Total assets	1,975,666	49,223	44,499	3,481	531,618	2,604,487
Expenditures for additions to long-lived assets	\$ 413,338	\$ 47,749	\$ 3,594	\$ 2,061	\$ 7,153	\$ 473,895
As of or for the Year Ended December 31, 2005 (As Adjusted):						
Revenues	\$ —	\$ —	\$ —	\$ 3,005	\$ —	\$ 3,005
Depreciation, depletion and amortization	55	—	—	58	1,212	1,325
Non-cash compensation expense	1,235	—	—	327	1,796	3,358
Loss from operations	(21,461)	(7,601)	—	(553)	(22,946)	(52,561)
Equity in net loss of limited partnership (4)	(1,031)	—	—	—	—	(1,031)
Gain on sale of investment in unconsolidated affiliate (5)	—	—	—	20,206	—	20,206
Derivative gain	837	—	—	—	—	837
Interest expense	(9,424)	—	—	—	(7,949)	(17,373)
Interest income	2,645	—	—	—	14,875	17,520
Income tax benefit	—	—	—	—	2,045	2,045
Goodwill	76,844	—	—	—	—	76,844
Total assets	783,837	—	—	2,328	503,982	1,290,147
Expenditures for additions to long-lived assets	\$ 271,879	\$ —	\$ —	\$ 2,785	\$ 6,095	\$ 280,759

CHENIERE ENERGY, INC. AND SUBSIDIARIES
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- (1) Includes corporate activities and certain intercompany eliminations.
- (2) Natural gas pipeline income from operations for the year ended December 31, 2006, includes the impact of the regulatory asset recorded in the second quarter of 2006 as prescribed by SFAS No. 71. Not including the impact of the recognition of this regulatory asset, natural gas pipeline income from operations would have been a net loss of \$4.1 million for the year ended December 31, 2006.
- (3) Primarily represents recognized losses on the termination of the Sabine Pass Credit Facility and the Term Loan in November 2006. See Note 17—"Long-Term Debt and Credit Facility."
- (4) Represents equity in net loss of our investment in Freeport LNG, excluding the 2005 Suspended Loss of \$4.0 million. Our investment basis was reduced to zero as of December 31, 2005.
- (5) Represents gain on sale of our interest in Gryphon Exploration Company. See Note 24—"Gain on Sale of Investment in Unconsolidated Affiliate."

NOTE 26—SUPPLEMENTAL CASH FLOW INFORMATION AND DISCLOSURES OF NON-CASH TRANSACTIONS

The following table provides supplemental disclosure of cash flow information (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Cash paid during the year for:			
Interest, net of amounts capitalized	\$ 106,640	\$ 43,253	\$ 12,792
Construction-in-process and debt issuance additions funded with accrued liabilities	\$ 112,824	\$ 26,436	\$ 42,833

During 2007, 688,249 shares of common stock were issued in satisfaction of cashless exercises of options to purchase 731,670 shares of common stock.

In 2005, non-vested stock grants of 175,151 shares were made to employees and outside directors under the 2003 Plan. We recorded \$6.7 million to additional paid-in-capital, offset by a corresponding amount of deferred compensation to stockholders' equity. During 2005, we recorded \$3.6 million in total non-cash compensation expense. As of December 31, 2005, the balance of non-cash deferred compensation was \$9.7 million. With the adoption of SFAS No. 123R in January 2006, we reclassified the \$9.7 million of unamortized deferred compensation to additional paid-in-capital.

In 2005, 129,842 shares of our common stock were issued in satisfaction of cashless exercises of stock options and warrants to purchase 33,868 and 100,000 shares, respectively.

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SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
OIL AND GAS RESERVES AND RELATED FINANCIAL DATA
(unaudited)

Costs Incurred in Oil and Gas Producing Activities

Presented below are costs incurred in oil and gas property acquisition, exploration and development activities (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Acquisition of properties			
Proved properties	\$ —	\$ —	\$ —
Unproved properties	—	55	1,530
Exploration costs	1,091	4,574	2,681
Development costs	—	—	—
Subtotal	<u>\$ 1,091</u>	<u>\$ 4,629</u>	<u>\$ 4,211</u>
Asset retirement costs	207	59	—
Total	<u>\$ 1,298</u>	<u>\$ 4,688</u>	<u>\$ 4,211</u>

Capitalized Costs Related to Oil and Gas Producing Activities

The following table presents total capitalized costs of proved and unproved properties and accumulated depreciation, depletion and amortization related to oil and gas producing operations (in thousands):

	December 31,	
	2007	2006
Proved properties	\$ 2,526	\$ 2,343
Unproved properties	—	779
	<u>2,526</u>	<u>3,122</u>
Accumulated depreciation, depletion and amortization	(653)	(263)
	<u>\$ 1,873</u>	<u>\$ 2,859</u>

Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities are as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Revenues	\$ 5,376	\$ 2,310	\$ 3,005
Production costs	(358)	(237)	(237)
Depreciation, depletion and amortization	(734)	(227)	(41)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	<u>\$ 4,284</u>	<u>\$ 1,846</u>	<u>\$ 2,727</u>

CHENIERE ENERGY, INC. AND SUBSIDIARIES
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
OIL AND GAS RESERVES AND RELATED FINANCIAL DATA—(Continued)
(unaudited)

Reserve Quantities

Estimates of our proved reserves and the related standardized measure of discounted future net cash flow information are based on the reports generated by our independent petroleum engineers, Sharp Petroleum Engineering, Inc., in accordance with the rules and regulations of the SEC. The independent engineers' estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data provided by us. These estimates represent our interest in the reserves associated with our properties. All of our oil and gas reserves are located within the United States or its territorial waters.

Our estimates of proved reserves and proved developed reserves of oil and gas as of December 31, 2007, 2006 and 2005 and the changes in our proved reserves are as follows:

	2007		2006		2005	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Proved reserves:						
Beginning of year	23,683	1,736,021	1,313	390,687	3,021	919,120
Revisions of prior estimates	(7,140)	(322,977)	2,101	(1,645)	459	(132,149)
Production	(8,905)	(609,715)	(3,294)	(318,352)	(2,167)	(396,284)
Sale of reserves in place	—	—	—	—	—	—
Extensions, discoveries and other additions	1,231	456,604	23,563	1,665,331	—	—
End of year	8,869	1,259,933	23,683	1,736,021	1,313	390,687
Proved developed reserves:						
Beginning of year	23,683	1,736,021	1,313	390,687	3,021	919,120
End of year	8,869	1,259,933	23,683	1,736,021	1,313	390,687

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and future amounts and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures, geologic success and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, our reserves may be subject to downward or upward revision based upon production history, purchases or sales of properties, results of future development, prevailing oil and gas prices and other factors.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows was calculated by applying year-end prices (adjusted for location and quality differentials) to estimated future production, less future expenditures (based on year-end costs) to be incurred in developing and producing our proved reserves and the estimated effect of future income taxes based on the current tax law. The resulting future net cash flows were discounted using a rate of 10% per annum.

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(unaudited)

From our inception, we have recorded annual net operating losses for both financial reporting purposes and for federal and state income tax reporting purposes. Accordingly, we are not presently a taxpayer, and therefore there is no tax effect on future net cash flow amounts.

The standardized measure of discounted future net cash flow amounts contained in the following tabulation does not purport to represent the fair market value of oil and gas properties. No value has been given to unproved properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. Future realization of oil and gas prices over the remaining reserve lives may vary significantly from current prices. In addition, the method of valuation utilized, based on year-end prices and costs and the use of a 10% discount rate, is not necessarily appropriate for determining fair value.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows (in thousands):

	December 31,		
	2007	2006	2005
Future gross revenues	\$ 8,651	\$ 10,095	\$ 3,548
Less—future costs:			
Production	(1,328)	(1,575)	(212)
Development and abandonment	(575)	(360)	(80)
Income taxes	—	—	—
Future net cash flows	6,748	8,160	3,256
Less—10% annual discount for estimated timing of cash flows	(1,586)	(1,998)	(511)
Standardized measure of discounted future net cash flows	\$ 5,162	\$ 6,162	\$ 2,745

The following table summarizes the principal sources of change in the standardized measure of discounted future net cash flows (in thousands, except for prices):

	Year Ended December 31,		
	2007	2006	2005
Standardized measure—beginning of period	\$ 6,162	\$ 2,745	\$ 4,148
Sales of oil and gas produced, net of production costs	(5,018)	(2,304)	(2,768)
Extensions, discoveries and other additions	3,077	6,307	—
Revisions to previous quantity estimates, timing and other	(1,476)	486	58
Net changes in prices and production costs	1,801	(1,346)	971
Sale of reserves in place	—	—	—
Development costs incurred	—	—	—
Changes in estimated development costs	—	—	—
Net changes in income taxes	—	—	—
Accretion of discount	616	274	336
Standardized measure—end of period	\$ 5,162	\$ 6,162	\$ 2,745
Current prices at year-end, used in standardized measure			
Oil (per Bbl)	\$ 92.63	\$ 56.86	\$ 53.72
Gas (per Mcf)	\$ 6.21	\$ 5.04	\$ 8.90

We may receive amounts different from those incorporated into the standardized measure of discounted cash flow for a number of reasons, including changes in prices. Therefore, the present value shown above should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

Quarterly Financial Data—(in thousands, except per share amounts)

	<u>First Quarter</u>	<u>Second Quarter</u>	<u>Third Quarter</u>	<u>Fourth Quarter</u>	<u>Year</u>
Year ended December 31, 2007:					
Revenues	\$ (1,256)	\$ 872	\$ 394	\$ 637	\$ 647
Gross profit (1)	(1,412)	680	(30)	317	(445)
Loss from operations	(29,772)	(40,224)	(47,274)	(46,670)	(163,940)
Net loss	(34,556)	(41,119)	(53,454)	(52,648)	(181,777)
Net loss per share—Basic and Diluted	\$ (0.63)	\$ (0.76)	\$ (1.14)	\$ (1.14)	\$ (3.60)
Year ended December 31, 2006:					
Revenues	\$ 422	\$ 413	\$ 737	\$ 799	\$ 2,371
Gross profit (1)	312	358	589	587	1,846
Loss from operations	(22,567)	(8,749)	(17,476)	(27,082)	(75,874)
Net loss (2)	(15,811)	(3,619)	(33,106)	(93,317)	(145,853)
Net loss per share—Basic and Diluted	\$ (0.29)	\$ (0.07)	\$ (0.61)	\$ (1.71)	\$ (2.68)

(1) Revenues less production costs and oil and gas depreciation, depletion and amortization.

(2) The fourth quarter of 2006 includes a \$43.2 million loss from the early extinguishment of debt (see Note 17—"Long-Term Debt and Credit Facility") and a \$20.1 million loss primarily from the termination of the Swaps and Term Loan Swaps (see Note 14—"Derivative Instruments").

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Based on their evaluation as of the end of the fiscal year ended December 31, 2007, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management Report on Internal Control Over Financial Reporting

Our Management Report on Internal Control Over Financial Reporting is included in the Financial Statements on page 52 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

None.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Items 10 through 14 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2007.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements—Cheniere Energy, Inc. and Subsidiaries:

Management Reports to the Stockholders of Cheniere Energy, Inc.	61
Reports of Independent Registered Public Accounting Firm—Ernst & Young LLP	62
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(2) Financial Statement Schedules:

[Schedule I—Condensed Parent Company Financial Statements for the years ended December 31, 2007, 2006 and 2005](#)

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(3) Exhibits:

<u>Exhibit No.</u>	<u>Description</u>
2.1*	Seismic Data Purchase Agreement, dated June 21, 2000 between Seitel Data Ltd. and the Company. (Incorporated by reference to Exhibit 10.39 to the Company's Quarterly Report on Form 10-Q (SEC File No. 000-09092), filed on August 11, 2000)
2.2*	Settlement and Purchase Agreement, dated and effective as of June 14, 2001 by and between the Company, CXY Corporation, Crest Energy, L.L.C., Crest Investment Company and Freeport LNG Terminal, LLC, and two related letter agreements each dated February 27, 2003. (Incorporated by reference to Exhibit 10.36 to Cheniere Energy Partner, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on January 25, 2007)
2.3*	Agreement and Plan of Merger, dated February 8, 2005, by and among Cheniere LNG, Inc., Cheniere Acquisition, LLC, BPU Associates, LLC and BPU LNG, Inc. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8 K (SEC File No. 001-16383), filed on February 8, 2005)
3.1*	Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2004 (SEC File No. 001 16383), filed on August 10, 2004)
3.2*	Certificate of Amendment of Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8 K (SEC File No. 001-16383), filed on February 8, 2005)
3.3*	Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (SEC File No. 333-112379), filed on January 20, 2004)
3.4*	Amendment No. 1 to Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 6, 2005)
3.5*	Amendment No. 2, dated September 6, 2007, to the Amended and Restated By-Laws of Cheniere Energy, Inc. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 12, 2007)
4.1*	Specimen Common Stock Certificate of the Company. (Incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 (SEC File No. 333-10905), filed on August 27, 1996)
4.2*	Certificate of Designation of Series A Junior Participating Preferred Stock. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001 16383), filed on October 14, 2004)
4.3*	Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated as of October 14, 2004. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 14, 2004)
4.4*	First Amendment to Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated January 24, 2005. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 24, 2005)

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<u>Exhibit No.</u>	<u>Description</u>
4.5*	Indenture, dated as of July 27, 2005, between the Company, as issuer, and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 27, 2005)
4.6*	Indenture, dated as of November 9, 2006, between Sabine Pass LNG, L.P., as issuer, and The Bank of New York, as trustee. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
4.7*	Form of 7.25% Senior Secured Note due 2013 (Included as Exhibit A1 to Exhibit 4.7 above)
4.8*	Form of 7.50% Senior Secured Note due 2016 (Included as Exhibit A1 to Exhibit 4.7 above)
10.1*	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.2*	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.3*	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.4*	Guaranty, dated as of November 9, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001 16383), filed on November 15, 2004)
10.5*	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.6*	Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.28 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.7*	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.8*	Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.9*	Amended and Restated Terminal Use Agreement, dated November 9, 2006, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.10*	Amendment of LNG Terminal Use Agreement, dated June 25, 2007, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 26, 2007)
10.11*	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement, dated October 23, 2007 (amending the Amended and Restated Terminal Use Agreement, dated November 9, 2006, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P.). (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter September 30, 2007 (SEC File No. 001-16383), filed on November 6, 2007)

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<u>Exhibit No.</u>	<u>Description</u>
10.12*	Guarantee Agreement, dated as of November 9, 2006, by the Company. (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.13*	Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 20, 2004)
10.14*	Change Orders 1 through 27 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (SEC File No. 001-16383), filed on March 13, 2006)
10.15*	Change Orders 28, 29 and 31 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006).
10.16*	Change Orders 30, 32 and 33 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006).
10.17*	Change Orders 34, 35, 36, 37 and 38 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2006).
10.18*	Change Order 39 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.34 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006).
10.19*	Change Order 40 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 11, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.31 of Sabine Pass LNG, L.P.'s Registration Statement on Form S-4/A (SEC File No. 333-138916), filed on January 10, 2007)
10.20*	Change Order 41 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 11, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.36 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on January 25, 2007).
10.21*	Change Order 42 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated January 18, 2007, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.22*	Change Order 43 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.34 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on April 3, 2007)

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<u>Exhibit No.</u>	<u>Description</u>
10.23*	Change Orders 44 and 45 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter March 31, 2007 (SEC File No. 001-16383), filed on May 8, 2007)
10.24*	Change Orders 46, 47, 48 and 49 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter June 30, 2007 (SEC File No. 001-16383), filed on August 8, 2007)
10.25*	Change Order 50 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter September 30, 2007 (SEC File No. 001-16383), filed on November 6, 2007)
10.26	Change Orders 51 and 52 to Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004, between Sabine Pass LNG, L.P. and Bechtel Corporation.
10.27*	Agreement for Engineering, Procurement and Construction Services, effective February 1, 2006, between Cheniere Sabine Pass Pipeline Company and Willbros Engineers, Inc. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006)
10.28*	Change Orders 1, 2, 3, 4, 5 and 6 to Agreement for Engineering, Procurement and Construction Services, effective February 1, 2006, between Cheniere Sabine Pass Pipeline Company and Willbros Engineers, Inc. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter June 30, 2007 (SEC File No. 001-16383), filed on August 8, 2007)
10.29	Change Orders 9 through 13 to Agreement for Engineering, Procurement and Construction Services, effective February 1, 2006, between Cheneire Sabine Pass Pipeline Company and Willbros Engineers, Inc.
10.30*	Engineering, Procurement and Construction Services Agreement for Preliminary Work, dated April 13, 2006, between Corpus Christi LNG, LLC and La Quinta LNG Partners, LP. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006)
10.31*	Agreement for Engineering, Procurement, Construction and Management of Construction Services for the Sabine Phase 2 Receiving, Storage and Regasification Terminal Expansion, dated July 21, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.32*	Change Order 1 to Agreement for Engineering, Procurement, Construction and Management of Construction Services for the Sabine Phase 2 Receiving, Storage and Regasification Terminal Expansion, dated July 21, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.33*	Change Orders 2 and 3 to Agreement for Engineering, Procurement, Construction and Management of Construction Services for the Sabine Phase 2 Receiving, Storage and Regasification Terminal Expansion, dated July 21, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.38 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on June 11, 2007)

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<u>Exhibit No.</u>	<u>Description</u>
10.34*	Change Order 4 to Agreement for Engineering, Procurement, Construction and Management of Construction Services for the Sabine Phase 2 Receiving, Storage and Regasification Terminal Expansion, dated July 21, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter June 30, 2007 (SEC File No. 001-16383), filed on August 8, 2007)
10.35	Change Orders 5, 6, 7 and 8 to Agreement for Engineering, Procurement, Construction and Management of Construction Services for the Sabine Phase 2 Receiving, Storage and Regasification Terminal Expansion, dated July 21, 2006, between Sabine Pass LNG, L.P. and Bechtel Corporation.
10.36*	Engineer, Procure and Construct (EPC) LNG Tank Contract, dated July 21, 2006, between Sabine Pass LNG, L.P., Zachry Construction Corporation and Diamond LNG LLC. (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.37*	Change Order 1, 2 and 3 to Engineer, Procure and Construct (EPC) LNG Tank Contract, dated July 21, 2006, between Sabine Pass LNG, L.P., Zachry Construction Corporation and Diamond LNG LLC. (Incorporated by reference to Exhibit 10.37 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on June 11, 2007)
10.38*	Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.39	[Reserved]
10.40*	Change Order 5 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter June 30, 2007 (SEC File No. 001-16383), filed on August 8, 2007)
10.41*	Change Order 6 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter September 30, 2007 (SEC File No. 001-16383), filed on November 6, 2007)
10.42	Change Order 7 to Engineer, Procure and Construct (EPC) LNG Unit Rate Soil Contract, dated July 21, 2006, between Sabine Pass LNG, L.P. and Remedial Construction Services, L.P.
10.43*	Construction Agreement, dated January 5, 2007, between Cheniere Creole Trail Pipeline, L.P. and Sunland Construction, Inc. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.44*	Construction Agreement, dated January 10, 2007, between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.45*	Change Orders 1, 2 and 3 to Construction Agreement dated January 10, 2007 between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter June 30, 2007 (SEC File No. 001-16383), filed on August 8, 2007)
10.46*	Change Orders 4, 5, 6, 7, 8, 9, 10 and 11 to Construction Agreement, dated January 10, 2007, between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter September 30, 2007 (SEC File No. 001-16383), filed on November 6, 2007)

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<u>Exhibit No.</u>	<u>Description</u>
10.47	Change Orders 12 through 26 to Construction Agreement dated January 10, 2007 between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company.
10.48*	Purchase Order dated August 4, 2006, by and between Cheniere Creole Trail Pipeline, L.P. and Corinth Pipeworks S.A. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 7, 2006)
10.49*	Purchase Order dated August 4, 2006, by and between Cheniere Creole Trail Pipeline, L.P. and ILVA S.p.A. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 7, 2006)
10.50*	Amendment No. 1 to Purchase Order dated August 4, 2006, by and between Cheniere Creole Trail Pipeline, L.P. and ILVA S.p.A. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 23, 2007)
10.51*	Purchase Order dated January 29, 2007, by and between Cheniere Creole Trail Pipeline, L.P. and The Bayou Companies, LLC. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 31, 2007)
10.52*	Construction Agreement, dated March 12, 2007, between Cheniere Creole Trail Pipeline, L.P. and Sunland Construction, Inc. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 16, 2007)
10.53*	Change Orders 2, 3 and 7 to Construction Agreement, dated January 5, 2007, between Cheniere Creole Trail Pipeline, L.P. and Sunland Construction, Inc. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter September 30, 2007 (SEC File No. 001-16383), filed on November 6, 2007)
10.54*	First Amended and Restated Credit Agreement, dated July 21, 2006, among Sabine Pass LNG, L.P., Société Générale, HSBC Bank USA, National Association and the Lenders named thereto. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 4, 2006)
10.55*	Confirmation, dated July 22, 2005, between Cheniere Energy, Inc. and Credit Suisse First Boston International. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.56*	Notice of Adjustment, dated July 26, 2005, between Cheniere Energy, Inc. and Credit Suisse First Boston International. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.57*	Notice of Commitment, dated May 31, 2007. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.58*	Collateral Trust Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, Sabine Pass LNG-GP, Inc. and Sabine Pass LNG-LP, LLC. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.59*	Amended and Restated Parity Lien Security Agreement, dated November 9, 2006, by and between Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.60*	Third Amended and Restated Multiple Indebtedness Mortgage, Assignment of Rents and Leases and Security Agreement, dated November 9, 2006, between the Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)

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<u>Exhibit No.</u>	<u>Description</u>
10.61*	Amended and Restated Parity Lien Pledge Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., Sabine Pass LNG-GP, Inc., Sabine Pass LNG-LP, LLC and The Bank of New York, as collateral trustee. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.62*	Security Deposit Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, and The Bank of New York, as depository agent. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.63*	Credit Agreement, dated as of May 31, 2007, among Cheniere Subsidiary Holdings, LLC, Perry Capital, L.L.C., the several lenders from time to time parties thereto, and The Bank of New York, as Administrative Agent. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.64*	Guarantee and Pledge Agreement, dated as of May 31, 2007, by Cheniere Energy, Inc., Cheniere LNG Holdings, LLC, Cheniere FLNG-GP, LLC, and Cheniere Subsidiary Holdings, LLC in favor of The Bank of New York, as Administrative Agent. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.65*	Credit Agreement dated as of September 14, 2007, among Cheniere Marketing, Inc., the lenders party thereto and BNP Paribas, as administrative agent for the lenders. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 20, 2007)
10.66*	Security Agreement dated as of September 14, 2007, between Cheniere Marketing, Inc. and BNP Paribas, as collateral trustee. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.67*	Collateral Trust Agreement dated as of September 14, 2007, between Cheniere Marketing, Inc. and BNP Paribas, as collateral trustee. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.68*	Gas Purchase and Sale Agreement, dated April 4, 2006, between Cheniere LNG Marketing, Inc. and PPM Energy, Inc. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2006)
10.69*	Master Ex-Ship LNG Sales Agreement, dated April 26, 2007, between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S., including Letter Agreement, dated April 26, 2007, and Specific Order No. 1, dated April 26, 2007. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter March 31, 2007 (SEC File No. 001-16383), filed on May 8, 2007)
10.70*	GDF Transatlantic Option Agreement, dated April 26, 2007, between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter March 31, 2007 (SEC File No. 001-16383), filed on May 8, 2007)
10.71*	Amended and Restated Shareholders Agreement, dated May 8, 2007, between Mercuria Energy Holding B.V. and Cheniere LNG Services, Inc. (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter March 31, 2007 (SEC File No. 001-16383), filed on May 8, 2007)
10.72*	Master Loan Agreement, dated May 8, 2007, between Cheniere LNG Services, Inc. and J & S Cheniere SA. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter March 31, 2007 (SEC File No. 001-16383), filed on May 8, 2007)

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<u>Exhibit No.</u>	<u>Description</u>
10.73*	Letter Agreement, dated May 8, 2007, between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter March 31, 2007 (SEC File No. 001-16383), filed on May 8, 2007)
10.74*†	Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan. (Incorporated by reference to Exhibit 10.14 to the Company's Quarterly on Form 10-Q (SEC File No. 000-16383), filed on November 4, 2005)
10.75*†	Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 4, 2005)
10.76*†	Addendum to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (SEC File No. 001-16383), filed on March 13, 2006)
10.77*†	Amendment No. 1 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 4.10 to the Company's Registration Statement on Form S-8 (SEC File No. 333-134886), filed on June 9, 2006)
10.78*†	Amendment No. 2 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.84 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.79*†	Form of Non-Qualified Stock Option Grant for Employees and Consultants (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.80*†	Form of Non-Qualified Stock Option Grant for Employees and Consultants (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.81*†	Form of Non-Qualified Stock Option Grant for Non-Employee Directors under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.82*†	Form of Restricted Stock Grant (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.83*†	Form of Restricted Stock Grant (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007)
10.84*†	Form of Restricted Stock Agreement for Non-Employee Directors. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.85*†	Form of Cancellation and Grant of Non-Qualified Stock Options (three-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 2, 2005)
10.86*†	Form of Amendment to Non-Qualified Stock Option Agreement. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on April 3, 2007)

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<u>Exhibit No.</u>	<u>Description</u>
10.87*†	Form of French Stock Option Grant for Employees and Consultants (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.91 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.88*†	Form of French Restricted Shares Grant for Employees, Consultants and Non-Employee Directors (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.92 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.89*†	Form of French Restricted Shares Grant for Employees, Consultants and Non-Employee Directors (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.93 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007)
10.90†	Summary of Compensation for Executive Officers.
10.91*†	Summary of Compensation to Non-Employee Directors. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383, filed on June 1, 2007)
10.92*†	Summary of 2007 Performance Bonus Plan. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on April 5, 2007)
10.93*†	Summary of Terms for Cheniere Energy, Inc. Incentive Compensation Plan for Executive Committee Members and Other Key Employees. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 1, 2007)
10.94	Share Purchase Agreement, dated December 7, 2007, between Mercuria Energy Holding B.V. and Cheniere LNG Services, Inc.
10.95	Change order 1 to Construction Agreement, dated January 5, 2007, between Cheniere Creole Trail Pipeline, L.P. and Sunland Construction, Inc.
21.1	Subsidiaries of Cheniere Energy, Inc.
23.1	Consent of Ernst & Young LLP
23.2	Consent of UHY LLP
23.3	Consent of Sharp Petroleum Engineering, Inc.
31.1	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Incorporated by reference
† Management contract or compensatory plan or arrangement

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—
CHENIERE ENERGY, INC.
CONDENSED BALANCE SHEET
(in thousands)

	December 31,	
	2007	2006
<u>ASSETS</u>		
CURRENT ASSETS		
Cash and cash equivalents	\$ 46,945	\$ 1
Prepaid expenses and other	238	32
Total current assets	47,183	33
DEBT RECEIVABLE—AFFILIATES	581,358	547,145
OTHER	6,198	7,822
Total assets	\$ 634,739	\$ 555,000
<u>LIABILITIES AND STOCKHOLDERS' (DEFICIT) EQUITY</u>		
CURRENT LIABILITIES	3,075	3,628
LONG-TERM DEBT	325,000	325,000
LONG-TERM DEBT—AFFILIATE	391,708	—
INVESTMENT IN AND EQUITY IN LOSSES OF AFFILIATES	217,070	83,125
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' (DEFICIT) EQUITY	(302,114)	143,247
Total liabilities and stockholders' equity	\$ 634,739	\$ 555,000

See accompanying notes to condensed financial statements.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—
CHENIERE ENERGY, INC.

CONDENSED STATEMENT OF OPERATIONS
(in thousands)

	Year Ended December 31,		
	2007	2006	2005
Revenues			
Total revenues	\$ —	\$ —	\$ —
Operating costs and expenses	60	3,494	3,891
Loss from operations	(60)	(3,494)	(3,891)
Interest expense, net	(8,698)	(8,676)	(3,741)
Interest income	3,336	—	20
Interest income—affiliates	34,213	34,213	25,353
Interest expense—affiliates	(22,496)	—	—
EQUITY LOSSES OF AFFILIATES	(188,082)	(167,896)	(47,279)
Other income	10	—	—
Income tax (provision) benefit	—	—	—
Net loss	\$ (181,777)	\$ (145,853)	\$ (29,538)

See accompanying notes to condensed financial statements.

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**SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—
CHENIERE ENERGY, INC.**

**CONDENSED STATEMENT OF CASH FLOWS
(in thousands)**

	Year Ended December 31,		
	2007	2006	2005
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	\$ (28,604)	\$ 4,218	\$ (20,209)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Return of capital from (capital contributions to) affiliates	4,223	(6,856)	(66,571)
Other	184	4	(28)
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	4,407	(6,852)	(66,599)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings from long-term debt	391,708	—	325,000
Purchase of treasury shares	(325,062)	2	11
Issuance of long-term debt—affiliate	—	—	(240,359)
Purchase of issuer call spread	—	—	(75,703)
Sale of common stock	3,155	1,995	80,115
Amortization of debt issuance costs	1,377	1,614	(9,182)
Issuance of restricted stock	—	—	6,662
Other	(37)	(977)	(27)
NET CASH PROVIDED BY FINANCING ACTIVITIES	71,141	2,634	86,517
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	46,944	—	(291)
CASH AND CASH EQUIVALENTS—BEGINNING OF YEAR	1	1	292
CASH AND CASH EQUIVALENTS—END OF YEAR	\$ 46,945	\$ 1	\$ 1

**SUPPLEMENTAL CASH FLOW INFORMATION AND
DISCLOSURES OF NON-CASH TRANSACTIONS**

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Cash paid during the year for:			
Non-cash capital contributions(1)	\$ 188,082	\$ 145,853	\$ 47,279

(1) Amounts represent equity losses of affiliates not funded by Cheniere.

See accompanying notes to condensed financial statements.

CHENIERE ENERGY, INC.
NOTES TO CONDENSED FINANCIAL STATEMENTS

Note 1—Summary of Significant Accounting Policies

The condensed financial statements represent the financial information required by Securities and Exchange Commission Regulation S-X 5-04 for Cheniere Energy, Inc (“Cheniere”).

In the condensed financial statements, Cheniere’s investments in affiliates are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded in the balance sheets. The loss from operations of the affiliates is reported on a net basis as equity in net losses of affiliates.

A substantial amount of Cheniere’s operating, investing, and financing activities are conducted by its affiliates. The condensed financial statements should be read in conjunction with Cheniere’s consolidated financial statements.

Note 2—Debt

As of December 31, 2007 and 2006, our long-term debt consisted of the following (in thousands):

	December 31,	
	2007	2006
Convertible Senior Unsecured Notes	325,000	325,000
Long-Term Note—Affiliate	391,708	—
Total Long-Term Debt	\$ 716,708	\$ 325,000

Below is a schedule of future principal payments that we are obligated to make on our outstanding long-term debt at December 31, 2007 (in thousands):

	Payments Due for Years Ended December 31,				
	Total	2008	2009 to 2010	2011 to 2012	Thereafter
Convertible Senior Unsecured Notes	325,000	—	—	325,000	—
Long-Term Note-Affiliate	391,708	—	—	391,708	—
Total	\$716,708	\$—	\$ —	\$ 716,708	\$ —

Long-Term Note-Affiliate

In May 2007, we entered into a \$391.7 million long-term note (“Long-Term Note-Affiliate”) with Cheniere Subsidiary Holdings, LLC (“Cheniere Subsidiary”), a newly formed wholly-owned subsidiary of Cheniere. Cheniere Subsidiary received the \$391.7 million net proceeds from a \$400 million credit agreement entered into in May 2007. Borrowings under the Long-Term Note-Affiliate bear interest equal to the terms of Cheniere Subsidiary’s credit agreement at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the Long-Term Note-Affiliate outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. The Long-Term Note-Affiliate will mature on May 31, 2012. The \$391.7 million from the Long-Term Note-Affiliate are being used for general corporate purposes, including our repurchase, completed during the year ended December 31, 2007, of approximately 9.2 million shares of our outstanding common stock pursuant to the exercise of the call options acquired in the issuer call spread purchased by us in connection with the issuance of the Convertible Senior Unsecured Notes.

CHENIERE ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 3—GUARANTEES

Guarantees on Behalf of Cheniere Marketing, Inc.

TUA Agreement

Cheniere Marketing, Inc. (“Cheniere Marketing”), a wholly owned subsidiary of Cheniere, has a 20-year, firm commitment Terminal Use Agreement (“TUA”) with Sabine Pass LNG, L.P. for regasification capacity at the Sabine Pass LNG receiving terminal. Cheniere Marketing must make the full contracted amount of capacity reservation fee payments under its TUA whether or not it uses any of its reserved capacity. Provided the Sabine Pass LNG receiving terminal has achieved commercial operation, which we expect will occur during the second quarter of 2008, Cheniere Marketing’s capacity reservation fee TUA payments are approximately \$250 million per year for at least 19 years commencing January 1, 2009, plus capacity payments of \$5 million per month during an initial commercial operations ramp-up period in 2008. Cheniere has guaranteed Cheniere Marketing’s obligations under its TUA.

Marketing and Trading Guarantees

Cheniere Marketing is developing a natural gas and LNG marketing and trading business. Many of Cheniere Marketing’s natural gas purchase, sale, transportation and shipping agreements have been guaranteed by Cheniere. These contracts that have been guaranteed by Cheniere have a \$26.6 million maximum potential of future payments and various expiration dates. As of December 31, 2007, the carrying amount of the liability related to these guaranteed contracts was \$2.5 million.

Pipeline Construction Guarantee

In January 2007, Cheniere Creole Trail Pipeline, L.P. (“CCTP”), a wholly owned subsidiary of Cheniere, entered into an agreement with Sunland Construction, Inc. (“Sunland”) for the construction of approximately 23 miles of the Creole Trail Pipeline. Under the terms of the agreement, Sunland will provide CCTP with equipment, labor, inspection, manufacture, fabrication, installation, delivery, transportation, storage, assembly and construction services in connection with the Creole Trail Pipeline. As of December 31, 2007, change orders for \$5.7 million had been approved, increasing the total estimated contract price to \$75.8 million. Progress payments will be paid based on quantities of work performed, minus 5% retainage on construction work that will be paid upon final completion. CCTP may at any time terminate, for convenience, Sunland’s performance effective upon receipt of a written notice by Sunland and payment for items provided or services performed prior to termination. The agreement is subject to a cancellation fee not to exceed 5% of the estimated contract price. Such work is expected to be fully complete in the second quarter of 2008. Cheniere has guaranteed up to \$12.0 million of CCTP’s obligations under the construction agreement with Sunland.

Long-term Debt Guarantee

In May 2007, Cheniere Subsidiary entered into a \$400.0 million credit agreement (“2007 Term Loan”). Borrowings under the 2007 Term Loan generally bear interest at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the 2007 Term Loan outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. The 2007 Term Loan will mature on May 31, 2012. Cheniere guaranteed the payment of all principal and interest.

Creole Trail Pipeline Guarantee

Cheniere Creole Trail Pipeline, L.P. (“CCTP”) is constructing an integrated pipeline system originating at the Sabine Pass LNG receiving terminal to points of interconnection with multiple interstate and intrastate

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CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

natural gas pipelines throughout southern Louisiana (the “Creole Trail Pipeline”). Initial construction of Phase I of the Creole Trail Pipeline (consisting of 94 miles of natural gas pipeline) commenced in the second quarter of 2007, and we anticipate that it will be available for operations in the second quarter of 2008.

Cheniere Marketing has entered into a firm transportation agreement with CCTP for transportation at a negotiated rate for the transport and sale of revaporized natural gas that it derives from its own imported LNG or LNG that it purchases from other importers for sale into North American markets. In connection with this firm transportation agreement, Cheniere has guaranteed CCTP’s pre-service Creole Trail Pipeline construction costs, estimated to be \$550 million at December 31, 2007.

SCHEDULE D-1

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving, Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-051

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 20, 2007

CONTRACTOR: Bechtel Corporation

Bundle of Changes #11

- A. Corrosion Resistant Barrier for Non-insulated Pipe
- B. Start-up Services for Temporary Compressor
- C. Contractor Representatives Designated

DATE OF AGREEMENT: December 18, 2004

The Agreement between the Parties listed above is changed as follows:

A. Corrosion Resistant Barrier for Non-insulated Pipe (T-7014)

Supply and install Corrosion Resistant Barriers under all non-insulated piping that is in direct contact with the supporting steel.

B. Start-Up Services for Temporary Pipeline Compressor (T-7023)

Provide start-up services for temporary pipeline compressor. Start-up services to include inspection of piping for cleaning, valve operation, instrument checks, Vendor support, monitoring, N2 purge of piping and compressor and leak checks.

C. Designation of Contractor Representatives

Effective October 18, 2007, Section 2.2(B) of the Agreement is hereby revised to delete reference to Asok Kumar and add the following "Contractor Representatives":

Carl Strock, Project Director
Pat McCormack, Project Manager

Both newly appointed Contractor Representatives have complete authority to act on behalf of Contractor on all matters pertaining to the Agreement or the Work including giving instructions and making changes to the Work.

ATTACHMENTS:

- A-1) Detail Estimate Corrosion Resistant Barriers (T-7014)
- A-2) Payment Milestones Wear Plates (T-7014)
- B-1) Detail Estimate Start-Up Services (T-7023)
- B-2) Payment Milestones Start-Up Services (T-7023)

\$ 526,656

\$ 20,000

Change Order SP/BE-051 TOTAL: \$ 546,656

SCHEDULE D-1
CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving,
Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-051

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 20, 2007

CONTRACTOR: Bechtel Corporation

Bundle of Changes #11

- A. Corrosion Resistant Barrier for Non-insulated Pipe
- B. Start-up Services for Temporary Compressor
- C. Contractor Representatives Designated

DATE OF AGREEMENT: December 18, 2004

Adjustment to Contract Price

The original Contract Price was	\$ 646,936,000
Net change by previously authorized Change Orders (#SP/BE-002 to 028, 031, 033 thru 035; 037 thru 050)	\$ 164,899,545
The Contract Price prior to this Change Order was	\$ 811,835,545
The Contract Price will be increased by this Change Order in the amount of	\$ 546,656
The new Contract Price including this Change Order will be	\$ 812,382,201

Adjustment to dates in Project Schedule

The following dates are modified:

The Target Bonus Date will be unchanged.

The Target Bonus Date as of the date of this Change Order therefore is April 3 2008 (1,095 Days following the NTP)

The Guaranteed Substantial Completion Date will be unchanged December 20, 2008.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is 1,355 days following NTP.

Adjustment to other Changed Criteria: Not Applicable

Adjustment to Payment Schedule: See attached "Payment Milestone – Send-Out Piping Modifications (T-2002).

Adjustment to Minimum Acceptance Criteria: No Change

Adjustment to Performance Guarantees: No Change

Adjustment to Design Basis: No Change.

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: No Change

This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change as described in this Change Order upon the Changed Criteria and shall be deemed to compensate Contractor fully for such change.

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

SCHEDULE D-1
CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving,
Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-051

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 20, 2007

CONTRACTOR: Bechtel Corporation

Bundle of Changes #11

- A. Corrosion Resistant Barrier for Non-insulated Pipe
- B. Start-up Services for Temporary Compressor
- C. Contractor Representatives Designated

DATE OF AGREEMENT: December 18, 2004

/s/ Charif Souki

* Charif Souki
Chairman

/s/ C. Asok Kumar

Contractor

C. Asok Kumar

Name

Project Director

Title

1/7/08

Date of Signing

12-19-07

Date of Signing

/s/ Stan Horton

* Stan Horton
President & COO Cheniere Energy

12/19/07

Date of Signing

/s/ Ed Lehotsky

* Ed Lehotsky
Owner Representative

December 18, 2007

Date of Signing

* Required Owner signature – Mr. Horton may sign on behalf of Mr. Souki during Mr. Souki's absence.

SCHEDULE D-1

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving, Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-052

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 1, 2007

CONTRACTOR: Bechtel Corporation

LNG Tank Force Majeure Settlement & Tank Stainless Steel Material Adjustment

DATE OF AGREEMENT: December 18, 2004

The Agreement between the Parties listed above is changed as follows:

Owner and Contractor agree to implement and incorporate the following changes in connection with the completion of Tanks 1, 2 & 3 ("Tank Settlement"). This Tank Settlement settles and resolves all issues or claims arising out of or relating to hurricanes Katrina, Rita, Wilma, or Humberto, or any Excessive Monthly Precipitation events or other Force Majeure events occurring prior to the date of this Change Order, to the extent relating to the LNG Tanks or the Tank Subcontractor. This agreement does not prejudice or waive any rights the Parties' may have with respect to any Force Majeure events, if any, occurring after the date of this Change Order. All amounts paid to Contractor hereunder (and future Change Orders if a System 1 RFCD Bonus, Tank 2 RFCD Bonus, and/or Tank 3 Early RFCD Bonus is earned under Section IV below) will in turn be promptly paid in full to Contractor's LNG Tank Subcontractor (a joint venture of Diamond LNG LLC and Matrix Service, Inc., such joint venture collectively referred to as "Matrix"). Owner and Contractor also agree to implement the stainless steel material adjustments in Section IV.E.(2) below.

I. Change Order No. SP/BE-0037 Payment Method Adjustment

A. Force Majeure Provisional Sums

Change Order No. SP/BE-0037 identified an adjustment to the Contract Price in the amount of \$6,888,833.00 referred to as "Revised Compensation & Equipment Forecast to recover schedule impacts" (hereafter "FM Provisional Sum"). As of November 1, 2007, the remaining balance (not yet invoiced) of the FM Provisional Sum is \$2,207,884.00. Owner agrees to pay to Contractor the FM Provisional Sum balance in six (6) equal consecutive monthly payments of \$367,980.67 commencing with the first invoice cycle following execution by both Parties of this Change Order No. SP/BE-052. This agreement as to the payment method for the FM Provisional Sum supersedes any provision to the contrary contained in Change Order No. SP/BE-0037.

B. Potential Bonus Amounts—Tanks 1, 2&3

Price adjustments for "Potential Bonuses" to be paid to the LNG Tank Subcontractor as identified in Section 2 (and Attachment A, Items 5.01, 5.02 & 5.03) of Change Order No. SP/BE-0037 shall remain unchanged.

Except as specifically modified above and by Section IV.E.(4), all other provisions of Change Order No. SP/BE-0037 shall remain unchanged.

II. Additional Force Majeure Sums

Owner agrees to provide an additional price adjustment to the Contract Price in the amount of \$3,852,467.00 for the purpose of attracting qualified craft and supervision personnel and to offset the costs of increased craft compensation claimed by Matrix ("Additional FM Sums"). Owner agrees to pay to Contractor the Additional FM Sums in six (6) equal consecutive monthly payments of \$642,077.80 commencing with the first invoice cycle following execution by both Parties of this Change Order No. SP/BE-052.

III. Additional Schedule Recovery & Labor Hour Increases – Lump Sum

For the purpose of facilitating the schedule recovery efforts with respect to the LNG Tanks and supplementing Matrix's costs due to labor hour increases, Owner agrees to provide an additional Contract Price adjustment of \$2,000,000 to facilitate Matrix's schedule recovery efforts. Contractor will invoice Owner for the full lump sum amount of \$2,000,000 following execution by both Parties of the Change Order No. SP/BE-052. Such invoice is due and payable no later than twenty-five (25) Days after receipt by Owner.

IV. Additional Schedule Recovery & Labor Hour Increases – Bonus & Other Conditions

SCHEDULE D-1

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving, Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-052

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 1, 2007

CONTRACTOR: Bechtel Corporation

LNG Tank Force Majeure Settlement & Tank Stainless Steel Material Escalation

DATE OF AGREEMENT: December 18, 2004

For the purpose of facilitating Matrix's schedule recovery efforts with respect to the LNG Tanks and supplementing Matrix's costs due to labor hour increases, Owner agrees to pay an amount not to exceed \$5,622,041 should the following milestones be achieved, or as adjusted as described below:

A. System 1 RFCD Bonus

In the event RFCD for System 1 is achieved by the date of February 18, 2008, Contractor will be entitled to and Owner will pay an additional \$2,300,000.00 (System 1 RFCD Bonus) to Contractor. If RFCD for System 1 is not achieved by February 18, 2008, then the amount of the System 1 RFCD Bonus will be decreased by \$230,000.00 for each Day after February 18, 2008 that RFCD for System 1 has not been achieved, down to a System 1 RFCD Bonus of zero (U.S. \$0).

B. Tank 2 RFCD Bonus

In the event System 1 and Tank 2 are RFCD by March 23, 2008 Contractor will be entitled to and Owner will pay an additional \$2,300,000.00 (Tank 2 RFCD Bonus) to Contractor. If RFCD for System 1 is met by March 23, 2008, but the RFCD for Tank 2 is not achieved by March 23, 2008 (or if RFCD for Tank 2 is met by March 23, 2008 but RFCD for System 1 is not met by March 23, 2008), the amount of the Tank 2 RFCD Bonus will be decreased by \$230,000.00 for each Day after March 23, 2008 that RFCD for System 1 and Tank 2 have not been achieved down to a Tank 2 RFCD Bonus of zero (U.S. \$0).

C. Tank 3 Early RFCD Bonus

In the event System 1 and Tank 3 are RFCD by April 27, 2008, Contractor will be entitled to and Owner will pay an additional \$1,022,041.00 (Tank 3 RFCD Bonus) to Contractor. If RFCD for System 1 is met by April 27, 2008, but RFCD for Tank 3 is not achieved by April 27, 2008 (or if RFCD for Tank 3 is met by April 27, 2008, but RFCD for System 1 is not met by April 27, 2008), the amount of the Tank 3 RFCD Bonus will be decreased by \$15,723.00 for each Day after April 27, 2008 that RFCD for System 1 and Tank 3 have not been achieved, down to a Tank 3 RFCD Bonus of zero (U.S. \$0).

D. RFCD Bonus

Dates noted above under Sections A, B, and C are fixed unless modified by Change Order executed between the Parties. A separate Change Order to authorize payment of the foregoing bonus amounts will be executed at such time as each bonus is earned.

E. Other Conditions

(1) Craft Special Incentive

Any payment of the System 1 RFCD Bonus amount and Tank 2 RFCD Bonus amount by Contractor to Matrix shall be subject to a condition that a portion of such payment shall be used to fund a special incentive plan for the benefit of Matrix's craft and field staff personnel ("Craft Special Incentive"), such plan to be developed and implemented by Matrix with the assistance of Contractor, as further provided herein. This Craft Special Incentive is in addition to any currently existing incentive and/or bonus plans of Matrix.

The Craft Special Incentive shall be funded from the payments made for System 1 RFCD Bonus amount and Tank 2 RFCD Bonus amount, in an amount total not to exceed \$700,000.00 as follows:

In the event Contractor receives the full System 1 RFCD Bonus amount, not less than \$350,000.00 of such System 1 RFCD Bonus shall fund the Craft Special Incentive. If the System 1 RFCD date is not timely

SCHEDULE D-1

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving, Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-052

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 1, 2007

CONTRACTOR: Bechtel Corporation

LNG Tank Force Majeure Settlement & Tank Stainless Steel Material Escalation

DATE OF AGREEMENT: December 18, 2004

achieved as provided in Section IV above, the amount of the Craft Special Incentive to be funded from the System 1 RFCD Bonus will be decreased by \$35,000.00 for each Day after February 18, 2008 that RFCD for System 1 has not been achieved, down to a Craft Special Incentive amount of zero (U.S. \$0).

In the event Contractor receives the full Tank 2 RFCD Bonus amount, not less than \$350,000.00 of such Tank 2 RFCD Bonus shall fund the Craft Special Incentive. If the Tank 2 RFCD date is not timely achieved as provided in Section IV above, the amount of the Craft Special Incentive to be funded from the Tank 2 RFCD Bonus will be decreased by \$35,000.00 for each Day after March 23, 2008 that RFCD for System 1 and Tank 2 has not been achieved, down to a Craft Special Incentive amount of zero (U.S. \$0).

(2) Stainless Steel Material Escalation Index

Effective January 1, 2007, the formulas contained in Sections 3.4 and 3.8 of Attachment EE, Rev 1, shall be amended as follows:

3.4 Adjustment for Tank Stainless Steel ("TankSS_{adj}")

$$\text{TankSS}_{\text{adj}} = \text{U.S.}\$524,846 * [((S_1 + \text{SSC}_1) / 2798.2) - 1]$$

3.8 Adjustment for Piping and Valves ("PV_{adj}")

$$\text{PV}_{\text{adj}} = \text{U.S.}\$6,463,670 * 0.5 * [((S_1 + \text{SSC}_1) / 2798.2) - 1]$$

Except as specifically amended above, Sections 3.4 and 3.8 of Attachment EE, Rev 1 remain unchanged.

(3) The adjusted Ready for Cool Down dates, Target Bonus Date and Forecasted Substantial Completion date identified in Change Order No. SP/BE-0032 dated May 16, 2007 shall remain unchanged.

(4) Unless a Force Majeure event occurs after the date of this Change Order, Contractor waives and releases Owner through the term of the Agreement from and against any and all claims for any additional compensation or other relief with respect to Matrix ability to attract qualified craft and supervision personnel, schedule relief or supplement costs incurred by Matrix due to labor increases.

REFERENCES:

- Change Order No. SP/BE-0032 dated May 16, 2006
- Change Order No. SP/BE-0037 dated September 30, 2006
- Change Order No. SP/BE-006 dated April 18, 2005
- Change Order No. SP/BE-033 dated May 30, 2006
- Change Order No. SP/BE-041 dated January 2, 2007
- Change Order No. SP/BE-049 dated June 11, 2007

Change Order SP/BE-052 TOTAL: \$5,852,467.00

SCHEDULE D-1

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving, Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-052

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 1, 2007

CONTRACTOR: Bechtel Corporation

LNG Tank Force Majeure Settlement & Tank Stainless Steel Material Escalation

DATE OF AGREEMENT: December 18, 2004

Adjustment to Contract Price

The original Contract Price was	\$ 646,936,000
Net change by previously authorized Change Orders (#SP/BE-002 to 028, 031, 033 thru 035; 037 thru 050)	\$ 164,899,545
The Contract Price prior to this Change Order was	\$ 811,835,545
Change Order No. SP/BE-051 dated November 20, 2007	\$ 546,656
The Contract Price will be increased by this Change Order in the amount of	\$ 5,852,467
The new Contract Price including this Change Order will be	\$ 818,234,668

Adjustment to dates in Project Schedule

The following dates are modified:

The Target Bonus Date will be unchanged.

The Target Bonus Date as of the date of this Change Order therefore is April 3 2008 (1,095 Days following the NTP)

The Guaranteed Substantial Completion Date will be unchanged December 20, 2008.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is 1,355 days following NTP.

Adjustment to other Changed Criteria: Not Applicable

Adjustment to Payment Schedule: Refer to Section II and Section III for payment details

Adjustment to Minimum Acceptance Criteria: No Change

Adjustment to Performance Guarantees: No Change

Adjustment to Design Basis: No Change.

Other adjustments to liability or obligation of Contractor or Owner under the Agreement: No Change

This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change as described in this Change Order upon the Changed Criteria and shall be deemed to compensate Contractor fully for such change.

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

SCHEDULE D-1
CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Receiving,
Storage and Regasification Terminal

CHANGE ORDER NUMBER: SP/BE-052

OWNER: Sabine Pass LNG, L.P.

DATE OF CHANGE ORDER: November 1, 2007

CONTRACTOR: Bechtel Corporation

**LNG Tank Force Majeure Settlement & Tank
Stainless Steel Material Escalation**

DATE OF AGREEMENT: December 18, 2004

/s/ Charif Souki

* Charif Souki
Chairman

Carl A. Strock

Contractor

Carl A. Strock

Name

Project Director

Title

28 Jan 08

Date of Signing

12-19-07

Date of Signing

/s/ Stan Horton

* Stan Horton
President & COO Cheniere Energy

12/19/07

Date of Signing

/s/ Ed Lehotsky

* Ed Lehotsky
Owner Representative

December 28, 2007

Date of Signing

* Required Owner signature – Mr. Horton may sign on behalf of Mr. Souki during Mr. Souki's absence.

CHANGE ORDER FORM**PROJECT NAME:** 42-inch Sabine Pass Pipeline Project**COMPANY:** Cheniere Sabine Pass Pipeline Company**CONTRACTOR:** Willbros Engineers, Inc.**DATE OF AGREEMENT:** February 01, 2006**CHANGE ORDER NUMBER:** CO-009**DATE OF CHANGE ORDER:** August 3, 2007**The Agreement between the Parties listed above is changed as follows:***(attach additional documentation if necessary)*

Pursuant to Paragraph 9.1 of Schedule A, Owner hereby directs and Contractor agrees to perform all Work necessary to utilize horizontal directional drilling for the crossing of the Chevron plant through State Highway 82 near MP1.1 to avoid existing belowground obstacles at this portion of the Work Site. Without limiting the generality of the foregoing, Contractor shall revise applicable Drawings and re-issue such Drawings for permitting and construction, apply PowerCrete or ARO to the pipe in Houston, Texas, and truck the pipe from New Iberia, Louisiana to Houston, Texas and back to the Work Site.

The cost basis for the increase in Guaranteed Maximum Price to perform the Work set forth in this Change Order is set forth in the attached documents titled "Change Order No. 012 Chevron Plant and Highway 82 HDD Cost Basis—June 17, 2007". A provisional amount of \$18,155 is included in the adjustment to the Guaranteed Maximum Price for all engineering Work related to this Change Order and shall be subject to further adjustment via subsequent Change Order based upon the actual engineering Work Performed.

Adjustment to price under the Agreement:

The original Guaranteed Maximum Price was	\$ 67,670,200
Net change by previously authorized Change Orders (#001-008)	\$ (951,269)
The Guaranteed Maximum Price prior to this Change Order was	\$ 66,718,931
The Guaranteed Maximum Price will be (increased) (decreased) (unchanged) by this Change Order in the amount of	\$ 776,665
The new Guaranteed Maximum Price including this Change Order will be	\$ 67,495,596

Adjustment to dates:

The Preparation and Material Receipt Commencement Date will be (~~increased~~) (~~decreased~~) (unchanged) by zero (0) calendar days and as a result of this Change Order is now: January 01, 2007.

The Construction Commencement Date will be (~~increased~~) (~~decreased~~) (unchanged) by zero (0) calendar days and as a result of this Change Order is now: April 1, 2007.

The Scheduled Mechanical Completion Date will be (~~increased~~) (~~decreased~~) (unchanged) by zero (0) calendar days and as a result of this Change Order is now: September 30, 2007.

Other impacts to liability or obligation of Willbros or Cheniere under the Agreement: None

Upon execution of this Change Order by Cheniere and Willbros, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Cheniere's Authorized Representative and Willbros' Authorized Representative.

CHENIERE SABINE PASS PIPELINE COMPANY

/s/ R. Keith Teague

Name

Cheniere's Authorized Representative

Title

President

Date of Signing

8/7/2007

WILLBROS ENGINEERS, INC.

/s/ Mike Reifil

Name

Willbros' Authorized Representative

Title

Project Manager

Date of Signing

9/4/2007

CHANGE ORDER FORM

PROJECT NAME: 42-inch Sabine Pass Pipeline Project

COMPANY: Cheniere Sabine Pass Pipeline Company

CONTRACTOR: Willbros Engineers, Inc.

DATE OF AGREEMENT: February 01, 2006

CHANGE ORDER NUMBER: CO-010

DATE OF CHANGE ORDER: August 3, 2007

The Agreement between the Parties listed above is changed as follows:*(attach additional documentation if necessary)*

Pursuant to Paragraph 9.1 of Schedule A, Owner hereby directs and Contractor agrees to perform all Work necessary to road bore the Duck Blind Road crossing at the Work Site so as to ensure the structure of the road is not disturbed, minimize interference in this high traffic area of the Work Site and to account for the existing underground power line. Without limiting the generality of the foregoing, Contractor shall revise applicable Drawings and re-issue such Drawings for permitting and construction, apply PowerCrete or ARO to the pipe in Houston, Texas, and truck the pipe from New Iberia, Louisiana to Houston, Texas and back to the Work Site.

The cost basis for the increase in Guaranteed Maximum Price to perform the Work set forth in this Change Order is set forth in the attached documents titled "Change order No. 014 Duck Blind Road Bore Cost Basis - July 11, 2007". [A provisional amount of \$10,620 is included in the adjustment to the Guaranteed Maximum Price for all engineering Work related to this Change Order and shall be subject to further adjustment via subsequent Change Order based upon the actual engineering Work performed.]

Adjustment to price under the Agreement:

The original Guaranteed Maximum Price was	\$ 67,670,200
Net change by previously authorized Change Orders (#001-009)	\$ (174,604)
The Guaranteed Maximum Price prior to this Change Order was	\$ 67,495,596
The Guaranteed Maximum Price will be (increased) (decreased) (unchanged) by this Change Order in the amount of	\$ 600,000
The new Guaranteed Maximum Price including this Change Order will be	\$ 68,095,596

Adjustment to dates:

The Preparation and Material Receipt Commencement Date will be ~~(increased)~~~~(decreased)~~(unchanged) by zero (0) calendar days and as a result of this Change Order is now: January 01, 2007.

The Construction Commencement Date will be ~~(increased)~~~~(decreased)~~(unchanged) by zero (0) calendar days and as a result of this Change Order is now: April 1, 2007.

The Scheduled Mechanical Completion Date will be ~~(increased)~~~~(decreased)~~(unchanged) by zero (0) calendar days and as a result of this Change Order is now: September 30, 2007.

Other impacts to liability or obligation of Willbros or Cheniere under the Agreement: None

Upon execution of this Change Order by Cheniere and Willbros, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Cheniere's Authorized Representative and Willbros' Authorized Representative.

CHENIERE SABINE PASS PIPELINE COMPANY

/s/ R. Keith Teague

Name

Cheniere's Authorized Representative

Title

President

Date of Signing

8/7/2007

WILLBROS ENGINEERS, INC.

/s/ Mike Reifl

Name

Willbros' Authorized Representative

Title

Project Manager

Date of Signing

9/4/07

CHANGE ORDER FORM

PROJECT NAME: 42-inch Sabine Pass Pipeline Project

COMPANY: Cheniere Sabine Pass Pipeline Company

CONTRACTOR: Willbros Engineers, Inc.

CHANGE ORDER NUMBER: CO-011

DATE OF CHANGE ORDER: August 3, 2007

DATE OF AGREEMENT: February 1, 2006

The Agreement between the Parties listed above is changed as follows: (attach additional documentation if necessary)

This Change Order represents a full settlement of all claims, damages, losses, costs and expenses that Contractor has or may have against Owner for any event, circumstance or any other act or omission occurring at any time up through the date of this Change Order, including but not limited to all claims, damages, losses, costs and expenses arising from or related to Contractor's change order requests 7193-07-WRPI-L-117-LEC dated May 18, 2007 (DMPA Drainage) and 7193-07-WRPI-L-116-JFM dated May 15, 2007 (Fence Crossings). Further, this Change Order represents a full settlement of all claims, damages, losses, costs and expenses that Contractor has or may have against Owner for any event, circumstance or any other act or omission occurring at any time, whether through or after the date of this Change Order, arising out of or related to Contractor's selection of or availability to select push construction method versus land lay construction method at all points of the Work represented on the issued for construction Drawings CH-5763D-1101 through 1106.

The Guaranteed Maximum Price is herein increased as a result of Owner's direction, pursuant to Paragraph 9.1 of Schedule A, and Contractor's agreement to perform all Work necessary to perform pre-production test of the field applied girth weld coating systems used on the Project.

Contractor is authorized to reimbursement from the Contingency Pool for the following Contingency Costs:

- Foreign Line Crossing at MP 5.0 (Willbros CO-009;7193-07-WRPI-L-108-JFM) – All costs, including Work stoppage and lifting of the abandoned pipeline to allow the Push #1 pipe string to pass underneath, associated with the foreign line crossing located at 263+41.
- GIS Development Support (Willbros CO-011) – All costs associated with the implementation of Schedule B, Scope of Work, Section 1.12 which shall include development of Domain Tables; asset to document linkage file as described in

Cheniere’s New Construction “Life of Pipe” Data Sources; quality control and checking. Development of the new seed file to match the domain tables will be done by a third party.

- Conversion of Proposed Push #2, Push #3 and Push #4 to Land Lay (Willbros CO-013; 7193-07-WRPI-L-126-JFM; 7193-07-WRPI-L-131-JFM) – All costs associated with the conversion of significant portions (station 449+81 east of Harrington Pond to station 833+48 end of the Project, approximately 3.43 miles) of the Project from a “push-pull” construction technique to a more conventional land lay approach including but not limited to:
 - o Delays incurred while re-permitting the construction R/W width from 100 feet to 120 feet.
 - o Stabilization of the Work platform including pumping, well pointing and matting.
 - o Additional personnel and/or equipment required to facilitate a modified approach to the proposed installation of the Work.
- DMPA Drainage Pumps (7193-07-WRPI-L-117-LEC) – All costs associated with preparation of the DMPA drainage outfall for a major rain event while the drainage is blocked prior to and following installation of the Work across subject drainage ditch to the river so as to avoid installing the crossing which would have been required by the FERC Wetland and Waterbody Plan and Procedures.
- Duncan Oil Line Crossing (7193-07-WRPI-L-103-JFM; 7193-07-WRPI-L-106-JFM; 7193-07-WRPI-L-109-JFM; 7193-07-WRPI-L-113-LEC; 7193-07-WRPI-L-121-JFM and; 7193-07-WRPI-L-122-LEC) – Stand-by and additional costs associated with subject crossing not limited to conditions resulting from or created by the pipeline alignment including longitudinal occupation of the of the gas well gathering pipeline R/W or providing uninterrupted access to the gas well facilities on both sides of the flotation ditch or re-permitting for additional work space.
- NGPL Pipeline Crossing @ 51+45 and 52+45 respectively (WEI notice dated June 5, 2007; 7193-07-WRPI-L-129-LEC) – All extra costs associated with subject foreign pipeline crossings including extra depth ditch, shoring, ditch dewatering and schedule impact.

Adjustment to price under the Agreement:

The original Guaranteed Maximum Price was	\$67,670,200
Net change by previously authorized Change Orders #1 – 10	\$ 425,396
The Guaranteed Maximum Price prior to the Change Order was	\$68,095,596
The Guaranteed Maximum Price will be (increased) (decreased) (unchanged) by this Change Order in the amount of	\$ 12,000
The new Guaranteed Maximum Price including this Change Order will be	\$68,107,596

Adjustment to dates:

The Preparation and Material Receipt Commencement Date will be (increased) (decreased) (unchanged) by zero (0) calendar days and as a result of this Change Order is now:	January 1, 2007
The Construction Commencement Date will be (increased) (decreased) (unchanged) by zero (0) calendar days and as a result of this Change Order is now:	April 1, 2007
The Scheduled Mechanical Completion Date will be (increased) (decreased) (unchanged) by twenty (20) calendar days and as a result of this Change Order is now:	October 20, 2007

Other impacts to liability or obligation of Willbros or Cheniere under the Agreement:

As of the effective date of this Change Order, Contractor hereby waives and releases Owner from and against any and all claims, damages, losses, costs and expenses that Contractor has or may have against Owner for any event, circumstance or any other act or omission occurring at any time up through the date of this Change Order, including but not limited to all claims, damages, losses, costs and expenses related to Contractor's change order requests 7193-07-WRPI-L-117-LEC dated May 18, 2007 (DMPA Drainage) and 7193-07-WRPI-L-116-JFM dated May 15, 2007 (Fence Crossings). Further, Contractor hereby waives and releases Owner from and against any and all claims, damages, losses, costs and expenses that Contractor has or may have against Owner for any event, circumstance or any other act or omission occurring at any time, whether through or after the date of this Change Order, arising out of or related to Contractor's selection of or availability to select push construction method verses land lay construction method.

Upon execution of this Change Order by Cheniere and Willbros, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Cheniere's Authorized Representative and Willbros' Authorized Representative.

CHENIERE SABINE PASS PIPELINE COMPANY

Name /s/ R. Keith Teague
Cheniere's Authorized Representative

Title President
Date of Signing 8/7/2007

WILLBROS ENGINEERS, INC.

Name /s/ Mike Reifil
Willbros' Authorized Representative

Title Project Manager
Date of Signing 9/4/07

CHANGE ORDER FORM

PROJECT NAME: 42-inch Sabine Pass Pipeline Project

COMPANY: Cheniere Sabine Pass Pipeline Company

CONTRACTOR: Willbros Engineers, Inc.

CHANGE ORDER NUMBER: CO-012

DATE OF CHANGE ORDER: September 4, 2007

DATE OF AGREEMENT: February 1, 2006

The Agreement between the Parties listed above is changed as follows: (attach additional documentation if necessary)

Per Cheniere's request, this change order involves the relocation of approximately 62 joints of 42" pipe and equipment mats from their current location in the contractor's designated pipeyard at the LNG terminal to a location on the north side of the pipeyard. At Cheniere's request, Contractor will coordinate the movement of these materials with Cheniere's Richard Prudhomme.

Due to the uncertainties associated with this activity, this change will be performed on a time and material basis utilizing the contract rates, the total cost of which will be added to the Guaranteed Maximum Price. A cost estimate for this work is attached. For estimating purposes, a provisional sum is used below.

Adjustment to price under the Agreement:

The original Guaranteed Maximum Price was	\$	67,670,200
Net change by previously authorized Change Orders #1 - 11		437,396
The Guaranteed Maximum Price prior to the Change Order was	\$	68,107,596
The Guaranteed Maximum Price will be (increased) (decreased) (unchanged) by this Change Order in the amount of (Provisional Sum)		23,250
The new Guaranteed Maximum Price including this Change Order will be	\$	68,130,846

Adjustment to dates:

The Preparation and Material Receipt Commencement Date will be (increased) (decreased) (unchanged) by 0 calendar days and as a result of this Change Order is now:	January 1, 2007
The Construction Commencement Date will be (increased) (decreased) (unchanged) by 0 calendar days and as a result of this Change Order is now:	April 1, 2007
The Scheduled Mechanical Completion Date will be (increased) (decreased) (unchanged) as a result of this Change Order:	October 20, 2007

Other impacts to liability or obligation of Willbros or Cheniere under the Agreement: None

Upon execution of this Change Order by Cheniere and Willbros, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Cheniere's Authorized Representative and Willbros' Authorized Representative.

CHENIERE SABINE PASS PIPELINE COMPANY

Name /s/ R. Keith Teague
Cheniere's Authorized Representative
Title R. Keith Teague
Date of Signing 10/8/2007

WILLBROS ENGINEERS, INC.

Name /s/ Curtis E. Simkin
Willbros' Authorized Representative
Curtis E. Simkin
Title President
Date of Signing 10/22/07

CHANGE ORDER FORM

PROJECT NAME: 42-inch Sabine Pass Pipeline Project

COMPANY: Cheniere Sabine Pass Pipeline Company

CONTRACTOR: Willbros Engineers, Inc.

CHANGE ORDER NUMBER: CO-013

DATE OF CHANGE ORDER: September 25, 2007

DATE OF AGREEMENT: February 1, 2006

The Agreement between the Parties listed above is changed as follows: (attach additional documentation if necessary)

Hurricane Humberto hit the project area the evening of September 11, 2007 and created a stoppage of construction activities between September 12, 2007 and September 18, 2007. Willbros provided a Notification of a Force Majeure Event to Cheniere on September 13, 2007. Due to the heavy rains encountered (approximately 13.5 inches), work was completely shutdown for a 5-day continuous period between September 12 and September 17, 2007. On September 17, 2007, construction crews returned to their respective work locations; however, the crews could not resume productive work at that time due to the wet right-of-way conditions. Two tie-in crews, a fabrication crew, an environmental crew and a supervision/support crew experienced work delays on September 17 and 18, 2007; ranging from 5.5 hours to 16 hours.

In accordance with Paragraph 20.1 of the Agreement, Willbros requests reimbursement of the standby costs for the above crews that were incurred beyond the five day continuous time period along with a resultant increase in the Guaranteed Maximum Price, and a 6-day increase to the Scheduled Mechanical Completion Date.

Please refer to the attached WRPI letter dated September 24, 2007 for backup to the change order including the change order basis, Force Majeure Event notification letter, standby cost summary, daily construction progress reports, and crew time sheets.

Adjustment to price under the Agreement:

The original Guaranteed Maximum Price was	\$ 67,670,200
Net change by previously authorized Change Orders #1 – 12	460,646
The Guaranteed Maximum Price prior to the Change Order was	\$ 68,130,846
The Guaranteed Maximum Price will be (increased) (decreased) (unchanged) by this Change Order in the amount of	92,211
The new Guaranteed Maximum Price including this Change Order will be	\$ 68,223,057

Adjustment to dates:

The Preparation and Material Receipt Commencement Date will be (increased) (decreased) (unchanged) by 0 calendar days and as a result of this Change Order is now:	January 1, 2007
The Construction Commencement Date will be (increased) (decreased) (unchanged) by 0 calendar days and as a result of this Change Order is now:	April 1, 2007
The Scheduled Mechanical Completion Date will be (increased) by 6 calendar days (decreased) (unchanged) and as a result of this Change Order is now:	October 26, 2007

Other impacts to liability or obligation of Willbros or Cheniere under the Agreement: None

Upon execution of this Change Order by Cheniere and Willbros, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Cheniere's Authorized Representative and Willbros' Authorized Representative.

CHENIERE SABINE PASS PIPELINE COMPANY

Name /s/ R. Keith Teague
Cheniere's Authorized Representative

Title President
Date of Signing Nov 13, 2007

WILLBROS ENGINEERS, INC.

Name /s/ Curtis E. Simkin
Willbros' Authorized Representative

Curtis E. Simkin
Title President
Date of Signing 11/19/07

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

COMPANY: Sabine Pass LNG, L.P.

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

CHANGE ORDER NUMBER: SP2/BE-005

DATE OF CHANGE ORDER: September 12, 2007

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#2**

The Agreement between the Parties listed above is changed as follows:

Increase in the Fixed Fee associated with the implementation of the following agreed Scope Changes:

- | | | |
|----|---|--------------|
| 1. | <u>Addition of 9 Ambient Air Vaporizers</u> (Trend No. F-1009R1)
Engineer, design, procure and install AAV Pilot Test Train based on eighteen (18) Ambient Air Vaporizer (AAV) Cells, an increase of nine AAVs. | \$ 5,987,000 |
| 2. | <u>Additional Dredging Marine Basin & Flare Area</u> (Trend No. F-0004)
Proceed with contracting for additional dredging in the marine infield and the construction dock area to address build up of silt layers. | \$ 5,306,000 |
| 3. | <u>ESD Philosophy Revisions</u> (Trend No. F-1001)
Provide Home Office services to support ESD Philosophy changes. This modification revises the initial delineation in Phase 1 design for ESD-1 and ESD-2 application between PERC valve and unloading operation valves. | \$ 181,000 |
| 4. | <u>ESD Equipment Revisions</u> (Trend No. F-1006)
Delete 24" SCV subheader (eliminating ESD valve), and replace with (2) 30" ESD valves on the dual header, complete with modified functionality including P&ID updates and DCS changes. | \$ 67,000 |
| 5. | <u>Pipeline Compressor Additions</u> (Trend No. F-1008)
Add additional pipeline compressor equipment and testing services to existing Purchase Order | \$ 74,002 |
| 6. | <u>Send-Out Piping Modifications</u> (Trend No. F-1014)
Implement changes to Reciprocating Packaged Compressor as identified in Extra Charge Approval Request (ECAR) No. 7 dated April 5, 2007 | \$ 75,030 |
| 7. | <u>Change Order SP2/BE-004 Remainder</u>
The total changes identified under Change Order No. SP2/BE-004 amounted to increased costs of \$25,400,000. The Fixed Fee adjustment was calculated based on \$25,000,000. This line item represents the excess cost of \$400,000 not previously included in the Fixed Fee adjustment. | \$ 400,000 |

Total Changes: \$ 12,090,032

Fixed Fee Adjustment: \$ 400,000

The Total Changes listed above increase the cost of the Phase 2 Project by US\$12,090,032. Pursuant to Section 7.2 of Article 7 of the Agreement, for each US\$5,000,000 increase in the cost of the Phase 2 Project, individually or in the aggregate, the Fixed Fee will be adjusted by US\$200,000. Consequently, this Change Order represents an adjustment to the Fixed Fee in the amount of US \$400,000 (4% x \$10,000,000). The remaining \$ 2,090,032 of the Total Changes will added to a future Change Order when the next US\$5,000,000 threshold is achieved.

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

COMPANY: Sabine Pass LNG, L.P.

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

CHANGE ORDER NUMBER: SP2/BE-005

DATE OF CHANGE ORDER: September 12, 2007

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#2**

References:

Bechtel Letter No. 25279-001-T007-GAM-00031
Bechtel Letter No. 25279-001-T007-GAM-00035
Bechtel Letter No. 25279-001-T007-GAM-00039
SPLNG Letter No. SP-BE-C-258 dated April 17, 2007
Project Instruction Forms SP2-007, SP2-017, SP2-018 and SP2-019
Extra Charge Approval Request (ECAR) No. 7 dated April 5, 2007
Change Order No. SP2/BE-004

Detail Estimates:

Attachment A – Ambient Air Vaporizers
Attachment B – Additional Dredging
Attachment C – ESD Philosophy Revisions
Attachment D – ESD Equipment Revisions
Attachment E – Pipeline Compressor Additions
Attachment F – Send-Out Piping Modifications
Attachment G – Adjusted Fixed Fee Table

Adjustment to Contractor's Fixed Fee

The original Fixed Fee was	\$ 18,500,000
Change in Fixed Fee by previously authorized Change Orders	\$ 1,000,000
The Fixed Fee prior to this Change Order was	\$ 19,500,000
The Fixed Fee will be increased by this Change Order in the amount of	\$ 400,000
The new Fixed Fee including this Change Order will be	\$ 19,900,000

This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change as described in this Change Order #005 upon the Fixed Fee and shall be deemed to compensate Bechtel fully for such change.

Upon execution of this Change Order by Company and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

COMPANY: Sabine Pass LNG, L.P.

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

CHANGE ORDER NUMBER: SP2/BE-005

DATE OF CHANGE ORDER: September 12, 2007

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#2**

/s/ Stan Horton

* Charif Souki
Chairman

10/2/07

Date of Signing

/s/ Jose Montalvo

Contractor

Jose Montalvo

Name

Project Manager

Title

08 Oct 07

Date of Signing

/s/ Stan Horton

* Stan Horton
President & COO Cheniere Energy

10/2/07

Date of Signing

/s/ Ed Lehotsky

* Ed Lehotsky
Owner Representative

2 October 2007

Date of Signing

* Required Owner signature – Mr. Horton may sign on behalf of Mr. Souki during Mr. Souki's absence.

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2 Receiving, Storage and Re-Gasification Terminal Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-006

DATE OF CHANGE ORDER: December 10, 2007

COMPANY: Sabine Pass LNG, L.P.

ADJUSTMENT TO CONTRACTOR'S FIXED FEE NO#3

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

The Agreement between the Parties listed above is changed as follows:

I. Increase in the Fixed Fee associated with the implementation of the following agreed Scope Changes:

- 1. Change Order SP2/BE-005 Carry-Over Balance \$ 2,090,032

The total changes identified under Change Order No. SP2/BE-005 amounted to increased costs of \$12,090,032. The corresponding Fixed Fee adjustment was calculated based on \$10,000,000. This line item represents the remainder difference of \$2,090,032 not previously included in the Fixed Fee adjustment calculation.

- 2. Kinder Morgan Meters \$ 9,915,447

- a. Procure and install piles for pipe supports related to the addition of two (2) Kinder Morgan meters.
- b. Prepare a Class IV Estimate identifying costs associated with the Engineering, Procurement and Construction (EPC) of the additional Kinder Morgan Meters based on design criteria provided by Company.
- c. EPC of Kinder Morgan Meters and associated facilities.

Amount Eligible for Fixed Fee Calculation: \$ 12,005,479

- 3. Change Order SP2/BE-006 Carry Over

Fixed Fee increases are based on increments of \$5,000,000. Consequently, the Fixed Fee increase associated with this Change Order is calculated based on \$10,000,000 (4% x \$10,000,000) for a total Fixed Fee Adjustment of \$400,000. The remaining balance of \$2,005,479 will added to a future Change Order when the next US\$5,000,000 threshold is achieved.

Total Fixed Fee Adjustment Amount: \$ 400,000

II. Article 2 of the Agreement titled "DEFINITIONS" is hereby amended to add the following definitions:

2.87 "Kinder Morgan Meters" means the meters to be engineered, procured and constructed for the Phase 2 Facility by Bechtel or a Company Contractor, which are designated as "KM Meters".

2.88 "Provisional Acceptance (KM Meters) means that all Services to be performed by Bechtel or its Subcontractors and all work to be performed by Company Contractors and all other obligations under this Agreement are fully and completely performed in accordance with the terms of this Agreement, to achieve the following: (i) RFH of the KM Meters; (ii) delivery by Bechtel to Company of a comprehensive Punchlist for the Services, including a cost estimate to complete the Punchlist, and the approval of such Punchlist and cost estimate by Company; (iii) delivery by Bechtel to Company of all documentation required to be delivered under this Agreement as a prerequisite of achievement of Provisional Acceptance (KM Meters), including as-built drawings; (iv) delivery by Bechtel to Company of all remaining capital spares, capital spare parts and consumable spare parts purchased by Bechtel or its Subcontractors and still in Bechtel's or its Subcontractors' possession; and (iv) delivery by Bechtel to Company of a Notice of Provisional Acceptance (KM Meters) as required under Section 11.5(A).

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-006

DATE OF CHANGE ORDER: December 10, 2007

COMPANY: Sabine Pass LNG, L.P.

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#3**

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

III. Section 2.39 of Article 2 of the Agreement is hereby deleted in its entirety and replaced by the following Section 2.39:

"2.39 "Final Acceptance" means that all Services to be performed by Bechtel or its Subcontractors and all work to be performed by Company Contractors and all other obligations under this Agreement (except for Services and obligations that survive the termination or expiration of this Agreement, including obligations for Warranties and correction of Defective Services) are fully and completely performed in accordance with the terms of this Agreement, including: (i) the achievement of Provisional Acceptance (BOP), Provisional Acceptance (Tank S-104), Provisional Acceptance (Tank S-105) and Provisional Acceptance (KM Meters); (ii) the completion of all Punchlist items, except those Punchlist items that Company has expressly in writing excused Bechtel or Company Contractors from performing; (iii) delivery by Bechtel to Company of a fully executed final conditional lien and claim waiver in the form of Attachment I, Schedule I-3; (iv) delivery by Bechtel of fully executed final conditional lien and claim waivers from all Major Bechtel Subcontractors in the form of Attachment I, Schedule I-4; (v) delivery by all Company Contractors and their subcontractors of conditional or unconditional final lien and claim waivers as required by the applicable Company Contracts; (vi) delivery by Bechtel to Company of all documentation required to be delivered under this Agreement as a prerequisite of achievement of Final Acceptance; (vii) unless otherwise instructed by Company pursuant to Section 18.2, removal from the Phase 2 Site of all of the personnel, supplies, waste, materials, rubbish, and temporary facilities of Bechtel, Bechtel Subcontractors and Company Contractors; and (viii) delivery by Bechtel to Company of all remaining consumable spare parts and capital spare parts purchased by Bechtel or its Subcontractors and still in Bechtel's or its Subcontractors' possession; (ix) delivery by Bechtel to Company of a Notice of Final Acceptance as required under Section 11.6."

IV. Section 11.2 of Article 11 of the Agreement is hereby deleted in its entirety and replaced by the following Section 11.2:

"Punchlist. Whenever a System is Ready for Handover, Bechtel shall submit to Company for Company's review a Punchlist for that System. Bechtel shall thereafter modify the Punchlist as directed by Company, and the Parties shall then mutually agree upon the Punchlist for such System. Bechtel shall update such Punchlist as appropriate as additional Services and work are performed with respect to such System. At the same time that it gives Company notice that the requirements for Provisional Acceptance (BOP), Provisional Acceptance (Tank S-104), Provisional Acceptance (Tank S-105) or Provisional Acceptance (KM Meters) have been met pursuant to Section 11.3, 11.4, 11.5 or 11.5(A), as applicable, Bechtel shall also submit to Company for Company's review an updated Punchlist for all Systems. Bechtel shall thereafter modify such updated Punchlist as directed by Company, and the Parties shall then mutually agree upon the final Punchlist for all Systems. Bechtel shall not have any obligation to perform Company Contractor's Punchlist work."

V. Article 11 of the Agreement is hereby amended to add the following Section 11.5(A):

"11.5(A) Provisional Acceptance (KM Meters). When all the requirements for Provisional Acceptance (KM Meters) have been met, Bechtel shall so notify Company in writing using the Notice of Provisional Acceptance Form attached hereto as Attachment N. Within thirty (30) days of the date of such notice, Company shall give Bechtel written notice of Company's Provisional Acceptance (KM Meters), or will advise Bechtel in writing of any Services remaining to be performed by Bechtel and any work remaining to be performed by Company Contractors, related to the KM Meters, other than Services or work of a Punchlist nature. Upon completion of such Services and the completion of such work by Company Contractors, Bechtel shall so notify Company in writing using the Notice of Provisional Acceptance Form attached hereto as Attachment N. Within ten (10) days of the date of such notice, Company shall in writing give Bechtel

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-006

DATE OF CHANGE ORDER: December 10, 2007

COMPANY: Sabine Pass LNG, L.P.

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#3**

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

notice of Company's Provisional Acceptance (KM Meters), or written notice of any Services remaining to be performed by Bechtel and any work remaining to be performed by Company Contractors, related to the Services. In the latter instance, the foregoing procedure with respect to such specified unfinished Services and work will be repeated. Company's use of the Services shall not constitute Provisional Acceptance (KM Meters). If Company fails to give the required notice within the specified period above, provided that Bechtel gave notice of Provisional Acceptance (KM Meters) on the required Notice of Provisional Acceptance Form, and provided further that Bechtel has reasonably complied with the requirements for achieving Provisional Acceptance (KM Meters), as defined herein, then Bechtel shall be deemed to have achieved Provisional Acceptance (KM Meters), but only as between Bechtel and Company, and not with respect to any Company Contractor. Such Provisional Acceptance (KM Meters) shall not relieve Bechtel of any obligations surviving Provisional Acceptance (KM Meters), Final Acceptance or of any Defective Services."

VI. The first sentence of Section 11.6 of Article 11 of the Agreement is hereby revised to include reference to Provisional Acceptance (KM Meters) as follows:

"After Provisional Acceptance (BOP), Provisional Acceptance (Tank S-104), Provisional Acceptance (Tank S-105) and Provisional Acceptance (KM Meters), Bechtel shall ensure that all items on the Punchlist are completed unless Company in writing excuses the completion of certain Punchlist items."

VII. The first sentence of Section 13.1.2 of Article 13 of the Agreement is hereby revised to include reference to Provisional Acceptance (KM Meters) as follows:

"Provided Company has notified Bechtel in writing, within a reasonable time after Company's discovery of a Defect in the Services at any time during the performance of the Services and within eighteen (18) months after Provisional Acceptance (BOP) with respect to the Balance of Plant, and within eighteen (18) months after Provisional Acceptance (Tank S-104) with respect to Tank S-104, and within eighteen (18) months after Provisional Acceptance (Tank S-105) with respect to Tank S-105, and within eighteen (18) months after Provisional Acceptance (KM Meters) with respect to the KM Meters (each such period during the performance of the Services and for eighteen (18) months after the respective Provisional Acceptance hereinafter called "Defect Correction Period"), stating with reasonable specificity the reasons Company believes such Services are Defective, Bechtel shall promptly correct (by repair, replacement, re-performance or otherwise) such Defective Services and perform any other Services, including construction and management Services, necessary to correct such Defective Services ("Corrective Services")."

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-006

DATE OF CHANGE ORDER: December 10, 2007

COMPANY: Sabine Pass LNG, L.P.

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#3**

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

References:

Project Instruction Form SP2-030
Project Instruction Form SP2-032
Project Instruction Form SP2-034
Change Order No. SP2/BE-005

Detail Estimates:

Attachment A – Kinder Morgan Meters
Attachment B – Adjusted Fixed Fee Table

Adjustment to Contractor's Fixed Fee

The original Fixed Fee was	\$ 18,500,000
Change in Fixed Fee by previously authorized Change Orders	\$ 1,400,000
The Fixed Fee prior to this Change Order was	\$ 19,900,000
The Fixed Fee will be increased by this Change Order in the amount of	\$ 400,000
The new Fixed Fee including this Change Order will be	\$ 20,300,000

This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change as described in this Change Order#006 upon the Fixed Fee and shall be deemed to compensate Bechtel fully for such change.

Upon execution of this Change Order by Company and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-006

DATE OF CHANGE ORDER: December 10, 2007

COMPANY: Sabine Pass LNG, L.P.

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#3**

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

/s/ Charif Souki
* Charif Souki
Chairman

12-19-07
Date of Signing

/s/ Stan Horton
* Stan Horton
President & COO Cheniere Energy

12/19/07
Date of Signing

/s/ Ed Lehotsky
* Ed Lehotsky
Owner Representative

Dec 18, 2007
Date of Signing

Bechtel /s/ Jose Montalvo
Contractor
/s/ Jose Montalvo
Name
Project Mgr
Title
07 Jan 08
Date of Signing

* Required Owner signature – Mr. Horton may sign on behalf of Mr. Souki during Mr. Souki's absence.

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-007

DATE OF CHANGE ORDER: December 3, 2007

COMPANY: Sabine Pass LNG, L.P.

Commissioning and Start-Up Support Services

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

The Agreement between the Parties listed above is changed as follows:

- I. Section 4.13 of the Agreement, titled "Commissioning and Start-Up Support Services", is hereby revised to add the following Section 4.13.5:
Notwithstanding the foregoing, and if requested by Company to do so, Bechtel will provide preliminary support services related to Commissioning and Start-Up ("Preliminary CSU Services") such as assistance with planning activities, estimate preparation and development of procedures and initial schedules. For the performance of such Preliminary CSU Services, Company shall pay Bechtel a total compensation consisting of Bechtel's recoverable costs as defined in Attachment C "Recoverable Costs," plus a Fixed Fee. For all other CSU Services, Bechtel may furnish commissioning, start-up and performance testing personnel on a "seconded" basis as provided above in this Section 4.13.

Note: Actual compensation adjustments for Preliminary CSU Services provided will be addressed in a future Change Order.

Adjustment to Contractor's Fixed Fee

The original Fixed Fee was	\$ 18,500,000
Change in Fixed Fee by previously authorized Change Orders	\$ 1,800,000
The Fixed Fee prior to this Change Order was	\$ 20,300,000
The Fixed Fee will be increased by this Change Order in the amount of	\$ 0.00
The new Fixed Fee including this Change Order will be	\$ 20,300,000

This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change as described in this Change Order #007 upon the Fixed Fee and shall be deemed to compensate Bechtel fully for such change.

Upon execution of this Change Order by Company and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-007

DATE OF CHANGE ORDER: December 3, 2007

COMPANY: Sabine Pass LNG, L.P.

Commissioning and Start-Up Support Services

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

/s/ Charif Souki
* Charif Souki
Chairman

1-10-08
Date of Signing

/s/ Stan Horton
* Stan Horton
President & COO Cheniere Energy

1-9-08
Date of Signing

/s/ Ed Lehotsky
* Ed Lehotsky
Owner Representative

Jan 8, 2008
Date of Signing

/s/ Jose Montalvo
Contractor
Jose Montalvo
Name
Project Manager
Title
22 Jan 2008
Date of Signing

* Required Owner signature – Mr. Horton may sign on behalf of Mr. Souki during Mr. Souki's absence.

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-008

DATE OF CHANGE ORDER: December 18, 2007

COMPANY: Sabine Pass LNG, L.P.

ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#4

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

The Agreement between the Parties listed above is changed as follows:

I. Increase in the Fixed Fee associated with the implementation of the following agreed Scope Changes:

1. <u>Additional Dredging</u> (Trend F-1058)	\$ 3,644,168
Add additional dredging quantities in the tug berth (bucket dredge) and main basin (suction dredge).	
2. <u>Pipe Corrosion Pads</u> (Trend F-1047)	\$ 111,320
Incorporate into specification and design a corrosion barrier to prevent contact between bare pipe and steel supports and prevent moisture build-up.	
3. <u>4" Parallel Bypass Control Valve on P1 Recondenser</u> (Trend F-1044)	\$ 52,351
Provide technical confirmation that SPLNG procured valve is appropriate for the process system; identify and procure miscellaneous piping components and provide installation of valve assembly.	
Total Amount of agreed Scope Changes: (Items 1, 2 & 3 above)	
	<u>\$ 3,807,839</u>
4. <u>Change Order SP2/BE-006 Carry-Over</u>	\$ 2,005,479
This line item represents the remainder difference of \$2,005,479 not previously included in the Fixed Fee adjustment calculation.	
Amount Eligible for Fixed Fee Calculation: (Items 1, 2, 3 & 4 above)	
	<u>\$ 5,813,318</u>
5. <u>Change Order SP2/BE-008 Fixed Fee</u>	
Fixed Fee increases are based on increments of \$5,000,000. Consequently, the Fixed Fee increase associated with this Change Order is calculated based on \$5,000,000 (4% x \$5,000,000) for a total Fixed Fee Adjustment of \$200,000. The remaining balance of \$813,318 will be added to a future Change Order when the next US\$5,000,000 threshold is achieved.	
Total Fixed Fee Adjustment Amount:	
	<u>\$ 200,000</u>

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-008

DATE OF CHANGE ORDER: December 18, 2007

COMPANY: Sabine Pass LNG, L.P.

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#4**

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

ATTACHMENTS:

Attachment A – Trend Estimate (F-1058)
Attachment B – Trend Estimate (F-1047)
Attachment C – Trend Estimate (F-1044)
Attachment D – Adjusted Fixed Fee Table

REFERENCES:

Project Instruction Form SP2-018
Project Instruction Form SP2-028
Project Instruction Form SP2-029

Adjustment to Contractor's Fixed Fee

The original Fixed Fee was	\$ 18,500,000
Change in Fixed Fee by previously authorized Change Orders	\$ 1,800,000
The Fixed Fee prior to this Change Order was	\$ 20,300,000
The Fixed Fee will be increased by this Change Order in the amount of	\$ 200,000
The new Fixed Fee including this Change Order will be	\$ 20,500,000

This Change Order **shall** constitute a full and final settlement and accord and satisfaction of all effects of the change as described in this Change Order#008 upon the Fixed Fee and shall be deemed to compensate Bechtel fully for such change.

Upon execution of this Change Order by Company and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

CHANGE ORDER FORM

PROJECT NAME: Sabine Pass LNG Phase 2
Receiving, Storage and Re-Gasification Terminal
Expansion ("Phase 2 Project")

CHANGE ORDER NUMBER: SP2/BE-008

DATE OF CHANGE ORDER: December 18, 2007

COMPANY: Sabine Pass LNG, L.P.

**ADJUSTMENT TO CONTRACTOR'S
FIXED FEE NO#4**

CONTRACTOR: Bechtel Corporation

DATE OF AGREEMENT: July 21, 2006

/s/ Charif Souki

* Charif Souki
Chairman

1-10-08

Date of Signing

/s/ Jose Montalvo

Contractor
Jose Montalvo

Name
Project Manager

Title

22 Jan 08

Date of Signing

/s/ Stan Horton

* Stan Horton
President & COO Cheniere Energy

1-9-08

Date of Signing

/s/ Ed Lehotsky

* Ed Lehotsky
Owner Representative

1/8/2008

Date of Signing

* Required Owner signature – Mr. Horton may sign on behalf of Mr. Souki during Mr. Souki's absence.

CHANGE ORDER FORM

(for use when the Parties execute the Change Order pursuant to Section 32 of the General Conditions)

PROJECT NAME: Sabine Pass LNG Project (Phase 2)
CHANGE ORDER NUMBER: 007
DATE OF CHANGE ORDER: September 11, 2007
PURCHASER: Sabine Pass LNG, L.P.
SOIL CONTRACTOR: Remedial Construction Services, L.P.
CONTRACT NO. 25279-004-OC2-C000-00001
DATE OF AGREEMENT: July 21, 2006

The Agreement between the Parties listed above is charged as follows:*(attach additional documentation if necessary)*

Description of Change: This CO No. 007 is issued to incorporate into the Soil Improvement Contract the following:

Adjustment of quantities as presently forecasted by Engineering and as described in the revised Exhibit "C" Quantities, Pricing and Data, dated September 11, 2007, revised Exhibit "D", Scope of Work, dated September 11, 2007, and revised Exhibit "E", Drawings, dated September 11, 2007.

Attachments:

- 1) Contract Exhibit "C", Quantities, Pricing and Data, dated September 11, 2007 that supersedes and replaces Exhibit "C", Quantities, Pricing and Data, dated August 6, 2007 in its entirety.
- 2) Contract Exhibit "D", Scope of Work, dated September 11, 2007 that supersedes and replaces Exhibit "D", Scope of Work, dated 01 November 2006 in its entirety.
- 3) Contract Exhibit "E", Drawings, dated September 11, 2007 that supersedes and replaces Exhibit "E", Drawings, dated 01 November 2006 in its entirety.

The original contract price was	\$ 28,526,962.28
Net Change by previously authorized Change Orders	\$ 134,157.95
The Contract Price prior to this Change Order	\$ 28,661,120.23
The Contract Price will be increased <decreased> by this Change Order amount of	\$ -2,389,279.66
The New Contract Price including this Change Order will be	\$ 26,271,840.57

Upon execution of this Change Order by Sabine Pass LNG, L.P. and Remedial Construction Services, L.P. the above referenced change shall become a valid and binding part of the original agreement without exception or qualification unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and Condition of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Purchaser:
Sabine Pass LNG, L.P.
By: Sabine Pass LNG-GP, Inc.,
Its general partner

Soil Contractor:
Remedial Construction Services, L.P.

Authorized
Signature: /s/ Carlos Macias
Name: Carlos Macias
Title: Dir. Proj. Mgmt
Date of Signing: Sept 20, 2007

Authorized
Signature: /s/ Steven R. Birdwell
Name: Steven R. Birdwell
Title: President
Date of Signing: 10/1/07

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-012

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 10-20-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

**SUBJECT: Additional Clearing Crew Move Around from
Station Number 1634+71 to 1648+71.**

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Schedule D-3 per the construction agreement between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007, Cheniere will compensate SPLCC by line item M-38.

Cheniere had not secured agreements necessary to clear this property therefore forcing the Clearing Crew to move-around this location to continue clearing.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ 65,605,739.22
Net change by previously authorized Change Orders	\$ 4,548,491.02
The Estimated Contract Price prior to this Change Order was	\$ 70,154,230.24
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ 16,000.00
The new Estimated Contract Price including this Change Order will be	<u>\$ 70,170,230.24</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
 Owner
/s/ T. R. Hutton
 Signature
 T. R. Hutton
 Name
 Director - EPC
 Title
11/2/07
 Date of Signing

Sheehan Pipe Line Construction Company
 Contractor
/s/ Robert A. Riess, Sr.
 Signature
 Robert A. Riess, Sr.
 Name
 President & COO
 Title
Nov. 26, 2007
 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-013

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 10-20-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Additional Clearing Crew Move Around from
Station Number 1068+95 to 1083+68.

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Schedule D-3 per the construction agreement between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007, Cheniere will compensate SPLCC by line item M-38.

Cheniere had instructed crew to skip area where there was an environmental restriction area for the Red Headed Woodpecker from Station 1068+95 to 1083+68.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	<u>\$ 65,605,739.22</u>
Net change by previously authorized Change Orders	<u>\$ 4,564,491.02</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 70,170,230.24</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 16,000.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 70,186,230.24</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.

 Owner
 /s/ T.R. Hutton

 Signature
 T.R. Hutton

 Name
 Director - EPC

 Title
 11/2/07

 Date of Signing

Sheehan Pipe Line Construction Company

 Contractor
 /s/ Robert A. Riess, Sr.

 Signature
 Robert A. Riess, Sr.

 Name
 President & COO

 Title
 Nov. 26, 2007

 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-014

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 10-20-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Clearing Crew Stand by Charges for Friday,
Oct. 19, 2007.

The Agreement between the Parties listed above is changed as follows: Per the terms and conditions outlined under Article 6.2-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; a Partial Clearing Crew Standby due to various properties that had not been released for clearing. This occurred on Friday, October 19, 2007. The clearing crew is currently waiting on two tracks to be released at the north end of the project.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	<u>\$ 65,605,739.22</u>
Net change by previously authorized Change Orders	<u>\$ 4,580,491.02</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 70,186,230.24</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 4,200.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 70,190,430.24</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A
The Guaranteed Mechanical Completion Date will be unchanged.
The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.
The Guaranteed Substantial Completion Date will be unchanged.
The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.
The Guaranteed Final Completion Date will be unchanged.
The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
Owner
/s/ T. R. Hutton
Signature
T. R. Hutton
Name
Director - EPC
Title
11/2/07
Date of Signing

Sheehan Pipe Line Construction Company
Contractor
/s/ Robert R. Riess, Sr.
Signature
Robert R. Riess, Sr.
Name
President & COO
Title
Nov. 26, 2007
Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-015

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 11-01-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: **Clearing Crew Demobilization**

The Agreement between the Parties listed above is changed as follows: Per the terms and conditions outlined under Article 6.2-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; a Clearing Crew demobilization on October 19, 2007 due to various properties that had not been released for clearing.

Cheniere and Sheehan Pipe Line Company agree the Clearing Crew Demobilization is the most economical decision.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	<u>\$ 65,605,739.22</u>
Net change by previously authorized Change Orders	<u>\$ 4,584,691.02</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 70,190,430.24</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 35,000.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 70,225,430.24</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P. _____
 Owner
 /s/ R. Keith Teague _____
 Signature
 R. Keith Teague _____
 Name
 President _____
 Title
 Nov 5/ 2007 _____
 Date of Signing

Sheehan Pipe Line Construction Company _____
 Contractor
 /s/ Robert A. Riess, Sr. _____
 Signature
 Robert A. Riess, Sr. _____
 Name
 President & COO _____
 Title
 Nov. 26, 2007 _____
 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-016

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 11-01-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

**SUBJECT: Furnish, install, and remove Isolation Fencing
(Orange Safety Fence, Item #M25)**

The Agreement between the Parties listed above is changed as follows: Per the terms and conditions outlined under Article 6.1-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; Cheniere requested the installation of safety fence installed on 10/09/07 from Station #1001+50 to Station #1005+15 for a total of 365 feet installed.

Items M1 through M50 will only be considered for payment if they are over and above the Scope of Work requirements, and if specifically requested and/or authorized by Owner via Change Order. This pricing is provided in Schedule D-3 and will be subject to Change Orders.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	<u>\$ 65,605,739.22</u>
Net change by previously authorized Change Orders	<u>\$ 4,619,691.02</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 70,225,430.24</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 2,555.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 70,227,985.24</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.

 Owner
 /s/ T. R. Hutton

 Signature
 T. R. Hutton

 Name
 Director - EPC

 Title
 11/2/07

 Date of Signing

Sheehan Pipe Line Construction Company

 Contractor
 /s/ Robert A. Riess, Sr.

 Signature
 Robert A. Riess, Sr.

 Name
 President & COO

 Title
 Nov. 26, 2007

 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-017

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 11-20-07

CONTRACTOR: Sheehan Pipe Line Construction Company (SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Clearing Crew Remobilization

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Article 6.2-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; a Clearing Crew remobilization on October 31, 2007 due to various properties that have been released for clearing.

Cheniere and Sheehan Pipe Line Company agreed the Clearing Crew Demobilization/Remobilization was the most economical decision.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ 65,605,739.22
Net change by previously authorized Change Orders	\$ 4,622,246.02
The Estimated Contract Price prior to this Change Order was	\$ 70,227,985.24
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ 35,000.00
The new Estimated Contract Price including this Change Order will be	\$ 70,262,985.24

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*) N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
Owner

Sheehan Pipe Line Construction Company
Contractor

/s/ T.R. Hutton /s/ R. Keith Teague
Signature

/s/ Robert A. Riess, Sr.
Signature

T.R. Hutton R. Keith Teague
Name

Robert A. Riess, Sr.
Name

Director-EPC President
Title

President & COO
Title

11/26/07 11-26-07
Date of Signing

Nov. 30, 2007
Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-018

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 11-20-07

CONTRACTOR: Sheehan Pipe Line Construction Company (SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Costs of purchasing pipe to be used for testing welders.

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Article 6.2-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; the cost of purchasing 40 ft. of 12" x .375 wt bare pipe to be used for testing welders. Cheniere had requested Sheehan purchase the pipe.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ 65,605,739.22
Net change by previously authorized Change Orders	\$ 4,657,246.02
The Estimated Contract Price prior to this Change Order was	\$ 70,262,985.24
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ 7,624.44
The new Estimated Contract Price including this Change Order will be	\$ 70,270,609.68

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
Owner

Sheehan Pipe Line Construction Company
Contractor

/s/ T.R. Hutton
Signature

/s/ Robert A. Riess, Sr.
Signature

T.R. Hutton
Name

Robert A. Riess, Sr.
Name

Director EPC
Title

President & COO
Title

11/26/07
Date of Signing

Nov. 30, 2007
Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-019

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 11-20-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Clearing Crew Move Back

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Schedule D-3 per the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; Cheniere will compensate SPLCC by line item M-38 for Clearing Crew move back to clear Tract # LA-CC-190.000 at the south side of Houston River Road.

Clearing Subcontractor was unable to clear this tract when they were working back from Houston River Road initially. Crew initially had to move back out to Houston River Road, therefore there was not a charge for the initial move-around. This change order compensates SPLCC for the cost incurred for crew moving back to clear tract after being released for construction.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	<u>\$ 65,605,739.22</u>
Net change by previously authorized Change Orders	<u>\$ 4,664,870.46</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 70,270,609.68</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 16,000.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 70,286,609.68</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.

 Owner
 /s/ T.R. Hutton

 Signature
 T.R. Hutton

 Name
 Director - EPC

 Title
 12/4/07

 Date of Signing

Sheehan Pipe Line Construction Company

 Contractor
 /s/ Ronnie Powell

 Signature
 Ronnie Powell

 Name
 Manager, Projects

 Title
 12/07/07

 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-020

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-01-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Additional Timber Mats to be installed in Uplands

The Agreement between the Parties listed above is changed as follows: Per the terms and conditions outlined under Article 6.1-B per the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; Cheniere will compensate SPLCC for additional Timber Mats (uplands), Item C-9 of attachment J "Pricing Schedule", to be installed in upland areas due to heavy rainfall.

Cheniere and Sheehan Pipe Line Company agree to an additional 19,000 Timber Mats (uplands) at a reduced rate of \$420.00 ea. (\$7,980,000.00), and additional 4,000 Timber Mats (uplands) at a reduced rate of \$370.00 ea. (\$1,480,000.00). The total amount of additional Timber Mats (uplands) is \$9,460,000.00.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ 65,605,739.22
Net change by previously authorized Change Orders	<u>\$ 4,680,870.46</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 70,286,609.68</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 9,460,000.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 79,746,609.68</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
 Owner
/s/ R. Keith Teague
 Signature
R. Keith Teague
 Name
President
 Title
12/5/2007
 Date of Signing

Sheehan Pipe Line Construction Company
 Contractor
/s/ Ronnie Powell
 Signature
Ronnie Powell
 Name
Manager, Projects
 Title
12/07/07
 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-021

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-01-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Four Each Additional 42" Cut and Bevels

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Article 6.2-C per the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; Cheniere will compensate SPLCC for additional four ea. 42" cut and bevels, Item M-10 of Schedule D-3 "Pricing for Change Orders".

The joints on string #122 - 124 were damaged in transit prior to Sheehan and Sheehan sub-contractors obtaining possession, requiring four ea. additional 42" cut and bevels. The unit price for additional 42" cut and bevels outlined in Schedule D-3 is \$756.00 ea, for a total of \$3,024.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ 65,605,739.22
Net change by previously authorized Change Orders	<u>\$ 14,140,870.46</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 79,746,609.68</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 3,024.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 79,749,633.68</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A
The Guaranteed Mechanical Completion Date will be unchanged.
The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.
The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.
The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
Owner
/s/ T.R. Hutton
Signature
T.R. Hutton
Name
Director - EPC
Title
12/4/07
Date of Signing

Sheehan Pipe Line Construction Company
Contractor
/s/ Ronnie Powell
Signature
Ronnie Powell
Name
Manager, Projects
Title
12/07/07
Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-022

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-10-07

CONTRACTOR: Sheehan Pipe Line Construction
Company (SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: **Correct Change Order CCT 3A-001 Estimate to Actual Amount.**

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Item #1 per agreement letter between Cheniere Creole Trail Pipeline, LP and Sheehan Pipe Line Company dated May 25, 2007; this change order is in reference to SPLCC Change Order # CCT 3A-001, this change order reflects a reduction in estimated contract price of \$71,621.25.

The total amount of transportation costs for hauling pipe from TBC facility in New Iberia to Sheehan Pipe Line Company's Westlake yard is \$528,378.75; the estimate amount is \$600,000.00. This change order is for the difference of the total amount of transportation costs and the estimate amount of transportation costs for a reduction in the estimated contract price of \$71,621.25.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ <u>65,605,739.22</u>
Net change by previously authorized Change Orders	\$ <u>14,143,894.46</u>
The Estimated Contract Price prior to this Change Order was	\$ <u>79,749,633.68</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ <u>-71,621.25</u>
The new Estimated Contract Price including this Change Order will be	\$ <u>79,678,012.43</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
 Owner
 /s/ T.R. Hutton
 Signature
 T.R. Hutton
 Name
 Director
 Title
 12/17/07
 Date of Signing

Sheehan Pipe Line Construction Company
 Contractor
 /s/ Robert A. Riess, Sr.
 Signature
 Robert A. Riess, Sr.
 Name
 President & COO
 Title
 12/19/07
 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-023

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-10-07

CONTRACTOR: Sheehan Pipe Line Construction
Company (SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Total Crew Move Around, Item M-50

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Schedule D-3 per the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; Cheniere will compensate Sheehan Pipe Line Company's for a complete crew move around.

Sheehan Pipe Line Construction Company was requested to begin construction at the north side of the Houston River, work to the end of the project, and then move back to the original kickoff location, and then work back to the Houston River. This request necessitates an entire crew move back to the original kickoff location.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ <u>65,605,739.22</u>
Net change by previously authorized Change Orders	\$ <u>14,072,273.21</u>
The Estimated Contract Price prior to this Change Order was	\$ <u>79,678,012.43</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ <u>200,000.00</u>
The new Estimated Contract Price including this Change Order will be	\$ <u>79,878,012.43</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.

 Owner
 /s/ R. Keith Teague

 Signature
 R. Keith Teague

 Name
 President

 Title
 12/17/2007

 Date of Signing

Sheehan Pipe Line Construction Company

 Contractor
 /s/ Robert A.Riess, Sr.

 Signature
 Robert A.Riess, Sr.

 Name
 President & COO

 Title
 12/19/07

 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-024

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-10-07

CONTRACTOR: Sheehan Pipe Line Construction
Company (SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Total Crew Move Around, Item M-50

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Attachment J (Pricing Schedule) of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; the estimated quantity to furnish and install crushed stone as described for Item No. C-15 is being revised from 3,600 tons to 8,000 tons (estimated quantity).

Additional Quantities of 4,400 tons of Crushed Stone in addition to the previously estimated 3,600 tons is to be utilized for Access Pads and continued maintenance of access roads to maintain unobstructed travel by construction traffic and avoid tracking mud onto roadways.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ <u>65,605,739.22</u>
Net change by previously authorized Change Orders	\$ <u>14,272,273.21</u>
The Estimated Contract Price prior to this Change Order was	\$ <u>79,878,012.43</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ <u>176,000.00</u>
The new Estimated Contract Price including this Change Order will be	\$ <u>80,054,012.43</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P. _____
 Owner
 /s/ R. Keith Teague _____
 Signature
 R. Keith Teague _____
 Name
 President _____
 Title
 12/17/2007 _____
 Date of Signing

Sheehan Pipe Line Construction Company _____
 Contractor
 /s/ Robert A. Riess, Sr. _____
 Signature
 Robert A. Riess, Sr _____
 Name
 President & COO _____
 Title
 12/19/07 _____
 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-025

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-10-07

CONTRACTOR: Sheehan Pipe Line Construction
Company (SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Various Scope Changes from Original Contract

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Article 6.1-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; Cheniere and Sheehan Pipe Line Company agree to various scope changes from the original contract. The changes result in a total increase of \$597,274.00.

The scope changes are 6,607 ft. of 42" x .600 WT pipe with 42" x .720 WT pipe. Replace 194 ft. of 42" x .720 WT pipe with 42" x .864 WT pipe. Change Interstate 10 bore to a directional drill. Grind back joint seams. Furnish & install concrete set-on weights. Decrease the quantity of concrete coated pipe.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ <u>65,605,739.22</u>
Net change by previously authorized Change Orders	\$ <u>14,448,273.21</u>
The Estimated Contract Price prior to this Change Order was	\$ <u>80,054,012.43</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	\$ <u>597,274.00</u>
The new Estimated Contract Price including this Change Order will be	\$ <u>80,651,286.43</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
 Owner
 /s/ R. Keith Teague
 Signature
 R. Keith Teague
 Name
 President
 Title
 12/17/2007
 Date of Signing

Sheehan Pipe Line Construction Company
 Contractor
 /s/ Robert A. Riess, Sr.
 Signature
 Robert A. Riess, Sr.
 Name
 President & COO
 Title
 12/19/07
 Date of Signing

SCHEDULE D-1

CHANGE ORDER FORM

(for use when the Parties mutually agree upon and execute the Change Order pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Alternate Route 42" Single Line Option
Creole Trail Pipeline - Segment 3A Project

CHANGE ORDER NUMBER: CCT 3A-026

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 12-10-07

CONTRACTOR: Sheehan Pipe Line Construction Company
(SPLCC)

DATE OF AGREEMENT: January 10, 2007

SUBJECT: Additional 30,000 LF of Staked Silt Fence

The Agreement between the Parties listed above is changed as follows:Per the terms and conditions outlined under Article 6.2-B of the Construction Agreement for Segment 3A project between Cheniere Creole Trail Pipeline, L.P. and Sheehan Pipe Line Construction Company dated January 10, 2007; the estimated quantity to furnish, install, and remove staked silt fence as described for Item No. C-1 is being revised from 45,000' to 75,000' (estimated quantity).

Inclement weather required the need for additional staked silt fence. Silt Fence installed to date (41,072') was used along various wetland areas. The remaining estimated quantity (33,928') will be utilized in accordance with Item No. C-1 descriptions (furnish, install, and remove staked silt fence) and paid in conjunction with the progress payment on the weekly construction invoice.

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	<u>\$ 65,605,739.22</u>
Net change by previously authorized Change Orders	<u>\$ 15,045,547.21</u>
The Estimated Contract Price prior to this Change Order was	<u>\$ 80,651,286.43</u>
The Estimated Contract Price will be increased by this Change Order in the amount of	<u>\$ 180,000.00</u>
The new Estimated Contract Price including this Change Order will be	<u>\$ 80,831,286.43</u>

Adjustment to dates in Project Schedule

The following dates are modified (*list all dates modified; insert N/A if no dates modified*): N/A

The Guaranteed Mechanical Completion Date will be unchanged.

The Guaranteed Mechanical Completion Date as of the date of this Change Order therefore is January 31, 2008.

The Guaranteed Substantial Completion Date will be unchanged.

The Guaranteed Substantial Completion Date as of the date of this Change Order therefore is February 29, 2008.

The Guaranteed Final Completion Date will be unchanged.

The Guaranteed Final Completion Date as of the date of this Change Order therefore is March 31, 2008.

Adjustment to other Changed Criteria: N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previously issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.
 Owner
/s/ R. Keith Teague
 Signature
R. Keith Teague
 Name
President
 Title
12/17/2007
 Date of Signing

Sheehan Pipe Line Construction Company
 Contractor
/s/ Ronnie W. Powell
 Signature
Ronnie W. Powell
 Name
Project Manager
 Title
01/07/08
 Date of Signing

Summary of Compensation for Executive Officers

The executive officers of Cheniere Energy, Inc. (“Cheniere” or “Company”) are “at will” employees and none of them has an employment or severance agreement except, as noted below, in limited circumstances with respect to local foreign practice where employment agreements are required under the laws of foreign countries where an executive officer works.¹ The written and unwritten arrangements under which Cheniere’s executive officers are compensated include:

- a base salary, reviewed annually by the Compensation Committee of the Board of Directors of Cheniere;
- an annual incentive awards pursuant to the 2007 Incentive Compensation Plan (the “2007 Incentive Plan”) and the 2008 – 2010 Incentive Compensation Plan (the “2008 Incentive Plan”) for members of the Executive Committee and other key employees;
- eligibility for awards under Cheniere’s Amended and Restated 2003 Stock Incentive Plan, as determined by the Compensation Committee; and
- a broad-based benefits package offered to all employees, including medical, dental and vision benefits and long-term disability, life, accidental death and dismemberment and voluntary life insurance.

Annual Incentive Awards

At the beginning of 2007, the Section 162(m) Subcommittee (the “Subcommittee”) of the Compensation Committee (the “Compensation Committee”) of Cheniere’s Board of Directors established the performance goals, the performance period and the maximum pay-outs for the Company’s executive officers for the 2007. Subsequently, on May 25, 2007, the Subcommittee adopted the 2007 Incentive Plan and the 2008 – 2010 Incentive Plan and the forms of phantom stock grant agreements and established the number of shares of phantom stock to be granted to each executive officer for each of the 2007, 2008, 2009 and 2010. A summary of the 2007 Incentive Plan and 2008 – 2010 Incentive Plan is described in the Summary Terms for the Cheniere Energy, Inc. Incentive Compensation Plan for Executive Committee Members and Other Key Employees attached as Exhibit 10.3 to the Company’s Current Report on Form 8-K filed on June 1, 2007.

2007 Incentive Plan. Pursuant to the 2007 Incentive Plan, the phantom stock granted to the executive officers for the 2007 performance period was payable in equal shares of the Company’s common stock if a stock price hurdle of \$33.57 was met for the performance period from January 1, 2007 through December 31, 2007. The achievement of the 2007 stock price hurdle was determined by averaging the closing price of the Company’s common stock as reported on the American Stock Exchange for the last 20 trading days of the 2007 performance period.

¹ Jean Abiteboul, located in our French office, has an employment agreement with a subsidiary of Cheniere. The agreement is for an unlimited term and may be terminated by the subsidiary or Mr. Abiteboul upon three months prior notice. The agreement provides for compensation substantially similar to the arrangements described above for Cheniere’s other executive officers.

The average closing price of the Company's common stock for the last 20 days of the 2007 performance period was \$33.62 and, on January 11, 2008, the Subcommittee certified that the stock price hurdle of \$33.57 had been achieved for the 2007 performance period. Accordingly, the phantom stock issued pursuant to the 2007 Incentive Plan vested and became payable in equal shares of the Company's common stock. On January 18, 2008, each executive officer received one share of the Company's common stock for each share of phantom stock granted to the executive officer. Also, on January 11, 2008, the Compensation Committee approved base salary increases for all of Cheniere's executive officers, effective as of January 16, 2008. The following table sets forth the 2008 annual base salary and the amount of phantom stock that vested under the 2007 Incentive Plan for each of the executive officers:

<u>Executive Officer</u>	<u>2008 Annual Base Salary</u>	<u>No. of Shares of 2007 Phantom Stock Vested</u>
Charif Souki Chairman and Chief Executive Officer	\$ 600,540	100,000
Stanley C. Horton President and Chief Operating Officer	\$ 464,010	66,000
Walter L. Williams Vice Chairman	\$ 272,820	37,000
Don A. Turkleson Senior Vice President and Chief Financial Officer	\$ 272,820	37,000
H. Davis Thames Senior Vice President, Marketing	\$ 272,820	25,000
Jonathan S. Gross Senior Vice President, Exploration	\$ 272,820	37,000
Zurab S. Kobiashvili Senior Vice President and General Counsel	\$ 272,820	37,000
David B. Gorte Senior Vice President and Chief Risk Officer	\$ 272,820	37,000
Jean Abiteboul Senior Vice President - International	\$ 334,544 ²	37,000
Stuart J. Wagner Senior Vice President – Corporate Development	\$ 272,820	37,000
Robert K. Teague Vice President – Pipeline Operations	\$ 215,120	25,000

2008 – 2010 Incentive Plan. For the 2008, 2009 and 2010 performance periods, the executive officers' annual incentive awards may include a cash pool in addition to the grants of phantom stock. For the 2008, 2009 and 2010 performance periods, in the event the Company's earnings before taxes and depreciation ("EBTD") for the respective fiscal year, taking into account any bonus accruals, is greater than 75% of the budget approved by Cheniere's Board of Directors for the applicable fiscal year (the "EBTD Hurdle"), the Subcommittee, in its sole discretion, may fund a cash pool, in an amount equal to 3% of EBTD for the year and allocate

² Represents the US dollar equivalent of 229,140 Euros based on an exchange rate of 1.46 as of December 31, 2007.

payments to executive officers. No later than 90 days after the beginning of each plan year, the Subcommittee will approve the allocation of the maximum amount of payments that can be awarded from the cash pool to the executive officers. On January 11, 2008, the Subcommittee determined that the cash pool (if any) for 2008 would be allocated among the executive officers, as set forth below.

2008 Allocation of Cash Pool

<u>Position</u>	<u>Maximum Percentage of Allocation of Cash Pool</u>
Chairman and Chief Executive Officer	20%
President and Chief Operating Officer	14%
Vice Chairman and Senior Vice Presidents	7%
Other key employees	5%

Payments from the cash pool will be made following the end of the respective performance period. No executive officer may be awarded a payment that exceeds the specified percentage for his or her position with the Company. The Subcommittee retains the discretion to decrease, but not increase, the amount of the cash pool payable to any executive officer following the end of the plan year, provided that the amount of a discretionary decrease (if any) may not be reallocated and used to increase another executive officer's payment. The executive officers only become entitled to payment if they are employed by the Company or any of its subsidiaries on the date of the Subcommittee's certification that the EBTD Hurdle has been achieved. The executive officers will be paid within 10 business days following such certification of the EBTD Hurdle by the Subcommittee.

On May 25, 2007, the Subcommittee also established the stock price hurdles for each of the 2008, 2009 and 2010 performance periods and the number of shares of phantom stock to be granted to the executive officers for the three-year period, as set forth below.

**Stock Price Hurdles
2008 – 2010 Incentive Compensation Plan**

<u>Performance Period</u>	<u>Stock Price Hurdle</u>
2008 Performance Period – 1/1/08 to 12/31/08	\$ 42.00
2009 Performance Period – 1/1/09 to 12/31/09	\$ 50.00
2010 Performance Period – 1/1/10 to 12/31/10	\$ 60.00

**Phantom Stock Grants
2008 – 2010 Incentive Compensation Plan**

<u>Position</u>	<u>Aggregate Number of Shares of Phantom Stock</u>
Chairman and Chief Executive Officer	300,000
President and Chief Operating Officer	198,000
Vice Chairman and Senior Vice Presidents	111,000
Other key employees	75,000

One-third of the Phantom Stock will be paid out in equal shares of the Company's common stock upon achievement of the applicable stock price hurdle. Achievement of the stock price hurdle will be determined by averaging the closing price of the Company's common stock as reported on the American Stock Exchange for the last 20 trading days of the respective performance period. If the stock price hurdle is not met for the applicable performance period, the phantom stock for the applicable performance period may be payable for any future performance period provided the stock price hurdle applicable to such future performance period is achieved. Notwithstanding the foregoing, no shares of phantom stock will be payable for a stock price hurdle achieved after the end of the 2010 performance period. At the Subcommittee's sole discretion, an executive officer may receive cash in lieu of the Company's common stock for all or a portion of the phantom stock. The executive officers will only become entitled to receive shares of the Company's common stock, or cash in lieu of Company common stock, if they are employed by the Company or any of its subsidiaries on the date of the Subcommittee's certification that the applicable stock price hurdle has been achieved, or earlier, on the date of a change of control of the Company. The executive officers will be paid within 10 business days following such certification of achievement of the stock price hurdle. In the event of a change of control of the Company as defined in the 2003 Plan, phantom stock will be payable if, as applicable, (i) the consideration to be paid to stockholders for each share of the Company's common stock in connection with such change of control is equal to or exceeds the applicable stock price hurdle or (ii) the closing price of the Company's common stock as reported on the American Stock Exchange on the effective date of such change of control is equal to or exceeds the applicable stock price hurdle. If an executive officer's employment with the Company is terminated for any reason, any phantom stock that is not payable on the date of such termination will be automatically forfeited to the Company.

SHARE PURCHASE AGREEMENT

This **Share Purchase Agreement** (this “**Agreement**”) is made as of December 7, 2007 by and between **Mercuria Energy Holding B.V.**, a corporation organized under the laws of Netherlands with an address at Koningslaan 112, 3583 GV Utrecht, Netherlands (the “**Seller**”) and **Cheniere LNG Services, Inc.**, a corporation organized under the laws of Delaware, USA with an address at 700 Milam Street, Suite 800, Houston Texas, 77002 USA (the “**Buyer**”), and each a “**Party**” and together the “**Parties**”.

Whereas:

A. J & S Cheniere SA (the “**Company**”) is a company incorporated under the laws of Switzerland with registered domicile in Nyon, with a share capital of CHF 100,000 (one hundred thousand Swiss Francs) divided into 100 (one hundred) registered shares with a par value of CHF 1,000 (one-thousand Swiss Francs) each (the “**Shares**”).

B. Effective as of May 8, 2007, the Parties entered into an Amended and Restated Shareholders Agreement (the “**Amended SHA**”) under the terms of which, among other things: (i) each Party made a separate loan to the Company in the amount of USD \$25,000,000 (twenty-five million U.S. dollars) (a “**Shareholder Loan**”); (ii) Buyer increased its ownership in the Company from 20 (twenty) registered Shares of the Company to 49 (forty-nine) registered Shares of the Company and Seller reduced its ownership in the Company from 80 (eighty) registered Shares of the Company to 51 (fifty-one) registered Shares of the Company, so that, as of the date hereof, Seller currently owns 51 (fifty-one) registered Shares of the Company and the Buyer currently owns 49 (forty-nine) registered Shares of the Company; and (iii) Buyer has appointed 3 (three) members of the board of directors of the Company.

C. The Company is a party to the following: (i) LNG Carrier Time Charter Party with “K”-Line LNG Transports Co., Ltd. (“**K Transport**”) dated 25 August 2004, as amended and supplemented by addendum No 1 and No. 2 of the same date each, and as further amended and novated by a novation agreement, dated 13 October 2005, whereby Polar LNG Shipping (UK) Limited (“**Polar**”) agreed, as disponent owner, to assume the obligations of K Transport under the above novated LNG carrier time charter party, and a subsequent re-novation agreement dated 11 August 2006 whereby “K” Line Shipping (UK) Limited (“**K Line**”) agreed to assume, as disponent owner, the obligations of Polar under the above re-novated LNG carrier time charter party (as amended, novated and re-novated as provided above, the “**K Line Time Charter**”); and (ii) LNG Carrier Time Charter Party with Trinity LNG

Transport S.A. (“**Trinity**”) dated 26 August 2004, as amended and supplemented by addendum No 1 and No. 2 of the same date each (the “**Trinity Time Charter**” and with the K Line Time Charter, collectively, the “**Charter Party Agreements**” and individually a “**Charter Party Agreement**”).

D. In accordance with the terms of the respective Charter Party Agreements:

1. J&S Holding Limited, the then ultimate holding company of the Company, entered into irrevocable guarantees in favor of (i) K Transport, dated August 25, 2004, and (ii) Trinity, dated August 26, 2004 with regard to the obligations of the Company under the respective Charter Party Agreements (each a “**Parent Company Guarantee**”). On 7th April 2005 J&S Holding Limited changed its name to J&S Group Limited, and subsequently on 11th January 2007 further changed its name to Mercuria Energy Group Limited (the “**Parent Company Guarantor**”).
2. BNP Paribas (Suisse) SA on behalf of the Company issued (i) a Deed of Guarantee (GADE 6562325) dated 30 October 30 2006, as amended under date of 23 November 2007 in favor of Trinity, and (ii) a Deed of Guarantee (GADE 6567838) dated 23 November 2006 in favor of K Line, with regard to the obligations of the Company under the respective Charter Party Agreements (collectively the “**Bank Guarantees**” and individually, a “**Bank Guarantee**”).

E. The Parties acknowledge that: (i) Buyer has made an offer, in accordance with Section 3.2 of the Amended SHA, to purchase 51 (fifty-one) registered Shares of the Company (the “**Seller Shares**”), which represents all of the Shares of the Company not owned by Buyer, and that Seller has accepted such offer to sell all its Seller Shares to Buyer on the terms and conditions set forth in this Agreement; and (ii) concurrent with the closing of the sale of the Seller’s Shares in accordance with the terms hereof, the Company has agreed with Seller to repay, with interest as provided below, the principal loan amount under Seller’s Shareholder Loan.

Now, therefore, in consideration of the mutual covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller and Buyer agree as follows:

1. Purchase and Sale of the Shares

In accordance with the terms of this Agreement, Seller hereby agrees to sell to Buyer, and Buyer hereby agrees to purchase from Seller the Seller Shares which, upon closing, will be registered in the name of Buyer.

2. Payments at Closing

- A. The total Closing Amount (as defined below) due Seller at closing in accordance with the terms of this Agreement will consist of the following: (i) a purchase price for the Seller Shares of USD \$15,000,000 (fifteen million U.S. dollars) (the “**Purchase Price**”); and (ii) a repayment by the Company of the USD \$25,000,000 (twenty-five million U.S. dollars) principal amount due under Seller’s Shareholder Loan, plus interest as determined below (the “**Loan Amount**” and with the Purchase Price, collectively, the “**Closing Amount**”).
- B. The total interest actually earned (after fees) on the funds deposited, from time to time, by the Company and currently in such account will be ascertained by the Secretary of the Company effective as of the business day preceding closing, who will notify in writing the Parties of such amount. One-half of such interest will be remitted by Company to Seller at closing along with repayment of Seller’s Shareholder Loan.

3. Charter Party Agreements

The Parties acknowledge that the primary assets of the Company are the Charter Party Agreements, true copies of which, along with the related Parent Company Guarantees, have been provided to Buyer by the Secretary of the Company prior to the date hereof.

4. Representations and Warranties

- A. Seller represents and warrants to Buyer as of the date hereof and as of the Closing Date (except as indicated otherwise) that the following is complete, correct and not misleading:

-
- (i) Seller has valid title to the Seller Shares, free of all liens, claims, and encumbrances and upon consummation of the sale of the Seller Shares as contemplated by this Agreement; Buyer will receive good and valid title to the Seller Shares.
 - (ii) Seller is duly authorized to enter into and perform its obligations under or in connection with this Agreement. The obligations of Seller according to this Agreement are valid, binding and enforceable against it.
 - (iii) Seller entering into this Agreement and the performance thereof: (a) do not breach or affect either wholly or partly the conditions of any of the contracts entered into by the Seller or of the contracts to which the Seller is subject to; (b) do not lead to the creation of any kind of rights of third parties or of encumbrances upon assets of the Company; (c) do not violate any court judgments or temporary restraining orders issued against Seller or the Company; and (d) do not lead to automatic termination of any contracts whatsoever entered into by the Company and do not lead to termination rights of the respective other party to the contract.
 - (iv) No governmental, administrative, regulatory, court, arbitration, or other proceedings are pending or, to the best of the Seller's knowledge after reasonable inquiry, threatened against the Company.
 - (v) Seller has not directly or indirectly taken any action: (a) to amend or modify the two Charter Party Agreements from those delivered in accordance with Section 3A; and (b) which would cause the two Charter Party Agreements not to be in full force and effect.
 - (vi) Seller has not directly or indirectly taken any action which would cause the representations and warranties made by Seller in Section 7.3(a) of the Amended SHA not to remain correct, except: (a) for such changes as Seller has advised Buyer in writing prior to the date hereof; and (b) as contemplated by the terms of this Agreement.
- B. Buyer represents and warrants to Seller as of the date hereof and as of the Closing Date (except as indicated otherwise) that the following is complete, correct and not misleading:
- (i) Buyer is duly authorized to enter into and perform its obligations under or in connection with this Agreement. The obligations of Buyer according to this Agreement are valid, binding and enforceable against it.

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- (ii) Buyer entering into this Agreement and the performance thereof: (a) do not breach or affect either wholly or partly the conditions of any of the contracts entered into by the Buyer or of the contracts to which the Buyer is subject to; and (b) do not violate any court judgments or temporary restraining orders issued against Buyer.
 - (iii) Buyer has not directly or indirectly taken any action which would cause the representations and warranties made by Buyer in Section 7.3(b) of the Amended SHA not to remain correct, except: (a) for such changes as Buyer has advised Seller in writing prior to the date hereof; and (b) as contemplated by the terms of this Agreement.
 - (iv) Buyer has not directly or indirectly taken any action: (a) to amend or modify the two Charter Party Agreements from those delivered in accordance with Section 3A, and (b) which would cause the two Charter Party Agreements not to be in full force and effect.
- C. If and to the extent that any representation or warranty set forth in this Section 4 is breached, incorrect or incomplete in a material respect, the non-complying Party shall immediately, or at the latest within one month after request to this effect, remedy such situation. If a complete remedy is not possible or is not achieved within 30 (thirty) days of such request, the complying Party shall be compensated by the non-complying Party in cash for the damage suffered due to such breach. The damages shall be the difference in value of the Company's assets between the represented and/or warranted status and the actual status in the Company or, if such a difference cannot reasonably be determined, the estimated amount of the costs incurred by the Company for bringing about the represented and/or warranted status. Claims according to this Section 4 are to be notified within 2 (two) months after the underlying facts become known to and fully appreciated by the party.

5. Closing and Closing Conditions

- A. The obligations of Buyer to purchase the Seller Shares are subject to the performance of the Seller of its covenants and obligations hereunder and to the following additional condition that the representations and warranties of Seller provided for in Section 4A shall be true and correct on the date hereof and the Closing Date.

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- B. The obligations of Seller to sell the Seller Shares are subject to the performance of the Buyer of its covenants and obligations hereunder and to the following additional conditions: (i) receipt by Seller of a letter of indemnification from Cheniere Energy, Inc. substantially in the form attached as Exhibit "A"; and (ii) the representations and warranties of Buyer provided for in Section 4B shall be true and correct on the date hereof and the Closing Date.
- C. Subject to the terms and conditions of this Agreement, the closing of the transaction contemplated by this Agreement shall occur on December 11, 2007 in the offices of Buyer in Houston, Texas or at such other time or place no later than the 30th business day thereafter, as may be mutually agreed by the Parties in writing (the "**Closing Date**"). The Parties agree to have their respective representatives meet for a pre-closing the day preceding the Closing Date so as to confirm the satisfaction of all required conditions to closing.
- D. At least two business days preceding the Closing Date, Seller will advise each of the Company and Buyer of its account for purposes of payment as provided below. On the Closing Date, the Closing Amount shall be made to Seller as follows: (i) payment of the Purchase Price for the Seller Shares shall be made by wire transfer in immediately available funds to the account previously specified in writing by Seller as provided above, against delivery of certificates for the Seller Shares to Buyer duly registered in the name of Buyer; and (ii) repayment of the Loan Amount (with interest as provided above) to Seller by the Company shall be made by wire transfer in immediately available funds to the account previously specified in writing by Seller as provided above, against cancellation of the Seller Shareholder Loan. For funds to be wire transferred from the U.S. by Buyer, it is agreed that receipt by Seller of a confirmation from Buyer's bank that the wire transfer has been initiated will allow closing to be consummated. To the extent the Company in accordance with any of the Charter Party Agreements is required to cash collateralize any of the required bank guarantees prior to the Closing Date, Buyer agrees to advance funds to the Company under the terms of Buyer's Shareholder Loan in order to allow the repayment of the Loan Amount for or on behalf of the Company on the Closing Date, as provided above.

6. Transition & Miscellaneous

- A. Until the Closing Date, the Parties agree to cause the Company to meet its respective ongoing obligations under the two Charter Party Agreements.
- B. The Parties agree to cause the board of directors of the Company to adopt the resolutions attached as Exhibit "B" in order: (i) to authorize the repayment of Seller's Shareholder Loan (with interest as provided above) in accordance with the terms of this Agreement; and (ii) to approve the transfer of the Seller's Shares into the name of the Buyer, upon the occurrence of closing in accordance with the terms of this Agreement.
- C. On the Closing Date, Seller will deliver or cause to be delivered to the Buyer resignations from the board of directors of the Company of all directors previously elected by Seller under the terms of the Amended SHA, along with a waiver and release of the Company of any claims by any such resigning directors, and arrangements will have been made for delivery of all the books, records and contracts of the Company to Buyer or Buyer's designee. On the same date following closing, Buyer and Seller will cause the Company to deliver to all directors of the Company a discharge for their activity performed in their capacity as board member of the Company.
- D. Effective as of the Closing Date, following the consummation of the transaction contemplated by this Agreement: (i) the Amended SHA shall be automatically terminated without further action; and (ii) the Seller's Shareholder Loan shall be automatically terminated without further action.
- E. Each Party agrees to take such further action as may be reasonably required to implement the transactions contemplated by this Agreement. After the Closing Date the Parties will cooperate in the transfer of the books and records of the Company to Buyer or its designee and Seller agrees to use commercially reasonable efforts to assist, at Buyer's cost and expense, in preparation of Company financial statements and satisfying any required statutory filings.
- F. This Agreement may be terminated upon written notice by either Party to the other Party, if the Closing Date has not occurred on or before January 15, 2008.

7. **Applicable Law and Jurisdiction**

This Agreement shall be governed by and construed in accordance with the substantive laws of Switzerland, including the Act, excluding any conflicts of law rule or principle which might refer such construction to the laws of another jurisdiction.

The Parties hereby irrevocably submit to the exclusive jurisdiction of the Commercial Court of the Canton of Vaud, with reserve of appeals to the Swiss Federal Supreme Court (*Schweizerisches Bundesgericht*), to settle any disputes which may arise out of or in connection with this Agreement or the transactions contemplated hereby.

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So agreed as of the date first set forth above.

Mercuria Energy Holding B.V.

By: /s/ Jarek Asyrannosicz
Attorney-in-fact

Cheniere LNG Services, Inc.

By: /s/ Jean Abiteboul
Jean Abiteboul, Attorney-in-Fact

J&S Cheniere, S.A. hereby consents to repay Mercuria Energy Holding B.V., a total of USD \$25,000,000 (twenty-five million U.S. dollars), the principal amount due under Seller's Shareholder Loan, plus interest as determined above, on the Closing Date in accordance with the terms and conditions of the above Agreement. Upon repayment of the principal amount due under the Seller's Shareholder Loan, plus interest, J&S Cheniere hereby consents that the Shareholder Loan with the Seller shall be automatically terminated without further action.

J&S Cheniere, S.A.

By: /s/ Jean Abiteboul
~~Attorney-in-Fact~~
Chairman

**Schedule D-1
CHANGE ORDER FORM**

(for use when the parties mutually agree upon and execute the Change Order Pursuant to Section 6.1B or 6.2C)

PROJECT NAME: Creole Trail Pipeline – Segment 1
Project, Preferred Route Single Line Option

CHANGE ORDER NUMBER: CO 1-001

OWNER: Cheniere Creole Trail Pipeline, L.P.

DATE OF CHANGE ORDER: 2/7/08

CONTRACTOR: Sunland Construction, Inc.

DATE OF AGREEMENT: March 12, 2007

The Agreement between the Parties listed above is changed as follows:*(attach additional documentation if necessary)*

Provide labor and equipment to install and remove one extra push site at MLV 1-3. This change order includes additional board road material and mats required at the site. Seventy percent (70%) will be payable upon installation of the push site (\$1,029,221.20) and thirty percent (30%) will be payable upon removal of the push site (\$441,094.80).

Adjustment to Estimated Contract Price

The original Estimated Contract Price was	\$ 43,617,209
Net change by previously authorized Change Order (# _____)	\$ 0
The Estimated Contract Price prior to this Change Order was	\$ 43,617,209
The Estimated Contract Price will be <u>increased</u> by this Change Order in the amount of	\$ 1,470,316
The new Estimated Contract Price including this Change Order will be	\$ 45,087,525

Adjustment to dates in Project Schedule

The following dates are modified *(list all dates modified; insert N/A if no dates modified)*:

The Required Mechanical Completion Date will be unchanged by _____ () Days

The Required Mechanical Completion Date as of the date of this Change Order therefore is March 15, 20 08

(attach additional documentation if necessary) No Attachment

The Required Substantial Completion Date will be unchanged by _____ () Days

The Required Substantial Completion Date as of the date of this Change Order therefore is

(attach additional documentation if necessary) No Attachment

The Required Final Completion Date will be unchanged by _____ () Days

The Required Final Completion Date as of the date of this Change Order therefore is

(attach additional documentation if necessary) No Attachment

Adjustment to other Changed Criteria (insert N/A if no changes or impact; *attach additional documentation if necessary*) N/A

Upon execution of this Change Order by Owner and Contractor, the above-referenced change shall become a valid and binding part of the original Agreement without exception or qualification, unless noted in this Change Order. Except as modified by this and any previous issued Change Orders, all other terms and conditions of the Agreement shall remain in full force and effect. This Change Order is executed by each of the Parties' duly authorized representatives.

Cheniere Creole Trail Pipeline, L.P.

Owner

/s/ R. Keith Teague

Name

R. Keith Teague/President

Title

2/21/2008

Date of Signing

Sunland Construction, Inc.

Contractor

/s/ Randy P. Mat

Name

Project Manager

Title

2-19-08

Date of Signing

SUBSIDIARIES

<u>Name of Subsidiary</u>	<u>Jurisdiction of Organization</u>	<u>Assumed Names</u>
Cheniere Corpus Christi Pipeline, L.P.	Delaware	None
Cheniere Creole Trail Pipeline, L.P.	Delaware	None
Cheniere Energy Investments, LLC	Delaware	None
Cheniere Energy Operating Co., Inc.	Delaware	None
Cheniere Energy Partners GP, LLC	Delaware	None
Cheniere Energy Partners, L.P.	Delaware	None
Cheniere Energy Shared Services, Inc.	Delaware	None
Cheniere FLNG, L.P.	Delaware	None
Cheniere FLNG-GP, LLC	Delaware	None
Cheniere International Investments, B.V.	Switzerland	None
Cheniere LNG Holdings, LLC	Delaware	None
Cheniere LNG International S.A.R.L.	Netherlands	None
Cheniere LNG O&M Services, LLC	Delaware	None
Cheniere LNG Services S.A.R.L.	France	None
Cheniere LNG Services, Inc.	Delaware	None
Cheniere LNG Terminals, Inc.	Delaware	None
Cheniere LNG, Inc.	Delaware	None
Cheniere Marketing, Inc.	Delaware	None
Cheniere Pipeline Company	Delaware	None
Cheniere Pipeline GP Interests, LLC	Delaware	None
Cheniere Southern Trail GP, Inc.	Delaware	None
Cheniere Southern Trail Pipeline, L.P.	Delaware	None
Cheniere Subsidiary Holdings, LLC	Delaware	None
Cheniere Supply & Marketing, Inc.	Delaware	None
Corpus Christi LNG, LLC	Delaware	None
Creole Trail LNG, L.P.	Delaware	None
Frontera Pipeline, LLC	Delaware	None
Grand Cheniere Pipeline, LLC	Delaware	None
J&S Cheniere S.A.	Switzerland	None
Marea GP, LLC	Delaware	None
Marea Associates, L.P.	Texas	None
Sabine Pass LNG, L.P.	Delaware	None
Sabine Pass LNG-GP, Inc.	Delaware	None
Sabine Pass LNG-LP, LLC	Delaware	None
Sabine Pass Tug Services, LLC	Delaware	None
Sonora Pipeline, LLC	Delaware	None
Terranova Energia S. De R.L. de C.V.	Mexico	None

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements (Form S-3 Nos. 333-57533, 333-49847, 333-70195, 333-83949, 333-94841, 333-61238, 333-71496, 333-105295, 333-114006, 333-111454 and 333-127269, including any amendments thereto and Form S-8 Nos. 333-52479, 333-35868, 333-112379, 333-35866, 333-111457, 333-118816, 333-127266 and 333-134886, including any amendments thereto) of our reports dated February 26, 2008, with respect to the consolidated financial statements and schedule of Cheniere Energy, Inc. and subsidiaries, and the effectiveness of internal control over financial reporting of Cheniere Energy, Inc. and subsidiaries, included in this Annual Report (Form 10-K) for the year ended December 31, 2007.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2008

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-57533, 333-49847, 333-70195, 333-83949, 333-94841, 333-61238, 333-71496, 333-105295, 333-114006, 333-111454 and 333-127269 (including any amendments thereto)) and on Form S-8 (Nos. 333-52479, 333-35868, 333-112379, 333-35866, 333-111457, 333-118816, 333-127266 and 333-134886 (including any amendments thereto)) of Cheniere Energy, Inc. and subsidiaries of our report dated February 27, 2007, except for financial statement schedule I as to which the date is February 26, 2008, relating to the consolidated financial statements and financial statement schedule of Cheniere Energy, Inc. and subsidiaries, which appear in this Annual Report on Form 10-K on page 64.

/s/ UHY LLP
UHY LLP

Houston, Texas
February 26, 2008

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-57533, 333-49847, 333-70195, 333-83949, 333-94841, 333-61238, 333-71496, 333-105295, 333-114006, 333-111454 and 333-127269 (including any amendments thereto)) and on Form S-8 (Nos. 333-52479, 333-35868, 333-112379, 333-35866, 333-111457, 333-118816, 333-127266 and 333-134886 (including any amendments thereto)) of Cheniere Energy, Inc. of our reserve reports, which appear in this Annual Report on Form 10-K.

/s/ SHARP PETROLEUM ENGINEERING, INC.

SHARP PETROLEUM ENGINEERING, INC.

Houston, Texas
February 26, 2008

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER PURSUANT TO
RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Charif Souki, certify that:

1. I have reviewed this annual report on Form 10-K of Cheniere Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2008

/s/ Charif Souki
Charif Souki
Chief Executive Officer

**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Don A. Turkleson, certify that:

1. I have reviewed this annual report on Form 10-K of Cheniere Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2008

/s/ Don A. Turkleson
Don A. Turkleson
Chief Financial Officer

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Cheniere Energy, Inc. (the "Company") on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charif Souki, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: February 26, 2008

/s/ Charif Souki

Charif Souki

Chief Executive Officer

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Cheniere Energy, Inc. (the "Company") on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Don A. Turkleson, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: February 26, 2008

/s/ Don A. Turkleson

Don A. Turkleson
Chief Financial Officer