UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **April 7, 2005**

CHENIERE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**1-16383**	**95-4352386**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

717 Texas Avenue **Suite 3100** **Houston, Texas**	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(713) 659-1361**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

Cheniere Energy, Inc. is filing this Report to provide updates of its business description and risk factors, as set forth below in this Item 8.01, which reflects recent changes and developments. As used in this Form 8-K, unless we indicate otherwise or the context otherwise requires, the terms “our,” “we,” “us,” “Cheniere” and similar terms refer to Cheniere Energy, Inc., our subsidiaries and certain other entities in which we own interests.

Forward-Looking Statements

This Form 8-K 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, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 that we expect to commence or complete construction of each of our proposed liquefied natural gas, or LNG, receiving terminals by certain dates, or at all;
- statements that we expect to receive a Draft Environmental Impact Statement, or DEIS, or a Final Environmental Impact Statement, or FEIS, from the Federal Energy Regulatory Commission, or FERC, by certain dates, or at all, or that we expect to receive an order from FERC authorizing us to construct and operate proposed LNG receiving terminals by a certain date, or at all;
- statements regarding future levels of domestic natural gas production or consumption or the future levels of LNG imports into North America, regardless of the source of such information, or the transportation or other infrastructure or prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, whether on the part of Cheniere or at the project level, including financing arrangements for which we may have received commitment letters;
- statements relating to the construction of our proposed LNG receiving terminals, including statements concerning the engagement of any engineering, procurement and construction, or EPC, contractor and the anticipated terms and provisions of any agreement with an EPC contractor, and anticipated costs related thereto;
- statements regarding any terminal use agreement, or TUA, or other agreement 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 our total regasification capacity that is, or may become subject to, TUAs;
- statements regarding possible equity or asset purchases or sales, including of interests in current or future projects;
- statements that our proposed LNG receiving terminals and pipelines, when completed, will have certain characteristics, including amounts of regasification and storage capacities, a number of storage tanks and docks, pipeline deliverability and a number of pipeline interconnections;

- statements regarding possible expansions of the currently projected size of any of our proposed LNG receiving terminals;
- statements regarding our business strategy, our business plans or any other plans, forecasts or objectives any or all of which are subject to change;
- statements regarding any Securities and Exchange Commission, or SEC, or other governmental inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions; 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,” “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 Form 8-K.

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” included in this Form 8-K and those risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2004, which is incorporated by reference into this Form 8-K. 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 Form 8-K. We assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

Business

LNG industry

LNG is a well-established, global source of natural gas for electric generation, heating and industrial applications. According to the Energy Information Administration, or EIA, as of October 2003, there were 66 liquefaction plants in 12 countries capable of producing 6.6 trillion cubic feet, or Tcf, of LNG per year and 44 receiving terminals in 12 countries capable of receiving and regasifying LNG. The EIA also reports Japan as the largest importer of LNG in 2003, importing approximately 7.7 billion cubic feet per day, or Bcf/d, followed by South Korea (2.5 Bcf/d), Spain (1.4 Bcf/d), and North America (1.4 Bcf/d).

North America has the largest interconnected natural gas market in the world, consuming approximately 74 Bcf/d in 2003, according to the EIA. Currently, there are only four import LNG receiving terminals in North America with a combined sustainable sendout capacity of natural gas of approximately 2.5 Bcf/d, or about 3% of total North American current natural gas consumption. By contrast, EIA reports that Japan imports more than 80% of its natural gas as LNG.

LNG's contribution to the North American market has historically been minimal, due mainly to an abundant supply of domestically sourced, low cost natural gas. The EIA has reported, however, that the average wellhead price of natural gas produced in the United States has more than doubled in the last five years, an indication of a declining domestic resource base. Chairman of the Federal Reserve, Alan Greenspan, stated in May 2003 in testimony before Congress that greater access to global natural gas reserves is required for North American natural gas markets "to be able to adjust effectively to unexpected shortfalls in domestic supply [and that] access to world natural gas supplies will require a major expansion of LNG terminal import capacity."

We believe that LNG is needed as a reliable source of supply to meet demand and that LNG can be delivered to North America at a competitive price.

Business strategy

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

- complete the development and construction of our onshore U.S. Gulf Coast LNG receiving terminals;
- secure long-term arrangements covering approximately two-thirds of the total existing and future regasification capacity at LNG terminals that we control, including long-term TUAs with creditworthy "anchor tenants" for approximately one-half of such total regasification capacity, thus providing for an expected stream of contracted cash flows when terminals become operational;
- retain the remaining capacity to capitalize on future long-term, short-term or spot market opportunities;
- apply proven, conventional technology to mitigate development and operating risk and facilitate permitting, while utilizing the latest control and safety technology;
- grow our terminal business by expanding our existing projects and pursue the development of additional LNG receiving terminals on the U.S. Gulf Coast and elsewhere; and

- pursue other energy business initiatives, including downstream opportunities such as natural gas pipelines and storage, marketing and trading, as well as upstream opportunities such as investment in LNG shipping businesses, securing foreign LNG supply arrangements, development of foreign natural gas reserves that could be converted into LNG, and oil and gas exploration, development, production, transportation and processing activities generally, any of which may include acquisitions, dispositions, investments and/or joint ventures.

Competitive strengths

We believe that we hold several competitive advantages including the following:

Early mover advantage. We established our business plan in 1999, when constructing new LNG import capacity in the United States was only beginning to undergo reconsideration since completion of the last domestic LNG import terminal in the early 1970s. As an early mover, we secured what we believe to be among the best sites for LNG receiving terminals along the U.S. Gulf Coast. Today, we believe that we have maintained that advantage and believe that our LNG receiving terminals are currently further along in the development process than most other proposed U.S. LNG receiving terminals, with construction having commenced at two of our terminals, a third terminal currently expected to commence construction in 2005 and a fourth terminal currently planned to commence construction in 2006.

U.S. Gulf Coast focus. The U.S. Gulf Coast area is conducive to LNG receiving terminal development, as it is distinguished by substantial local consumption coupled with extensive natural gas pipeline infrastructure. According to the EIA, natural gas consumption in Texas and Louisiana in 2003 totaled approximately 14.5 Bcf/d and pipeline capacity from the U.S. Gulf Coast in 2001 totaled approximately 19 Bcf/d. Capacity is currently available on major natural gas pipelines in the vicinity of each of our sites and, with declining U.S. Gulf Coast natural gas production, we believe that more of the existing pipeline infrastructure will become available for transporting natural gas imported as LNG.

Economies of scale and flexibility. At 2.6 or 3.3 Bcf/d of initial regasification capacity each, we believe that our Sabine Pass, Corpus Christi and Creole Trail facilities, described below, are currently the largest proposed LNG receiving terminals in North America and are each designed to have more than two times the capacity of any existing North American terminal. With this capacity, we believe that these terminals will benefit from economies of scale in construction and operation. Furthermore, with three ports, six unloading docks and 10 storage tanks among the three facilities, we will be capable of offering flexible landing options to our customers.

Environmentally sound and community-friendly approach. We are committed to an environmentally sound and community-friendly approach in developing our LNG receiving terminals. At each potential site, we invest time to develop strong community relationships. We begin the application process for a facility only after we are convinced that the local community understands the process and is willing to support our project. Furthermore, the local governments in Texas and Louisiana are familiar with and supportive of the energy industry. We have received written letters in support of the development of our Sabine Pass LNG receiving terminal from Louisiana state representatives, a U.S. Senator from Louisiana, the Governor of Louisiana and local organizations. We have received written letters in support of the development of our Corpus Christi LNG receiving terminal from the Governor of Texas, the Mayor of Corpus Christi, the local Sierra Club and other local organizations. In addition, FERC has held public hearings with respect to the development of our proposed Sabine Pass and Corpus Christi LNG receiving terminals, at which the local communities expressed support for our facilities.

Experienced management team with significant shareholdings . To pursue this business, we have assembled a team of professionals with extensive experience in the LNG industry. Through tenure with major oil companies, major operators of LNG receiving terminals and major engineering and construction companies, our senior management team has an average of more than 20 years of experience in the areas of LNG project development, operation, engineering, technology, transportation and marketing.

Our LNG receiving terminals

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 the United States. We have focused our initial development efforts on four LNG receiving terminal projects at the following locations: on Quintana Island near Freeport, Texas; in Cameron Parish, Louisiana near Sabine Pass; near Corpus Christi, Texas; and at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana, which we refer to as Creole Trail.

Freeport LNG

Development

In 2001, we initiated development of the LNG receiving facility on Quintana Island near Freeport, Texas. In February 2003, we consummated a transaction with entities controlled by Michael S. Smith, or the Smith entities. We contributed to Freeport LNG Development, L.P., or Freeport LNG, all of the interest in the Freeport site and project we had acquired in June 2001 in exchange for a 40% limited partner interest in Freeport LNG and $6.7 million of cash payments. Smith entities owned the general partner interest and the remaining 60% limited partner interest. Smith entities committed to contribute up to $9 million to fund Freeport LNG's development costs and to apply available proceeds from any sales of options, capacity reservations and loans related to capacity reservations to these costs. In addition, Freeport LNG assumed our obligation to pay to the seller of the lease option for the Freeport site a royalty of, generally, $0.03 per million cubic feet, or Mcf, of gas processed through the Freeport LNG terminal. The minimum royalty is $2 million per year and the maximum royalty is $11 million per year after production begins. In March 2003, we sold a 10% limited partner interest in Freeport LNG to an affiliate of Contango Oil & Gas Company. As a result of the sale, we now hold a 30% limited partner interest in Freeport LNG. In July 2004, ConocoPhillips Company, or ConocoPhillips, acquired a 50% general partner interest in Freeport LNG from one of the Smith entities, thereby reducing its general partner interest from 100% to 50%. In December 2004, a subsidiary of The Dow Chemical Company, or Dow, acquired a 15% limited partner interest in Freeport LNG from one of the Smith entities, reducing its limited partner interest from 60% to 45%.

As a limited partner in Freeport LNG, we must rely on the general partner to successfully implement Freeport LNG's business plans. We are generally required to keep economic terms of the Freeport LNG TUAs and other contracts confidential.

The Freeport LNG receiving terminal is being developed on a 233-acre tract of land and is designed with regasification capacity of 1.5 Bcf/d, one dock and two LNG storage tanks with an aggregate LNG storage capacity of 6.7 billion cubic feet of natural gas equivalent using the ratio of six thousand cubic feet, or Mcf, of natural gas to one barrel (or 42 United States gallons liquid volumes) of crude oil, condensate and natural gas liquids, or Bcfe. The unloading dock will be able to handle 78,000 cubic meter, or cm, to 250,000 cm LNG tankers. We have been advised by Freeport LNG that it has entered into a lump-sum turnkey contract for its 1.5 Bcf/d facility and that the estimated cost to construct the facility is approximately $750 million, before financing costs. We believe that this cost estimate is subject to change due to such items as cost overruns, change orders and changes in commodity prices.

In January 2005, FERC authorized Freeport LNG to commence construction of the LNG receiving terminal. In order to complete certain phases of the project, Freeport LNG will be required to satisfy remaining conditions specified by FERC. Construction began in the first quarter of 2005, and we expect that terminal operations will commence in 2008. We have been advised that Freeport LNG expects to have increases in expenses and debt and increases in contributed capital from the partners as it proceeds with planning, development and construction of the Freeport LNG receiving terminal.

Freeport LNG has advised us that it intends to initiate an application seeking an additional order from FERC that would authorize the construction of an expansion that would substantially increase the capacity at its currently permitted 1.5 Bcf/d Freeport LNG terminal. The anticipated costs, physical description and financing and construction plans for this potential expansion have not been stated by Freeport LNG. These aspects of the development, construction and operation of the Freeport LNG facility, as well as the anticipated financial consequences for us as a limited partner in Freeport LNG, would change as a result of such an expansion from what we are currently able to describe in this Form 8-K.

Dow TUA

In March 2004, Dow entered into a 20-year TUA with Freeport LNG, pursuant to which Freeport LNG is obligated to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the proposed LNG receiving terminal. In addition, Freeport LNG will provide for the transportation and delivery of natural gas through the facility’s 9.4-mile pipeline to Stratton Ridge, Texas for interconnection with downstream pipelines. Freeport LNG has no obligation to provide certain services such as (i) harbor, mooring and escort services for LNG tankers, including the provision of tugboats, and (ii) the transportation of natural gas downstream from Stratton Ridge or the construction of any pipelines to provide such transportation.

Dow has reserved 195,275,000 million British thermal units, or MMbtu, of annual LNG receipt capacity under the TUA, which is equivalent to approximately 500 million cubic feet per day, or MMcf/d, of regasification capacity, assuming an energy content of 1.05 MMbtu per Mcf after adjustment for energy content and gas retention for fuel. The Dow TUA commences between April 2007 and March 2008, runs for an initial term of 20 years from the date on which services commence for Dow at the Freeport LNG facility and is subject to three additional 10-year extensions. Dow is required to pay Freeport LNG a monthly reservation fee for this regasification capacity. In addition, each month Freeport LNG is entitled to retain a percentage of Dow’s share of LNG to be used as fuel at the facility. Dow is also required to pay a portion of power and other operating costs.

Freeport LNG and Dow are liable for certain delays and nonperformance under *force majeure* circumstances. In addition, Freeport LNG is obligated to pay liquidated damages in the event of certain types of docking and unloading delays.

Each of Freeport LNG and Dow may assign or pledge its interests under the TUA in connection with the construction and term financing of the proposed Freeport LNG receiving terminal. In addition, Dow may assign all or a portion (each, limited by quantity and duration) of its right to use the available services to (i) an affiliate upon notice to, but without the consent of, Freeport LNG or (ii) any other person upon the written consent of Freeport LNG, which consent is not to be unreasonably withheld, provided that the assignee executes a TUA with Freeport LNG and Dow agrees to modifications to the gas redelivery and quantity provisions of the Dow TUA to reflect such assignment.

Dow may terminate the TUA during the construction period if Dow reasonably determines that substantial completion of the Freeport LNG terminal (so that it is ready to be used for its intended purpose) will not occur by a future confidential date, provided that Freeport LNG does not cure the situation within 30 days following notice thereof. Each of Dow and Freeport LNG may terminate the TUA if Freeport has not provided to Dow evidence that it has successfully arranged and closed on financing of the Freeport LNG receiving terminal by June 30, 2005. Either party may terminate the TUA if the other party fails to make certain payments.

ConocoPhillips TUA

ConocoPhillips paid nonrefundable fees of $13.5 million during 2004 and has reserved approximately 1.0 Bcf/d of regasification capacity in the terminal, has purchased options to reserve up to 500 MMcf/d of additional regasification capacity in the event the terminal is expanded, has acquired a 50% interest in the general partner of Freeport LNG and has agreed to provide a substantial majority of the construction funding. ConocoPhillips will be primarily responsible for managing the construction and operation of the facility.

In July 2004, ConocoPhillips and Freeport LNG entered into a long-term TUA. Under the TUA between Freeport LNG and ConocoPhillips, Freeport LNG is obligated to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the proposed LNG receiving terminal. In addition, Freeport LNG will provide for the transportation and delivery of natural gas through the facility's 9.4-mile pipeline to Stratton Ridge, Texas for interconnection with downstream pipelines. Freeport LNG has no obligation to provide certain services to ConocoPhillips such as (i) harbor, mooring and escort services for LNG tankers, including the provision of tugboats, and (ii) the transportation of natural gas downstream from Stratton Ridge or the construction of any pipelines to provide such transportation.

ConocoPhillips has reserved 390,550,000 MMbtu of annual LNG receipt capacity under the TUA, which is equivalent to approximately 1.0 Bcf/d of regasification capacity, assuming an energy content of 1.05 MMbtu per Mcf after adjustment for energy content and gas retention for fuel. The ConocoPhillips TUA commences between April 2007 and March 2008, runs for an initial term until February 2033 and is subject to six additional 10-year extensions. ConocoPhillips is required to pay Freeport LNG a monthly reservation fee for this regasification capacity, which is subject to reduction for any calculated annual shortfalls in available capacity, which are reconciled on both a monthly and an annual basis. In addition, each month Freeport LNG is entitled to retain ConocoPhillips' allocable share of LNG used as fuel at the facility and its allocable portion of all other actual losses. ConocoPhillips is also required to pay on a monthly basis a portion of power and other operating costs.

Freeport LNG and ConocoPhillips are liable for certain delays and nonperformance under *force majeure*. In addition, Freeport LNG is obligated to pay liquidated damages in the event of certain types of docking and unloading delays.

Both Freeport LNG and ConocoPhillips may assign their interests under the TUA to affiliates. In addition, Freeport LNG may pledge its interest under the TUA to lenders to secure indebtedness incurred to finance the construction and term financing of the proposed facility. In addition, ConocoPhillips may make a partial assignment of its total reserved regasification capacity to nonaffiliates upon the written consent of Freeport LNG, which consent is not to be unreasonably withheld. Any such partial assignee would be required to enter into a TUA with Freeport LNG with appropriate modifications to the quantity provisions but otherwise with substantially the same terms as the TUA between Freeport LNG and ConocoPhillips. An assignment will not end the obligations of ConocoPhillips under the TUA unless the assignee agrees to be bound by the provisions of the TUA and, in the case of ConocoPhillips, its assignee demonstrates, including through a parent guarantee or irrevocable letter of credit, that it has a creditworthiness that is the same or better than that of ConocoPhillips.

ConocoPhillips may terminate the TUA during the construction period if ConocoPhillips reasonably determines that the conversion date (as defined in the credit agreement between Freeport LNG and ConocoPhillips) will not occur by a future confidential date, subject to a 30-day cure period on the part of Freeport LNG. Either party may terminate the TUA if the other party fails to make certain payments.

Funding

Freeport LNG has entered into a credit agreement with ConocoPhillips for ConocoPhillips to provide a substantial majority of the debt financing for the project. To the extent that the funding provided by ConocoPhillips is insufficient or not available to meet the capital expenditures or working capital requirements of Freeport LNG, the general partner of Freeport LNG may obtain such additional funding from any of the following sources:

- cash reserves of Freeport LNG;
- loans from banks and other non-affiliate independent sources;
- additional capital contributions made to Freeport LNG by the partners;
- loans made to Freeport LNG by the partners or their affiliates; or
- any other funding source determined by the general partner of 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 2004 and February 2005, we received notices from the general partner of Freeport LNG stating that its affiliated limited partner’s pre-agreed total capital contributions would be made and that additional capital contributions were being called for from all limited partners to fund a portion of Freeport LNG’s budgeted 2005 expenditures. We presently intend to fund our 30% pro rata share, or approximately $2.5 million, of these capital calls, which cover the period December 2004 through June 2005. Additional capital calls may be made upon us and the other limited partners in Freeport LNG. 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, revenues from advance capacity reservation fees and funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

The general partner of Freeport LNG is authorized to do all things necessary to obtain debt and equity financing in connection with any expansion of the facility. Any equity financing obtained for such expansion will dilute the ownership interests of the limited partners on a pro rata basis. However, we and the other limited partners have preemptive rights that allow any limited partner to maintain its percentage ownership interest in Freeport LNG.

Our expectations regarding Freeport LNG

We account for our ownership in Freeport LNG under the equity method. Excluding effects of any future expansion by Freeport LNG, we estimate that we would receive pre-tax cash distributions with respect to our interest in Freeport LNG ranging from approximately $10 million to $20 million per year, based on the following assumptions:

- our ownership interest remains at 30%;
- construction of the 1.5 Bcf/d facility occurs on schedule at expected project and financing costs;
- operating costs fall within expected ranges; and
- the Dow and ConocoPhillips TUAs remain in effect in their current forms.

These expectations involve assumptions, risks and uncertainties beyond our control, and these expectations may prove to be incorrect.

Pipeline

The Freeport LNG facility includes a 9.4-mile, 36-inch diameter pipeline through which natural gas will be transported to the delivery point at Stratton Ridge, Texas, which is a major point of interconnection with the Texas intrastate gas pipeline grid.

Sabine Pass LNG

Development

We are developing an LNG receiving terminal in Cameron Parish, Louisiana, near Sabine Pass. We formed Sabine Pass LNG, L.P., or Sabine Pass LNG, to develop the terminal. We have entered into leases for three tracts of land comprising 853 acres in Cameron Parish, Louisiana for the project site.

The LNG receiving terminal will be designed with an initial regasification capacity of 2.6 Bcf/d, two docks and three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcfe. Subject to obtaining financing and an additional order by FERC authorizing construction of an expansion at our Sabine Pass LNG receiving terminal, the facility near Sabine Pass could be expanded from its initial capacity of 2.6 Bcf/d to approximately 4.0 Bcf/d.

The facility will have two unloading docks that can handle 87,000 cm to 250,000 cm LNG shipping vessels. The cost to construct the Sabine Pass LNG facility is currently estimated at approximately $750 million to $850 million, before financing costs. In December 2004, we entered into a lump-sum turnkey agreement with Bechtel Corporation, or Bechtel, a major international EPC contractor. Our cost estimate is subject to change due to such items as cost overruns, change orders and changes in commodity prices (particularly steel).

In March 2005, FERC issued an order authorizing Sabine Pass LNG to commence construction of the Sabine Pass LNG receiving terminal. In order to complete certain phases of the project, Sabine Pass LNG will be required to satisfy remaining conditions specified by FERC. Preliminary construction began in March 2005, and we expect to commence terminal operations in 2008.

Total TUA

In September 2004, Sabine Pass LNG entered into a TUA with Total LNG USA, Inc., or Total, to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the proposed LNG receiving terminal. Sabine Pass LNG has no obligation to provide Total with certain services such as (i) harbor, mooring and escort services for LNG tankers, including the provision of tugboats, (ii) the transportation of natural gas downstream from the LNG terminal or the construction of any pipelines to provide such transportation or (iii) the marketing of natural gas.

Under the TUA, Total has reserved 390,915,000 MMbtu of annual LNG receipt capacity, which is equivalent to approximately 1.0 Bcf/d of regasification capacity, assuming an energy content of 1.05 MMbtu per Mcf and retainage of 2%. The Total TUA is scheduled to commence no later than April 2009, subject to substantial completion, runs for an initial term of 20 years and is subject to six additional 10-year extensions. Beginning on the commercial start date of the Sabine Pass LNG facility, Total has agreed to pay a monthly fixed capacity reservation fee of $9.1 million; a monthly operating fee of $1.3 million, which is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers); and certain other incremental costs and governmental authority taxes and costs. After the Total TUA commences, the sum of these payments would be approximately $125 million per year before inflation. This calculation assumes that the Total TUA remains in effect in its current form. These monthly payment amounts are equivalent to payments of $0.28 per MMbtu for capacity and $0.04 per MMbtu for operating fees, respectively, of reserved monthly LNG receipt capacity. In addition, each month Sabine Pass LNG is entitled to retain 2% of the LNG delivered for Total’s account for use as fuel at the facility. Total’s obligations under the TUA are supported by an irrevocable guarantee in favor of Sabine Pass LNG by Total S.A.

If any governmental authority (i) imposes any taxes on Sabine Pass LNG (excluding taxes on revenue or income) with respect to the services provided under the TUA, or the proposed LNG receiving terminal or (ii) enacts any safety or security related regulation which materially increases the costs of Sabine Pass LNG in relation to the services provided or the proposed LNG receiving terminal, Total will bear such taxes or increased regulatory costs at the rate of 40%, subject to adjustment if the LNG regasification facilities are expanded. To the extent any ad valorem taxes are imposed and not abated, we will reimburse Total for up to one-half of such amount not to exceed $3.9 million per year.

Sabine Pass LNG is obligated to pay liquidated damages to Total in the event of certain types of docking and unloading delays.

Both Sabine Pass LNG and Total may assign their interests under the TUA to affiliates, and, as permitted by the TUA and discussed below, Sabine Pass LNG has pledged its interest under the TUA to lenders to secure indebtedness incurred to finance the construction and term financing of the proposed LNG receiving terminal. In addition, Total may make a partial assignment of its total reserved regasification capacity to nonaffiliates provided that (i) the assignee agrees to be bound by the TUA, (ii) the parent guarantee continues to apply to all assigned obligations and (iii) Total and the assignee designate a representative and jointly exercise all rights under the TUA.

Total may terminate the TUA if:

- Sabine Pass LNG has declared *force majeure* with respect to a period that has extended, or is projected to extend, for 18 months; or
- for reasons not excused by *force majeure* or Total's actions, Sabine Pass LNG:
  - fails to deliver at least 191,625,000 MMbtu of Total's total natural gas nominations in a 12-month period;
  - fails entirely to receive at least 15 cargoes nominated by Total over a period of 90 consecutive days; or
  - fails to unload, or notifies Total that it will be unable to unload, 50 cargoes or more scheduled for delivery by Total for a 12-month period.

Sabine Pass LNG may terminate the TUA if:

- the parent guarantee ceases to be in full force and effect;
- for a period exceeding 15 days, two of the parent guarantor's credit ratings fall below investment grade; or
- the parent guarantor commences bankruptcy or liquidation proceedings, or has such proceedings commenced against it.

Either party may terminate the TUA with 30 days written notice if (i) a party has failed to pay when due an amount owed that causes its cumulative delinquency to exceed three times the monthly capacity reservation fee, (ii) the cumulative delinquency has not been paid within 60 days of such notice and (iii) the other party has subsequently given 30 days written notice to terminate the TUA.

In November 2004, Total exercised its option to proceed with the transaction by delivering to Sabine Pass LNG an advance capacity reservation fee payment of $10 million and a guarantee by its parent entity, Total S.A., of certain Total obligations under the TUA. Cheniere, Sabine Pass LNG and Total also entered into an omnibus agreement in September 2004, under which the TUA remains subject to certain conditions. Under the omnibus agreement, if Sabine Pass LNG enters into a new TUA with a third party, other than our affiliates, for capacity of 50 MMcf/d or more, with a term of five years or more, prior to the commercial start date of the terminal, Total will have the option, exercisable within 30 days of the receipt of notice of such transaction, to adopt the pricing terms contained in such new TUA for the remainder of the term of the Total TUA.

Because Total has elected to proceed with the transaction and Bechtel has accepted the final notice to proceed, or NTP, an additional advance capacity reservation fee payment of $10 million is payable by Total to Sabine

Pass LNG in April 2005. Total has the right to terminate this transaction under the omnibus agreement if these conditions are not satisfied by June 30, 2005.

Chevron USA TUA

In November 2004, Sabine Pass LNG entered into a TUA with Chevron USA, Inc., or Chevron USA, pursuant to which Sabine Pass LNG is obligated to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at the proposed LNG receiving terminal. Sabine Pass LNG has no obligation to provide certain services such as (i) harbor, mooring and escort services for LNG tankers, including the provision of tugboats, (ii) the transportation of natural gas downstream from the LNG terminal or the construction of any pipelines to provide such transportation or (iii) the marketing of natural gas.

Under the TUA, Chevron USA has reserved 282,761,850 MMbtu of annual LNG receipt capacity, which is equivalent to approximately 700 MMcf/d of regasification capacity, assuming an energy content of 1.085 MMbtu per Mcf and retainage of 2%. The Chevron USA TUA commences between February 2009 and July 2009, subject to substantial completion, runs for an initial term of 20 years and is subject to two additional 10-year extensions. Beginning on the commercial start date of the Sabine Pass LNG facility, Chevron USA is required to pay Sabine Pass LNG a fixed monthly fee for this regasification capacity that is comprised of (i) a reservation fee of $0.28 per MMbtu of one-twelfth of the reserved annual LNG receipt capacity, (ii) an operating fee of $0.04 per MMbtu of one-twelfth of the reserved annual LNG receipt capacity and (iii) certain taxes and regulatory costs. After the Chevron USA TUA commences, the sum of these payments would be approximately $90 million per year before inflation. This calculation assumes that the Chevron USA TUA remains in effect in its current form. The operating fee is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers). In addition, each month Sabine Pass LNG is entitled to retain 2% of the LNG delivered for Chevron USA’s account for use as fuel at the facility. ChevronTexaco Corporation will be required to guarantee 80% of Chevron USA’s payment obligations under the TUA.

If any governmental authority (i) imposes any taxes on Sabine Pass LNG (excluding taxes on revenue or income) with respect to the services provided under the TUA, or the proposed LNG receiving terminal or (ii) enacts any safety or security related regulation which materially increases the costs of Sabine Pass LNG in relation to the services provided or the proposed LNG receiving terminal, Chevron USA will bear a proportionate share of such taxes or increased regulatory costs equal to 28%, subject to adjustment if Chevron USA exercises its capacity options.

Sabine Pass LNG is obligated to pay liquidated damages to Chevron USA in the event of certain types of docking and unloading delays.

Both Sabine Pass LNG and Chevron USA may assign their interests under the TUA to affiliates, and, as permitted by the TUA and discussed below, Sabine Pass LNG has pledged its interest under the TUA to lenders to secure indebtedness incurred to finance the construction and term financing of the proposed LNG receiving terminal. In addition, Chevron USA may make a partial assignment of its total reserved regasification capacity to nonaffiliates provided (i) the assignee agrees to be bound by the TUA, (ii) the parent guarantee continues to apply to all assigned obligations, (iii) Chevron USA remains liable for payments owed and (iv) the respective responsibilities of the parties under the TUA are not increased or decreased.

An assignment under the TUA will terminate Chevron USA's obligations only if (i) the assignment constitutes all of such party's rights and obligations under the TUA, (ii) the assignee agrees to be bound by the TUA and (iii) the assignee demonstrates creditworthiness at the time of the assignment that is the same or better than the guarantor, in the case of Chevron USA, or Sabine Pass LNG, in its case.

Chevron USA may terminate the TUA if:

- Sabine Pass LNG has declared *force majeure* with respect to a period that has extended, or is projected to extend, for 18 months; or
- for reasons not excused by *force majeure* or Chevron USA's actions, Sabine Pass LNG:
  - fails to deliver at least 141,380,925 MMbtu of Chevron USA's total natural gas nominations in a 12-month period;
  - fails entirely to receive 12 cargoes or more nominated by Chevron USA over a period of 90 days; or
  - fails to unload, or notifies Chevron USA that it will be unable to unload, 37 cargoes or more scheduled for delivery by Chevron USA for a 12-month period.

Sabine Pass LNG may terminate the TUA if the parent guarantee ceases to be in full force and effect or if the parent guarantor or Chevron USA commences bankruptcy, insolvency or liquidation proceedings, or has such proceedings commenced against it, that are not stayed within 60 days.

Either party may terminate the TUA with 30 days written notice if (i) a party has failed to pay when due an amount owed that causes its cumulative delinquency to exceed three times the monthly capacity reservation fee, (ii) the cumulative delinquency has not been paid within 60 days after issuance of a delinquency notice and (iii) the other party has subsequently given 30 days written notice to terminate the TUA.

Cheniere, Sabine Pass LNG and Chevron USA simultaneously entered into an omnibus agreement, under which Chevron USA agreed to make advance capacity reservation fee payments. Under the omnibus agreement, Chevron USA has the option, at the same fee, either to reduce its reserved capacity at the Sabine Pass LNG facility to 500 MMcf/d by July 1, 2005 or to increase its reserved capacity to 1.0 Bcf/d by December 1, 2005, which before inflation would result in annual gross payments after the Chevron USA TUA commences of approximately $65 million (for 500 MMcf/d) or $129 million (for 1 Bcf/d), respectively. This calculation assumes that the Chevron USA TUA remains in effect in its current form.

The omnibus agreement requires Chevron USA to make advance capacity reservation fee payments to Sabine Pass LNG totaling up to $20 million, beginning with $5 million paid in November 2004 and $7 million paid in December 2004. Bechtel has accepted the NTP and, as a result, a third payment of $5 million is payable by Chevron USA to Sabine Pass LNG in April 2005. A payment of $3 million will be due if Chevron USA exercises the option to increase its reserved capacity at the Sabine Pass LNG facility to approximately 1.0 Bcf/d.

EPC agreement

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC agreement with Bechtel. Under the EPC agreement, Bechtel will provide Sabine Pass LNG with services for the engineering, procurement and construction of the Sabine Pass LNG receiving, storage and regasification terminal. The work to be performed by Bechtel will include all of the work required to achieve substantial completion and final completion of the Sabine Pass LNG receiving terminal in accordance with the requirements of the EPC agreement, including achieving specified minimum acceptance criteria and performance guarantees. Bechtel is obligated to perform its work in accordance with good engineering and construction practices and applicable laws, codes and standards.

In December 2004, a limited notice to proceed, or LNTP, was issued to and accepted by Bechtel, upon which time Bechtel was required to promptly commence performance of certain off-site engineering and preparatory work under the EPC agreement. Upon its receipt from Sabine Pass LNG of a NTP, Bechtel must commence all other aspects of the work under the EPC agreement. Sabine Pass LNG issued the NTP in early April 2005. Bechtel must achieve substantial completion in accordance with the requirements of the EPC agreement within 1,247 days after delivery of the NTP. Final completion must be attained no later than 90 days after achieving substantial completion.

Until substantial completion under the terms of the EPC agreement, Sabine Pass LNG has certain rights to request change orders, and Bechtel has the right to request change orders up to and after substantial completion in the event of specified occurrences, including, among other things:

- a *force majeure* event;
- a suspension of work ordered by Sabine Pass LNG;
- certain acts and omissions by Sabine Pass LNG (including failure to fulfill obligations), but, in each case, only where such act or omission adversely affects Bechtel's costs of the performance of work or its ability to perform the work in accordance with the project schedule; and
- certain changes in law or the issuance of the NTP after April 4, 2005, but, in each case, only where such delay adversely affects Bechtel's costs of the performance of the work or its ability to perform the work in accordance with the project schedule.

Sabine Pass LNG will pay to Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work under the EPC agreement. 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 bonus of $12 million, or a lesser amount in certain cases, if Bechtel, within 1,095 days after delivery of the NTP, completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. In February 2005, a change order for $1.5 million was approved, thereby increasing the total contract price to $648.4 million.

Bechtel warrants in the EPC agreement that:

- the equipment required for the Sabine Pass LNG receiving terminal will be new and of good quality;
- the work and the equipment will meet the requirements of the EPC agreement, including good engineering and construction practices and applicable laws, codes and standards; and

- the work and the equipment will be free from encumbrances to title.

Until 18 months after substantial completion, Bechtel will be liable to promptly correct any work that is found defective.

In the event of an uncured default by Bechtel, Sabine Pass LNG may terminate the EPC agreement and take any of the following actions:

- take possession of the facility, equipment, construction equipment, work product and books and records;
- take assignment of certain subcontracts; and
- complete the work.

Following such a termination, if the cost to reach final completion exceeded the unpaid balance of the contract price, Bechtel would be liable for the difference. If the cost to reach final completion were less than the unpaid balance of the contract price, the difference would be payable to Bechtel.

Sabine Pass LNG also has the right to terminate the EPC agreement for convenience. In the event of any such termination for convenience, Bechtel would be paid:

- the portion of the contract price for the work performed prior to termination, less that portion of the contract price paid previously;
- actual reasonable cancellation charges owed by Bechtel to subcontractors (if Sabine Pass LNG does not take assignment of such subcontracts);
- actual costs associated with demobilization charges; and
- lost profits, except in certain cases, equal to 10% of the contract price less a portion of the advance payment related to the NTP.

Sabine Pass LNG may, upon a 30-day written notice to Bechtel, suspend the work under the EPC agreement. In the event of such suspension for a period exceeding 90 consecutive days or 120 aggregate days, other than any suspension due to an event of *force majeure* or the fault or negligence of Bechtel or its subcontractors, Bechtel would be permitted to terminate the EPC agreement subject to giving a 14 day notice. In the event of such a termination, Bechtel would be entitled to the compensation described above in relation to termination for convenience. If Sabine Pass LNG suspends work under the EPC agreement, Bechtel could be entitled to a change order to recover the reasonable costs of the suspension, including demobilization and remobilization costs. Bechtel may also suspend or terminate the EPC agreement upon the occurrence of certain other events, including *force majeure* and uncured defaults of Sabine Pass LNG such as:

- failure to pay any undisputed amounts;
- failure to comply materially with material obligations under the EPC agreement; and
- insolvency.

If Bechtel experiences a *force majeure* event, it could be entitled to an extension of the date by which substantial completion is to be accomplished and an extension of the date by which it could earn the $12 million bonus. If any *force majeure* delay lasts at least 30 days, Bechtel would be entitled to an adjustment of the contract price under the EPC agreement to compensate it for its standby expenses, up to a limit of $3.8 million in the aggregate. A *force majeure* event generally occurs if any act or event occurs that:

- prevents or delays the affected party's performance of its obligations in accordance with the terms of the EPC agreement;
- is beyond the reasonable control of the affected party, not due to its fault or negligence; and
- could not have been prevented or avoided by the affected party through the exercise of due diligence.

Operation

In February 2005, Sabine Pass LNG entered into an Operation and Maintenance Agreement, or O&M Agreement, with Cheniere LNG O&M Services, L.P., or Cheniere O&M, a wholly-owned subsidiary of Cheniere. Pursuant to the O&M Agreement, Cheniere O&M has agreed to provide all necessary services required to operate and maintain the Sabine Pass LNG receiving terminal. The O&M Agreement will remain in effect until 20 years after substantial completion of the facility. Prior to substantial completion of the project, Sabine Pass LNG is required to reimburse Cheniere O&M for its operating expenses and pay a fixed monthly fee of $95,000 (indexed for inflation). The fixed monthly fee will increase to $130,000 (indexed for inflation) upon substantial completion of the facility, and Cheniere O&M will thereafter be entitled to a bonus equal to 50% of the salary component of labor costs.

In February 2005, Sabine Pass LNG also entered into a Management Services Agreement, or MSA, with Sabine Pass LNG-GP, Inc., or Sabine Pass GP, its general partner and a wholly-owned subsidiary of Cheniere. Pursuant to the MSA, Sabine Pass LNG appointed Sabine Pass GP to manage the business of Sabine Pass LNG, excluding those matters provided under the O&M Agreement. The MSA terminates 20 years after the commercial start date set forth in the Total TUA. Prior to substantial completion of construction of the Sabine Pass LNG receiving facility, Sabine Pass LNG is required to pay Sabine Pass GP a monthly fixed fee of $340,000; thereafter, the monthly fixed fee will increase to $520,000 (indexed for inflation).

Funding

On February 25, 2005, Sabine Pass LNG entered into an $822 million credit facility, or Sabine Pass Credit Facility, with an initial syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Bank USA, National Association, or HSBC, serves as collateral agent. The Sabine Pass Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation the Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Sabine Pass Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Sabine Pass Credit Facility will be permanently canceled. Before Sabine Pass LNG may make an initial borrowing under the Sabine Pass Credit Facility, it will be required to provide evidence that it has received equity contributions in amounts sufficient to fund $216 million of the project costs. We plan to fund the equity contribution required by the lenders with net proceeds of approximately $285.9 million from our offering of common stock completed in December 2004 or, if applicable, with available working capital or proceeds from a debt offering, or a combination thereof.

Borrowings under the Sabine Pass Credit Facility bear interest at a variable rate equal to LIBOR plus the applicable margin. The applicable margin varies from 1.25% to 1.625% during the term of the Sabine Pass Credit Facility. The Sabine Pass Credit Facility provides for a commitment fee of 0.50% per annum on the daily committed, undrawn portion of the Sabine Pass Credit Facility. Administrative fees must also be paid annually to the agent and the collateral agent. The principal of loans made under the Sabine Pass Credit Facility must be repaid in semi-annual installments commencing six months after the later of (i) the date that substantial completion of the project occurs under the EPC agreement and (ii) the commercial start date under the Total TUA. Sabine Pass LNG may specify an earlier date to commence repayment upon satisfaction of certain conditions. In any event, payments under the Sabine Pass Credit Facility must commence no later than October 1, 2009, and all obligations under the Sabine Pass Credit Facility mature and must be fully repaid by February 25, 2015.

The Sabine Pass Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. Sabine Pass LNG has obtained and may in the future seek consents, waivers and amendments to the Sabine Pass Credit Facility documents. Currently, Sabine Pass LNG is seeking a consent, waiver and amendment under the Sabine Pass Credit Facility documents to allow it to assume obligations under a 2001 agreement (which among other things provides for a royalty payment obligation that was assumed in February 2003 by Freeport LNG on gas processed at its facility). The obligations of Sabine Pass LNG under the Sabine Pass Credit Facility are secured by all of Sabine Pass LNG's personal property, including the Total and Chevron USA TUAs, and the partnership interests in Sabine Pass LNG.

In connection with the closing of the Sabine Pass Credit Facility, Sabine Pass LNG entered into swap agreements with HSBC and Société Générale. Under the terms of the swap agreements, Sabine Pass LNG will be able to hedge against rising interest rates, to a certain extent, with respect to its drawings under the Sabine Pass Credit Facility up to a maximum amount of $700 million. The swap agreements have 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 to March 25, 2009 and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the swap agreements will be March 25, 2012.

Pipeline

FERC issued an order in December 2004 authorizing construction, subject to specified conditions that must be satisfied, of a 16-mile, 42-inch diameter natural gas pipeline designed to transport 2.6 Bcf/d of regasified LNG from the Sabine Pass LNG facility, running easterly along a corridor that will allow for interconnection points with interstate and intrastate natural gas pipelines in southwest Louisiana, including pipelines operated by Natural Gas Pipeline Company of America, Transcontinental Gas Pipeline Corporation and Louisiana Resources Pipeline Company. We believe these existing pipelines are currently capable of transporting approximately 3.8 Bcf/d. It is also possible that one or more other pipeline operators will undertake to build pipeline connections to the Sabine Pass LNG facility. We expect that constructing such pipeline connections would require far less capital and time than the construction of our Sabine Pass LNG facility. Notwithstanding the completion of the foregoing permitting work, we are under no obligation under the terms of our TUAs with Total and Chevron USA to provide pipeline arrangements from the terminals to downstream locations.

In April 2005, we announced initiation of a FERC open season process for the marketing of natural gas pipeline transportation capacity on an alternative pipeline system. The proposed alternative system would connect both our Sabine Pass and our Creole Trail facilities, would allow potential interconnection with as many as fifteen different interstate and intrastate pipeline systems and would extend across southern Louisiana to a termination point in the vicinity of Rayne, Louisiana. Our ultimate decisions regarding pipeline connection to the facility will depend upon future developments, including, in particular, customer interest and general market demand for natural gas from the terminal.

Corpus Christi LNG

Development

We are also developing an LNG receiving terminal near Corpus Christi, Texas. We formed Corpus Christi LNG, L.P., or Corpus Christi LNG, in May 2003 to develop the terminal. We contributed our technical expertise and know-how, and all of the work in progress related to the Corpus Christi project, in exchange for a 66.7% limited partner interest in Corpus Christi LNG. A third party, BPU LNG, Inc., or BPU LNG, contributed approximately 212 acres of land and easements and committed to contribute cash to fund the first $4.5 million of Corpus Christi LNG project expenses, in exchange for its 33.3% limited partner interest. Corpus Christi LNG also obtained related easements and additional rights to an additional 400 acres. In January 2004, BPU LNG entered into an option agreement with Corpus Christi LNG to acquire 100 MMcf/d of regasification capacity at the terminal , which was subsequently assigned to its sole stockholder, BPU Associates, LLC. In February 2005, we acquired BPU's 33.3% limited partner interest in exchange for 1 million restricted shares of Cheniere common stock, which we may be required to register pursuant to a piggy-back registration rights agreement in the event that we intend to register our common stock for certain purposes. We will manage the project through the sole general partner interest in Corpus Christi LNG held by our wholly-owned subsidiary.

The Corpus Christi LNG receiving terminal is designed with regasification capacity of 2.6 Bcf/d, two docks and three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcfe. Subject to obtaining financing and an additional order by FERC authorizing construction of an expansion at our Corpus Christi LNG receiving terminal, the facility near Corpus Christi could be expanded from its initial capacity of 2.6 Bcf/d to approximately 3.2 Bcf/d.

The facility will have two unloading docks, which can handle 87,000 cm to 250,000 cm LNG shipping vessels. The cost to construct the Corpus Christi facility is currently estimated at approximately $650 million to $750 million, before financing costs. This estimate is based in part on our negotiations regarding a lump-sum turnkey agreement with a major international EPC contractor. Our cost estimate is subject to change due to such items as cost overruns, change orders and changes in commodity prices (particularly steel). BPU LNG was required to fund 100% of the first $4.5 million of Corpus Christi LNG's expenditures, which amount was funded as of March 31, 2004. From that date until February 8, 2005, when we acquired BPU LNG's 33.3% interest, we funded 66.7% of the expenditures of Corpus Christi LNG, with BPU LNG funding the balance. As the sole owner of Corpus Christi LNG, we are now required to fund 100% of expenditures incurred after February 8, 2005.

In December 2003, we submitted to FERC an application for a permit to build the Corpus Christi LNG receiving terminal, as well as a separate but concurrent permit application for its related pipeline. In March 2005, FERC issued the FEIS for our proposed Corpus Christi LNG receiving terminal and our related pipeline. In the FEIS, FERC concluded that the facility, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. We currently anticipate that we will receive, by the second quarter of 2005, an order by FERC authorizing construction of this terminal, which will likely be subject to specified conditions that must be satisfied prior to commencement of construction. We expect to begin construction in the third quarter of 2005 and to commence terminal operations in 2008. The front-end engineering design work for the Corpus Christi LNG terminal has been completed. We expect to engage a major international EPC contractor to perform the EPC work for the facility under a lump-sum turnkey agreement.

Customers

We have provided detailed information to and engaged in preliminary discussions with potential customers and other third parties in an effort to secure long-term TUAs with one or more creditworthy “anchor tenants” for portions of the capacity of our Corpus Christi LNG receiving terminal. Corpus Christi LNG has not yet entered into any TUAs. We are currently marketing 1.0 Bcf/d of capacity under long-term TUAs at $0.32 per MMbtu, the same price contracted for at Sabine Pass LNG. We intend to market the remaining capacity under other long-term, mid-term and/or short-term contracts. However, we may not be able to obtain any TUAs or other contracts for Corpus Christi LNG on terms acceptable to us, or at all.

Funding

We currently expect to fund the costs of the Corpus Christi LNG terminal using project financing similar to that used for our Sabine Pass LNG facility, proceeds from debt or equity offerings, or a combination thereof.

Pipeline

We have submitted to FERC an application to construct a 24-mile, 48-inch diameter natural gas pipeline designed to transport 2.6 Bcf/d of regasified LNG from the site of our proposed Corpus Christi LNG receiving terminal, running northwesterly along a corridor that will allow for interconnection points with interstate and intrastate natural gas transmission pipelines in south Texas, including pipelines operated by Texas Eastern Transmission Corporation, Gulf South Pipeline Company, L.P., Gulf Terra Intrastate, L.P. (Channel), Kinder Morgan Tejas Pipeline, L.P., Crosstex CCNG Marketing, Ltd., Transcontinental Gas Pipeline Corporation and Natural Gas Pipeline Company of America. We believe these existing pipelines are currently capable of transporting approximately 4.6 Bcf/d. It is possible that one or more other pipeline operators will undertake to build pipeline connections to the Corpus Christi LNG facility. We expect that constructing these pipeline connections will require far less capital and time than the construction of our Corpus Christi LNG facility. Our ultimate decisions regarding pipeline connection to the facility will depend upon future events, including, in particular, customer interest and general market demand for natural gas from the terminal.

Creole Trail LNG

Development

We are also developing an LNG receiving terminal at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana. We formed Creole Trail LNG, L.P., or Creole Trail LNG, in December

2004 to develop the terminal. We have options to lease tracts of land comprising 1,463 acres in Cameron Parish, Louisiana for the project site.

The Creole Trail LNG receiving terminal is anticipated to be designed with regasification capacity of 3.3 Bcf/d, two docks and four LNG storage tanks with an aggregate LNG storage capacity of 13.5 Bcfe. Subject to obtaining financing and an additional order by FERC authorizing construction of an expansion at our Creole Trail LNG receiving terminal, the facility could be expanded from its initial capacity of 3.3 Bcf/d up to approximately 4.0 Bcf/d.

The facility will have two unloading docks, which can handle 87,000 cm to 250,000 cm LNG shipping vessels. The cost to construct the Creole Trail facility is currently estimated at approximately $850 million to $950 million, before financing costs. Our cost estimate is preliminary and is subject to change based on negotiating a definitive EPC agreement and other future uncertainties.

In January 2005, we initiated the National Environmental Policy Act, or NEPA, pre-filing process with FERC to obtain an order to commence construction of the facility. Construction is anticipated to begin in the third quarter of 2006, and terminal operations are anticipated to commence in 2009, assuming the timely receipt of necessary permits and the entering into of TUAs and other necessary agreements.

Customers

We have engaged in preliminary discussions with potential customers and other third parties in an effort to secure long-term TUAs with one or more creditworthy “anchor tenants” for a portion of our capacity at our Creole Trail terminal. Creole Trail LNG has not yet entered into any TUAs. We anticipate marketing 1.0 Bcf/d of capacity under long-term TUAs at $0.32 per MMbtu, the same price contracted for at Sabine Pass LNG. We intend to market the remaining capacity under other long-term, mid-term and/or short-term contracts. However, we may not be able to obtain any TUAs or other contracts for Creole Trail LNG on terms acceptable to us, or at all.

Funding

We currently expect to fund the costs of the Creole Trail LNG terminal using project financing similar to that used for our Sabine Pass LNG facility, proceeds from debt or equity offerings, or a combination thereof.

Pipeline

In connection with the NEPA pre-filing process, we have sought approval to construct dual 118 mile, 42-inch diameter natural gas pipelines designed to transport 3.3 Bcf/d of regasified LNG from the site of our proposed Creole Trail LNG receiving terminal, running north/northeasterly along a corridor through six Louisiana parishes where they will terminate near Rayne, Louisiana. The pipelines are anticipated to be designed with potential interconnections to as many as 15 interstate and intrastate natural gas pipelines in southwestern Louisiana. We believe that these existing pipelines are currently capable of transporting approximately 12.0 Bcf/d.

In April 2005, we announced initiation of a FERC open season process for the marketing of natural gas pipeline transportation capacity on an expanded pipeline system. The proposed expanded Creole Trail pipeline system would also connect our Sabine Pass LNG receiving terminal. Our ultimate decisions regarding pipeline connection to the facility will depend upon future events, including, in particular, customer interest and general market demand for natural gas from the terminal.

Other sites

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

LNG receiving terminal operating costs

We anticipate that the annual fixed operating cost for each of our Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals will be approximately $25 million to $30 million, assuming current estimates for staffing levels, maintenance costs and property taxes. Current tax estimates are based on our receiving tax abatements at each facility, without which our estimated taxes will be substantially greater. In addition, we believe that Corpus Christi LNG will incur approximately $10 million to $15 million in variable operating expenses for purchased power, assuming full utilization and current power rates.

J & S Cheniere

We hold a minority interest in J & S Cheniere S.A., or J&S Cheniere. The majority interest in J&S Cheniere is held by J & S Energy Holding B.V., or J&S Holding, a Netherlands corporation affiliated with J & S Trading Company, Ltd., an international petroleum trading and marketing company. Pursuant to a shareholders agreement, we identify and assist with LNG-related business opportunities that we determine are appropriate for J&S Cheniere. We are not required to offer any particular business opportunities nor funding to J&S Cheniere. All financing of these business opportunities will be provided by J&S Holding should it determine that a business opportunity is appropriate for J&S Cheniere. However, J&S Holding is not required to fund any particular business opportunity. The shareholders agreement gives us the right to purchase additional shares up to a maximum of 50% of the outstanding shares of J&S Cheniere. The shareholders agreement also provides J&S Holding the right to acquire all of our J&S Cheniere shares in the event that we experience a change in control (defined in the stockholders agreement to include a change in a majority of our board, the acquisition of more than 40% of our outstanding common stock other than as approved by our board of directors and a merger or consolidation that results in 50% or less of the surviving entity’s voting securities being owned by the holders of our voting securities immediately prior to such transaction).

As its initial LNG business opportunity, in August 2003, J&S Cheniere chartered its first LNG tanker, the 130,000 cm-capacity Tenaga Empat. In January 2004, J&S Cheniere signed a transportation agreement with Sonatrach, the national oil company of Algeria, for the Tenaga Empat to actively transport LNG cargoes into the United States and Europe. Since the agreement terminated in July 2004, the vessel has been operating on a spot charter basis.

In August 2004, J&S Cheniere executed a time charter for its second LNG tanker for up to 10 years with Kawasaki Kisen Kaisha, Ltd., or K-Line, to charter a new build, 145,000 cm-capacity LNG tanker being constructed by Kawasaki Shipbuilding Corporation. The tanker is expected to be delivered in the fourth quarter of 2007.

In August 2004, J&S Cheniere also executed a time charter agreement for up to 10 years for its third LNG tanker with a joint venture company established by K-Line, Shoei Kisen Kaisha, Ltd.

and others. The new build 154,200 cm-capacity LNG tanker is being constructed by Imabari Shipbuilding Co., Ltd. and is expected to be delivered in the fourth quarter of 2007.

J&S Cheniere entered into an agreement with us in December 2003 under which J&S Cheniere has an option to enter into a TUA reserving up to 200 MMcf/d of capacity at each of our Sabine Pass and Corpus Christi facilities. Following execution of the option agreement, an option fee of $1 million was paid to us by J&S Cheniere in January 2004. The option agreement may be terminated by J&S Cheniere and the option fee refunded in the event that we do not receive an order by FERC authorizing construction of at least one of the two facilities (which condition was satisfied upon receiving the FERC authorization in March 2005 for Sabine Pass LNG), or if we decide not to proceed with the development of at least one of the two facilities, in either case, before December 15, 2005. J&S Cheniere may exercise the option as to each facility by entering into a TUA no later than 60 days after receipt of written notification by us that such facility has been approved by FERC and all other approvals and permits have been received which are necessary to begin construction of the facility. The option agreement provides that any such TUA will provide for: (i) a fee per MMbtu delivered equal to 8% of the then current price of natural gas at Henry Hub (instead of a capacity reservation fee payable whether or not it uses the terminal); (ii) an initial five-year term, with up to three additional five-year renewal periods upon payment of a $1 million fee for each renewal; and (iii) a minimum of two LNG vessel deliveries per month at the facility. The terms of the TUA contemplated by the J&S Cheniere option agreement have not been negotiated or finalized. We anticipate that definitive arrangements with J&S Cheniere may involve different terms and transaction structures than were contemplated when the option agreement was entered into in December 2003.

Other energy business initiatives

As part of our overall energy business strategy, we are pursuing initiatives that could complement the development of our LNG receiving terminal business. These initiatives include pursuing downstream opportunities such as natural gas pipelines, storage, marketing and trading. In addition, these initiatives include pursuing upstream opportunities such as investment in LNG shipping businesses, securing foreign LNG supply arrangements, development of foreign natural gas reserves that could be converted into LNG, and oil and gas exploration, development, production, transportation and processing activities generally.

Competition

The volume of natural gas supply additions required to meet U.S. consumption needs is a function not only of demand growth, but also the decline in the underlying production base. In North America, this natural decline has been accelerating over the last decade, significantly increasing the need to bring on new supplies. According to a 2003 report by The National Petroleum Council, the natural gas production from existing wells in the U.S. in 1991 declined 17%, or 9.0 Bcf/d, by 1992, while natural gas production from existing wells in 2000 declined 27%, or 16.0 Bcf/d, by 2001.

New supplies to replace North America’s natural decline of natural gas production 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 natural gas could be met by alternative energy forms, including coal, hydroelectric, oil, wind, solar and nuclear energy. LNG will face competition from each of these energy sources.

We compete with other companies to be among the first to construct LNG receiving terminals in economically desirable locations. There are currently over 35 LNG receiving terminals actively proposed to be constructed in the U.S., although we anticipate that only eight will be constructed by 2010. In addition, other companies are pursuing offshore terminals and shipboard regasification facilities to import LNG into U.S. markets.

EIA has reported that, as of December 31, 2003, there were over 6,000 Tcf of proved natural gas reserves worldwide, and we believe that LNG has the potential to be a significant new source of lower cost supply to North America. We will compete with other importers of LNG at existing and proposed North American LNG receiving terminals. There are currently four LNG receiving terminals operating in North America, which will compete with any terminals that we develop. We believe that all of the capacity at these four existing United States terminals is committed to customers under long-term arrangements. There are currently 44 LNG receiving terminals in 12 countries, and we will compete with these and other proposed LNG receiving terminals worldwide to be the most economical delivery point for LNG production for both long-term contracted and spot volumes.

Oil and gas exploration and development

For a discussion about our oil and gas exploration and development business, please see our Annual Report on Form 10-K for the fiscal year ended December 31, 2004, which is incorporated by reference into this Form 8-K.

Governmental regulation

Our LNG operations are subject to extensive regulation under federal, state and local statutes, rules, regulations and other laws. Among other matters, these laws require the acquisition of certain consultations, permits and other authorizations before commencement of construction and operation of our 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, construct and operate our proposed LNG receiving terminals, we must receive and maintain authorization from FERC under Section 3 of the Natural Gas Act of 1938, or NGA. The FERC permitting process includes:

- public notice;
- data gathering and analysis at FERC's request;

- issuance of a DEIS by FERC;
- public meetings;
- issuance of a FEIS by FERC; and
- FERC order authorizing construction.

In addition, an order from FERC authorizing construction of an LNG receiving terminal will likely be subject to specified conditions that must be satisfied prior to commencement of construction.

Freeport LNG

FERC granted Freeport LNG authorization under Section 3 of the NGA to site, construct and operate an LNG receiving terminal and to construct a 9.4 mile pipeline, together with related facilities, in Brazoria County, Texas. NGA Section 3 authorization was required because the Freeport LNG facility will be used to import natural gas from a foreign country. The Freeport LNG send-out pipeline will not interconnect with any interstate natural gas pipelines and will not be used to provide interstate transportation service under the NGA. Therefore, the proposed Freeport LNG 9.4 mile pipeline will be subject to FERC’s more limited NGA Section 3 jurisdiction rather than the more extensive FERC regulation under Section 7 of the NGA related to facilities used to transport natural gas in interstate commerce.

Sabine Pass LNG/Corpus Christi LNG/Creole Trail LNG

The construction and operation of our proposed Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals will also be subject to FERC’s regulation under Section 3 of the NGA. However, unlike our Freeport LNG project, the Sabine Pass, Corpus Christi and Creole Trail projects include interstate natural gas pipelines which will connect these proposed LNG facilities to the interstate natural gas pipeline grid. To the extent that we construct and operate interstate natural gas pipeline facilities, we must obtain authorization pursuant to Section 7 of the NGA to construct and operate these pipeline facilities and will be subject to FERC’s regulation under NGA Section 7, including open access and tariff requirements. FERC’s exercise of jurisdiction over interstate gas pipelines pursuant to NGA Section 7 is substantially broader than its exercise of jurisdiction over LNG terminals under NGA Section 3 and would continue as long as these pipelines are operated in interstate commerce.

Other federal governmental permits, approvals and consultations

In addition to FERC authorization under Section 3 of the NGA, our construction and operation of LNG receiving terminals is 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.

Environmental matters

Our LNG 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 authorizations before we may conduct certain activities or may require us to limit certain activities in order to protect endangered or threatened species or sensitive areas. These environmental laws may impose substantial penalties for noncompliance and substantial liabilities for pollution. As with the industry generally, compliance with these laws increases our overall cost of business. While these laws affect our capital expenditures and earnings, we believe that these regulations do not affect our competitive position in the industry because our competitors are similarly affected by these laws. Environmental regulations have historically been subject to frequent change. Consequently, we are unable to predict the future costs or other future impacts of environmental regulations on our future operations. Environmental laws that may affect our operations include:

CERCLA

The federal Comprehensive Environmental Response, Compensation and Liability Act, or 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.

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 liquefied natural gas from its definition of “hazardous substances,” this exemption may be limited or modified by the United States Congress in the future.

Clean Air Act

Our operations are subject to the federal Clean Air Act, or CAA, and comparable state and local laws. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The Environmental Protection Agency, or EPA, and states have been developing regulations to implement these requirements. We may be required to incur certain capital expenditures in 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.

Certain persons have expressed concerns that air emissions from our Sabine Pass LNG project located in Cameron Parish, Louisiana, which are allowed under our existing permits, will adversely impact regional air quality in southeastern Texas so as to trigger future federal sanctions for that area under the Clean Air Act. While we have no reason to believe that any formal challenge will be made regarding our existing permits under the Clean Air Act, there can be no assurance that challenges will not be pursued or that, if pursued, they would not result in costs or conditions that could have a material adverse effect on our business and operations.

Clean Water Act

Our operations are also subject to the federal Clean Water Act, or CWA, and analogous state and local laws. Pursuant to certain requirements of the CWA, the EPA has adopted regulations concerning discharges of 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. In addition, our operations, including construction of LNG receiving terminals, in areas deemed to be wetlands, or which otherwise involve discharges of dredged or fill material into navigable waters of the United States, may be subject to Army Corps of Engineers permitting requirements.

Hazardous waste

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes govern the disposal of “hazardous wastes.” In the event any hazardous wastes are generated in connection with our LNG operations, we may be subject to regulatory requirements affecting the handling, transportation, storage and disposal of such wastes.

Endangered species

Our operations may be restricted by requirements under the Environmental Species Act, or ESA, 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.

Litigation

We have been a party to various legal proceedings, which are incidental to the ordinary course of business, and may in the future be included in litigation in the ordinary course of business. Our management regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. There are presently no threatened or pending legal matters that we believe would have a material impact on our consolidated results of operations, financial position or cash flows.

We received a letter dated December 17, 2004 advising us of a nonpublic, informal inquiry being conducted by the SEC and captioned “In the Matter of Trading in the Securities of Cheniere Energy, Inc.” The SEC requested a chronology, documents and other information, including the names of persons and entities involved in or aware of events leading up to our press releases and related Form 8-K filings in November and December 2004, regarding our negotiations and agreements with Chevron USA and our public offering of 5 million shares of common stock. We are cooperating fully with this SEC informal inquiry.

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 incurred losses, and we will likely continue to incur operating losses and experience negative operating cash flow during the next several years. We have not yet started the construction of two of our planned LNG receiving terminals. We do not anticipate that our LNG receiving operations will generate positive operating cash flow until at least one of our planned facilities is built, which we expect will not be until 2008 at the earliest. Although we may commence operations, revenues under any particular TUA may not commence for up to one year or more after operations at the related facility commence. We will continue to incur significant capital and operating expenditures while we develop our planned LNG receiving terminals. We do not anticipate that our current oil and gas exploration activities, which are limited in scope, or advance sales of regasification capacity at our planned LNG receiving terminals will generate sufficient funds to cover these expenditures. As a result, we expect to continue to have operating losses and negative operating cash flow on a quarterly and an annual basis over the next several years. Any delays beyond the expected development periods for our planned LNG receiving terminals would prolong, and could increase the level of, our operating losses and negative operating cash flow. Our future liquidity may also be affected by (i) the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and (ii) 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 LNG development projects and market their capacity, and our ability to do so is subject to a number of risks, including those discussed below.

Our ability to develop our planned LNG receiving terminals is contingent on our ability to obtain financing. 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.

We currently estimate that the cost of completing the four LNG development projects will exceed $3 billion, before financing costs. Our cost estimate is subject to change due to such items as cost overruns, change orders and charges (particularly steel). To fund these development projects, we will have to pursue a variety of sources of financing, including most, if not all, of the following:

- debt and/or equity financing at the project level;
- debt and/or equity financing by Cheniere; and
- asset sales and joint venture arrangements by Cheniere and/or our subsidiaries and partnerships.

Our ability to obtain these types of financing 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 and such markets' view at such time of our industry and prospects. 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 developer. 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. Any project-level debt financing will also typically be conditioned upon our prior receipt of commitments for a portion of projected regasification capacity under long-term TUAs, and our ability to fund the projects will likely be subject to the achievement of additional milestones in our project financing. A failure to obtain financing at any point in the development process 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;
- borrowings or debt issuances at the project level may subject the project entity to certain restrictive covenants, including covenants restricting its ability to make distributions to us;
- 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 of our common stock;
- sales of oil and gas exploration prospects would reduce potential future revenues from our exploration and production activities; and

- 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 such arrangement is entered into. If circumstances change, we may need to seek waivers of conditions or covenants under our financing arrangements, which we might not be able to obtain on a timely basis, or at all.

Risks relating to our LNG receiving terminal development business

The construction of our planned LNG receiving terminals is subject to a number of development risks, which could cause cost overruns and delays or prevent completion of one or more of our LNG development projects.

Key factors that may affect the timing of, and our ability to complete, our LNG development projects include, but are not limited to:

- the issuance and/or continued availability of necessary permits, licenses and approvals from FERC, other governmental agencies and third parties as are required to construct and operate the facilities;
- the availability of sufficient debt financing and equity financing, both on the part of Cheniere and at the project level;
- our ability to obtain satisfactory long-term TUAs with "anchor tenant" customers for a portion of the capacity at each proposed LNG receiving terminal and for these customers to perform under those TUAs during the terms thereof and to maintain their creditworthiness;
- our ability to enter into a satisfactory agreement with an EPC contractor for each facility and to maintain good relationships with these contractors, and the ability of those EPC contractors to perform their obligations under EPC agreements and to maintain their creditworthiness;
- site development difficulties, including change orders, cost overruns, construction delays and changes in commodity prices (particularly steel);
- unanticipated changes in domestic and international market demand for natural gas or the supply of LNG, which will depend, in part, on supplies of, and prices for, alternative energy sources;
- competition with other domestic and international LNG receiving terminals;
- commercial arrangements for pipelines and related equipment to transport natural gas from each LNG receiving terminal;
- local and general economic conditions;
- catastrophes, such as explosions, fires and product spills;
- resistance in the local community to the development of LNG receiving terminals;
- labor disputes; and
- weather conditions.

Delays in the construction of an LNG receiving terminal beyond the estimated development periods, as well as cost overruns, could increase the cost of completion beyond the amounts currently estimated in our capital budget, which could require us to obtain additional sources of financing to fund our operations until the LNG receiving terminal is developed (which could cause further delays). Any delay in completion of the LNG receiving terminals would also cause a delay in the receipt of revenues projected from operation of the facilities. Delays could also erode our competitive advantage of being one of the first companies to develop new LNG receiving terminals. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on our business, results of operations, financial condition and prospects.

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

The design, construction and operation of LNG receiving terminals and the transportation of LNG and natural gas are all highly regulated activities. FERC approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, is required in order to construct and operate our proposed LNG receiving terminals. Although we have obtained NGA Section 3 authorization to construct and operate the Freeport and Sabine Pass LNG receiving terminals, we have not yet received an NGA Section 3 FERC order authorizing construction of either our Corpus Christi or Creole Trail projects. 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. 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 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.

We face competition in the LNG receiving terminal development business from competitors with far greater resources and the potential for overcapacity in the LNG receiving terminal marketplace.

Many companies are considering the development of infrastructure in the domestic LNG market, including, without limitation, major oil and gas companies such as ExxonMobil, ConocoPhillips, Royal Dutch/Shell and ChevronTexaco. Other energy companies such as Sempra, Tractebel, McMoRan Exploration, AES, Excelerate Energy and other public and private companies have also proposed LNG receiving facilities, both onshore and offshore. Almost all of our competitors have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we do. The superior resources that these competitors have available to deploy could allow them to surpass us in terms of the status of their LNG receiving terminal development projects. Among other things, these competitors may not have to rely on external financing to the same extent we do, if at all. Industry analysts have predicted that if all of the proposed LNG receiving terminals in North America that have been announced by developers were actually built, there would likely be substantial excess capacity for such terminals in the future. Accordingly, there is a substantial risk that slower-paced LNG receiving terminal development projects may never be completed. Any perception in the LNG receiving terminal marketplace that we may be unable to complete our proposed LNG receiving terminals, because competing projects are further along in their development or otherwise, could have a material adverse effect on our business, results of operations, financial condition and prospects.

In addition, our proposed LNG receiving terminals will likely continue to face competition when and if they are completed, including competition from North American sources of natural gas and onshore, offshore and shipboard LNG regasification facilities. If the number of LNG receiving terminals built outstrips demand for natural gas from those terminals, the excess capacity will likely lead to a decrease in the prices that we will be able to obtain for uncommitted amounts of our regasification services. Because of the substantial likelihood that we will have significant debt service obligations, any such price decreases would impact us more severely than our competitors with greater financial resources. Accordingly, potential overcapacity in the LNG receiving terminal marketplace could have a material adverse effect on our business, results of operations, financial condition and prospects.

Cyclical changes in the demand for LNG regasification capacity may result in reduced operating revenues and may cause operating losses in the future.

The economics of LNG terminal 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, whether through LNG receiving terminal construction or expansion, take several years to become operational and are therefore necessarily based upon estimates of future demand for natural gas;
- when demand for natural gas increases, competition to build new LNG regasification capacity may heighten because new capacity may be more profitable, with a lower marginal cost of production;
- when LNG regasification capacity significantly increases, the competition for the receipt and regasification of LNG increases;
- under-supplies of LNG also increase competition among LNG terminals and may cause LNG receiving terminal operators to compete aggressively on price in order to maximize capacity utilization;
- when demand for LNG receiving capacity decreases, the high fixed cost structure of capital-intensive LNG receiving terminals causes producers and transporters of natural gas to compete aggressively on price in order to maximize capacity utilization;
- substantial increases in the receiving capacity of LNG receiving terminals will substantially increase the potential supply of natural gas to U.S. markets, which could substantially amplify the downswings related to the over-supply of available natural gas;
- supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy cause changes in the demand for natural gas;
- as competition in natural gas is focused on price, being a low-cost supplier is critical to profitability. This would favor the construction of larger LNG receiving facilities, which maximize economies of scale, but also could cause an increase in capacity that can outstrip the existing growth in demand for natural gas;
- cyclical trends in general business and economic conditions cause changes in the demand for natural gas.

The increases and decreases in the available supply of natural gas as a result of changes in available LNG receiving capacity available could materially adversely affect our business, results of operations, financial condition and prospects.

Failure of imported LNG to become a competitive source of energy in the United States could have a detrimental effect on our ability to implement and complete our business plan.

In the United States, due mainly to an abundant supply of natural gas, imported LNG has not historically been a major energy source. Our business plan is based on the belief that LNG can be produced and delivered to the United States 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 would further increase the available supply of natural gas at a lower cost than LNG. In addition to natural gas, LNG also competes with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy. As a result, LNG may not become a competitive source of energy in the United States. The failure of LNG to become a competitive supply alternative to domestic natural gas, oil and other import alternatives could have a material adverse effect on our business, results of operations, financial condition and prospects.

The inability to import LNG into the United States due to, among other things, governmental regulation or potential instability in countries that supply natural gas, could materially adversely affect our business plans and results of operations.

Upon completion of the LNG receiving terminals, our business will be dependent upon the ability of our customers to import LNG 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 in such countries to export LNG to the United States. Such foreign suppliers 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. In addition, we believe that the existing fleet of tankers that is available to transport LNG is inadequate, and the failure to expand LNG tanker capacity would impede our customers’ ability to import LNG into the United States. Any significant impediment to the ability to import LNG into the United States could have a material adverse affect on our business, results of operations, financial condition and prospects.

Decreases in the price of natural gas in North America could be harmful to our ability to develop our proposed LNG receiving terminals.

The development of domestic LNG receiving terminals is based on assumptions about the future price of natural gas and the availability of imported LNG. 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 forecasted to be, lower than the cost to produce and deliver LNG to North American 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, any significant decline in the price of natural gas could have a material adverse effect on our business, results of operations, financial condition and prospects.

Natural gas prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to any 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 as compared with other energy sources; and
- the effect of federal and state regulation on the production, transportation and sale of natural gas.

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 covering a significant portion of the regasification capacity at each of 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 long-term TUAs covering approximately one-half of regasification capacity in advance of the commencement of construction. In addition, we anticipate that we will be able to rely on these capacity reservation fee payments to cover a portion of operating costs prior to commencement of operations at our proposed LNG receiving terminals. As of the date of this Form 8-K, we do not have any TUAs in place for either our proposed Corpus Christi facility or our proposed Creole Trail facility.

We may experience difficulty attracting additional customers because we are a small, developing company with no operating history in the LNG receiving terminal business. In order to succeed, we must convince additional potential customers, among other things, that the terminal sites that we are developing will be approved by appropriate governmental agencies and that we will be able to secure adequate financing for their construction. Additional factors that may cause us to change this business strategy include the inability to enter into TUAs prior to construction, our view regarding future prices, demand and supply of natural gas and regasification capacity, or other factors. 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.

Freeport LNG has entered into long-term TUAs with Dow and ConocoPhillips, and Sabine Pass LNG has entered into long-term TUAs with subsidiaries of Total S.A. and ChevronTexaco. Each of the TUAs contains various termination rights. For example, Dow may terminate its TUA during the construction period of the proposed Freeport LNG terminal if it reasonably determines that “substantial completion” of the terminal will not occur prior to a future confidential date. Similarly, ConocoPhillips may terminate its TUA during the construction period of the proposed Freeport LNG terminal if it reasonably determines that the “conversion date” (the date of conversion of construction loans into term loans under the credit facility between Freeport LNG and ConocoPhillips) will not occur prior to a future confidential date. Total has the right to terminate its TUA under an omnibus agreement if specified conditions are not satisfied by

June 30, 2005, including evidence of Bechtel's acceptance of the NTP. Total may also terminate its TUA with Sabine Pass LNG if Sabine Pass LNG fails to deliver a specified amount of natural gas nominations or fails to receive or unload a specified number of cargoes. In addition, in the case of each of our TUAs, we are dependent on the respective counterparties' creditworthiness and their continued willingness to perform their obligations under the TUAs. If any of these counterparties fail to perform its obligations under its respective TUA, our business, results of operations, financial condition and prospects could be materially adversely affected, even if we were to be ultimately successful in seeking damages from that counterparty for a breach of the TUA.

The construction of our proposed LNG receiving terminals will be dependent on performance by, and our relationship with, the EPC contractor that we engage at each facility.

Sabine Pass LNG entered into an EPC agreement in December 2004 with Bechtel. Freeport LNG has advised us that it has entered into a lump-sum turnkey agreement for the construction of its Freeport LNG receiving terminal. We also plan to enter into similar types of contracts with a major international EPC contractor for the construction of our proposed Corpus Christi and Creole Trail LNG receiving terminals. The success of our LNG receiving terminal development projects is highly dependent on our ability to enter into acceptable contracts with reputable EPC contractors and for the EPC contractors to perform their obligations under the contracts, including completing the projects on a timely basis. However, we may not be able to enter into an acceptable EPC contract for the construction of our proposed Corpus Christi or Creole Trail LNG receiving terminal. In addition, we have no prior experience working with any EPC contractor, including Bechtel. As a result, we may encounter unexpected delays or problems in connection with the construction of any of our proposed LNG receiving terminals. In addition, any EPC agreement could be terminated under certain circumstances prior to completion of construction. For example, see the description of the termination provisions of the EPC agreement with Bechtel as described above. If our relationship with any initial EPC contractor fails for any reason, we would be forced to engage a substitute contractor, which would likely result in a significant delay in our development schedule and could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our initiatives to pursue upstream and downstream 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 pipelines and storage, marketing and trading. Similarly, we 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, and 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. We may not be successful in our efforts to pursue any or all of these initiatives. We may also pursue other upstream or downstream opportunities. 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.

If completed, the actual construction cost of our proposed LNG receiving terminals may be significantly higher than our current estimates, which are before financing costs. The cost of constructing these facilities will be dependent on several items, including change orders, cost overruns and commodity prices (particularly steel).

We do not have any prior experience in constructing LNG receiving terminals, and no LNG receiving terminal has been constructed in the United States in over 25 years. As construction progresses, we may decide or be forced to submit change orders to our EPC contractors that could result in longer construction periods and higher construction costs. Similarly, we may encounter significant cost overruns during some phases of the construction process. In addition, under any agreement with an EPC contractor, we expect to retain the commodity price risk for nickel and various types of steel used in the construction process. As a result, any significant change orders, cost overruns or increases in the commodity price of nickel or steel could have a material adverse effect on our business, results of operations, financial condition and prospects.

Risks relating to our business in general

We are currently a small, developing company with no operating history in the LNG receiving terminal business. Our business model is contingent on our ability to manage successfully our anticipated expansion and transition to operating in that business.

As of March 18, 2005, we had 65 employees, who, for the most part, are focused on the pre-construction stages of the development of our proposed LNG receiving terminals. As we begin construction of the LNG receiving terminals, we will have to hire new onsite employees to manage the construction of each facility. Once our proposed LNG receiving terminals commence operations, we will have to hire an entire staff to operate each facility. We have no experience in the construction or operation of LNG receiving terminals, and, as a result, we will be forced to rely to a significant extent on the new employees we hire to perform these functions. We currently estimate that at least 60 employees will be required to operate each LNG receiving terminal. 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.

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 agreements 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.

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 will be subject to the inherent risks normally 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 on our assets and the assets of third parties on which our operations are dependent.

In accordance with customary industry practices, we intend to maintain insurance against some, but not all, of these risks and losses. We may not be able to maintain adequate 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 United States governmental regulation, taxation and price controls could seriously harm us.

Our LNG terminal development and operations are subject to extensive federal, state and local laws and regulations that regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Failure to comply with such rules and regulations can result in substantial penalties and may harm us. Present, as well as future, legislation and regulations could cause additional expenditures, restrictions and delays in our business, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances.

The construction and operation of our LNG receiving terminals is subject to issuance of necessary permits, licenses, consultations and approvals from numerous federal agencies, including from FERC under Section 3 of the NGA. The costs that we incur to obtain and maintain FERC and other governmental approvals authorizing us to commence construction of our proposed LNG receiving terminals and to comply with the ongoing regulation of the operation and maintenance of such terminals could have a material adverse effect on our business, results of operations, financial condition and prospects. In addition, delay in receipt of, or modification or other regulatory action with respect to, FERC or other required governmental authorization could cause substantial delays in the commencement of construction or operations of our LNG receiving terminals, increased costs or even result in the cessation of operations. Any interstate pipeline transmission system connected to our LNG receiving terminals, as will be the case with our proposed Sabine Pass, Corpus Christi and Creole Trail terminals, is subject to FERC regulation under Section 7 of the NGA. Such regulation may restrict the ability of our customers to transport gas to and from our terminals, which could have a material adverse effect on our business, results of operations, financial condition and prospects. FERC has in the past regulated the prices at which natural gas could be sold. Federal reenactment of price controls or increased regulation of the transport of natural gas could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our LNG terminal development and operations are also subject to extensive federal, state and local laws and regulations governing the discharge of natural gas, hazardous substances, materials and other compounds into the environment or otherwise relating to environmental protection. These laws and regulations may restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and impose substantial liabilities for pollution or releases of hazardous substances, materials or compounds or impose conditions that require additional costs or charges 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 civil and criminal fines and penalties. Moreover, state and federal environmental laws and regulations may become more stringent.

Federal laws and regulations such as CERCLA, the CAA, the Oil Pollution Act of 1990 and the CWA, and analogous state laws have regularly imposed increasingly strict requirements for water and air pollution control, hazardous waste and materials management and strict financial responsibility and remedial response obligations. The cost of complying with such environmental legislation could have a material adverse effect on our business, results of operations, financial condition and prospects.

Existing environmental laws and regulations may be revised or reinterpreted or new laws and regulations may be adopted or become applicable to us. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, results of operations, financial condition and prospects.

Some of our economic value is derived from our ownership of minority interests in entities over which we exercise no day-to-day control.

We own a 30% limited partner interest in Freeport LNG, an effective 9.3% interest in Gryphon Exploration Company, or Gryphon Exploration, (after giving effect to the potential conversion of Gryphon Exploration's preferred stock) and a minority interest in J&S Cheniere. Some of our value is attributable to these investments. In this Form 8-K, we may use the words "our," "we" or "us" in describing these investments or their assets and operations; however, we do not exercise control over Freeport LNG, Gryphon Exploration or J&S Cheniere. The management team of Freeport LNG, Gryphon Exploration or J&S Cheniere could make business decisions without our consent that could impair the economic value of our investments in those entities. Any such diminution in the value of either 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 certain entities that could be counted as investment securities. We also currently hold a substantial portion of the balance of proceeds from our December 2004 equity offering in commercial paper and other liquid investments that may constitute investment securities.

We generally plan to invest our liquid assets in commercial paper or other assets that are 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. We intend to rely on a safe harbor rule allowing us to invest more than 40% of our assets in investment securities for a transition period of one year from the date that proceeds are received from any debt or equity offering, and also plan to request exemptive relief, if necessary, for such investments after the expiration of such one-year period. However, in the event the SEC declines to grant such exemptive relief, or should it determine that we are not entitled to rely on the safe harbor rule, we would likely have to invest our liquid assets, or some significant portion of them, in government securities or cash items that yield lower returns than our other proposed investments of liquid assets. Moreover, if the value of our interest in companies we do not control were to increase relative to the value of our controlled subsidiaries, we might be required to divest some of our non-controlled business interests, or take other action, in order to avoid classification as an investment company.

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

If we begin conducting operations or making investments outside of the United States, we may 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 and investments outside of the United States include risks of:

- currency fluctuations;
- war;
- expropriation or nationalization of assets;
- renegotiation or nullification of existing contracts;
- changing political conditions;
- changing laws and policies affecting trade, taxation and investment;
- overlap of 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 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 charges on our reporting for results from those operations in our financial statements.

Terrorist attacks or sustained military campaigns may adversely impact our business.

The terrorist attacks that took place in the United States on September 11, 2001 were unprecedented events that have created many economic and political uncertainties, some of which may materially adversely impact our business. The continued threat of terrorism and the impact of military and other action will likely lead to continued volatility in prices for natural gas and could affect the markets for the operations of our LNG customers on which we will be dependent. Furthermore, the United States government has issued public warnings that indicate that pipelines and other energy assets might be specific targets of terrorist organizations. The continuation of these developments may subject our operations to increased risks and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations, financial condition and prospects.

Risks relating to our oil and gas exploration and production business

We have not included any risk factors relating to our oil and gas exploration and production business in this Form 8-K. For information about the risks associated with our oil and gas exploration and production business, we refer you to the risk factors contained in our Annual Report on Form 10-K for the year ended December 31, 2004 which is incorporated by reference into this Form 8-K.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

CHENIERE ENERGY, INC.

Date: April 7, 2005

By: /s/ Zurab S. Kobiashvili

Name: Zurab S. Kobiashvili
Title: Senior Vice President and General Counsel