CHENIERE ENERGY INC
Form 10-K
March 13, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 001-16383

CHENIERE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**95-4352386**
(State or other jurisdiction of incorporation or organization)	**(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**

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

None

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

Common Stock, $ 0.003 par value	**American Stock Exchange**
(Title of Class)	**(Name of each exchange on which registered)**

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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

The aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $1,508,000,000 as of June 30, 2005.

54,742,805 shares of the registrant s Common Stock were outstanding as of February 28, 2006.

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

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CAUTIONARY STATEMENT

REGARDING FORWARD-LOOKING STATEMENTS

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

- statements that we expect to commence or complete construction of each of our proposed liquefied natural gas, or LNG, receiving terminals or our proposed pipelines, or any expansions or extensions thereof, by certain dates, or at all;
- statements that we expect to receive Draft Environmental Impact Statements, or DEIS, or Final Environmental Impact Statements, 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 or proposed pipelines by certain dates, or at all;
- statements regarding future levels of domestic or foreign natural gas production or consumption or future levels of LNG imports into North America or sales of natural gas in 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, or ability to enter into such transactions, 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 and our proposed pipelines, 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 entered into or performed substantially in the future, including any cash distributions and revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total regasification capacity that is, or may become subject to, TUAs or other contracts;
- 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 the number of pipeline interconnections, if any;
- 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 or regulatory inquiry or investigation;

- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;

- statements regarding our anticipated LNG and natural gas marketing activities; and

- any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as achieve, anticipate, believe, estimate, expect, forecast, plan, project, propose, strategy and similar

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terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this annual report.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in Risk Factors beginning on page 35 of this annual report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. These forward-looking statements are made as of the date of this annual report. Other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

ITEMS 1. AND 2. *BUSINESS AND PROPERTIES*

General

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, in the energy business generally. As used in this annual report, the terms we , us and our refer to Cheniere Energy, Inc. and its subsidiaries. We are currently engaged primarily in the business of developing and constructing, and then owning and operating, a network of three onshore LNG receiving terminals, and related natural gas pipelines, along the Gulf Coast of the United States. We are also engaged, to a limited extent, in oil and natural gas exploration and development activities in the Gulf of Mexico.

Our common stock has been publicly traded since July 3, 1996 under the name Cheniere Energy, Inc. Our common stock is traded on the American Stock Exchange under the symbol LNG. Our principal executive offices are located at 717 Texas Avenue, Suite 3100, Houston, Texas 77002, and our telephone number is (713) 659-1361. Our internet address is www.cheniere.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website (located at www.cheniere.com), where we provide a link to the SEC s website (at www.sec.gov). We make our website content available for informational purposes only. The website should not be relied upon for investment purposes nor is it incorporated by reference into this Form 10-K.

In this annual report, unless the context otherwise requires:

Bcf means billion cubic feet;

Bcf/d means billion cubic feet per day;

Bcfe means billion cubic feet of natural gas equivalent, using the ratio of six Mcf of natural gas to one barrel (or 42 United States gallons of liquid volume) of crude oil, condensate and natural gas liquids;

cm means cubic meter;

EPC means engineering, procurement and construction;

IPA means indexed purchase agreement;

LNG means liquefied natural gas;

Mcf means thousand cubic feet;

MMcf means million cubic feet;

MMcf/d means million cubic feet per day;

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MMBtu means million British thermal units;

Tcf means trillion cubic feet; and

TUA means terminal use agreement.

General Development of Our Business

We were originally incorporated in Delaware in 1996 under the name Cheniere Energy Operating Co. for the purpose of engaging in the oil and gas exploration business, initially on the Louisiana Gulf Coast. In 1996, we underwent a reorganization with a publicly-held corporation, pursuant to which we became a publicly-held corporation and changed our name to Cheniere Energy, Inc. In 1999, we began developing our LNG receiving terminal business.

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

- complete the development and construction of our three onshore U.S. Gulf Coast LNG receiving terminals with an aggregate designed regasification capacity of approximately 10 Bcf/d, subject to further expansion;
- secure an additional 2 Bcf/d of long-term arrangements under TUAs with creditworthy anchor tenants, resulting in approximately 4 Bcf/d of our total existing and future regasification capacity, thus providing for an expected stream of contracted cash flows as terminals become operational;
- secure long-term indexed purchase agreements, or IPAs, for approximately 3 Bcf/d through the purchase of LNG from foreign suppliers and the sale of revaporized natural gas into North American markets, utilizing our planned regasification capacity;
- reserve approximately 3 Bcf/d of regasification capacity for future short-term or spot market opportunities and terminal operations requirements;
- grow our LNG receiving terminal business by expanding our existing projects and potentially pursuing development of additional LNG receiving terminals on the U.S. Gulf Coast and elsewhere;
- develop natural gas pipelines and other infrastructure to transport natural gas from our LNG receiving terminals to North American markets;
- to complement our LNG receiving terminal business, develop our LNG and natural gas marketing business by entering into domestic natural gas purchase and sale transactions;
- pursue other energy business initiatives, including participating in projects that own or are developing foreign natural gas reserves that could be converted into LNG and investing in LNG shipping businesses; and

engage in additional oil and gas exploration, development, production, transportation and processing activities generally.

Within the context of this long-term strategy, our immediate focus is on our LNG receiving terminals being developed in western Cameron Parish, Louisiana on the Sabine Pass Channel and near Corpus Christi, Texas. We have allocated 2.5 Bcf/d of regasification capacity within these two terminals to our marketing affiliate (1.5 Bcf/d at Sabine Pass and 1.0 Bcf/d at Corpus Christi) to enable it to pursue approximately 200 LNG cargoes annually for its *LNG Gateway* program. In April 2006, we anticipate offering the remaining regasification capacity in Sabine Pass (500 MMcf/d) to potential TUA customers through a formal request-for-proposal process. As we see the market develop for regasification capacity, we will introduce from time to time additional capacity at our Corpus Christi LNG receiving terminal through the same request-for-proposal process.

We anticipate reserving the regasification capacity at our Creole Trail LNG receiving terminal for strategic relationships.

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We operate four business activities:

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

At this stage in our development, our operations are divided into two reporting segments in our financial statements for the years ended December 31, 2005, 2004 and 2003 as required under Statement of Financial Accounting Standards (SFAS) No. 131, *Disclosures about Segments of an Enterprise and Related Information*: LNG Receiving Terminal Development and Oil and Gas Exploration and Development.

LNG Receiving Terminal Development Business

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

LNG is a well-established, global source of natural gas for electric generation, heating and industrial applications. According to the Groupe International des Importateurs de Gaz Naturel Liquifié, or GIIGNL, as of the end of 2004, there were 69 liquefaction plants in 12 countries capable of producing 19.2 Bcf/d and 47 receiving terminals in 13 countries capable of receiving and regasifying LNG.

North America has the largest interconnected natural gas market in the world, consuming approximately 75.7 Bcf/d in 2004, according to BP Statistical Review. Currently, there are only four onshore LNG receiving terminals in North America (excluding Puerto Rico) with a combined sustainable sendout capacity of natural gas of approximately 2.8 Bcf/d, according to GIIGNL. This regasification capacity represents about 4% of total North American current natural gas consumption. By contrast, Japan imports all of its natural gas as LNG, according to BP Statistical Review.

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 Energy Information Administration 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. The need to increase US regasification capacity and LNG imports to supplement natural gas supplies has been recognized in recent years. Indicative of this, the Former Chairman of the Federal Reserve testified before Congress that North America needs 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. His successor, Ben Bernanke, said in February 2006 that building LNG terminals is one thing that we can do and we should continue to do to create a more global market for natural gas. Also in February 2006, President Bush said that we ve got to make sure that we ve got enough natural gas to meet our home heating and industrial needs. And one of the best ways to secure supply is to expand our ability to receive liquefied natural gas.

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. We also believe that global LNG supplies will be more than ample.

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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 development efforts on three, 100% owned LNG receiving terminal projects at the following locations: Sabine Pass LNG in western Cameron Parish, Louisiana on the Sabine Pass Channel; Corpus Christi LNG near Corpus Christi, Texas; and Creole Trail LNG at the mouth of the Calcasieu Channel in central Cameron Parish, Louisiana. In addition, we own a 30% interest in a fourth project, Freeport LNG, located on Quintana Island near Freeport, Texas. We retained this interest following the sale of 70% of our interest in 2003 to finance our other activities.

Our LNG Receiving Terminals

Sabine Pass LNG

Development

We are developing the Sabine Pass LNG receiving terminal in western Cameron Parish, Louisiana, on the Sabine Pass Channel. 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 initial phase, or Phase 1, of the Sabine Pass LNG receiving terminal was designed with an initial regasification capacity of 2.6 Bcf/d and three LNG storage tanks with an aggregate LNG storage capacity of 10.1 Bcfe, along with two unloading docks capable of handling 87,000 cm to 250,000 cm LNG shipping vessels. In July 2005, we made a filing with FERC seeking approval to increase the regasification capacity of the Sabine Pass LNG receiving terminal up to 4.0 Bcf/d and to add up to three additional LNG storage tanks and related facilities, which is referred to as Phase 2.

Phase 1

In March 2005, FERC issued an order authorizing Sabine Pass LNG to commence construction of Phase 1 of the Sabine Pass LNG receiving terminal. Construction began in March 2005, and we expect to commence terminal operations in 2008. In order to commence operations of Phase 1 (which is not dependent on completion of Phase 2), Sabine Pass LNG will be required to satisfy certain conditions specified by FERC.

The cost to construct Phase 1 of the Sabine Pass LNG facility is currently estimated at approximately $900 million to $950 million, before financing costs, but including the change orders discussed below. In December 2004, we entered into a lump-sum turnkey agreement with Bechtel Corporation, or Bechtel, a major international EPC contractor, which currently requires us to pay Bechtel approximately $712 million. Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel), escalation of labor costs and additional funds which may be expended to maintain our construction schedule, as described below.

In August 2005, construction at Phase 1 of our Sabine Pass LNG receiving terminal site was temporarily suspended in connection with Hurricane Katrina, as a precautionary measure. In September 2005, the terminal site was again secured and evacuated in anticipation of Hurricane Rita, the eye of which made landfall to the east of the site. No significant damage occurred to the site, equipment or materials as a result of either of these hurricanes. Construction activities were remobilized at the site and returned to pre-hurricane levels by mid-November 2005. Recent assessments from Bechtel and certain subcontractors of the hurricanes impact indicate that, due to their residual effects, the primary impediment to our overall construction plan continues to be a shortage of available skilled labor, with likely delay of the anticipated construction schedule in the absence of remedial action. As a result, we are currently in negotiations with Bechtel and certain subcontractors concerning additional activities and expenditures in order, among other things, to attract sufficient skilled labor to mitigate potential schedule delays and still provide a reasonable opportunity to attain the initial target bonus date of April 3, 2008 (the date originally anticipated for completion of construction sufficient to achieve a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours and that, if attained, would

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entitle Bechtel to a scheduled $12 million bonus). As part of these negotiations, we have agreed in principle to defer the date by which substantial completion of the entire project is required to be accomplished under the EPC contract from September 3 to December 20, 2008. In the absence of substantial completion by such date, Bechtel would be obligated to pay us certain liquidated damages as provided under the terms of the EPC contract. We expect that the above-described arrangement will not exceed $50 million, although such amount is subject to change, requires approval of the lenders under our Sabine Pass Credit Facility (as described below under Funding) and requires that a change order be agreed upon with Bechtel.

Phase 2

Phase 2 of our Sabine Pass LNG facility may be constructed in stages. It is expected that the initial stage will consist of two LNG storage tanks, additional vaporizers and related facilities to increase the total regasification capacity to 4.0 Bcf/d. This stage is estimated to cost approximately $500 million to $550 million, before financing costs. In a subsequent stage still under evaluation, we may add a sixth LNG storage tank and related facilities. We currently anticipate that Phase 2 will be constructed under a reimbursable engineering, procurement, construction and management agreement currently under negotiation with Bechtel pursuant to which Bechtel would manage, on behalf of Sabine Pass LNG, the construction activities of other contractors under agreements currently being negotiated between Sabine Pass LNG and those contractors.
Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs.

Subject to our receipt of the required regulatory governmental approvals, including FERC approval, and acceptable funding arrangements, which may include existing cash balances, proceeds from debt or equity offerings, or a combination thereof, we anticipate beginning construction of the first stage of Phase 2 during the second quarter of 2006. Assuming we achieve this schedule, we anticipate that Phase 2 operations would commence in 2009. In order to commence such operations, we will be required to satisfy certain conditions specified by FERC.

Customers

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 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. 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, for an amount up to $2.5 billion, 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 LNG receiving terminal or (ii) enacts any

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safety or security related regulation which materially increases the costs of Sabine Pass LNG in relation to the services provided or the 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 under Funding, 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 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, if 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 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. Because Total elected to proceed with the transaction and Bechtel accepted the final notice to proceed, or NTP, an additional advance capacity reservation fee payment of $10 million was paid by Total to Sabine Pass LNG in April 2005.

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. In addition, the omnibus agreement provided Total with an option to increase its reserved capacity in the event that either party provided notice of a plan to expand the Sabine Pass LNG facility. During 2005, we provided such notice to Total and its option expired.

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 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.

In December 2005, Chevron USA exercised its option under its omnibus agreement to increase its regasification capacity by 300 MMcf/d for a total of 1.0 Bcf/d and paid Sabine Pass LNG an additional $3 million advance capacity reservation fee. As a result of Chevron USA exercising its option, the TUA is being amended to reflect such increased reservation of regasification capacity. Under the TUA, before the amendment described above, Chevron USA had 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. 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. Chevron Corporation, or Chevron, will be required to guarantee Chevron USA s payment obligations under the TUA, up to a maximum of 80% of the fees payable 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 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 at the LNG receiving terminal, Chevron USA will bear a proportionate share of such taxes or increased regulatory costs equal to 28%, subject to adjustment for Chevron USA s exercise of its capacity option in December 2005.

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 under Funding, 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 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 or Sabine Pass LNG s obligations only if (i) the assignment constitutes all of such party s rights and obligations under the TUA, (ii) the assignee agrees to

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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, if 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 would be unable to unload, 37 cargoes or more scheduled for delivery by Chevron USA for a 12-month period.

The foregoing amounts are subject to adjustment in connection with the pending amendment of the TUA as a result of Chevron USA s December 2005 exercise of its capacity option.

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 exercised an option in December 2005, at the same fee, to increase its reserved capacity to 1.0 Bcf/d. As a result, a total of $20 million of advance capacity reservation fee payments were paid to Sabine Pass LNG by Chevron USA under the omnibus agreement. In addition, the omnibus agreement provided Chevron USA with an option to increase its reserved capacity in the event that either party provided notice of a plan to expand the Sabine Pass LNG facility. During 2005, we provided such notice to Chevron USA and its option expired.

Cheniere LNG Marketing

Cheniere LNG Marketing, Inc., or Cheniere Marketing, our wholly-owned subsidiary, intends to enter into a TUA with Sabine Pass LNG for 1.5 Bcf/d of regasification capacity at our Sabine Pass LNG receiving terminal, which capacity will be reduced to 600 MMcf/d in the event that both the Total TUA and the Chevron USA TUA commence prior to the completion of Phase 2 of our Sabine Pass LNG facility. See LNG and Natural Gas Marketing Business for a discussion of our regasification capacity expected to be utilized by Cheniere Marketing.

Proposed Capacity Offering

Sabine Pass LNG intends to conduct a formal request-for-proposal process with unaffiliated third parties for up to 500 MMcf/d of regasification capacity at the Sabine Pass LNG receiving terminal. This process is expected to commence in April 2006 and will be subject to prior commitment to qualified third parties. We expect the request-for-proposal period to conclude in the second quarter of 2006; however, we may not be able to obtain any TUAs on terms acceptable to us, or at all.

EPC Agreement

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC agreement with Bechtel for the construction of Phase 1 of the Sabine Pass LNG receiving terminal. Under the EPC agreement, Bechtel agreed to

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provide Sabine Pass LNG with services for the engineering, procurement and construction of the Sabine Pass LNG receiving, storage and regasification terminal. Except for certain specified third-party work specified in the EPC agreement, the work to be performed by Bechtel includes 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.

Sabine Pass LNG issued a limited notice to proceed, or LNTP, in December 2004 and a final notice to proceed, or NTP, in early April 2005, which required Bechtel to commence all other aspects of the work under the EPC agreement. Bechtel must achieve substantial completion in accordance with the requirements of the EPC agreement on or before September 3, 2008. 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, its ability to perform the work in accordance with the project schedule or its ability to perform any material obligation under the EPC agreement; and
- certain changes in law, but only where such delay adversely affects Bechtel s costs of the performance of the work, its ability to perform the work in accordance with the project schedule or its ability to perform any material obligation under the EPC agreement.

Sabine Pass LNG agreed to 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 scheduled bonus of $12 million, or a lesser amount in certain cases, if on or before April 3, 2008, Bechtel completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. Bechtel will be entitled to receive an additional bonus of $67,000 per day (up to a maximum of $6 million) for each day that commercial operation is achieved prior to April 1, 2008. As of February 28, 2006, change orders for $64.8 million had been approved, increasing the total contract price to $711.8 million. We anticipate additional change orders intended to mitigate ongoing effects of the 2005 hurricanes that would increase the contract price by an amount not expected to exceed $50 million. We expect to submit any such change orders to our lenders by May 3, 2006 for approval under the Sabine Pass Credit Facility described below under Funding .

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.

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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 days 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.

Under the EPC agreement, 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.

Bechtel has claimed events of *force majeure* arising out of three hurricanes that made landfall along the U.S. Gulf Coast in 2005. Sabine Pass LNG is currently in negotiations with Bechtel and certain subcontractors concerning additional activities and expenditures in order, among other things, to attract sufficient skilled labor to mitigate potential schedule delays and provide a reasonable opportunity for Bechtel to attain the initial target bonus date of April 3, 2008 (the date originally anticipated for completion of construction sufficient to achieve a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours and that, if attained, would entitle Bechtel to a scheduled $12 million bonus). As part of these negotiations, we have agreed in principle to defer the date by which substantial completion of the entire project is required to be accomplished under the EPC contract from September 3 to December 20, 2008. In the absence of substantial completion by such date, Bechtel would be obligated to pay us certain liquidated damages as provided under the terms of the contract. We expect that the above-described arrangement will not exceed $50 million, although such amount is subject to change, requires approval of the lenders under our Sabine Pass Credit Facility (as described below under Funding) and requires that a change order be agreed upon with Bechtel.

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 in certain circumstances 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

In February 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 Phase 1 of 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 could make an initial borrowing under the Sabine Pass Credit Facility, it was required to provide evidence that it had received equity contributions in amounts sufficient to fund $233.7 million of the project costs. As of December 31, 2005, the $233.7 million equity contributions had been funded and, as a result, we began drawing under the Sabine Pass Credit Facility in January 2006. As of February 28, 2006, $58.5 million had been drawn under the Sabine Pass Credit Facility. In addition, we made a $37.4 million subordinated loan to Sabine Pass LNG in late 2005.

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 administrative 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

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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. 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.

We are currently evaluating funding alternatives for the construction of Phase 2 of the Sabine Pass LNG facility, which may include existing cash balances, proceeds from debt or equity offerings, or a combination thereof.

Corpus Christi LNG

Development

We are also developing the Corpus Christi 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 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 other 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 LNG s 33.3% limited partner interest in exchange for two million restricted shares of Cheniere common stock, which were subsequently registered for resale.

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. The facility will have two unloading docks, which can handle 87,000 cm to 250,000 cm LNG shipping vessels. The total cost to construct this facility is currently estimated at approximately $650 million to $750 million, before financing costs. This estimate is based in part on our negotiations with a major international EPC contractor. Our cost estimate is subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs. 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. Since February 8, 2005, BPU LNG has not been required to fund any expenditures, and as the sole owner of Corpus

Christi LNG, we are now required to fund 100% of the expenditures.

In December 2005, FERC issued an order authorizing Corpus Christi LNG to commence initial construction of the Corpus Christi LNG receiving terminal, subject to satisfaction of certain conditions specified by FERC. We are negotiating and anticipate entering into an arrangement with a major international EPC contractor for the Corpus Christi LNG receiving terminal. We expect to begin site preparation and detailed engineering work in the second quarter of 2006 and to commence operations at the Corpus Christi LNG receiving terminal in early 2010.

Customers

Cheniere Marketing intends to enter into a TUA with Corpus Christi LNG for 1.0 Bcf/d of regasification capacity at that terminal. See LNG and Natural Gas Marketing Business for a discussion of our regasification capacity expected to be utilized by Cheniere Marketing.

Corpus Christi LNG intends to conduct a formal request-for-proposal process with unaffiliated third parties for up to 1.0 Bcf/d of regasification capacity at the Corpus Christi LNG receiving terminal. This process, a time for which has not been established, will be subject to prior commitment to qualified third parties. However, we may not be able to obtain any TUAs on terms acceptable to us, or at all.

Funding

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

Creole Trail LNG

Development

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

In May 2005, we filed on application with FERC to obtain an order to site, construct and operate the facility. In December 2005, FERC issued the DEIS for our Creole Trail facility, preliminarily concluding that the facility, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. Once we obtain FERC authorization, we expect to begin construction in 2007 after obtaining financing and entering into an EPC agreement. Based on this schedule, we expect to commence terminal operations in 2011.

Customers

We have not entered into any contracts for the regasification capacity at our proposed Creole Trail LNG receiving terminal. We anticipate reserving the regasification capacity at our Creole Trail LNG receiving terminal for strategic relationships. We may not be able to obtain any TUAs on terms acceptable to us, or at all. We currently intend that a portion of the regasification capacity not committed to unaffiliated third parties will be contracted to Cheniere Marketing. See LNG and Natural Gas Marketing Business for a discussion of our regasification capacity expected to be utilized by Cheniere Marketing.

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Funding

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

Other Sites

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

Other LNG Interests Freeport LNG

Development

In 2001, we initiated development of an LNG receiving facility on Quintana Island near Freeport, Texas. In 2003, we contributed to Freeport LNG Development, L.P., or Freeport LNG, all of our interest in the Freeport site and project in exchange for a 40% limited partner interest in Freeport LNG and $6.7 million of cash payments. We subsequently sold a 10% limited partner interest in Freeport LNG to an affiliate of Contango Oil & Gas Company. As a result of the sale, we own a 30% limited partner interest in Freeport LNG. As a limited partner in Freeport LNG, we must rely largely on the general partner to successfully implement Freeport LNG s business plans.

The Freeport LNG receiving terminal is being developed on land leased from Port Freeport. The initial phase of the project includes regasification capacity of 1.5 Bcf/d, one dock, two LNG storage tanks with an aggregate LNG storage capacity of 6.7 Bcfe, and a 9.4-mile, 42-inch diameter pipeline through which natural gas will be transported to a customer redelivery point at Stratton Ridge, Texas, which is a major point of interconnection with the Texas intrastate gas pipeline grid. We have been advised by Freeport LNG that it has entered into a lump-sum turnkey contract for its receiving terminal, and that the estimated cost to construct the terminal and associated facilities (before the proposed expansion discussed below) is approximately $800 million to $850 million, before financing costs. We believe that this cost estimate is subject to change due to such items as cost overruns and change orders under the EPC agreement.

In January 2005, FERC authorized Freeport LNG to commence construction of the LNG receiving terminal and natural gas pipeline. Construction began in the first quarter of 2005, and we expect that terminal operations will commence in early 2008. In order to commence operations, Freeport LNG will be required to satisfy certain conditions specified by FERC.

Freeport LNG has filed an application seeking an additional order from FERC to authorize the construction of an expansion that would increase the regasification capacity from its currently permitted 1.5 Bcf/d LNG receiving terminal to approximately 4.0 Bcf/d. In addition to increased regasification capacity, the proposed expansion includes a second dock, a third LNG storage tank and 7.5 Bcf of underground salt cavern gas storage. 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, will change as a result of any such expansion.

TUA Customers

Freeport LNG has entered into TUAs with three customers: The Dow Chemical Company, or Dow, ConocoPhillips Company, or ConocoPhillips, and MC Global Gas Corporation, or MC Global, a wholly-owned subsidiary of Mitsubishi Corporation. Under the TUAs, Freeport LNG is obligated to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at its 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.

In March 2004, Dow entered into a long-term TUA with Freeport LNG, pursuant to which Dow has reserved 195,275,000 MMBtu of annual LNG receipt capacity under the TUA, which is equivalent to approximately 500 MMcf/d of regasification capacity. The Dow TUA commences between April 2007 and March 2008 (subject to extensions), runs for an initial term of 20 years and is subject to three 10-year extensions. Dow is required to pay Freeport LNG a monthly reservation fee for this regasification capacity, which is subject to reduction under certain circumstances. 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.

In July 2004, ConocoPhillips and Freeport LNG entered into a long-term TUA, pursuant to which ConocoPhillips has reserved 390,550,000 MMBtu of annual LNG receipt capacity, which is equivalent to approximately 1.0 Bcf/d of regasification capacity. In addition, ConocoPhillips has exercised its option to reserve approximately 300 MMcf/d of regasification capacity with respect to the additional capacity resulting from the proposed expansion. The ConocoPhillips TUA commences between April 2007 and March 2008 (subject to extensions), runs for an initial term until February 2033 and is subject to six 10-year extensions. ConocoPhillips is required to pay Freeport LNG a monthly reservation fee for this regasification capacity, which is subject to reduction under certain circumstances. 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 its allocable portion of power and other operating costs.

In January 2005, Freeport LNG announced that it had executed a 17-year TUA with MC Global. Pursuant to the TUA, MC Global has reserved approximately 150 MMcf/d of regasification capacity in the Freeport LNG terminal and has an option to increase its total regasification capacity by an additional 100 MMcf/d, to a total of 250 MMcf/d.

Funding

In July 2004, Freeport LNG entered into a credit agreement with ConocoPhillips for ConocoPhillips to provide a substantial majority of the debt financing for the initial phase of the project. In December 2005, Freeport LNG announced that it had closed a $383 million private placement of notes, which will be used to fund the remaining portion of the initial phase of the project, a portion of the cost of expanding the LNG receiving terminal and the development of 7.5 Bcf of underground salt cavern gas storage. As a result of such financing being obtained, we do not anticipate that any capital calls will be made upon the limited partners of Freeport LNG in the foreseeable future.

To the extent that the funding provided by ConocoPhillips and the private placement notes 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 various funding sources. Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG s own cash flows, borrowings or other sources, and with capital contributions by the limited partners. We received capital calls, and made capital contributions, in the amount of approximately $2.1 million in 2005. No capital calls are currently outstanding, and in view of the closing of the Freeport LNG financing described above, we do not anticipate any in the foreseeable future. However, in the event of any 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 any future 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 and funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

The general partner of Freeport LNG is also 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

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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.

Competition

The volume of natural gas supply additions required to meet U.S. consumption needs is a function of not only 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 United States in 1991 declined 17%, or 9.0 Bcf/d, by 1992. In contrast, data from IHS Energy shows that natural gas production from existing wells in 2004 declined 28%, or 17 Bcf/d, by 2005.

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. According to FERC, there are currently over 40 LNG receiving terminals actively proposed to be constructed in the United States, although we anticipate that only four new terminals will be constructed in the United States by 2010. In addition, one shipboard regasification facility has commenced operations, and companies are pursuing other offshore terminals and shipboard regasification facilities to import LNG into U.S. markets.

BP Statistical Review has reported that, as of December 31, 2004, there was 6,333 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. As of December 31, 2005, there were four onshore 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 onshore United States terminals is committed to customers under long-term arrangements. As of December 31, 2005, there were 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.

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.

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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 and public meetings;
- data gathering and analysis at FERC s request;
- issuance of a Draft Environmental Impact Statement by FERC;
- public meetings;
- issuance of a Final Environmental Impact Statement by FERC; and
- FERC order authorizing construction.

In addition, orders from FERC authorizing construction of an LNG receiving terminal are typically subject to specified conditions that must be satisfied prior to commencement of construction.

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 are also subject to additional federal permits, approvals and consultations required by certain other federal agencies, including: Advisory Counsel on Historic Preservation, U.S. Army Corps of Engineers, U.S. Department of Commerce, National Marine Fisheries Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency and U.S. Department of Homeland Security.

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

Energy Policy Act of 2005

In 2005, the Energy Policy Act of 2005, or EPAct, was signed into law. The EPAct contains numerous provisions relevant to the natural gas industry and to interstate pipelines. The EPAct includes several provisions which amend the NGA. The primary provisions of interest to our proposed interstate pipelines focus on two areas: infrastructure development, and market manipulation and enforcement. Regarding infrastructure development, the EPAct states that FERC has exclusive authority to approve or deny an application for the siting, construction, expansion or operation of an LNG receiving terminal. The EPAct also provides for market-based rates for new storage facilities placed into service after August 8, 2005, even if the storage provider has market power if FERC determines that market-based rates are in the public interest and necessary to encourage the construction of the storage capacity and customers are adequately protected from the exercise of market power. Regarding market manipulation and enforcement, the EPAct amends the NGA to prohibit market manipulation. The EPAct also amends the NGA and the NGPA to increase civil and criminal penalties. FERC has initiated a rulemaking proceeding regarding market-based storage rates. In addition, FERC issued a Final Rule effective January 26, 2006 regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC s jurisdiction, to defraud, make an untrue statement or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud. This Final Rule works together with FERC s enhanced penalty authority to provide increased oversight of the natural gas marketplace.

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

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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.

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.

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.

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.

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.

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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.

Natural Gas Pipeline Development Business

We formed Cheniere Pipeline Company, a wholly-owned subsidiary, to develop natural gas pipelines that will provide optimal access to North American natural gas markets for customers of our Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals. Development efforts to date have focused primarily on advancing our pipeline projects through the regulatory review and authorization process. As these development efforts have progressed, our focus has expanded to also include the construction and operation of our proposed natural gas pipelines. Our pipeline systems will connect with multiple pipelines that provide a means of delivering revaporized natural gas from our LNG receiving terminals to various North American natural gas markets. Our ultimate decisions regarding pipeline connections to our facilities will depend upon future events, including, in particular, customer preferences and general market demand for natural gas from a particular LNG receiving terminal.

Our Proposed Pipelines

Sabine Pass Pipeline

We formed Cheniere Sabine Pass Pipeline Company, a wholly-owned subsidiary of Cheniere, to develop, construct, own and operate the natural gas pipeline servicing our Sabine Pass LNG receiving terminal. FERC issued an order in December 2004 authorizing construction, subject to specified conditions that must be satisfied, of our proposed 16-mile, 42-inch diameter natural gas pipeline connection to our Sabine Pass LNG receiving terminal. This interstate pipeline is designed to transport 2.6 Bcf/d of regasified LNG from the site of our Sabine Pass LNG facility, running easterly along a corridor that will allow for interconnection points with existing interstate and intrastate natural gas pipelines in southwest Louisiana, including pipelines operated by Natural Gas Pipeline Company of America, Transcontinental Gas Pipeline Corporation, Tennessee Gas Pipeline Company, Florida Gas Transmission and Bridgeline Holdings, L.P. We believe that these existing pipelines are currently capable of transporting approximately 3.8 Bcf/d.

Preliminary engineering, survey and easement acquisition is in progress. Subject to FERC approval of the implementation plan for construction of our Sabine Pass pipeline, we anticipate beginning construction in early 2007. We anticipate commencing operations of the pipeline in the fourth quarter of 2007.

We estimate that the total cost to construct the Sabine Pass pipeline, including certain work not included in the EPC pipeline contract, such as interconnection with third-party pipelines, will be approximately $90 million. Our total cost estimate is preliminary and subject to change due to such items as cost overruns, change orders, changes in commodity prices (particularly steel) and escalating labor costs.

EPC Pipeline Contract

On February 21, 2006, Cheniere Sabine Pass Pipeline Company entered into an EPC pipeline contract with Willbros Engineers, Inc., or Willbros. Under the EPC pipeline contract, which is effective as of February 1, 2006, Willbros will provide Cheniere Sabine Pass Pipeline Company with services for the management, engineering, material procurement, construction and construction management of the Sabine Pass pipeline. Cheniere Sabine Pass Pipeline Company entered into the EPC pipeline contract sufficiently in advance of commencement of physical construction of the pipeline in order to perform detailed engineering and procure materials.

The work to be performed by Willbros includes all management, engineering, procurement, construction and construction management for the Sabine Pass pipeline, including providing all equipment, materials, supplies, labor, workmanship, apparatus, machinery, tools, structures, inspection, manufacture, fabrication,

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installation, design, delivery, transportation, storage and any incidental work reasonably inferable as required and necessary to complete the Sabine Pass pipeline in accordance with applicable law, applicable codes and standards and all other provisions of the EPC pipeline contract. In addition, Willbros will provide reasonable assistance to Cheniere Sabine Pass Pipeline Company in its efforts to obtain required rights of way, access roads, pipe yards, ware yards and all other land rights or property interests necessary for construction.

The work to be performed by Willbros is based upon and must comply with the preliminary engineering developed by Cheniere Sabine Pass Pipeline Company s other consultants and contractors and the certificate issued by FERC authorizing, among other things, the construction of the Sabine Pass pipeline.

Willbros may not commence work related to ware yard preparation and material receipt earlier than January 1, 2007 and may not commence work related to the construction of the Sabine Pass pipeline earlier than April 1, 2007. Willbros must achieve mechanical completion of the Sabine Pass pipeline no later than September 30, 2007, except as adjusted by change order. At any time upon written notice, either party has the right to request change orders.

Cheniere Sabine Pass Pipeline Company will pay to Willbros a contract price not to exceed $67.7 million, subject to additions and deductions by any change order as provided in the EPC pipeline contract, excluding Louisiana sales and use taxes applicable to permanent materials and equipment to be incorporated into the Sabine Pass pipeline, which Cheniere Sabine Pass Pipeline Company is obligated to reimburse in accordance with the EPC pipeline contract.

Payments under the EPC pipeline contract will be made in accordance with the payment schedule set forth in the EPC pipeline contract.

Willbros warrants that the work and each component thereof will be:

- new, complete, fit for the purposes specified in the EPC pipeline contract and of suitable grade for the intended function and use;
- in accordance with all of the requirements of the EPC pipeline contract, including in accordance with good engineering and construction practices, applicable law and applicable codes and standards;
- free from encumbrances to title; and
- free from defects in design, material and workmanship and otherwise conform to the standards and requirements contained in the specifications and elsewhere in the EPC pipeline contract.

Except with respect to materials or equipment procured by Willbros from a third-party vendor, if within 12 months after start-up any work is found to be defective, Willbros will be obligated to immediately and on an expedited basis correct any such defective work. With respect to materials or equipment procured by Willbros from a third-party vendor, Willbros liability during the 12 months after start-up for such materials and equipment will be limited to passing through to Cheniere Sabine Pass Pipeline Company the benefits of any warranties Willbros receives from the applicable vendor.

In the event of an uncured default by Willbros, Cheniere Sabine Pass Pipeline Company may terminate for default Willbros performance of all or part of the work. In the case of termination for default, Cheniere Sabine Pass Pipeline Company may complete the work by whatever method it deems expedient, including:

- taking possession, for the purposes of completing the work, of all Willbros equipment and materials, and/or

- taking assignment of any or all subcontracts or purchase orders for the construction of the Sabine Pass pipeline.

Following such a termination, Willbros will not be entitled to receive any further payment until the work is fully completed and accepted by Cheniere Sabine Pass Pipeline Company, and Willbros will be liable to

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Cheniere Sabine Pass Pipeline Company for all costs, damages, losses and expenses (including all attorneys fees, consultant fees and litigation or arbitration expenses) incurred by Cheniere Sabine Pass Pipeline Company in completing the work, including all liquidated damages to the extent payable pursuant to the EPC pipeline contract.

Cheniere Sabine Pass Pipeline Company also has the right to terminate the EPC pipeline contract. In the event of any such termination for convenience, Willbros would be paid:

- the reasonable value of the work satisfactorily performed prior to termination (the basis of payment being based on the terms of the EPC pipeline contract, less previous payments, if any, paid to Willbros under the EPC pipeline contract), plus

- reasonable direct close-out costs, but in no event will Willbros be entitled to receive any amount for unabsorbed overhead, contingency or anticipatory profit.

Cheniere Sabine Pass Pipeline Company may at any time, whether or not for cause, suspend performance of the work, or any part thereof, by a change order specifying the work to be suspended and the effective date of such suspension. Except when such suspension ordered by Cheniere Sabine Pass Pipeline Company is the result of or due to the fault or negligence of Willbros or any subcontractor or vendor, Willbros will be entitled to the reasonable costs (including actual, but not unabsorbed, overhead, contingency, risk and reasonable profit) of such suspension incurred during the suspension period, including demobilization and remobilization costs and costs incurred for Willbros personnel and for Willbros equipment, at specified standby rates and a time extension to the preparation and material receipt commencement date, the construction commencement date or the scheduled mechanical completion date if and to the extent permitted under the EPC pipeline contract.

If the commencement, prosecution or completion of any work is delayed by a *force majeure* event, then Willbros may be entitled to an extension to the scheduled mechanical completion date. If such delay or prevention occurs for a continuous period of at least 5 days in any 30 day period, Willbros would be entitled to an adjustment of the contract price under the EPC pipeline contract to reimburse it for its standby expenses, up to a limit of $1.5 million in the aggregate. A *force majeure* event generally occurs if any act or event occurs that:

- renders impossible or impracticable the affected party s performance of its obligations under the EPC pipeline contract;

- is beyond the reasonable control of the affected party and 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.

The obligation of either party to pay money under or pursuant to the EPC pipeline contract will not be excused by reason of a *force majeure* event.

Corpus Christi Pipeline

We formed Cheniere Corpus Christi Pipeline Company, a wholly-owned subsidiary of Cheniere, to develop, construct, own and operate the natural gas pipeline servicing our Corpus Christi LNG receiving terminal. FERC issued an order in April 2005 authorizing construction, subject to specified conditions that must be satisfied, of our proposed 24-mile, 48-inch diameter natural gas pipeline. This interstate pipeline is 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 existing 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, Tennessee Gas Pipeline Company and Natural Gas Pipeline Company of America. We believe these existing pipelines are currently capable of transporting approximately 4.6 Bcf/d. Construction contracts for the Corpus Christi pipeline have not been negotiated.

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Creole Trail Pipelines

We formed Cheniere Creole Trail Pipeline Company, a wholly-owned subsidiary of Cheniere, to develop, construct, own and operate the natural gas pipelines servicing our Creole Trail LNG receiving terminal. In connection with the FERC application for our Creole Trail LNG receiving terminal, we have sought approval to construct dual 117-mile, 42-inch diameter natural gas pipelines. These interstate pipelines are 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 and terminating near Rayne, Louisiana. The Creole Trail pipelines are anticipated to be designed with potential interconnections to existing interstate and intrastate natural gas pipelines in southwestern Louisiana operated by ANR Pipeline Company, Bridgeline Holdings, L.P., Sabine Pipeline Company, Targa Louisiana Intrastate L.L.C., Gulf South Pipeline Company, L.P., Transcontinental Gas Pipeline Corporation, Trunkline Gas Pipeline Company, Texas Eastern Transmission Corporation, Tennessee Gas Pipeline, Florida Gas Transmission Company, Columbia Gulf Transmission Company and Cypress Gas Pipeline, L.L.C. We believe that these existing pipelines are currently capable of transporting approximately 12.0 Bcf/d. Construction contracts for the Creole Trail pipeline have not been negotiated.

Other Pipelines

We continue to evaluate, and may develop, additional pipelines that we believe may be commercially desirable based on customer preferences and general market demand for natural gas from a particular LNG receiving terminal.

Funding

We estimate that approximately $800 million to $1 billion of total capital expenditures will be required to construct our three proposed pipelines. We currently expect to fund the costs of our proposed pipelines from our existing cash balances, project financing, proceeds from future debt or equity offerings, or a combination thereof.

Customers

We offered our pipeline capacity to potential customers through a formal request-for-proposal process, and we awarded our marketing affiliate all of the capacity in our proposed Sabine Pass and Corpus Christi pipelines. Cheniere Marketing has entered into binding precedent agreements for transportation services on each of these pipelines at the maximum tariff rate for the transport and sale of revaporized natural gas that it derives from its own imported LNG or LNG that it purchases from other importers for sale into North American markets. See LNG and Natural Gas Marketing Business below. Transportation precedent agreements have not been executed for our Creole Trail pipelines. Cheniere Marketing s capacity rights and obligations under the transportation precedent agreements are fully assignable, and we anticipate that unaffiliated customers with whom we enter into TUAs for our LNG receiving terminals will also desire to enter into agreements for the transportation of revaporized gas on our proposed pipelines. Furthermore, we expect that other unaffiliated third-party shippers of domestic natural gas may desire transportation services in our pipelines on at least an interruptible basis.

Competition

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

Our pipelines will face competition from other intrastate and/or interstate pipelines that connect with our LNG receiving terminals. In particular, our Sabine Pass pipeline will compete with the proposed Kinder Morgan

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Louisiana Pipeline owned by Kinder Morgan Energy Partners, L.P., or Kinder Morgan. Kinder Morgan has announced that it is building a 3.2 Bcf/d take-away pipeline system from our Sabine Pass LNG receiving terminal. The Kinder Morgan Louisiana Pipeline will consist of two segments: a 137-mile, 2 Bcf/d pipeline extending to Evangeline Parish, Louisiana, and interconnecting with 11 interstate pipelines as well as a series of intrastate pipes; and a one-mile, 1.2 Bcf/d pipeline interconnecting with the Natural Gas Pipeline Co. of America system near our Sabine Pass LNG receiving terminal. Total and Chevron USA have both announced agreements with Kinder Morgan securing 100% of the initial capacity on the Kinder Morgan Louisiana Pipeline for 20 years.

Governmental Regulation

Interstate Natural Gas Pipelines

Under the NGA, FERC regulates the transportation of natural gas in interstate commerce. Under FERC s regulations, transportation service includes natural gas storage service. In general, FERC s authority to regulate pipelines and the services they provide includes:

- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

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

The natural gas industry historically has been heavily regulated. FERC regulates the transportation rates and terms and conditions of service of interstate natural gas pipelines. See Rates below. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, FERC may not continue this approach.

Our Sabine Pass, Corpus Christi and Creole Trail pipelines will be interstate natural gas pipelines, which will connect our LNG facilities directly to the interstate natural gas pipeline grid. To the extent that we construct and operate interstate natural gas pipelines, we must obtain authorization pursuant to Section 7 of the NGA to construct and operate these pipeline facilities and the rates that we charge will be subject to FERC s regulation under NGA Section 4 as well as to FERC s open access and tariff requirements. FERC s exercise of jurisdiction over interstate gas pipelines is substantially broader than its exercise of jurisdiction over LNG terminals and would continue as long as these pipelines are operated in interstate commerce.

Pipeline Safety

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

The Pipeline Safety Improvement Act of 2002, or PSIA, which is administered by the U.S. Department of Transportation Office of Pipeline Safety, or OPS, governs the areas of testing, education, training and communication. The PSIA requires pipeline companies to perform integrity tests on natural gas transmission

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pipelines that exist in high population density areas designated as high consequence areas. Pipeline companies are required to perform the integrity tests on a seven year cycle. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. In December 2003, the Department of Transportation issued a Final Rule that became effective January 14, 2004, requiring pipeline operators to develop integrity management programs for gas transportation pipelines. The Final Rule requires pipeline operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline, as necessary; and implement preventive and mitigation actions. This rule incorporates the requirements of the PSIA.

Energy Policy Act of 2005

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

Rates

Under the NGA, rates charged for the interstate transportation of natural gas must be just and reasonable and non-discriminatory. Amounts collected by the pipeline in excess of just and reasonable rates are subject to refund with interest. Beginning in the mid-1980s, FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) requiring open-access, nondiscriminatory transportation of natural gas;

- Order No. 497 (1988), which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction; and

- Order No. 636 (1992), which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to unbundle or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies whether purchased from the pipeline or from other merchants such as marketers or producers. Order No. 636 also permitted pipeline customers to release all or part of their firm transportation capacity to third parties. Order 636 has been affirmed in all material respects upon judicial review.

- Order No. 637 (2000) which, among other things, required pipelines to implement imbalance management services; restricted the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and implemented new pipeline reporting requirements.

On November 25, 2003, FERC issued a series of orders adopting revised Standards of Conduct (Order No. 2004) that apply uniformly to interstate natural gas pipelines. In light of the changing structure of the energy industry, these Standards of Conduct govern relationships between regulated interstate natural gas pipelines and all of their energy affiliates. These new Standards of Conduct were designed to govern relationships between the pipeline and any energy affiliate, rather than governing conduct between the pipeline and its marketing affiliate. The rule is designed to prevent interstate natural gas pipelines from giving an undue preference to any of their energy affiliates and to ensure that transmission is provided on a nondiscriminatory basis. Order No. 2004 requires interstate pipelines to operate independently from their energy affiliates, prohibits interstate pipelines from providing non-public transportation or shipper information to their energy affiliates, and prohibits interstate pipelines from favoring their energy affiliates in providing service. Our interstate natural gas pipelines will be required to comply with these Standards of Conduct.

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Environmental Matters

Our pipeline business will be subject to the same federal, state and local laws and regulations relating to the protection of the environment that are applicable to our LNG receiving terminals. See LNG Receiving Terminal Development Business Environmental Matters above.

LNG and Natural Gas Marketing Business

Our LNG and natural gas marketing business is in its early stages of development. We have formed Cheniere Marketing to utilize the portion of our planned LNG receiving terminal regasification capacity that we intend not to allocate to third parties but rather to reserve for use by Cheniere Marketing. Cheniere Marketing anticipates entering into IPAs for approximately 3.0 Bcf/d for LNG purchased from foreign suppliers and then selling revaporized natural gas into North American markets. We intend to purchase LNG from foreign suppliers, arrange the transportation of LNG to our network of LNG receiving terminals, utilize Cheniere Marketing s reserved revaporization capacity at our terminals to revaporize imported LNG, arrange the transportation of revaporized natural gas through our pipelines and other interconnected pipelines, and sell natural gas to buyers in the North American market. We also expect to enter into domestic natural gas purchase and sale transactions as part of our marketing activities.

To complement our LNG receiving terminal business, we anticipate engaging in the foregoing commercial activities, which may include the use of derivative transactions, to manage or hedge exposure to price, volume, timing, location, quality and credit risk associated with the marketing of LNG and natural gas. We are currently developing risk management policies, procedures and systems to assist us in controlling and managing our proposed marketing activities. We expect that we will need to hire additional employees in connection with the development of our marketing business.

Concurrently with making any commitments to purchase LNG as described above, we expect that Cheniere Marketing would enter into substantially corresponding agreements for the sale of the revaporized gas into the North American market. Although we are actively seeking foreign sources of LNG and domestic buyers of revaporized natural gas for such potential LNG supplies, we currently have no agreements for either, and we may not be able to obtain any such agreements on terms acceptable to us, or at all. We anticipate that credit support may be required by certain counterparties to any of the above-referenced transactions, including derivatives, which may subject us to additional funding requirements.

Customers

Sabine Pass LNG and Corpus Christi LNG

Cheniere Marketing intends to enter into a TUA with Sabine Pass LNG for 1.5 Bcf/d of regasification capacity at our Sabine Pass LNG receiving terminal, which capacity is expected to be reduced to 600 MMcf/d in the event that both the Total TUA and the Chevron USA TUA commence prior to the completion of Phase 2 of our Sabine Pass LNG facility. In addition, Cheniere Marketing intends to enter into a TUA with Corpus Christi LNG for 1.0 Bcf/d of regasification capacity at our Corpus Christi LNG receiving terminal.

Competition

Our LNG purchase efforts will compete with the following for supplies of LNG:

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

In addition, there will be competition for suitable tankers available to transport LNG to North American markets from foreign sources, which will impact our access to LNG supplies and the cost of LNG delivered to the U.S. Gulf Coast.

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Our natural gas marketing business will compete with the following for the sale of natural gas:

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

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 or 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 shareholders 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. The vessel was operated under a transportation agreement and on a spot charter basis until August 2005.

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 LNG and Corpus Christi LNG facilities. Following execution of the option agreement, an option fee of $1 million was paid to us in January 2004 by J & S Cheniere. 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.

We have recently commenced discussions to renegotiate our existing arrangements with, and to increase our ownership interest to as much as 49% in, J & S Cheniere. The related investment is expected to be approximately $25 million.

Governmental Regulation

The prices at which we will sell natural gas are not regulated, insofar as the interstate market is concerned and, for the most part, are not subject to state regulation. Our sales of natural gas will be affected by the availability, terms and cost of pipeline transportation. As noted above, under Natural Gas Pipeline Development Business Governmental Regulation, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas transmission These initiatives may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes to our proposed natural gas marketing operations. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we anticipate competing.

Oil and Gas Exploration and Development Business

Although our focus is primarily on development of LNG-related businesses, we continue to be involved to a limited extent in oil and gas exploration, development and exploitation, and in exploitation of our existing 3D seismic database through prospect generation. We have historically focused on evaluating and generating drilling prospects using a regional and integrated approach with a large seismic database as a platform. We expect that our oil and gas exploration activities will continue in the Gulf of Mexico, through active interpretation of our seismic data and generation of prospects, through participation in the drilling of wells, and through farm-out arrangements and back-in interests (a reversionary interest in oil and gas leases reserved by us) whereby the capital costs of such activities are borne primarily by industry partners. Cheniere will, from time to time, invest in drilling a share of these prospects. Our current oil and gas exploration and development activities are focused on two areas:

- the Cameron Project, which covers an area of approximately 230 square miles extending roughly three to five miles on either side of the westernmost 28 miles of Louisiana coastline; and

- the Offshore Texas Project Area, which covers approximately 6,800 square miles in the shallow waters offshore Texas and the West Cameron Area of offshore Louisiana.

Our officers and technical staff have extensive experience both onshore and offshore in the Gulf Coast and believe that we are well-positioned to evaluate, explore and develop properties in these areas. From time to time, we may pursue opportunities in other geographic locations as well.

Cameron Project Seismic Exploration Program

We were formed in 1996 to fund the acquisition of a proprietary seismic database along the transition zone (the area approximately three to five miles on either side of the Gulf of Mexico shore line) in Cameron Parish,

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Louisiana. Under the terms of an exploration agreement with an industry partner, we paid for certain seismic costs in the amount of approximately $16.5 million and acquired a 50% ownership interest in the seismic data covering the Cameron project, among other interests that have subsequently expired or terminated. After the termination of the exploration agreement, we purchased our partner s 50% interest in the seismic data for $500,000 and sold all of the seismic data to a seismic marketing company for $3.3 million. We now retain a license to all of the seismic data for use in our exploration program. We are also entitled to receive at no additional cost any subsequent reprocessing of the data, which may be performed by the seismic marketing company.

In 1999, we licensed 8,800 square miles of seismic data from Fairfield Industries covering a portion of the Offshore Louisiana Area, and made a commitment to fund the reprocessing of the entire 8,800-square-mile seismic database. In 2000, we entered into an agreement with Warburg, Pincus Equity Partners, L.P., a global private equity fund based in New York, to fund exploration and development in the Offshore Louisiana Area through a then newly formed private corporation, Gryphon Exploration Company, or Gryphon. In September 2005, Gryphon was sold, which resulted in net proceeds to us of $20.2 million.

Seismic Exploration Program in Offshore Texas Project Area

In 2000, we acquired two licenses to an aggregate of approximately 1,900 square miles of seismic data from Seitel Data Ltd., a division of Seitel Inc. In October 2000, we exercised our option to expand the agreement with Seitel Data Ltd. to cover an additional 1,900 square miles of seismic data. Together, the licenses acquired from Seitel represent coverage of over 433 Outer Continental Shelf blocks in the shallow waters offshore Texas and Louisiana in the Gulf of Mexico. In 2001, we sold to Gryphon for $3.5 million one of our two licenses to the Seitel 3D seismic data. We retain one license to the Seitel 3D seismic data.

In 2000, we also negotiated a Master Data Users Agreement with a Houston-based firm, Jebco Seismic L.P., to acquire 3,000 square miles (333 blocks) of seismic data in both state and federal waters offshore Texas, bringing our total data set in the shallow waters offshore Texas and Louisiana to approximately 6,800 square miles of seismic coverage. As of December 31, 2003, we had received reprocessed data for the 3,000 square miles of seismic data in the Jebco data set and the 3,800 square miles of seismic data in the Seitel data set, representing all of the reprocessing to be done in the Offshore Texas Project Area. In 2001, we sold to Gryphon for $3.5 million one of our two licenses to the Jebco 3D seismic data covering an additional 3,000 square miles. We retain one license to the Jebco 3D seismic data.

Our exploration team generated and captured 24 prospects during 2003, 2004 and 2005 and sold interests in 23 of the prospects to industry partners, retaining various overriding royalty interests and working interests ranging from an overriding royalty interest (a share of the hydrocarbons produced from an oil and gas property, free of the expense of production) of 3.358% up to 5.0% to a carried working interest (an agreement whereby we retain an interest in a well but bear none or only a portion of the cost of drilling the initial well) of approximately up to 24% and a cost-bearing working interest of up to 25%. Fourteen of the prospects sold during 2003, 2004 and 2005 have been drilled by our industry partners, and we expect that several of the remaining prospects sold during that period will be drilled by our industry partners during 2006. However, we do not serve as operator of any of these prospects, and our partners in the prospects are not contractually obligated to drill them.

Drilling Activities

During 2003 and 2004, we did not participate directly in the drilling of any wells; in 2005, we participated directly in the drilling of two wells. Our industry partners drilled nine wells, two wells and three wells in 2003, 2004 and 2005, respectively, on prospects that we generated. During 2003, seven of the nine wells were productive; during 2004, both wells were productive; and during 2005, one well was productive. At

December 31, 2005, we had a 20% working interest in one well and overriding royalty interests (ranging from 0.63% to 5.0%) in nine other productive wells.

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Production and Sales

The following table presents certain information with respect to our oil and natural gas production, average sales prices received and average production costs during 2003, 2004 and 2005. In April 2002, we sold our interests in the Redfish and Stingray wells on West Cameron Block 49, representing all of our directly-owned producing properties at the time.

	Year Ended December 31,		
	2005	2004	2003
Production:			
Oil (Bbl)	2,167	1,362	17
Gas (Mcf)	396,284	328,677	123,392
Gas equivalents (Mcfe)	409,286	336,849	123,494
Average sales prices:			
Oil (per Bbl)	$ 48.64	$ 36.69	$ 20.66
Gas (per Mcf)	$ 7.32	$ 5.93	$ 5.33
Selected data per Mcfe:			
Average sales price	$ 7.34	$ 5.93	$ 5.32
Production costs(1)	$ 0.58	$ 0.35	$
Oil and gas depreciation, depletion and amortization excluding impairments	$ 5.90	$ 2.48	$ 0.98

(1) No production costs were recorded in 2003, as we owned non-cost bearing overriding royalty interests in wells located in offshore federal waters not subject to state production taxes.

Acreage and Wells

The following table sets forth certain information with respect to our developed and undeveloped leased acreage as of December 31, 2005.

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Offshore Louisiana			10,000	513
Offshore Texas	640	128	40,426	12,148
Total	640	128	50,426	12,661

(1) We have 421 net lease acres expiring in 2006.

At December 31, 2005, we had working interests in one gross (0.2 net) producing gas well; we had overriding royalty interests in nine producing gas wells.

Drilling Activities

All of our drilling activities are conducted through arrangements with independent contractors. We own no drilling equipment. At December 31, 2005, we had a net working interest of 20% in one exploratory gas well.

Oil and Gas Reserves

All of the information herein regarding estimates of our proved reserves, related future net revenues and PV-10 as of December 31, 2005 is taken from the report generated by Sharp Petroleum Engineering, Inc., our independent petroleum engineer, in accordance with the rules and regulations of the SEC. The independent

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engineer s estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data that we provided.

	December 31, 2005			
	Proved Reserves			
	Oil (Bbl)	Gas (Mcf)	Mcfe	PV-10(1)
Offshore Texas	147	145,179	146,061	$ 737,642
Offshore Louisiana	1,166	245,508	252,504	$ 2,007,249
Proved Reserves	1,313	390,687	398,565	$ 2,744,891
Proved Developed Reserves	1,313	390,687	398,565	$ 2,744,891

(1) The PV-10 amount (present value of estimated pre-tax future net revenues discounted at 10%) is calculated using year-end prices of $53.72 per barrel of oil and $8.90 per Mcf of gas.

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

In accordance with SEC guidelines, the estimates of future net revenues from our proved reserves and the present value thereof are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. We may receive amounts different than the estimates for a number of reasons, including changes in prices. See Supplemental Information to Consolidated Financial Statements. Estimates of our proved oil and gas reserves were not filed with or included in reports to any other federal authority or agency other than the SEC during the fiscal year ended December 31, 2005.

Business Strategy

Our objective in the Exploration and Development business is to expand the net value of our assets by building an oil and gas reserve base in a cost-efficient manner, through exploitation of our seismic database to facilitate identifying drilling prospects.

Seismic Data

We have acquired the following two significant seismic database assets:

- a license to a 228-square-mile seismic program covering the transition zone in Cameron Parish, and
- a license to a 6,800-square-mile seismic database comprising several seismic surveys in the shallow waters offshore Texas and Louisiana.

The offshore Texas database has been available previously to the industry and was processed using a technique called dip move out, or DMO. We acquired the DMO data and underwrote the reprocessing of the data utilizing

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another technology known as prestack time migration, or PSTM. Both DMO and PSTM are processing techniques which improve seismic data quality to more accurately image subsurface features and delineate hydrocarbon accumulations. Of the two techniques, PSTM is more advanced and technically accurate. The regional PSTM data is the technology tool which management believes gives us a competitive advantage.

Analysis and Methodology

We have developed a prospect generation infrastructure capable of detailed analyses of large volumes of seismic, geological and engineering data. We employ a rigorous methodology which includes:

- the detailed analyses of existing fields to identify geological and geophysical attributes for use as analogs;
- regional trend mapping to extend prolific plays into under-explored areas;
- the use of workstation interpretation techniques to rapidly identify prospects with attributes similar to those identified in the analog fields;
- the integration of seismic interpretation, well control, structure, stratigraphy, timing, sourcing factors, and production data to quantify prospect potential; and
- the integration of the above sciences with experience and conservative economic evaluation to focus the exploration program on highly commercial projects.

By conducting a thorough analysis of the data and strict adherence to the methodology, we believe that we can reduce the risk of dry holes and achieve significant growth, while maintaining a competitive cost of exploration and development.

Experience

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

Competition and Markets

The availability of a ready market for and the price of any hydrocarbons that we produce will depend on many factors beyond our control, including the extent of domestic production and imports of foreign oil, the marketing of competitive fuels, the proximity and capacity of natural gas pipelines, the availability of transportation and other market facilities, the demand for hydrocarbons, the political conditions in international oil-producing regions, the effect of federal and state regulation of allowable rates of production, taxation, the conduct of drilling operations and federal regulation of natural gas. In the past, as a result of excess deliverability of natural gas, many pipeline companies curtailed the amount of natural gas taken from producing wells, shut in some producing wells, significantly reduced gas taken under existing contracts, refused to make payments under applicable take-or-pay provisions and have not contracted for gas available from some newly completed wells.

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

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

Governmental Regulation

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

MMS Regulations

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

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

Bonding and Financial Responsibility Requirements

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

Regulation of Production

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

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

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

Environmental Matters

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

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

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

Financial Information About Segments

During the last three fiscal years, all of our revenues have resulted from our oil and gas exploration and development activities. For information about our segments revenues, profits and losses and total assets, see Note 23 to our Consolidated Financial Statements.

Subsidiaries

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

Employees

We had 130 full-time employees as of February 28, 2006.

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ITEM 1A. ***RISK FACTORS***

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

Risks Relating to Our Financial Matters

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

From our inception, we have generally incurred operating losses, and we will likely continue to incur operating losses and experience negative operating cash flow for at least the next two years. We have not yet started the construction of two of our three planned LNG receiving terminals or our pipelines. We do not anticipate that our LNG receiving operations or our three pipelines will generate positive operating cash flow until at least one of our planned LNG receiving terminals is built, which we expect will not be until 2008 at the earliest. Although we may commence operations at our LNG receiving terminals, 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 and pipelines. 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 for at least the next two years.

Any delays beyond the expected development periods for our planned LNG receiving terminals or pipelines would prolong, and could increase the level of, our operating losses and negative operating cash flow. Our future liquidity may also be affected by (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 the capacity of our facilities, 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 and pipelines is contingent on our ability to obtain funding. If we are unable to do so, we may be unable to implement or complete our business plan and our business may ultimately be unsuccessful.

As of December 31, 2005, we had $693 million in cash and cash equivalents, exclusive of $177 million in restricted cash. We currently estimate that the cost of completing our three LNG receiving terminals will be approximately $3.0 billion, before financing costs, and the cost of constructing our three proposed pipelines will be approximately $800 million to $1 billion. Our cost estimate is subject to change due to such items as cost overruns, change orders under existing or future EPC agreements, changes in commodity prices (particularly steel), escalating labor costs and additional funds that may need to be expanded to maintain construction schedules. In addition, the development of our marketing business will require the expenditure of funds before any revenues are received. To fund these development projects, we will have to draw on our Sabine Pass Credit Facility and pursue a variety of additional sources of funding, 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, to the extent permitted, and joint venture arrangements by Cheniere and/or our subsidiaries.

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 of our industry and prospects at such time. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all, even if our development projects are otherwise proceeding on schedule. In addition, our ability to obtain some types of financing may be dependent upon our ability to obtain other types of financing. For example, project-level debt financing is typically contingent upon a significant equity capital contribution from the project sponsor. As a result, even if we are able to identify potential project-level lenders, we may still have to obtain another form of external financing for us to fund an equity capital contribution to the project subsidiary. Any project-level debt financing 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 or cross-defaults to our other indebtedness;
- 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 or limiting our ability to sell our interests in such entity;
- additional sales of interests in our LNG projects would reduce our interest in future revenues once the LNG receiving terminals commence operations;
- the prepayment of terminal use fees by, or a business development loan from, prospective customers would reduce future revenues once the LNG receiving terminals commence operations;
- offerings of our equity securities would cause dilution of our common stock;
- sales of oil and gas exploration prospects would reduce potential future revenues from our exploration and production activities;
- our ability to borrow funds under some project financing arrangements will likely be subject to our satisfying the conditions and covenants in the financing and the construction schedule agreed to at the time we enter into such arrangement. If circumstances change, we may need to seek waivers of conditions or covenants under our financing arrangements to prevent defaults thereunder and acceleration thereof, which we might not be able to obtain on a timely basis, or at all; and
- we may be required to make equity contributions before we can borrow under certain financing arrangements, such as the Sabine Pass Credit Facility.

The actual construction costs of our proposed LNG receiving terminals and pipelines may be significantly higher than our current estimates, which are before financing costs.

We do not have any prior experience in constructing LNG receiving terminals or pipelines, 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.

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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, such as hurricanes.

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 may also cause a delay in the receipt of revenues projected from operation of the facilities or cause a loss of our TUA customers in the event of significant delays. 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 us and our LNG projects.

The design, construction and operation of LNG receiving terminals 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 our Sabine Pass and Corpus Christi LNG receiving terminals, we have not yet received an NGA Section 3 FERC order authorizing construction of our Creole Trail project. 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 existing or potential interventions or other actions by third parties will 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 Chevron. Other energy companies such as Sempra, Tractebel, McMoRan Exploration, Occidental Petroleum, AES, Excelerate Energy and other public and private companies have also proposed developing 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.

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. Our proposed Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals will also compete with the Freeport LNG receiving terminal in which we own a 30% interest. 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, or a significant decline in natural gas prices, 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 and marketing operations could be subject to cyclical swings, reflecting alternating periods of under-supply and over-supply of LNG importation capacity and available natural gas, principally due to the combined impact of several factors, including:

significant additions in regasification capacity, 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 at the foreign supply source 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; and

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.

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 approximately 4 Bcf/d of our total existing and future regasification capacity at our LNG receiving terminals, including a commitment to pay capacity reservation fees, prior to the commencement of construction of each facility. The portion of our total regasification capacity that we plan to commit under such long-term TUAs has changed in the past and may change in the future for various reasons, including responding to market factors or perceived opportunities that we believe may be available to us. Our ability to obtain project-level financing for each LNG receiving facility may be contingent on our ability to enter into long-term TUAs covering approximately 4 Bcf/d 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 filing, we do not have any TUAs in place for either our proposed Corpus Christi facility or our proposed Creole Trail facility nor do we have any contracts in place for the use of our pipelines.

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

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 third-party customers and Cheniere Marketing to import LNG supplies into the United States. Political instability in foreign countries that have supplies of natural gas, or strained relations between such countries and the United States, may impede the willingness or ability of LNG suppliers 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 us and other 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 both our and 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 harm our ability to develop our proposed LNG receiving terminals and market the sale of natural gas.

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.

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

Sabine Pass LNG has entered into long-term TUAs with subsidiaries of Total S.A. and Chevron. Each of the TUAs contains various termination rights. For example, Total may 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 fails to perform its obligations under its respective TUA, our business, results of operations, financial condition and prospects could be materially adversely affected, even if 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 contractors that we engage at each facility.

Sabine Pass LNG entered into an EPC agreement in December 2004 with Bechtel. We also plan to enter into 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 other contractors performing portions of the construction on our projects and for such 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 acceptable contracts for the construction of Phase 2 of our Sabine Pass LNG receiving terminal or our proposed Corpus Christi or Creole Trail LNG receiving terminals. Other than with respect to Phase 1 of our Sabine Pass LNG receiving terminal, we have no prior experience working with any EPC contractor, including Bechtel, or other construction contractor. 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 by an EPC contractor under certain circumstances prior to completion of construction. For example, see the description of the termination provisions of the EPC agreement with Bechtel under LNG Receiving Terminal Development Business Our LNG Receiving Terminals Sabine Pass LNG EPC Agreement 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.

Risks Relating to Our Pipeline Development Business

Expanding our business by constructing pipelines subjects us to risks.

The construction of a new pipeline involves numerous regulatory, environmental, political and legal uncertainties beyond our control and requires the expenditure of significant amounts of capital that we will be required to finance through borrowings, through the issuance of additional equity or from operating cash flow. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost. For instance, if we build a new pipeline, the construction will occur over an extended period of time, and we will not receive any revenues until the pipeline has been completed and customers pay for transportation service on the pipeline. Moreover, we may construct pipelines to capture anticipated future growth in a region in which such growth does not materialize. As a result, our pipelines may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. The success of our pipeline construction project may depend upon the level of LNG import activity in the areas proposed to be serviced by the project as well as our ability to obtain commitments from LNG suppliers and other customers to utilize the newly constructed pipelines.

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

The design, construction and operation of natural gas pipelines and the transportation of natural gas are all highly regulated activities. FERC approval under Section 7 of the NGA, as well as several other material state governmental and regulatory approvals and permits, is required in order to construct and operate our proposed pipelines. We have obtained authorization from FERC pursuant to Section 7(c) of the NGA to construct and operate our Sabine Pass and Corpus Christi pipelines, subject to certain conditions. However, we have not yet received authorization from FERC to construct and operate our Creole Trail pipelines. We also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed pipelines. We have no control over the timing of the review and approval process nor can we predict the outcome of the process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any third parties will attempt to interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, we may not be able to recover our investment in the projects. Failure to obtain and maintain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

Our proposed pipelines will be subject to FERC rate-making, which could have an adverse impact on our ability to recover the full cost of operating our pipelines, including a reasonable return.

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

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

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

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

We will depend upon third-party pipelines and other facilities that will provide delivery options to and from our proposed pipelines. If any pipeline connection were to become unavailable for volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to continue shipping natural gas to end markets could be restricted, thereby reducing our revenues. Any temporary or permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our proposed pipelines could have a material adverse effect on our business, results of operations and financial condition.

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

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

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

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

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

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

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

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

Risks Relating to Our LNG and Natural Gas Marketing Business

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

We have just recently begun developing our LNG and natural gas marketing business. To date, the business has only a few employees, has generated no revenues and has no operating history upon which you can evaluate our business strategy or the future prospects of the business. The ability of our LNG and natural gas marketing business to generate revenues in the future will depend upon whether we can successfully develop and implement our business strategy and make the transition from a development stage business to an operating business. We may encounter many expenses, delays, problems and difficulties that we have not anticipated and for which we have not planned in developing and operating our LNG and natural gas marketing business.

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

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

- expected supply is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or

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there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

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

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

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

Other risks related to our LNG receiving terminal development business could have similar adverse effects on our marketing business.

Some of the risks described above under Risks Relating to Our LNG Receiving Terminal Development Business could have an adverse impact on our marketing business, including those set forth under the following headings:

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

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;

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; and

Decreases in the price of natural gas in North America could harm our ability to develop our proposed LNG receiving terminals and market the sale of natural gas.

Risks Relating to Our Oil and Gas Exploration and Development Business

We are subject to significant exploration risks, including the risk that we may not be able to find or produce enough oil and gas to generate any profits.

Our exploration activities involve significant risks, including the risk that we may not be able to find or produce enough oil and gas to generate any profits. The wells we drill may not discover any oil or gas. Furthermore, there is no way to know in advance of drilling and testing whether any prospect will yield oil or gas in sufficient quantities to make money for us. In addition, we are highly dependent on seismic activity and the related application of new technology as a primary exploration methodology. This methodology, however, requires greater pre-drilling expenditures than traditional drilling strategies. Even when fully used and properly interpreted, 3D seismic data can only assist us in identifying subsurface reservoirs and hydrocarbon indicators, and will not allow us to determine conclusively if hydrocarbons will in fact be present and recoverable. If our exploration efforts are unsuccessful, our business, results of operations, financial condition and prospects could be materially adversely affected.

We may not be able to acquire the oil and gas leases we need to sustain profitable operations.

In order to engage in oil and gas exploration in the areas covered by our 3D seismic data, we must first acquire rights to conduct exploration and recovery activities on such properties. We may not be successful in

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acquiring farm-outs (agreements whereby the owner of lease interests grants to a third party the right to earn an assignment of an interest in the lease, typically by drilling one or more wells), seismic permits, lease options, leases or other rights to explore for or recover oil and gas. Both the U.S. Department of the Interior and the States of Texas and Louisiana award oil and gas leases on a competitive bidding basis.
Non-governmental owners of the onshore mineral interests within the area covered by our exploration program are not o