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CHENIERE

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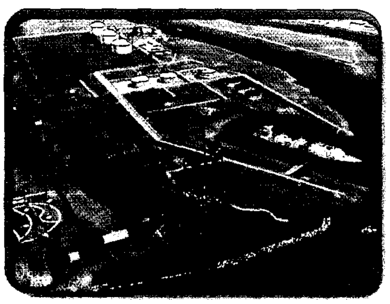
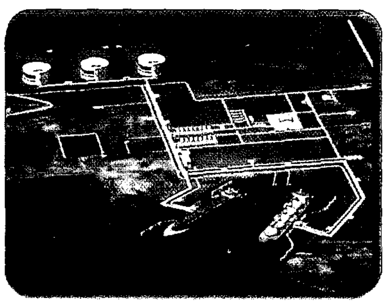
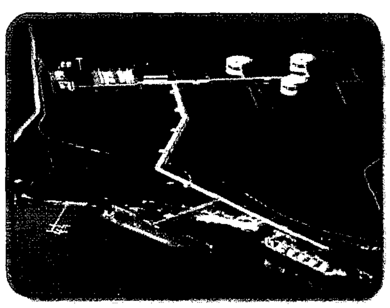
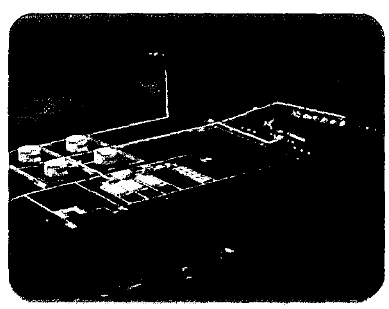



2004 Annual Report

CHENIERE

March 24, 2005

Dear Shareholders,

In the attached 10-K, we are required to report significant events in the company's history dating to three years ago. If you read it carefully, you will note that:

In 2002, our then President and Chief Executive Officer, Charles Reimer, loaned the company $30,000 so that the company could meet its payroll. In 2002, this was a significant event. Our market capitalization at the end of 2002 was $17 million and we had 13 employees.

In 2003, we completed a transaction in February with Michael Smith whereby in exchange for agreeing to spend $14 million Michael received a 60% interest in our Freeport project and became the general partner of Freeport LNG. In 2003, this was a significant event for Cheniere. Our market capitalization at the end of 2003 was $193 million and we had 17 employees.

In 2004, we sold 5 million shares at $60 per share and raised $300 million in equity. This was a significant event in 2004. Our market capitalization at the end of 2004 was $1.6 billion and we had 44 employees.

For the past two years, our stock was among the top 5 performers on the American Stock Exchange, with our stock price increasing by 914% in 2003 and by 444% in 2004.

Charles and Michael have teamed up at Freeport LNG, which in January 2005 became the first new LNG receiving terminal to break ground in the United States in several decades. We are still a 30% limited partner in Freeport.

This month our Sabine Pass LNG receiving terminal became the second terminal to break ground. We own 100% of Sabine Pass.

Also this month, we received the Final Environmental Impact Statement for our Corpus Christi LNG receiving terminal. We expect to receive the order from The Federal Energy Regulatory Commission to build and operate the facility in the near future and their authorization to break ground in Corpus Christi later this year. We own 100% of Corpus Christi.

There is a strong likelihood that during 2005, Cheniere will be associated with all new LNG receiving terminals under construction in the U.S. This will be a significant event in 2005.

Obviously, we expect this situation will not last and for the benefit of our country, we hope additional terminals will be built. However, it is now undeniable that Cheniere's early move into LNG regasification has secured us a very strong position in the industry. We have developed some of the best sites in the nation and have navigated the permitting process effectively, earning the trust of the communities and agencies with whom we work. Our terminal use tariff at $0.32 per MMbtu is fair and our activities are completely transparent.

Freeport LNG and Sabine Pass will add 4.1 Bcf/day of U.S. regas capacity by 2008 - more than the current sendout capacity of all four existing terminals combined.

With Corpus Christi, we plan to add another 2.6 Bcf/day, bringing our total capacity to 6.7 Bcf/d by the end of 2008. To this we are working on adding our new project, Creole Trail, at 3.3 Bcf/d. We expect to have a total 10.0 Bcf/day of capacity by 2010 and the possibility of expansion at each location.

Once the Freeport terminal is completed and has commenced commercial operations, our 30% share of Freeport's revenues is estimated to generate about $15 million per year in distributions. When the Sabine Pass terminal is completed and has commenced commercial operations, the existing contracts with Total LNG and Chevron USA for 1.7 Bcf/d will generate revenues of $215 million per year. Combined revenues from Freeport and Sabine Pass are therefore expected to be approximately $230 million on an annualized basis. The challenge now is to commercialize the excess capacity at Sabine Pass and our new terminals at Corpus Christi and Creole Trail.

All of these numbers are large and yet for 5 years now we have never deviated from our original model. We have consistently believed that the decline in domestic production would require a significant new infrastructure to enable us to import natural gas. It is gratifying today to see our dream becoming a reality.

Our employees have shared our conviction. They have worked hard, against the odds, with wonderful spirit. We believe in the future of Cheniere.

We know what we must do during the next three years to finish what we started. If we execute correctly, we will have created the premier LNG receiving company in the U.S. and probably in the world. We are committed to this vision.

It has been exciting, but it is not over.

Sincerely,

Charif Souki
Chairman and CEO

Our Company

Cheniere Energy, Inc. is an independent energy company engaged in developing, constructing, owning and operating onshore Liquefied Natural Gas (LNG) receiving terminals along the Gulf Coast of the United States.

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 believe that our planned LNG projects are well-positioned as compared to other proposed projects based on a number of competitive strengths. We have secured what we believe to be among the best sites for LNG receiving terminals along the U.S. Gulf Coast, an area that is highly conducive to such development given the substantial local consumption, existing industrial complexes and access to significant natural gas pipeline infrastructure. Furthermore, we believe that our terminals are further along in the development process than most other proposed U.S. terminals, with three of our terminals currently expected to commence construction in 2005 and a fourth terminal planned to commence construction in 2006. We have entered into long-term agreements with well-known "anchor tenants" for a significant portion of our planned LNG receiving capacity. Our experienced management team has sought to protect our early mover advantage by planning our facilities based on proven technology and design concepts and by employing an environmental and community friendly approach to the development of our projects. This approach and the locations and capacities of our proposed facilities are intended to benefit from economies of scale.

We continue to evaluate new opportunities in the natural gas market. We may develop additional sites that we believe may be commercially desirable locations for LNG receiving terminals, and we will continue to study the market both upstream and downstream to determine where best to make investments.

What is LNG?

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 receiving terminals offload LNG from tankers, store the LNG, then heat the LNG to return it to a gaseous state and deliver the resulting natural gas into pipelines for transportation to market.

Our Industry

LNG is a well-established, global source of natural gas for electric generation, heating and industrial applications. According to the Energy Information Administration, or EIA, as of October 2003, there were 66 liquefaction plants in 12 countries capable of producing 6.6 trillion cubic feet, or Tcf, of LNG per year and 44 receiving terminals in 12 countries capable of receiving and regasifying LNG.

North America has the largest interconnected natural gas market in the world, consuming approximately 74 Bcf/d in 2003, according to the EIA. Currently, there are only four import LNG receiving terminals in North America with a combined sustainable sendout capacity of approximately 2.5 Bcf/d, or about 3% of total current natural gas consumption. LNG's contribution to the North American market has historically been minimal, due mainly to an abundant supply of domestically sourced, low cost natural gas. The EIA has reported, however, that the average wellhead price of natural gas produced in the United States has more than doubled in the last five years, an indication of a declining domestic resource base. Chairman of the Federal Reserve, Alan Greenspan, stated in May 2003 that greater access to global natural gas reserves is required for North American natural gas markets "to be able to adjust effectively to unexpected shortfalls in domestic supply [and that] access to world natural gas supplies will require a major expansion of LNG terminal import capacity." We believe that LNG is needed as a reliable source of supply to meet demand and that LNG can be delivered to North America at a competitive price.

This Annual Report contains certain statements that may include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please refer to page 1 of the accompanying10-K for an explanation of "forward-looking statements" an applicable assumptions.

For the Glossary of Terms please see page 2 in the accompanying 10-K.

Our Strategy

We plan to pursue a strategy with the following primary components:

- complete the development and construction of our onshore U.S. Gulf Coast LNG receiving terminals;
- secure "anchor tenants" under long-term Terminal Use Agreements, or TUAs, for approximately one-half of existing and future regasification capacity at the LNG terminals that we control, thus providing for an expected stream of contracted cash flows when the terminals become operational;
- retain the remaining capacity for our own account to capitalize on future long-term, short-term or spot market opportunities;
- apply proven, conventional technology to mitigate development and operating risk and facilitate permitting, while utilizing the latest control and safety technology;
- grow our terminal business by expanding our existing projects and pursue the development of additional LNG receiving terminals on the U.S. Gulf Coast and elsewhere; and
- pursue other energy business initiatives, including downstream opportunities such as natural gas pipelines and storage, marketing and trading, as well as upstream opportunities such as investment in LNG shipping businesses, securing foreign LNG supply arrangements, development of foreign natural gas reserves that could be converted into LNG, and oil and gas exploration, development, production, transportation and processing activities generally.

Our Competitive Strengths

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

Early mover advantage. We established our business plan in 1999, when constructing new LNG import capacity in the United States hadn't occured since the early 1970s. As an early mover, we secured what we believe to be among the best sites for LNG receiving terminals along the U.S. Gulf Coast. Today, we believe that we have maintained that advantage and believe that our LNG receiving terminals are currently further along in the development process than most others, especially with three of our facilities currently expected to commence construction in 2005 and a fourth in 2006.

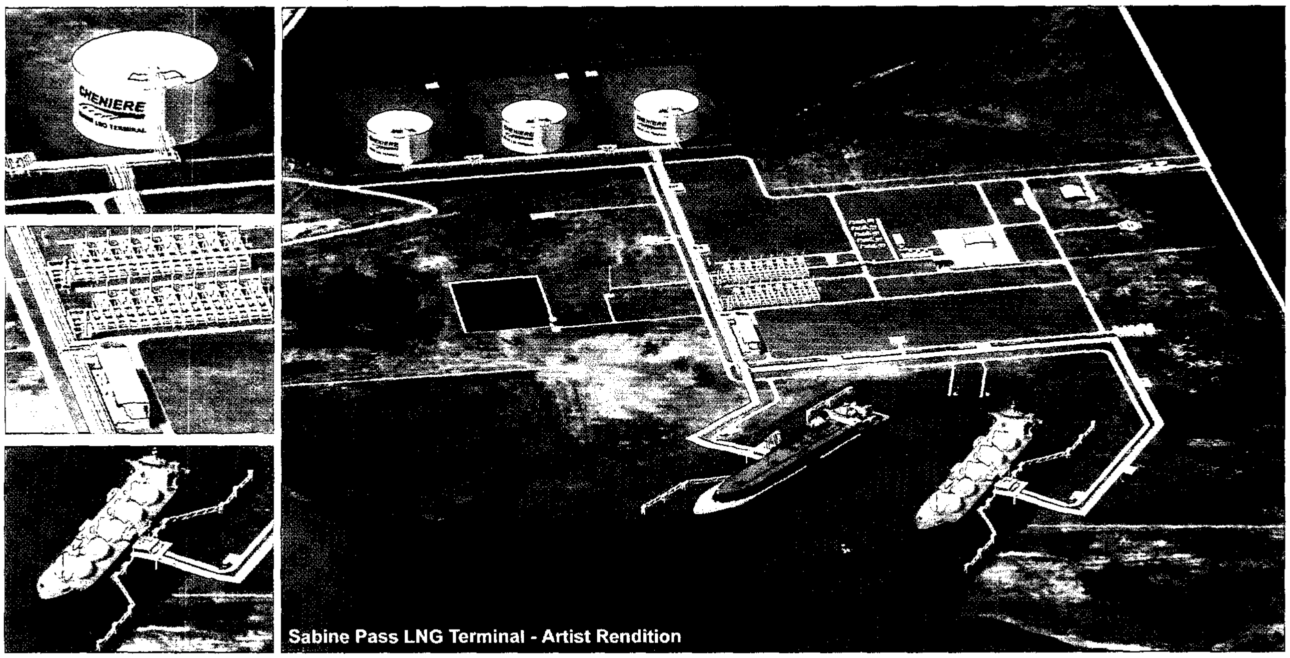
U.S. Gulf Coast focus. The U.S. Gulf Coast area is conducive to LNG receiving terminal development, as it is distinguished by substantial local consumption coupled with extensive natural gas pipeline infrastructure.

Economies of scale and flexibility. At 2.6 Bcf/d of regasification capacity at each Sabine Pass and Corpus Christi, and 3.3 Bcf/d of regasification capacity at Creole Trail, we believe that our facilities are the largest proposed LNG receiving terminals in North America. With this capacity, we believe that we will benefit from economies of scale in construction and operation. Furthermore, with 3 ports, 6 unloading docks and 10 storage tanks among the 3 facilities, we will be capable of offering flexible landing options.

Environment and community-friendly approach. We are committed to an environmentally sound and community friendly approach in developing our LNG receiving terminals. We invest time to develop strong community relationships. We begin the application process for a facility only after we are convinced that the local community understands the process and is willing to support our project. We have received letters in support of the development of our Sabine Pass LNG receiving terminal from the Governor of Louisiana, several Louisiana state and federal representatives, the Cameron Parish Police Jury, and local organizations. We have received letters in support of the development of our Corpus Christi LNG receiving terminal from the Governor of Texas, the Texas Railroad Commission, several state and federal representatives, the Mayors of Corpus Christi and its surrounding cities, Portland, Ingleside, Aransas Pass and Port Aransas, as well as the Sierra Club and local organizations.

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

Sabine Pass LNG Terminal



Sabine Pass LNG Terminal - Artist Rendition

Site:	853 acres
Accessibility:	40' channel
Proximity:	3.7 nautical miles from coast
Berthing/Unloading:	2 docks
Storage:	3 tanks (10 Bcfe)
Vaporization:	2.6 Bcf/d sendout
In Service:	2008

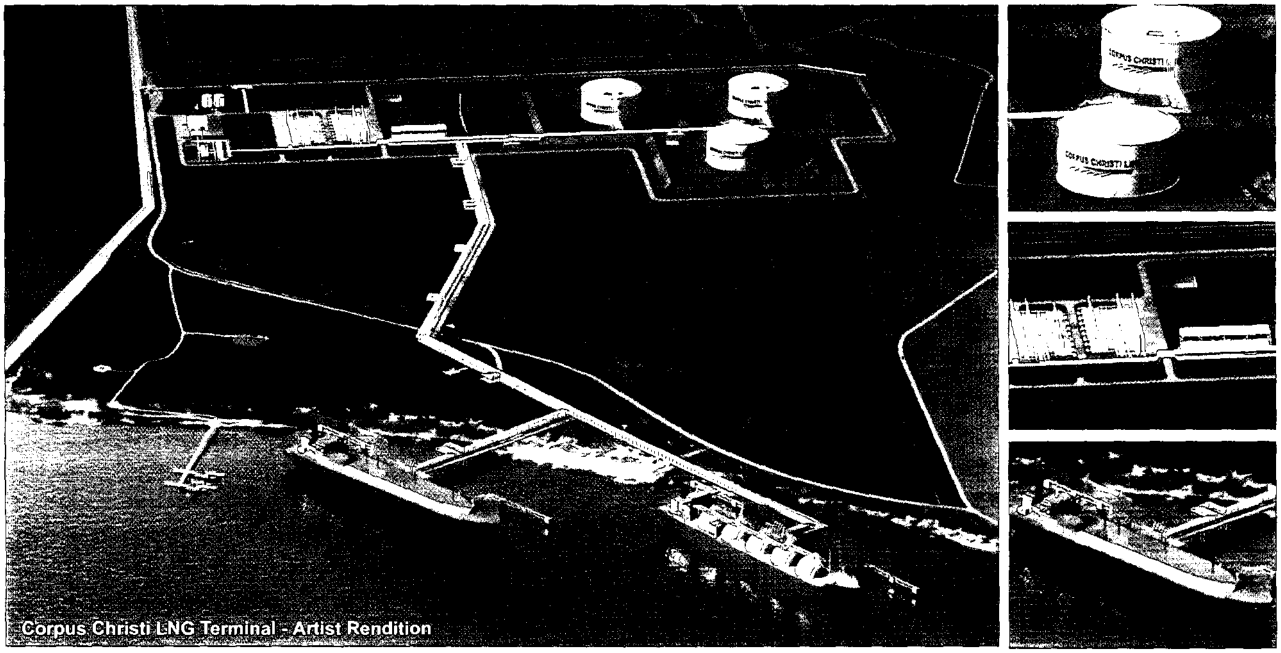
Our 100%-owned limited partnership Sabine Pass LNG, L.P. is building an LNG receiving terminal in Cameron Parish, Louisiana. Sabine Pass LNG received an order from FERC in December 2004 authorizing construction of the LNG receiving terminal. Construction began in the first quarter of 2005 and we expect to commence terminal operations in 2008.

Sabine Pass LNG entered into 20-year TUA's with Total LNG and Chevron USA to provide 1.0 Bcf/d and 700 MMcf/d of regasification capacity, respectively. Each of the TUA's provides for the customer to pay a fee of $0.32 per MMbtu of reserved capacity regardless of usage, subject in part to adjustment for inflation. Chevron USA has options either to decrease its reserved capacity to 500 MMcf/d by July 1, 2005 or to increase its capacity to 1.0 Bcf/d by December 1, 2005. In January 2004, we were paid $1 million by J & S Cheniere in connection with an option to purchase LNG regasification capacity in each of our Sabine Pass and Corpus Christi LNG facilities. Subject to obtaining an additional order by FERC authorizing construction of an expansion, and obtaining financing, the facility could be expanded from its initial capacity of 2.6 Bcf/d to approximately 4.0 Bcf/d. Under certain conditions Total LNG and Chevron USA have options to acquire additional processing capacity in the event of an expansion.

We estimate that the cost of constructing the 2.6 Bcf/d Sabine Pass LNG facility will be approximately $750 million to $850 million, before financing costs. In December 2004, we entered into a lump-sum turnkey agreement valued at approximately $647 million with Bechtel Corporation, a major international engineering, procurement and construction, or EPC, contractor.

In February 2005, HSBC Securities (USA) Inc. and Société Générale arranged $822 million of non-recourse project debt financing to fund a substantial majority of the Sabine Pass LNG terminal construction costs.

Corpus Christi LNG Terminal



Corpus Christi LNG Terminal - Artist Rendition

Site:	612 acres
Accessibility:	45' channel
Proximity:	14.3 nautical miles from coast
Berthing/Unloading:	2 docks
Storage:	3 tanks (10 Bcfe)
Vaporization:	2.6 Bcf/d sendout
In Service:	2008

We are developing an LNG receiving terminal near Corpus Christi, Texas. We formed Corpus Christi LNG, L.P. 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. A third party, BPU LNG, Inc., contributed the land and the first $4.5 million toward project expenses, in exchange for its 33.3% limited partner interest. In February of 2005, we acquired BPU LNG's interest in the project, whereby we now hold 100% of the general partner interest and 100% of the limited partner interest in Corpus Christi LNG, L.P.

Implementing the strategy that we used for Sabine Pass, we have provided detailed information and engaged in preliminary discussions with potential customers in an effort to secure long-term TUA's for our Corpus Christi terminal. On December 22, 2003, we submitted to FERC an application for a permit to build the Corpus Christi LNG receiving terminal, as well as a separate but concurrent permit application for its related pipeline. On November 18, 2004, FERC issued the Draft Environmental Impact Statement for our proposed Corpus Christi LNG receiving terminal and our related pipeline. On March 7, 2005, FERC issued the Final Environmental Impact Statement, which concluded that the facility, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. We expect to engage a major international EPC contractor to perform the EPC work for the facility under a lump-sum turnkey agreement. We expect to begin construction in the third quarter of 2005 and to commence terminal operations in 2008.

We estimate that the cost of constructing the 2.6 Bcf/d Corpus Christi LNG facility will be approximately $650 million to $750 million, before financing costs. This estimate is based in part on our negotiations regarding a lump-sum turnkey agreement with a major international EPC contractor.

Creole Trail LNG Terminal

Site:	1,463 acres
Accessibility:	40+' deep water channel
Proximity:	3.2 nautical miles from coast
Berthing/Unloading:	2 docks
Storage:	4 tanks (13.5 Bcfe)
Vaporization:	3.3 Bcf/d sendout
In Service:	2009

We hold 100% of the general partner and limited partner interests in Creole Trail LNG, L.P. In November 2004, we announced that we had secured options to lease a site near the Creole Trail at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana. We plan to make the initial filing with FERC that is required to obtain an order to commence construction of the facility. We expect the permitting process to take 12 to 18 months and for construction to begin in the third quarter of 2006, with terminal operations commencing in 2009.

We have engaged in preliminary discussions with potential customers in an effort to secure long-term TUA's for our Creole Trail terminal. Creole Trail LNG has not yet entered into any TUA's. We estimate that the cost of constructing the 3.3 Bcf/d Creole Trail LNG facility will be approximately $850 million to $950 million, before financing costs.

Freeport LNG Terminal

Site:	233 acres
Accessibility:	45' channel
Proximity:	on intracoastal waterway
Berthing/Unloading:	1 dock
Storage:	2 tanks (6.7 Bcfe)
Vaporization:	1.5 Bcf/d sendout
In Service:	2008

The Freeport LNG receiving terminal will be located on Quintana Island, near Freeport, Texas. We developed this project and then sold a 60% limited partner interest to Michael Smith, the general partner of Freeport LNG and a 10% limited partner interest to Contango Oil & Gas Company. We continue to own a 30% non-operating limited partner interest in Freeport LNG. We have been advised by Freeport LNG that it has entered into a lump-sum turnkey contract, and we believe that the estimated cost to construct the facility is approximately $750 million, before financing costs. Pursuant to authorization from FERC, Freeport LNG commenced construction in January of 2005; terminal operations are expected to commence in 2008.

The Freeport LNG's capacity is fully subscribed under TUA's for at least 20 years with ConocoPhillips for 1.0 Bcf/d and with Dow for 500 MMcf/d. ConocoPhillips and Dow will both pay monthly capacity reservation fees and a portion of power, fuel and other operating costs. ConocoPhillips has also agreed to provide a substantial majority of the construction funding for the Freeport LNG facility. ConocoPhillips also owns a 50% interest in the general partner entity responsible for managing the construction and operation. In the event of an expansion of the Freeport LNG facility, ConocoPhillips has options to acquire up to 500 MMcf/d of additional regasification capacity.

Cheniere Pipeline Companies

Cheniere Sabine Pass Pipeline Company

Cheniere Sabine Pass Pipeline Company is planning construction of a 16-mile long, 42-inch diameter natural gas pipeline. This pipeline will originate at the proposed Sabine Pass LNG receiving terminal near Sabine Lake in Cameron Parish, Louisiana and will run eastward along a corridor that will allow for interconnection points with interstate and intrastate natural gas transmission pipelines in South Louisiana, including the following: Natural Gas Pipeline Company of America, Transcontinental Gas Pipeline Corporation, Tennessee Gas Pipeline Company, Florida Gas Transmission Company, and Bridgeline Holdings L.P. (LRC). Final pipeline sizing and exact interconnects will be determined by customer interest and market demand.

Cheniere Corpus Christi Pipeline Company

Cheniere Corpus Christi Pipeline Company is planning construction of a 24-mile long, 48-inch diameter natural gas pipeline to be located in San Patricio County, Texas. This pipeline will commence at the proposed LNG receiving terminal near Corpus Christi, Texas and will run northwesterly along a corridor that will allow for interconnection points with interstate and intrastate natural gas transmission pipelines in South Texas, including the following: Texas Eastern Transmission Corporation, Gulf South Pipeline Company, L.P., Enterprise Intrastate, L.P. (Channel), Kinder Morgan Tejas Pipeline, L.P., Crosstex CCNG Marketing, Ltd., Transcontinental Gas Pipeline Corporation, Natural Gas Pipeline Company of America, Enterprise Texas Pipeline, L.P. (Valero), Tennessee Gas Pipeline Company, and Houston Pipeline Company, L.P. Exact interconnects will be determined by customer interest and market demand.

Cheniere Creole Trail Pipeline Company

Cheniere Creole Trail Pipeline Company is proposing construction of a dual 42-inch diameter, natural gas pipeline system to interconnect with over 12 Bcf/d of interstate and intrastate pipeline infrastructure in southwest Louisiana. This pipeline will originate at the proposed Creole Trail LNG Terminal on the Calcasieu Ship Channel, and extend north/northeasterly approximately 118-miles through Cameron, Calcasieu, Beauregard, Allen, Jefferson Davis and Acadia Parishes where it will terminate near Rayne, Louisiana. Cheniere has initiated the NEPA Pre-filing process to apply to FERC for permits to build and operate the Cheniere Creole Trail Pipeline. Plans are also under evaluation for a western leg of the Creole Trail Pipeline to connect the Sabine Pass LNG Terminal. The need for this segment will also be determined by customer interest and market demand.

Cheniere Exploration

The exploration team generates revenue for the company by generating prospects on its 3D seismic database. For the past three years, the company has been successful generating and selling prospects for a combination of cash, retained overriding royalty interests and back-in working interests. Since July 2001, the company has sold 19 prospects to industry partners on which 21 wells have been drilled and 16 discoveries made.

Our team has experience both onshore and offshore in the Gulf Coast and we believe that we are well-positioned to evaluate, explore and develop properties in these areas 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 by industry partners. Our current oil and gas exploration and development activities are focused on 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 on 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.

Cheniere Ventures

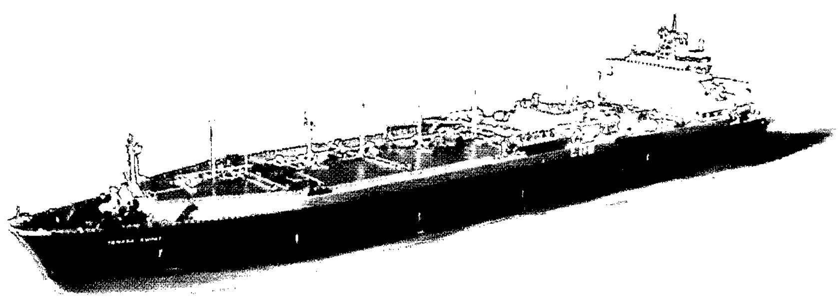
J & S Cheniere

We hold a minority interest in J & S Cheniere S.A. The majority interest in J & S Cheniere is held by J & S Energy Holding B.V. a Netherlands corporation affiliated with J & S Trading Company, Ltd., an international petroleum trading and marketing company. Under a shareholders agreement, we identify and assist with LNG-related business opportunities that we determine are appropriate for J & S Cheniere. We are not required to offer any particular business opportunities nor funding to J & S Cheniere. All financing of these business opportunities will be provided by J & S Holding should it determine that a business opportunity is appropriate for J & S Cheniere. However, J & S Holding is not required to fund any particular business opportunity.

In December 2003, we entered into an agreement with J & S Cheniere providing it with an option to purchase LNG regasification capacity of up to 200 Mmcf/d in each of our Sabine Pass and Corpus Christi LNG facilities. We were paid $1 million in connection with the execution of the option agreement by J & S Cheniere in January 2004.

As its initial LNG business opportunity, in August 2003, J & S Cheniere chartered its first LNG tanker, the 130,000 cubic meter (cm) capacity Tenaga Empat. In January 2004, J & S Cheniere signed a transportation agreement with Sonatrach, the national oil company of Algeria, for the Tenaga Empat to actively transport LNG cargoes into the United States and Europe.

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. Also in August 2004, J & S Cheniere 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.



Gryphon Exploration

In 1999, Cheniere made a commitment to Fairfield Industries to underwrite the reprocessing of a 1,100 block (8,800 square mile) 3D seismic database. The company hired an experienced staff of geologists, geophysicists and engineers to utilize the newly reprocessed data to explore for previously unseen prospects. The area covered by the Fairfield data had yielded numerous discoveries, but geophysical technologies such as pre-stack time migration (PSTM), amplitude variation with offset (AVO), and rock properties modeling had not been attempted on such a regional scale. The regional scale is critical to reducing exploration risk by making available to the explorationists all nearby producing field analogs for comparison to prospects.

In October 2000, Cheniere entered into an agreement with Warburg, Pincus Equity Partners, L.P. (Warburg), a global private equity fund based in New York, to fund exploration and development in the Offshore Louisiana area through the formation of a new corporation, Gryphon Exploration Company (Gryphon). As of January 1, 2004, Gryphon had received contributions from Warburg totaling $85 million for preferred shares, which when converted, leave Cheniere a 9.3% ownership interest in Gryphon. Cheniere plans to monetize its interest in Gryphon at some point and is optimistic that drilling success and high commodity prices could enhance the value of this holding for the foreseeable future.

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

Form 10-K*

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

For the fiscal year ended December 31, 2004

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No ☐

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $352,000,000 as of June 30, 2004.

26,756,954 shares of the registrant's Common Stock were outstanding as of February 28, 2005.

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.

* Incorporates amendments made in Amendment No. 1 to Form 10-K of the registrant, filed on March 16, 2005.

CHENIERE ENERGY, INC.
Index to Form 10-K

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 by certain dates, or at all;
- statements that we expect to receive Draft Environmental Impact Statements or Final Environmental Impact Statements from the Federal Energy Regulatory Commission, or FERC, by certain dates, or at all, or that we expect to receive an order from FERC authorizing us to construct and operate proposed LNG receiving terminals by a certain date, or at all;
- statements regarding future levels of domestic or foreign natural gas production or consumption or the future level of LNG imports into North America, regardless of the source of such information, or the transportation or other infrastructure or prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, whether on the part of Cheniere or at the project level, including financing arrangements for which we may have received commitment letters;
- statements relating to the construction of our proposed LNG receiving terminals, including statements concerning the engagement of any engineering, procurement and construction, or EPC, contractor and the anticipated terms and provisions of any agreement with an EPC contractor, and anticipated costs related thereto;
- statements regarding any terminal use agreement, or TUA, or other agreement to be performed substantially in the future, including any cash distributions and revenues anticipated to be received;
- statements regarding possible equity or asset purchases or sales;
- statements that our proposed LNG receiving terminals and pipelines, when completed, will have certain characteristics, including amounts of regasification and storage capacities, a number of storage tanks and docks, pipeline deliverability and a number of pipeline interconnections;
- statements regarding possible expansions of the currently projected size of any of our proposed LNG receiving terminals;
- statements regarding our business strategy, our business plans or any other plans, forecasts or objectives;
- statements regarding any Securities and Exchange Commission, or SEC, or other governmental inquiry or investigation; 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" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this annual report.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in "Risk Factors" beginning on page 29 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, onshore LNG receiving terminals along the Gulf Coast of the United States. 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. We are also engaged, to a lesser extent, in oil and natural gas exploration and development activities in the Gulf of Mexico and, through a minority interest in J & S Cheniere S.A., in the chartering and international operation of LNG tankers.

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.

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 liquid volume) of crude oil, condensate and natural gas liquids;
- *cm* means cubic meter;
- *LNG* means liquefied natural gas;
- *Mcf* means thousand cubic feet;
- *MMcf* means million cubic feet;
- *MMcf/d* means million cubic feet per day;
- *MMbtu* means million British thermal units; and
- *Tcf* means trillion cubic feet.

Access to Public Filings

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.

General Development of Business

Cheniere Energy Operating Co., Inc., or Cheniere Operating, was incorporated in Delaware in February 1996 for the purpose of engaging in the oil and gas exploration business, initially on the Louisiana Gulf Coast. On July 3, 1996, Cheniere Operating underwent a reorganization whereby Bexy Communications, Inc., a publicly-held Delaware corporation, or Bexy, received 100% of the outstanding shares of Cheniere Operating, and the former stockholders of Cheniere Operating received approximately 93% of the issued and outstanding Bexy shares. As a result of the share exchange, a change in control occurred. The transaction was accounted for as a recapitalization of Cheniere Operating. Bexy spun off its existing assets and liabilities to its original stockholders and changed its name to Cheniere Energy, Inc. Cheniere Operating became a wholly-owned subsidiary of Cheniere.

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

- complete the development and construction of our onshore U.S. Gulf Coast LNG receiving terminals;
- secure long-term terminal use agreements, or TUAs, with one or more creditworthy "anchor tenants" for approximately one-half of existing and future regasification capacity at the LNG terminals that we control, thus providing for an expected stream of contracted cash flows when the terminals become operational;
- retain the remaining capacity for our own account to capitalize on future long-term, short-term or spot market opportunities;
- apply proven, conventional technology to mitigate development and operating risk and facilitate permitting, while utilizing the latest control and safety technology;
- grow our terminal business by expanding our existing projects and pursue the development of additional LNG receiving terminals on the U.S. Gulf Coast and elsewhere; and
- pursue other energy business initiatives, including downstream opportunities such as natural gas pipelines and storage, marketing and trading, as well as upstream opportunities such as investment in LNG shipping businesses, securing foreign LNG supply arrangements, development of foreign natural gas reserves that could be converted into LNG, and oil and gas exploration, development, production, transportation and processing activities generally.

We have two reporting segments: one segment is the LNG Receiving Terminal Development business and the other is the Oil and Gas Exploration and Development business.

LNG Receiving Terminal Development

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

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

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

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

Our LNG Receiving Terminals

We began developing our LNG receiving terminal business in 1999 and, since then, have been among the first companies to secure sites and commence development of new LNG receiving terminals in the United States. We have focused our initial development efforts on four LNG receiving terminal projects at the following locations: on Quintana Island near Freeport, Texas; in Cameron Parish, Louisiana near Sabine Pass; near Corpus Christi, Texas; and at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana.

Freeport LNG

Development

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

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

The Freeport LNG receiving terminal is being developed on a 233-acre tract of land and is designed with regasification capacity of 1.5 Bcf/d, one dock and two LNG storage tanks with an aggregate LNG storage capacity of 6.7 Bcfe. The unloading dock will be able to handle 78,000 cm to 250,000 cm LNG tankers. We have been advised by Freeport LNG that it has entered into a lump-sum turnkey contract for its 1.5 Bcf/d facility and that the estimated cost to construct the facility is approximately $750 million, before financing costs and contingencies. We believe that this cost estimate is subject to change due to such items as cost overruns, change orders and changes in commodity prices.

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

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

Dow TUA

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

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

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

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

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

ConocoPhillips TUA

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

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

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

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

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

ConocoPhillips may terminate the TUA during the construction period if ConocoPhillips reasonably determines that the conversion date (as defined in the credit agreement between Freeport LNG and

ConocoPhillips) will not occur by a future confidential date, subject to a 30-day cure period on the part of Freeport LNG.

Funding

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

- cash reserves of Freeport LNG;
- loans from banks and other non-affiliate independent sources;
- additional capital contributions made to Freeport LNG by the partners;
- loans made to Freeport LNG by the partners or their affiliates; or
- any other funding source determined by the general partner of Freeport LNG.

Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG's own cash flows, borrowings or other sources, and, up to a pre-agreed total amount, with capital contributions by the limited partners. In December 2004 and February 2005, we received notices from the general partner of Freeport LNG stating that its affiliated limited partner's pre-agreed total capital contributions would be made and that additional capital contributions were being called for from all limited partners to fund a portion of Freeport LNG's budgeted 2005 expenditures. We presently intend to fund our 30% pro rata share, or approximately $2.5 million, of these capital calls, which cover the period December 2004 through June 2005. Additional capital calls may be made upon us and the other limited partners in Freeport LNG. In the event of each such future capital call, we will have the option either to contribute the requested capital or to decline to contribute. If we decline to contribute, the other limited partners could elect to make our contribution and receive back twice the amount contributed on our behalf, without interest, before any Freeport LNG cash flows are otherwise distributed to us. We currently expect to evaluate Freeport LNG capital calls on a case-by-case basis and to fund additional capital contributions that we elect to make using cash on hand, revenues from advance capacity reservation fees and funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

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

Pipeline

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

Sabine Pass LNG

Development

We are developing an LNG receiving terminal in Cameron Parish, Louisiana, near Sabine Pass. We formed Sabine Pass LNG, L.P., or Sabine Pass LNG, to develop the terminal. At December 31, 2004, we had options on three tracts of land comprising 568 acres in Cameron Parish, Louisiana for the project site. In January 2005, we entered into leases with initial terms of 30 years and which provide for six 10-year optional extensions related to this acreage. In February 2005, two of the three leases were amended, increasing the total acreage under lease to 853 acres.

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

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

In December 2004, FERC issued an order authorizing Sabine Pass LNG to construct and operate the Sabine Pass LNG receiving terminal, subject to specified conditions that must be satisfied prior to commencement of construction. In February 2005, FERC authorized Sabine Pass LNG to commence soil testing at the site of the LNG receiving terminal. Final FERC authorization to commence construction of the Sabine Pass LNG receiving terminal is expected by early April 2005, with the final notice to proceed, or NTP, expected to be delivered to the EPC contractor promptly thereafter. Terminal operations are anticipated to commence in 2008.

Total TUA

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

Under the TUA, Total has reserved 390,915,000 MMbtu of annual LNG receipt capacity, which is equivalent to approximately 1.0 Bcf/d of regasification capacity, assuming an energy content of 1.05 MMbtu per Mcf and retainage of 2%. The Total TUA is scheduled to commence no later than April 2009, 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; and a monthly operating fee of $1.3 million, which is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers). These monthly payment amounts are equivalent to payments of $0.28 per MMbtu for capacity and $0.04 per MMbtu for operating fees, respectively, of reserved monthly LNG receipt capacity. In addition, each month Sabine Pass LNG is entitled to retain 2% of the LNG delivered for Total's account for use as fuel at the facility. Total's obligations under the TUA are supported by an irrevocable guarantee in favor of Sabine Pass LNG by Total S.A.

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

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

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

Total may terminate the TUA if:

- Sabine Pass LNG has declared *force majeure* with respect to a period that has extended, or is projected to extend, for 18 months; or
- for reasons not excused by *force majeure* or Total's actions, if Sabine Pass LNG:
    - failed to deliver at least 191,625,000 MMbtu of Total's total natural gas nominations in a 12-month period;
    - failed entirely to receive at least 15 cargoes nominated by Total over a period of 90 consecutive days; or
    - failed 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 after issuance of a delinquency notice and (iii) the other party has subsequently given 30 days written notice to terminate the TUA.

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

Because Total has elected to proceed with the transaction, an additional advance capacity reservation fee payment of $10 million will be payable to Sabine Pass LNG pursuant to the Total omnibus agreement upon receiving evidence of the ability to finance construction of the facility, which will be deemed satisfied if an acceptable EPC contractor has accepted the NTP with construction. Total has the right to terminate this transaction under the omnibus agreement if these conditions are not satisfied by June 30, 2005. Though non-refundable, these capacity reservation fee payments will be amortized over a 10-year period as a reduction of Total's regasification capacity tariff under the TUA. As a result, we record the advance payments that we receive as deferred revenue to be amortized to income over the corresponding 10-year period.

Chevron USA TUA

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

Under the TUA, Chevron USA has reserved 282,761,850 MMbtu of annual LNG receipt capacity, which is equivalent to approximately 700 MMcf/d of regasification capacity, assuming an energy content of 1.085 MMbtu per Mcf and retainage of 2%. The Chevron USA TUA commences between February 2009 and July 2009, 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 and (ii) an operating fee of $0.04 per MMbtu of one-twelfth of the reserved annual LNG receipt capacity. The operating fee is adjusted annually for changes in the U.S. Consumer Price Index (All Urban Consumers). In addition, each month Sabine Pass LNG is entitled to retain 2% of the LNG delivered for Chevron USA's account for use as fuel at the facility. ChevronTexaco Corporation will be required to guarantee 80% of Chevron USA's payment obligations under the TUA.

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

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

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

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

Chevron USA may terminate the TUA if:

- Sabine Pass LNG has declared *force majeure* with respect to a period that has extended, or is projected to extend, for 18 months; or

- for reasons not excused by *force majeure* or Chevron USA's actions, if Sabine Pass LNG:
  - failed to deliver at least 141,380,925 MMbtu of Chevron USA's total natural gas nominations in a 12-month period;
  - failed entirely to receive 12 cargoes or more nominated by Chevron USA over a period of 90 days; or
  - failed to unload, or notified Chevron USA that it would be unable to unload, 37 cargoes or more scheduled for delivery by Chevron USA for a 12-month period.

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

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

Cheniere, Sabine Pass LNG and Chevron USA simultaneously entered into an omnibus agreement, under which Chevron USA agreed to make advance capacity reservation fee payments. Under the omnibus agreement, Chevron USA has the option, at the same fee, either to reduce its reserved capacity at the Sabine Pass LNG facility to 500 MMcf/d by July 1, 2005 or to increase its reserved capacity to 1.0 Bcf/d by December 1, 2005.

The omnibus agreement requires Chevron USA to make advance capacity reservation fee payments to Sabine Pass LNG totaling up to $20 million, beginning with $5 million paid in November 2004 and $7 million paid in December 2004. A third payment of $5 million will be due upon acceptance by Bechtel Corporation, or Bechtel, of the NTP under the EPC agreement. A payment of $3 million will be due if Chevron USA exercises the option to increase its reserved capacity at the Sabine Pass LNG facility to approximately 1.0 Bcf/d. Though non-refundable, these capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron USA's regasification capacity tariff under the TUA. As a result, we record the advance payments that we receive as deferred revenue to be amortized to income over the corresponding 10-year period.

EPC Agreement

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

In December 2004 a limited notice to proceed, or LNTP, was issued to and accepted by Bechtel, upon which time Bechtel was required to promptly commence performance of certain off-site engineering and preparatory work under the EPC agreement. Upon its receipt from Sabine Pass LNG of a NTP, Bechtel must commence all other aspects of the work under the EPC agreement. Sabine Pass LNG plans to issue the NTP in April 2005 but may not issue the NTP until:

- it has documented to Bechtel that it has sufficient funds, or has obtained sufficient financing, to pay the amounts required of it under the EPC agreement;
- it has obtained certain specified permits;
- it has paid to Bechtel 5% of the contract price as an advance payment;

- it has paid Bechtel all undisputed amounts owed that were earned in connection with work completed under the LNTP; and
- 90 or more days have elapsed since the LNTP.

Bechtel must achieve substantial completion in accordance with the requirements of the EPC agreement within 1,247 days after delivery of the NTP. Final completion must be attained no later than 90 days after achieving substantial completion.

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

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

Sabine Pass LNG will pay to Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work under the EPC agreement. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. Payments under the EPC agreement will be made in accordance with the payment schedule set forth in the EPC agreement. The contract price and payment schedule, including milestones, may be amended only by change order. Bechtel will be liable to Sabine Pass LNG for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a bonus of $12 million, or a lesser amount in certain cases, if Bechtel, within 1,095 days after delivery of the NTP, completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. In February 2005, a change order for $1.5 million was approved, thereby increasing the total contract price to $648.4 million.

Bechtel warrants in the EPC agreement that:

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

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

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

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

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

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

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

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

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

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

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

Operation

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

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

Funding

On February 25, 2005, Sabine Pass LNG entered into an $822 million senior secured credit facility, or Credit Facility, with a syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Securities (USA) Inc. serves as collateral agent. The Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation the Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Credit Facility will be permanently canceled. Before Sabine Pass LNG may make an initial borrowing under the Credit Facility, it will be required to provide evidence that it has received equity contributions in amounts sufficient to fund $216 million of the project costs.

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

The Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. The obligations of Sabine Pass LNG under the 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 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 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 Credit Facility with respect to hedged drawings under the Credit Facility up to a maximum of $700 million at 4.49% from July 25, 2005 to March 25, 2009 and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the swap agreements will be March 25, 2012.

Pipeline

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

Corpus Christi LNG

Development

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

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

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

In December 2003, we submitted to FERC an application for a permit to build the Corpus Christi LNG receiving terminal, as well as a separate but concurrent permit application for its related pipeline. On March 7, 2005, FERC issued the Final Environmental Impact Statement, or FEIS, for our proposed Corpus Christi LNG receiving terminal and our related pipeline. In the FEIS, FERC concluded that the facility, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. We currently anticipate that we will receive, by the second quarter of 2005, an order by FERC authorizing construction of this terminal, which will likely be subject to specified conditions that must be satisfied prior to commencement of construction. We expect to begin construction in the third quarter of 2005 and to commence terminal operations in 2008. The front-end engineering design work for the Corpus Christi LNG terminal has been completed. We expect to engage a major international EPC contractor to perform the EPC work for the facility under a lump-sum turnkey agreement.

Customers

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

Funding

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

Pipeline

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

Creole Trail LNG

Development

We are also developing an LNG receiving terminal at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana. We formed Creole Trail LNG, L.P., or Creole Trail LNG, in December 2004 to develop the terminal. We have options to lease tracts of land comprising 1,463 acres in Cameron Parish, Louisiana for the project site.

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

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

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

Customers

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

Funding

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

Pipeline

In connection with the NEPA pre-filing process, we are seeking approval to construct dual 118 mile, 42-inch diameter natural gas pipelines designed to transport 3.3 Bcf/d of regasified LNG from the site of our proposed Creole Trail LNG receiving terminal, running north/northeasterly along a corridor through six Louisiana parishes where they will terminate near Rayne, Louisiana. The pipelines are anticipated to be designed with potential interconnections to over 15 interstate and intrastate natural gas pipelines in southwest Louisiana. We believe that these existing pipelines are currently capable of transporting approximately 14.0 Bcf/d. Our ultimate decisions regarding pipeline connection to the facility will depend upon future events, including, in particular, customer interest and general market demand for natural gas from the terminal.

Other Sites

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

J & S Cheniere

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

As its initial LNG business opportunity, in August 2003, J & S Cheniere chartered its first LNG tanker, the 130,000 cm-capacity Tenaga Empat. In January 2004, J & S Cheniere signed a transportation agreement with

Sonatrach, the national oil company of Algeria, for the Tenaga Empat to actively transport LNG cargoes into the United States and Europe. Since the agreement terminated in July 2004, the vessel has been operating on a spot charter basis.

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

In August 2004, J & S Cheniere also executed a time charter agreement for up to 10 years for its third LNG tanker with a joint venture company established by K-Line, Shoei Kisen Kaisha, Ltd. and others. The new build, 154,200 cm-capacity LNG tanker is being constructed by Imabari Shipbuilding Co., Ltd. and is expected to be delivered in the fourth quarter of 2007.

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

Other Energy Business Initiatives

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

Competition

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

New supplies to replace North America's natural decline of natural gas production could be developed from a combination of the following sources:

- existing producing basins in the United States, Canada and Mexico;
- frontier basins in Alaska, northern Canada and offshore deepwater;

- areas currently restricted from exploration and development due to public policies, such as areas in the Rocky Mountains and offshore Atlantic, Pacific and Gulf of Mexico coasts; and
- imported LNG.

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

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

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

Governmental Regulation

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

FERC

In order to site, construct and operate our proposed LNG receiving terminals, we must receive authorization from FERC under Section 3 of the Natural Gas Act of 1938, or NGA. The FERC permitting process includes:

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

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

Freeport LNG

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

Sabine Pass LNG/Corpus Christi LNG/Creole Trail LNG

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

Other Federal Governmental Permits, Approvals and Consultations

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

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

Environmental Matters

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

CERCLA

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

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

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

Clean Air Act

Our operations may be 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 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.

Clean Water Act

Our operations are also subject to the federal Clean Water Act, or CWA, and analogous state and local laws. Pursuant to certain requirements of the CWA, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under an EPA general permit. In addition, our operations, including construction of LNG receiving terminals, in areas deemed to be wetlands, or which otherwise involve discharges of dredged or fill material into navigable waters of the United States, may be subject to Army Corps of Engineers permitting requirements.

Hazardous Waste

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

Endangered Species

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

Oil and Gas Exploration and Development

Although our current focus is primarily on the development of an LNG receiving terminal business, we continue to be involved 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 by industry partners. 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.

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, 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. See "—Investment in Gryphon Exploration Company" below.

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 29 prospects during 2002, 2003 and 2004 and sold interests in 28 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 less than 1% 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 24%. Nineteen of the prospects sold during 2002, 2003 and 2004 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 2005. 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 2002, 2003 and 2004, we did not participate directly in the drilling of any wells. Our industry partners drilled eight wells, nine wells and two wells in 2002, 2003 and 2004, respectively, on prospects that we generated. During 2002, six of the eight wells were productive; during 2003, seven of the nine wells were productive; and during 2004, both wells were productive. At December 31, 2004, we had a 20% working interest in one well and overriding royalty interests (ranging from 0.7% to 3.7%) in nine other productive wells.

Investment in Gryphon Exploration Company

Cheniere owns 100% of the outstanding common stock of Gryphon. However, after giving effect to the potential conversion of all shares of Gryphon's convertible preferred stock to shares of Gryphon common stock, we effectively had a 9.3% ownership interest in Gryphon as of December 31, 2004. Although historically we had the ability to exercise significant influence over Gryphon because of our participation on the Gryphon board of directors, we lost the ability to exercise such influence when our representation on Gryphon's board was reduced to one director in December 2002. As a result, effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting (see Note 8 in the Notes to the Consolidated Financial Statements). Accordingly, no disclosures concerning Gryphon's 2003 or 2004 activities are included in this Form 10-K.

In 2000, we contributed to Gryphon the license to 8,800 square miles of seismic data that we had originally licensed from Fairfield Industries. The data covered more than 1,100 outer continental shelf blocks in the shallow waters of the Gulf of Mexico (the Offshore Louisiana Area). We also assigned our rights in a Joint Exploration Agreement with an industry partner, which ran from March 2000 through August 2001. For a description of licenses sold to Gryphon in 2001, see "—Seismic Exploration Program in Offshore Texas Project Area" above.

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 2002, 2003 and 2004. 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, 2004	2003	2002
Production:			
Oil (Bbl)	1,362	17	495
Gas (Mcf)	328,677	123,392	91,470
Gas equivalents (Mcfe)	336,849	123,494	94,441
Average sales prices:			
Oil (per Bbl)	$ 36.69	$ 20.66	$20.03
Gas (per Mcf)	$ 5.93	$ 5.33	$ 2.58
Selected data per mcfe:			
Average sales price	$ 5.93	$ 5.32	$ 2.53
Production costs(1)	$ 0.35	—	$ 0.95
Oil and gas depreciation, depletion and amortization excluding impairments	$ 2.48	$ 0.98	$ 0.79

(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, 2004.

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Louisiana	—	—	5,000	5,000
Texas	640	128	35,280	5,259
Total	640	128	40,280	10,259

(1) We have no net lease acreage expiring in 2005.

At December 31, 2004, 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, 2004, 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, 2004 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 engineer's estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data that we provided.

	December 31, 2004 Proved Reserves			
	Oil (Bbl)	Gas (Mcf)	Mcfe	PV-10(1)
Offshore Texas	713	452,505	456,783	$1,821,000
Offshore Louisiana	2,308	466,615	480,463	$2,327,000
Proved Reserves	3,021	919,120	937,246	$4,148,000
Proved Developed Reserves	3,021	919,120	937,246	$4,148,000

(1) The PV-10 amount (present value of estimated pre-tax future net revenues discounted at 10%) is calculated using year-end prices of $38.10 per barrel of oil and $6.04 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, 2004.

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 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.

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.

Natural Gas Marketing

FERC regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the NGA and the Natural Gas Policy Act, or NGPA. Sales of our gas are currently not regulated and are made at market prices. However, in the past, the federal government has regulated the prices at which natural gas could be sold, and Congress could reenact price controls in the future.

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—Governmental Regulation—Environmental Matters" above. In addition, our oil and gas exploration, development and related operations are subject to the following regulations.

NORM

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.

Oil Pollution Act

The federal Oil Pollution Act, 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 18 in Notes to 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 our development of an LNG receiving terminal business.

Employees

We had 63 full-time employees as of February 28, 2005.

RISK FACTORS

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

Risks Relating to Our Financial Matters

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

From our inception, we have incurred losses, and we will likely continue to incur operating losses and experience negative operating cash flow during the next several years. Although we have begun preliminary engineering work at our Sabine Pass LNG receiving terminal, we have not yet started the construction of any of our planned LNG receiving terminals other than the facility on Quintana Island near Freeport, Texas. We do not anticipate that our LNG receiving operations will generate positive operating cash flow until at least one of our planned facilities is built, which we expect will not be until 2008. Although we may commence operations, revenues under any particular TUA may not commence for up to one year after operations at the related facility commence. We will continue to incur significant capital and operating expenditures while we develop our planned LNG receiving terminals. We do not anticipate that our oil and gas exploration activities, which are limited in scope, or advance sales of regasification capacity at our planned LNG receiving terminals will generate sufficient funds to cover these expenditures. As a result, we expect to continue to have operating losses and negative operating cash flow on a quarterly and an annual basis over the next several years. Any delays beyond the expected development periods for our planned LNG receiving terminals would prolong, and could increase the level of, our operating losses and negative operating cash flow. Our 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 our ability to do so is subject to a number of risks, including those discussed below.

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

We currently estimate that the cost of completing the four LNG development projects will exceed $3 billion, before financing costs and contingencies. To fund these development projects, we will have to pursue a variety of sources of financing, including most, if not all, of the following:

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

Our ability to obtain these types of financing will depend, in part, on factors beyond our control, such as the status of various capital and industry markets at the time financing is sought. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, if at all, even if our development projects are otherwise proceeding on schedule. In addition, our ability to obtain some types of financing may be dependent upon our ability to obtain other types of financing. For example, project-level debt financing is typically contingent upon a significant equity capital contribution from the project developer. As a result, even if we are able to identify potential project-level lenders, we may still have to obtain another form of external financing for us to fund an equity capital contribution. Any project-level debt financing will also typically be conditioned upon our prior receipt of commitments for a portion of projected regasification capacity under long-term TUAs, and our ability to fund the projects will likely be subject to the achievement of additional milestones in our project financing. A failure to obtain financing at any point in the development process could cause us to delay or fail to complete our business plan, which could cause our business to be unsuccessful.

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

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

- borrowings or debt issuances may subject us to certain restrictive covenants, including covenants restricting our ability to raise additional capital;
- borrowings or debt issuances at the project level may subject the project entity to certain restrictive covenants, including covenants restricting its ability to make distributions to us;
- additional sales of interests in our LNG projects would reduce our interest in future revenues once the LNG receiving terminals commence operations;
- the prepayment of terminal use fees by, or a business development loan from, prospective customers would reduce future revenues once the LNG receiving terminals commence operations;
- offerings of our equity securities would cause dilution of our common stock; and
- sales of oil and gas exploration prospects would reduce potential future revenues from our exploration and production activities.

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 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 an adequate portion of the capacity at each proposed LNG receiving terminal and for these customers to perform under those TUAs during the terms thereof and to maintain their creditworthiness;
- our ability to enter into a satisfactory agreement with an EPC contractor for each facility and to maintain good relationships with these contractors, and the ability of those EPC contractors to perform their obligations under EPC agreements and to maintain their creditworthiness;
- site development difficulties, including change orders, cost overruns, construction delays and changes in commodity prices (particularly steel);
- unanticipated changes in domestic and international market demand for natural gas or the supply of LNG, which will depend, in part, on supplies of, and prices for, alternative energy sources;
- competition with other domestic and international LNG receiving terminals;
- commercial arrangements for pipelines and related equipment to transport natural gas from each LNG receiving terminal;

- local and general economic conditions;
- catastrophes, such as explosions, fires and product spills;
- resistance in the local community to the development of LNG receiving terminals;
- labor disputes; and
- weather conditions.

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

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

The design, construction and operation of LNG receiving terminals and the transportation of LNG and natural gas are all highly regulated activities. FERC approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, is required in order to construct and operate our proposed LNG receiving terminals. Although we have obtained NGA Section 3 authorization to construct and operate the Freeport and Sabine Pass LNG receiving terminals, subject to specified conditions that must be satisfied prior to commencement of construction in the case of Sabine Pass LNG, we have not yet received an NGA Section 3 FERC order authorizing construction of either our Corpus Christi or Creole Trail projects. We also have not obtained several other material governmental and regulatory approvals and permits required in order to construct and operate our proposed LNG receiving terminals. We have no control over the outcome of the review and approval process. If we are unable to obtain the necessary approvals and permits, we may not be able to recover our investment in the projects. Failure to obtain any of these approvals and permits could have a material adverse effect on our business, results of operations, financial condition and prospects.

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

Many companies are considering the development of infrastructure in the domestic LNG market, including, without limitation, major oil and gas companies such as ExxonMobil, ConocoPhillips, Royal Dutch/Shell and ChevronTexaco. Other energy companies such as Sempra, Tractebel, McMoRan Exploration, AES, Excelerate Energy and other public and private companies have also proposed LNG receiving facilities, both onshore and offshore. Almost all of our competitors have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we do. The superior resources that these competitors have available to deploy could allow them to surpass us in terms of the status of their LNG receiving terminal development projects. Among other things, these competitors may not have to rely on external financing to the same extent we do, if at all.

Industry analysts have predicted that if all of the proposed LNG receiving terminals in North America that have been announced by developers were actually built, there would likely be substantial excess capacity for such terminals in the future. Accordingly, there is a substantial risk that slower-paced LNG receiving terminal development projects may never be completed. Any perception in the LNG receiving terminal marketplace that we may be unable to complete our proposed LNG receiving terminals, because competing projects are further along in their development or otherwise, could have a material adverse effect on our business, results of operations, financial condition and prospects.

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

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

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

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

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

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

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

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

Upon completion of the LNG receiving terminals, our business will be dependent upon the ability of our customers to import LNG into the United States. Political instability in foreign countries that have supplies of natural gas, or strained relations between such countries and the United States, may impede the willingness or ability of LNG suppliers in such countries to export LNG to the United States. Such foreign suppliers may also be able to negotiate more favorable prices with other LNG customers around the world than with customers in the United States, thereby reducing the supply of LNG available to be imported into the United States market. In addition, we believe that the existing fleet of tankers that is available to transport LNG is inadequate, and the failure to expand LNG tanker capacity would impede our customers' ability to import LNG into the United States. Any significant impediment to the ability to import LNG into the United States could have a material adverse affect on our business, results of operations, financial condition and prospects.

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

The development of domestic LNG receiving terminals is based on assumptions about the future price of natural gas and the availability of imported LNG. The willingness of potential customers to contract for regasification capacity would be negatively impacted and, once facilities are in operation, LNG throughput volumes would likely decline if the price of natural gas in North America is, or is forecasted to be, lower than the cost to produce and deliver LNG to North American markets. Any significant decline in the price of natural gas could cause the cost of natural gas produced from imported LNG to be higher than domestically produced natural gas. As a result, any significant decline in the price of natural gas could have a material adverse effect on our business, results of operations, financial condition and prospects.

Natural gas prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to any of the following factors:

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

We may have difficulty obtaining enough customers for regasification capacity at our proposed LNG receiving terminals to implement and complete our business plan.

Our current marketing strategy calls for us to enter into long-term TUAs covering a significant portion of the regasification capacity at each of our LNG receiving terminals, including a commitment to pay capacity reservation fees, prior to the commencement of construction of each facility. 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 a significant portion 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.

We may experience difficulty attracting additional customers because we are a small, developing company with no operating history in the LNG receiving terminal business. In order to succeed, we must convince additional potential customers, among other things, that the terminal sites that we are developing will be approved by appropriate governmental agencies and that we will be able to secure adequate financing for their construction. If these efforts are not successful, our business, results of operations, financial condition and prospects could be materially adversely affected.

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

Freeport LNG has entered into long-term TUAs with Dow and ConocoPhillips, and Sabine Pass LNG has entered into long-term TUAs with subsidiaries of Total S.A. and ChevronTexaco. Each of the TUAs contains various termination rights. For example, Dow may terminate its TUA during the construction period of the proposed Freeport LNG terminal if it reasonably determines that "substantial completion" of the terminal will not occur prior to a future confidential date. Similarly, ConocoPhillips may terminate its TUA during the construction period of the proposed Freeport LNG terminal if it reasonably determines that the "conversion date" (the date of conversion of construction loans into term loans under the credit facility between Freeport LNG and ConocoPhillips) will not occur prior to a future confidential date. Total has the right to terminate its TUA under an omnibus agreement if specified conditions are not satisfied by June 30, 2005, including evidence of the ability to finance construction of the facility. Total may also terminate its TUA with Sabine Pass 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. Chevron USA may terminate its TUA with Sabine Pass LNG if Sabine Pass LNG fails or is unable to load a specified number of cargoes scheduled for delivery by Chevron USA during a twelve month period. 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 under its respective TUA, our business, results of operations, financial condition and prospects could be materially adversely affected, even if we were to be ultimately successful in seeking damages from that counterparty for a breach of the TUA.

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

Sabine Pass LNG entered into an EPC agreement in December 2004 with Bechtel. Freeport LNG has advised us that it has entered into a lump-sum turnkey agreement for the construction of its LNG receiving terminal. We also plan to enter into similar types of contracts with a major international EPC contractor for the construction of our proposed Corpus Christi and Creole Trail LNG receiving terminals. The success of our LNG receiving terminal development projects is highly dependent on our ability to enter into acceptable contracts with reputable EPC contractors and for the EPC contractors to perform their obligations under the contracts, including completing the projects on a timely basis. However, we may not be able to enter into an acceptable EPC contract for the construction of our proposed Corpus Christi or Creole Trail LNG receiving terminal. In addition, we have no prior experience working with any EPC contractor, including Bechtel. As a result, we may encounter unexpected delays or problems in connection with the construction of any of our proposed LNG receiving terminals. In addition, any EPC agreement could be terminated under certain circumstances prior to completion of construction. For example, see the description of the termination provisions of the EPC agreement with Bechtel under "—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.

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

We do not have any prior experience in constructing LNG receiving terminals, and no LNG receiving terminal has been constructed in the United States in over 25 years. As construction progresses, we may decide or be forced to submit change orders to our EPC contractor that could result in a longer construction period 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.

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

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

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 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 obligated to lease their mineral rights to us except where we have already obtained lease options. In addition, other major and independent oil and gas companies with financial resources significantly greater than ours may bid against us for the purchase of oil and gas leases. If we are unsuccessful in acquiring these leases, permits, options and other interests, the area covered by our 3D seismic data that could be explored through drilling will be significantly reduced, and our business, results of operations, financial condition and prospects could be materially adversely effected.

If we are unable to obtain satisfactory turnkey contracts, we may have to assume additional risks and expenses when drilling wells.

We anticipate that any wells drilled in which we have an interest will be drilled by established industry contractors under turnkey contracts that limit our financial and legal exposure. Under a turnkey drilling contract, a negotiated price is agreed upon and the money placed in escrow. The contractor then assumes all of the risk and expense, including any cost overruns, of drilling a well to contract depth and completing any agreed upon evaluation of the wellbore. Upon performance of all these items, the escrowed money is released to the contractor.

Circumstances may arise, however, where a turnkey contract is not economically beneficial to us or is otherwise unobtainable from proven industry contractors. In such instances, we may decide to drill wells on a day-rate basis. Under a day-rate drilling contract, the operator pays an agreed sum for each day of drilling required to reach contract depth. All risk and expense of drilling a well to total depths lies with the operator in day-rate contracts. The drilling of such test wells would subject us to the usual drilling hazards such as cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution and other environmental risks. We would also be liable for any cost overruns attributable to drilling problems that otherwise would have been covered by a turnkey contract. These liabilities, if incurred, could have a materially adverse effect on our business, results of operations, financial condition and prospects.

If we are unsuccessful at marketing our oil and gas at commercially acceptable prices, our profitability will decline.

Our ability to market oil and gas at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- federal and state regulation of production and transportation;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these factors could have a material adverse effect on our business, results of operations, financial condition and prospects.

Shortage of rigs, equipment, supplies or personnel may restrict our operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, demand for, and wage rates of, qualified drilling rig crews rises with increases in the number of active rigs in service. Shortages of drilling rigs, equipment or supplies could delay or restrict our exploration and development operations, which in turn could have a material adverse effect on our business, results of operations, financial condition and prospects.

We depend on industry partners and could be seriously harmed if they do not perform satisfactorily, which is usually not within our control.

Because we have few employees and limited operating revenues, we are and will continue to be largely dependent on industry partners for the success of our oil and gas exploration projects. We could be seriously harmed if we fail to attract industry partners to participate in the drilling of prospects which we identify or if our industry partners do not perform satisfactorily on projects that affect us. We often have and will continue to have no control over factors that would influence the performance of our partners.

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

Numerous uncertainties, including those beyond our control, are inherent in estimating quantities of proved oil and gas reserves. Information included herein for 2004 relating to estimates of our proved reserves is based on reports prepared by Sharp Petroleum Engineering, Inc. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows may vary considerably from the actual results because of a number of variable factors and assumptions involved. These include:

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

Therefore, the estimates of the quantities of oil and gas and the expected future net cash flows computed by different engineers or by the same engineers (but at different times) may vary significantly. The actual production, revenues and expenditures related to our reserves may vary materially from the engineers' estimates. In addition, we may make changes to our estimates of reserves and future net cash flows. These changes may be based on the following factors:

- production history;
- results of future development;
- oil and gas prices;
- performance of counterparties under agreements to which we are a party; and
- operating and development costs.

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

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

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

Because of our lack of diversification, factors harming the oil and gas industry in general, including downturns in prices for oil and gas, would be especially harmful to us.

We are an independent energy company and are not actively engaged in any other industry. Our revenues and results of operation are substantially dependent on the oil and gas industry in general and the prevailing prices for oil and gas in particular. Circumstances that harm the oil and gas industry in general will have an especially harmful effect on us. Oil and 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 oil and gas;
- political conditions in international oil producing regions;
- the extent of domestic production and importation of oil in relevant markets;
- the level of consumer demand;
- weather conditions;
- the competitive position of oil or gas as a source of energy as compared with other energy sources;
- the refining capacity of oil purchasers; and
- the effect of federal and state regulation on the production, transportation and sale of oil and gas.

It is likely that adverse changes in the oil and gas market or the regulatory environment would have an adverse effect on our business, results of operations, financial condition and prospects, including our ability to develop and implement our LNG project and to obtain capital from lending institutions, industry participants, private or public investors or other sources.

Risks Relating to Our Business in General

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

As of February 28, 2005, we had 63 employees, who, for the most part, are focused on the pre-construction stages of the development of our proposed LNG receiving terminals. As we begin construction of the LNG receiving terminals, we will have to hire new onsite employees to manage the construction of each facility. Later, once our proposed LNG receiving terminals commence operations, we will have to hire an entire staff to operate each facility. We have no experience in the construction or operation of LNG receiving terminals, and, as a result, we will be forced to rely to a significant extent on the new employees we hire to perform these functions. We currently estimate that at least 60 employees will be required to operate each LNG receiving terminal. As our operations expand, we will also have to expand our administrative staff. If we are not able to successfully manage the expansion of our business, our business, results of operation, financial condition and prospects could be materially adversely affected.

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

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

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

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

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

Existing and future United States governmental regulation, taxation and price controls could seriously harm us.

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

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

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

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

Existing environmental laws and regulations may be revised or new laws and regulations may be adopted or become applicable to us. Revised or additional laws and regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from insurance or our customers, could have a material adverse effect on our business, results of operations, financial condition and prospects.

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

We own a 30% limited partner interest in Freeport LNG, an effective 9.3% interest in Gryphon (after giving effect to the potential conversion of Gryphon's preferred stock) and a minority interest in J & S Cheniere. Some of our value is attributable to these investments. In this annual report, we may use the words "our," "we" or "us" in describing these investments or their assets and operations; however, we do not exercise control over Freeport LNG, Gryphon or J & S Cheniere. The management team of Freeport LNG, Gryphon or J & S Cheniere could make business decisions without our consent that could impair the economic value of our investments in those entities. Any such diminution in the value of either investment could have an adverse impact on our business, results of operations, financial condition and prospects.

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

The Investment Company Act of 1940, or Investment Company Act, requires registration for companies that are engaged primarily in the business of investing, reinvesting, owning, holding or trading in securities. A company may be deemed to be an investment company if it owns investment securities with a value exceeding 45% of the value of its total assets (excluding government securities and cash items) on an unconsolidated basis, unless an exemption or safe harbor applies. Securities issued by companies other than majority-owned subsidiaries are generally counted as investment securities for purposes of the Investment Company Act. We own minority equity interests in certain entities that could be counted as investment securities. If the value of our minority interests in these entities exceeds 45% of the value of our total assets (excluding government securities and cash items), we could be considered an investment company in the future if we do not obtain an exemption or qualify for a safe harbor. As a result, fluctuations in the value, or the income and revenues attributable to us from our ownership of interests in companies that we do not control could cause us to be deemed an investment company. Registration as an investment company would subject us to restrictions that are inconsistent with our fundamental business strategy. We may have to take actions, including buying, refraining from buying, selling or refraining from selling securities or other assets, contrary to what we would otherwise deem to be in our best interest, in order to continue to avoid registration under the Investment Company Act.

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

If we begin conducting operations outside of the United States, our operations may be affected by economic, political and governmental conditions in the countries where we engage in business. Any disruption caused by these factors could harm our business. Risks associated with sales and operations outside of the United States include risks of:

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

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

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

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

ITEM 3. *LEGAL PROCEEDINGS*

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

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

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

None.

PART II

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

Our common stock has traded on the American Stock Exchange under the symbol LNG since March 24, 2003. Our common stock had previously traded on the American Stock Exchange under the symbol CXY from March 5, 2001 through March 23, 2003. The table below presents the high and low daily closing sales prices of the common stock, as reported by the American Stock Exchange, for each quarter during 2003 and 2004.

	High	Low
Three Months Ended		
March 31, 2003	$ 1.60	$ 1.20
June 30, 2003	5.10	1.39
September 30, 2003	6.03	4.29
December 31, 2003	11.90	5.05
Three Months Ended		
March 31, 2004	19.08	11.11
June 30, 2004	20.84	11.07
September 30, 2004	20.84	16.25
December 31, 2004	64.70	20.13

As of February 28, 2005, we had 26.8 million shares of common stock outstanding held by approximately 5,200 beneficial owners.

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

ITEM 6. *SELECTED FINANCIAL DATA*

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

	Year Ended December 31, (in thousands, except per share data)				
	2004	**2003**	**2002**	**2001**	**2000**
Revenues	$ 1,998	$ 658	$ 239	$ 2,373	$ 5,320
LNG terminal development expenses (1)	17,166	6,705	1,557	1,789	343
Production costs	117	—	90	420	389
Depreciation, depletion and amortization	1,324	429	369	1,244	3,371
Ceiling test write-down	—	—	—	5,126	—
General and administrative expenses	12,476	2,542	1,918	2,504	1,595
Loss from operations	(29,085)	(9,018)	(3,695)	(8,710)	(378)
Interest income	501	3	8	19	24
Equity in net loss of affiliate (2)	—	—	(2,185)	(2,974)	(427)
Equity in net loss of limited partnership (3)	(1,346)	(4,471)	—	—	—
Gain on sale of properties	—	—	340	—	—
Gain on sale of LNG assets	—	4,760	—	—	—
Gain on sale of limited partnership interest	—	423	—	—	—
Reimbursement from limited partnership investment	2,500	—	—	—	—
Minority Interest (4)	2,862	3,015	—	—	—
Loss on extinguishment of debt	—	—	(100)	—	—
Net loss	(24,568)	(5,288)	(5,632)	(11,665)	(781)
Net loss per share (basic and diluted) (5)	(1.26)	(0.36)	(0.42)	(0.89)	(0.07)
Weighted average shares outstanding (basic and diluted)(5)	19,447	14,772	13,297	13,035	10,733

	December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Cash	$308,443	$ 1,258	$ 590	$ 611	$ 1,889
Working Capital	305,752	155	(1,413)	(530)	1,234
Oil and gas properties, proved, net	2,368	1,087	843	1,929	6,728
Oil and gas properties, unproved	16,688	18,048	16,751	16,237	18,254
Total assets	333,567	24,591	21,059	25,024	34,666
Total liabilities	5,529	4,332	3,262	1,874	1,604
Deferred revenue	23,000	1,000	—	—	—
Total stockholders' equity	304,601	19,139	17,797	23,149	33,061

(1) The year ended 2002 includes $1.7 million in recoveries of project expenses reimbursable under the term of an agreement related to our sale of the Freeport LNG site, which closed in February 2003. See Note 9 to our Consolidated Financial Statements.

(2) Effective January 1, 2003, we began accounting for this investment in Gryphon using the cost method of accounting. The amounts listed for 2002, 2001 and 2000 represent our equity in the net loss of Gryphon under the equity method of accounting. See Note 8 to our Consolidated Financial Statements.

(3) Represents our equity in the net loss of Freeport LNG. See Note 9 to our Consolidated Financial Statements.

(4) Represents minority interest in the net loss of Corpus Christi LNG. See Note 10 to our Consolidated Financial Statements.

(5) Net loss per share and weighted average shares outstanding have been restated to give effect to the one-for-four reverse stock split which was effective in October 2000.

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

General

We are engaged primarily in the development of an LNG receiving terminal business and related LNG business opportunities centered on the U.S. Gulf Coast. Upon completion of LNG receiving terminals, our business will consist of receiving deliveries of LNG from LNG carriers, processing such LNG to return it to a gaseous state and delivering it to pipelines for transportation to purchasers. We own interests in four limited partnerships that are developing LNG receiving terminals:

- Freeport LNG, in which we own a 30% interest, is developing an LNG receiving terminal on Quintana Island, near Freeport, Texas;
- Sabine Pass LNG, in which we own a 100% interest, is developing an LNG receiving terminal near Sabine Pass in Cameron Parish, Louisiana;
- Corpus Christi LNG, in which we own a 100% interest (33.3% of which we acquired in February 2005), is developing an LNG receiving terminal near Corpus Christi, Texas; and
- Creole Trail LNG, in which we own a 100% interest, is developing an LNG receiving terminal at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana.

Freeport LNG

Freeport LNG is developing an LNG receiving terminal with an anticipated regasification capacity of 1.5 Bcf/d. We developed this project and then sold a 60% limited partner interest to an affiliate of the general partner of Freeport LNG and a 10% limited partner interest to another unaffiliated party. We continue to own a 30% limited partner interest in Freeport LNG. Freeport LNG has received authorization from FERC to commence construction of the Freeport LNG facility. In order to complete certain phases of the project, Freeport LNG will be required to satisfy remaining conditions specified by FERC. Construction began in the first quarter of 2005, and we currently expect that terminal operations will commence in 2008.

In June 2003, Dow signed an agreement with Freeport LNG for the potential long-term use of the receiving terminal beginning with commercial start-up of the facility expected to occur in 2008. In 2004, Dow entered into a 20-year TUA with Freeport LNG providing for a firm commitment by Dow for the use of 500 MMcf/d of regasification capacity.

In December 2003, ConocoPhillips and Freeport LNG signed an agreement under which ConocoPhillips would reserve approximately 1.0 Bcf/d of regasification capacity in the Freeport LNG receiving terminal. ConocoPhillips would also obtain a 50% interest in the general partner of Freeport LNG and provide a substantial majority of the financing to construct the facility. Freeport LNG received a non-refundable capacity reservation fee of $10 million from ConocoPhillips in January 2004. The ConocoPhillips transaction closed in July 2004, at which time ConocoPhillips paid Freeport LNG an additional non-refundable $3.5 million to secure an option on 500 MMcf/d of additional capacity in the event the terminal is expanded.

Sabine Pass LNG

Our 100%-owned limited partnership entity, Sabine Pass LNG, is developing an LNG receiving terminal with an initial regasification capacity of 2.6 Bcf/d. In December 2004, FERC issued an order authorizing Sabine Pass LNG to construct and operate the Sabine Pass LNG receiving terminal, subject to specified conditions that must be satisfied prior to commencement of construction. In February 2005, FERC authorized Sabine Pass LNG to commence soil testing at the site of the LNG receiving terminal. Final FERC authorization to commence construction of the Sabine Pass LNG receiving terminal is expected by early April 2005, with the NTP expected to be delivered to the EPC contractor promptly thereafter. Terminal operations are anticipated to commence in early 2008.

In September 2004, Sabine Pass LNG entered into a TUA to provide Total with approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. 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 Total S.A. of certain Total obligations under the TUA. Cheniere, Sabine Pass LNG and Total also entered into an omnibus agreement in September 2004, under which the TUA remains subject to certain conditions described above under "Items 1. and 2. Business and Properties—LNG Receiving Terminal Development—Our LNG Receiving Terminals—Sabine Pass LNG—Total TUA."

The TUA provides for Total to pay a fee of $0.32 per MMbtu, subject in part to adjustment for inflation, for approximately 1.0 Bcf/d of regasification capacity for a 20-year period beginning not later than April 1, 2009. In addition, under the omnibus agreement, if Sabine Pass LNG enters into a new TUA with a third party, other than Cheniere affiliates, for capacity of 50 MMcf/d or more, with a term of five years or more, prior to the commercial start date of the terminal, Total will have the option, exercisable within 30 days of the receipt of notice of such transaction, to adopt the pricing terms contained in such new TUA for the remainder of the term of the Total TUA.

Because Total has elected to proceed with the transaction, an additional advance capacity reservation fee payment of $10 million will be payable to Sabine Pass LNG under the Total omnibus agreement upon receiving evidence of the ability to finance construction of the facility, which will be deemed satisfied if an acceptable EPC contractor has accepted the notice to proceed with construction. Total has the right to terminate this transaction under the omnibus agreement if this remaining condition is not satisfied by June 30, 2005.

In November 2004, Sabine Pass LNG entered into a TUA to provide Chevron USA with approximately 700 MMcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. Chevron USA has also agreed to make advance capacity reservation fee payments. The TUA provides for Chevron USA to pay a fee of $0.32 per MMbtu, subject in part to adjustment for inflation, for approximately 700 MMcf/d of regasification capacity for a 20-year period beginning not later than July 1, 2009. Chevron USA has the option, at the same fee, either to reduce its reserved capacity at Sabine Pass to approximately 500 MMcf/d by July 1, 2005 or to increase its reserved capacity to approximately 1.0 Bcf/d by December 1, 2005. ChevronTexaco will guarantee certain Chevron USA payment obligations under the TUA.

Chevron USA is required to make advance capacity reservation fee payments to Sabine Pass LNG totaling up to $20 million, of which $12 million has been paid. Further advance capacity reservation fee payments are due as described below under "—Liquidity and Capital Resources—LNG Terminal Development—Sabine Pass LNG."

We estimate that the cost of constructing the 2.6 Bcf/d Sabine Pass LNG facility will be approximately $750 million to $850 million, before financing costs and contingencies. In December 2004, we entered into a lump-sum turnkey agreement with Bechtel at a cost of $646.9 million. Our cost estimate is subject to change due to such items as cost overruns, change orders and changes in commodity prices (particularly steel). In February 2005, a change order for $1.5 million was approved, thereby increasing the total contract price to $648.4 million. On February 25, 2005, Sabine Pass LNG entered into an $822 million senior secured credit facility, or Credit Facility, with a syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Securities (USA) Inc. serves as collateral agent. The Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation the Sabine Pass LNG receiving terminal.

Corpus Christi LNG

We own a 100% limited partner interest in Corpus Christi LNG, which is developing an LNG receiving terminal with a regasification capacity of 2.6 Bcf/d. We are marketing 1.0 Bcf/d of capacity under long-term TUAs of $0.32 per MMbtu, the same price contracted for at Sabine Pass. We intend to market the remaining capacity under other long-term, mid-term and/or short-term contracts. However, we may not be able to obtain any TUAs for Corpus Christi on terms acceptable to us at that price, or at all. We currently anticipate that, by the second quarter of 2005, FERC will issue an order authorizing construction of this terminal, which will likely be subject to specified conditions that must be satisfied prior to commencement of construction. Construction is anticipated to begin in the third quarter of 2005, with terminal operations commencing in 2008.

Creole Trail LNG

We own a 100% limited partner interest in Creole Trail LNG. In November 2004, we announced the acquisition of an option on a proposed LNG site at the mouth of the Calcasieu Channel in Cameron Parish, Louisiana, which we refer to as Creole Trail LNG. We plan to develop Creole Trail in the same manner as our Sabine Pass LNG facility, though it will be a larger facility with two docks, four 160,000 cm storage tanks and an initial regasification capacity of 3.3 Bcf/d. We anticipate marketing 1.0 Bcf/d of capacity under long-term TUAs at $0.32 per MMbtu, the same price contracted for at Sabine Pass LNG. We intend to market the remaining capacity under other long-term, mid-term and/or short-term contracts. However, we may not be able to obtain any TUAs for Creole Trail on terms acceptable to us, or at all. In January 2005, we initiated the NEPA pre-filing process with FERC to obtain an order to commence construction of the facility. Construction is anticipated to begin in the third quarter of 2006, with terminal operations commencing in 2009.

Other Activities

In December 2003, we entered into an option agreement with J & S Cheniere (an entity in which we are a minority owner), providing J & S Cheniere with an option to purchase LNG regasification capacity of up to 200 MMcf/d in each of our Sabine Pass and Corpus Christi LNG facilities. We were paid $1 million in connection with the execution of the option agreement by J & S Cheniere in January 2004. The option agreement may be terminated by J & S Cheniere and the option fee refunded in the event that FERC does not issue an order authorizing Cheniere LNG to construct at least one of the facilities or if Cheniere LNG decides not to proceed with the development of at least one of the facilities, in either case, before December 15, 2005. J & S Cheniere may exercise the option as to each facility by entering into a TUA no later than 60 days after receipt of written notification by us that FERC has issued an order authorizing construction of at least one of the facilities and all other approvals and permits have been received that are necessary to begin construction of the facility.

As part of our overall energy business strategy, we are pursuing additional potential LNG receiving terminal projects, downstream opportunities and upstream opportunities. We are also engaged, to a lesser extent, in oil and gas exploration and development activities in the Gulf of Mexico.

Liquidity and Capital Resources

LNG Terminal Development

We are primarily engaged in developing LNG receiving terminals. These LNG terminal projects will require significant amounts of capital and are subject to risks and delays in completion. Even if successfully completed, these projects will not begin to operate and generate significant cash flows until several years from now. As a result, our business success will depend to a significant extent upon our ability to obtain the funding necessary to construct these LNG terminals, to bring them into operation on a commercially viable basis and to finance the costs of staffing, operating and expanding our company during that process.

We own a 30% limited partner interest in Freeport LNG, a 100% limited partner interest in Sabine Pass LNG, a 100% limited partner interest in Corpus Christi LNG and a 100% limited partner interest in Creole Trail LNG. We currently estimate that, in the aggregate, these four terminal projects will require in excess of $3 billion, before financing costs and contingencies, to construct and place in service. In addition, we have related potential pipeline projects in different stages of development. These projects and the other downstream and upstream opportunities we are pursuing, if successfully pursued, will also require significant amounts of capital.

In January 2004, we initiated the marketing of regasification capacity for our proposed Sabine Pass and Corpus Christi LNG receiving terminals. We have been actively engaged in the marketing process since that time, seeking long-term, creditworthy "anchor tenant" TUA contracts for our planned regasification capacity. Upon execution of each TUA, we typically receive an advance payment for regasification capacity sold. This provides additional capital to help meet our ongoing liquidity needs. Furthermore, these TUAs are designed to serve as collateral to facilitate project level debt financing that we intend to obtain with respect to the construction of the related LNG receiving terminal.

As of December 31, 2004, we had working capital of $305.8 million. We must augment our existing sources of cash with significant additional funds in order to carry out our business plan.

We currently expect that capital requirements for the four current LNG terminal projects will be financed in part through issuances of project-level debt, equity or a combination of the two and in part with net proceeds of debt or equity securities issued by Cheniere or other Cheniere borrowings. Our anticipated capital requirements and financing plans for the four current LNG terminal development projects follow.

Freeport LNG

We developed the Freeport LNG project and received cash proceeds of $6.7 million in connection with the disposition in February 2003 of a 60% limited partner interest to an affiliate of the general partner of Freeport LNG (which, in December 2004, sold a 15% limited partner interest to a subsidiary of Dow) and the disposition in March 2003 of a 10% limited partner interest to another unaffiliated party. We retain a 30% limited partner interest in Freeport LNG.

We have been advised by Freeport LNG that it has entered into a lump-sum turnkey contract for its 1.5 Bcf/d facility and that the estimated cost to construct this facility is approximately $750 million, before financing costs and contingencies. ConocoPhillips has agreed to provide a substantial majority of the financing to construct this facility. ConocoPhillips has also paid Freeport LNG an aggregate of $10 million in connection with the reservation of approximately 1.0 Bcf/d of LNG regasification capacity at the terminal and $3.5 million for options of up to 500 MMcf/d of additional capacity in the event the terminal is expanded.

Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG's own cash flows, borrowings or other sources, and, up to a pre-agreed total amount, with capital contributions by the limited partners. In December 2004 and February 2005, we received notices from the general partner of Freeport LNG stating that its affiliated limited partner's pre-agreed total capital contributions would be made and that additional capital contributions were being called for from all limited partners to fund a portion of Freeport LNG's budgeted 2005 expenditures. We presently intend to fund our 30% pro rata share, or approximately $2.5 million, of these capital calls, which covered the period December 2004 through June 2005. Additional capital calls may be made upon us and the other limited partners in Freeport LNG. In the event of each such future capital call, we will have the option either to contribute the requested capital or to decline to contribute. If we decline to contribute, the other limited partners could elect to make our contribution and receive back twice the amount contributed on our behalf, without interest, before any Freeport LNG cash flows are otherwise distributed to us. We currently expect to evaluate Freeport LNG capital calls on a case-by-case basis and to fund additional capital contributions that we elect to make using cash on hand, revenues from advance capacity reservation fees and funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

Sabine Pass LNG

On February 25, 2005, Sabine Pass LNG entered into an $822 million Credit Facility with a syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Securities (USA) Inc. serves as collateral agent. The Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation the Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Credit Facility will be permanently canceled. Before Sabine Pass LNG may make an initial borrowing under the Credit Facility, it will be required to provide evidence that it has received equity contributions in amounts sufficient to fund $216 million of the project costs.

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

The Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. The obligations of Sabine Pass LNG under the 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 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 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 Credit Facility with respect to hedged drawings under the 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.

In December 2004, Sabine Pass LNG entered into a lump-sum turnkey EPC agreement with Bechtel pursuant to which Bechtel will provide Sabine Pass LNG with services for the engineering, procurement and construction of the Sabine Pass LNG receiving terminal. In December 2004, a LNTP was issued to and accepted by Bechtel, at which time Bechtel was required to promptly commence performance of certain off-site engineering and preparatory work under the EPC agreement. Upon its receipt from Sabine Pass LNG of a NTP, Bechtel must commence all other aspects of the work under the EPC agreement. Sabine Pass LNG generally may not issue the NTP until, among other things, it has documented to Bechtel that it has sufficient funds, or has obtained sufficient financing, to pay the amounts required of it under the EPC agreement and it has paid to Bechtel 5% of the contract price, or approximately $32.3 million, as an advance payment.

Sabine Pass LNG will pay to Bechtel a contract price of $646.9 million plus certain reimbursable costs for the work under the EPC agreement. This contract price is subject to adjustment for changes in certain commodity prices, contingencies, change orders and other items. Payments under the EPC agreement will be made in accordance with the payment schedule set forth in the EPC agreement. The contract price and payment schedule, including milestones, may be amended only by change order. Bechtel will be liable to Sabine Pass LNG for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a bonus of $12 million, or a lesser amount in certain cases, if Bechtel, within 1,095 days after delivery of the NTP, completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. In February 2005, a change order for $1.5 million was approved, thereby increasing the total contract price to $648.4 million.

Total has paid Sabine Pass LNG a nonrefundable advance capacity reservation fee of $10 million in connection with the reservation of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG receiving terminal. An additional advance capacity reservation fee payment of $10 million will be payable to Sabine Pass LNG upon satisfaction of specified conditions. The capacity reservation fee payments will be amortized over a 10-year period as a reduction of Total's regasification capacity fee under the TUA. As a result, we record the advance payments that we receive, though non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

In November 2004, Chevron USA paid Sabine Pass LNG a nonrefundable advance capacity reservation fee of $5 million. Chevron USA paid an additional advance capacity reservation fee of $7 million in December 2004. Further advance capacity reservation fees by Chevron USA will also be due under the TUA: $5 million upon confirmation of evidence of the ability to finance construction of the facility, and $3 million if Chevron USA exercises the option to increase its capacity at Sabine Pass to approximately 1.0 Bcf/d. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron USA's regasification capacity tariff under the TUA. As a result, we record the advance payments that we receive, though non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

In January 2004, we were paid $1 million by J & S Cheniere in connection with an option to purchase LNG regasification capacity in each of our Sabine Pass and Corpus Christi LNG facilities. We have recorded the option fee as deferred revenue, and it is anticipated that the option fee will be recognized as revenue over the initial five-year periods of the TUAs contemplated by the option agreement.

Corpus Christi LNG

We currently estimate that the cost of constructing the Corpus Christi LNG facility will be approximately $650 million to $750 million, before financing costs and contingencies. The former minority owner was required to fund 100% of the first $4.5 million of Corpus Christi LNG's expenditures, which amount was reached as of March 31, 2004, and thereafter 33.3%, with us funding the balance. In February 2005, we acquired the minority owner's interest in Corpus Christi LNG, and from that time forward we will fund or arrange for funding of 100% of Corpus Christi LNG's expenditures. We currently expect to be able to fund the costs of the Corpus Christi LNG terminal using project financing similar to that used for our Sabine Pass LNG facility, proceeds from future debt or equity offerings, or a combination thereof. If these types of financing are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Creole Trail LNG

We currently estimate that the cost of constructing the Creole Trail LNG facility will be approximately $850 million to $950 million, before financing costs and contingencies. We currently expect to be able to fund the costs of the Creole Trail LNG terminal using project financing similar to that used for our Sabine Pass LNG facility, proceeds from future debt or equity offerings, or a combination thereof. If these types of financing are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Short-Term Liquidity Needs

We anticipate funding our more immediate liquidity requirements, including some expenditures related to the construction of the LNG receiving terminals, through a combination of any or all of the following:

- cash balances;
- issuances of Cheniere debt and equity securities, including issuances of common stock pursuant to exercises by the holders of existing warrants and options;
- LNG receiving terminal capacity reservation fees;

- collection of receivables; and
- sales of prospects generated by our exploration group.

Historical cash flows

Net cash used in operations totaled $661,000 in 2004 compared to $7.6 million in 2003. The improvement in 2004 primarily resulted from the receipt of $22 million in advance regasification capacity fees related to our Sabine Pass LNG terminal. This amount was more than offset, however, as a result of the expansion of our LNG receiving terminal business. In the first quarter of 2003, we phased out our direct involvement in developing the Freeport LNG terminal site, but in subsequent periods, we accelerated the development schedule of our Sabine Pass, Corpus Christi and Creole Trail LNG receiving terminals.

Net cash provided by investing activities was $1.2 million in 2004 as a result of the reimbursement from limited partnership investment, sales of our interests in oil and gas prospects and collection of proceeds from the sale of a limited partnership interest, partially offset by oil and gas property and fixed asset additions, LNG site costs, the purchase of the restricted certificate of deposit and additional capital contributions to Freeport LNG. Net cash provided by investing activities was $30,000 in 2003 as a result of the sale of LNG assets, a limited partnership interest and interests in oil and gas prospects, mostly offset by oil and gas property and fixed asset additions.

Net cash provided by financing activities was $306.7 million in 2004 compared to $8.2 million in 2003. The significant increase in 2004 relates to the completion of our $300 million public equity offering of common stock in December 2004 (before related offering costs of $14.1 million). In addition, we received $20.9 million related to a private sale of our common stock in January 2004 (before offering costs of $965,000) and exercises of warrants and stock options throughout the year. We also received partnership contributions from a minority owner in Corpus Christi LNG. All of the aforementioned were partially offset by debt issuance costs related to our LNG project debt financing and repayments of notes payable. Cash provided by financing activities in 2003 resulted from a private sale of common stock, exercises of warrants and stock options, and partnership contributions by a minority owner in Corpus Christi LNG, partially offset by repayments of notes payable.

Primarily as a result of the aforementioned, our working capital increased to $305.8 million as of December 31, 2004 compared to $155,000 at December 31, 2003.

Issuances of Common Stock

Since our inception, the primary source of financing for our operating expenses, investments in our exploration program and investments in our development of LNG receiving terminals has been the sale of our equity securities. During 2004 and 2003, we raised $305.9 million and $4.4 million, respectively, net of offering costs, from the exchange or exercise of warrants, the exercise of stock options, the public equity offering of common stock and the sale of Cheniere common stock to accredited investors pursuant to Regulation D. Proceeds of the offerings were used for the development of LNG receiving terminals and for general corporate purposes.

We issued a total of 9 million shares of common stock in 2004. In January 2004, we issued 1.1 million shares of common stock in a private placement under Regulation D to twelve accredited investors for total consideration of $14.9 million, or $13.50 per share. We paid a 6.5% sales commission totaling $965,000, resulting in $13.9 million of net proceeds received from the offering. In February 2004, under the 2003 Stock Incentive Plan, 383,000 shares were issued to employees and outside directors in the form of bonus and restricted stock awards related to our performance in 2003. We recorded $2.4 million of non-cash compensation expense in 2004 related to the issuance of 161,000 shares (bonus stock awards) valued at $15.00 per share, which shares were fully vested on the date of grant. In addition, we recorded $3.3 million of deferred compensation as a reduction to stockholders' equity related to the issuance of 222,000 shares (restricted stock awards) valued at $15.00 per share on the grant date that vest on each of the first and second anniversaries of the grant date. In November 2004, 118,176 shares were issued under the 2003 Stock Incentive Plan to employees and outside directors in the form of restricted stock awards related to our performance in 2004. We recorded $4.9 million of deferred compensation as a reduction to stockholders' equity based on the $41.85 value per share on the date of the grant. One-third of the restricted shares granted in November 2004 vest on each of the first, second and third anniversaries of the grant date. In December 2004, we issued 5 million shares of common stock in connection with a public offering, for which we received net proceeds of $285.9 million. Throughout 2004, we issued a total of 907,916 shares pursuant to the exercise of warrants, resulting in net cash proceeds of $3.4 million. We also issued 1.2 million shares pursuant to the exercise of stock options, resulting in net proceeds of $2.7 million. During 2004, 276,706 shares of our common stock were issued in satisfaction of cashless exercises of stock options and warrants to purchase 195,062 and 125,000 shares, respectively.

We issued a total of 3.2 million shares of common stock in 2003. In April 2003, we issued 750,000 shares of common stock pursuant to a contingent contractual obligation related to Cheniere's 2001 acquisition of an option to lease the Freeport LNG terminal site. In May 2003, we issued 792,892 shares of common stock to seventeen investors in a private placement made pursuant to Regulation D. The purchase price of the shares included cash of $1.2 million and the surrender of existing warrants to purchase 792,892 shares of our common stock. Offering expenses relating to the private placement were $57,000. In August 2003, we issued 378,308 shares pursuant to a cashless exercise of warrants to purchase 700,000 shares. Throughout 2003, we issued a total of 1.1 million shares pursuant to the exercise of warrants, resulting in net cash proceeds of $2.9 million. We also issued 187,500 shares pursuant to the exercise of stock options, resulting in proceeds of $292,000.

We did not sell any equity securities in 2002.

Contractual Obligations

We are committed to making cash payments in the future on certain of our contracts. We have no off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed the debt of any other party. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2004 (in thousands).

	Payments Due for Years Ended December 31,						
	Total	2005	2006	2007	2008	2009	Thereafter
Operating Leases(1)	$4,217	$642	$728	$505	$505	$461	$1,376
Telecommunication Contract(1)	381	127	127	127	—	—	—
Total	$4,598	$769	$855	$632	$505	$461	$1,376

(1) A discussion of these obligations can be found at Note 17 of the Notes to Consolidated Financial Statements.

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

Lease Obligations

In October 2003, we entered into a lease agreement for new office space with a term which runs from December 2003 through April 2014. Beginning in April 2004, our monthly lease rental is $21,000 and escalates to $24,000 beginning in February 2009 through the remaining term of the lease. We have an option to renew the lease for an additional five years at the then-current market rate. In May 2004, we amended our office lease agreement to increase our rentable square footage (the "Expansion Space"). The lease term for the Expansion Space runs from September 2004 through August 2009. Our monthly lease rental for the Expansion Space is

$14,000 beginning in June 2005. We have the option, subject and subordinate to another tenant's renewal option, to renew the lease for an additional five years at a rate specified in the amendment. We are also responsible for our proportionate share of the building operating expenses.

In December 2003, we entered an agreement to lease software for use in our exploration activities. This lease provides for annual payments of $230,000 per year to be made prior to the beginning of each contract year. The lease runs through December 31, 2006.

On January 15, 2005, we exercised our Sabine Pass site options and executed 30-year leases related to the option acreage. On February 24, 2005, certain of these leases were amended increasing our total acreage and increasing the annual payments to $1.5 million. We have the option to renew these leases for six 10-year periods.

Restricted Certificate of Deposit and Letter of Credit

Under the terms of our office lease, we are required to post a standby letter of credit in favor of the lessor. The initial amount of the letter of credit was increased from $865,000 to $1.1 million in April 2004 related to the expansion of our office space; and the amount will be reduced by $225,000 per annum over a five-year period. This letter of credit was initially established under the terms of our bank line of credit at that time.

Upon the termination of our bank line of credit in June 2004, we purchased a certificate of deposit in the amount of $1.1 million and entered into a pledge agreement in favor of the commercial bank that had previously issued the standby letter of credit for $1.1 million. In October 2004, both the letter of credit and certificate of deposit were amended to decrease the face amounts by $225,000 to $898,000. The renewed letter of credit and the certificate of deposit both mature on November 30, 2005. Under the terms of the pledge agreement, the commercial bank was assigned a security interest in the certificate of deposit as collateral for the letter of credit. As a result, the certificate of deposit plus $2,000 of accrued interest is classified as restricted on our balance sheet at December 31, 2004.

Off-Balance Sheet Arrangements

As of December 31, 2004, we had no "off-balance sheet arrangements" that may have a current or future material affect on our consolidated financial condition or results of operations.

Inflation

During 2002, 2003 and 2004, inflation and changing prices have not had any impact on our revenues or income from continuing operations.

Prior Bank Line of Credit

In June 2004, we terminated our $5 million line of credit with a commercial bank. This facility was originally established in July 2003 with a borrowing base of $2 million. During 2003, we borrowed $1 million under the facility to acquire oil and gas leases. The balance was repaid in January 2004 and the line of credit was terminated in June 2004.

Short-Term Promissory Notes

In February 2003, we executed a promissory note payable in the amount of $225,000. The proceeds of the note were used to pay certain costs related to our 3-D seismic database. In July 2003, we repaid the note payable.

In June 2002, we received a $750,000 payment for the sale of options to purchase an aggregate of up to a 20% interest in the Freeport LNG receiving terminal project. The payment was refundable, and repayment was secured by a note payable that we executed. In March 2003, an option was exercised and the note payable was canceled.

Exploration Funding

In October 2000, we completed a transaction with Warburg to fund our exploration program on approximately 8,800 square miles of seismic data in the Gulf of Mexico through a newly formed affiliated company, Gryphon. We contributed selected assets and liabilities in exchange for 100% of the common stock of Gryphon (36.8% effective interest after conversion of preferred stock) and $2 million in cash. Warburg contributed $25 million and received preferred stock, with an 8% cumulative dividend, convertible into 63.2% of Gryphon's common stock.

Cheniere and Warburg also have the option, in connection with subsequent capital calls made by Gryphon, to contribute up to an additional $75 million to Gryphon, proportionate to their respective ownership interests. Under the terms of the agreement governing these additional contributions, in the event that either we or Warburg elects not to participate in any additional contribution, the other investor has the option to purchase the non-participating investor's proportionate share. During 2001 and 2002, Gryphon made cash calls totaling $60 million against its capital commitment of $75 million. We declined to participate in such cash calls, and Warburg elected to purchase our proportionate share of such cash calls. As a result, our ownership interest in Gryphon, after the potential effect of converting preferred stock into common stock, was reduced from 36.8% in 2000 to 9.3% in 2002.

Prior to 2003, we accounted for our investment in Gryphon using the equity method of accounting. Effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting because we lost the ability to exercise significant influence over Gryphon's operating and financial policies, as our representation on Gryphon's board of directors was reduced to one director.

Seismic Reprocessing

Between June 2000 and October 2000, we acquired licenses to approximately 6,800 miles of seismic data primarily in the shallow waters offshore Texas and also in the West Cameron area in the Gulf of Mexico (the "Offshore Texas Project Area") in separate transactions with Seitel Data Ltd., a division of Seitel Inc., and Jebco Seismic, L.P. We committed to reprocess all of the data from the Offshore Texas Project Area at a cost of approximately $8.5 million, payable in installments beginning in October 2000 and continuing through the final delivery of reprocessed data, which was received in 2003. We have no existing or contingent liability related to seismic reprocessing as of December 31, 2004.

Results of Operations—Comparison of the Fiscal Years Ended December 31, 2004 and 2003

Overview—Our financial results for the year ended December 31, 2004 reflect a net loss of $24.6 million, or $1.26 per share (basic and diluted), compared to a net loss of $5.3 million, or $0.36 per share (basic and diluted), in 2003.

The major factors contributing to our net loss during 2004 were: LNG receiving terminal development expenses of $17.2 million (which were partially offset by a $2.9 million minority interest in the operations of Corpus Christi LNG) and general and administrative expenses of $12.5 million. These factors were partially offset by a $2.5 million reimbursement from our limited partnership investment in Freeport LNG.

LNG Receiving Terminal Development Activities—LNG receiving terminal development expenses were 156% higher in 2004 ($17.2 million) than in 2003 ($6.7 million). Because we have been in the preliminary stage of developing our LNG receiving terminals, substantially all of the costs to date related to such activities have been expensed. These costs primarily include professional fees associated with front-end engineering and design work, obtaining an order from FERC authorizing construction of our terminals and other required permitting for the Sabine Pass LNG, Corpus Christi LNG and Creole Trail LNG receiving terminals and their related natural gas pipelines. The expenses of our LNG employees directly involved in the development of our LNG receiving terminals are also included. LNG receiving terminal development expenses were significantly higher in 2004 because we accelerated, beginning in the third quarter of 2003, the schedule of receiving terminal development for our Sabine Pass and Corpus Christi LNG receiving terminals. We accelerated the development of our Creole Trail LNG receiving terminal in the fourth quarter of 2004.

In 2004, we recorded $5.8 million in terminal development expenses related to the Corpus Christi LNG receiving terminal. This amount was partially offset by $2.9 million related to the minority interest of our 33.3% limited partner. Substantially all expenditures incurred through March 31, 2004 were the obligation of the minority owner, as the minority owner was required to fund 100% of the first $4.5 million of project expenditures. As project expenditures had reached $4.5 million by March 31, 2004, the minority owner began sharing all subsequent project expenditures based on its 33.3% limited partner interest. Also during 2004, we incurred direct receiving terminal development expenses of $6.4 million related to our Sabine Pass LNG receiving terminal and $375,000 related to our Creole Trail LNG receiving terminal, in each of which we own 100% of the projects. In addition, during 2004, we incurred $4.8 million in LNG employee-related costs. In connection with the expansion of our LNG receiving terminal business, our employee costs increased, as we expanded our LNG staff from 4 employees during 2003 to an average of 15 employees during 2004. LNG employee-related costs for 2004 also included cash bonuses of $2 million and non-cash compensation of $928,000 (which included unrestricted and restricted stock awards) related to our 2003 and 2004 company performance.

In 2003, we incurred $6.7 million in LNG receiving terminal development expenses. Of this amount, $3 million related to development costs for the Corpus Christi LNG project. However, these costs were entirely offset by the minority interest of our 33.3% limited partner as discussed above. Also during 2003, we incurred $3.7 million primarily for development expenses related to the Sabine Pass LNG project and LNG employee-related costs.

In February 2003, our Freeport LNG receiving terminal project was acquired by Freeport LNG, from whom we retained a 40% limited partnership interest and received payments totaling $5 million over time. In connection with the sale of LNG assets to Freeport LNG, we reported a gain of $4.8 million. We also sold a 10% interest in Freeport LNG in March 2003 for $2.3 million, resulting in a gain of $423,000. During 2003, we received payments totaling $2.5 million from Freeport LNG, plus $1.7 million in reimbursement of project costs, which were recorded as a reduction to our investment in the partnership. In addition, during 2003 we recorded equity in the 2003 loss incurred by Freeport LNG attributable to our 30% limited partner interest, which reduced our investment basis to zero as of December 31, 2003. In January 2004, we received the final $2.5 million payment from Freeport LNG. Because our investment basis in Freeport LNG had been reduced to zero, the payment was recorded as a reimbursement from limited partnership investment in our consolidated statement of operations for 2004.

In 2004, our 30% equity share of the net loss from Freeport LNG was $1.3 million, including $278,000 of loss that was suspended as of December 31, 2003 (see Note 9 to Consolidated Financial Statements). This compares to our equity share of the loss of $4.5 million for 2003. The significant improvement between periods for Freeport LNG was a result of Freeport LNG's receipt of a non-refundable fee of $10 million from ConocoPhillips in January 2004.

General and Administrative Expenses—General and administrative, or G&A, expenses primarily relate to our general corporate and other activities. These expenses increased $9.9 million, or 391%, to $12.5 million in 2004 compared to $2.5 million in 2003. The increase in G&A resulted primarily from the expansion of our business (including increases in average corporate staff from an average of 5 employees in 2003 to an average of 16 employees in 2004). Corporate employee-related costs for 2004 also included cash bonuses of $2.2 million and non-cash compensation of $2.7 million (which included unrestricted and restricted stock awards) related to our 2003 and 2004 company performance. We capitalize as oil and gas property costs that portion of G&A expenses directly related to our exploration and development activities. We capitalized $1.6 million in 2004 compared to $976,000 in 2003.

Depreciation, Depletion and Amortization Expenses—DD&A expenses increased $895,000, or 209%, to $1.3 million in 2004 from $429,000 in 2003. The increase primarily resulted from higher oil and gas DD&A as a result of an increase in our DD&A rate from $0.98 per Mcfe to $2.48 per Mcfe and higher production volumes discussed below. DD&A also increased as a result of more depreciation expense resulting from the acquisition of furniture, fixtures and equipment associated with the expansion of our business.

Interest and Other Income—Interest and other income increased to $501,000 in 2004 from $3,000 in 2003 primarily because of an increase in our cash balance resulting from our $300 million public equity offering of our common stock in December 2004 (before related offering costs of $14.1 million). In addition, we received $22 million in advance regasification capacity payments in November and December of 2004 and raised $20 million in net cash proceeds related to a private placement of our common stock and exercises of options and warrants to purchase our common stock during 2004.

Oil and Gas Activities—Oil and gas revenues increased by $1.3 million, or 204%, to $2 million in 2004 from $658,000 in 2003 as a result of a 173% increase in production volumes (336,849 Mcfe in 2004 compared with 123,494 Mcfe in 2003) and an 11% increase in average natural gas prices to $5.93 per Mcf in 2004 from $5.33 per Mcf in 2003. We produced from an average of 10 wells in 2004 as compared with an average of 7 wells in 2003. We incurred little or no production cost in 2003 and 2004 because all of our revenues were generated from non-cost bearing overriding royalty interests, or ORRI, until December 2004. The small amount of production costs in 2004 is attributable to our share of production taxes on two producing wells located in Texas state waters and operating costs attributable to a well converted from an ORRI to a working interest at payout in December 2004.

Results of Operations—Comparison of the Fiscal Years Ended December 31, 2003 and 2002

Overview—Our financial results for the year ended December 31, 2003 reflect a net loss of $5.3 million, or $0.36 per share (basic and diluted), compared to a net loss of $5.6 million, or $0.42 per share (basic and diluted), in 2002. The major factors contributing to our loss in 2003 were: LNG receiving terminal development expenses of $6.7 million (which were offset by a $3 million minority interest in the operations of Corpus Christi LNG), our equity share of the loss in Freeport LNG of $4.5 million and general and administrative expenses of $2.5 million. These factors were offset by a $4.8 million gain on the sale of LNG assets and a $423,000 gain on the sale of a limited partnership interest in Freeport LNG.

LNG Terminal Development Activities—Our principal focus in both 2003 and 2002 was the development of LNG receiving terminals. As a result, receiving terminal development expenses represented a major part of our operating costs and expenses for both years. In 2003, we phased out our direct involvement in developing the Freeport, Texas, site, but we accelerated the schedule of receiving terminal development at Sabine Pass, and near Corpus Christi. Accordingly, gross receiving terminal development expenses, before any cost recoveries, were 103% higher in 2003 ($6.7 million) than in 2002 ($3.3 million).

In 2003, we formed a limited partnership to develop the Corpus Christi LNG receiving terminal. We are the general partner of the limited partnership, and throughout 2003 we owned a 67% limited partner interest. We recorded $3 million in receiving terminal development expenses related to this site in 2003; however, this amount was completely offset by the minority interest of our 33% partner who provided funding for all development costs in 2003. The remainder of our 2003 receiving terminal development expenses primarily related to the Sabine Pass LNG site, where we own 100% of the project, and LNG employee-related expenses.

In 2002, we incurred $3.3 million in receiving terminal development expenses for the Freeport LNG receiving terminal. We entered into an agreement in August 2002 to sell a 60% interest in the receiving terminal in exchange for payments to us totaling $5 million over time and payments to others of up to $9 million for expenses, which were already incurred or were to be incurred in connection with the development of the Freeport LNG receiving terminal. During 2002, $1.7 million in such development expenses were charged to the purchaser. This recovery reduced our receiving terminal development expenses reported for 2002 to $1.6 million.

In February 2003, our Freeport LNG receiving terminal project was acquired by Freeport LNG in which we retained a 40% limited partnership interest in addition to the consideration described above. In connection with the sale of LNG assets to Freeport LNG, we reported a gain of $4.8 million. Furthermore, we sold a 10% interest in Freeport LNG in March 2003 for $2.3 million, resulting in a gain of $423,000. Throughout 2003, we received payments totaling $2.5 million from Freeport LNG, which amounts were recorded as a reduction to our investment in the partnership. In addition, our 30% limited partner interest in the operations of Freeport LNG resulted in our recording equity in the net loss of the partnership of $4.5 million for 2003. This non-cash loss reduced our investment in Freeport LNG to zero.

General and Administrative Expenses—G&A expenses relate to our general corporate and other activities. These expenses increased $624,000, or 33%, to $2.5 million in 2003 compared to $1.9 million in 2002. The principal components of G&A are employee compensation and contracted services, legal fees and travel. We incurred more legal expenses in 2003 in connection with securities compliance filings and increased securities registration costs. We traveled more in 2003 as we increased our profile among the investment community and as we developed an LNG trading venture based in Europe.

Oil and Gas Activities—Oil and gas revenues increased by $419,000, or 175%, to $658,000 in 2003 from $239,000 in 2002 as a result of increased production volumes (123,494 Mcfe in 2003 compared with 94,441 Mcfe in 2002) and increased average natural gas prices of $5.33 per Mcf in 2003 from $2.58 per Mcf in 2002. We had production from an average of seven wells in 2003 as compared with one well in 2002. We incurred no production costs in 2003 because all of our revenues were generated from non-cost bearing ORRI. Production costs in 2002 totaled $90,000 and related to the early months of 2002 before we sold our cost-bearing working interests in oil and gas properties.

Equity in Net Loss of Unconsolidated Affiliate—On January 1, 2003, we began accounting for our interest in Gryphon on the cost method of accounting because we no longer had sufficient board representation to provide us with the opportunity to exert significant influence over the financial and operating policies of the company. In 2002, we accounted for our investment in Gryphon using the equity method of accounting, and our equity share of Gryphon's losses was $2.2 million.

Other Matters

Critical Accounting Estimates and Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and believe the proper implementation and consistent application of the accounting rules are critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them, and often consult with our independent accountants about the appropriate interpretation and application of these policies.

Accounting for LNG Activities

Because we have been in the preliminary stage of developing our LNG receiving terminals, substantially all of the costs to date related to such activities have been expensed. These costs primarily include professional fees associated with front-end engineering and design work and obtaining an order from FERC authorizing construction of our terminals and other required permitting for the Sabine Pass LNG, Corpus Christi LNG and Creole Trail LNG receiving terminals and their related natural gas pipelines. Land costs associated with LNG terminal sites are capitalized. Costs of certain permits are capitalized as intangible LNG assets. We have also capitalized costs related to options to purchase or lease land that may be used for potential LNG terminal sites.

Revenue Recognition

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

Full Cost Method of Accounting

We follow the full cost method of accounting for our oil and gas properties. Under this method, all productive and non-productive exploration and development costs incurred for the purpose of finding oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, together with internal costs directly attributable to property acquisition, exploration and development activities. Interest is capitalized on oil and gas properties not subject to amortization and in the process of development.

The costs of our oil and gas properties, including the estimated future costs to develop proved reserves and the carrying amounts of any asset retirement obligations, are depreciated using a composite unit-of-production rate based on estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, then the amount of the impairment is added to the capitalized costs to be amortized. Net capitalized costs are limited to a capitalization ceiling, calculated on a quarterly basis as the aggregate of the present value, discounted at 10%, of estimated future net revenues from proved reserves (based on current economic and operating conditions), but excluding asset retirement obligations, plus the lower of cost or fair market value of unproved properties, less related income tax effects.

Our allocation of seismic exploration costs between proved and unproved properties involves an estimate of the total reserves to be discovered through our exploration program. This estimate includes a number of assumptions that we have incorporated into a three-year plan. Such factors include an estimate of the number of exploration prospects generated, prospect reserve potential, success ratios and ownership interests. We transfer unproved properties to proved properties based on a ratio of proved reserves discovered at a point in time to the estimate of total reserves to be discovered in our exploration program. The carrying value of unproved properties is evaluated for possible impairment by comparing it to the estimated future net cash flows associated with the estimated total reserves to be discovered in our exploration program. To the extent that the carrying value of unproved properties is greater than the estimated future net revenue, any excess is transferred to proved. It is reasonably possible, based on the results obtained from future drilling and prospect generation, that revisions to this estimate of total reserves to be discovered could affect our capitalization ceiling.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

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

Oil and Gas Reserves

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

Our proved reserve information included in this annual report for 2004 is based on estimates prepared by Sharp Petroleum Engineering, Inc. Estimates prepared by others may be higher or lower than our estimates.

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

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

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

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment,* that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for equity instruments of the company, such as stock options and restricted stock. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using the APB Opinion No. 25 and requires instead that such transactions be accounted for using a fair value-based method. We currently account for stock-based compensation using the intrinsic method pursuant to APB Opinion No. 25. SFAS No. 123R requires that all stock-based payments to employees, including grants of employee stock options and restricted stock, be recognized as compensation expense in the financial statements based on their fair values. SFAS No. 123R will be effective for periods beginning after June 15, 2005. Accordingly, we will be required to apply SFAS No. 123R beginning in the fiscal quarter ending September 30, 2005. We are currently assessing the provisions of SFAS No. 123R and its impact on our consolidated financial statements.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

The development of our LNG receiving terminal business is based upon the foundational premise that prices of natural gas in the U.S. will be sustained at levels of $3.00 per Mcf or more. Should the price of natural gas in the U.S. decline to sustained levels below $3.00 per Mcf, our ability to develop and operate LNG receiving terminals could be significantly negatively affected.

We produce and sell natural gas, crude oil and condensate. As a result, our financial results can be affected as these commodity prices fluctuate widely in response to changing market forces. We had not entered into any derivative transactions as of December 31, 2004.

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

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

INDEX TO FINANCIAL STATEMENTS

CHENIERE ENERGY, INC. AND SUBSIDIARIES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of Freeport LNG Development, L.P. ("Freeport LNG"), an investment which, as discussed in Note 9 to the consolidated financial statements, is accounted for by the equity method of accounting. The investment in Freeport LNG was ($1,071,000) and zero as of December 31, 2004 and 2003, respectively, and the equity in its net loss was $1,346,000, $4,471,000 and zero, respectively, for each of the three years in the period ended December 31, 2004. We also did not audit the financial statements of Gryphon Exploration Company ("Gryphon"), an investment which, as discussed in Note 8 to the consolidated financial statements, has been, until January 1, 2003, accounted for by the equity method of accounting. The investment in Gryphon was zero as of December 31, 2004 and 2003, and the equity in its net loss was zero, zero and $2,185,000, respectively, for each of the three years in the period ended December 31, 2004. The financial statements of Freeport LNG and Gryphon were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Freeport LNG and Gryphon, are based solely on the reports of the other auditors.

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

In our opinion, based on our audits and the reports of other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cheniere Energy, Inc. and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Cheniere Energy, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

/s/ UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP
UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP

Houston, Texas
March 10, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing on page 63, that Cheniere Energy, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that Cheniere Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by COSO. Also, in our opinion, Cheniere Energy, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 10, 2005 expressed an unqualified opinion on those consolidated financial statements.

/s/ UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP
UHY MANN FRANKFORT STEIN & LIPP CPAs, LLP

Houston, Texas
March 10, 2005

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

Management's Report on Internal Control Over Financial Reporting

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

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2004, based on criteria in *Internal Control—Integrated Framework* issued by the COSO. Our assessment of the effectiveness of Cheniere's internal control over financial reporting as of December 31, 2004, has been audited by UHY Mann Frankfort Stein & Lipp CPAs, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Management's Certifications

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

CHENIERE ENERGY, INC.

By: /s/ CHARIF SOUKI
Charif Souki
Chief Executive Officer

By: /s/ DON A. TURKLESON
Don A. Turkleson
Senior Vice President
and Chief Financial Officer

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(in thousands, except share data)

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$308,443	$ 1,258
Restricted Certificate of Deposit	900	—
Accounts Receivable		
Affiliates	—	1,000
Other	1,374	1,828
Prepaid Expenses	564	401
Total Current Assets	311,281	4,487
OIL AND GAS PROPERTIES, full cost method		
Proved Properties, net	2,368	1,087
Unproved Properties, not subject to amortization	16,688	18,048
Total Oil and Gas Properties	19,056	19,135
LNG SITE AND OTHER RELATED COSTS	786	311
FIXED ASSETS, net	1,038	578
DEBT ISSUANCE COSTS	1,302	—
INVESTMENT IN LIMITED PARTNERSHIP	—	—
INTANGIBLE LNG ASSETS	88	80
OTHER	16	—
Total Assets	$333,567	$ 24,591
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 1,262	$ 1,984
Accrued Liabilities	3,196	1,348
Accrued Losses on Investment in Limited Partnership	1,071	—
Note Payable	—	1,000
Total Current Liabilities	5,529	4,332
DEFERRED REVENUE	23,000	1,000
LONG-TERM ASSET RETIREMENT OBLIGATION	99	—
MINORITY INTEREST	338	120
COMMITMENTS AND CONTINGENCIES	—	—
STOCKHOLDERS' EQUITY		
Preferred Stock, $.0001 par value		
Authorized: 5,000,000 shares		
Issued and Outstanding: none	—	—
Common Stock, $.003 par value		
Authorized: 40,000,000 shares		
Issued and Outstanding: 25,459,291 shares at December 31, 2004 and 16,488,187 shares at December 31, 2003	76	49
Additional Paid-in-Capital	364,581	48,035
Deferred Compensation	(6,543)	—
Accumulated Deficit	(53,513)	(28,945)
Total Stockholders' Equity	304,601	19,139
Total Liabilities and Stockholders' Equity	$333,567	$ 24,591

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2004	2003	2002
Revenues			
Oil and Gas Sales	$ 1,998	$ 658	$ 239
Total Revenues	1,998	658	239
Operating Costs and Expenses			
LNG Terminal Development Expenses	17,166	6,705	1,557
Production Costs	117	—	90
Depreciation, Depletion and Amortization	1,324	429	369
General and Administrative Expenses	12,476	2,542	1,918
Total Operating Costs and Expenses	31,083	9,676	3,934
Loss from Operations	(29,085)	(9,018)	(3,695)
Equity in Net Loss of Unconsolidated Affiliate	—	—	(2,185)
Equity in Net Loss of Limited Partnership	(1,346)	(4,471)	—
Gain on Sale of Proved Oil and Gas Properties	—	—	340
Gain on Sale of LNG Assets	—	4,760	—
Gain on Sale of Limited Partnership Interest	—	423	—
Reimbursement from Limited Partnership Investment	2,500	—	—
Loss on Early Extinguishment of Debt	—	—	(100)
Interest and Other Income	501	3	8
Loss Before Income Taxes and Minority Interest	(27,430)	(8,303)	(5,632)
Provision for Income Taxes	—	—	—
Loss Before Minority Interest	(27,430)	(8,303)	(5,632)
Minority Interest	2,862	3,015	—
Net Loss	$(24,568)	$ (5,288)	$ (5,632)
Net Loss Per Share—Basic and Diluted	$ (1.26)	$ (0.36)	$ (0.42)
Weighted Average Number of Shares Outstanding—Basic and Diluted	19,447	14,772	13,297

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock		Additional Paid-In Capital	Deferred Compensation	Accumulated Deficit	Total Stockholder's Equity
	Shares	Amount				
Balance—December 31, 2001	13,297	$ 40	$ 41,134	$ —	$(18,025)	$ 23,149
Issuances of Warrants	—	—	280	—	—	280
Net Loss	—	—	—	—	(5,632)	(5,632)
Balance—December 31, 2002	13,297	40	41,414	—	(23,657)	17,797
Issuances of Stock	3,191	9	5,733	—	—	5,742
Issuances of Warrants	—	—	945	—	—	945
Expenses Related to Offerings	—	—	(57)	—	—	(57)
Net Loss	—	—	—	—	(5,288)	(5,288)
Balance—December 31, 2003	16,488	$ 49	$ 48,035	—	$(28,945)	$ 19,139
Issuances of Stock	8,631	26	323,321	—	—	323,347
Issuances of Restricted Stock	340	1	8,275	(8,276)	—	—
Amortization of Deferred Compensation	—	—	—	1,733	—	1,733
Expenses Related to Offerings	—	—	(15,050)	—	—	(15,050)
Net Loss	—	—	—	—	(24,568)	(24,568)
Balance—December 31, 2004	25,459	$ 76	$364,581	$(6,543)	$(53,513)	$304,601

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Loss	$(24,568)	$(5,288)	$(5,632)
Adjustments to Reconcile Net Loss to Net Cash Used In Operating Activities:			
Depreciation, Depletion and Amortization	1,324	429	369
Non-Cash Compensation	3,618	—	—
Gain on Sale of Proved Oil and Gas Properties	—	—	(340)
Reimbursement from Limited Partnership Investment	(2,500)	—	—
Loss on Early Extinguishment of Debt	—	—	100
Equity in Net Loss of Unconsolidated Affiliate	—	—	2,185
Equity in Net Loss of Limited Partnership	1,346	4,471	—
Gain on Sale of LNG Assets	—	(4,760)	—
Gain on Sale of Limited Partnership Interest	—	(423)	—
Minority Interest	(2,862)	(3,015)	—
Other	(18)	(4)	(32)
Changes in Assets and Liabilities			
Accounts Receivable—Affiliates	1,000	—	—
Other Accounts Receivable	(890)	230	(753)
Prepaid Expenses	(257)	(483)	(28)
Deferred Revenue	22,000	—	—
Accounts Payable and Accrued Liabilities	1,146	1,284	1,367
NET CASH USED IN OPERATING ACTIVITIES	(661)	(7,559)	(2,764)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchases of Fixed Assets	(915)	(341)	(15)
Oil and Gas Property Additions	(2,025)	(2,514)	(1,430)
Net Proceeds from Sale of Proved Oil and Gas Properties	—	—	2,235
Sale of Interest in Oil and Gas Prospects	2,381	392	628
Sale of Oil and Gas Seismic Data	—	—	825
LNG Site and Other Related Costs	(458)	—	(250)
Purchase of Intangible LNG Assets	(8)	(80)	—
Investment in Limited Partnership	(275)	—	—
Reimbursement from Limited Partnership Investment	2,500	—	—
Sale of LNG Assets	—	1,873	—
Sale of Limited Partnership Interest	883	700	—
Investment in Restricted Certificate of Deposit	(898)	—	—
NET CASH PROVIDED BY INVESTING ACTIVITIES	1,185	30	1,993
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from Issuances of Notes Payable	—	1,225	1,250
Repayment of Note Payable	(1,000)	(225)	(500)
Sale of Common Stock	320,933	4,429	—
Offering Costs	(15,050)	(57)	—
Debt Issuance Costs	(1,302)	—	—
Partnership Contributions by Minority Owner	3,080	2,825	—
NET CASH PROVIDED BY FINANCING ACTIVITIES	306,661	8,197	750
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	307,185	668	(21)
CASH AND CASH EQUIVALENTS—BEGINNING OF YEAR	1,258	590	611
CASH AND CASH EQUIVALENTS—END OF YEAR	$308,443	$ 1,258	$ 590

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

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

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

Cheniere Energy, Inc., a Delaware corporation, is a Houston-based company engaged, through its subsidiaries, primarily in developing and constructing, and then owning and operating, onshore liquified natural gas ("LNG") receiving terminals along the Gulf Coast of the United States. The terms "Cheniere", "we", "our", and "us" refer to Cheniere Energy, Inc. and its subsidiaries. We are also engaged, to a lesser extent, in oil and natural gas exploration and development activities in the Gulf of Mexico and, through a minority interest position, in the chartering and international operation of LNG tankers.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Cheniere Energy, Inc. and its majority-owned subsidiaries. We also hold ownership interests in entities that are accounted for under the equity method and cost method of accounting. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain items in the prior year financial statements have been reclassified to conform with the 2004 presentation.

LNG Activities

We have been in the preliminary stage of developing LNG receiving terminals and related pipelines. Substantially all costs related thereto have been expensed when incurred. Land costs associated with LNG terminal sites are capitalized. Costs of certain permits are capitalized as intangible LNG assets. We have also capitalized costs related to options to purchase or lease land, or obtain right-of-way access that may be used for potential LNG terminal sites and pipelines.

Oil and Gas Properties

We follow the full cost method of accounting for our oil and gas properties. Under this method, all productive and nonproductive exploration and development costs incurred for the purpose of finding oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, together with internal costs directly attributable to property acquisition, exploration and development activities. Interest is capitalized on oil and gas properties not subject to amortization and in the process of development. We capitalized interest totaling $4,000, $41,000 and ($42,000) and general and administrative expenses, net of reimbursements, totaling $1,569,000, $976,000 and $829,000 for the years 2004, 2003 and 2002, respectively. Capitalized interest for 2002 was negative due to a refund of interest that was paid in 2001.

The costs of our oil and gas properties, including the estimated future costs to develop proved reserves and the carrying amounts of any asset retirement obligations, are depreciated using a composite unit-of-production rate based on estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, then the amount of the impairment is added to the capitalized costs to be amortized. Net capitalized costs are limited to a capitalization ceiling, calculated on a quarterly basis as the aggregate of the present value, discounted at 10%, of estimated future net revenues from proved reserves (based on current economic and operating conditions), but excluding asset retirement obligations, plus the lower of cost or fair market value of unproved properties, less related income tax effects.

Our allocation of seismic exploration costs between proved and unproved properties involves an estimate of the total reserves to be discovered through our exploration program. This estimate includes a number of assumptions that we have incorporated into a three-year plan. Such factors include an estimate of the number of exploration prospects generated, prospect reserve potential, success ratios and ownership interests. We transfer unproved properties to proved properties based on a ratio of proved reserves discovered at a point in time to the estimate of total reserves to be discovered in our exploration program. The carrying value of unproved properties is evaluated for possible impairment by comparing it to the estimated future net cash flows associated with the estimated total reserves to be discovered in our exploration program. To the extent that the carrying value of unproved properties is greater than the estimated future net revenue, any excess is transferred to proved. It is reasonably possible, based on the results obtained from future drilling and prospect generation, that revisions to this estimate of total reserves to be discovered could affect our capitalization ceiling.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

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

On January 1, 2003, the date of adoption of SFAS No. 143, we had no legal obligations associated with the retirement of any long-lived assets, as all of our oil and gas property interests were non-cost bearing overriding royalty interests (ORRI). In 2004, we converted an ORRI to a working interest at well payout. As a result, we recorded $97,000, the present value of the expected abandonment cost of the well and related equipment, as a long-term asset retirement obligation and a corresponding amount to proved oil and gas properties. Accretion expense for 2004 was $2,000 and was included in depreciation, depletion, and amortization expense. The resulting long-term asset retirement obligation was $99,000 at December 31, 2004.

Revenue Recognition

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

Revenues from the sale of oil and gas production are recognized upon passage of title, net of royalty interests. When sales volumes differ from our entitled share, an underproduced or overproduced imbalance occurs. To the extent an overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. At December 31, 2004 and 2003, we had no gas imbalances.

Fixed Assets

Fixed assets are recorded at cost. Repairs and maintenance costs are charged to operations as incurred. Depreciation is computed using the straight-line method over estimated useful lives of the assets, which range from two to ten years. Upon retirement or other disposition of fixed assets, the cost and related accumulated depreciation is removed from the accounts and the resulting gains or losses are recorded.

Offering Costs

Offering costs consist primarily of underwriter's fees, placement fees, professional fees, legal fees and printing costs. These costs are charged against the related proceeds from the sale of common stock in the periods in which they occur or charged to expense in the event of a terminated offering.

Income Taxes

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

Stock-Based Compensation

SFAS No. 123, *Accounting for Stock-Based Compensation,* encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of FASB Statement No. 123*, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. The statement also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results.

We have chosen to continue to account for stock-based compensation issued to employees using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of our stock at the date of the grant over the amount an employee must pay to acquire the stock. We grant options at or above the market price of its common stock at the date of each grant.

The fair value of options is calculated using the Black-Scholes option-pricing model. Had we adopted the fair value method of accounting for stock-based compensation, compensation expense would have been higher, and net loss attributable to common stockholders would have increased for the periods presented. No change in cash flows would occur. The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands except per share amounts)		
Net loss as reported	$(24,568)	$(5,288)	$(5,632)
Deduct:			
Total stock-based employee compensation expense determined under fair value method for all awards, net of related income tax	(2,206)	(967)	(608)
Pro forma net loss	$(26,774)	$(6,255)	$(6,240)
Net Loss Per Share			
Basic and diluted—as reported	$ (1.26)	$ (0.36)	$ (0.42)
Basic and diluted—pro forma	(1.38)	(0.42)	(0.47)

The weighted average fair value of warrants and options granted as employee compensation during 2004, 2003 and 2002 was $11.63, $1.44, and $1.20, respectively. The fair values were determined using the Black-Scholes option-pricing model with the following weighted average assumptions, and a forfeiture rate that is assumed to be negligible:

	Year Ended December 31,		
	2004	2003	2002
Dividend yield	0.0%	0.0%	0.0%
Weighted average volatility	95.9%	107.5%	107.8%
Risk-free interest rate	3.4%	3.0%	2.9%
Expected lives of options	4.0 years	4.0 years	4.0 years

Earnings (Loss) Per Share

Earnings (loss) per share ("EPS") is computed in accordance with the requirements of SFAS No. 128, *Earnings Per Share*. Basic EPS excludes dilution and is computed by dividing net income (loss) by the weighted average number of shares outstanding during the period. Diluted EPS reflects potential dilution and is computed by dividing net income by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued. Potential dilutive common stock equivalents include stock options from employee benefit plans and warrants to purchase common stock. Basic and diluted EPS for all periods presented are the same since the effect of our options and warrants is anti-dilutive to our net loss per share under SFAS No. 128. Stock options and warrants representing securities that could potentially dilute basic EPS in the future that were not included in the fully diluted computation because they would have been anti-dilutive for the years 2004, 2003 and 2002 were 1,566,299, 3,259,583, and 4,577,132, respectively. No adjustments were made to reported net loss in the computation of EPS.

Cash Equivalents

We classify all investments with original maturities of three months or less as cash equivalents.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, restricted certificate of deposit, accounts receivable, accounts payable and notes payable approximate fair value because of the short maturity of those instruments.

Commodity Price Risk

We produce and sell natural gas, crude oil and condensate. As a result, our financial results can be affected as these commodity prices fluctuate widely in response to changing market forces. We had not entered into any hedging transactions as of December 31, 2004.

Concentration of Credit Risk

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

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires that we make estimates and assumptions that affect the amounts reported in the financial statements and the accompanying notes. The most significant estimate pertains to proved oil and gas reserve volumes. Actual results could differ from those estimates.

New Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, "*Share-Based Payment*," that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for equity instruments of the company, such as stock options and restricted stock. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25 and requires instead that such transactions be accounted for using a fair value-based method. We currently account for stock-based compensation using the intrinsic method pursuant to APB Opinion No. 25. SFAS No. 123R requires that all stock-based payments to employees, including grants of employee stock options and restricted stock, be recognized as compensation expense in the financial statements based on their fair values. SFAS No. 123R will be effective for periods beginning after June 15, 2005. Accordingly, we will be required to apply SFAS No. 123R beginning in the fiscal quarter ending September 30, 2005. We are currently assessing the provisions of SFAS No. 123R and its impact on our consolidated financial statements.

NOTE 3—RESTRICTED CERTIFICATE OF DEPOSIT AND LETTER OF CREDIT

Under the terms of our office lease, we are required to post a standby letter of credit in favor of the lessor. The initial amount of the letter of credit was increased from $865,000 to $1,123,000 in April 2004 related to the expansion of our office space; and the amount will be reduced $225,000 per annum over a five-year period. This letter of credit was initially established under the terms of our bank line of credit at that time.

Upon the termination of our bank line of credit in June 2004, we purchased a certificate of deposit in the amount of $1,123,000 and entered into a pledge agreement in favor of the commercial bank that had previously issued the standby letter of credit for $1,123,000. In October 2004, both the letter of credit and certificate of deposit were amended to decrease the face amounts by $225,000 to $898,000. The renewed letter of credit and the certificate of deposit both mature on November 30, 2005. Under the terms of the pledge agreement, the commercial bank was assigned a security interest in the certificate of deposit as collateral for the letter of credit. As a result, the certificate of deposit plus $2,000 of accrued interest is classified as restricted on our balance sheet at December 31, 2004.

NOTE 4—DEBT ISSUANCE COSTS

As of December 31, 2004, we had incurred $1,302,000 of costs directly associated with arranging project debt financing related to the construction of our planned LNG receiving terminals. Such costs have been capitalized and are included in our consolidated balance sheet as of December 31, 2004. These costs will be amortized as interest expense over the term of the loan.

NOTE 5—ACCRUED LIABILITIES

Accrued liabilities consist of the following (in thousands):

	December 31,	
	2004	2003
Accrued LNG development expenses	$1,611	$1,183
Accrued insurance expense	488	—
Accrued legal expense	342	—
Taxes other than income	111	37
Other accrued liabilities	644	128
Accrued liabilities	$3,196	$1,348

NOTE 6—FIXED ASSETS

Fixed assets consist of the following (in thousands):

	December 31,	
	2004	2003
Computers and office equipment	$ 905	$ 524
Furniture and fixtures	523	210
Other	434	409
	1,862	1,143
Less accumulated depreciation	(824)	(565)
Fixed assets, net	$1,038	$ 578

Depreciation expense related to our fixed assets totaled $410,000, $165,000, and $185,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

NOTE 7—OIL AND GAS PROPERTIES

Investments in oil and gas properties consist of the following (in thousands):

	December 31, 2004	December 31, 2003
Oil and gas properties:		
Proved	$ 3,339	$ 1,223
Unproved	16,688	18,048
	20,027	19,271
Less accumulated depreciation, depletion and amortization	(971)	(136)
	$19,056	$19,135

Depreciation, depletion and amortization of oil and gas property costs totaled $835,000, $121,000 and $75,000 for the years ended December 31, 2004, 2003 and 2002, respectively. Depreciation, depletion and amortization per equivalent Mcf (using an Mcf-to-barrel conversion factor of 6 to 1) was $2.48, $0.98 and $0.79 for the years ended December 31, 2004, 2003 and 2002, respectively.

We have made substantial investments in acquiring, processing and reprocessing our seismic databases covering a 6,800-square-mile project area offshore Texas and Louisiana and a 228-square-mile project area onshore and offshore Louisiana. The costs of these projects become subject to amortization on a ratable basis as the oil and gas reserves expected to be recovered from the projects are discovered. We began drilling prospects identified within our seismic databases in 1999, but did not participate directly in the drilling of any wells in 2001, 2002, 2003 or 2004. We did, however, have overriding royalty interests in wells drilled by others on prospects we generated during these periods. Interpretation of this data and related prospect generation is ongoing.

In April 2002, we sold all of our proved working interests in oil and gas properties for $2,235,000. A gain of $340,000 was recorded on the sale.

NOTE 8—INVESTMENT IN UNCONSOLIDATED AFFILIATE

In October 2000, we completed a transaction with Warburg to fund our exploration program on approximately 8,800 square miles of seismic data in the Gulf of Mexico through a newly formed affiliated company, Gryphon Exploration Company ("Gryphon"). We contributed selected assets and liabilities in exchange for 100% of the common stock of Gryphon (36.8% effective interest after conversion of preferred stock) and $2,000,000 in cash. Warburg contributed $25,000,000 and received preferred stock, with an 8% cumulative dividend, convertible into 63.2% of Gryphon's common stock.

Cheniere and Warburg also have the option, in connection with subsequent capital calls made by Gryphon, to contribute up to an additional $75,000,000 to Gryphon, proportionate to their respective ownership interests. Under the terms of the agreement governing these additional contributions, in the event that either we or Warburg elects not to participate in any additional contribution, the other investor has the option to purchase the non-participating investor's proportionate share. During 2001 and 2002, Gryphon made cash calls totaling $60,000,000 against its capital commitment of $75,000,000. We declined to participate in such cash calls, and Warburg elected to purchase our proportionate share of such cash calls. As a result, our ownership interest in Gryphon, after the potential effect of converting preferred stock into common stock, was reduced from 36.8% in 2000 to 9.3% in 2002.

Prior to 2003, we accounted for our investment in Gryphon using the equity method of accounting. Effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting because we lost the ability to exercise significant influence over Gryphon's operating and financial policies, as our representation on Gryphon's board of directors was reduced to one director.

During 2002, as a result of Gryphon's cumulative losses and preferred dividend arrearages, the basis of our investment in Gryphon was reduced to zero, but not below zero, because we do not guarantee any obligations of Gryphon and are not committed to provide additional financial support to Gryphon. Our equity share of Gryphon's losses for 2002 was $2,185,000, calculated by applying our 100% common stock ownership interest to Gryphon's net loss of $519,000, reducing such result for Gryphon's preferred dividend arrearages of $5,845,000 for the year and limiting the cumulative amount of net loss recognized to the balance of our investment in Gryphon. The amount of the net loss that was not recorded by us as of December 31, 2002 was $4,179,000.

NOTE 9—INVESTMENT IN LIMITED PARTNERSHIP

In August 2002, we entered into an agreement with entities controlled by Michael S. Smith ("Smith entities") to sell a 60% interest in the Freeport site and project. On February 27, 2003, we sold our interest in the site and project to Freeport LNG Development, L.P. ("Freeport LNG"), in which we held a 40% limited partner interest. Smith entities held the general partner interest and remaining 60% limited partner interest in Freeport LNG. We recovered $1,740,000, in costs that we had incurred on the project and received an additional $5,000,000 ($2,500,000 during 2003 and $2,500,000 in January 2004) from Freeport LNG. For the funding of Freeport LNG project development costs, Smith entities also committed to contribute up to $9,000,000 and to allocate available proceeds from any sales of options or capacity reservations and/or proceeds from loans related to capacity reservations to these costs. In connection with the closing, we issued warrants to Smith entities to purchase 700,000 shares of our common stock at a price of $2.50 per share, exercisable for a period of 10 years.

We accounted for the transfer of the site and planned LNG receiving terminal to Freeport LNG in accordance with Emerging Issues Task Force Issue No. 01-2, *Interpretations of APB Opinion No. 29*. Accordingly, we recorded a $4,760,000 gain on sale of LNG assets to the extent of the 60% interest not retained.

Effective March 1, 2003, we sold a 10% limited partner interest in Freeport LNG to an affiliate of Contango Oil & Gas Company ("Contango") for $2,333,000 payable over time, including the cancellation of our $750,000 short-term note payable. We also issued warrants to Contango to purchase 300,000 shares of common stock at a price of $2.50 per share, exercisable for a period of 10 years. As a result of the sale, we now hold a 30% limited partner interest in Freeport LNG. In December 2004, a subsidiary of The Dow Chemical Company ("Dow") acquired a 15% limited partner interest in Freeport LNG from one of the Smith entities, thereby reducing its limited partner interest from 60% to 45%.

We account for our 30% limited partnership investment in Freeport LNG using the equity method of accounting. During 2003, we received installment payments totaling $2,500,000 from Freeport LNG, which amounts were recorded as a reduction to the basis of our investment in the partnership. In addition, we recorded $4,471,000 related to our 30% equity share of the 2003 net loss of Freeport LNG. This non-cash loss reduced the basis of our investment in Freeport LNG to zero, and as a result, we did not record $278,000 ("Suspended Loss") of our equity share of the loss of the partnership as of December 31, 2003 because we did not guarantee any obligations of Freeport LNG and had not committed to provide additional financial support to Freeport LNG at that time.

In January 2004, we received the final $2,500,000 payment from Freeport LNG. As our investment basis in Freeport LNG had been reduced to zero as of December 31, 2003, the payment was recorded as a reimbursement from limited partnership investment in our consolidated statement of operations.

In December 2004 and February 2005, we received cash call notices from Freeport LNG related to the funding of forecasted partnership expenditures. As a result, we made a payment in December 2004 to Freeport LNG in the amount of $275,000 which was recorded as an increase to our investment in limited partnership amount. The cash call notices also request additional cash payments from January through June 2005 totaling $2,216,000.

During 2004, we recorded $1,346,000 related to our 30% equity share of the 2004 net loss of Freeport LNG including the $278,000 Suspended Loss from 2003. This non-cash loss reduced our investment basis to zero and resulted in us recording accrued losses on investment in limited partnership of $1,071,000 as of December 31, 2004. We accrued this liability, as we presently intend to provide additional financial support through the cash calls as described above.

The financial position of Freeport LNG at December 31, 2004 and 2003 and the results of Freeport LNG's operations for the years ended December 31, 2004 and 2003 and for the period from inception (December 1, 2002) through December 31, 2003 are summarized as follows (in thousands):

	December 31, 2004	December 31, 2003
Current assets	$38,106	$ 295
Fixed assets, net, and security deposit	10,320	150
Total assets	$48,426	$ 445
Current liabilities	$ 5,676	$ 5,887
Notes payable	48,041	—
Deferred revenue	3,500	—
Partners' capital	(8,791)	(5,442)
Total liabilities and partners' capital	$48,426	$ 445

	Year Ended, December 31, 2004	Year Ended, December 31, 2003	Inception (December 1, 2002) through December 31, 2004
Loss from continuing operations	$(3,569)	$(14,940)	$(19,401)
Net loss	(3,561)	(14,940)	(19,393)
Cheniere's equity in losses from limited partnership	(1,346)	(4,471)	(5,817)

NOTE 10—MINORITY INTEREST IN LIMITED PARTNERSHIP

In May 2003, we formed a limited partnership, Corpus Christi LNG, L.P. ("Corpus Christi LNG"), to develop an LNG receiving terminal near Corpus Christi, Texas. Under the terms of the limited partnership agreement, 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. We also manage the project as the general partner through our wholly-owned subsidiary.

For the years ended December 31, 2004 and 2003, the consolidated statement of operations includes \$2,862,000 and \$3,015,000, respectively, related to the minority interest of Corpus Christi LNG. Substantially all Corpus Christi LNG expenditures incurred through March 31, 2004 were the obligation of the minority owner, as the minority owner was required to fund 100% of the first \$4,500,000 of partnership expenditures. As partnership expenditures had reached \$4,500,000 as of March 31, 2004, the minority owner began sharing all subsequent expenditures based on its 33.3% limited partner interest.

On February 8, 2005, we acquired the minority interest of Corpus Christi LNG through the acquisition of BPU LNG, Inc. in exchange for 1,000,0000 restricted shares of our common stock. BPU LNG, Inc. held as its sole asset the 33.3% limited partner interest in Corpus Christi LNG. As a result of this transaction, we now own 100% of the limited partner interest of Corpus Christi LNG.

NOTE 11—NOTES PAYABLE

At December 31, 2003, we had an outstanding debt obligation of \$1,000,000 on a line of credit with a commercial bank. The balance was repaid in January 2004 and the line of credit was terminated in June 2004, as discussed below.

At December 31, 2002, we had a \$750,000 short-term note payable outstanding. This note was canceled in March 2003, as discussed below.

Set forth below is a description of our financing facilities under which financing cash inflows and outflows occurred during the three years ended December 31, 2004.

July 2003—Commercial Bank Financing

In July 2003, we established a \$5,000,000 line of credit with a commercial bank, with an initial borrowing base of \$2,000,000. The facility was secured by our assets, and its term, as amended, ran through December 31, 2004. Borrowings bore interest at the bank's prime rate plus 2.5% per annum, and a commitment fee of 0.5% per annum was assessed on the unused borrowing base capacity. The interest and commitment fee were payable quarterly. A loan origination fee of 1% of the initial borrowing base was paid at closing. At December 31, 2003, we had a debt obligation of \$1,000,000 and an \$865,000 letter of credit outstanding against this line of credit. The \$1,000,000 debt obligation was repaid in January 2004, and the \$5,000,000 line of credit was terminated in June 2004.

February 2003—Promissory Note

In February 2003, we executed a promissory note payable in the amount of \$225,000. The proceeds of the note were used to pay certain costs related to our 3-D seismic database.

The note bore interest at a rate of approximately 12% per annum and was secured by a pledge of our oil and gas receivables. In July 2003, we repaid the balance outstanding on the promissory note payable. The note and related security agreement were canceled.

June 2002—LNG Receiving Terminal Financing

In June 2002, we received a \$750,000 payment for the sale of two options to purchase an aggregate of up to a 20% interest in our Freeport LNG receiving terminal project. The payment was refundable in the event an option was not exercised. The potential repayment was secured by an 8% note payable executed by us. In March 2003, an option was exercised, the note payable canceled, and the payment applied to the purchase price per the terms of the agreement.

March 2002—$500,000 Bridge Financing

In March 2002, we entered into a short-term bridge financing arrangement with an unrelated third-party lender. The amount of the borrowing was $500,000. The term was 120 days. Interest was payable monthly at 10% per annum. Warrants were issued to the lender for the purchase of 150,000 shares of our common stock, exercisable at a price of $2.50 per share on or before March 7, 2012. In addition, we extended the term to March 7, 2012 on existing warrants for the purchase of 255,417 shares held by parties affiliated with the lender. Based on the Black-Scholes model, the warrants issued (150,000 shares) and the extension of existing warrants (255,417 shares) in connection with this financing arrangement have an aggregate value of $242,000. Debt discount of $163,000 was recorded based on the relative fair values of the note payable and the warrants. An additional 50,000 warrants were required to be issued to the lender for each month or partial month for which the principal remained unpaid after April 7, 2002. We repaid the loan on April 22, 2002, resulting in a loss on early extinguishment of debt in the amount of $100,000, which is classified as an ordinary loss in our statement of operations. We also issued an additional 50,000 warrants to the lender, valued at $24,000 based on the Black-Scholes model.

NOTE 12—DEFERRED REVENUE

In December 2003, we entered into a shareholders agreement whereby we became a minority owner of J & S Cheniere S.A., a Switzerland joint-stock company ("J & S Cheniere"). The majority owner is J & S Energy Holding B.V. ("J & S Holding"), a Netherlands corporation affiliated with J & S Trading Company, Ltd., an international petroleum trading and marketing company. J & S Cheniere was formed for the purpose of buying, selling, transporting and trading LNG. Pursuant to the shareholders agreement, we identify and assist with LNG-related business opportunities that we determine are appropriate for J & S Cheniere. We are not required to offer any particular business opportunities nor funding to J & S Cheniere. We have no board of director representation nor do we participate in the day-to-day management of J & S Cheniere. All financing of the 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. We account for this investment using the cost method of accounting. At December 31, 2004, Cheniere's investment basis was $16,000.

Also in December 2003, we entered into an agreement with J & S Cheniere under which J & S Cheniere has an option to enter into a terminal use agreement ("TUA") reserving up to 200 million cubic feet per day ("MMcf/d") of capacity at each of our Sabine Pass and Corpus Christi LNG facilities. Following execution of the option agreement, $1,000,000 was paid by J & S Cheniere to us in January 2004. At December 31, 2003, the $1,000,000 was included in accounts receivable. The option fee is refundable if we do not receive FERC approval for at least one of the terminals or if we decide not to proceed with the development of at least one of the terminals prior to December 15, 2005. Upon receipt of notice from us that FERC approval and other related approvals and permits have been received as necessary to begin construction of a terminal, J & S Cheniere has 60 days to exercise its option at that terminal. The option agreement contemplates negotiation of a definitive TUA for each of the facilities, which will specify the terms and conditions of the purchase and sale of the capacity and related services. We recorded the option fee as deferred revenue to be amortized over the initial five-year period of the TUA contemplated by the option agreement.

In November 2004, Total LNG USA, Inc. ("Total") exercised its option to acquire approximately 1 billion cubic feet per day ("Bcf/d") of capacity at our Sabine Pass LNG receiving terminal pursuant to a previously signed TUA and omnibus agreement. As a result, Total paid a non-refundable advance capacity reservation fee of $10,000,000. An additional advance capacity reservation fee payment of $10,000,000 will be payable by Total upon satisfaction of specified conditions. The capacity reservation fee payments will be amortized over a 10-year period as a reduction of Total's regasification fee under the TUA. As a result, we record the advance payments that we receive, though non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

Also, in November 2004, we entered into a TUA to provide Chevron USA, Inc. ("Chevron USA") with approximately 700 MMcf/d of LNG regasification capacity at our Sabine Pass LNG receiving terminal. Chevron USA has the option either to reduce its reserved capacity at Sabine Pass to approximately 500 MMcf/d by July 1, 2005 or to increase its reserved capacity to approximately 1.0 Bcf/d by December 1, 2005. Chevron USA has also agreed to make advance capacity reservation fee payments totaling up to $20,000,000. As of December 31, 2004, Chevron USA has paid us nonrefundable advance capacity reservation fees totaling $12,000,000. Further advance capacity reservation fees by Chevron USA will also be due under the TUA: $5,000,000 upon confirmation of evidence of the ability to finance construction of the facility, and $3,000,000 if Chevron USA exercises the option to increase its capacity at Sabine Pass to approximately 1.0 Bcf/d. These capacity reservation fee payments will be amortized over a 10-year period as a reduction of Chevron USA's regasification capacity fee under the TUA. As a result, we record the advance payments that we receive, though non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

As of December 31, 2004, we had recorded $23,000,000 as deferred revenue related to the above advance option and capacity reservation fee payments.

NOTE 13—INCOME TAXES

From our inception, we have recorded losses for both financial reporting purposes and for federal income tax reporting purposes. Accordingly, we are not presently a taxpayer and have not recorded a provision for income taxes in any of the periods presented in the accompanying financial statements.

At December 31, 2004, we had net operating loss ("NOL") carryforwards for federal income tax reporting purposes of approximately $45,793,000. In accordance with SFAS No. 109, a valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our NOL carryforwards and other deferred tax assets.

Deferred tax assets and liabilities reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities at December 31, 2004 and 2003 are as follows (in thousands):

	December 31,	
	2004	2003
Deferred tax assets		
NOL carryforwards	$ 16,944	$ 9,809
Advance payments—terminal use agreements	8,140	—
Startup costs associated with LNG projects	6,223	1,304
Investment in limited partnership	1,250	—
Investment in unconsolidated affiliate	1,553	513
	34,110	11,626
Deferred tax liabilities		
Oil and gas properties and fixed assets	4,828	56
Stock grant compensation expense	237	—
	5,065	56
Net deferred tax assets	29,045	11,570
Less: valuation allowance	(29,045)	(11,570)
	$ —	$ —

NOL carryforwards expire starting in 2012 extending through 2024. Certain of our NOLs which were previously subject to annual utilization limitations under Internal Revenue Code Section 382 change of ownership regulations are now available for utilization due to increases in the allowed NOL utilization amounts provided for in Section 382. The NOL carryforward amounts presented in the table above include approximately $8,323,000 and $644,000 for the years ended December 31, 2004 and 2003, respectively, of tax benefit related to the exercise of non-qualified employee stock options. The full amount of the related tax benefit is included in our deferred tax asset valuation allowance.

The change in the deferred tax asset valuation allowance was $17,475,000, $2,760,000 and $(2,582,000) during the years ended December 31, 2004, 2003 and 2002, respectively.

NOTE 14—WARRANTS

As of December 31, 2004, we have issued and outstanding 266,667 warrants for the purchase of our common stock. We have reserved an equal number of shares of common stock for issuance upon the exercise of the outstanding warrants. Warrants we issued do not confer upon the holders thereof any voting or other rights of a stockholder of Cheniere. Warrants have been granted in connection with certain of our debt or equity financings and as compensation for services. In instances where warrants were granted in connection with financings, such warrants were valued based on the estimated fair market value of the stock at the date of issuance. Where warrants were issued for services, fair value was calculated using the Black-Scholes pricing model. The terms of warrants outstanding at December 31, 2004 range from approximately five to ten years, with a weighted average remaining life of 6.0 years. Prices at which the warrants are exercisable range from $1.20 to $2.50 per share, with a weighted average exercise price of $2.42 per share at December 31, 2004. Information related to our warrants is summarized in the following table:

	December 31,		
	2004	2003	2002
Outstanding at beginning of period	1,299,583	2,593,521	2,850,288
Warrants issued	—	1,716,250	312,500
Warrants exercised	(1,021,922)	(1,082,093)	—
Warrants canceled	(10,994)	(1,928,095)	(569,267)
Outstanding at end of period	266,667	1,299,583	2,593,521
Weighted average exercise price of warrants outstanding	$ 2.42	$ 3.30	$ 4.06
Weighted average remaining contractual life of warrants outstanding	6.0 years	5.5 years	2.7 years

The following table summarizes information about warrants outstanding at December 31, 2004:

Exercise Prices	Number Outstanding	Weighted Average Years Remaining Contractual Life
$2.50	250,000	6.2
$1.20	16,667	2.7
	266,667	

In February 2003, in connection with the sale of a 60% interest in our Freeport LNG project, we issued warrants valued at $540,000 to purchase 700,000 shares of Cheniere common stock. We also issued warrants to purchase 241,250 shares of common stock to a former employee of Cheniere and the current President and Chief Operating Officer of Freeport LNG, in replacement of his options to purchase 241,250 shares of common stock. The number and exercise prices of the warrants were the same as the options replaced and ranged from $1.06 to $12.00 per share. Warrants to purchase 225,000 shares of common stock and valued at $174,000 were issued to LNG consultants for services previously performed. In connection with the sale of a 10% interest in the limited partnership, we issued warrants valued at $242,000 to purchase 300,000 shares of common stock to the purchaser.

In April 2003, we issued warrants to purchase 250,000 shares of common stock at $2.50 per share to our Chief Executive Officer as a signing bonus. At the time of issue, the current market price was $1.80 per share. The warrants vested one year from the date of issue and were exercised in September 2004.

In August 2003, we issued 378,308 shares of common stock in exchange for the surrender of warrants to purchase 700,000 shares in a cashless transaction. The warrants were exercisable at $2.50 per share based on the then-current market price of $5.44 per share.

In August 2004, we issued 56,461 shares of common stock in exchange for the surrender of warrants to purchase 62,500 shares in a cashless transaction. The warrants were exercisable at $1.75 per share based on the then current market price of $18.11 per share.

In October 2004, we issued 28,862 and 28,683 shares of common stock in exchange for the surrender of warrants to purchase 31,250 and 31,250 shares of common stock in separate cashless transactions. The warrants were exercisable at $1.75 per share based on the then-current price of $22.90 and $21.30 per share, respectively.

NOTE 15—STOCK-BASED COMPENSATION

In 1997, we established the Cheniere Energy, Inc. 1997 Stock Option Plan, as amended (the "Option Plan"), which allows for the issuance of options to purchase up to 2,500,000 shares of our common stock. Options on 2,500,000 shares of our common stock had been granted and were outstanding or had been exercised as of December 31, 2004. The term of options granted under the Option Plan is generally five years. Vesting varies, but generally occurs over three or four years, in increments of 33% or 25%, respectively, on each anniversary of the grant date. All options granted under the Option Plan have exercise prices equal to or greater than fair market value at the date of grant.

In 2004, we established the Cheniere Energy, Inc. 2003 Stock Incentive Plan (the "2003 Stock Incentive Plan") which allowed for the issuance of options to purchase common stock or awards of common stock up to 1,000,000 shares. On February 2, 2004, 383,000 shares were issued to employees and outside directors in the form of bonus and restricted stock awards under the plan related to our performance in 2003. We recorded $2,415,000 of non-cash compensation expense in 2004 related to the issuance of 161,000 shares (bonus stock awards) valued at $15.00 per share, which shares were fully vested on the date of grant. In addition, we recorded $3,330,000 of deferred compensation as a reduction to stockholders' equity related to the issuance of 222,000 shares (restricted stock awards) valued at $15.00 per share on the grant date that vest on each of the first and second anniversaries of the grant date. Additionally, on November 15, 2004, 118,176 shares were issued under the 2003 Stock Incentive Plan to employees and outside directors in the form of restricted stock awards related to our performance in 2004. We recorded $4,946,000 of deferred compensation as a reduction to stockholders' equity based on the $41.85 value per share on the date of the grant. One-third of the restricted shares vest on each of the first, second, and third anniversaries of the grant date. During 2004, we recorded $4,148,000 (before capitalization of $529,000 as oil and gas property costs) in total non-cash compensation expense of which $2,415,000 related to bonus stock awards and $1,733,000 related to amortization of deferred compensation associated with restricted stock awards. As of December 31, 2004, the balance of non-cash deferred compensation was $6,543,000.

At December 31, 2004, options to purchase 367,500 shares of our common stock had been issued to employees under the 2003 Stock Incentive Plan. All of these options vest in one-third increments on the first, second, and third anniversaries of the grant date. All options granted under the 2003 Stock Incentive Plan have exercise prices equal to or greater than fair market value at the date of grant.

Options granted and common shares awarded under the 2003 Stock Incentive Plan totaled 868,676 shares as of December 31, 2004. Following stockholder approval on February 8, 2005, the 2003 Stock Incentive Plan was amended to increase the number of shares of common stock authorized for issuance under the plan from 1,000,000 to 4,000,000.

A summary of the status of our stock options is presented below:

	December 31, 2004	2003	2002
Options outstanding at beginning of period	1,960,000	1,983,611	1,741,111
Options granted at an exercise price of $62.30 to $64.70 per share	55,000	—	—
Options granted at an exercise price of $19.50 to $22.51 per share	65,000	—	—
Options granted at an exercise price of $16.15 to 17.20 per share	190,000	—	—
Options granted at an exercise price of $15.00 to $15.49 per share	275,000	—	—
Options granted at an exercise price of $12.37 to $14.80 per share	160,000	—	—
Options granted at an exercise price of $4.45 to $4.62 per share	—	100,000	—
Options granted at an exercise price of $1.44 to $2.70 per share	—	370,000	—
Options granted at an exercise price of $0.93 to $1.27 per share	—	20,000	347,500
Options exercised	(1,348,006)	(187,500)	—
Options converted to warrants	—	(241,250)	—
Options surrendered in cashless exercises, cancelled, or expired	(57,362)	(84,861)	(105,000)
Options outstanding at end of period	1,299,632	1,960,000	1,983,611
Options exercisable at end of period	222,133	1,161,980	1,106,111
Weighted average exercise price of options outstanding	$ 11.88	$ 2.23	$ 2.07
Weighted average exercise price of options exercisable	$ 3.97	$ 2.49	$ 2.56
Weighted average fair value of options granted during the period	$ 11.63	$ 1.60	$ 1.20
Weighted average remaining contractual life of options outstanding	3.7 years	2.9 years	3.4 years

The following table summarizes information about fixed options outstanding at December 31, 2004:

	Options Outstanding		Options Exercisable
Exercise Prices	Number Outstanding	Weighted Average Years Remaining Contractual Life	Number Outstanding
$62.30 to $64.70 per share	55,000	4.9	—
$19.50 to $22.51 per share	65,000	4.8	—
$16.15 to $17.20 per share	185,000	4.2	25,000
$15.00 to $15.49 per share	275,000	4.2	—
$12.37 to $14.80 per share	160,000	4.2	—
$4.45 to $4.62 per share	70,000	3.6	50,000
$1.44 to $2.75 per share	290,466	2.9	50,467
$0.93 to $1.27 per share	199,166	2.7	96,666
	1,299,632		222,133

NOTE 16—RELATED PARTY TRANSACTIONS

In conjunction with our private placement of equity in January 2004, placement fees were paid to T. R. Winston & Company, Inc., a company in which the son of Charif Souki, Cheniere's Chairman, President and Chief Executive Officer, is employed. Placement fees to T. R. Winston for such placement totaled $965,000.

In December 2003, we entered into a shareholders agreement whereby we acquired a minority interest in J & S Cheniere. One of the directors of J & S Cheniere is the brother of Charif Souki. We also entered into an option agreement with J & S Cheniere providing for a $1,000,000 payment to us from J & S Cheniere for the option to acquire regasification capacity at our Sabine Pass and Corpus Christi LNG receiving terminals.

In April 2002, Charles M. Reimer, Cheniere's then-President, advanced amounts totaling $30,000 to us. Subsequent to our sale of producing oil and gas properties, we repaid the advances on April 25, 2002, with accrued interest at 10% per annum, totaling $122.

In March 2002, we sold 51,400 shares of Gryphon common stock owned by us to Gryphon, subject to an option to repurchase the shares, thereby reducing our interest in Gryphon from 20.2% to 13.7% on an as-converted basis. Such sale was made in connection with the settlement of a lawsuit filed by Fairfield Industries Incorporated against Gryphon and Cheniere. In connection with our sale of Gryphon common stock to Gryphon, we had a one-year option to repurchase all or a portion of the 51,400 shares at a price of $50 per share if exercised within 120 days of the sale or at prices increasing ratably thereafter to approximately $68 per share one year after the sale. As consideration for the shares, Gryphon agreed to make payments in full satisfaction of certain of our existing and contingent obligations totaling $3,562,000. We reached a settlement agreement with Gryphon and Fairfield Industries whereby a lawsuit and related claims asserted by Fairfield against Gryphon and Cheniere were dismissed.

Commencing October 1, 2001, we have made office space available for use by Keith F. Carney, a non-management director. The pro rata amount of office lease expense related to that space was $3,000, $4,000, and $5,000 in 2004, 2003 and 2002, respectively.

NOTE 17—COMMITMENTS AND CONTINGENCIES

Lease Commitments

In October 2003, we entered into a lease agreement for new office space with a term which runs from December 2003 through April 2014. Beginning in April 2004, our monthly lease rental is $21,000 and escalates to $24,000 beginning in February 2009 through the remaining term of the lease. We have an option to renew the lease for an additional five years at the then-current market rate. In May 2004, we amended our office lease agreement to increase our rentable square footage (the "Expansion Space"). The lease term for the Expansion Space runs from September 2004 through August 2009. Our monthly lease rental for the Expansion Space is $14,000 beginning in June 2005. We have the option, subject and subordinate to another tenants' renewal option, to renew the lease for an additional five years at a rate specified in this amendment. We are also responsible for our proportionate share of the building operating expenses. In connection with the lease, we have issued a letter of credit in favor of the landlord in the amount of $898,000. The letter of credit amount decreases by $225,000 each October for the next four years. In addition, the lease creates a lien on all property that we place on the premises as a security interest for payment of amounts due under the terms of the lease.

In December 2003, we entered into an agreement to lease software for use in our exploration activities. This lease provides for annual payments of $230,000 per year to be made prior to the beginning of each contract year. The lease runs through December 31, 2006.

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

Year Ending December 31,	Operating Lease
2005	$ 642
2006	728
2007	505
2008	505
2009	461
Thereafter	1,376
Total	$4,217

Our total rental expense for the years ending December 31, 2004, 2003 and 2002 was $445,000, $128,000, and $131,000, respectively.

LNG Commitments

Freeport LNG

Under the limited partnership agreement of Freeport LNG, development expenses of the Freeport LNG project and other Freeport LNG cash needs generally are to be funded out of Freeport LNG's own cash flows, borrowings or other sources, and, up to a pre-agreed total amount, with capital contributions by the limited partners. In December 2004 and February 2005, we received notices from the general partner of Freeport LNG stating that its affiliated limited partner's pre-agreed total capital contributions would be made and that additional capital contributions were being called for from all limited partners to fund a portion of Freeport LNG's budgeted 2005 expenditures. We presently intend to fund our 30% pro rata share, or approximately $2,491,000, of these capital calls, which will be contributed to Freeport LNG over the period from December 2004 through June 2005. As of December 31, 2004, we had funded $275,000, leaving $2,216,000 remaining to be funded in 2005. Additional capital calls may be made upon us and the other limited partners in Freeport LNG. In the event of each such future capital call, we will have the option either to contribute the requested capital or to decline to contribute. If we decline to contribute, the other limited partners could elect to make our contribution and receive back twice the amount contributed on our behalf, without interest, before any Freeport LNG cash flows are otherwise distributed to us. We currently expect to evaluate Freeport LNG capital calls on a case-by-case basis and to fund additional capital contributions that we elect to make using cash on hand, revenues from advance capacity reservation fees and funds raised through the issuance of Cheniere equity or debt securities or other Cheniere borrowings.

In connection with the acquisition of the option to lease the Freeport LNG receiving terminal site in June 2001, we issued 500,000 shares of common stock valued at $1,150,000, or $2.30 per share, the closing price of our common stock on the date of the transaction, to the seller of the lease option. We also committed to issue an additional 750,000 shares of our common stock to the seller of the lease option in April 2003, for which we received no additional consideration. These shares were issued in April 2003 at a value of $1,312,500, or $1.75 per share, the closing price of our common stock on the date of issuance. The seller of the lease option also obtained the right to receive a royalty payment on the gross quantities of gas processed at LNG terminals that we own. The royalty is generally calculated based on $0.03 per Mcf of gas processed, subject to a minimum royalty of $2,000,000 per year and a maximum royalty of $10,950,000 per year after production begins. In 2002, a long-term lease was secured by Freeport LNG, and at the closing of the sale of our interests in the site and project, Freeport LNG assumed the obligation to pay the royalty with respect to gas processed and produced at the Freeport LNG facility.

Obligations under LNG TUAs

Our wholly-owned limited partnership, Sabine Pass LNG, L.P., has entered into TUAs with Total and Chevron USA to provide berthing for LNG tankers and for the unloading, storage and regasification of LNG at our proposed Sabine Pass LNG receiving terminal.

LNG Option Agreements

We entered into an agreement with J & S Cheniere under which J & S Cheniere has an option to enter into a TUA reserving up to 200 MMcf/d of capacity at each of our Sabine Pass and Corpus Christi LNG facilities. Following execution of the option agreement, $1,000,000 was paid by J & S Cheniere to us in January 2004. The option fee is refundable if we do not receive FERC approval for at least one of the terminals and we do not proceed with the development of at least one of the terminals. Upon FERC approval and other related approvals and receipt of permits for each terminal, J & S Cheniere has 60 days to exercise its option at each terminal. The option agreement contemplates negotiation of a definitive terminal use agreement for each of the facilities, which will specify the terms and conditions of the purchase and sale of the capacity and related services.

In January 2004, Corpus Christi LNG, L.P. entered into an option agreement with BPU LNG, Inc. ("BPU LNG") to provide 100 MMcf/d of regasification capacity at our proposed LNG receiving terminal near Corpus Christi, Texas. The option agreement was subsequently assigned by BPU LNG to its sole stockholder, BPU Associates, LLC.

LNG Site Leases

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

In January 2005, we exercised our options and entered into three land leases comprising 568 acres for our Sabine Pass LNG terminal site. The initial term of the leases is for 30 years with options to renew for six 10-year extensions. In February 2005, two of the three leases were amended increasing the total acreage under lease to 853 acres and increasing the annual lease payments to $1,501,000.

EPC Agreement

In December 2004, we entered into a lump-sum turnkey EPC agreement with Bechtel Corporation ("Bechtel") pursuant to which Bechtel will provide services for the engineering, procurement and construction of the Sabine Pass LNG receiving terminal. In December 2004, a limited notice to proceed ("LNTP") was issued and accepted by Bechtel, at which time Bechtel was required to promptly commence performance of certain off-site engineering and preparatory work under the EPC agreement. Upon Bechtel's receipt from us of a final notice to proceed ("NTP"), Bechtel must commence all other aspects of the work under the EPC agreement. We generally may not issue the NTP until, among other things, we have documented to Bechtel that we have sufficient funds, or have obtained sufficient financing, to pay the amounts required under the EPC agreement and we have paid to Bechtel 5% of the contract price, or $32,347,000 as an advance payment.

We will pay to Bechtel a contract price of $646,937,000 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 us for certain delays in achieving substantial completion, minimum acceptance criteria and performance guarantees. Bechtel will be entitled to a bonus of $12,000,000, or a lesser amount in certain cases, if Bechtel, within 1,095 days after delivery of the NTP, completes construction sufficient to achieve, among other requirements specified in the EPC agreement, a sendout rate of at least 2.0 Bcf/d for a minimum sustained test period of 24 hours. In February 2005, a change order for $1.5 million was approved, thereby increasing the total contract price to $648.4 million.

Other Commitments

In December 2004, we entered into a three-year service agreement with a third party to provide certain telecommunications services to us. The agreement provides for monthly payments by us totaling $127,000 for 2005, 2006 and 2007, respectively.

We have issued $400,000 in surety bonds in favor of the Minerals Management Service related to our offshore U.S. Gulf Coast oil and gas operations.

Legal proceedings

We have been and may in the future be involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management and legal counsel, as of December 31, 2004, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

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

NOTE 18—BUSINESS SEGMENT INFORMATION

Our business activities are conducted within two principal operating segments: LNG receiving terminal development and oil and gas exploration and development. These segments operate independently, and there are no intercompany revenues or expenses between them.

Our LNG receiving terminal segment is in the preliminary stage of developing LNG receiving terminals along the U.S. Gulf Coast, primarily near Corpus Christi and Freeport, Texas and in Cameron Parish, Louisiana.

Our oil and gas exploration and development segment explores for oil and natural gas using a regional database of 7,000 square miles of regional 3D seismic data. Exploration efforts are focused on the shallow waters of the Gulf of Mexico offshore of Louisiana and Texas and consist primarily of seismic data interpretation and prospect generation activities. This segment participates in drilling and production operations with industry partners on the prospects that we generate.

	Segments				
	LNG Receiving Terminal	Oil & Gas Exploration and Development	Total	Corporate and Other(1)	Total Consolidated
			(in thousands)		
As of or for the Year Ended December 31, 2004:					
Revenues	$ —	$ 1,998	$ 1,998	$ —	$ 1,998
Depreciation, depletion, and amortization	78	868	946	378	1,324
Income (loss) from operations	(17,245)	17	(17,228)	(11,857)	(29,085)
Equity in net loss of equity method investee (2)	(1,346)	—	(1,346)	—	(1,346)
Reimbursement from limited partnership investment (3)	2,500	—	2,500	—	2,500
Total assets	24,355	19,931	44,286	289,281	333,567
Expenditures for additions to long-lived assets	460	2,676	3,136	868	4,004
As of or for the Year Ended December 31, 2003:					
Revenues	$ —	$ 658	$ 658	$ —	$ 658
Depreciation, depletion, and amortization	142	192	334	95	429
Income (loss) from operations	(6,847)	466	(6,381)	(2,637)	(9,018)
Equity in net loss of equity method investee (4)	(4,471)	—	(4,471)	—	(4,471)
Gain on sale of LNG assets (5)	4,760	—	4,760	—	4,760
Gain on sale of limited partnership interest (6)	423	—	423	—	423
Total assets	2,953	20,219	23,172	1,419	24,591
Expenditures for additions to long-lived assets	—	2,554	2,554	533	3,087
As of or for the Year Ended December 31, 2002:					
Revenues	$ —	$ 239	$ 239	$ —	$ 239
Depreciation, depletion, and amortization	109	190	299	70	369
Income (loss) from operations	(1,666)	(41)	(1,707)	(1,988)	(3,695)
Equity in net loss of equity method investee (7)	—	(2,185)	(2,185)	—	(2,185)
Gain on sales of assets (8)	—	340	340	—	340
Total assets	2,506	17,730	20,236	823	21,059
Expenditures for additions to long-lived assets	125	2,828	2,953	15	2,968

(1) Includes corporate activities and certain intercompany eliminations.
(2) Represents equity in net loss of our investment in Freeport LNG for 2004 totaling $1,068,000 plus the 2003 Suspended Loss of $278,000.
(3) In January 2004, we received the final $2,500,000 payment due from Freeport LNG. See Note 9 to the consolidated financial statements.
(4) Represents equity in net loss of our investment in Freeport LNG, excluding the 2003 Suspended Loss of $278,000. Our investment basis was reduced to zero as of December 31, 2003.
(5) In February 2003, we sold a 60% interest in our Freeport LNG terminal project to Freeport LNG. A gain of $4,760,000 was recognized on the sale. See Note 9 to the Consolidated Financial Statements.
(6) In March 2003, we sold a 10% limited partner interest in Freeport LNG to a third party and recognized a gain of $423,000. See Note 9 to the Consolidated Financial Statements.
(7) For the year 2002, we recognized a loss of $2,185,000 on our equity investment in Gryphon. Its investment basis was reduced to zero as of December 31, 2002. Effective January 1, 2003, we began using the cost method of accounting for this investment. See Note 8 to the Consolidated Financial Statements.
(8) In April 2002, we sold our producing wells and recognized a gain of $340,000.

NOTE 19—SUPPLEMENTAL CASH FLOW INFORMATION AND DISCLOSURES OF NON-CASH TRANSACTIONS

In 2004, we recorded $97,000, the present value of the expected abandonment cost of a well in which we hold a working interest, and its related equipment, as a long-term asset retirement obligation. A corresponding amount was recorded to proved oil and gas properties. Non-cash accretion expense for 2004 was $2,000 and was included in depreciation, depletion and amortization expense.

In 2004, we established the 2003 Stock Incentive Plan which allowed for the issuance of options to purchase common stock or awards of common stock up to 1,000,000 shares. On February 2, 2004, 383,000 shares were issued to employees and outside directors in the form of bonus and restricted stock awards under the plan related to our performance in 2003. We recorded $2,415,000 of non-cash compensation expense in 2004 related to the issuance of 161,000 shares (bonus stock awards) valued at $15.00 per share, which shares were fully vested on the date of grant. We recorded $3,330,000 of deferred compensation as a reduction to stockholders' equity related to the issuance of 222,000 shares (restricted stock awards) valued at $15.00 per share on the grant date that vest on each of the first and second anniversaries of the grant date. On November 15, 2004, 118,176 shares were issued under the 2003 Stock Incentive Plan to employees and outside directors in the form of restricted stock awards related to our performance in 2004. We recorded $4,946,000 of deferred compensation as a reduction to stockholders' equity based on the $41.85 value per share on the date of the grant. One-third of the restricted shares vest on each of the first, second and third anniversaries of the grant date. During 2004, we recorded $4,148,000 (before capitalization of $529,000 as oil and gas property costs) in total non-cash compensation expense of which $2,415,000 related to bonus stock awards and $1,733,000 related to amortization of deferred compensation associated with restricted stock awards. As of December 31, 2004, the balance of non-cash deferred compensation was $6,543,000.

In 2004, 276,706 shares of our common stock were issued in satisfaction of cashless exercises of stock options and warrants to purchase 195,062 and 125,000 shares, respectively.

In December 2003, the minority interest owner of Corpus Christi LNG contributed two tracts of land valued at $311,000 to be used for the LNG terminal site.

In August 2003, we issued 378,308 shares of common stock in exchange for the surrender of warrants to purchase 700,000 shares in a cashless transaction.

In April 2003, pursuant to a contingent contractual obligation related to our 2001 acquisition of an option to lease the Freeport LNG terminal site, we issued 750,000 shares of our common stock, valued at $1,312,000 on the date of issuance, to satisfy a closing requirement related to the February 2003 sale of a 60% interest in our Freeport LNG project.

In February 2003, in connection with the sale of a 60% interest in the Freeport LNG site and project, we issued warrants valued at $540,000 to purchase 700,000 shares of common stock. As a result of the closing of the Freeport transaction, we issued warrants valued at $174,000 to purchase 225,000 shares of common stock to LNG consultants for services previously performed for us. In connection with the sale of a 10% interest in Freeport LNG, we issued warrants valued at $242,000 to purchase 300,000 shares of common stock to the purchaser, and the purchaser canceled the $750,000 note previously payable by us. These transactions are described in more detail in Note 9 to the Consolidated Financial Statements.

In 2002, we transferred computer equipment with a net book value of $29,000 to an exploration consulting company as compensation for its services. We sold 51,400 shares of Gryphon common stock owned by us to Gryphon in consideration for their assumption of certain of our existing and contingent liabilities totaling $3,562,000. In connection with the sale of our proved oil and gas properties, we issued warrants to purchase 50,000 shares of common stock to a consultant valued at $23,000. We issued warrants to purchase 200,000 shares of common stock and extended the expiration period on existing warrants to purchase 255,417 shares of common stock, all at a value of $266,000, in connection with a short-term bridge financing arrangement with an unrelated third-party lender. We issued warrants to purchase 50,000 shares of common stock to a consultant valued at $39,000 for assistance in marketing our LNG terminal capacity. We issued 12,500 stock options valued at $10,000 to a consultant for assistance in developing our LNG terminal business. We issued warrants to purchase 12,500 shares of common stock to an investor relations consultant valued at $10,000. During 2002, we accrued an additional $97,000 for the services of an LNG project consultant. As of December 31, 2002, we had an accrued liability to this consultant of $367,000, of which $167,000 was the estimated value of warrants to be issued to purchase 225,000 shares of common stock. These warrants were issued in February 2003 at an exercise price of $2.50 per share of common stock.

We paid $4,000, $41,000 and $56,000 for interest in the years ended December 31, 2004, 2003 and 2002, respectively. We have not paid any income taxes in the three years ended December 31, 2004.

The values of securities issued by us in connection with the transactions described above are based on third party arms-length negotiated prices or the fair value as calculated using the Black-Scholes pricing model.

NOTE 20—SUBSEQUENT EVENTS

On February 8, 2005, we acquired the minority interest of Corpus Christi LNG through the acquisition of BPU LNG, Inc. in exchange for 1,000,000 restricted shares of our common stock. BPU LNG, Inc. held as its sole asset the 33.3% limited partner interest in Corpus Christi LNG. As a result of this transaction, we now own 100% of the limited partner interests of Corpus Christi LNG. This transaction will be accounted for using the Purchase Method of Accounting as prescribed by SFAS No. 141, *Accounting for Business Combinations*, and will be valued at $77,090,000, or $77.09 per share, the closing price of our common stock on February 8, 2005, plus incidental transaction costs. Nearly all of the transaction value will be recognized as goodwill which will be accounted for under SFAS No. 142, *Goodwill and Other Intangible Assets.*

Also on February 8, 2005, our stockholders approved a proposal to amend the Cheniere Energy, Inc. 2003 Stock Incentive Plan to increase the number of shares of common stock available for issuance under the plan from 1,000,000 shares to 4,000,000 shares. At the same time, our stockholders approved a proposal to amend our Restated Certificate of Incorporation to increase the number of shares of authorized common stock from 40,000,000 to 120,000,000.

On February 25, 2005, Sabine Pass LNG entered into an $822 million senior secured credit facility, or Credit Facility, with a syndicate of 47 financial institutions. Société Générale serves as the administrative agent and HSBC Securities (USA) Inc. serves as collateral agent. The Credit Facility will be used to fund a substantial majority of the costs of constructing and placing into operation the Sabine Pass LNG receiving terminal. Unless Sabine Pass LNG decides to terminate availability earlier, the Credit Facility will be available until no later than April 1, 2009, after which time any unutilized portion of the Credit Facility will be permanently canceled. Before Sabine Pass LNG may make an initial borrowing under the Credit Facility, it will be required to provide evidence that it has received equity contributions in amounts sufficient to fund $216 million of the project costs.

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

The Credit Facility contains customary conditions precedent to the initial borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. The obligations of Sabine Pass LNG under the 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 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 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 Credit Facility with respect to hedged drawings under the Credit Facility up to a maximum of $700 million at 4.49% from July 25, 2005 through March 25, 2009 and at 4.98% from March 26, 2009 through March 25, 2012. The final termination date of the swap agreements will be March 25, 2012.

In January 2005, we exercised our options and entered into land leases comprising 568 acres for our Sabine Pass LNG receiving terminal site. The initial term of the leases is for 30 years with options to renew for six 10-year periods. In February 2005, we amended certain of these leases increasing our total acreage to 853 acres and increasing our annual lease payments to $1,501,000.

During January and February 2005, we issued 92,369 shares of common stock pursuant to the exercise of stock options at an average price of $11.14 generating proceeds of $1,029,000. We also issued 200,000 shares of common stock upon exercise of warrants with an average exercise price of $2.50 per share, generating proceeds of $500,000.

On March 7, 2005, FERC issued the Final Environmental Impact Statement ("FEIS") for our proposed Corpus Christi LNG receiving terminal. In the FEIS, FERC concluded that the facility, with appropriate mitigating measures as recommended, would have limited adverse environmental impact. We currently anticipate that we will receive FERC approval and complete the permitting process for this terminal in the second quarter of 2005.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

Costs Incurred in Oil and Gas Producing Activities

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

	Year Ended December 31,		
	2004	2003	2002
Acquisition of properties			
Proved properties	$ —	$ —	$ —
Unproved properties	318	937	131
Exploration costs	2,261	1,577	2,682
Development costs	—	—	15
Subtotal	$2,579	$2,514	$ 2,828
Asset retirement costs	97	—	—
Total	$2,676	$2,514	$ 2,828
Proportional share of unconsolidated affiliate(1)			$43,496

(1) Effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting. Prior to that time, we accounted for this investment using the equity method of accounting. Accordingly, the amount for 2002 represents our proportional share, based on our 100% common stock ownership, of the costs incurred in oil and gas activities of Gryphon. Upon the conversion of Gryphon's preferred shares, such proportional share of Gryphon activities would be reduced to 9.3%, or $4,045,000 for 2002.

Included in the costs incurred for the years ended December 31, 2004, 2003 and 2002 were $1,573,000, $1,064,000 and $849,000, respectively, of capitalized general and administrative expenses, capitalized interest expense and capitalized debt discount directly related to property acquisition, exploration and development.

Capitalized Costs Related to Oil and Gas Producing Activities

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

	December 31,	
	2004	2003
Proved properties	$ 3,339	$ 1,223
Unproved properties	16,688	18,048
	20,027	19,271
Accumulated depreciation, depletion and amortization	(971)	(136)
	$19,056	$19,135

Costs Not Being Amortized

Presented below is a summary of oil and gas property costs not being amortized at December 31, 2004, by the year in which such costs were incurred. Such costs included capitalized interest of $169,000. The majority of the evaluation activities are expected to be completed within three years.

	Cumulative Balance at December 31, 2004	Costs incurred for the years ended December 31, 2004	2003	2002	2001 and earlier
		(in thousands)			
Acquisition costs	$ 767	$317	$ 43	$ 37	$ 370
Exploration costs	15,921	372	1,142	850	13,557
Development costs	—	—	—	—	—
Total	$16,688	$689	$1,185	$887	$13,927

Results of Operations from Oil and Gas Producing Activities

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

	Year Ended December 31, 2004	2003	2002
Revenues	$1,998	$ 658	$239
Production costs	(117)	—	(90)
Depreciation, depletion and amortization(1)	(837)	(122)	(75)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$1,044	$ 536	$ 74
Equity in results of operations from oil and gas producing activities (excluding corporate overhead and interest costs) of unconsolidated affiliate(2)			$828

(1) Includes $2,000 of asset retirement accretion expense in 2004.

(2) Effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting. Prior to that time, we accounted for this investment using the equity method of accounting. Accordingly, the amount for 2002 represents our proportional share, based on our 100% common stock ownership, of the results of operations from oil and gas producing activities (excluding corporate overhead and interest costs). Such proportional share will be reduced to 9.3% upon the conversion of Gryphon's preferred shares, resulting in a decrease in our proportional interest in the results of operations from oil and gas producing activities to $77,000 for 2002.

Reserve Quantities

Estimates of our proved reserves and the related standardized measure of discounted future net cash flow information are based on the reports generated by our independent petroleum engineers, Sharp Petroleum Engineering, Inc. in 2004 and 2003 and substantially, but not wholly, based on the report generated by Ryder Scott Company in 2002, in accordance with the rules and regulations of the SEC. The independent engineers' estimates were based upon a review of production histories and other geologic, economic, ownership and engineering data provided by us. These estimates represent our interest in the reserves associated with our properties. All of our oil and gas reserves are located within the United States or its territorial waters.

Our estimates of proved reserves and proved developed reserves of oil and gas as of December 31, 2004, 2003 and 2002 and the changes in our proved reserves are as follows:

	2004		2003		2002	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Proved reserves:						
Beginning of year	5,123	912,779	3,980	1,333,000	15,088	3,245,000
Revisions of prior estimates	(738)	(159,303)	(3,830)	(1,093,920)	—	—
Production	(1,364)	(328,676)	(17)	(123,392)	(495)	(91,470)
Sale of reserves in place	—	—	—	—	(14,598)	(3,177,278)
Extensions, discoveries and other additions	—	494,320	4,990	797,091	3,985	1,356,748
End of year	3,021	919,120	5,123	912,779	3,980	1,333,000
Interest in proved reserves of unconsolidated affiliate—end of year(1)					371,808	27,508,000
Proved developed reserves:						
Beginning of year	3,024	759,095	1,606	503,000	15,088	3,245,000
End of year	3,021	919,120	3,024	759,095	1,606	503,000
Interest in proved developed reserves of unconsolidated affiliate—end of year(1)					165,421	16,332,000

(1) Effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting. Prior to that time, we accounted for this investment using the equity method of accounting. Accordingly, the amount for 2002 represents our proportional share, based on our 100% common stock ownership, of the proved reserves and proved developed reserves of Gryphon. Upon the conversion of Gryphon's preferred shares, such proportional share of Gryphon reserves would be reduced to 9.3%, or proved reserves of 34,578 Bbls and 2,558,000 Mcf and proved developed reserves of 15,384 Bbls and 1,519,000 Mcf at December 31, 2002. Such reserves were not considered in our calculation of depreciation, depletion and amortization or the calculation of our ceiling test.

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.

Standard Measure of Discounted Future Net Cash Flows

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

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

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

	December 31,		
	2004	2003	2002
Future gross revenues	$5,666	$5,231	$6,344
Less—future costs:			
Production	(570)	(134)	(164)
Development and abandonment	(80)	—	(57)
Income taxes	—	—	—
Future net cash flows	5,016	5,097	6,123
Less—10% annual discount for estimated timing of cash flows	(868)	(819)	(992)
Standardized measure of discounted future net cash flows	$4,148	$4,278	$5,131

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

	Year Ended December 31,		
	2004	**2003**	**2002**
Standardized measure—beginning of period	$ 4,278	$ 5,131	$ 2,923
Sales of oil and gas produced, net of production costs	(1,881)	(657)	(149)
Extensions, discoveries and other additions	1,849	3,692	5,209
Revisions to previous quantity estimates, timing and other	(698)	(4,945)	(29)
Net changes in prices and production costs	268	727	—
Sale of reserves in place	—	—	(2,213)
Development costs incurred	—	—	15
Changes in estimated development costs	—	—	(625)
Net changes in income taxes	—	—	—
Accretion of discount	332	330	—
Standardized measure—end of period	$ 4,148	$ 4,278	$ 5,131
Standardized measure—end of period—proportional interest in reserves of unconsolidated affiliate(1)			$95,211
Current prices at year-end, used in standardized measure			
Oil (per Bbl)	$ 38.10	$ 31.00	$ 29.23
Gas (per Mcf)	$ 6.04	5.63	4.64

(1) Effective January 1, 2003, we began accounting for our investment in Gryphon using the cost method of accounting. Prior to that time, we accounted for this investment using the equity method of accounting. Accordingly, the amount for 2002 represents our proportional share, based on our 100% common stock ownership, of the standardized measure of Gryphon's proved oil and gas reserves. Such proportional share of Gryphon's standardized measure will be reduced to 9.3% upon the conversion of Gryphon's preferred shares, resulting in a decrease in Cheniere's proportional interest in the standardized measure of unconsolidated affiliate to $8,855,000 at December 31, 2002.

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

Quarterly Financial Data—(unaudited in thousands)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2004:					
Revenues	$ 332	$ 335	$ 465	$ 866	$ 1,998
Gross profit(1)	247	243	346	177	1,013
Loss from operations	(7,218)	(7,327)	(5,505)	(9,035)	(29,085)
Net loss(3)	(1,075)	(8,053)	(5,639)	(9,801)	(24,568)
Net loss per share—basic and diluted	$ (0.06)	$ (0.43)	$ (0.29)	$ (0.46)	$ (1.26)
Year ended December 31, 2003:					
Revenues	$ 110	$ 122	$ 135	$ 291	$ 658
Gross profit(1)	82	143	32	209	466
(Loss) from operations	(863)	(1,186)	(2,924)	(4,045)	(9,018)
Net income (loss)(2)	3,121	(1,624)	(2,387)	(4,398)	(5,288)
Net income (loss) per share—basic and diluted	$ 0.23	$ (0.11)	$ (0.16)	$ (0.27)	$ (0.36)

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

(2) The first quarter of 2003 includes $4,760,000 and $423,000 in gains, respectively, on sales of 60% of the Freeport LNG terminal project to Freeport LNG and a 10% limited partner interest in Freeport LNG to a third party. See Note 9 to the Consolidated Financial Statements.

(3) The first quarter of 2004 includes a $2,500,000 gain recognized on receipt of the final $2,500,000 payment from Freeport LNG. See Note 9 to the Consolidated Financial Statements.

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

None.

ITEM 9A. ***CONTROLS AND PROCEDURES***

Evaluation of Disclosure Controls and Procedures

Based on their evaluation as of the end of the fiscal year ended December 31, 2004, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

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

Changes in Internal Controls

There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation. There were no material weaknesses, and therefore, there were no corrective actions taken.

Management Report on Internal Control Over Financial Reporting

Our Management Report on Internal Control Over Financial Reporting is included in the Financial Statements on page 63 and is incorporated herein by reference.

ITEM 9B. ***OTHER INFORMATION***

All of our executive officers are "at will" employees and none of them has an employment or severance agreement. The unwritten arrangements under which our executive officers are compensated include:

- a salary, reviewed annually by the Compensation Committee;
- eligibility for a discretionary annual cash bonus, as determined by the Compensation Committee;
- eligibility for awards under Cheniere's 2003 Stock Incentive Plan, as determined by the Compensation Committee;
- health, life, disability and other insurance and/or benefits; and
- vacation, paid sick leave and all other employee benefits.

Cheniere covers 100% of the dependent insurance coverage for our Chairman, President and Chief Executive Officer. For all other employees electing such dependent coverage, 50% of the cost of such coverage is borne by the employee.

In November 2004, the Compensation Committee of our Board of Directors established the annual base salaries (effective as of January 1, 2005) for our executive officers after a review of performance and competitive market data. In addition, the Compensation Committee authorized the payment of cash and restricted stock bonuses to each of the executive officers with respect to the year ended December 31, 2004. The following table sets forth the annual base salary and 2004 cash and restricted stock bonus amounts for each of our executive officers:

Executive Officer	Annual Base Salary	2004 Cash Bonus Amount	2004 Restricted Stock Grant
Charif Souki			
Chairman, President and Chief Executive Officer	$450,000	$675,000	20,293 shares
Walter L. Williams			
Vice Chairman	$240,000	$240,000	7,215 shares
Don A. Turkleson			
Senior Vice President, Chief Financial Officer and Secretary	$240,000	$360,000	7,215 shares
Jonathan S. Gross			
Senior Vice President – Exploration	$240,000	$240,000	7,215 shares
Keith M. Meyer			
Senior Vice President – LNG	$240,000	$240,000	7,215 shares
Zurab S. Kobiashvili			
Senior Vice President & General Counsel	$240,000	$115,068	3,459 shares
Craig K. Townsend			
Vice President and Chief Accounting Officer	$175,000	$104,281	3,135 shares

In November 2004, the Compensation Committee determined to compensate our non-employee directors for the period from May 2004 through May 2005 100% in restricted stock as follows:

Director	2004 Restricted Stock Grant
Nuno Brandolini	3,006 shares
Keith F. Carney	3,006 shares
Paul J. Hoenmans	3,006 shares
David B. Kilpatrick	3,006 shares
J. Robinson West	3,006 shares

PART III

ITEM 10. *DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Item 10 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement involving the election of directors, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2004.

ITEM 11. *EXECUTIVE COMPENSATION*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Item 11 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement involving the election of directors, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2004.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Item 12 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement involving the election of directors, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2004.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Item 13 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement involving the election of directors, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2004.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Item 14 of Part III is incorporated by reference from Cheniere's definitive proxy statement involving the election of directors, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2004.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements, Schedules and Exhibits

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

The financial statements of Freeport LNG Development, L.P. for the period from December 1, 2002 to December 31, 2004, for which Cheniere used the equity method of accounting, have been filed as part of this report on Form 10-K. (See Item 15(c))

The financial statements of Gryphon Exploration Company for the fiscal year ended December 31, 2002, for which Cheniere used the equity method of accounting, have been filed as part of this report on Form 10-K. (See Item 15(c))

(2) Financial Statement Schedules

All consolidated financial statement schedules have been omitted because they are not required, are not applicable, or the required information has been included elsewhere within this Form 10-K.

(3) Exhibits

Exhibit No.	Description
1.1*	Underwriting Agreement, dated as of December 2, 2004, by and among Cheniere Energy, Inc. (the "Company") and the Underwriters named on Schedule I thereto. (Incorporated by reference to Exhibit 1.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 6, 2004)
2.1*	Agreement and Plan of Merger, dated February 8, 2005, by and among Cheniere LNG, Inc., Cheniere Acquisition, LLC, BPU Associates, LLC and BPU LNG, Inc. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
3.1*	Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 4.1 of the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2004 (SEC File No. 001-16383), filed on August 10, 2004)
3.2*	Certificate of Amendment of Restated Certificate of Incorporation of the Company. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
3.3*	Amended and Restated By-laws of the Company. (Incorporated by reference to Exhibit 4.3 of the Company's Registration Statement on Form S-8 (SEC File No. 333-112379), filed on January 20, 2004)
4.1*	Specimen Common Stock Certificate of the Company. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (SEC File No. 333-10905), filed on August 27, 1996)
4.2*	Certificate of Designations, Preferences and Rights of Series A Convertible Preferred Stock of Gryphon Exploration Company. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K (SEC File No. 000-09092), filed on October 20, 2000)
4.3*	Certificate of Designation of Series A Junior Participating Preferred Stock. (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 14, 2004)
4.4*	Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated as of October 14, 2004. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on October 14, 2004)
4.5*	First Amendment to Rights Agreement by and between the Company and U.S. Stock Transfer Corp., as Rights Agent, dated January 24, 2005. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 24, 2005)
4.6*	Piggy-Back Registration Rights Agreement, dated February 8, 2005, by and between the Company and BPU Associates, LLC. (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
10.1*†	Cheniere Energy, Inc. 1997 Stock Option Plan. (Incorporated by reference to Exhibit 10.25 of the Company's Quarterly on Form 10-Q for the quarter ended November 30, 1997 (SEC File No. 000-09092), filed on January 14, 1998)
10.2*†	Amendment No. 1 to Cheniere Energy, Inc. 1997 Stock Option Plan. (Incorporated by reference to Exhibit 10.27 of the Company's Annual Report on Form 10-K for the year ended December 31, 1999 (SEC File No. 000-09092), filed on March 29, 2000)

Exhibit No.	Description
10.3*†	Amendment No. 2 to Cheniere Energy, Inc. 1997 Stock Option Plan. (Incorporated by reference to Exhibit 4.7 of the Company's Registration Statement on Form S-8 (SEC File No. 333-111457), filed on December 22, 2003)
10.4*†	Amendment No. 3 to Cheniere Energy, Inc. 1997 Stock Option Plan. (Incorporated by reference to Exhibit 8 of the Company's Registration Statement on Form S-8 (SEC File No. 333-111457), filed on December 22, 2003)
10.5*†	Amendment No. 4 to Cheniere Energy, Inc. 1997 Stock Option Plan. (Incorporated by reference to Exhibit 9 of the Company's Registration Statement on Form S-8 (SEC File No. 333-111457), filed on December 22, 2003)
10.6†	Amendment No. 5 to Cheniere Energy, Inc. 1997 Stock Option Plan.
10.7*†	Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 4.5 of the Company's Registration Statement on Form S-8 (SEC File No. 333-112379), filed on January 30, 2004)
10.8*†	Amendment to Cheniere Energy, Inc. 2003 Stock Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005)
10.9†	Amendment No. 2 to Cheniere Energy, Inc. 2003 Stock Incentive Plan.
10.10†	Form of Non-Qualified Stock Option Grant (four-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan.
10.11†	Form of Non-Qualified Stock Option Grant (three-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan.
10.12†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2003 Stock Incentive Plan, including Schedule A thereto listing grants made on November 15, 2004.
10.13*	Seismic Data Purchase Agreement, dated June 21, 2000 between Seitel Data Ltd. and the Company. (Incorporated by reference to Exhibit 10.39 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2000 (SEC File No. 000-09092), filed on August 11, 2000)
10.14*	Contribution and Subscription Agreement, dated as of September 15, 2000, by and among the Company, Gryphon Exploration Company and the other investors listed therein. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 000-09092), filed on October 20, 2000)
10.15*	Stockholders Agreement, dated as of October 11, 2000. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 000-09092), filed on October 20, 2000)
10.16*	Settlement and Purchase Agreement, dated and effective as of June 14, 2001 by and between the Company, CXY Corporation, Crest Energy, L.L.C., Crest Investment Company and Freeport LNG Terminal, LLC. (Incorporated by reference to Exhibit 10.10 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 (SEC File No. 001-16383), filed on April 1, 2002)
10.17*	Stock Transfer Agreement, dated March 19, 2002, by and between Gryphon Exploration Company and the Company. (Incorporated by reference to Exhibit 10.11 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 (SEC File No. 001-16383) filed on April 1, 2002)

Exhibit No.	Description
10.18*	Contribution Agreement, dated as of August 26, 2002, by and among Freeport LNG Investments, LLC, Freeport LNG-GP, Inc., the Company, Cheniere LNG, Inc. and Freeport LNG Terminal, LLC. (Incorporated by reference to Exhibit 2 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 4, 2002)
10.19*	Extension and Amendment to Contribution Agreement, dated as of September 19, 2002, by and among Freeport LNG Investments, LLC, Freeport LNG-GP, Inc., the Company, Cheniere LNG, Inc. and Freeport LNG Terminal, LLC. (Incorporated by reference to Exhibit 2 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 26, 2002)
10.20*	Second Extension and Amendment to Contribution Agreement, effective as of October 4, 2002, by and among Freeport LNG Investments, LLC, Freeport LNG-GP, Inc., the Company, Cheniere LNG, Inc. and Freeport LNG Terminal, LLC. (Incorporated by reference to Exhibit 1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on November 5, 2002)
10.21*	Third Amendment to Contribution Agreement, effective as of February 27, 2003, by and among Freeport LNG Investments, LLC, Freeport LNG-GP, Inc., the Company, Cheniere LNG, Inc. and Freeport LNG Terminal, LLC. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 7, 2003)
10.22*	Amended and Restated Limited Partnership Agreement of Freeport LNG Development, L.P., dated as of February 27, 2003, by and among Freeport LNG-GP, Inc., Freeport LNG Investments, LLC and Cheniere LNG, Inc. (Incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 7, 2003)
10.23*	First Amendment to Amended and Restated Partnership Agreement of Freeport LNG Development, L.P., dated as of December 20, 2003, by and among Freeport LNG-GP, Inc., Freeport LNG Investments, LLC and Cheniere LNG, Inc. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 19, 2003)
10.24*	Warrant to Purchase Common Stock, dated as of February 27, 2003, issued by Cheniere in favor of Freeport LNG Investments, LLC. (Incorporated by reference to Exhibit 10.6 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 7, 2003)
10.25*	Option Agreement, dated February 27, 2003, by and between Freeport LNG Investments, LLC and the Company. (Incorporated by reference to Exhibit 10.7 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 7, 2003)
10.26*	Partnership Interest Purchase Agreement, dated as of March 1, 2003, among Contango Sundance, Inc., Contango Oil & Gas, Cheniere LNG, Inc. and the Company. (Incorporated by reference to Exhibit 10.8 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 7, 2003)
10.27*	Warrant to Purchase Common Stock, dated March 1, 2003, issued by the Company in favor of Contango Sundance, Inc. (Incorporated by reference to Exhibit 10.9 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 7, 2003)
10.28*	Credit Agreement, dated as of July 25, 2003, by and between Cheniere, Cheniere LNG, Inc., Cheniere Energy Operating Co., Inc., Cheniere LNG Services, Inc., Cheniere-Gryphon Management, Inc. and Sterling Bank. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 001-16383), filed on August 13, 2003)

Exhibit No.	Description
10.29*	First Amendment to Credit Agreement, dated as of October 24, 2003, by and between Cheniere, Cheniere LNG, Inc., Cheniere Energy Operating Co., Inc., Cheniere LNG Services, Inc., Cheniere-Gryphon Management, Inc. and Sterling Bank. (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003 (File No. 001-16383), filed on November 13, 2003)
10.30*	Limited Partnership Agreement of Corpus Christi LNG, L.P., dated as of May 15, 2003, by and among Corpus Christ LNG-GP, Inc., BPU LNG, Inc. and the Company. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 11, 2003)
10.31	Amended and Restated Limited Partnership Agreement of Corpus Christi LNG, L.P., dated as of February 8, 2005, by and among Corpus Christi LNG-GP, Inc., Corpus Christi LNG-LP, LLC and Corpus Christi LNG-LP, Inc.
10.32*	Omnibus Agreement, dated as of December 20, 2003, by and among Freeport LNG Development, L.P., Freeport LNG-GP, Inc., and ConocoPhillips Company. (Incorporated by reference to Exhibit 10.25 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2003 (SEC File No. 001-16383), filed on March 25, 2004)
10.33*	First Amendment to Omnibus Agreement, dated July 2, 2004, among Freeport LNG Development, L.P., Freeport LNG-GP and ConocoPhillips Company. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 10, 2004)
10.34*	Warrant to Purchase Common Stock, dated April 16, 2003, issued by the Company in favor of Charif Souki. (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q/A (SEC File No. 001-16383), filed on May 26, 2004)
10.35*	Form of Subscription Agreement between the Company and the investors to be identified therein in connection with the private placement completed in January 2004. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 13, 2004)
10.36*◆	LNG Terminal Use Agreement, dated March 1, 2004 between The Dow Chemical Company and Freeport LNG Development, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 13, 2004)
10.37*◆	Credit Agreement, dated July 2, 2004, among Freeport LNG Development, L.P., Freeport LNG-GP, Inc., ConocoPhillips Company and various financial institutions from time to time party thereto as lenders. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 10, 2004)
10.38*◆	LNG Terminal Use Agreement, dated July 2, 2004, between ConocoPhillips Company and Freeport LNG Development, L.P. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 10, 2004)
10.39*	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.40	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P.
10.41*	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)

Exhibit No.	Description
10.42*	Guaranty, dated as of November 9, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.43*	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.44*	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A., Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.45*	Lump Sum Turnkey Engineering, Procurement and Construction Agreement dated December 18, 2004 between Sabine Pass LNG, L.P. and Bechtel Corporation. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 20, 2004)
10.46*	Credit Agreement, dated February 25, 2005, among Sabine Pass LNG, L.P., Société Générale, HSBC Bank USA, National Association and the Lenders named thereto. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.47*	Security Agreement, dated February 25, 2005, among Sabine Pass LNG, L.P., Société Générale, and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.48*	Pledge Agreement, dated February 25, 2005, among Sabine Pass LNG-LP, LLC, Sabine Pass LNG-GP, Inc., Société Générale, Sabine Pass LNG, L.P. and HSBC Bank USA, National Association. (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.49*	Collateral Agency Agreement, dated February 25, 2005, among Sabine Pass LNG, L.P., HSBC Bank USA, National Association and Société Générale. (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.50*	Operation and Maintenance Agreement, dated February 25, 2005, between Sabine Pass LNG, L.P. and Cheniere LNG O&M Services, L.P. (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.51*	Management Services Agreement, dated February 25, 2005, between Sabine Pass LNG-GP, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.52*	International Swap Dealers Association, Inc. Master Agreement and Schedules, dated February 25, 2005, between HSBC Bank USA, National Association and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.53*	Confirmation, dated February 25, 2005, effective July 25, 2005, between HSBC Bank USA, National Association and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.54*	Confirmation, dated February 25, 2005, effective March 25, 2009, between HSBC Bank USA, National Association and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)

Exhibit No.	Description
10.55 *	International Swap Dealers Association, Inc. Master Agreement and Schedules, dated February 25, 2005, between Société Générale, New York, and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.56 *	Confirmation, dated February 25, 2005, effective July 25, 2005, between Société Générale, New York, and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.57 *	Confirmation, dated February 25, 2005, effective March 25, 2009, between Société Générale, New York, and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.58 *	Secured Party Addition Agreement, dated February 25, 2005, executed by HSBC Bank, National Association. (Incorporated by reference to Exhibit 10.13 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.59 *	Secured Party Addition Agreement, dated February 25, 2005, executed by Société Générale. (Incorporated by reference to Exhibit 10.14 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2005)
10.60†	Summary of Compensation for Executive Officers
10.61†	Summary of Compensation for Non-Employee Directors
21	Subsidiaries of Cheniere Energy, Inc.
23.1	Consent of UHY Mann Frankfort Stein & Lipp CPAs, LLP
23.2	Consent of KPMG LLP
23.3	Consent of Hein & Associates LLP
23.4	Consent of Sharp Petroleum Engineering, Inc.
23.5	Consent of Ryder Scott Company
31.1	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Incorporated by reference

† Management contract or compensatory plan or arrangement

◆ Confidential treatment was granted by the SEC for certain portions of this agreement. The confidential portions were filed separately with the SEC.

(c) Freeport LNG Development, L.P. Financial Statements, for which Cheniere used the equity method of accounting for the period from December 1, 2002 to December 31, 2004, are filed as a part of this report beginning on page 109.

Gryphon Exploration Company Financial Statements, for which Cheniere used the equity method of accounting for the fiscal year ending December 31, 2002, are filed as a part of this report beginning on page 120.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHENIERE ENERGY, INC.
(Registrant)

By: /s/ CHARIF SOUKI

Charif Souki
President, Chief Executive Officer and Chairman of the Board

Date: March 10, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ CHARIF SOUKI **Charif Souki**	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 10, 2005
/s/ WALTER L. WILLIAMS **Walter L. Williams**	Vice Chairman of the Board and Director	March 10, 2005
/s/ DON A. TURKLESON **Don A. Turkleson**	Senior Vice President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 10, 2005
/s/ CRAIG K. TOWNSEND **Craig K. Townsend**	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 10, 2005
/s/ NUNO BRANDOLINI **Nuno Brandolini**	Director	March 10, 2005
/s/ KEITH F. CARNEY **Keith F. Carney**	Director	March 10, 2005
/s/ PAUL J. HOENMANS **Paul J. Hoenmans**	Director	March 10, 2005
/s/ DAVID B. KILPATRICK **David B. Kilpatrick**	Director	March 10, 2005
/s/ J. ROBINSON WEST **J. Robinson West**	Director	March 10, 2005

INDEX TO FINANCIAL STATEMENTS

Freeport LNG Development, L.P. Audited Financial Statements

Gryphon Exploration Company Audited Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of
Freeport LNG Development, L.P., a Limited Partnership
Houston, Texas

We have audited the accompanying consolidated balance sheets of Freeport LNG Development, L.P., a Delaware limited partnership (a development stage limited partnership) and subsidiary, as of December 31, 2004 and 2003, and the related consolidated statements of operations, changes in partners' capital (deficit) and cash flows for the years ending December 31, 2004 and 2003, and for the period from inception (December 1, 2002) through December 31, 2004. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Freeport LNG Development, L.P. and subsidiary, as of December 31, 2004 and 2003, and the results of their operations and their cash flows for the years ending December 31, 2004 and 2003, and for the period from inception (December 1, 2002) through December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

/s/ HEIN & ASSOCIATES LLP

HEIN & ASSOCIATES LLP
Phoenix, Arizona

February 18, 2005

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED BALANCE SHEETS

	Years Ended December 31, 2004	2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 58,000	$ 77,000
Cash restricted for construction and current general operations	37,866,000	—
Prepaid expenses	182,000	218,000
Total current assets	38,106,000	295,000
Office equipment and leasehold improvements, net	144,000	121,000
Construction in progress	9,728,000	—
Other assets	448,000	29,000
TOTAL ASSETS	$48,426,000	$ 445,000
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable and accrued liabilities	$ 5,676,000	$ 3,386,000
Amounts payable to limited partners	—	2,501,000
Total current liabilities	5,676,000	5,887,000
Note payable	48,041,000	—
Deferred revenue	3,500,000	—
Commitments and Contingency (Notes 3 and 8)		
Partners' capital (deficit), including deficit accumulated during the development stage of $19,393,000 and $15,832,000, respectively.	(8,791,000)	(5,442,000)
TOTAL LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)	$48,426,000	$ 445,000

See accompanying notes to the financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2004	Years Ended December 31, 2003	Inception (December 1, 2002) through December 31, 2004
REVENUES	$10,000,000	$ —	$ 10,000,000
EXPENSES:			
Quintana site rental and related costs	820,000	573,000	1,393,000
Personnel and related costs	2,326,000	2,193,000	4,732,000
Engineering	2,394,000	2,419,000	5,061,000
Environmental and special studies	791,000	1,063,000	2,076,000
Purchase of limited partners start up and preconstruction cost	—	5,000,000	5,000,000
Professional services	5,934,000	3,068,000	9,086,000
Other general and administrative costs	1,304,000	624,000	2,053,000
Total expenses	13,569,000	14,940,000	29,401,000
OPERATING LOSS	(3,569,000)	(14,940,000)	(19,401,000)
OTHER INCOME	8,000	—	8,000
NET LOSS	$ (3,561,000)	$(14,940,000)	$(19,393,000)

See accompanying notes to the financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL (DEFICIT)

	General Partner	Limited Partners	Accumulated Deficit	Total Partners' Capital (Deficit)
Balances at Inception (December 1, 2002)	$—	$ —	$ —	$ —
Net Loss	—	—	(892,000)	(892,000)
Balances at December 31, 2002	—	—	(892,000)	(892,000)
Capital Contributions	—	10,390,000	—	10,390,000
Net Loss	—	—	(14,940,000)	(14,940,000)
Balances at December 31, 2003	—	10,390,000	(15,832,000)	(5,442,000)
Contributions	—	6,152,000	—	6,152,000
Withdrawals	—	(5,940,000)	—	(5,940,000)
Net Loss	—	—	(3,561,000)	(3,561,000)
Balances at December 31, 2004	$—	$10,602,000	$(19,393,000)	$ (8,791,000)

See accompanying notes to the financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2004	Years Ended December 31, 2003	Inception (December 1, 2002) through 2004
OPERATING ACTIVITIES:			
Net loss	$ (3,561,000)	$(14,940,000)	$(19,393,000)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation	27,000	15,000	42,000
Changes in assets and liabilities:			
Prepaids and other assets	36,000	(218,000)	(182,000)
Accounts payable and accrued liabilities	(1,398,000)	2,494,000	1,988,000
Due to limited partners	(2,501,000)	2,501,000	—
Deferred revenue	3,500,000	—	3,500,000
Net cash used in operating activities	(3,897,000)	(10,148,000)	(14,045,000)
INVESTING ACTIVITIES:			
Purchase of property, equipment, and other assets	(469,000)	(165,000)	(634,000)
Construction in progress, net of increase in accounts payable related to construction in process	(6,040,000)	—	(6,040,000)
Net cash used in investing activities	(6,509,000)	(165,000)	(6,674,000)
FINANCING ACTIVITIES:			
Contributions from partners	6,152,000	10,390,000	16,542,000
Withdrawals by partners	(5,940,000)	—	(5,940,000)
Loan proceeds	48,041,000	—	48,041,000
Net cash provided by financing activities	48,253,000	10,390,000	58,643,000
Net increase in cash and cash equivalents	37,847,000	77,000	37,924,000
Cash, cash equivalents and restricted cash at beginning of period	77,000	—	—
Cash, cash equivalents and restricted cash at end of period	$37,924,000	$ 77,000	$ 37,924,000

See accompanying notes to the financial statements.

FREEPORT LNG DEVELOPMENT, L.P.
(A DEVELOPMENT STAGE LIMITED PARTNERSHIP)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Business Activity—Freeport LNG Development, L.P. (the "Partnership") is in the process of developing, building and commercializing a liquefied natural gas (LNG) receiving and regasification facility on Quintana Island, near Freeport, Texas (the "Facility"). After construction is completed, the Partnership will own and operate the Facility. During the year, FLNG Land, Inc., (Land) a whole owned subsidiary was formed to facilitate land related transactions.

Principles of Consolidation—The consolidated financial statements include the accounts of the Freeport LNG Development, L.P. and its 100% owned subsidiary. All intercompany accounts and transactions are eliminated in the consolidation.

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

Cash and Cash Equivalents—The Partnership considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Cash received from advances on the note payable can only be used for construction and regular operations and cannot be used to fund any additional expansion studies or be used to pay expenses that were incurred prior to when the Company obtained Federal Energy Regulatory Commission ("FERC") approval.

Property, Plant and Equipment—Property, plant and equipment are stated at cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets for financial reporting purposes. Expenditures for major renewals and betterments that extend the useful lives will be capitalized. Expenditures for normal maintenance and repairs will be expensed as incurred. When assets are sold or abandoned, the cost of the assets sold or abandoned and the related accumulated depreciation will be eliminated from the accounts and any gains or losses will be charged or credited to other income (expense) of the respective period. The estimated useful lives by classification are as follows:

Office Equipment	5 years
Leasehold Improvements	15 years

Construction in Progress—Construction in progress through December 31, 2004 relates to engineering, land, acquisition, title work, and other direct costs related to Phase 1 construction of the Facility, which were incurred after the Partnership obtained FERC approval and closed on the related construction loan.

Revenue Recognition—Revenues will be recognized for terminal use fees as they are earned from the regasification process. Revenue from capacity reservations are generally deferred.

The Company also recognized revenue from a transaction in which it provided engineering and design studies to ConocoPhillips. In connection with this sale, the Company also agreed to reserve a specific amount of capacity for ConocoPhillips.

Concentrations of credit risk and other concentrations—The Partnership periodically maintains cash balances in excess of the FDIC insurance limits. As discussed in Note 5, ConocoPhillips has significant involvement with the Partnership.

Income Taxes—The Partnership files its Federal income tax return as a partnership under the Internal Revenue Code. In lieu of corporate income taxes, the partners of the Partnership are taxed on their proportionate share of the Partnership's taxable income. Accordingly, no provision or liability has been recognized for federal income tax purposes for those periods, as taxes are the responsibility of the individual partners of the Partnership.

Income taxes are provided for Land in accordance with Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes". A deferred tax asset or liability is recorded for all temporary differences between income for financial statement purposes and income for tax purposes as well as operating loss carry forwards. Deferred tax expense (or benefit) results from the net change during the year of deferred tax assets and liabilities.

The net deferred tax assets for Land was approximately $130,000 before the valuation allowance. The net deferred tax asset has been reduced to zero after consideration of the valuation allowance. A valuation allowance is recorded when, in the opinion of management, it is likely that some portion of the deferred tax asset will not be realized. Deferred taxes are adjusted for the effects of changes in tax laws and rates. No income taxes were paid in 2004.

2. Development Stage Operations:

The Partnership was formed December 1, 2002. Through June 2004, operations were devoted to preconstruction costs such as obtaining approvals from the Federal Energy Regulatory Commission ("FERC"), obtaining the appropriate leases and permits, completing the engineering and environmental studies necessary for further development of the Facility, and obtaining financing to construct the Facility.

In June 2004, the Partnership obtained FERC approval for the Facility subject to satisfaction to certain conditions. The conditions were satisfied and FERC issued approval to begin construction in January 2005. Construction began on January 17, 2005. The Partnership is in the early phases of construction which is expected to take several years.

3. Liquidity and Continued Operations:

The Partnership will ultimately need to complete construction of the facility and operate it profitably. There is significant construction which needs to be completed, and start up of the facility is expected in 2008.

Notwithstanding the foregoing, the Partnership believes it will continue as a going-concern based on favorable results related to the engineering studies, having secured all permits and government approvals required, the strong financial backing of its partners and future customers, its success in commercializing the expected available capacity and its current financing obtained from ConocoPhillips.

4. Contribution by Limited Partner:

The Partnership was formed with one General Partner, Freeport LNG-GP, Inc. ("Freeport GP") and one Limited Partner, Freeport LNG Investments, LLC. The General Partner owned 0% and the Limited Partner owned 100% of the Partnership. The purpose of the limited partnership is to develop and operate the Facility.

In February 2003 the Partnership agreement was amended and restated ("Amended and Restated Partnership Agreement") to provide for, among other things, the addition of Cheniere LNG Inc. ("Cheniere") as an additional limited partner.

Cheniere has represented to the Partnership that, prior to the amendment of the Partnership agreement, Cheniere incurred costs related to the LNG Facility. These costs included research and development, various feasibility and environmental studies, preconstruction costs and other related start-up costs. Together these costs are referred to as Cheniere's "know how." The estimated fair value of the work performed by Cheniere was agreed to by all the partners to be $14,300,000. Cheniere had expensed all the costs as incurred.

The partners agreed that Cheniere would "contribute" know how valued at $9,300,000 to the Partnership for a 40% limited partner interest in the Partnership. The Partnership agreed to purchase the remaining know how from Cheniere for $5,000,000, payable in installments during 2003 of $2.5 million with the remaining $2.5 million due when the project receives FERC approval, or the Partnership receives a stipulated amount of cash from future customers for capacity reservations for the Facility.

The Amended and Restated Partnership Agreement also provided for Freeport LNG Investments LLC to fund an agreed upon amount of capital to the Partnership, after which time all additional costs would be borne by the partners in relation to their respective ownership percentages. The capital requirement was met by Freeport LNG Investment LLC in 2004.

Because Cheniere's basis in the contributed assets was zero and the project was still in the preconstruction phase, no value was reflected on the balance sheet for Cheniere's know how, and Cheniere's capital account for accounting purposes was recorded at zero. The $5,000,000 due to Cheniere for the purchase of the remaining know how has been expensed in the statement of operations.

Subsequent to the contribution, Cheniere sold a 10 percent interest in the Partnership to Contango Oil and Gas Company.

In December of 2003, Freeport LNG Investments, LLC was converted to Freeport LNG Investments, LLLP (Delaware).

In December 2004, the principal investor of Freeport LNG Investments LLLP sold a 15 percent interest in the Partnership to Texas LNG Holding, LLC, a wholly-owned subsidiary of Dow Chemical Company.

5. Agreement With ConocoPhillips:

In December 2003, the Partnership, Freeport GP, and ConocoPhillips executed an omnibus agreement. This agreement governs several transactions among the entities, including the following:

- ConocoPhillips agreed to pay the Partnership $10,000,000 for specific engineering and design studies, which occurred in January 2004. The Partnership recorded the payment as revenue in 2004.
- ConocoPhillips and the Partnership agreed to a term sheet providing for ConocoPhillips to make a loan to cover a substantial majority of the facility's anticipated construction costs, including interest during the construction phase. The debt service under this loan will be fully serviced by the ConocoPhillips Terminal Use Agreement ("TUA"). The Partnership made loan draws of approximately $48 million against this construction loan and expects to make loan draws in excess of $400 million prior to completion of construction of the Facility. Additional draws were made against the loan subsequent to December 31, 2004.
- ConocoPhillips agreed to purchase 50% of the stock of Freeport LNG GP for $9,000,000. After the purchase of the stock, ConocoPhillips and the principal investor of Freeport LNG GP each appointed three persons to a board which manage the construction and operation of the Facility.

- ConocoPhillips agreed to the form of the TUA which will govern the terms under which LNG is processed and will reserve a specified capacity.

6. Deferred Revenue:

The Partnership received $3,500,000 from ConocoPhillips in 2004 to reserve a specific capacity that is expected to be available if the Partnership completes a potential Phase 2 expansion of the plant. This revenue will not be recognized unless a Phase 2 expansion is completed. The Partnership is still researching the feasibility of Phase 2, and at this time, it is uncertain when Phase 2 construction or operations will begin.

7. Notes Payable:

The Partnership has entered into an agreement with ConocoPhillips to provide financing to construct the Facility. ConocoPhillips has agreed to finance the first $460,000,000 of construction cost, including $10,000,000 in support of any channel widening efforts undertaken by the Brazos River Harbor Navigation District, and has agreed to provide financing up to 50% of any additional supplemental costs incurred. The Partnership has drawn $47,621,000 as of December 31, 2004. The interest rate on the note is 8%. Interest capitalized and included in notes payable as of December 31, 2004 is $420,000. Repayments on this loan will not begin until the facility is constructed and operating. The loan is collateralized by all assets of the Partnership.

8. Commitments:

The Partnership has entered into lease agreements with Brazos River Harbor Navigation District (the "Port") for the lease of the land on which the Facility will be constructed and areas around the Facility. The leases will terminate in 2033, with six options to renew the leases for an additional 10 years for each option. The lease agreements require $2,200,000 in payments each year. The lease payments will also increase based on increases in the Consumer Price Index ("CPI") from year to year.

Additionally, the leases provide that the Partnership will guarantee thru-put fees of $1,250,000 per year (subject to increase for the CPI index) to be received by the Dock Facilities operated by the Port from carriers shipping LNG to the Facility. This guarantee is expected to begin in 2008.

The Partnership has entered a lease agreement in 2005 with Pinto Energy Partners, L.P. for the lease of land on which a storage facility may be constructed. The lease will terminate in 2033, with six options to renew for an additional 10 years for each option. Base rent is $250,000 until March 1, 2010. If construction of the storage facility has not begun prior to March 1, 2010 base rent will increase to $750,000 until construction begins. Based on the projected beginning of construction and the projected completion date, base rent will increase between $400,000 and $1,400,000. If the storage facility is completed (beginning no earlier than March 1, 2010) rent will increase to $2,000,000 per year. All amounts due under the lease are subject to annual adjustments based on the CPI. The Partnership also can make a one time payment of $2,500,000 between March 1, 2010 and April 30, 2010 to terminate the lease (adjusted for CPI), if construction has not started.

The Partnership has executed a new office lease with base rent of $194,000 per year with an estimated additional rent of $130,000 which will be adjusted by the landlord each calendar year. Additional rent is to reimburse taxes and expenses incurred by the landlord which the Partnership is obligated to pay based on the terms of the lease. The term of the lease is 100 months beginning on May 1, 2005.

The following table presents the future minimum lease payments due under the leases and ignoring any increases related to the CPI index, the thru-put guarantee or increases based on construction of the storage facility:

	Land	Land-Storage	Office
2005	$ 2,385,000	$ 250,000	$ 149,000
2006	2,200,000	250,000	324,000
2007	2,200,000	250,000	324,000
2008	2,200,000	250,000	324,000
2009	2,200,000	250,000	324,000
Thereafter	50,600,000	17,250,000	1,274,000
	$61,785,000	$18,500,000	$2,719,000

Rent expense and related cost was $820,000 and $573,000 for the years ended December 31, 2004 and 2003, respectively.

Employment Agreements—The Partnership has entered into employment agreements with various executives which will terminate during 2005. The remaining compensation due under these agreements is approximately $695,000.

Capacity Reservations—Freeport LNG Investments LLLP has entered into an agreement whereby it borrowed $5,000,000 from The Dow Chemical Company ("Dow"). In connection with this agreement, the Partnership agreed to reserve a stipulated capacity at the Facility for Dow. The Dow Capacity Reservation and the ConocoPhillips TUA are expected to fully reserve substantially all of the Facility's anticipated Phase 1 capacity.

9. Office Equipment and Leasehold Improvements:

Property and equipment consists of:

	Years Ended December 31,	
	2004	2003
Office equipment	$142,000	$ 97,000
Leasehold improvements	44,000	39,000
Property and equipment	186,000	136,000
Less: accumulated depreciation	(42,000)	(15,000)
Total property and equipment, net	$144,000	$121,000

10. Accounts Payable And Accrued Liabilities:

Accounts payable and accrued liabilities consist of the following:

	Years Ended December 31,	
	2004	2003
Employee bonuses	$ 489,000	$ 476,000
Engineering and study costs	275,000	1,447,000
Professional fees	644,000	887,000
Investment banking advisor fees	117,000	515,000
Construction related costs	3,688,000	—
Other accrued liabilities and payables	463,000	61,000
Total accounts payable and accrued liabilities	$5,676,000	$3,386,000

11. Subsequent Event:

In January 2005, the Partnership purchased land which will be used for wetland mitigation for $4,000,000. The Partnership intends to donate this land to a non-profit conservation entity.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Gryphon Exploration Company

We have audited the accompanying balance sheet of Gryphon Exploration Company, as of December 31, 2002, and the related statements of income (loss), stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Gryphon Exploration Company, as of December 31, 2002, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ KPMG LLP
KPMG LLP

July 12, 2004
Houston, Texas

GRYPHON EXPLORATION COMPANY

BALANCE SHEET

(dollars in thousands, except share related items)

	December 31, 2002
ASSETS	
CURRENT ASSETS	
Cash and Cash Equivalents	$ 3,246
Receivables from Joint Interest Owners and Revenue Receivables	3,188
Prepaid Expenses and Other	5,781
Total Current Assets	12,215
OIL AND GAS PROPERTIES, full cost method	
Proved Properties, net	54,322
Unproved Properties, not subject to amortization	36,685
Total Oil and Gas Properties	91,007
FIXED ASSETS, net	458
Total Assets	$103,680
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES	
Accounts Payable and Accrued Liabilities	$ 5,773
Advances from Joint Interest Owners	1,875
Revenue Payable	5
Short-term Note Payable	2,865
Hedge Liability	1,352
Total Current Liabilities	11,870
DEFERRED TAX LIABILITY	2,043
COMMITMENTS AND CONTINGENCIES (NOTE 10)	
STOCKHOLDERS' EQUITY	
Preferred Stock, $.01 par value	
Authorized: 500,000 shares; Issued and Outstanding: 85,000 shares	2
Common Stock, $.01 par value	
Authorized: 4,000,000 shares; Issued: 145,600 shares	
Outstanding: 87,460 shares	1
Additional Paid-in-Capital	93,160
Retained Earnings	(416)
Treasury Stock	
Recorded at cost—58,140 shares	(2,980)
Total Stockholders' Equity	89,767
Total Liabilities and Stockholders' Equity	$103,680

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

GRYPHON EXPLORATION COMPANY

STATEMENT OF INCOME (LOSS)

(dollars in thousands)

	Year ended December 31, 2002
Oil and Gas Revenue	$12,495
Loss on Derivative Instruments	(1,352)
	11,143
Operating Costs and Expenses	
Production Costs	804
Workover Costs	3,226
Depreciation, Depletion and Amortization	6,521
General and Administrative Expenses	1,423
Total Operating Costs and Expenses	11,974
Income (Loss) from Operations Before Interest Income and Income Taxes	(831)
Interest Income	157
Income (Loss) From Operations Before Income Taxes	(674)
Income Tax Benefit	155
Net Income (Loss)	$ (519)

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

GRYPHON EXPLORATION COMPANY

STATEMENT OF STOCKHOLDERS' EQUITY

(dollars in thousands)

	Common Stock		Preferred Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
Balance—December 31, 2001	138,860	$ 1	55,000	$ 1	$63,161	$ 103	$ (418)	$62,848
Treasury Stock	(51,400)	—	—	—	—	—	(2,562)	(2,562)
Issuance of Preferred Stock	—	—	30,000	1	29,999	—	—	30,000
Net Loss	—	—	—	—	—	(519)	—	(519)
Balance—December 31, 2002	87,460	$ 1	85,000	$ 2	$93,160	$(416)	$(2,980)	$89,767

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

GRYPHON EXPLORATION COMPANY

STATEMENT OF CASH FLOWS

(dollars in thousands)

	Year ended December 31, 2002
CASH FLOWS FROM OPERATING ACTIVITIES:	
Net Income (Loss)	$ (519)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:	
Depreciation, Depletion and Amortization	6,521
Loss on Derivative Instruments	1,352
Deferred Income Taxes	862
	8,216
Changes in Operating Assets and Liabilities	
Accounts Receivable	(1,869)
Prepaid Expenses	(1,920)
Accounts Payable and Current Liabilities	5,517
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	9,944
CASH FLOWS FROM INVESTING ACTIVITIES:	
Oil and Gas Property Additions	(43,495)
Purchases of Fixed Assets	(323)
NET CASH USED IN INVESTING ACTIVITIES	(43,818)
CASH FLOWS FROM FINANCING ACTIVITIES:	
Sale of Preferred Stock	30,000
Purchase of Treasury Stock	(2,562)
Offering Costs	—
Proceeds from borrowings	—
Repayment of borrowings	—
NET CASH PROVIDED BY FINANCING ACTIVITIES	27,438
NET DECREASE IN CASH	(6,436)
CASH—BEGINNING OF PERIOD	9,682
CASH—END OF PERIOD	$ 3,246

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

GRYPHON EXPLORATION COMPANY

NOTES TO FINANCIAL STATEMENTS

(dollars in thousands, except share related items)

NOTE 1—Organization and Nature of Operations

Gryphon Exploration Company, a Delaware corporation, ("Gryphon" or the "Company") is a Houston-based company formed for the purpose of oil and gas exploration, development and exploitation. The Company is currently engaged in the exploration and production for oil and natural gas in the Gulf of Mexico. The Company began operations October 2000.

On October 11, 2000 ("Inception"), Gryphon completed a transaction with Warburg, Pincus Equity Partners, L.P. and certain affiliates thereof, ("Warburg") a global private equity fund based in New York, and Cheniere Energy, Inc. ("Cheniere") to fund an exploration program based upon approximately 8,800 square miles of 3D seismic data in the Gulf of Mexico (the "Fairfield data set"). Cheniere contributed selected net assets in exchange for 100% of the common stock of Gryphon. These assets included the Fairfield data set license, certain offshore leases, a prospect then being drilled, an exploration agreement with an industry partner (described in Note 4) and certain other assets and liabilities. In addition, Gryphon assumed certain liabilities and obligations of Cheniere in connection with the contribution of assets. The assets received from Cheniere less the liabilities assumed were recorded at their estimated net fair value at the date of the transaction. Also, at inception, Warburg contributed $25,000 and received Gryphon Series A convertible preferred stock, with an 8% cumulative dividend (Series A preferred stock). Cheniere and Warburg also agreed, under certain circumstances, to contribute additional capital up to $75,000 to Gryphon, proportionate to their respective ownership interests.

As further discussed in Note 7, Warburg and certain employees of the Company contributed an additional $60,000 in exchange for 60,000 shares of Series A preferred stock during 2001 and 2002.

NOTE 2—Summary of Significant Accounting Policies

Basis of Presentation

The financial statements include the accounts of Gryphon Exploration Company. As an independent oil and gas producer, the Company's revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas, oil and condensate, which are dependent upon numerous factors beyond the Company's control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and gas prices could have a material adverse effect on the Company's financial position, results of operations, cash flows, access to capital, and on the quantities of oil and gas reserves that may be economically produced.

Oil and Gas Properties

General. The Company uses the full cost method of accounting for exploration and development activities as defined by the U.S. Securities and Exchange Commission ("SEC"). Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

The sum of net capitalized costs and estimated future development and abandonment costs of oil and gas properties and mineral investments is amortized using the unit-of-production method. The carrying values of oil and gas properties included in these financial statements do not purport to represent replacement or market values.

In accordance with SEC Regulation S-X·Rule 410 a(2), proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from new reservoirs under existing economic and operating conditions. Reserves are considered proved if they can be produced economically as demonstrated by either actual production or conclusive formation tests. The Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates, made by the Company's engineers and an independent third party reservoir engineering firm, are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based upon, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

Unproved Oil and Gas Properties. Unproved oil and gas properties include costs that are excluded from proved oil and gas properties and are not subject to amortization. These amounts generally represent costs of investments in unproved properties, non-producing leases, seismic data sets, and major development projects. Gryphon excludes these costs until proved reserves are found or it is determined that the costs are impaired. All costs excluded are reviewed at least annually to determine if impairment has occurred. Any impairment is transferred to the costs to be amortized (the proved oil and gas property pool). The Company evaluates significant properties, composed primarily of costs associated with offshore leases and seismic data sets, at least annually. Non-producing leases are evaluated based on the progress of the Company's exploration program to date. Exploration costs are transferred from unproved oil and gas properties to proved oil and gas properties upon completion the first exploratory well on each property.

Capitalized Seismic Costs / General & Administrative Expenses. The Company capitalizes the costs associated with its 3D data sets as well as a portion of its General and Administrative expenses which are applicable to its exploration activities. As the direct costs associated with drilled properties are transferred from the Company's unproved oil and gas properties to its proved oil and gas properties, the Company allocates a portion of the capitalized 3D seismic and General and Administrative expense to the proved property pool. The Company's allocation of these costs is based upon the capitalized costs associated with each 3D data set area divided by the estimated number of prospects projected to be developed from each respective data set. During 2002, the Company allocated approximately $3,400 of seismic exploration cost, general and administrative, and other costs transferred by Cheniere at Inception, to the cost of proved properties based on this allocation method. It is reasonably possible, based on the results obtained from future drilling, that revisions to this estimate could occur in the future, which could affect the Company's capitalization ceiling.

Capitalized Interest. SFAS No. 34, "Capitalization of Interest Costs," provides standards for the capitalization of interest costs as part of the historical cost of acquiring assets. Financial Accounting Standards Board Interpretation ("FIN") No. 33 provides guidance for the application of SFAS No. 34 to the full cost method of accounting for oil and gas properties. Under FIN No. 33, costs of investments in unproved properties and major development projects, which are not subject to amortization and on which exploration or development activities are in progress, qualify for capitalization of interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of costs included in unproved oil and gas properties. Capitalized interest cannot exceed gross interest expense. As costs are transferred from the unproved oil and gas properties pool to the proved oil and gas properties pool, the associated capitalized interest is also transferred to the proved oil and gas properties pool. The Company incurred no interest expense during in 2002, thus no interest costs were capitalized during those periods.

Ceiling Test. The Company limits the capitalized costs of proved oil and gas properties, net of accumulated Depreciation, Depletion, and Amortization ("DD&A") and the related deferred income taxes, to the estimated future net cash flows from proved oil and gas reserves, using prices in effect at the end of the applicable reporting period held flat for the life of production, discounted at 10%, net of related tax effects. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional DD&A.

Revenue Recognition

Revenues from the sale of oil and gas produced are recognized upon passage of title, net of royalty interests. When sales volumes differ from the Company's entitled share, an overproduced or underproduced imbalance occurs. To the extent the overproduced imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. At December 31, 2002, the Company had no material gas imbalances.

Reimbursable expenses

The Company performs administrative services on behalf of third parties in accordance with certain contractual arrangements. The Company was reimbursed $810 during 2002 related to these services. These reimbursements are offset against general and administrative expenses of the Company.

Prepaid expenses

Prepaid expenses at December 31, 2002 consist of prepaid insurance premiums of $4,093, as well as other prepaid expenses.

Fixed Assets

Fixed assets are recorded at cost. Repairs and maintenance costs are charged to operations as incurred. Depreciation is computed using the straight-line method calculated to amortize the cost of assets over their estimated remaining useful lives, which are estimated as 9 to 36 months for software and computer equipment and 1 to 5 years for office furnishings. Leasehold improvements are amortized over the term of the underlying lease. Upon retirement or other disposition of property and equipment, the cost and related depreciation is removed from the accounts and the resulting gains or losses are recorded.

Income Taxes

The Company utilizes the liability method of accounting for income taxes, as set forth in Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes." Under the liability method, deferred taxes are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. Valuation allowances are recorded against deferred tax assets when it is considered more likely than not that the deferred tax assets will not be utilized.

Stock-Based Compensation

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"), and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the market price of the Company's stock at the date of the grant over the amount an employee must pay to acquire the stock. The Company grants options at or above the market price of its common stock at the date of each grant.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123. This statement amends FASB Statement No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

The fair value of options is calculated using the Black-Scholes option-pricing model. Assumptions used for 2002 were as follows: no dividend yield, no volatility, risk-free interest rate of 4.3%, and an expected average option life of 5 years. If the Company had adopted the recognition provisions of SFAS No. 123 for 2002, the Company's financial statements would have not reflected a change in reported net income.

Cash Equivalents

The Company classifies all investments with original maturities of three months or less as cash equivalents.

Restricted Cash Deposits

Current restricted cash deposits represent deposits reserved for the funding of contractual drilling costs on behalf of the Company and its working interest partners within one year.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable, and short-term debt approximate fair value because of the short maturities of those instruments.

Derivative Instruments

On January 1, 2001, the Company adopted SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activity, an Amendment of SFAS 133. SFAS Nos. 133 and 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. See Note 6 for information regarding the Company's derivative instruments and hedging activities.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and the accompanying notes. Actual results could differ from those estimates. Changes in such estimates may affect amounts reported in future periods.

Concentration of Credit Risk

The Company maintains cash balances with a bank and frequently exceeds federally insured limits. The Company invests its cash in money market securities, investment grade commercial paper, and U.S. Government-backed securities. The Company's joint interest partners consist primarily of independent oil and gas producers. The Company's oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies. The Company performs credit evaluations of its customers' financial condition and, if deemed necessary, obtains letters of credit and parental guarantees from selected customers. The Company has not experienced any significant losses from uncollectible accounts. All of the Company's derivative transactions have been carried out in the over-the-counter market.

Environmental Liabilities

Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated.

Recently Issued Accounting Standards

In June 2001, the Financial Accounting Standard Board issued the Statement of Financial Accounting Standards No. 143 ("SFAS 143"), "Accounting for Asset Retirement Obligations" (ARO), which requires that an asset retirement cost be capitalized as part of the cost of the related long-lived asset and allocated to expense by using a systematic and rational method. Under this Statement, an entity is not required to re-measure an ARO liability at fair value each period but is required to recognize changes in an ARO liability resulting from the passage of time and revisions in cash flow estimates. This Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. The Company expects to adopt SFAS 143 on January 1, 2003. The Company has not yet determined the impact that the adoption of SFAS 143 will have on its earnings or statement of financial position.

In October 2001, the Financial Accounting Standard Board issued the Statement of Financial Accounting Standards No. 144 ("SFAS 144"), "Accounting for the Impairment or Disposal of Long-Lived Assets". The Statement requires that long-lived assets that are to be disposed of by sale be measured at lower of book value or fair value less cost of sale. The Statement also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this Statement are effective for fiscal years beginning after December 15, 2001. The provisions of this Statement will impact any asset dispositions the Company makes after January 1, 2002.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* SFAS No. 145 amends existing guidance on reporting gains and losses on the extinguishment of debt to prohibit the classification of the gain or loss as extraordinary, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provisions of the Statement related to the rescission of Statement No. 4 are applied in fiscal years beginning after May 15, 2002. Earlier application of these provisions is encouraged. The provisions of the Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 is not expected to have a material effect on the Company's financial statements.

(dollars in thousands, except share related items)

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity*. The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of SFAS No. 146 is not expected to have a material effect on the Company's financial statements.

In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statement No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34*. This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on the Company's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002.

In January 2003, the FASB issued Interpretation No. 46 *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. This Interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the Interpretation. The Interpretation applies immediately to variable interest in variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. For nonpublic enterprises, such as the Company, with a variable interest in a variable interest entity created before February 1, 2003, the Interpretation is applied to the enterprise no later than the end of the first annual reporting period beginning after June 15, 2003. The application of this Interpretation is not expected to have a material effect on the Company's financial statements. The Interpretation requires certain disclosures in financial statements issued after January 31, 2003 if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when the Interpretation becomes effective.

NOTE 3—Fixed Assets

Fixed assets consisted of the following:

	December 31, 2002
Computers and Office Equipment	$ 1,362
Furniture, Fixtures and Other	240
	1,602
Less Accumulated Depreciation	(1,144)
Fixed Assets, net	$ 458

NOTE 4—Exploration Agreements

In 2002, Gryphon entered into an exploration agreement with an industry partner. Under the terms of the agreement, the partner acquired an option to participate at a 25% working interest level in up to seven drilling prospects generated by Gryphon in the Gulf of Mexico. During the term of the agreement, Gryphon received overhead reimbursements from this partner. In addition, Gryphon receives an increased interest in each prospect after the partner has received cumulative cash flows equal to its capital costs in each respective prospect. Gryphon is the operator of the prospects drilled pursuant to this agreement. Overhead reimbursements received under the agreement are credited as a recovery of general and administrative expenses. Total overhead reimbursements received in 2002 under this program and from other various industry partners were $1,160.

(dollars in thousands, except share related items)

NOTE 5—INCOME TAXES

The difference between the provision for income taxes and the amount that would be determined by applying the statutory federal income tax rate to the income or loss before income taxes is set forth below:

	Year ended December 31, 2002
Federal Income Tax Expense (Benefit) at 34%	$(229)
Permanent Differences	21
Other	53
Income Tax Provision (Benefit)	$(155)

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the carrying amounts used for income tax purposes. Deferred income taxes also reflect the net tax effects of net operating loss carryforwards. The tax effects of the Company's temporary differences and carryforwards are as follows:

	Year ended December 31, 2002
Deferred Tax Assets:	
Net Operating Loss Carryforwards	$ 7,529
Total Deferred Tax Assets	7,529
Deferred Tax Liabilities:	
Differences between Book and Tax Bases of Oil and Gas Properties, Plant and Equipment	(9,572)
Deferred Tax Liabilities, net	$(2,043)

There was no current income tax provision for 2002 and no income taxes were payable during that period..

The Company has determined that it is more likely than not that the deferred tax assets will be realized and a valuation allowance for such assets is not required.

At December 31, 2002, the Company had net operating loss (NOL) carryforwards for tax reporting purposes of approximately $22,144, which will expire as follows:

2020	$ 2,170
2021	19,251
2022	723

(dollars in thousands, except share related items)

NOTE 6—Derivative Instruments and Hedging Activities

The Company produces and sells natural gas, crude oil and condensate. As a result, the Company's financial results can be significantly affected as these commodity prices fluctuate widely in response to changing market forces. The Company maintains a commodity-price-risk management strategy that uses derivative instruments to minimize significant, unanticipated earning fluctuations caused by commodity-price volatility. The Company does not speculate using derivative instruments.

By using derivative financial instruments to reduce exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk for the Company. When the fair value of a derivative contract is negative, the Company owes the counterparty and, therefore, it does not incur credit risk. The Company minimizes the credit risk in derivative instruments by entering into transactions with high-quality counterparties whose credit rating is investment grade.

Market risk is the adverse effect on the value of a financial instrument that results from a change in commodity prices. The market risk associated with commodity-price contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

The Company periodically enters into natural gas and crude oil option contracts for a portion of its anticipated hydrocarbon sales, to reduce the price risk associated with fluctuations in market prices. The option contracts limit the unfavorable affect that price decreases will have on hydrocarbon sales. The maximum term over which the Company is hedging exposures to the variability of cash flows for commodity price risk is 24 months.

Effective January 1, 2001, the Company adopted SFAS No. 133 and SFAS No. 138, an amendment to SFAS 133. SFAS 133 and 138 require that derivatives be reported on the balance sheet at fair value and, if the derivative is not designated as a hedging instrument, changes in fair value must be recognized in earnings in the period of change. If the derivative is designated as a hedge and to the extent such hedge is determined to be effective, changes in fair value are either (a) offset by the change in fair value of the hedged asset or liability (if applicable) or (b) reported as a component of other comprehensive income (loss) in the period of change, and subsequently recognized in earnings when the offsetting hedged transaction occurs. During 2002, the Company did not attempt to qualify for the hedge provisions under SFAS 133 and thus has not designated its derivative transactions during that period as hedging instruments. Accordingly, the Company accounted for the changes in market value of these derivatives through current earnings.

As of December 31, 2002, the Company had hedged portions of its expected 2003 natural gas production as follows:

Instrument	Volume (mmbtus)	Prices
Swaps	2,300,000	\$3.95-\$4.08
Collars	1,320,000	floor-\$3.50 / cap-\$6.00

The fair value of these derivative positions at that date was a \$1,352 liability.

NOTE 7—Equity Transactions

At December 31, 2002, the Company had 85,000 shares of Series A preferred stock issued and outstanding. The preferred stock is convertible at the option of the holder at a rate of $100 per share of common stock upon the occurrence of certain qualifying events. The preferred stock has voting rights as if converted. Each share has a liquidation preference of $1,000. Dividends accrue at a rate of 8% per annum, become payable quarterly as declared, and are cumulative and payable in the event of liquidation of the Company. At December 31, 2002, there was $9,349 of undeclared dividends in arrears.

During 2002, the Company issued four private placements of Series A preferred stock in the amounts of $5,000, $10,000, $5,000, and $10,000, which were consummated on April 22, 2002, June 17, 2002, September 3, 2002, and November 5, 2002, respectively. As discussed in Note 1, Cheniere has a right to participate in offerings of Series A preferred stock by the Company. Cheniere elected not to participate in any of the Company's offerings during 2002. Based upon the conversion features of the Company's Series A preferred stock, the interests of the Company's holders of Series A preferred stock would represent approximately 91% on an as converted basis of the outstanding and issued Common Stock at December 31, 2002.

As further discussed in Note 9, in July 2001, the Company acquired a 3D seismic data set from Cheniere. In connection with that transaction, the Company repurchased 6,740 shares of Common Stock for aggregate consideration of approximately $418. These shares are included as treasury stock as of December 31, 2002.

In March 2002, the Company and Cheniere settled litigation which had been filed against them on a joint and several basis by a seismic company (the "Claimant"). Pursuant to this settlement, the Company made a payment to the Claimant and committed to make certain additional payments if production rights are obtained by the Company or Cheniere in the area covered by the data set licensed from the Claimant. In addition, the Company agreed to become responsible for certain contingent obligations of Cheniere associated with the Seitel data set. The maximum amount of the assumed liabilities associated with this litigation and the contingent liabilities associated with the Seitel dataset was approximately $2,561 in the aggregate. As consideration for the Company's agreement to assume these contingent liabilities, Cheniere has transferred to Gryphon 51,400 shares of the Company's common stock which Cheniere held. Pursuant to this agreement, Cheniere has an option valid until March 16, 2003 to repurchase these shares from the Company at a cost equal to $50 per share, subject to an escalation adjustment. At December 31, 2002, the maximum amount of the contingent obligations assumed is $934.

Based upon the foregoing transactions, Cheniere holds an interest of approximately 9% in the Company, calculated on a fully diluted basis as of December 31, 2002.

(dollars in thousands, except share related items)

NOTE 8—Stock-Based Compensation

In 2000, the Company established the Gryphon Exploration Company 2000 Stock Option Plan (the "Option Plan"). In 2001, the Option Plan was amended and restated. The Option Plan, as amended, allows for the issuance of options to purchase up to 186,493 shares of Gryphon common stock at an exercise price of $100 per share. The Company has reserved an equivalent number of shares of common stock for issuance upon the exercise of options which have been granted or which may be granted. The term of options granted under the Option Plan is generally ten years. Vesting occurs over a three-year period, one-third on each anniversary of the grant date. The following table summarizes the Company's stock option activity and related information for the periods presented:

	Year ended December 31, 2002
Outstanding at Beginning of Period	81,122
Options Granted at an Exercise Price of $100 per share	20,332
Options Forfeited	(350)
Outstanding at End of Period	101,104
Exercisable at End of Period	40,604
Weighted Average Exercise Price of Options Outstanding	$ 100
Weighted Average Exercise Price of Options Exercisable	$ 100
Weighted Average Fair Value of Options Granted During the Period	$ —
Weighted Average Remaining Contractual Life of Options Outstanding	8.44 years
Weighted Average Remaining Contractual Life of Options Exercisable	8.11 years

The fair value of options is calculated using the Black-Scholes option-pricing model. Assumptions used for 2002 were as follows: no dividend yield, no volatility, risk-free interest rate of 4.3%, and an expected average option life of 5 years. If the Company had adopted the recognition provisions of SFAS No. 123 for 2002, the Company's financial statements would have not reflected a change in reported net income.

NOTE 9—Related Party Transactions

As discussed in Note 7 above, in March 2002, the Company entered into a settlement agreement to resolve litigation against Cheniere and the Company. Pursuant to the settlement, the Company agreed to assume certain obligations of Cheniere. The maximum amount of the assumed liabilities pursuant to the settlement and associated agreements was approximately $2,561 in the aggregate. As consideration for the Company's agreement to assume these contingent liabilities, Cheniere transferred to Gryphon 51,400 shares of the Company's common stock which Cheniere held. Pursuant to this agreement, Cheniere has an option valid for one year from the date of the agreement to repurchase these shares from the Company at a cost equal to $50 per share, subject to escalation beginning four months after the date of the stock transfer. At December 31, 2002, Cheniere had not exercised any its repurchase rights under the option agreement.

During 2000, 2001, and 2002, the Company issued nine private placements of Series A preferred stock for aggregate consideration of $85,000. Of this amount, Warburg contributed $84,679 and the Company's management contributed $321 (see Note 7).

(dollars in thousands, except share related items)

NOTE 10—Commitments and Contingencies

The Company has entered into an office lease agreement with a non-cancelable term, which runs through March 2003. Future minimum lease payments are $66 for the year ended December 31, 2003. Total rental expense for office space for 2002 was $286.

At Inception, Gryphon acquired a master license agreement covering the license of approximately 8,800 square miles of 3-D seismic data in the Gulf of Mexico. In connection with the license agreement, the Company has made a commitment to reprocess certain of the seismic data and to pay a fee for such reprocessing as the reprocessed data are delivered. At December 31, 2002, the Company had met its commitments related to future deliveries of reprocessed data.

In connection with the purchase from Cheniere of the JEBCO data set (see Note 9), the Company has an obligation to pay for the related seismic data once it has been delivered to the Company, and accepted by Cheniere.

NOTE 11—Oil and Gas Operations

The Company uses the full cost method of accounting for its oil and natural gas properties. Unproved oil and gas properties include costs that are excluded from proved oil and gas properties and that are not subject to amortization. These amounts generally represent costs of investments in unproved properties, non-producing leases, seismic data sets, and major development projects. Gryphon excludes these costs until proved reserves are found or it is determined that the costs are impaired. The costs of unproved oil and natural gas properties are reviewed at least annually to determine if impairment has occurred. Any impairment is transferred to the proved oil and gas property pool. The Company evaluates significant properties, composed primarily of costs associated with offshore leases and seismic data sets, at least annually. Non-producing leases are evaluated based on the progress of the Company's exploration program to date.

The following table summarizes the costs of unproved properties for the periods during which the costs were incurred:

	Year ended December 31, 2002
Period that costs were incurred—	
Inception through December 31, 2000	$15,469
2001	12,598
2002	8,618
Totals	$36,685

NOTE 12—Subsequent Events

On February 10, 2003, the Company entered into a three-year, reserve based, revolving credit facility. The nominal amount of the facility is $100,000 and the initial borrowing base is $18,000. The borrowing base will be adjusted from time to time based upon changes in the Company's oil and gas reserves. The facility is secured by substantially all of the Company's assets, consisting primarily of its oil and gas properties. Proceeds borrowed from the facility can be used to fund the Company's operations, for acquisitions, and for general corporate purposes. The facility requires quarterly interest payments based upon up floating rate indexes and includes covenants typically associated with similar credit agreements. The credit facility matures February 10, 2006. As of March 14, 2003, the Company had drawn $5,000 under the facility.

In January 2003, the Company entered into an amendment and extension to its office lease. Pursuant to this amendment, the Company expanded its office space by approximately 40% and extended the term by seven years from March 2003. The extended term includes an option which allows the Company to terminate the lease at the end of the fifth year of the extension period. The estimated aggregate obligation of the Company pursuant to the amendment is approximately $2,990 assuming a seven year extension or approximately $2,170 assuming the extension is terminated at the end of year five.

GRYPHON EXPLORATION COMPANY

SUPPLEMENTAL INFORMATION TO THE FINANCIAL STATEMENTS
OIL AND GAS RESERVES AND RELATED FINANCIAL DATA
(dollars in thousands)

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The following tables set forth information about the Company's oil and gas producing activities pursuant to the requirements of Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" ("SFAS 69").

Investments in oil and gas properties are set forth below:

	Year ended December 31, 2002
Oil and Gas Properties:	
Proved	$61,583
Unproved	36,685
	98,268
Less Accumulated Depreciation, Depletion and Amortization	(7,261)
	$91,007

As of December 31, 2002, the Company's investment in oil and gas properties included $36,685 in unevaluated properties, which have been excluded from amortization. Such costs will be evaluated in future periods based on management's assessment of exploration activities, expiration dates of licenses, permits and concessions, changes in economic conditions and other factors.

The Company capitalized as oil and gas property costs approximately $2,408 of general and administrative expenses directly related to its exploration and development activities in 2002.

The Company has made a substantial investment in acquiring, processing and reprocessing Gulf of Mexico seismic data, which cover various areas having an aggregate size of 18,000 square miles. The costs of these projects become subject to amortization on a ratable basis as prospects are identified in each of the data set project areas.

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration, and development activities are set forth in the table below:

	Year ended December 31, 2002
Acquisition of Properties:	
Proved Properties	$ —
Unproved Properties	8,414
Exploration Costs	19,788
Development Costs and Other Costs	15,288
Total	$43,490

For the year ended December 31, 2002, depreciation, depletion and amortization of the capitalized costs of oil and gas properties was $1.70 per mcfe.

Reserve Quantities

The following table shows estimates of proved reserves and proved developed reserves, net of royalty interest, of natural gas, crude oil, and condensate owned at year-end and changes in proved reserves during the last two years prepared by independent petroleum engineers in accordance with the rules and regulations of the Securities and Exchange Commission. Volumes for natural gas are in millions of cubic feet (mmcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. Liquid hydrocarbons, consisting of oil and condensates, are expressed in standard 42 gallon barrels (bbls). These estimates represent the Company's interest in the reserves associated with its properties. All of the Company's oil and gas reserves are located within the United States and its territorial waters.

The Company's reserves increased in 2002 primarily from exploration and development drilling activities, offset in part by production. The Company emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. These estimates are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

	Year Ended December 31, 2002	
	Oil (bbls)	Gas (mmcf)
Proved Reserves:		
Beginning of Period	210,151	17,468
Revisions of Previous Estimates	(44,750)	(745)
Extensions, Discoveries and Other Additions	246,787	14,063
Production	(40,320)	(3,278)
End of Period	371,868	27,508
Proved Developed Reserves:		
Beginning of Period	186,011	12,070
End of Period	165,421	16,332

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 the control of the Company. 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, the Company's 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.

(dollars in thousands)

Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth estimates of future cash flows from proved reserves of gas, oil and condensate which were prepared by independent petroleum engineers. The standardized measure of discounted future cash flow amounts are based upon year-end prices of $31.35 per barrel of oil (WTI—Cushing) and $4.75 per mcf of natural gas (NYMEX—Henry Hub) at December 31, 2002. Estimated future cash inflows are reduced by estimated future development and production costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. Income tax expense is calculated by applying the existing statutory tax rates, including any known future changes, to the pre-tax net cash flows giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense.

The present value of future net revenues does not purport to be an estimate of the fair market value of Gryphon's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Significant changes in estimated reserve volumes or commodity prices could have a material effect on the Company's financial statements.

Under the full cost method of accounting, a non-cash charge to earning related to the carrying value of the Company's oil and gas properties on a country-by-country basis may be required when prices are low. Whether the Company will be required to take such a charge depends on the prices for crude oil and natural gas at the end of any quarter, as well as the effect of both capital expenditures and changes to proved reserves during the quarter. If a non-cash charge were required, it would reduce earnings for the period and result in lower DD&A expense in future periods.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is set forth in the following table:

	Year ended December 31, 2002
Future Cash Inflows (Sales)	$148,628
Less—Future Costs:	
Production	(8,923)
Development and Dismantlement	(7,288)
Future Net Cash Flows before Income Taxes	132,417
Less—10% Annual Discount for Estimated Timing of Cash Flow	(25,477)
Present Value of Future net Cash Flows before Income Taxes	106,940
Less—Present Value of Future Income Taxes	(11,729)
Standardized Measure of Discounted Future net Cash Flows	$ 95,211

GRYPHON EXPLORATION COMPANY

SUPPLEMENTAL INFORMATION TO THE FINANCIAL STATEMENTS
OIL AND GAS RESERVES AND RELATED FINANCIAL DATA—(Continued)

(dollars in thousands)

The following table summarizes the principal sources of change in the standardized measure of discounted future net cash flows:

	Year ended December 31, 2002
Standardized Measure—Beginning of Period	$28,778
Increases (Decreases)—	
Sales, net of Production Costs	(8,465)
Increase due to passage of time (Accretion of Discount)	3,257
Net Change in Sales Prices, net of Production Costs	30,736
Changes in Estimated Future Development Costs	(759)
Revisions of Quantity Estimates	(3,962)
Extensions, Discoveries and Other Additions, net of Future Production and Development Costs	53,367
Development Costs Incurred during the Period that Reduced Previously Estimated Development Cost	1,308
Net Change in Income Taxes	(7,938)
Changes in Production Rates (timing) and Other	(1,111)
Standardized Measure—End of Period	$95,211

Corporate Information

Board of Directors

Nuno Brandolini
Chairman and
Chief Executive Officer
Scorpion Holdings, Inc.

Keith F. Carney
President
Dolomite Advisors, L.L.C.

Paul J. Hoenmans
Retired Executive Vice President
Mobil Corporation

David B. Kilpatrick
President
Kilpatrick Energy Group

Charif Souki
Chairman of the Board, President and
Chief Executive Officer

J. Robinson West
Chairman
PFC Energy

Walter L. Williams
Vice Chairman of the Board
Cheniere Energy, Inc.

Contacts & Advisors

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Stock Exchange Listing:
American Stock Exchange Symbol: LNG

Transfer Agent
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1745 Gardena Avenue
Glendale, CA 91204-2991
Telephone: (818) 502-1404
Facsmile: (818) 502-0674

Independent Accountants
UHY Mann Frankfort Stein & Lipp
CPAs L.L.P.
Houston, Texas

Legal Counsel
Andrews Kurth L.L.P.
Houston, Texas

Investor Relations
Telephone: (713) 265-0208
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Management

Charif Souki
Chairman of the Board, President and
Chief Executive Officer

Walter L. Williams
Vice Chairman of the Board

Don A. Turkleson
Senior Vice President and
Chief Financial Officer, Secretary

Johnathan S. Gross
Senior Vice President - Exploration

Keith M. Meyer
Senior Vice President - LNG
President, Cheniere LNG, Inc.

Zurab Kobiashvilli
Senior Vice President & General Counsel

David E. Castaneda
Vice President Investor Relations

E. Darron Granger
Vice President LNG Technical

Craig K. Townsend
Vice President & Chief Accounting Officer

Herbert W. Cole
Controller

Graham McArthur
Treasurer

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On the Cover
Artist Renditions of LNG Terminals
From upper left: Freeport, Sabine Pass, Corpus Christi & Creole Trail