Introduction

The year 2014 marks the 50th anniversary of the start of the first export project for liquefied natural gas (LNG). During this time the LNG business has grown from a niche trade to one comprising almost one-third of the entire global natural gas trade. Much of the growth has occurred during the last two decades, when many countries sought to transition to natural gas due to its recognized environmental, safety, security of energy supply, and efficiency benefits. The future appears equally bright, with numerous new projects under construction or planned for the near to mid-term future, in part buoyed by rising demand for natural gas throughout the world.

This chapter reviews the history of LNG from a commercial and technical standpoint, focusing on key contractual, regulatory, and other legal developments over the decades that helped shape this important global industry. It addresses key developments by decade, focusing primarily on export projects that helped shaped the LNG industry.

1950s—U.S. Pioneers in Ocean Transportation of LNG

Although LNG has technological roots that significantly predate the 1950s,¹ today's “oil-based” natural gas business (as opposed to gas manufactured from coal and other sources)

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¹ Liquefaction technologies for gas were developed in Germany in the nineteenth century. See Dr. Chen-Hwa Chiu, “History of the Development of LNG Technology,” Hundred Years of Advancements in Fuels and Petrochemicals (AIChE Annual Conf. 2008). Some of the first uses of the technologies were for production of helium for military purposes during World War I. The United States developed the first “peak shaving” (i.e., storage) LNG projects in the 1940s, but a serious accident in Cleveland during World War II caused by a shortage of nickel steel appears to have discouraged additional peak shaving projects for some time, except for one constructed by Dresser Industries near Moscow in 1947. See C. M. Sliepcevich, “Liquefied Natural Gas—A New Source of Energy: Part I, Ship Transportation,” 53:2 American Scientist
was mostly confined to North America and included LNG only as a method to store natural gas for peak shaving needs. By the end of the 1950s, North America was producing more than 70% of the natural gas in the world and was estimated to have produced 243 trillion cubic feet (tcf) of the total 298 tcf of natural gas ever produced for commercial, industrial, and residential use. The benefits of gas were well known in the United States, where gas was then available across 46 states and in use in more than 18 million homes.

The origins of the global LNG industry came not from the supply side but from the demand side. It was the priority that U.S. suppliers then gave to residential customers that caused one American entrepreneur to set in motion efforts leading to the development of technologies enabling the ocean transportation and export of LNG. William Wood Prince, the dynamic CEO of Chicago Stock Yards, decided in 1951 that his small power company could no longer tolerate the increasing costs under its gas supply contracts. Gas supply contracts during this period were interruptible, allowing suppliers to curtail gas supply to industrial users in the event of shortages caused by severe weather. When one Chicago gas company tried to raise the price of gas under Chicago Stock Yards’ interruptible gas contracts, Prince’s response was to develop a method to liquefy “cheap” gas along the U.S. Gulf Coast and ship it by barge up the Mississippi River to Chicago. Surprisingly, rather than a land-based approach, the pioneering LNG plan adopted a floating-based approach for liquefaction facilities, using a barge-mounted liquefaction unit that could be moved around to various low-priced remote gas wells.

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2 See Malcolm W. H. Peebles, Evolution of the Gas Industry 51 (1980) (“While the first recorded use of manufactured gas was in the United Kingdom, the United States can fairly lay claim to being the birth-place of the natural gas industry as we know it today.”).

3 Gas could be distributed competitively across the United States in part as a result of the conversion of oil pipelines built using federal funds during World War II. The largest of these early pipelines were the “Big-Inch” (24-inch) and “Little Big Inch” (20-inch), running from Texas to Pennsylvania and converted in 1947 to flow natural gas to the gas-hungry northeastern cities. See id. at 56.

4 An unusual feature of Prince’s business plan by today’s standards was to use cooling generated during regasification at Chicago to freeze various products from stockyard operations. See W. L. Nelson, “Natural Gas to Move by Barge,” Oil & Gas J. 104 (Mar. 22, 1954).
By 1954, a barge-mounted liquefaction plant and a separate transport barge had been constructed at the Ingalls Ship Yard in Pascagoula, Mississippi. In 1954 when Prince brought Continental Oil Company (Continental Oil) (now ConocoPhillips) into the venture to advise on gas processing issues, the two partners determined, based on the results of an engineering and economic feasibility study, that the Mississippi barge venture was not economical. That study, however, also concluded that ocean transportation of LNG from gas-surplus countries to gas-deficient countries offered attractive potential. Constock International Methane Ltd. (Constock), a 50-50 joint venture of Continental Oil and the Union Stock Yard & Transit Co. (Union Stock Yards), was created in 1955 with the intention of profiting from the ocean transportation and export of LNG.

Between 1955 and 1957, Constock engaged in extensive testing of the two barges, which had been transferred to Bayou Long, Louisiana. The U.S. government was quick to exercise its regulatory powers over these formative efforts, with the Bureau of Mines and the U.S. Coast Guard (Coast Guard) supervising tests demonstrating how LNG could be pumped from the liquefaction barge onto the transportation barge. Tests were declared successful in May 1956, and the Coast Guard issued initial requirements for ocean transportation of LNG in 1957. During this period consultants across the United States contributed numerous innovations, including

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6 Peebles, *supra* note 2, at 190. Constock was able to obtain federal support for the tests by assuring that long-term supply for the United Kingdom would come from sources other than the United States. See “FPC Gets Constock Plan,” *Oil & Gas J.* 112 (Apr. 7, 1958) (noting Constock disclosed in a Federal Power Commission (FPC) filing that long term supply would come from outside the United States); “FPC Concludes It May Have Jurisdiction Over Transactions Involving Liquefied Natural Gas Imports, Exports, and Storage,” *FPC Newsletter* 2 (Jan. 14, 1963) (noting Constock withdrew its application to export liquefied methane from Louisiana to Great Britain, without FPC objection).
shipping designs in New York, gas processing and liquefaction in Missouri, insulation designs in Kentucky, and storage and cargo handling in Massachusetts.\textsuperscript{7}

Although by 1957 West Germany, France, Italy, Sweden, and Japan had expressed interest in importing LNG, the catalyst for the start of the ocean-going LNG trade was a switch from coal-based gas to oil-based gas in the United Kingdom, prompted in part by the enactment of air pollution regulations.\textsuperscript{8} The British government, through the British Gas Council, made the initial decision to import LNG, subject to the conclusion of successful trial shipments. This enticed Constock to build the necessary liquefaction plant, storage, and loading terminal on a river near Lake Charles, Louisiana, while the British Gas Council constructed complementary import facilities at Canvey Island, England. Constock and the British Gas Council agreed to share the cost of the pilot ship, a 5,000-ton dry cargo vessel, which was converted at the Port of Mobile, Alabama and renamed the \textit{Methane Pioneer}. This small trial vessel, insulated with laminated balsa wood, held only about 115 million cubic feet of gas (compared to today’s average cargo capacity of over 3.5 billion cubic feet).

On January 28, 1959, the \textit{Methane Pioneer} left Louisiana on its maiden voyage as an LNG tanker and, on February 20, 1959, docked and unloaded its LNG cargo successfully at Canvey Island. Additional trial cargoes continued for another year, proving ocean transport was practical even in very rough seas. After nine years of research and experimentation, Constock had proven ocean LNG transport was viable. The company attempted to protect its $15 million investment through various legal means, in particular by taking out several hundred patents on its inventions and processes. By the end of the 1950s, nonetheless, other companies had also awakened to the possibilities offered by the ocean-going LNG export business and were taking steps to implement comparable LNG processes. Attempts to restrict competition through patent enforcement actions proved unsuccessful; to avoid infringing these patents, competitors created alternative designs (especially related to LNG shipping) that actually advanced a budding industry.

\textsuperscript{7} Sliepcevich, \textit{supra} note 1, at 269.

\textsuperscript{8} The United Kingdom had already begun the switch from coal-based gas by this time. \textit{See} Peebles, \textit{supra} note 2, at 27–28.
1960s—Exports Begin from Algeria and Alaska

After demonstrating that gas in liquid form could be safely transported by vessel, the next step was to find a suitable project from which to supply interested buyers. The United Kingdom was, of course, a receptive LNG buyer. By the early 1960s, France had also developed an interest in importing LNG.\(^9\)

Algeria

In 1960, the Royal Dutch/Shell group of companies (Shell) acquired a 40% interest in Constock (with Continental Oil at 40% and Union Stockyards at 20%) and the name of the company was changed to Conch International Methane Ltd. (Conch).\(^{10}\) The headquarters of Conch were moved to London to better enable the company to carry out negotiations with the French government, which was then the owner of the large Hassi R'Mel gas field in Algeria. In spring 1960 a contract was agreed between Conch and the French government for the purchase of gas from the field and the construction of a liquefaction plant on the Algerian coast. The liquefaction plant was to be financed and built by a new company, the Compagnie Algérienne du Méthane Liquide (CAMEL), to be owned by Conch and French interests.\(^{11}\)

From a marketing standpoint, CAMEL agreed to sell two-thirds of its LNG production to the United Kingdom and one-third to France. However, the project was delayed by intervening events—the first being Algerian independence from France in July 1962 (resulting in a forced sale of a 20% shareholding in CAMEL to the Algerian government) and the second an 18 month delay.

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9 At this time, solid fuels (i.e., hard coal, patent fuel, coke, brown coal, and briquettes) supplied 41% of Western Europe’s energy requirements, with gas accounting for only 2.5% of all energy consumed in West Germany, the Netherlands, Belgium, France, Spain, Austria, Italy, and the United Kingdom. In comparison, natural gas then had a 29% market share in the United States. Howard A. McKinley, “The Prospects for Liquefied Natural Gas in the European Energy Market,” *Symposium on Petroleum Economics and Evaluation* 103–04 (Soc’y of Petroleum Eng’rs 1965).

10 Sliepcevich, *supra* note 1, at 278. The name was said to be “derived from CON = Continental, CH = Chicago Stock Yards, and CONCH = (sea) Shell.” *Id.* The company was incorporated in the Bahamas, a decision that later caused investment protection issues for the shareholders when Algeria threatened to nationalize Conch’s interest in CAMEL. *See infra* note 20.

11 Sliepcevich, *supra* note 1, at 278.
while awaiting final British government approval of gas imports from Algeria. An additional company, British Methane Limited, owned 50% by Conch and 50% by the British Gas Council, was established to buy LNG on a “free on board” (FOB) basis, to transport it to Canvey Island and to sell it to the British Gas Council. The French government established a separate company to purchase its one-third portion of LNG destined for a new import terminal to be constructed at Le Havre, France. While British Methane Limited ordered two new vessels (each having 30,000 cubic meters of LNG cargo capacity, to be built in England and Ireland and estimated to cost $13 million each) replicating the basic Methane Pioneer design originated by Constock, the French LNG purchasers avoided the Conch patents by building a nickel-steel-based vessel in France (reportedly at considerably lower cost) using a French designer, Ateliers et Chantiers de la Seine-Maritime.

When completed, Algeria’s CAMEL project, the world’s first LNG export project, was no small undertaking. It consisted of:

- a 300-mile, 24-inch pipeline from the gas field in the Sahara to the liquefaction plant on the Mediterranean coast at Arzew;
- a liquefaction plant (now owned 40% by Conch, 40% by French interests, and 20% by Algeria) with an LNG production capacity of about one million tonnes per annum (MTPA) and constructed by J. F. Pritchard & Co. (U.S.) and Technip (France);
- liquefaction technology supplied by the French company SEGANS (arguably such technology violated Constock’s French patents, but Constock agreed not to interfere

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12 Given the transformational changes and political implications of shifting from British coal to dependency on duty-free imported gas from a recently formed North African country, such a delay by the British government in hindsight seems understandable. See “What’s Involved in European Importation of Liquid Methane?” Oil & Gas J. 138 (Oct. 31, 1960).

13 FOB is one of the international commercial terms or “Incoterms” defined and published by the International Chamber of Commerce (ICC), most recently in 2010. See ICC, “Incoterms 2010—ICC Rules for the Use of Domestic and International Trade Terms” (2010).

14 Peebles, supra note 2, at 192.

with CAMEL’s operations and chose to settle the matter with SEGANS outside of French courts\(^{16}\); and

- three above-ground storage tanks adapted from the Constock approach.

Total cost of the CAMEL LNG project was estimated at $89 million. To finance this amount, CAMEL had to turn to the following:\(^{17}\)

- Shareholders of Conch (Shell, Continental Oil, and Union Stockyards) contributed equity of $12.7 million and shareholder loans of $14.8 million;
- The World Bank’s International Bank for Reconstruction and Development (IBRD) loaned CAMEL $20.5 million (which loan was guaranteed by the Algerian government);
- Societe d’Exploitation des Hydrocarbures d’Hassi R’Mel (SEHR), Algeria’s state-owned gas company and predecessor of Sonatrach, prepaid $26.5 million in exchange for CAMEL’s agreement to supply SEHR with roughly one-third of the plant’s output; and
- Caisse d’Equipment d’Algerie (CEDA), a public finance institution tasked with supporting economic development in Algeria, loaned $8.1 million and provided a grant of $3 million.

Upstream gas pricing was attractive to CAMEL, with a published wellhead value of about $.03 per million British thermal units (MMBtu). This price did not reflect the actual cost of upstream development but instead was based on a “net-back calculation to arrive at values at which the gas can be sold at all.”\(^{18}\)

On September 26, 1964, the world’s first LNG cargo sold under a long-term sales contract was loaded at the CAMEL plant in Algeria and was unloaded on February 12, 1964, at Canvey Island. The FOB price was $.53 per MMBtu (payable in French francs) and the delivered price was $.76 per MMBtu (payable in pounds sterling).\(^{19}\) Over the next few years, the plant and trade operated with few difficulties or interruptions of supply, further increasing the confidence in the

\(^{16}\) Id.
\(^{17}\) Id. at 12.
\(^{19}\) Appraisal Report, supra note 15, at 13–14.
budding LNG industry. Unfortunately for Conch, however, it did not realize the full benefit of the pioneering risks it took in developing LNG technology and investing in Algeria, as its shares in CAMEL were acquired/nationalized by Sonatrach in 1977 for an undisclosed sum.20

Alaska

While the plant in Algeria was under construction, a race occurred between Phillips Petroleum Company (Phillips) in Alaska and Conch (Continental Oil, Shell, and Chicago Stock Yards) in Brunei to see which company would be the first to supply LNG to Japan. In 1962, Phillips had discovered natural gas in the North Cook Inlet field near Kenai, Alaska and had determined that it would only be marketable as LNG and that such LNG would need to be exported to meet the required economics.21 In 1963, Shell discovered the South West Ampa gas field offshore Brunei, which sparked hopes that Conch could commercialize Brunei’s gas reserves via LNG. As discussed below, the Japanese in the end decided to buy first from Alaska (delaying the Brunei LNG start-up for several years), after years of difficult and tiresome negotiations that caused friction between UK and U.S. diplomats attempting to sway the Japanese decision.22

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20 A confidential U.S. Department of State (State Department) memo in 1976 claimed that Sonatrach was attempting to buy CAMEL from Conch for only $3 million versus Conch’s valuation of $39 million. Conch considered taking the matter to arbitration but eventually elected to settle the dispute. See Unclassified Cable, State Department, “Proposed Sonatrach Taking of Conch Shares in Camel” (No. 1976STATE167918_b July 7, 1976).

21 Lower transportation costs drove Phillips’ decision to market the LNG in Japan, rather than in potential markets along the West Coast. The Merchant Marine Act of 1920 (Jones Act), 41 Stat. 988, requires any transportation of merchandise between points in the United States to be on vessels that have either been built in the United States or rebuilt under Jones Act standards. See 46 U.S.C. § 55012. Since the requirement to use American-built tankers to ship LNG to potential markets along the West Coast would almost double Phillips’ shipping costs, it determined Japan to be the market with the most commercial potential. See Robert L. Hartig & John K. Norman, “Production, Conservation, and Utilization of Natural Gas in Alaska,” 3 Nat. Resources Law. 694, 699 (1970).

Coincidentally, around this same time, air pollution had prompted the enactment of Japanese environmental regulations, which stirred Japan’s interest in importing LNG. Although coal-fired power generation then dominated, residents and local government officials were demanding lower emissions. Japanese power companies realized they could substantially reduce emissions by adopting LNG for power generation. However, many Japanese power companies, particularly in highly populated areas, were at that time willing to switch to LNG only if they received financial assistance from the Japanese government to cover the “high” capital costs. Non-power companies had expressed their interest in LNG as well. For example, soon after Conch completed its test trials between Louisiana and England, Bridge Stone Tire Co. had announced plans to have Mitsubishi Nippon Heavy Industries build a tanker “based on the principles used by Conch International Methane in the Methane Pioneer.”

In an attempt to sell LNG, Phillips executives travelled to Japan in 1963 and 1964. Negotiations commenced in 1965 with Tokyo Electric and Tokyo Gas, who expressed interest in purchasing LNG. However, Phillips also faced competition from another potential LNG seller, Marathon Oil Co. (Marathon), which also had gas reserves in Alaska. In early 1966, Phillips and Marathon agreed to combine their Alaskan gas reserves by forming a joint venture to sell LNG to these Japanese entities. As Phillips and Marathon were closing in on a deal to sell LNG to Tokyo Electric Power Co. (Tokyo Electric) and Tokyo Gas Co. (Tokyo Gas) at the initial price of $.53 per MMBtu (with staggered price increases over 20 years), the Conch group offered to supply Tokyo Electric and Tokyo Gas with LNG at $.52 per MMBtu and to build its two LNG tankers in Japan. “Tokyo Gas informed Phillips and Marathon that they would lose the deal if they did not match Conch’s offer.”

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26 Id. at 82.
In fact, Conch had been in intense negotiations with Tokyo Electric and Tokyo Gas for almost four years; Conch had signed a detailed Heads of Agreement and had transmitted it to the two buyers for execution. The day before the Japanese executives were to sign the Heads of Agreement to buy from Brunei, the Japanese companies held a press conference and stated that they were resuming negotiations for Alaskan LNG “at the request of the American Embassy in Tokyo.” Conch believed that this action had been taken due to pressure on the State Department from the two U.S. Senators from Alaska. Conch’s lawyers at the time, Winston Strawn, alleged in a protest letter to Illinois Senator Everett Dirksen that an investigation “disclosed the State Department’s policy to help American business and that the stock ownership of Shell . . . in Conch militated against their helping Continental Oil and the Union Stock Yard . . . .” 27 British diplomats were then reporting that the Japanese Ministry of International Trade and Industry asserted that its decision between the two competing projects would be based on “price, stability of supply and transportation to Japan.” In the end, Alaska’s perceived security of supply appears to have been the deciding factor, as evidenced by comments behind the scenes that Tokyo Gas was “worried about possible instability in Brunei that might lead to failure of supply or arbitrary price increases.” 28

On March 6, 1967, the first Asian LNG sale and purchase agreement (SPA) was signed between the four parties, with Tokyo Electric to receive 75% of the delivered quantity and Tokyo Gas the remaining 25%. Although the sales price was set at $.52 per MMBtu until 1984, the following additional price review clause was agreed:

If in the future another Liquefied Natural Gas project is placed into operation to supply Japan with natural gas from foreign gas sources, such as Alaska, Canada, Australia, Brunei and the Middle East under similar conditions such as volume, distance, liquefaction and ocean transportation techniques, contract term and so forth, Sellers will hold a discussion with Buyers concerning the price as herein set forth, and shall endeavor to find a solution satisfactory to all parties concerned.

27 Letter from Thomas Tyler, to Senator Everett Dirksen, U.S. Senator (July 18, 1966), in Public Files, supra note 22.

28 Memorandum from Dudley Cheke, Chief Ambassador Tokyo Office, to Foreign Office (Apr. 27, 1966), in Public Files, supra note 22.
The SPA contained other provisions that were unusual by today’s standards, including that any disputes would be decided by arbitration in Tokyo with the arbitrators applying Japanese law.\textsuperscript{29} The SPA was subject to receiving all necessary approvals of the governments of Japan and of the United States.

The project was significantly larger than CAMEL’s Algerian LNG plant. At an estimated cost of $200 million, it was reported to be the largest project in either Phillips’ or Marathon’s history. Phillips and Marathon balance sheet funded, on a 70%/30% basis, the construction of the liquefaction project (using Phillips’ patented Cascade LNG process), with the construction handled by U.S. contractor Bechtel Corporation (Bechtel). Phillips and Marathon also agreed to construct two LNG tankers with 71,000 cubic meter capacity in Sweden and executed separate transportation agreements with Polar LNG Shipping Corp. and Arctic LNG Transportation Co. Yet another design was to be used for these ships, using integrated membrane tanks supported by the hull of the ship.

The first delivery of Alaskan LNG to Tokyo Electric and Tokyo Gas occurred in November 1969. Phillips and Marathon soon determined that the economics of the LNG project were unfavorable at the contracted price of $.52 per MMBtu, which led them to want to use the price review clause to negotiate a price increase as soon as another LNG project was put in place to sell LNG to Japan. Phillips and Marathon did not have to wait long for that opportunity. The project eventually benefited from the marked increase in LNG sales prices during the 1970s due to unprecedented increases in energy costs.\textsuperscript{30}

1970s—LNG Demand Increases Four-Fold

Libya

Even though Exxon Mobil Corp.’s (Exxon) Marsa el-Brega LNG plant in Libya was the next export project to sign the necessary contracts to support construction, the project suffered...
numerous major setbacks from the outset. Sales contracts had been concluded in 1965 with Italian and Spanish buyers; in fact, this project would introduce natural gas into Spain for the first time. However, construction of the $350+ million plant plus LNG tankers did not begin until mid-1967, after Esso Standard Libya, Inc. (Esso) awarded contracts for the largest phase of the project to Italian construction companies SNAM Progetti S.p.A. and Compagnia Italiana Montaggl. Mechanical engineering and procurement had been handled by Bechtel based on a process design completed by the U.S. company Air Products and Chemicals, Inc. (Air Products). Based on an Esso International “original design,” three LNG tankers were constructed in Genoa, Italy and one in El Ferrol, Spain by Ansaldo SpA at a total cost exceeding $50 million.

Plant construction was scheduled to be completed in late 1968, using the novel mixed refrigerant liquefaction technology provided by Air Products. Because of extensive technical and engineering problems, the first cargo was not transferred into storage until April 1970, and full operating capacity was not achieved until 1973. Moreover, LNG supply was interrupted during 1974 and 1975 due to price disputes between buyers, Esso, and the Libyan government, including losses to the seller caused by a depreciation of the U.S. dollar to the Italian lira. This project operated successfully during the remainder of the decade; however, due to sanctions instituted by the U.S. government, Esso withdrew from the project in November 1981, leaving the project to be owned and operated by a subsidiary of the Libyan National Oil Corporation, Sirte Oil Company. The project continued to have major technical and financial issues after Esso withdrew. Libyan President Muammar Gaddafi raised LNG prices several times, buyer SNAM of Italy terminated its purchase contract, and buyer Catalana de Gas y Electricidad of Spain dramatically scaled down its purchases. Although the plant operated sporadically during the last decade, today the Marsa-El-Brega plant is no longer in operation.

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32 See D. M. Latimer, “Esso Libya Venture,” First Int’l Conference on Liquefied Natural Gas 6 (Inst. of Gas Tech. 1968). The Latimer paper was delivered at the First International Conference on Liquefied Natural Gas that took place April 7–12, 1968, in Chicago. While 600 of the attendees to the week-long meeting were from the United States, an additional 150 delegates from 16 other countries attended the conference. English and French were the conference’s official languages.
33 See Peebles, supra note 2, at 195.
Brunei

Fortunately for the industry, other export projects during the decade were much more successful. In 1970, Shell, Mitsubishi, and the Brunei government\textsuperscript{35} were finally able to commence the Brunei LNG project when sale and purchase agreements (SPA) were signed with Tokyo Electric, Tokyo Gas, and Osaka Gas. Again, negotiation leverage on the side of the buyers resulted in the SPA being governed by Japanese law, with arbitration under the International Chamber of Commerce (ICC) arbitration rules to be held in either Tokyo or Osaka. The SPA was set at volumes much larger than predecessor projects. From the outset, Brunei LNG dwarfed projects of the prior decade through the sale of 3.7 MTPA from four liquefaction trains, requiring six new ships with cargo capacity of 75,000 cubic meters each that were built in France. Air Products again provided its mixed refrigerant liquefaction process, and Japan Gasoline Corp. (JGC) and Procon, Inc. (a division of Universal Oil Products based in Illinois) were awarded the construction contracts in 1970.

Regarding the Brunei LNG plant ownership and operation, a project company was incorporated in Bermuda, as Brunei LNG Limited, with Shell and Mitsubishi each holding a 45% interest and the government of Brunei holding only a 10% interest. At the time of the project's inception, lack of certainty regarding Brunei law may have induced the parties to incorporate the project offshore. The plant was originally financed by a combination of equity (16%), shareholder loans (45%), and third-party financing (39%). Of the 45% of the financing arranged through shareholder loans, Shell contributed 20%, Mitsubishi contributed 20%, and the government of Brunei contributed 5%. The loan made by Mitsubishi and its 5% equity contribution were financed through the Export-Import Bank of Japan (JEXIM) and commercial banks providing Overseas Investment Credit financing. An unusual aspect of the project was that Shell and Mitsubishi guaranteed the obligations of Brunei LNG Limited, the seller of the LNG under the original sales contract. The project's first cargo was delivered on time to Osaka Gas in December 1972.

Indonesia

The most significant development of the decade was the almost simultaneous development of two major export projects in Indonesia—the Bontang project in East Kalimantan

\textsuperscript{35} A reorganization of the project had resulted in Continental Oil and Union Stockyards leaving the project in 1967. See A. Ploum, “The Brunei Liquefied Natural Gas Plant,” \textit{Fifth International Conference on Liquefied Natural Gas} 2 (Inst. of Gas Tech. 1977).
and the Arun plant in Sumatra. These two projects helped make Indonesia the largest exporter of LNG globally, a position it held for over two decades. The development of these two projects was sparked by the separate discoveries in late 1971 of large, remote non-associated gas fields by two U.S. companies, Mobil and Roy M. Huffington Inc. (Huffco). Although Mobil was a large company with natural gas experience, it did not have any background in LNG. Huffco, which also had no background in LNG, was owned by Roy M. Huffington, a Texas oil man with a Ph.D. in geology from Harvard, who had left Humble Oil and Refining Co. in 1956 to establish his own company. Huffington teamed up with General Archibald (“Arch”) Sproul, chairman of Virginia International Company, to sign a production sharing contract in 1968 with the intention of looking for oil in East Kalimantan. Both Huffco and Mobil instead found non-associated gas fields that were far from any pipeline market, a development that forced Huffington to farmout most of his company’s participating interest to others in order to help fund further drilling and development. Nissho-Iwai (a major Japanese trading company) encouraged Huffco and Mobil to consider LNG development for sales to Japan, resulting in each company separately commencing feasibility studies on potential LNG projects. Each company recognized the immense challenge Indonesian law provided because neither company could own the LNG plant, making the raising of financing for the projects extremely difficult.

In late 1972 Pertamina, Indonesia’s state owned oil company, teamed up with Huffco, Mobil, and Nissho-Iwai to form a single team to develop the Indonesian LNG trade. The intention was to build two LNG plants simultaneously, assuming a market could be found or developed for the LNG output. In 1972 Japan and the United States were viewed as the only markets for natural gas offering enough LNG demand to support one or more LNG projects. Marketing started in March 1973. Even though Pertamina, Mobil, and Huffco jointly marketed the LNG, under Principles of Agreement executed by the parties in April 1973, it was agreed that the final sale would be solely in the name of Pertamina. The SPA was structured to be back-to-back with gas supply agreements signed by Mobil, Huffco, and other relevant production sharing contractors. Moreover, it was agreed that the plants would be operated on a non-profit basis. Although for obvious liability reasons separate companies (P.T. Badak and P.T. Arun) were to be incorporated to operate the two LNG plants and liquefy the gas, neither operator company was to purchase gas from upstream producers or be the seller of LNG to buyers. Since the company liquefying the gas did not make a profit, the parties agreed that all revenues generated would be shared at the upstream level according to the equity splits of Pertamina and the upstream production sharing
contractors in the relevant production sharing contracts. The agreement provided that the Indonesian government would finance and own the two LNG plants.

California utility Pacific Lighting Corp. (Pacific Lighting) quickly expressed interest in a 20-year purchase from Mobil’s project in North Sumatra. Although an SPA was executed in September 1973 to supply LNG from North Sumatra to California, there was concern about being able to obtain U.S. government approvals. The agreement SPA Pacific Lighting signed with Pertamina contained the following conditions precedent: “On or before September 6, 1975, the appropriate authorities in the United States shall, on conditions considered acceptable to [Pacific Lighting], have issued the required authorizations permitting the import and sale of LNG subject to this Contract . . . .” Those approvals never came, and the LNG from Indonesia’s Arun facility eventually made its way to Japan.36

As luck would have it, the October 1973 oil crisis affecting Middle Eastern supplies37 (the Japanese economy was then fueled largely by crude oil) generated keen interest in Indonesian LNG from five Japanese buyers and, most importantly, the Japanese government. In December 1973 Pertamina signed an SPA for 8.18 MTPA with Chubu Electric, Kansai Electric, Osaka Gas, Kyushu Electric, and Nippon Steel. The ex-ship sales price was divided into an “LNG Element” based on crude oil export prices and a “Transportation Element” (with the LNG Element being a minimum LNG price of $0.99 per MMBtu, escalating at an agreed rate, and the Transportation Element being $0.30 per MMBtu, escalating based on changes in seller’s actual cost of transportation payable to its transporter). The fixed prices achieved by LNG buyers during the 1960s were gone. The Japanese buyers were instead more focused on guaranteeing a steady, safe supply and were less concerned about price volatility.38 Furthermore, unlike the Alaskan SPA signed only six years prior, this SPA did not contain a commitment to Japanese arbitration and


governing law. The Indonesia SPA reflected the negotiating leverage of the sellers; the governing law of the SPA was New York law and any arbitration was to be held under the ICC arbitration rules in Paris.

At the same time, Pertamina completed negotiations with Bechtel on the design, engineering, and construction of both LNG plants. Pertamina had also concluded a transportation agreement (i.e., contract of affreightment) with Burmah Gas Transport Ltd., a New York subsidiary of a UK company, to transport LNG from Indonesia to Japan on seven Moss Rosenberg design 125,000 cubic meter LNG tankers39 to be constructed by General Dynamics Corp. in the United States and operated by Energy Transportation Corp. of New York.40

The complex financing of Arun and Bontang totaled $1.638 billion and involved considerable Japanese government support, including by a new Japanese entity, JILCO. The Japanese government made loans from the Overseas Economic Cooperation Fund to the Indonesian government and Pertamina. The Japanese government’s Ex-Im Bank and a group of associated commercial banks loaned the bulk of the project financing funds to JILCO, with 60% of these guaranteed by JNOC, a Japanese state-owned oil and gas company, and 40% guaranteed by the consortium of five major buyers, which had support from the Ministry of International Trade and Industry (MITI) in the form of overseas investment insurance. JILCO then loaned money for project development to Pertamina. Payments for LNG from the five buyers were sent to a trustee in New York for disbursement.41

Pertamina later suffered major (mostly unrelated) financial issues during LNG plant construction, and Pertamina, Huffco, and Mobil also had to withstand cost overruns on the

39 These vessels had been pre-ordered based on the original concept of Indonesia supplying California and had larger engines that provided additional flexibility in the Indonesia-Japan trade. See Dennis G.W. Allsop, “The Development and Placing in Service of LNG Carriers for the Indonesia/Japan Trade,” Eighth Annual Convention Proceedings 105, 116 (Indonesian Petroleum Ass’n 1979) (noting that although the vessels were originally designed for LNG delivery to U.S. West Coast facilities, the characteristics of these new vessels made them particularly suitable for LNG transportation from Indonesia to Japan).


41 Von der Mehden & Lewis, supra note 38, at 5.
vessels that resulted in renegotiation of the Transportation Agreement, the SPA, and other contracts. Nonetheless, construction was completed and the first Indonesia cargo was delivered from the Bontang plant to Osaka on August 19, 1977. The success of these Indonesian projects and continued interest from existing and new buyers in Asia allowed Pertamina and its production sharing contractors to continuously expand the LNG plants. Indonesia soon became the principal player in the LNG export market.\textsuperscript{42}

**United States’ Failed Attempt as LNG Importer**

The other significant development during the 1970s was the first failed attempt by the United States to become a meaningful importer of LNG. A perception of natural gas shortages during this period led many U.S. companies to commit to large, long-term LNG import projects. From October 1969 to October 1976, six long-term LNG supply contracts were signed (totaling over 1.5 tcf per year), and LNG import terminals were built in Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana. As a consequence, Algeria, as the largest supplier, built new export facilities in order to provide the purchased volumes of LNG.

Unfortunately, the U.S. natural gas “shortages” were caused primarily by the effects of federal regulation rather than by a true shortage of gas reserves. The U.S. Congress passed legislation that restricted the use of natural gas and petroleum by electric utilities and large industrial firms based on the belief natural gas supplies were scarce.\textsuperscript{43} Through such legislation, consumption of coal and other fuels by utilities and industrial firms was encouraged and the use of natural gas and petroleum was discouraged. Simultaneously, deregulation of domestic gas prices was considered to be a necessary step to encourage drilling for gas. Soon, gas supplies soared and a gas bubble formed that, along with restricted demand, caused domestic gas prices to fall.

The U.S. government then began to reject projects that would import LNG from Algeria, in part due to pricing under the deals being tied to oil prices. By the end of the decade, Algeria’s Sonatrach stopped delivering LNG to most U.S. importers because of continuing price disputes, with Sonatrach insisting on very large LNG price increases to match oil price increases. The

\textsuperscript{42} Indonesia had more than one-third of global LNG exports throughout the 1990s. Today, Indonesia’s global share is only about 7%, due to declining reserves and increasing domestic gas needs. See U.S. Energy Info. Admin. (EIA), “Indonesia Analysis Brief,” at 13 (Mar. 5, 2014).

problem for U.S. LNG buyers was that LNG import prices were often much higher than the price paid by interstate pipeline companies for domestic gas supplies. Eventually, these SPAs were terminated, most terminals were idled, and at least one U.S. importer declared bankruptcy, citing its liabilities to Sonatrach and inability to pass these liabilities on to its U.S. domestic gas customers. Litigation and arbitration surrounding the end of LNG trade from Algeria to the United States continued for most of the next decade among numerous participants, including the U.S. government, which had financed construction of several tankers. As a result, Algeria was left with its LNG complexes at Arzew and Skikda operating at less than half of their potential capacity for more than a decade, which caused a serious deterioration in plant performance that later required Algeria to spend additional funds to restore them to their original capacity.

The U.S. government was not the only government that intervened in the LNG trade in the 1970s, as governments of potential exporters also decided the fate of proposed export projects. In 1972, Peoples Gas, a regulated natural gas utility in Chicago, signed contracts with the Standard Oil Company of Indiana (Amoco) to import LNG from Amoco’s gas discoveries offshore Trinidad. However, the Trinidad and Tobago government canceled the project in 1974, deciding that the gas would be better used for internal industrial development (especially fertilizer, ammonia plants, and a steel mill). The Trinidad and Tobago government’s decision had the effect of delaying the country’s first LNG export until 1999.

1980s—Asian Demand Rises; Malaysia and Australia Join as Exporters

LNG demand continued to grow in the 1980s, led primarily by Asian demand from gas-powered electricity generation. Demand in Japan alone shot from around 17 MTPA in 1980 to over 45 MTPA in 1990. Although much of this new demand was captured by Indonesia, two new suppliers—Malaysia and Australia—joined the scene. As it had before for the Brunei project, Shell gave meaningful technical input on both of these new projects. The U.S. company, Air Products, achieved a dominant role on all liquefaction technology facilities built during the decade.

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44 See United States v. Panhandle E. Corp., 672 F. Supp. 149, 152 (D. Del. 1987) (stating that in one arbitration for LNG tankers the entity that shouldered much of the construction costs “had demanded damages in excess of $860 million”).

45 See “Algeria, 50 years on: is the jewel in the crown running out of gas?” Gas Matters 16 (Oct. 2012).

46 OTA Report, supra note 37, at 61.
Japanese investment played a sizeable role in allowing both projects to finally arrive, after many years of waiting. After Malaysia’s plant in the state of Sarawak was completed (along with existing plants in Brunei and Indonesia’s East Kalimantan), the remote island of Borneo became, in only a few short years, the primary global supply source for LNG.

**Malaysia**

As early as 1968 Shell had discovered substantial gas reserves offshore Sarawak, East-Malaysia, some 125 kilometers from Bintulu. However, negotiations between the government of Malaysia and Shell/Mitsubishi stalled for several years due to renegotiation of concession rights and disagreements over separation of liquefaction, transportation, and marketing functions. It was not until 1978 that a joint venture company, called Malaysia LNG Sdn. Bhd., was incorporated in Malaysia to undertake the MLNG Satu project, including LNG shipping. This was the first of three projects implemented by Malaysia. The company’s shareholders were PETRONAS (65%), Shell Gas B.V. (15%), Mitsubishi Corporation (15%), and the Sarawak state government (5%), making the foreign participation (30%) identical to that of the Brunei LNG project. An SPA was executed with LNG buyers in Japan, who also arranged for loans from JEXIM to Petronas and Mitsubishi. Operations at the MLNG Satu plant commenced in 1983 with three LNG trains having a total design capacity of 6.0 MTPA. In order to deliver these volumes, MLNG ordered five vessels to be constructed in France and elected to operate those vessels through Malaysian International Shipping Corporation (MISC).

**Australia**

Australia took a similarly long period of time before it was able to bring its first LNG project, the North West Shelf (NWS) Project, on line. Woodside Petroleum Limited (Woodside) had discovered gas in North Rankin in 1971, and the Western Australia state government enacted the *North West Gas Development (Woodside) Agreement Act 1979* to ratify an Agreement between the State of Western Australia and Woodside Petroleum Development Pty. Ltd., Woodside Oil Ltd., Mid-Eastern Oil Ltd., North West Shelf Development Pty. Ltd., BP Petroleum Development

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Australia Proprietary Limited and California Asiatic Oil Co. relating to the production of natural gas and condensate and the establishment of a treatment and liquefaction plant and to matters related thereto.49

However, it was not until 1981 that the NWS venture was able to obtain signed memoranda of understanding with eight Japanese buyers to evidence sufficient LNG demand could be available to launch the project. In 1981, although Woodside had a dominant 50% interest in the LNG and domestic gas projects, BP, Shell, Chevron, and BHP were instead responsible for all marketing and selling (including a requirement that Shell and BHP buy Woodside’s LNG on an FOB basis).50 However, the venture was unable to sign final agreements confirming the LNG sale (in part due to a downturn in the Japanese economy and oil prices) and was subject to competition from other would-be supply projects, such as the Canadian Dome Petroleum Ltd. (Dome Petroleum) project that signed an initial SPA with five Japanese buyers in 1982. To remedy this situation, the NWS venturers brought Mitsubishi and Mitsui into the venture in 1984, restructured the project to enable each of the six parties to own one-sixth each, and saved construction costs by switching from seawater cooling and steam turbines to air cooling and gas turbines.

Finally, SPAs were signed in May 1985 with five power companies and three gas companies, allowing the first Western Australia project to commence construction based on balance-sheet financing provided by the six joint venture participants, Woodside, BHP, BP, Chevron, Royal Dutch Shell (which also owned 24% of Woodside through Shell Australia), and Japan Australia LNG (MIMI) Pty. Ltd., a venture between Mitsubishi and Mitsui. Unusually, the venture was established as an unincorporated joint venture, and, as a result, gas competition issues influenced the structuring approach to the final SPAs. For instance, for the first time, multiple participants in one joint venture chose to execute separate, parallel SPAs with each buyer. “A total of 48 separate contracts were negotiated between the parties, . . . [but] they were

49 North West Gas Development (Woodside) Agreement Act 1979 (Act No. 104/1979) (Austl.). The Act placed requirements on the joint venturers in exchange for this approval, including to giving preference in employment to residents and in contract awards to suppliers, manufacturers, and contractors from Western Australia. See id. at sch 1, s 12(1).

almost identical and in practice, they functioned as one.\textsuperscript{51} Each of the multiple SPAs deemed a portion of each commingled cargo to be from the respective seller. The contracts also had an atypical LNG price clause that evolved into a series of rolling five-year pricing agreements. Shipping was provided by the sellers but included a “complicated arrangement . . . . [whereby] Japanese ship owners chartered two ships into the NWS project and they became the sellers’ ships, and both the ships were built in Japan.”\textsuperscript{52} The project’s first shipment to Japan occurred in July 1989.

In addition to these innovative structuring approaches, an important safety and liability issue arose when the initial Japanese FOB buyers from Indonesia insisted that a liability regime for LNG accidents at the loading port be incorporated into the SPA. In the 1981 Indonesian SPA, Pertamina and the Japanese buyers agreed to detailed principles for determining the liability of the “shoreside interests” and the “LNG vessel interests” in the event of an LNG “incident.” These SPA principles obligated the parties to agree to separate “Omnibus and Waiver Agreements,” governed by English law and subject to the jurisdiction of the High Court of Justice in London, overriding the existing conditions of use that the master of the LNG vessel was required to sign upon entry of the vessel into the Indonesian port. Under these port liability principles, the parties set the liability limit of the LNG vessel owner at $150 million, an amount much higher than would otherwise apply under law. A similar contractual approach to establishing port liability has thereafter been implemented in numerous ports globally.

Variable Prices

Despite the advancements of the Malaysian and Australian LNG trades, the immense variability of oil prices during the 1980s created many challenges for the LNG industry. Price disputes occurred with U.S. and European buyers, as prices under some LNG contracts exceeded the prices buyers were able to receive in the local gas resale market. For example, in 1985 Spain agreed to pay $500 million in compensation to Algeria for undertaking purchases under its 1973 SPA.\textsuperscript{53}

\textsuperscript{51} Shane McCarthy, “Negotiating Australia’s First LNG Export Contract,” \textit{Gas Today} 20, 22 (Nov. 2010).

\textsuperscript{52} Id.

It was not an easy decade for the numerous proposed export projects that were unable to find sales to allow the project participants to make a final investment decision, including projects that later were able to proceed (such as Nigeria, Qatar, and Norway), and also those that were abandoned, such as the Dome Petroleum project in Canada.

**1990s—Steep Rise in LNG Developments**

At the start of the 1990s, the LNG industry had grown to eight exporting countries (Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, UAE, and the United States) and eight importing countries (Belgium, France, Italy, Japan, South Korea, Spain, Taiwan and the United States). More than 50 MTPA was being shipped to 30 terminals. Despite considerable growth, however, LNG continued to be viewed as a “niche” fuel for a “club” of only a few international players. In fact, as of 1990, the Middle East had yet to become a real factor in LNG supply, other than Abu Dhabi’s Das Island project that began delivering LNG in 1977.\(^{54}\) The 1990s saw a steep rise in developments affecting the LNG industry, with SPAs being signed by new exporters in Qatar, Oman, Nigeria, and Trinidad and by new importers in Turkey, Puerto Rico, and Greece. In the first part of the decade, Asian suppliers (particularly Indonesia, Malaysia, and Qatar) signed, renewed, or substantially amended a multitude of SPAs with principally Japanese, South Korean, or Taiwanese buyers. But not all was rosy for the industry, as the decade also saw, in dollars terms, the largest reported contractual dispute ever, which occurred relating to an LNG SPA signed by Nigeria LNG.

**Qatar**

Like many other hopeful LNG producing countries, Qatar experienced a long wait from discovery of the North Field by Shell in 1971 until its first LNG cargo. During the 1970s and early 1980s Qatar had not been able to come to agreements on LNG developments with Shell or with Wintershall AG (Wintershall). Eventually, Qatar nationalized the Shell rights. In 1980, Wintershall also discovered non-associated natural gas and proposed an LNG project for the North Field, but despite years of negotiations, an agreement with respect to commercialization of the discovery

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\(^{54}\) While Abu Dhabi is not known for making many significant historical impacts on the industry, it is viewed as having introduced to Asian LNG sales in 1988 the “S-curve” form of pricing (where, to dampen the impact of high oil prices on the buyer and low oil prices on the seller, the price formula is different above and below a certain oil price). See Jeaseoung Choi & Gi C. Jung, “New LNG Projects in Asia and Their Effects on Pricing,” *22nd World Gas Conference, Tokyo 3* (Int’l Gas Union 2003).
was never reached with the Qatari government. Wintershall took the dispute to arbitration, claiming Qatar had expropriated its contractual rights by allowing the relinquishment period to expire on Wintershall’s exploration and production sharing agreement before reaching agreement on the method of gas utilization, including LNG. Fortunately for Qatar, the arbitration tribunal rejected almost all of Wintershall’s claims, including its claim of expropriation, causing investors in the Wintershall project to eventually lose any rights that would allow them to pursue an LNG project for the North Field. 55

Qatargas Operating Company Limited’s (Qatargas) first attempt to enter the LNG market occurred in 1984 with the signature of an agreement between Qatar General Petroleum Corporation (QGPC), BP, and CFP (now Total SA) creating Qatar Liquefied Natural Gas Company Limited. Unfortunately, Qatar Liquefied Natural Gas Company Limited was unable to find a buyer (especially after the NWS project moved forward) and spent the rest of the 1980s hoping to secure sufficient sales. The venture even brought in Mitsui and Marubeni in the late 1980s in hopes of gaining Japanese interest, but to no avail. After eight years of attempts, BP decided to relinquish its 7.5% share, stating in a January 14, 1992, press release that “the project does not give us a suitable return.”

BP’s departure from Qatargas created an opening for a more experienced LNG company to join. 56 Negotiations commenced with U.S. company Mobil (which was experiencing a decline in LNG production at Arun in Indonesia and needed to replace those significant revenues) to join, but Mobil insisted that it acquire at least a 20% overall interest. As “compensation” for Mobil agreeing to join the Qatargas project at a 10% interest, Qatar allowed Mobil in August 1992 to have a 30% interest in a new LNG project, to be called Ras Laffan Liquefied Natural Gas Company Limited (RasGas LNG). 57 Mobil had established a close relationship with Nissho Iwai in relation to marketing of LNG from the Arun plant, and Mobil quickly elected to bring in Nissho Iwai

56 Kohei Hashimoto, Jareer Elas & Stacy Eller, “Liquefied Natural Gas from Qatar: The Qatargas Project,” at 5 (Program on Energy & Sustainable Dev. Working Paper Dec. 2004). In fact, several other international oil companies had also been approached and had indicated they had no interest in joining the project. Id. at 8.
57 A decade later Qatar also awarded the Qatargas II project to ExxonMobil, in addition to approving numerous expansions of the RasGas project. Id. at 39.
and other Japanese trading companies to assist in marketing of RasGas LNG. At its inception, overall ownership interests in the RasGas LNG project were held 70% by QGPC and 30% by Mobil. However, a separate class of shares was established for Nissho Iwai and Itochu, and Nissho Iwai and Itochu together provided QGPC with $864 million in loan commitments and other financial assistance in order to enable the state-owned company to meet its share of the RasGas LNG project costs.

LNG demand in Japan and Korea had taken a positive turn by this time, and Qatargas was able, with the assistance of Mitsui, to secure an SPA with Chubu Electric in May 1992 (governed by New York law and providing for arbitration under ICC arbitration rules in Geneva). Total and the French government played a crucial role in financing the upstream joint venture, while Japanese financing supported the LNG plant. Japanese lender JEXIM supplied $1.6 billion via an intermediate financing company that was guaranteed by the two Japanese sponsors. While Japanese limitations on financing were satisfied since the borrower from JEXIM was a Japanese company, the borrower simultaneously lent the funds to Qatargas. Although front-end engineering work had been completed in Houston by U.S. construction contractor M.W. Kellogg, the final engineering, procurement, and construction was awarded in May 1993 to Japanese contractor Chiyoda.

Although RasGas LNG had brought in Japanese trading companies as shareholders in hopes of also obtaining Japanese buyers, success in LNG marketing first came instead from Korea Gas Corporation (Korea Gas). On October 16, 1995, RasGas LNG and Korea Gas signed a 25-year SPA (governed by New York law and providing for arbitration under ICC arbitration rules in London), and Korea Gas also acquired an equity interest in the venture. Mobil’s involvement in the venture allowed for a unique funding arrangement to be utilized. The first two trains of the RasGas LNG project were financed in 1997 with a combination of $1.2 billion in bonds and $1.35 billion in the form of limited-recourse loans extended by institutional lenders. The bond offering was the first of its kind in the Middle East and was more than 200% oversubscribed when initially made in late 1996. The bonds were secured by completion guarantees provided by QGPC and Mobil’s Qatari subsidiary, with parent guarantees additionally

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provided by the government of Qatar and Mobil itself. The financing extended by institutional lenders included a $450 million facility led by the Industrial Bank of Japan and Credit Suisse, a $465 million facility guaranteed by the Export-Import Bank of the United States, a $250 million facility guaranteed by the UK’s Export Credits Guarantee Department, and a $185 million facility guaranteed by SACE, the export credit agency of Italy. The cost of the LNG plant and upstream facilities, when completed in 1999, totaled $3.26 billion.

After more than a decade of desiring to enter the LNG business, Qatar had successfully built the foundation for developing the North Field’s enormous gas resource base. Its first steps were less bold than those that were taken later (Qatar started with only three trains, and not all production was pre-sold on a long-term basis) and did not evidence a desire by Qatar to control all shipping, as the first sales from RasGas were on an FOB basis. Qatar entered the LNG business during the brief sellers’ market of the mid-1990s. It was able to grow both projects over the next decade, allowing Qatar to overtake Indonesia in 2006 as the global leader in LNG and eventually to have facilities with a total production capacity of 77 MTPA, including six mega-trains with the world’s largest LNG capacity (7.8 MTPA each). Along the way it developed the world’s largest LNG fleet of over 50 vessels (several with “QFlex” and “QMax” cargo capacities exceeding 200,000 cubic meters) via Qatar Gas Transport Company Ltd. (known as “Nakilat”), a Qatari-listed shipping company established in 2004 and owned 50% by the public.

Perhaps due to the increase in third-party financing of export facilities (including in Qatar, Oman, Trinidad, and Indonesia), the 1990s marked the end of choosing a governing law other than New York or England in long-term SPAs. From a dispute resolution standpoint, very typical approaches were arbitration under ICC arbitration rules in Paris, Geneva, or London; or under the United Nations Commission on International Trade Law arbitration rules in London or New York. Regardless of whether experiencing a sellers’ market or a buyers’ market, SPA parties appear to have decided that pushing for “local” governing law and/or dispute resolution in the face of lender’s resistance was no longer a critical issue.

**Nigeria**

Another important development during the decade was Nigeria’s entrance into LNG, again after years of attempts. Nigeria had earlier hopes and in 1985 formed an LNG Working Committee, which eventually resulted in the incorporation of the project company “Nigeria LNG Limited” in May 1989. Ownership interests were: NNPC 49%, Shell Gas 25.6%, Total 15%, and Eni 10.4%, with Shell as the Technical Adviser. Nigeria then passed a law in 1990 called the
Nigeria LNG (Fiscal Incentives, Guarantees and Assurances) Act, which provided a legal framework including fiscal stability, a fiscal regime for the project, and arbitration under the International Centre for Settlement of Investment Disputes arbitration rules.

Thereafter, Nigeria LNG entered into long-term SPAs with ENEL in Italy, Enagas in Spain, Botas in Turkey, and Gaz de France in France, with LNG prices predominantly tied to oil product prices. However, ENEL decided in 1996 not to build an LNG receiving terminal on the coast of Tuscany and attempted to cancel its LNG sales contract. The impetus behind the cancellation was a veto of the proposed site for the terminal by a newly elected Italian government. Nigeria LNG then brought a breach of contract suit against ENEL for $13 billion (reportedly the largest claim ever brought under English law at that time). ENEL claimed the SPA force majeure clause relieved it of its purchase obligations. Nigeria was able to settle the arbitration in 1997 by agreeing to ship LNG to France (instead of Italy), in exchange for Russian gas being diverted by French buyers to Italy.

Although successfully launched, the Nigerian LNG project confronted even more global publicity in relation to a pattern of bribery associated with its construction contracts. In 1995, Nigeria LNG awarded a lump-sum turnkey construction contract to a consortium of Technip, Snamprogetti, Kellogg, and JGC (TSKJ) to construct two trains with a capacity of 5.84 MTPA and at a cost of $2.2 billion that was balance-sheet financed. Evidence later emerged that representatives of TSKJ, through agents, paid millions of dollars to Nigerian government officials in order to receive the construction work. Government investigations led to more than $1.7 billion in penalties and forfeiture orders from the TSKJ partners, their agents and individuals. Criminal convictions in the United States also led to prison sentences for a UK solicitor and for the former KBR CEO (who was sentenced to 2 1/2 years in prison).

Korean Shipping

Yet another development that reduced costs of shipping and allowed the LNG fleet to expand rapidly was South Korea’s arrival as an LNG shipbuilding country. It was not until 1994 that Hyundai Heavy Industries (HHI) constructed the Moss carrier Hyundai Eutopia to support Korea Gas Corporation’s FOB fleet to transport LNG from Indonesia. At the time, Japan dominated the LNG shipbuilding business, having built 10 of 13 LNG vessels between 1993 and 1994. There was some concern in the industry as to whether South Korea could deliver dependable LNG vessels on a timely basis, despite Korea’s pre-investment in the required mammoth docks. HHI delivered the first vessel on time and at less cost than Japanese shipyards.
(around $250 million), setting off keen competition for the remainder of the decade that was won by the Korean “Big Three”—Daewoo Shipbuilding and Marine Engineering, Samsung Heavy Industries, and HHI. In a few short years Korea took over the position of world’s largest LNG shipbuilder, constructing 10 out of 13 ships in 2000.\(^59\) Although the Chinese later entered the LNG shipbuilding market on the backs of their own import deals, South Korea has still managed to retain a dominant position. Between 2009 and 2013, of 134 LNG tankers built, 100 were made by South Korean yards, 20 by Chinese yards, and only 13 by Japanese yards.

**Oman and Trinidad**

Lastly, the decade ended with two other export projects that started deliveries of LNG—Oman LNG and Trinidad’s Atlantic LNG. Thanks to Shell’s efforts, Oman was able to sell one train (4 MTPA) to Korea Gas on an FOB basis. The one-train project that started up Atlantic LNG was particularly noteworthy in two respects. First, the project marked the return of the ConocoPhillips “optimized” cascade liquefaction process, an earlier version of which had been used in the Kenai plant years before. In 1996, ConocoPhillips had appointed Bechtel as the exclusive provider of certain construction services for the “optimized” cascade liquefaction process. Such a development brought more competition into the LNG construction market and, at least for a time, had the effect of lowering LNG plant costs.\(^60\) Second, Atlantic LNG was the first project in many years to be built and project financed chiefly to supply the United States (along with Spain), with Cabot LNG of Boston (now GDF Suez) arranging its foundation.\(^61\) Although Atlantic LNG’s U.S. volumes were designed to fill expected gas supply shortages in Massachusetts and nearby parts of the northeastern United States, within a few years other U.S.

\(^59\) The World Trade Organization (WTO) later confirmed the European Commission’s claim that Korea, through a government export credit agency, provided illegal subsidies to Korean shipbuilders, including for LNG carriers. The WTO recommended Korea withdraw the subsidies. *See* Panel Report, “Korea—Measures Affecting Trade in Commercial Vessels” (WT/DS273/R Mar. 7, 2005).


companies, and influential leaders, began to be concerned that overall U.S. gas production would be unable to meet rising U.S. gas demand throughout the country.

2000s—Lower Prices Followed by Increased Demand

New LNG export projects and expansions of existing projects experienced delays in the early 2000s as global demand moderated somewhat in the traditional LNG markets. Buyers used a perceived oversupply in LNG to their advantage, with some holding rather public competitive tender processes compared to the historically private negotiation approach. The immediate result was a lower LNG price that allowed additional trains to be constructed; lower prices helped convince China and India to purchase LNG in 2002, with sales by North West Shelf in Australia to Guangdong, China; RasGas LNG in Qatar to Petronet, India; and Tangguh in Indonesia to Fujian, China. At the time, Asian buyers were optimistic that these well-publicized contracts would reset the pricing basis for all other Asian LNG sales contracts. In fact, in early 2003 one Japanese expert declared that:

Although Japan-bound LNG has been long characterized by higher prices than US/EU-bound consignments and more rigid supply terms, falling prices and improving rigidity are likely from now on . . . .

. . . . [T]he Guangdong price is equivalent to a little over $3/MMBTU (when crude oil price is $20/bbl) in terms of the LNG price in Japan. From now on, the strong likelihood is that the Japanese importers will demand that their prices must be lowered to the Guangdong price level during price negotiations and contract renewal talks.62

Unfortunately for Japan, the Guangdong price level did not reset Asian prices for long, as new global economic factors (including higher oil prices and construction costs) arose that altered LNG prices.

United States Constructs New Import Terminals

By 2003, the United States became convinced it had a major supply-demand imbalance, claiming that “[t]raditional North American producing areas will provide 75% of long-term U.S. gas

62 Morita, supra note 60, at 1.
needs, but will be unable to meet projected demand." U.S. regulatory policy had experienced a major shift the year before when the U.S. Federal Energy Regulatory Commission (FERC) effectively deregulated LNG import terminals, allowing them to charge market-based rates and to operate without complying with open-access requirements. Not only did a wave of U.S., along with Canadian and Mexican, import terminal applications then follow (which had risen to 31 projects by November 2003), but new export projects and expansions were developed in anticipation of meeting the expected U.S. gas shortfall. In fact, Shell International predicted in 2004 that the United States could be “consuming over 50mtpa of LNG by 2013,” up from 5 MTPA in 2002. In response, at least 11 LNG trains were added in Africa, Asia, Europe, South America, and the Middle East in anticipation of meeting North American gas demand, including:

- Norway’s Snohvit project participants agreed to balance-sheet finance a one-train project based on sales to El Paso (later Statoil) priced assuming delivery to the United States;
- Equatorial Guinea LNG’s shareholders agreed to balance-sheet finance a one-train project based on sales to BG Group priced assuming delivery to the United States;
- Yemen LNG’s shareholders approved a long-delayed, balance-sheet financed, two-train project based in part on sales to Total and Suez (now GDF Suez) priced assuming delivery to the United States;

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64 James E. Vallee, “FERC Hackberry decision will spur more US LNG terminal development,” Oil & Gas J. 64 (Nov. 10, 2003).


67 See Daniel Fineren, “Yemen Gas Price Pressure Mounts on France’s Total,” Reuters (Feb. 16, 2014) (“Before work on the LNG project began in 2005, Yemen LNG agreed on 20-year deals to sell 2.05 million tonnes per annum (mtpa) to South Korea, 2.55 mtpa to France’s GDF-Suez and 2.10 mtpa to Total. . . . The contracts signed by Total and GDF-Suez were structured differently; since the two Western firms intended to ship most of the LNG to the United States, their deals were linked to the U.S. Henry Hub gas price index. In mid-2005 the U.S. LNG price was around $7 per MMBtu, but by the time the Yemen
• Angola LNG’s shareholders agreed to balance-sheet finance a one-train project based on sales to certain shareholders priced assuming delivery to the United States, and Sonangol and others elected to permit, construct and own their own LNG import terminal (Gulf LNG) in Mississippi;
• Peru LNG’s shareholders took FID on a one-train project based on sales to Repsol priced assuming delivery to Mexico (and secured $2.25 billion in loans to construct the $3.8+ billion project);
• Indonesia’s Tangguh project participants approved the sale of up to 3.7 MTPA (effectively one train) to Sempra’s LNG import terminal in Baja California, Mexico (and secured $3.5 billion in loans to construct the $5.0+ billion project);
• Qatar (along with ExxonMobil and ConocoPhillips) developed two expansion projects focused on U.S. demand and also elected to permit, construct and own their own LNG import terminal (Golden Pass) in Texas;
• Egypt LNG added an additional LNG train based on sales to BG Group priced assuming delivery to the United States; and
• Trinidad’s Atlantic LNG added three additional LNG trains based in part on supplying U.S. markets.

In the end, the United States reopened its three existing mothballed LNG import terminals. Eleven additional terminals were constructed in North America (most using balance-sheet or customer-based financing), and terminal use agreements were signed committing customers on a long-term basis to pay large reservation and other charges for securing import terminal capacity owned by third parties (such as Freeport LNG, Cheniere, Gulf LNG, and Sempra). Since the industry’s expectations were that the United States would soon become the second largest (after Japan) importer of LNG in the world, many other terminals were also approved and ready to proceed to construction. Of course, all these projects and plans were changed radically when North America discovered the true potential of unconventional shale gas.

**Increasing Asian Demand**

Despite the numerous trains added during the earlier part of the decade, by 2008 buyers in Asia were becoming concerned about supply, in particular from new buyers entering the market and decreasing supplies from some existing LNG suppliers due to maturing gas fields.

facility loaded its first cargo in late 2009, U.S. gas prices had collapsed below $2, largely due to the U.S. shale gas production boom.”).
Importantly, Qatar had imposed a moratorium in 2005 on additional LNG expansion for fear that rapid production could damage the North Field reservoir. Although Sakhalin Energy’s project was expected to open in 2009 to supply several Japanese buyers and Shell, demand for LNG was increasing at a rate that would support SPAs necessary for developing even more export projects.

Such increasing Asian demand and insufficient expansion ability at existing projects allowed Papua New Guinea (PNG) to move forward on LNG hopes that had been frustrated for many years. Throughout much of the 1990s the PNG LNG Project had been marketed by BP based upon the export of 4 MTPA from the reserves discovered in the Hides Field in 1987. BP was operator with a 45% share, with Exxon and Oil Search having 47.5% and 7.5% respectively. The project then targeted first LNG in 2005.68 However, BP sold out to Oil Search in 1998 and Exxon took over operatorship. During the early 2000s, due to the absence of a ready LNG market, ExxonMobil proposed that the PNG gas be instead sold by pipeline to Australia.69 By 2006 the Australia pipeline project was suspended due to a lack of buyers in Australia; at the same time, Interoil was pressing the PNG government to support an LNG option for Interoil’s recent gas discoveries. The time was right for ExxonMobil to revive its LNG project (with one train producing 6.6 MTPA), especially after the joint venture signed an agreement in May 2008 with the PNG government establishing the fiscal and legal framework for the project, including a unique benefit-sharing agreement enabling certain economic benefits to flow to the PNG people. A critical part of the agreement from the investor’s standpoint, given the political risk of such an emerging economy, was a detailed undertaking by the government to hold the project harmless for adverse economic effects from a change in PNG law. Soon thereafter, the project secured long-term sales from Japanese, Taiwanese, and Chinese buyers, which supported the signature of loan agreements for a $14 billion project financing package in December 2009.

**Increasing Global Demand**

Given the continuing shift to natural gas in general and the desire to develop new sources for imports versus pipeline supplies, by the end of the decade dozens of new import terminals were built around the world. New importing countries by 2010 included Argentina, Brazil, Chile, Argentina, Brazil, Chile, China, India, and South Korea. The growth in demand for LNG was driven by the desire to reduce dependence on coal and oil, as well as to take advantage of the lower greenhouse gas emissions associated with natural gas. This led to an increase in the number of countries importing LNG, with new terminals being constructed around the world. The growth in demand was particularly strong in Asia, where economies were growing rapidly and a desire to diversify energy supplies.

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Dubai, and Kuwait, and the UK experienced a rebirth of LNG imports with four new terminals being added to address gas deficiencies due to declining UK North Sea gas production. The industry had started 2000 with less than 30 import terminals and ended the decade with 83 terminals (including 10 floating structures) having a send-out capacity of 600 MTPA. While most North American terminals were underutilized, the remaining import terminals around the globe were generally seeing success. Demand for additional trains appeared so robust, and future supplies from conventional reserves so thin (other than from Western Australia), that buyers began to turn their attention to Australia’s undeveloped coal seam gas reserves for their future long-term supply base.

2010s—New Technologies (and Positive Outlook for Gas) Bring Change

Since 2010, numerous developments have occurred in the industry, many of them driven by technological advancements.

**Horizontal Drilling and Hydraulic Fracturing in North America**

Arguably the leading development arose from the application of horizontal drilling and hydraulic fracturing that demonstrated how North American unconventional shale gas can be produced economically. The shale gas production tide permitted Cheniere to sign LNG sales contracts (more similar to a tolling agreement), allowing it to obtain project financing and take a final investment decision (FID) in August 2012 on the first phase of the Sabine Pass liquefaction project in Louisiana. Sabine Pass is the only U.S. project, as of June 2014, to have taken FID to allow construction to proceed, but other FIDs are soon expected.

Each of the existing U.S. onshore LNG import facilities in Georgia, Louisiana, Maryland, Mississippi, and Texas is planning to add liquefaction and other facilities necessary to export LNG, most by offering third-party LNG processing/tolling services. For example, the Freeport project in Texas signed long-term Liquefaction Tolling Agreements with Japanese companies Osaka Gas, Chubu Electric, and Toshiba; with Korean company SK; and with BP. Numerous

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70 Under a tolling agreement, the export facility provides liquefaction and other services to a gas owner. The owner supplies the gas, pays a fee (the “tolling fee”) for the facility to liquefy the gas and provide other services, such as storage, berthing, and loading, and sells the LNG produced from the facility.

71 FID is the point at which the project sponsor has sanctioned and committed to undertake the LNG export project.
other greenfield projects are proposed, awaiting permits from the U.S. Department of Energy to export LNG to free trade\textsuperscript{72} and non-free trade countries.

The motivations behind Asian buyers contracting for U.S. supplies has been to secure additional LNG (needed as a consequence of Japan’s nuclear shutdown) at a lower price and to obtain pricing diversification by purchasing LNG supplies based on the Henry Hub index rather than a crude oil index. Asian buyers appear to be hoping (much as they mistakenly did in 2002 when prices briefly dropped to $3 from China’s purchases for Guangdong) that Henry Hub pricing will also assist in their upcoming price reviews under non-U.S. SPAs for Asian supplies.

**Unconventional Coal Seam Gas in Australia**

A wave of Australian LNG export projects are under construction, including Gorgon, Queensland Curtis, Gladstone LNG, Wheatstone, Australia Pacific, Prelude, and Ichthys LNG, with three of these projects in Queensland being supplied by unconventional coal seam gas. The total value of the LNG trains under construction in Australia is expected to exceed $200 billion. One project alone, the Gorgon project developed by Chevron, ExxonMobil and Shell, is now expected to cost $54 billion, up from an original budget of $37 billion.

No country has ever undertaken the construction of so many LNG export projects at the same time. All but one of the Australian projects now under construction were balance-sheet financed, with some funding for Queensland projects coming from the sale of equity to LNG buyers based in China, Malaysia, and Korea. The Ichthys LNG project (owned by several Japanese companies and Total) secured $20 billion in project financing in 2013, the largest project financing to date.

**Floating Liquefied Natural Gas Projects**

The world’s first floating liquefied natural gas (FLNG) project, Shell’s Prelude FLNG project, is under construction in Korea. Subsequent FLNG projects are now underway for Petronas (Malaysia) and Pacific Rubiales (Colombia), but have less production capacity than Prelude’s 3.6 MTPA planned output.

\textsuperscript{72} The United States currently has free trade agreements with 20 countries: Australia, Bahrain, Canada, Chile, Colombia, Costa Rica, Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, Korea, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, and Singapore.
Discovery of Offshore Gas Reserves

Anadarko and Eni made enormous gas discoveries in offshore Mozambique, which may position the country to one day become one of the largest LNG producers in the world. Additional major gas discoveries have been made offshore Tanzania and Israel/Cyprus that could lead to LNG export projects.

Arctic Development

The Russian project Yamal LNG took FID in late 2013, which should open up the Arctic to LNG production before the end of the decade. The Yamal LNG project, ice-bound nine months of the year, will open distinctive maritime routes for transporting LNG to Europe and Asia.

Floating Storage and Regasification Units

Floating storage and regasification units (FSRU) are now considered a fast-track import technology solution. At least 15 floating import facilities (including in Argentina, Brazil, China, Dubai, Indonesia, Israel, Italy, Kuwait, and Malaysia) are now in use, with many intended to receive LNG on an intermittent basis during the year. Moreover, FSRUs are under construction to be located soon in Chile, Indonesia, Lithuania, and Uruguay.

Rising Demand Shuts Down Egyptian Production

However, not all developments have been positive for the industry. Since 2012, insufficient gas production and reallocation of production to rising domestic demand have forced the shutdown of the Egyptian Damietta LNG project and the near shutdown of the Egyptian Idku LNG project. Effectively, more than 10 MTPA of LNG production has been lost and it is unclear when and if Egyptian LNG production will increase.

Conclusion

History has shown that the success of LNG export projects, or lack thereof, has been influenced by many factors, several of which are outside the sponsors’ control. Having sufficient gas resources to fully utilize an LNG plant for at least 20 years is, of course, a prerequisite to success. As a review of key commercial, technical, contractual, regulatory, and other legal developments in this chapter has evidenced, however, history suggests other factors may be as important in determining whether a project will be able to proceed without delay, such as: (1) LNG marketing timed with sufficient buyer demand; (2) appropriate governmental leadership and support; (3) predictable LNG prices that underpin project economics; (4) technology that enables
cost effective LNG production, transportation, and regasification; (5) controlled construction costs; and (6) sufficient funding from third parties.

Ocean transportation of LNG, which arose from U.S. pioneers who turned a failed Mississippi River project into a niche business first supplying countries switching to natural gas as a pollution-reducing move, has now grown into a vibrant worldwide industry. U.S. companies (chiefly Continental Oil/Union Stockyards, Phillips-Marathon, and Esso) led during these early years, developing liquefaction and shipping innovations; investing in and constructing export projects in Alaska, Algeria, and Libya; and successfully marketing long-term LNG sales to UK, French, Japanese, Italian, and Spanish buyers. During the 1970s, several new LNG exporters benefited from further increases in gas usage (especially in Asia) as a result of rising oil prices and insecurity of energy supplies. Growth during the 1980s slowed and projects were delayed, but Australia and Malaysia and eventually found the necessary sales to proceed. The 1990s saw Qatar finally find success, along with new LNG export projects in Africa, the Middle East, and South America. LNG put the “niche fuel” label behind it between 2000 and 2010, when LNG production more than doubled and LNG became a truly global industry with almost 90 import terminals spread across the world. Since 2010, unconventional gas resources in Australia and the United States have both assured the industry of plentiful supplies to meet continually growing demand for imports and provided a host of issues and challenges as to what the future holds for LNG.
## Appendix: Evolution of the LNG Industry—By Decade

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<tbody>
<tr>
<td>Exporting Countries</td>
<td>3</td>
<td>6</td>
<td>8</td>
<td>12</td>
<td>17(^{74})</td>
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<tr>
<td>Importing Countries</td>
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<td>10</td>
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<td>LNG Demand (MTPA)</td>
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<td>22</td>
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<tr>
<td>Import Terminals</td>
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<tr>
<td>Largest Seller Country</td>
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<td>Indonesia</td>
<td>Indonesia</td>
<td>Indonesia</td>
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<td>Japan</td>
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<td>Japan</td>
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<td>Asia % of Global Purchases</td>
<td>23%</td>
<td>72%</td>
<td>72%</td>
<td>65%</td>
<td>75%</td>
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<td>LNG Ships</td>
<td>8</td>
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<td>393</td>
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<tr>
<td>Average LNG Ship Capacity (cubic meters)</td>
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<td>112,000</td>
<td>117,000</td>
<td>121,000</td>
<td>148,000</td>
</tr>
<tr>
<td>Top Shipbuilder Country</td>
<td>France</td>
<td>USA</td>
<td>Japan</td>
<td>South Korea</td>
<td>South Korea</td>
</tr>
<tr>
<td>Key Trends / Advancements During Preceding Decade</td>
<td>Ship Cargo Capacity Increase</td>
<td>Remote Field Development; Oil-Based Pricing</td>
<td>Switch from Steam to Gas Turbines in Liquefaction Facilities</td>
<td>Competing Liquefaction Technologies; Floating Regasification Technology</td>
<td>Unconventional Feedgas; Floating Liquefaction Technology</td>
</tr>
</tbody>
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\(^{74}\) The United States and Libya have nominal installed liquefaction capacity, although they had no exports in 2013.

\(^{75}\) This counts the United States and Puerto Rico as separate countries.