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THE ROLE OF PROJECT FINANCE IN THE NATURAL GAS INDUSTRY: THE ICHTHYS LNG PROJECT

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ABSTRACT

The following case study describes the circumstances that led to the launch of the Ichthys LNG Project in Australia, one of the largest in the natural gas industry. The case illustrates the most significant phases of the project's development, from the initial conception to the final investment decision announced in January 2012 and the consequent financial close, reached after a complex project finance operation. The goal of the case study is to provide a comprehensive analysis of the main features of the financing arranged and the mitigation techniques used to manage the risks associated with massive integrated gas projects.

Keywords:

Project finance, liquefied natural gas, risk analysis, limited recourse

The role of project finance in the natural gas industry:

the Ichthys LNG Project

Introduction

"The Ichthys Final Investment Decision announced today by INPEX and Total signals the start of construction of one the world's largest LNG facilities based on an estimated 40 years of gas and condensate reserves from the Browse Basin offshore Western Australia".[1]

Mr. Kuroda, INPEX chairman - January 13th, 2012

With these words in mind, Mr. Seiya Ito, INPEX President Director in Australia and Head of the Ichthys Project Division, was drinking a cup of sakè and revising again all the details of the construction phase of the project. "Everything is ready for what turns out to be the biggest project of a Japanese company in Australia" – he thought. Few days before, the announcement of the Ichthys' launch generated a lot of enthusiasm within the company and drew the attention of the energy sector. Mr. Ito knew that the progress towards the Final Investment Decision has proven to be challenging but he was also convinced that the Ichthys project represented a main pillar for the company's long-term strategy and would contribute to meet Japan's energy needs and to support the Australian economy, reinforcing important trade ties between the two countries.

INPEX's project was just one of the many approved in Australia in 2012. After a decade of intensive exploration activities and the discovery of more-than-forecasted gas fields, the country was now experiencing a wave of Liquefied Natural Gas (LNG) projects that would allow it to become one the biggest exporters of natural gas around the world.

However, "Ichthys was special!" – Mr. Ito thought, because, among those projects, it was expected to contribute in a greater proportion to Australia's raising exports and to strengthen its position in the global energy scenario.

The Ichthys project, undertaken by a group of sponsors led by INPEX Corporation of Japan and Total SA of France, was considered the largest project ever financed through project financing and regarded as one of the most complex in the LNG industry, due to unprecedented engineering challenges in its development and construction, consisting of both offshore and onshore facilities and covering all the elements of the gas production chain.

[1] http://www.inpex.com.au/media/1114/13_01_2012_final_investment_decision_on_ichthys_lng_project.pdf.

Given its size and complexity, the limited-recourse financing arranged for the project represented a significant milestone not only for the gas sector but also for the international finance markets, making Ichthys a new example to look at in project finance transactions.

"But…Will everything work out as expected?" – Mr Ito asked himself.

THE ASIA-PACIFIC ENERGY MARKET

Australia: A new "energy superpower"

The petroleum and gas industry in Australia experienced a rapid growth in the 90s and 2000s thanks to the government's incentives to support finding and drilling operations. Indeed, Australia could count on a large amount of both conventional and unconventional gas reserves, with the latter mostly located in the Western Australia; estimates of reserves-to-production were believed to be in excess of 250 years and LNG was projected to be the country's fastest growing fuel export over the next two decades.[2] As of January 2009, the identified resources accounted for more than 10 trillion cubic metres, but there was still ample room for the discovery of further offshore gas fields. **Exhibit 1** shows the long-term outlook for Australian gas supply-demand balance.

Total natural gas production was around 50.4 billion cubic metres in 2010,[3] registering a significant increase of unconventional gas production of 7% if compared to 2003. The rise in the production, for uses other than domestic consumption, drove LNG exports and contributed to expand the export production capacity of the country.

The Australian domestic gas market was divided into three main geographically isolated regional markets (**Exhibit 6**): the Eastern Market, the Western Market and the Northern Market, with the first one being the largest consumer of gas within the country. Despite the high consumption levels, its contribution to gas' production accounted for almost 35% of the total gas produced. Conversely, the Western Market's rate of production outpaced the domestic consumption since 1989-90, allowing to raise the country's exports of gas as LNG.

The natural gas market's expansion was favoured by the Australian Government's energy policies aimed at encouraging and promoting further petroleum exploration in Australia's offshore waters.[4] Through the release of the annual Offshore Petroleum Acreage, the AUS

[2] Source: Oil & Gas Financial Journal
[3] Source: International Energy Agency, 2011
[4] Source: Australian Department of Industry, Innovation and Science

Department of Energy used to conduct competitive biddings to grant exploration permits and petroleum rights for a wide range of coastal regions and national offshore areas. The design of an attractive framework for petroleum operations and the transparent regulatory requirements propelled foreign investments, that concurred to further develop the domestic gas market. Among the sedimentary basins of Australia, the Browse Basin, situated on the North-West Coast, was one of the richest in terms of petroleum reserves and one of the most actively explored since 1967. Drilling activities brought to light a significant amount of gas accumulations and oil fields that pushed energy companies to undertake large LNG projects.

A "wave" of LNG projects in Australia

The "golden age" of exploration activities in Australia represented the base for the proliferation of several projects aimed at developing world-scale LNG infrastructures. In 2011, more than 50% of the biggest gas projects worldwide were located in Australia.[5] Between 2009 and 2012, the Australian Government approved numerous upstream and downstream "mega" projects that were key to Australia's future energy outlook. The spreading of such a large number of LNG investments was partially fostered by the rising contribution of gas production to the country's energy mix and exports within the Asia-Pacific region. Along with it, the country suffered from a 16$ billion trade deficit in petroleum products, as a consequence of the reduced levels of oil production since 2000.[6] Hence, negative prospects about the domestic market for crude oil prompted the Government to reconsider the potential for natural gas to become the new country's fuel for its economy. On top of that, the stable political environment, the high level of fiscal stability and the low-risk profile of the country together contributed to further attract investments from foreign companies.

Apart from favourable national conditions, LNG projects benefited from positive macroeconomic trends, mainly characterized by demand shifts towards lighter cleaner energy sources, such as natural gas, and decreasing construction costs that resulted in higher supply. The linkage to oil price sustained the growth in gas demand: by being traded at a discount to crude parity, rising demand led to inter-fuel substitution with the aim of reducing carbon emissions.[7]

[5] Bernstein Research, 2013. "Australia Gas: Riding the Next LNG Wave".
[6] Source: Oil & Gas Financial Journal
[7] Natural gas is considered to be a cleaner fuel source compared to oil, coal and other petroleum products.

In 2009-2010, five large LNG projects obtained the approval of the Australian government and took their final investment decision (Gordon LNG, Pluto LNG, Gorgon, Gladstone LNG and Queensland Curtis projects) and many others were already planned and about to announce their launch, such as the Bonaparte LNG project and Prelude Floating LNG project, operated by Shell. **Exhibit 7** shows the location of the major gas projects in Australia in 2013.

Given the high potential of these projects, LNG production levels were forecasted to increase by 500% to over 100 million tonnes per annum (mtpa) in the next ten years.

The 2011 Fukushima nuclear disaster: What's next for Japan?

Australia was one of the biggest exporters of natural gas to Asian countries, such as Japan and China. Indeed, the lack of significant domestic reserves and the continued strong demand of energy sources made Japan a growing customer of Australian LNG. Given its limited endowment of natural resources, Japan's dependency on LNG increased significantly in the last decade, making it the world's largest LNG importer. As such, the country committed massive investments in regasification facilities: in 2012, Japan could count on the highest regasification capacity in the world, estimated to be at more than 150 million tonnes per annum (mtpa) (**Exhibit 4**).

According to the AUS Department of Industry, Innovation and Science, in 2011, 73% of LNG exports were to Japan, and the projected increase in Australian production capacity could help Japan to further diversify its energy supply,[8] especially after the tremendous nuclear disaster at Fukushima of the same year, caused by a tremendous tsunami and earthquake that resulted in a shutdown of 12,000 MW of electric generating capacity.[9] Reduced availability of nuclear resources led the Government to pursue energy efficiency measures designed to compensate the loss of nuclear fuel with additional natural gas.

The need for Australian LNG became urgent also because of the lack of supply-side alternatives: Indonesia, its major exporter in the last 20 years, experienced a steep decline in gas production, that coupled with increased domestic demand, resulted in calls for gas to be used for domestic supply rather than being exported. In addition, the majority of Japan's long-term purchase contracts with other gas exporting countries were about to expire.

[8] Source: Reserve Bank of Australia, 2011

[9] http://www.jtsi.wa.gov.au/docs/default-source/default-document-library/comparison-of-natural-gas-pricing-mechanisms-of-the-end-user-markets.pdf?sfvrsn=2.

THE ICHTHYS PROJECT: historical background

The major sponsor: INPEX in Australia

INPEX Corporation was Japan's largest integrated energy company and the main national petroleum explorer and producer. Established in 1966 and headquartered in Tokyo, the company played a major role in sustaining the supply of energy to Japan, with natural gas as its core business. Its wide range of operations included more than 71 oil and gas projects around several regions of the world. Among them, Australia was considered to be vital to the company's long-term growth and to reach its goal of meeting Japan's increasing energy needs. To further diversify its business and consolidate its presence within the Asia-Pacific region, INPEX decided to commit huge capital investments mainly destined to enlarge its portfolio of activities in Australia in the latter half of the 80s. After acquiring more than a decade of experience collaborating with both international and domestic Engineering and Procurement (E&P) companies, INPEX established fruitful alliances and profitable partnerships and strengthened its participation in several Australian offshore projects, acting mainly as a joint venture partner.

Mr. Ito, INPEX managing executive officer and member of the corporate board since 2008, believed that Australia was central to accomplish their mission of securing stable gas supply to Japan. "Our involvement in drilling operations within the Australian territory may allow us to reach high production targets" – he said to Mr. Kuroda in one of their meetings. "From being a quiet achiever in Australian business, we need to move on and go one step forward in consolidating our presence in the country!"[10] – he agreed with Mr. Ito, believing that INPEX should have taken advantage of the bids organized by the Australian government to promote petroleum exploration. Indeed, during the years of operations in Australia in the 90s, INPEX's geological studies confirmed the presence of a large amount of gas and petroleum reserves in the Browse Basin.

Following the release of the Annual offshore petroleum acreage in 1997, INPEX participated in an open tender to gain drilling permits for the WA-285-P acreage off Western Australia, that was considered to be the one with the greatest potential for gas resources. In August 1998, the bid culminated with the winning of an exploration license, with INPEX having a 100% participating interest in the block as Operator.

[10] Source: INPEX company website

Despite the lack of financial support from the Japan Nation Oil Corporation[11], INPEX conducted several drilling campaigns, the first of which clearly demonstrated the existence of considerable gas and condensate reserves. The geological success of the initial drilling phase generated great expectations: "There could be even more!", was Mr. Ito's reaction to the promising results obtained after the first finding operations. A thorough analysis and interpretation of seismic data prompted INPEX to organize a second campaign, during which further exploratory wells confirmed the presence of a huge gas and condensate field, subsequently called "Ichthys field"[12].

In 2007, additional wells showed a substantial increase in recoverable reserves: accurate evaluation estimated them at 12,8 trillion cubic feet (Tcf) of gas and 527 million barrels of condensate. These encouraging numbers laid the foundations for the development of a major project in the Asia-Pacific LNG industry and were followed by the grant in 2009 of a Petroleum Retention Lease for WA-37-R block over the gas field and the concession of two production licenses, comprising WA-37-R and WA-51-L blocks.

Three "mega" projects into one: the development concept

During the exploration phase, INPEX realized several studies regarding the development concept of the Ichthys project. Given the location of the gas field, INPEX started to conceive a large LNG infrastructure that would cover the entire production chain of natural gas, from upstream to downstream operations. The first concern regarded the site selection for the onshore LNG plant; after an in-depth analysis and detailed assessment of possible alternatives, Darwin, in the Northern territory, was considered to be the most suitable location.

Offshore installations would, instead, comprise a subsea production system, consisting of a series of production wells[13], a drill center, flow lines and flexible risers. Extracted gas would be, then, directed to a semisubmersible central processing facility (CPF), whose advanced design and engineering best suited with deep sea operations. On board, liquids would be separated from the dried gas and then transferred by pipe to the Floating Production, Storage

[11] Independent Administrative Institution responsible for securing energy supply to Japan.

[12] "Ichthys meant "fish" in ancient Greek and was used to refer to the significant amount of fossilized fish discovered in the proximity of the Western Australia.

[13] According to estimates, the extraction of gas from the offshore field would require 20 wells in the initial construction phase and 30 remaining wells to be drilled once the facilities would become operative. Drilling cost was estimated at $90m per offshore well.

and Offloading facility (FPSO) for further processing. After a treatment phase, condensate would be collected in storage tanks and moved to off-take vessels for shipment.

The remaining gas would be transferred to the Darwin LNG plant through a 900km-pipeline. Onshore treatment would convert dried gas into LNG and liquefied petroleum gases (LPGs) and be operated by two large LNG processing trains, with an expected production capacity of 8.4 mtpa of LNG and 1.6 mtpa of LPGs, together with 100,000 barrels of condensate per day at peak. Having more than LNG train would, indeed, provide greater production flexibility and increase security of output. Onshore facilities would also include a module offloading facility tasked to receive gas-processing modules, a navigation channel, a turning basin and a berthing pocket for the product tankers. **Exhibit 10** provides an illustrative representation of the project's development concept.

THE ROAD TO THE FID

The FEED phase and the contracting strategy

The project planning was supported by Front-End Engineering Design (FEED) works, that were performed for both offshore and onshore installations from January 2009 to July 2011 and were contracted to AMEC and JKC Joint Venture (JKC JV)[14] respectively. The main goal of the FEED was to obtain reasonable and transparent estimates of the project's costs and a forecast of the potential technical requirements of each construction package, identifying, at the same time, all the implied risks. The FEED allowed the sponsors to design the contractual framework to be used in the following Engineering, Procurement and Construction (EPC) phase: indeed, having defined draft EPC contract terms and agreed negotiating guidelines was necessary to solicit bids from interested contractors and organize the subsequent Invitations to Tender (ITT). The FEED phase was also vital as it supported INPEX to define a feasible execution schedule and perform a preliminary bankability analysis of the project.

During this phase, INPEX elaborated a specific contracting strategy to be adopted for the EPC phase upon making the Final Investment Decision and intended to ensure reliable EPC contracts for the construction operations: this strategy focused on the issuance of open book tenders[15] and on the limited use of reimbursable elements in EPC agreements, as they could favour

[14] A joint venture created by three different construction companies, JCG Corporation, KBR Inc. and Chiyoda Corporation.
[15] Public tenders aimed to encourage more bidders to join the competition.

potential cost escalations.[16] On the contrary, INPEX maximised lump-sum contracts, that could help to reduce uncertainties related to the project costs. Following this approach, INPEX was able to conclude the negotiations and finalise the major EPC contracts: before the FID, several contracts were awarded to creditworthy and experienced construction companies for onshore and offshore facilities and for the pipeline's development; through a complex scheme of contractual arrangements, the sponsors were able to better manage costs and delivery schedules and to efficiently allocate risks among all project participants. **Exhibit 17** shows the main construction companies contracted for the EPC phase.

At project completion, upstream and downstream operations and maintenance would be managed by INPEX Operations Australia Pty Ltd., a wholly-owned subsidiary of INPEX. According to the contractual terms of the O&M contract, the operating company (OC) would receive reimbursement of the direct costs incurred that would be recharged to the project sponsors. During this phase, the OC would subcontract third-parties for the provision of specific support and engineering services. Major replacement expenditures were expected every 15 years, as it was the average period after which gas pipelines and storage tanks were subject to extraordinary maintenance and potential refurbishments. To operate on site and offshore installations, approximately a total of 340 workers would be required.

Securing LNG contracts

The high capital commitment of the project forced INPEX to identify potential LNG buyers and secure gas sales for the entire production phase. Having established sales agreements was, in fact, essential to make Ichthys financially viable and repay future debt financing.

"We need to have reliable and stable revenues from LNG production", Mr. Ito told Mr. Jiro Okada, Vice President of the Ichthys Project Division, while evaluating the terms of negotiations with some interested gas companies. "Yes, contracts have to be arranged on a long-term basis." Indeed, LNG market in the Asia-Pacific region was characterized by the dominance of 15 to 20 years sales agreements, with a very small percentage of shorter term arrangements.[17] As this was the norm, INPEX was able to successfully conclude the sale of the entire LNG volume by legally establishing Sales and Purchase Agreements (SPAs) with several energy

[16] Indeed, unpredictability of costs could result in expenditure overruns.

[17] Despite the reduced use of shorter-term agreements, the Asian market was experiencing a relatively modest shift towards LNG sales to spot markets. Following this trend, INPEX did not exclude to sell part of its LNG production in the spot market upon expiration of the long-term contracts.

companies, with a contract duration of 15 years from 2017 when production would commence. SPAs' details are shown in **Exhibit 16**.

Given the absence of a defined natural gas market and associated pricing mechanism, all sales agreements were structured in the form of oil-indexed contracts[18], linked to the Japan Crude Cocktail (JCC) reference price index[19] and contained "take or pay" clauses[20], that would ensure a constant revenue stream. Contract terms indicated that LNG would be delivered in 'FOB' shipping.[21] However, negotiated prices were not disclosed.

"High oil prices will allow us to strongly support the project cash flows and its financing", was Mr. Okada's belief by looking at the actual oil import price in Japan of $115/barrel.[22] "The actual forecasts point to increasing extraction and liquefaction costs (**Exhibit 34**), but with oil prices at this level, I am confident that we would be able to easily sustain all project expenditures and obtain significant returns" – Mr. Ito added. The signing of these agreements was considered to be a major step in providing steady gas supply to Japan, as 70% of LNG production would be delivered to the Asian country, while guaranteeing, at the same time, stable LNG operations.

Furthermore, INPEX planned to sell the full LPG volume and condensate in the spot markets of Far East and Southeast countries, where the demand for these products was projected to gradually increase, with a growth above the global average. These favourable trends, coupled with the high levels of production from Ichthys, were expected to positively contribute to the project economics.

INPEX SIGNS THE FID

"The largest, ever"

On January 12th, 2012 Mr. Kuroda announced the final investment decision for the Ichthys project, with first production to be expected in 2016. This achievement represented a major milestone for the LNG sector and the largest investment of a Japanese company in Australia. With an estimated life of 40 years and a forecasted capital cost of $34 billion, the Ichthys project

[18] The oil-indexation mechanism is shown in **Exhibit 15**.
[19] JCC is the weighted average monthly price of a basket of various crude oils imported into Japan. JCC usually moves in line with other global crude benchmarks.
[20] "Take-or-pay" arrangements require the buyers either to take the consignment of the goods contracted or to pay the supplier a penalty if they don't do so.
[21] FOB shipping requires the buyer to incur all the costs related to the shipment of LNG.
[22] Source: OECD database

was the result of a beneficial partnership between INPEX and Total SA of France, which joined the project in 2006 through an initial 24% participating interest, then increased to 30% in July 2012. For Total, Ichthys had the potential to provide "a gateway to Asian gas markets".[23] Its relevant experience in the development of world-scale LNG infrastructures and the high credit rating of both companies (AA) contributed to make Ichthys possible. The sponsor group included also some junior LNG offtakers, which had the 4% remaining interest in the project.

The FID arrived just after receiving the environmental approvals from the Australian Government, and the grant of production and pipeline licenses. Australia would benefit a lot from Ichthys: estimates pointed to more than $195 billion in exports, $73 billion in taxation revenue and to a $190 billion increase in GDP. Moreover, Ichthys would provide 10% of Japan's imports, contributing to fill the 'energy gap' in the next decades.

Besides its strategic importance for both Japan's energy supply and Australia's export capacity, the launch of Ichthys established several records: it was the first LNG project to be operated by a Japanese company; despite the global financial crisis, it secured the largest amount of project financing ever arranged for an energy project until then, and would imply the use of the most sophisticated technology for the construction of the biggest offshore facilities ever used in LNG projects, including the largest pipeline in the southern hemisphere.

The project structure: a unique Special Purpose Vehicle

As in every project finance transaction, the establishment of a special purpose vehicle (SPV) was necessary. However, the sponsors designed a peculiar commercial structure for the SPV: the ownership of the project, comprising onshore and offshore assets, was split between two different entities: an incorporated SPV (Ichthys LNG Pty Ltd.) and an unincorporated joint venture[24] (UPV) were created for downstream and upstream facilities respectively, with each participant having the same share in both of them so as to ensure a consistent sponsorship along the project value chain and, therefore, a perfect alignment of interests in all the phases of Ichthys. The downstream SPV was established as the gas marketing entity, being responsible for liquefaction and LNG sales, including storage and shipping and acted as a borrower for the debt funds arranged through project financing. Cash available to it would be used for debt repayment and to fund the debt service reserve account. In addition, it could lend portions of

[23] Source: TOTAL company website

[24] The establishment of an unincorporated joint venture for upstream operations and of an incorporated downstream entity for marketing operations is a common trait for large integrated petroleum projects.

debt to upstream participants, in proportion to their stake in the project. UJV participants were required to fund their contributions in accordance with agreed "cash calling" mechanisms.

UJV partners did not provide guarantees for the project-finance debt, but could still benefit from a cash flow waterfall mechanism that ensured the same availability of cash to finance onshore and offshore operations. Indeed, the account structure established by the sponsors guaranteed that cash could be easily transferred between the upstream and downstream entities. By splitting the ownership of the project assets, several advantages could be identified: indeed, the UPV structure guaranteed superior flexibility in marketing operations for condensate sales since it would allow each UJV partner to book a part of the condensate reserves as its assets and market the finished petroleum products to existing clients.[25] Moreover, UJV structures benefited from fiscal advantages, as they did not have to comply with the tax obligations imposed on incorporated companies. On the other hand, the creation of an incorporated SPV provided greater possibilities for a future expansion of the onshore installations and facilitated the negotiations with LNG buyers.

Given these features, the gas produced by upstream facilities would be sold by each UJV member to the downstream project company that, in turn, would treat and process it to sell LNG to third-party offtakers according to the long-term sales agreements already signed. Revenues from both upstream participants and the downstream company were required to be paid into secured accounts.

The Financing

The financing of the Ichthys project was a major achievement in project finance markets: after a year of efforts and negotiations, the sponsors were able to close a US$20 billion loan package in December 2012 through a complex financial arrangement comprising limited-recourse debt from export credit agencies and several commercial banks, along with upfront cash. "The sound financials of Ichthys (**Exhibit 29**) and the production slate, with three products (LNG, LPG and condensate) from one investment helped us to obtain such a large external financing and to conclude an efficient transaction" – was Mr. Ito's comment after the successful financial close. Besides that, the location of the project, that lowered the risk profile of the deal, and the good credit rating of the LNG buyers all contributed to make the project bankable and able to meet lenders' cash coverage requirements (**Exhibit 32**). Mizuho Corporate Bank and Crédit Agricole

[25] Source: Reuters, Project Finance international, 2016

Corporate & Investment Bank were appointed as lead arrangers for the overall financing process.

The debt financing, all in form of senior sponsor credit facilities, broke down into:

- $5.8 billion in direct Export Credit Agencies (ECAs) loans, with Japan Bank for International Cooperation (JBIC)[26] being the largest lender;
- $5.4 billion in ECA-covered loans;
- $4.8 billion in uncovered commercial bank debts from a syndicate of 24 lenders, including Japanese, Australian and other international commercial banks;
- $4 billion in senior shareholders loans, provided either by commercial lenders and guaranteed by sponsors or provided directly by the project sponsors.[27]

All loan agreements were in the same common loan facility: tenor was set at 16 years, with first drawdown in February 2013, while, in terms of pricing, ECA-covered and direct loans would pay the same margin of 220bps over LIBOR 6M with a fee of 200 bps. Commercial debt was priced at 240bps over LIBOR 6M throughout the entire construction phase and projected to rise to 375bps when production would start, with a fee in the mid-200 bps range to pay during construction.[28] The sponsor senior loans (**Exhibit 22**) mirrored the financing terms of the commercial portion of the debt. The limited recourse nature of the debt allowed the lenders to have a relative margin of safety over the loans extended, with 25% of the principal repayment being collateralized.

With loans totalling to $20, the remaining amount implied an equity proportion of 41,2% (**Exhibit 20**) of the overall capital structure, that was considered unusually large in project finance transactions, since market trends pointed to higher debt-to-equity ratios for LNG projects.

In addition, sponsors had the obligation to meet certain equity requirements: besides providing part of the equity contributions through "early revenues" generated by the development, they had to inject agreed amounts of equity, funded via subordinated debt.

Despite the limited-recourse financing, lenders could benefit from a customary debt service until project completion and exert a high level of control on the project operations as they could

[26] JBIC is Japanese policy-based financial institution and export credit agency, that provides lending and guarantees in order to contribute to enhance the competitiveness of Japanese industries and secure important resources for the national economy's development. Source: JBIC web site

[27] These loan facilities did not benefit from the sponsors' debit service undertaking.

[28] Source: IJ Global, Project Finance & Infrastructure Journal

have access to the entire expected cash flow and assets of the project, both upstream and downstream, following the "one project – one cashflow" principle promoted by the sponsors, notwithstanding the split of the ownership.

Sponsor support arrangements included also completion guarantees to lenders, debt service undertakings and contingent funding commitments.

The role of the ECAs

ECAs have been essential in securing a large financing and were instrumental to debt close. Their involvement in the project ensured additional debt capacity, with better financing terms, longer tenor and flexible schedule repayment. Indeed, ECA-backing allowed commercial banks to lend on a longer-term basis and to reduce the amount of capital that they were required to set aside to extend the loans and provide credit to the borrower. Through ECA guarantees, they were taking the risk of the ECA's government and not that of the project. This, in turn, resulted in cheaper costs of financing and more competitive pricing. **Exhibit 21** shows a typical ECA financing operation.

From ECAs perspective, Ichthys was of strategic importance: the relevance of the project for Japan's future energy scenario enabled JBCI to grant the largest ever direct loan to a single project. The need for LNG pushed also other Japanese ECAs and insurance companies to provide further commercial bank cover, among whom there was Nippon Export and Investment Insurance (NEXI). However, increasing gas demand was not the only reason for ECAs' participation: given the involvement of Korean companies as subcontractors for the projects, Korea Trade Insurance Corporation and the Export-Import Bank of Korea provided substantial direct lending and commercial and political risk coverage as well.

Insurance Arrangements

The complexity and size of Ichthys required its sponsors to accurately arrange insurance contracts for all the phases of the project so as to ensure an appropriate placement of capacity risk. During the construction and operations phase, there was all-risk coverage for property damage, third-party liabilities for both offshore and onshore facilities, including force majeure insurance and protection against any operators' extra expense and marine operations' risks. Insurance arrangements also comprised an Advance Loss of Profits insurance, covering potential income losses resulting from delays due to construction risks. Annual insurance fees would amount to roughly $1 million.

Conclusion

"This is a new beginning for INPEX in Australia!" – was everyone's belief within the company. Construction at Darwin was about to start very soon and contractors were planning to begin operations in the following weeks. Mr. Ito was optimistic about Ichthys' future development: it was expected to be one the best performing projects in the Australian LNG sector, with potential for further growth. The lending institutions' willingness to provide financing to Ichthys showed that a project with solid financials and appropriate economic support features could attract considerable funding.

However, raising concerns were made with respect to possible cost overruns and delays in the delivery of Ichthys, a common trait for projects of this size in the Australian gas industry, where problems in manufacturing processes and contract disputes have usually generated escalating costs and recent appreciations of the local currency against the US dollar have caused some projects' costs to rise since 2009.[29]

On the other hand, profitability of the project highly depended on oil market trends and volatility: rising crude price could sustain strong and massive cash flows, but the potential for significant price fluctuations could negatively affect Ichthys' economics.

Although there was little scepticism and some analysts called for more prudent valuations, Ichthys was ready to change the Australian LNG landscape.

But weren't all these expectations over-optimistic?

[29] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/02/NG-83.pdf.