Latest developments in LNG export capabilities of the United States, Canada, Australia, and Russia

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Introduction

The global energy landscape has experienced an incredible shift this past year. Last year, signs of a global crude oil supply glut began to weaken crude oil prices. This was exacerbated in the second half of last year when the Organization of the Petroleum Exporting Countries (OPEC) made a decision to uphold high oil production in the region. It is suspected they maintained high supply to lower the price of oil in an attempt to protect market share and squeeze out high cost producers.[i] This has had wide-reaching repercussions on economies and energy companies worldwide. It has forced reductions in capital expenditures and modifications to future strategies across several sectors. The decline in oil price has had varying consequences on global liquefied natural gas (LNG) development especially in resource rich economies such as the United States, Canada, Australia, and Russia that are in the process of developing and increasing export capacity.

LNG trade has increased substantially over the past decade. Since 2005, LNG exports have increased 70% with supply capacity set to increase another 40% in the next five years.[1] Imports into Asia alone have grown 95% in a decade, increasing Asia's share of total global imports from 65% in 2005 to 75% in 2014.[2] The burgeoning LNG demand in Asia has led current and potential LNG exporters to invest significant capital across multiple export infrastructure projects. When crude oil price remained over $100/bbl, project economics were favorable and LNG infrastructure development was worthwhile. The oil-linked prices of LNG flowing into Asia resulted in attractive arbitrage opportunities for new developers; however, when oil prices plummeted it diminished the arbitrage opportunity and the allure of several high cost liquefaction projects. Not only has the oil price decline dampened LNG export development appeal, but the International Energy Agency (IEA) forecasts global natural gas demand growth to weaken from a decade of 2.3% growth per annum to 2% per annum until 2020.[3] The recent oil price collapse and the reduced natural gas demand forecasts cause uncertainties for the future of LNG. For natural gas importers, such as Japan, the next decade will be one of determining the best new LNG supply opportunities. The United States, Canada, Australia, and Russia are all contenders in becoming new LNG supply sources but face new challenges in a low oil price environment and a weakened demand forecast. This report will examine the challenges and opportunities faced in LNG export development in the United States, Canada, Australia, and Russia.

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i It is presumed high cost U.S. shale production was a target.

1. Current Natural Gas Sectors:

Table 1.0 - Natural Gas Reserves

Country	Proved Natural Gas Reserves Tcf (BP)	% of World	Estimated Technically Recoverable Shale Gas Resources Tcf (EIA)	Rank in World
Russia	**1153**	**17.4%**	**285**	**9**
U.S.	**345**	**5.2%**	**665**	**4**
Australia	**132**	**2.0%**	**437**	**7**
Canada	**72**	**1.0%**	**573**	**5**

Source: BP, "BP Statistical Review of World Energy June 2015" & EIA "Technically Recoverable Shale Oil and Shale Gas Resources", 2013

The United States produces 21.4% and consumes 22.7% of the world's total natural gas, making it both the largest producer and consumer of natural gas in the world.[4] Production has been rapidly increasing, with total dry natural gas production growing 33% since 2007.[5] The increase is enabled by the advancement in shale gas extraction technologies. Shale gas production alone has grown sevenfold since 2007 and has advanced from contributing to 9% of total production to over 50% presently.[6] Production growth is expected to continue as the U.S. Energy Information Administration (EIA) forecasts growth of 10% from 2015 to 2020 and another 22% from 2020-2040.[7] Currently in the United States, there are five LNG export plants[ii] under construction with total liquefaction capacity of 53.4 million tonnes per annum (mtpa) and will place the United States as the third largest LNG exporter by 2020. The projects already under construction will be developed regardless of the oil price decline. The United States has traditionally been a net importer of gas; however, due to increased production, decreased imports, and the development of LNG export infrastructure, the country is forecasted to become a net exporter of gas by 2017.[8]

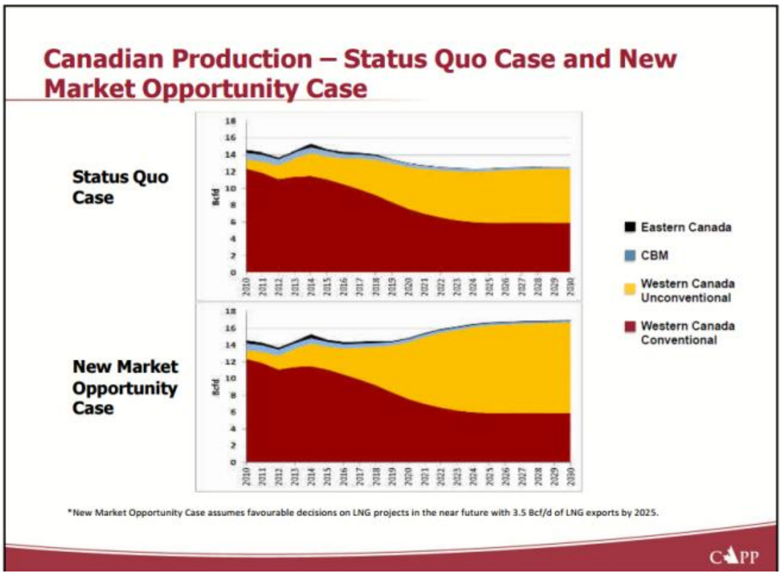
Canada's natural gas production has been declining an average of 2% per year since 2005, but grew 4% from 2013 to 2014 due to rising shale gas production.[9] Canada is one of the four countries[iii] in the world that produces commercial volumes of shale gas. In May of

[ii] Four terminals in the Gulf of Mexico and one on the Northeast Coast in Maryland

[iii] The four countries producing commercial volumes of Shale Gas and Tight Oil is the United States, Canada, China, and Argentina

2014 shale gas production had doubled since 2001.[10] Many Shale resources are still largely undeveloped leaving great potential for further production. Canada solely relies on the U.S. market for gas exports and over the past decade has exported around 50% of natural gas produced per year to the United States.[11] Increased U.S. production has directly displaced Canadian gas and since 2005, Canada's natural gas exports have decreased over 25% and consequently production volumes have decreased by 13%.[12] As the United States becomes increasingly independent, Canada must diversify its energy markets and is focusing on LNG to do so. Currently, on the West Coast of Canada there are several proposed LNG terminals at various stages of the approval process, but no projects have taken a Final Investment Decision (FID).[iv] Canadian projects are greenfield therefore require significant investments especially due to the remoteness and the need for new pipeline systems through difficult terrain. Since the oil price collapsed, the viability of the capital intensive Canadian LNG infrastructure is being questioned; therefore optimism of completed development before 2020 is weakening. If LNG development does not advance it will have diminishing effects on production as seen in Figure 1.0.

<u>Figure 1.0 - Canadian Production Forecasts</u>



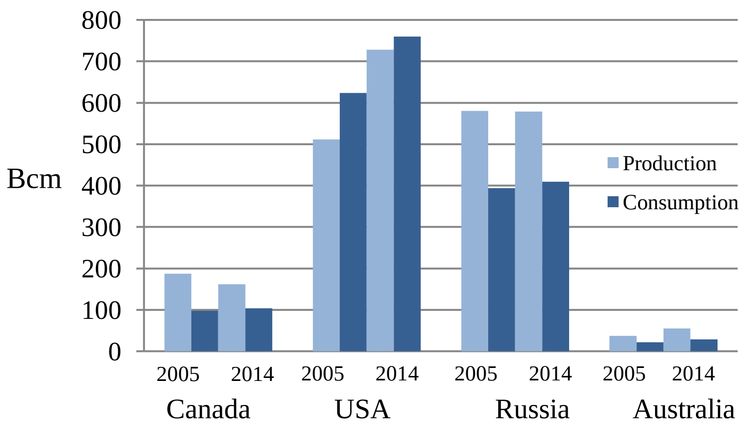
Source: Canadian Association of Petroleum Producers (CAPP), "Natural Gas Production Forecast", 2015

Australia's natural gas sector has experienced phenomenal growth over the past decade. Production has grown 49% since 2005 and LNG exports have increased 107% from

[iv] Petronas led Pacific Northwest LNG has taken a conditional FID pending federal environmental approval due in September 2015

11.411 mtpa in 2005 to 23.6 mtpa in 2014.[13] Australia's shale gas remains largely undeveloped, but Australia is a top producer of coal seam gas (CSG, or CBM (coalbed methane)) and has already been home to the first CBM-based liquefaction facilities. In 2014 Australia exported 57% of produced natural gas as LNG, with about 80% of exports flowing into Japan.[14] Australia has an advantage over other new supply sources as LNG development is well under way and Australia is set to become the world's largest LNG exporter by 2020. Australia's first plant was in 1989, the North West Shelf, with initial capacity of 7.5 mtpa.[v] Three more plants have become operational since and currently there are six projects under construction. If construction is completed on schedule, LNG liquefaction capacity is expected to grow to 85 mtpa by 2020.[15]

Figure 1.1 - Natural Gas Production vs Consumption in 2005 and 2014



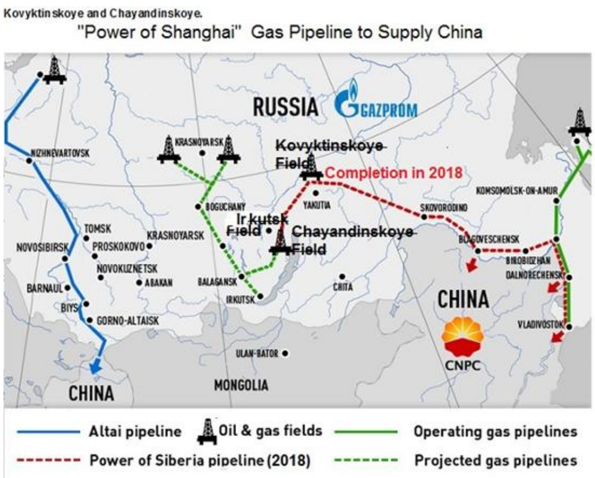
Source: BP, "BP Statistical Review of World Energy 2015", 2015

Russia holds 17.4% of the world's natural gas reserves which is the second largest amount in the world.[16] Russian production and exports have decreased in the past year due to both the oil and gas price decline's effect on the economy and state-owned energy giant Gazprom as well as decreased demand from Europe and specifically Ukraine. Russia's share in Ukraine's gas market was 74% in 2014 and has dropped to 37% in the first half of 2015.[17] In 2014, 93% of exports were via pipeline into Europe and the Former Soviet Union; however, pipeline exports into Europe from 2013 to 2014 have fallen by 9% from 162.4 Bcm to 147.7 Bcm and exports from Russia into the Former Soviet Union have fallen by 19% from 48.9 Bcm to 39.8 Bcm.[18] Russian natural gas production has remained fairly flat since 2005, but has fallen 4% from 2013 to 2014 and Gazprom, which produces around 75% of Russia' s gas, has forecasted another drop of 6.7% in 2015 production.[19] LNG accounts for the remaining 7% of

[v] Has since increased to 16.5mtpa.

exports. Russia’s first and only LNG plant, the Sakhalin 2, became operational in 2009 with a capacity of 9.6 mtpa. The plant is located on the East Coast of Russia and on average 80% of exported LNG flows into Japan.[20] Russia has proposed three additional LNG plans with the Yamal LNG project looking the most optimistic at this time. Imposed sanctions have limited Russia’s ability to access financing from the West that is required to fund LNG development, therefore diminishing optimism of LNG development, besides Yamal LNG, before 2020. Additionally, strained geopolitical relations with the West and the forthcoming increase of gas supply into Europe from North America have shifted Russia’s focus to increasing pipeline capacity into China. Two major proposed pipelines in agreement with China are the Power of Siberia and Altai pipelines seen in Figure 1.2.[vi]

<u>Figure 1.2 - Proposed Russian Pipelines into China</u>



Source: Gazprom, 2015

2. Effects of Crude Oil Price Decline on GDP and economic growth

As the largest energy consumer in the world, the United States economy was impacted less by the oil price decline as the low energy prices led to increased domestic energy consumption through energy savings. The United States economy is diverse therefore decreases in one sector can spur growth in another sector; therefore although the oil price has had some declining effects on the stock market, the energy cost savings allow consumers to spend elsewhere and help offset negative effects of the oil price decline.

Canada suffered from the decline in oil price as the oil and gas industries contribute to 7.5% of total GDP, 29% of merchandise exports, and 21% of Canadian capital expenditures.[21]

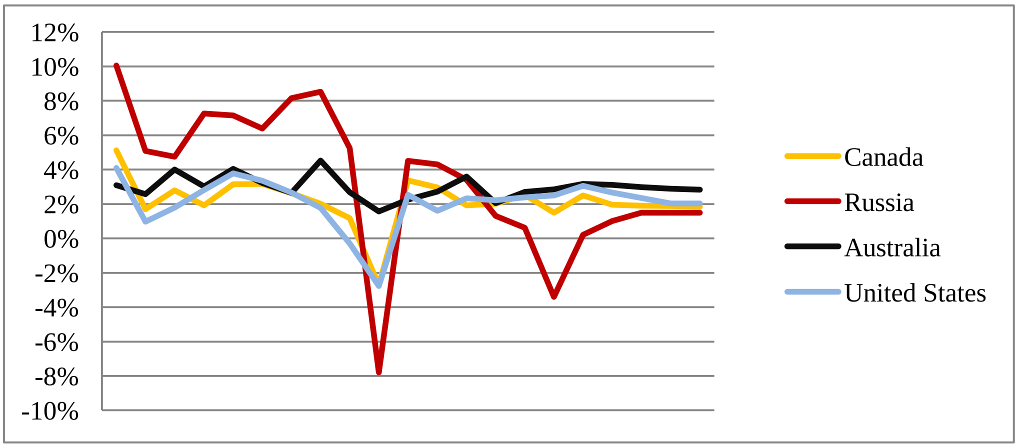
[vi] Power of Siberia has a capacity of 61 Bcm/yr and China has signed a 30 year contract for supplies of 38 Bcm/yr and the Altai has a planned capacity of 30 Bcm/yr

The Canadian dollar has depreciated 18% from CAD.94/USD in July 2014 to CAD.77/USD in July of 2015, which has helped only slightly to alleviate the hit on the energy sector in terms of exports and energy consumption. It is estimated that over 40,000 indirect and direct jobs in the energy sector in Canada, a majority in Alberta, have been lost.[22] The outlook for 2015 growth has weakened as GDP forecasts by IMF in June 2015 were revised downwards .7% from April 2015 forecasts to 1.5% with 2016 GDP growth remaining at 2.1%.

Australia's economy is more diversified and less reliant on oil and gas revenues as it only accounts for 2% of GDP and 11.3% of export revenue.[23] The Australian dollar depreciated over 20% since mid-2014 from AUD.93/USD to AUD.72/USD in July 2015. This was a relief for Australia as the inflated currency rate was hindering domestic industries including LNG development.

Russia was the most impacted by the oil price decline as Russia heavily relies on the oil and gas sector as an economic driver. Oil and gas exports made up 68% of total exports revenues in 2013 and oil and gas activities made up roughly 50% of Russia's federal budget revenues.[24] Geopolitical tensions and Western sanctions further economic woes and limited investments. The ruble has depreciated over 35% since mid-2014 year and GDP is forecasted to decline 3.4% in 2015 and grow minimally at 0.2% in 2016.[25] Gazprom accounted for 9% of Russian budget revenues in 2014 and it is predicted that the drop in gas prices and drop in production will lead to a 27% decrease in Gazprom's revenue.[26]

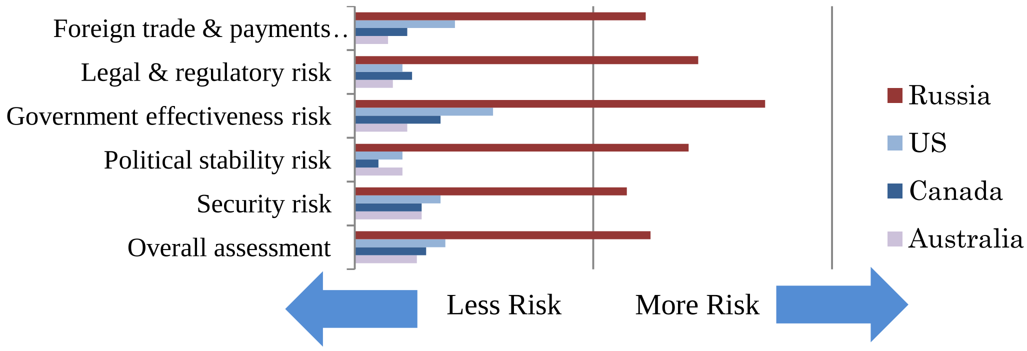
Figure 2.0 - Annual GDP Growth Rates



Source: IMF, United States, Canada, Australia, and Russia GDP Data, 2015

3. Political Environments:

Figure 3.0 - Risk Ratings



Source: The Economist's Intelligence Unit, ViewsWire, "Risk Briefing-Australia", "Risk Briefing- United States of America"," Risk Briefing- Russia", "Risk Briefing- Canada", 2015

As seen in Figure 3.0, Canada and Australia are both viewed globally as politically stable countries with low risk when it comes to foreign trade and government effectiveness. Canadian Federal elections will take place in October 2015 which could see a change in political parties and could have implications on the energy sector. The United States has a stable political environment, but as seen in Figure 3.0, holds slightly more risk than Canada and Australia in terms of foreign trade and government effectiveness. The US will also be having a Presidential election in November of 2016 which could have implications on the energy sector and economy therefore it will be important to follow the progress in these elections. The United States, Canada, and Australia all have a strong legal system and overall are have low political risk.

Russia, however, holds a considerable amount of risk and instability especially due to the recent Russian invasion of the Ukraine. The United States together with the European Union (EU) and other international leaders have imposed sanctions to directly affect Russia's energy industry. These targeted sanctions limit financing to six of Russia's largest banks and four energy companies, and prohibit any support from the international partners for exploration and production of Deepwater, Arctic offshore, or shale projects in Russia.[27] Recently in July 2015, the U.S. has increased sanctions to 15 more companies including affiliates of Rosneft and the major bank Vnesheconombank, which is increasing tensions between the U.S. and Russia. Russian companies have had to find alternate solutions to work around sanctions. One such alternative was a recent agreement between Novatek and China National Petroleum Corporation (CNPC) to receive nearly USD 20 billion for the development of the Yamal LNG project as

China is not included in the sanctioning countries.[vii] Additionally, international oil companies such as BP and Shell have pledged to stay committed to maintaining business relationships with Russia while abiding by the rules of the imposed sanctions.[viii] The BRICS New Development Bank that has been launched this year as well as increased investments from Saudi Arabia will also ease Russian financial woes.[ix]

4. LNG Regulatory Environments:

4.1 United States

The United States has experienced longer approval times than expected by the industry with both environmental and export authorizations for LNG plants; although authorities have made policy improvements at the request of the industry. Two of the major approvals that must be obtained are the Environmental Assessment or Environmental Impact Statement from the Federal Energy Regulatory Commission (FERC) and two separate export licenses from the Department of Energy (DOE), one for Free Trade Agreement (FTA) countries and one for non-FTA countries.[x] Sabine pass LNG was approved by FERC in April of 2012, but the other four projects were not approved until the end of 2014. Projects still continue to face hurdles with FERC; for example, very recently, Veresen led Jordan Cove LNG, a U.S. West Coast project, was notified by FERC that the environmental review would be delayed another six months to mid-2016 for unexpected reasons. Authorities claim that environmental assessment delays are a result of an increased work load and complexity in consolidating several government agency assessments.[28] It is likely that environmental assessments for greenfield projects will continue to face hurdles, but additional liquefaction capacity to preexisting infrastructure should be permitted more easily.

Acquiring an export license for non-FTA countries has also experienced longer times in approval by the DOE. Three recent projects waited an average of 100 days for export approval even after all environmental certificates were obtained. Projects were assessed in order that they had applied rather than commercially mature projects before early stage projects. The DOE recognized this was ineffective as 24 proposals were queued, including many that would

[vii] The sanctions had delayed project financing of the 16.5 mtpa Yamal LNG project which needs USD 20 billion in loans over the next 15 years in order to produce the first round of gas at 5.5 mtpa by 2017 and reach total capacity of 16.5 mtpa by 2021

[viii] Shell has recently signed an agreement with Gazprom to develop a third train (5mtpa) at the Sakhalin 2 plant and Gazprom has also signed a proposed agreement with Shell, Germany's E.ON and Austria's OMV to double the capacity of the Nord Stream Pipeline into Europe. The Nord Stream 2 will have 86% of the same route as Nord Stream 1

[ix] BRICS stands for Brazil, Russia, India, China, and South Africa

[x] Offshore must receive environmental approval from the Maritime Administration (MARAD) and the United States Coast Guard (USCG)

not near fruition.[29] Therefore, the DOE improved this by changing the assessment schedule to prioritizing the assessment of commercially mature projects and more recently enacted legislation that the DOE must give their decision within 45-days of environmental approval.

Another concern is the effects that increased fracking regulation will have on future shale gas production. New federal legislation includes increased government inspection and requires that companies must publicly disclose the chemicals used in fracking. As only a minor amount of production occurs on federal land this will not affect production directly, but it could become a standard for state legislatures who are in the process of forming state fracking laws therefore could lead to increased regulatory burdens and production costs of shale gas.[30]

4.2 Canada

Canada is facing considerable regulatory burdens that have led to delays and additional costs for project developers. Export licenses are granted by the Canadian National Energy Board (NEB) and the approval rate has been high; however, environmental approvals have seen less success. Canadian West Coast projects must receive both the British Columbia (B.C.) Environmental Assessment Certificate (BCEAA) and the Canadian Environmental Assessment Act (CEAA) Decision Statement. Only two projects out of the proposed 19 on the West Coast have all necessary environmental certifications; however the approved projects don't foresee FID's until 2016.[xi] Similar to the United States the slow progress in environmental approval can be attributed somewhat to the sudden increase in applications leading to strained regulatory resources, but process improvements are expected. Canadian projects do not only experience lengthy and thorough environmental approvals, but project developers must dedicate resources and time engaging with First Nation communities.[xii] Negotiations are ongoing and thorough with the First Nations who inhabit most of the land in B.C. where developers are hoping to build plants and pipelines. Many energy companies have developed strong relations with First Nations groups through revenue agreements, employment opportunities, and community enhancement. There has been an increase in First Nation's support of LNG development with the creation of groups such as the B.C. First Nations-LNG alliance which is a group created by First Nations that support the industry. Further, 28 First Nations groups have signed revenue sharing agreements with the B.C. government which aids in reducing financial investment risk for the developers and exhibits additional support.[31] Negotiations are not always successful as exemplified by the Petronas led Pacific Northwest LNG project's offer being rejected by the Lax Kw'alaams First Nation Group. The Lax

[xi] Shell led LNG Canada and Chevron/Woodside Kitimat LNG have both received all necessary certification

[xii] First Nations refers to the aboriginal people of Canada who have historical connections to the land needed for LNG infrastructure. They must be consulted before development may take place.

Kw'alaams rejected a USD 1 billion benefit package for the development of the export project on their land due to the potential environmental impacts to a salmon habitat. Energy companies and developers must take time to cooperate with First Nation's groups to ensure long lasting relationships to ease any future risk.

Both the provincial and federal governments have made efforts to alleviate development delays as they see the importance and potential in the LNG industry for Canada. Recently the B.C. Government has lowered the LNG income tax and the Federal government has raised the capital cost allowance to lower tax payments and aid projects in recovering capital costs more rapidly.[xiii] The B.C. government also passed legislature, the Liquefied Natural Gas Agreement, which allows the B.C. government to sign project agreements that lock in current provincial taxes and royalties to protect them against any unfavorable future changes in LNG income tax, carbon tax, or natural gas tax credits.[32]

4.3 Australia

Australia is facing increasing regulatory burdens as increases in domestic gas prices and availability of gas supply has caused concern from regulatory authorities. The first signs of increased domestic gas prices appeared in 2004 when initial export contracts were first renegotiated with North West Shelf LNG (Western Australia). This caused domestic prices to jump from USD 2.23/mmbtu to USD3.95-6.05/mmbtu in a year as they became tied with international gas prices.[33] As a result, the Western Australian state government implemented a domestic gas reservation policy of 15% for the LNG projects. Gas reservation policies in the West are agreed on a case-by-case basis and if LNG developers are not satisfied they may resort to project relocation.[34]

In Eastern Australia, where around 50% of the Australian population lives, there is increasing concern that there could be domestic supply issues as three new CSG LNG projects come online in 2015-2016.[xiv] Not only will the increase in demand diminish domestic supply and put upwards pressure on price, but the viability of CSG production is being questioned as reserves are proving harder to develop and becoming increasingly expensive. The East Coast projects initially believed they had adequate reserves to supply their LNG projects, but have all had to sign agreements to purchase gas supplies outside of the projects production.[35] The concern of supply as well as increasing concern of environmental effects of CSG production has caused increasing regulatory burden. A new federal approval is required for CSG

[xiii] LNG income tax was lowered to 1.5% before recovery of capital investment and 3.5% afterwards. The capital cost allowance was raised 22% to a total of 30% for liquefaction equipment and rose to 10% for non-residential facilities used for liquefaction.

[xiv] Queensland Curtis LNG July 2015 (8.5mtpa), Australia Pacific LNG Mid 2015 (9mtpa), & End Q3 2015Gladstone LNG (7.8mtpa)

developments (EPBC Act) that adds an additional USD360-730 million in costs and also exclusion zones for CSG production have been created which has caused some companies to reconsider exploration and production plans.[36] To better serve the market the Eastern state Queensland's Department of Natural Resources and Mines is developing a "Queensland Gas Supply and Demand Action Plan" that will be released in December of 2015. The plan will include ways to find solutions without market interventions, help to facilitate policy issues, and demonstrate support for the sector, among other things.[37]

4.4 Russia

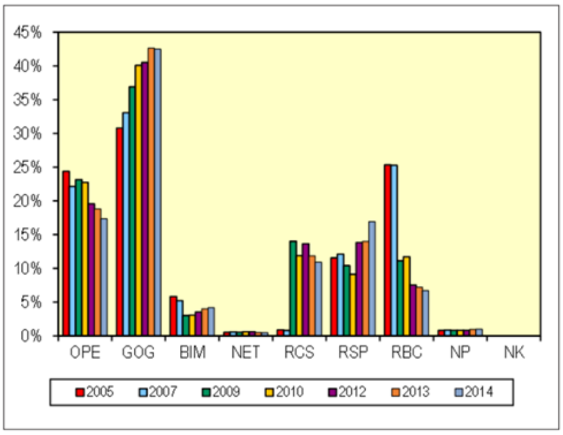
Russian projects must also receive export licenses and environmental approval although the process is less burdensome than its competitors. The Russian gas export market has mostly been dominated by state-owned Gazprom, but some recent policy changes in December of 2013 of the gas export market has allowed other companies to receive export licenses.[xv] Although there has been reform, the ability to export gas is still limited to Gazprom, Rosneft, and Novatek. Environmental authorities must assess projects, but the process is not entirely transparent to the public. For example, during the development of Sakhalin 2 oil and gas project there were issues surrounding environmental impact initially when Shell and Japan's Mitsui and Mitsubishi were the only owners. Shell faced possible fines of up to USD 30 billion, but immediately after Gazprom took a 50 % stake in the project, the environmental accusations were dropped and the project went on to completion.[38]

Russia does face some regulatory burdens in terms of gas sales into the EU. Russia currently exports over 90% of its gas into Europe via pipeline therefore gas sales are under EU jurisdiction. This has caused problems recently as a antitrust case has been filed against Gazprom by the EU. The EU claims Gazprom abused market power by maintaining unfair pricing policies in Central and Eastern Europe. Gazprom could further lose 10% of its revenues due to fines and further complications with the EU could pose challenges to proposed increases of gas export capacity into Europe.

[xv] Novatek received an export license for Yamal LNG.

5. Pricing Opportunities:

<u>Figure 5.0 - World Price Formation 2005 to 2014</u>



OPE- Oil Price Escalation

Gas-on-Gas Competition

BIM- Bilateral Monopoly

NET- netback from Final Product

RCS- Regulation: Cost of Service

RSP- Regulation: Social and Political

RBC- Regulation: Below Cost

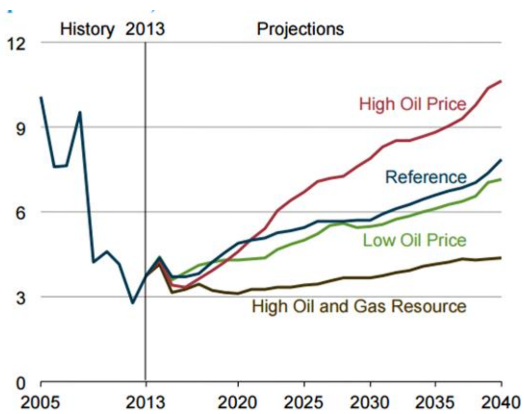
NP- No Price

NK- Not known

Source: International Gas Union, "Wholesale Gas Price Survey", 2015

Gas on gas (GOG) price formation has been rising as traditional oil indexed (OPE) sales have been declining as seen in Figure 5.0. Most of the increase in market based price comes from Europe due to replacement of oil indexed contracts by an increase in imported spot gas and trading hub volumes. Price formation in Asia Pacific has only changed slightly since 2005 with market based prices rising 6% and oil indexed prices declining 3% compared to a 46% increase in gas on gas pricing in Europe over the same time period.[39] To that effect, Asia Pacific is hoping to replace some oil-linked contracts with gas on gas market prices. Contract flexibility is also increasing with the elimination of contract constraints such as destination clauses which will help to increase liquidity as buyers can resell unneeded or uneconomic cargoes.

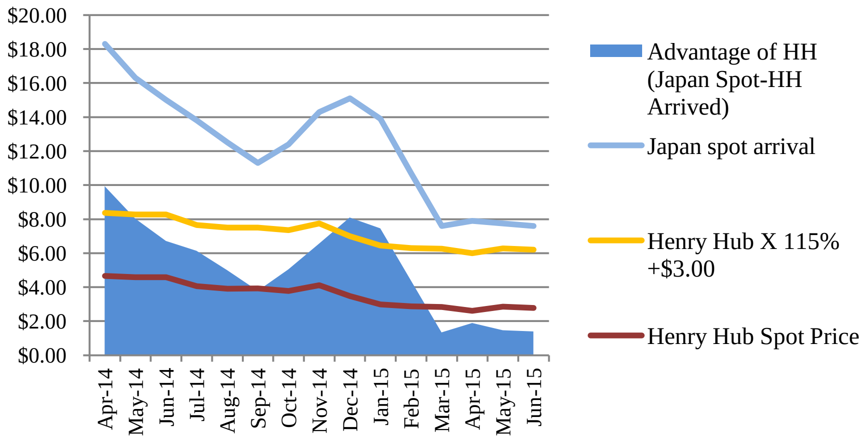
<u>Figure 5.1 - Average HH spot prices for Natural Gas in four cases, 2005-40 (2013$/mmbtu)</u>



Source: EIA, "Annual Energy Outlook 2015", 2015

With LNG exports from the United States expected to enter the market by 2015 a new LNG pricing mechanism will emerge. In the Gulf Coast of the United States, Cheniere's Sabine Pass LNG has negotiated sales contracts with gas priced at 115% x Henry Hub + USD 2.50-3.50/million btu fixed charge.[xvi] Japan and other Asian Pacific countries found the Henry Hub linked price incredibly attractive when oil was priced over USD 100/bbl last year and hoped to replace oil-linked contracts with Henry Hub linked contracts; however, since the oil price has declined Henry Hub linked pricing is seemingly less competitive as seen in Figure 5.2. In June of 2014 prices flowing into Japan were USD 16.3/mmbtu while Henry Hub to Japan would have been around USD 8.28/mmbtu allowing Japan great costs savings from U.S. gas.[xvii] Moving forward into June 2015, due to the oil price decline, prices flowing into Japan were USD 7.60/mmbtu leaving Henry Hub at USD 6.20/mmbtu, therefore the attractive spread has severely shrunk. Price forecasts by the EIA show in a high oil price environment a Henry Hub price increase will follow due to increased demand for Henry Hub and decreased demand for oil-linked prices. Alternatively, if more resource discovery is made resulting in increased U.S. production, downwards pressure will be put on Henry Hub price, but all of this is unpredictable. This exemplifies the volatile nature of the Henry Hub price and although cost-competitive, Henry Hub linked prices come with more risk and less security. Another new pricing option out of the U.S. is tolling agreements as exhibited by the U.S. Freeport project's contract with Chubu Electric, a Japanese energy firm. The contract enables Chubu to offtake 2.2 mtpa with no destination restrictions; therefore if bringing Henry Hub linked LNG into Japan is not economically viable they are able to sell their contracted supply to European or South American markets and find arbitrage opportunities.[40]

Figure 5.2 - Japan Spot Price vs estimated Henry Hub arrival price

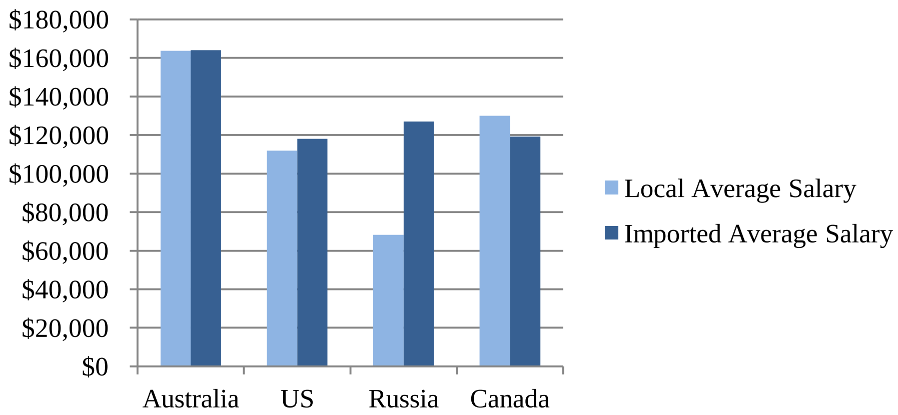


Source: EIA, "Henry Hub Natural Gas Spot Price", July 2015 & METI "Spot LNG Price Statistics", July 2015

[xvi] Henry Hub is the pricing point in Louisiana used for natural gas futures on the New York Mercantile Exchange
[xvii] Using 115% x 4.59/mmbtu (EIA June 2014 HH price) + 3.00/mmbtu and METI Spot LNG Price Statistics

Pricing mechanisms for Canadian gas is yet to be determined. An Oxford Energy Institute Study states Canada will be able to offer either hub based prices off of the Canadian Alberta Energy Company hub price, hybrid pricing, or project based pricing.[41] Although Canada can offer hub based pricing, liquefaction prices will be higher due to the greenfield nature of projects. Shell's LNG Canada application documents state it could be anywhere between USD 4.9/mmbtu to USD 11.3/mmbtu.[42] A recent study done by Cedigaz modeled delivered prices to Japan to be between USD 8.6/mmbtu and USD 16.1/mmbtu, including shipping, tariffs, tax.[43] An alternative export channel for Western Canadian gas is if Canadian prices are lower than U.S. prices, then Canadian gas could be exported via West Coast U.S. projects like Jordan Cove LNG. A change that especially affects Canadian exports is the buyer's deviation from long term supply contracts. Buyers have stated they are moving towards 5-10 year contracts rather than the 20-25 year contracts that have been common in the past, but Canadian projects need the long term contracts to secure buyers and obtain financing for the high cost Canadian projects. It may be likely to see a combination of oil-linked and hub based pricing mechanism in Canadian LNG contracts.

Figure 5.3 - Average Annual Oil & Gas Salary



Source: Hays, "Oil & Gas Global Salary Guide", 2014

Australian LNG prices have historically been oil linked, but the next wave of LNG supply using Henry Hub or hybrid pricing mechanisms from the United States could challenge the competitiveness of these traditional pricing agreements. Australia does not yet have a fully functioning nationwide gas hub and may experience higher liquefaction costs at the new projects as the cost overruns have been unprecedented due to of the simultaneous nature of construction. Thus far there has been an increase in budgets of all export projects under construction. For example, Gorgon LNG's budget has increased by 46% and QCLNG's has increased by 36% from their initial budgets.[44] This was caused by increased demand of materials resulting in higher costs, an appreciation of the Australian dollar, and increased demand for labor which has increased the average oil and gas salary in Australia to the highest in the world at USD 163,000 as seen in Figure 5.3.[45] Australian projects have much LNG contracted but may have troubles when renegotiating contracts as prices in Australia may be less competitive than spot market cargoes from North America.

Russia's LNG prices have also been oil linked, but a new price influencer will be the Power of Siberia and Altai pipelines into China from Russia. The major Russian and Chinese gas companies are state-owned; therefore prices could be influenced by politics rather than market fundamentals. Russia may be willing to take a less attractive price for the political benefits of a partnership with China as well as the ability to swing gas to both Eastern and Western markets.[46] There is speculation that the abundance of gas flowing into China from Russia at low prices could create a price floor, challenging the viability of higher priced LNG coming from the United States, Canada, and Australia.[47]

5.1 Shipping Costs:

Table 5.0 - Estimated LNG Shipping Costs to Himeji Port

Assumptions		
Round Trip Assumed		
Two days added for berthing		
140,000 m^3 tanker= 2995000 mmbtu		
18 knots (Russia Artic 12 knots)		
Fuel consumption	50 MT/day	IEA
Fuel consumption	160 MT/day	IEA
Fuel Cost	BW 380 $304/MT July 29	
Carrier Rate	$32,000/day	Platts July 20
Panama Tarriff	$.19/mmbtu	Panama Canal Authority
Suez Tariff	$.22/mmbtu	IEA
Artic additional co	$.31/mmbtu	IEA

Exporting Port		**Nautical Miles**	**Days**	**Hours**	**Carrier Cost $32,000/day**	**Total Fuel Cost $304/MT**	**Cost/Mmbtu**
U.S.	Sabine(Panama)	9492	23	23	$768,000.00	$1,100,480.00	$1.44
	Sabine(Suez)	14323	35	4	$1,152,000.00	$1,684,160.00	$2.11
	Coos Bay	4595	12	15	$416,000.00	$565,440.00	$0.66
Australia	Darwin	2951	8	20	$288,000.00	$370,880.00	$0.44
	Gladstone	3919	11	2	$384,000.00	$516,800.00	$0.60
	Dampier	3565	10	6	$352,000.00	$468,160.00	$0.55
Canada	Prince Rupert	4118	11	13	$384,000.00	$516,800.00	$0.60
	Kitimat	4234	11	19	$384,000.00	$516,800.00	$0.60
Russia	Sakhalin 2	1196	4	18	$672,000.00	$1,050,016.00	$0.22
	Murmansk Port (close to Yamal LNG) to Yokohama	5750	20	12	$160,000.00	$176,320.00	$1.81
		* Days are rounded up for cost estimations					

Source: Corbeau, Anne-Sophie et al, "The Asian Quest for LNG in a Globaising Market", IEA, 2014 & sea-distances.org & Jones, Stan, "Northern Sea Route beckons LNG shippers", Alaska Natural Gas Transportation Projects, 2013

Using estimates for the purpose of comparing costs, Russia's Sakhalin 2 has the lowest shipping costs. Although as stated by the IEA, vessels passing through the Arctic face increased costs due to slower shipping speeds and the need for ice breakers which adds USD .31/mmbtu and about a 10% fuel cost increase.[48] The United States Gulf Coast is disadvantaged in terms of shipping distance to Japan. Not only is shipping time longer, but Gulf LNG exports are subject to Panama Canal tariffs which have been announced to be between USD 560,000-700,000 with a round trip discount or between USD 620,000-780,00 without discount for vessel sizes between 138,000-177,000 cubic meters (around USD .19/mmbtu). It has also been speculated that that LNG tankers could have to compete with other ships for Panama Canal capacity therefore leading to bottlenecking.[49] Canada and Australia share similar distances and shipping costs, which gives them both an advantage in terms of shipping. The shipping costs will be subject to changes based on freight costs and fuel costs.

Conclusion:

The LNG market will be watched closely as the events in this decade will define the future of global natural gas trade. These four economies in particular will become big players in LNG exporting in the coming years, but it is clear that there are challenges to overcome and the preciseness of the contribution of each player is unclear. It is certain that five projects from the United States and six additional from Australia will come online by 2020 as they are already under construction. The future of other proposed projects in the United States and Australia seem less optimistic and may be delayed to development post 2020. The outlook for Canadian projects is uncertain, but Canada will give impetus to develop proposed projects as Canada needs to generate new export markets for its resources. It is likely a formal FID may come in the fall from the partners of the Pacific Northwest LNG project as they have already made a conditional FID pending the Federal environmental approval. Confidence is displayed by project proponents and the provincial government through continued investments and a recent visit by the B.C. finance minister to Malaysia to discuss with the leading shareholder, Petronas, the project and the new Liquefied Natural Gas Agreement. It seems this will become the first major export plant constructed on Canada's West Coast with hopes that it will be completed by 2020. Shell's LNG Canada project is also a leader as it has received full environmental approval in June 2015 and could see an FID in 2016. Canada will possibly see two or three smaller plants come online before 2020 and will likely see the remaining major projects constructed in the 2020-2025 period. Russia has been focused on pipeline development more so than LNG development and the result of the completion of pipelines into China could have implications on prices coming into Asia. Yamal LNG has received enough financing from China that it will most likely be constructed in time for 2020-21. The outcome of other proposed projects in Russia is unclear, but will most likely be pushed post 2020. With significant decisions being made every day by each economy and throughout the globe it will be vital to watch the LNG market as the next decade will be crucial to the long term future of LNG and the global energy landscape. Outlined below is a summary of main points covered in this paper and the projects in the four economies that are operational, under construction, and proposed.

Table 5.1 Comparative points: Competitive advantages and disadvantages

	LNG Supply	Economy	Political Stability	Regulatory Environment	Price
United States	Holds 5.2% of the worlds reserves and ranks 4th place for shale gas reserves. Produces the most natural gas in the world. Production of unconventional gas is forecasted to continue to increase. Five LNG export projects are under construction and the U.S. will become 3rd largest LNG exporter by 2020.	Strong currency and high energy consumption driven by lower prices aided in offsetting oil price decline effects. GDP growth forecasts for 2015 and 2016 are 2.5% and 3% respectively. 2015 was revised downwards from April forecast by .6%.	Reliable and politically stable country. Federal election in October 2015 could see changes that effect the energy sector.	Complex, but manageable with five projects fully approved. Longer than expected times with non-FTA export approval have motivated policy changes to decrease time lags in the future. Increasing regulatory burden is possible with fracking.	Offers Henry Hub linked gas. Although cost competitive, hub price will bring more volatility and less security. When oil price is low, Henry Hub is less competitive. Shipping disadvantage to Japan, but lower liquefaction costs.
Canada	Holds 1% of the worlds proved reserves and ranks in 5th for shale gas reserves. Has begun producing shale gas but still relatively under developed, has no LNG export projects operational or under construction, is in need of a new export market or production levels are forecasted to drop.	Economy was negatively impacted by oil price decline due to high reliance on oil and gas for GDP, exports, and investments. GDP forecasts by IMF for 2015 were revised downwards .7% from April 2015 forecasts to 1.5% with 2016 GDP growth remaining at 2.1%.	Reliable and politically stable country. Presidential election in November 2016 could have implications on economy and energy sector.	Complex and involved. Federal environmental approval is experiencing delays with only two projects gaining approval out of over 15 that have applied. Consistent engagement with First Nation groups is necessary.	Canada could offer hub based pricing, oil-linked, project based or a hybrid of these. The amount of Asian ownership in Canadian projects will help to create flexible sales contracts. Shipping advantage to Japan, but higher liquefaction costs.
Australia	Holds 2% of the worlds proved reserves and ranked 7th for shale gas reserves. Home to first coal seam gas LNG plants, high availability of supply, has four export facilities operating and six under construction which will place Australia as the top supplier of LNG in the world.	Economy slightly impacted by decline as there is less reliance on oil and gas for GDP revenues. Some industries were suffering from an inflated currency, therefore the currency decline brought on by oil price decline was helpful.	Reliable and politically stable country. Stable supply of LNG in the foreseeable future.	Growing concern of environmental effects of gas extraction and of rising domestic gas prices has motivated a heavier regulatory burden. Gas reservation policies and new environmental approvals have resulted from concerns.	Currently offer Oil-linked prices. A nation-wide domestic hub is not developed. Has a high shipping advantage.
Russia	Holds 17.4% of the worlds reserves and ranks 8th for shale gas reserves. One LNG project operational, one getting closer to beginning construction (Yamal LNG) and two-to-three proposed. Focusing on expanding pipeline capacity into China.	Economy impacted heavily by oil price decline as oil and gas exports make up 68% of export revenues. GDP forecasted to contract 3.4%, revised upwards .4% since April forecasts by IMF and .2% growth expected for 2016.	Politically unstable and uncertain future as the invasion into the Ukraine continues to strain international relations and the ability to do business globally.	Gas market dominated by state-owned compnay. Regulation procedures and assessments are not very transparent to public.	Typically oil-linked, but new pipelines into China could push Russian gas prices into Asian markets downwards. Prices could be motivated by politics therefore pushing prices down lower. Shipping advantage from the East, but disadvantaged from the Arctic (Yamal LNG).

Projects:

Country	Project Name	Capacity MTPA	Location	Year Online	Owners
Australia Operational	North West Shelf	7.5	Western Australia	1989	**16.6% Each** Woodside, BHP, BP, Chevron, Shell, Mitsui/Mitsubishi
	Train 4	4.4		2004	
	Train 5	4.4		2008	
	Pluto LNG	4.3	Western Australia	2012	Woodside(90%), Tokyo Gas(5%), Kansai Electric(5%)
	Darwin LNG	3.6	Northern Territory	2006	ConocoPhillips(56.72%), Santos(10.64%), INPEX(10.52%), Eni(12.04%), Tepco/Tokyo Gas(10.08%)
	Queensland Curtis LNG Train 1	4.25	Queensland	2014	BG Group(50%), CNOOC(50%)
	Train 2	4.25		2015	BG Group(97.5%), Tokyo Gas(2.5%)
U.S. Operational	Kenai LNG	1.5	Alaska	1969	ConocoPhillips
Russia Operational	Sakhalin 2	9.6	Sakhalin Island (East Coast)	2009	Gazprom(50%), Shell(27.5%),Mitsui(12.5%),Mitsubishi(10%)

Country	Project Name	Capacity MTPA	Location	Year Online	Owners	Status
U.S. Under Construction	Sabine Pass LNG Train 1	4.5	Louisiana	Early 2016	Cheniere Energy	Slated to start up Dec-2015. Recently granted approval to build two more trains totaling to 6. Brownfield project.
	Train 2	4.5		H1 2016		
	Train 3	4.5		H2 2016		
	Train 4	4.5		2017		
	Train 5	4.5		N/A		FID not yet made
	Train 6	4.5				
	Freeport LNG	13.2	Texas	H2 2018	Freeport LNG (20%), ZHA FLNG Purchaser (55%), Texas LNG Holdings (15%), Osaka Gas (10%)	First train operational Sept 2018, the 2nd Feb 2019 and 3rd August 2019, Brownfield project.
	Cameron LNG	12	Louisiana	2018	Sempra Energy (50.2%), GDF Suez (16.6%), Mitsubishi (16.6%), Mitsui (16.6%)	First train operational early 2018, 2nd mid 2018, and 3rd at end of year. Brownfield project.
	Corpus Christi Train 1	4.5	Texas	2018	Cheniere Energy	First US Greenfield project. FID in May 2015 with first train online in 2018 and second 6-9 months after.
	Train 2	4.5		2018		
	Train 3	4.5		N/A		
	Dominion Cove Point	5.25	Maryland	2017	Dominion Energy	Received all approvals and is under construction. An expansion of import facilities.

U.S. Proposed Projects	Jordan Cove Energy	6	Oregon	2019	Veresen Inc	Received full export license. Final Environmental Impact Statement will be released Sept 30 2015. Received license to export Canadian gas from NEB.
	Oregon LNG	9.6	Oregon	2020	Oregon LNG	Received export license for both FTA and non-FTA. Expecting environmental approval sometime in late 2015. Has also received license to export Canadian gas from NEB.
	Lavaca Bay LNG	8	Texas	---	Excelerate Energy	Offshore terminal, put on hold indefinitely due to oil price decline.
	Lake Charles LNG	15	Louisiana	2019+	BG Group (50%), Southern Union (50%)	Received export licenses but waiting on environmental assessment due late 2015. Reversal of import project BG/Shell merger could change outcome
	Golden Pass LNG	15.6	Texas	2020	ExxonMobil(17.6%), ConocoPhillips(12.4%), Qatar Petroleum (70%)	Located at existing import facility. FERC approval expected March 2016, waiting on DOE non-FTA export approval.
	CE FLNG	8	Plaquemines Parish	---	Cambridge Energy	Have been behind in submitting documentation to FERC and was given a deadline to complete application by August or FERC will suspend their pre-filling process.

Russia Proposed	Yamal LNG		Arctic		Gazprom	Received funding from CNPC of $20 billion to fund project.
	Train 1	5.5		2017		
	Train 2-3	11		2021		
	Far East LNG	5	Sakhalin (Eastern Russia)	---	Rosneft, ExxonMobil	Will be delayed for a while as there is a lack of access to pipeline gas due to Sakhalin II terminal
	Vladivostok LNG	10	Vladivostok (Eastern Russia)	---	Gazprom	Postponed. No secured buyers or foreign partners. Gazprom may be focusing more on Pipelines into China.
	Sakhalin 2 expansion	5	Sakhalin Island (East Coast)	2017+	Gazprom(50%), Shell(27.5%),Mitsui(12.5%),Mitsubishi(10%)	An agreement in June 2015 was signed to expand.

Australia Under Construction	Gorgon LNG		Western Australia		Chevron (47.33%), Shell Australia (25%), ExxonMobil Aus (25%), Osaka Gas (1.25%),Tokyo Gas (1%), Chubu Electric (.42%)	Highest cost LNG project at $54 billion, a 46% increase of initial budget.
	Train 1	5.2		2015-2016		
	Train 2	5.2		2016-2018		
	Train 3	5.2				
	Wheatstone LNG	8.9	Western Australia	2016	Chevron (64.14%), KUFPEC (13.4%), Kyushu Electric (1.46%), Woodside (13%), PE Wheatstone/TEPCO (8%)	60% complete. First cargo could be as early as end of year.
	Prelude	3.6	Northern Territory	2017	Shell (67.5%), INPEX (17.5%), KOGAS (10%), CPC (5%)	Will be the largest floating LNG facility in the world.
	Ichthys	8.4	Northern Territory	2016	INPEX (62.25%), Total (30%), Tokyo Gas (1.575%), Osaka Gas (1.2%), Chubu Electric (.735%), Toho Gas (.42%), CPC (2.625%), Kansai Electric (1.2%)	First shipment will commence in 2016.
	GLNG	7.8	Queensland	2015	Santos (30%), Petronas (27.5%), Total (27.5%), KOGAS (15%)	CSG liquefaction that is 90% complete and expects first cargo in H2 2015.
	Australia Pacific LNG	9	Queensland	2015	Origin (37.5%), ConocoPhillips (37.5%), Sinopec (25%)	CSG liquefaction. Origin said Train 1 expects sustained production in H2 2016.

Australia Proposed	Fishermans Landing LNG	3.8	Queensland	2020	LNG ltd	Is delayed while struggling to secure gas supplies, discussions to find buyers still continuing
	Browse FLNG	11.7	Western Australia	2017+	Woodside (31.3%), BP (18%),Shell (27%), PetroChina (9%), Mitsui/Mitsubishi (14.7%)	Planned FID was pushed back six months to end of 2016. In FEED phase.
	Scarborough FLNG	6	Western Australia	2020+	BHP (50%), ExxonMobil (50%)	Placed on backburner and could succumb to other investments by the companies
	Sunrise FLNG	4	Northern Territory	2020+	Shell (26.56%), Woodside (33.44%), Osaka Gas (10%), ConocoPhillips (30%)	Shelved due to regulatory and fiscal issues with Timor-Leste

Canada Proposed	Pacific Northwest LNG	12	Prince Rupert, BC	2019	Petronas (62%), Japex (10%), Sinopec (10%), Indian Oil Co. (10%), PetroleumBrunei (3%), Huadian (5%)	Gave a conditional positive FID while waiting for Federal Environmental Approval that is expected in Fall 2015
	LNG Canada	12	Kitimat, BC	2020+	Shell (50%), Mitsubishi (15%), PetroChina (20%), KOGAS (15%)	Received both Federal and BC environmental approval in June 2015 FID planned for 2016
	Douglas Channel FLNG	0.55	Kitimat, BC	2018	Alta Gas/Idemitsu (33.3%), Exmar (33.3%), EDF (33.3%)	FID expected at the end of this year, waiting on NEB export licenses and environmental assessments not needed, will be the first BC project in Operation. A precursor to the consortiums long-term project Triton LNG.
	Kitimat LNG	11	Kitimat, BC	2020	Chevron (50%), Woodside (50%)	Has all certification, but FID planned for 2016
	Prince Rupert LNG	14	Prince Rupert, BC	2021+	BG Group	Shell BG merger pushes this project back, possibly indefinitely
	Woodfibre LNG	2.1	Sqamish, BC	2019	Pacific Oil and Gas	Has sold 1 mtpa /25 years to China's Guangzhuo. Recently was granted extension on environmental review so they may engage further with Squamish First Nations groups.
	WCC LNG	15	Prince Rupert, BC	2024	ExxonMobile Canada (50%), Imperial Oil Resources (50%)	BCEAA in Pre-Application,CEAA substituted by BCEAA, NEB approved

Canada Proposed	Aurora	24	Digby Island, BC	2023	CNOOC (60%), Inpex (20%), JGC (20%)	FID in 2017. BCEAA in Pre-Application,CEAA substituted by BCEAA, NEB approved
	Wespac Tilbury	1.5	Delta, BC	2020	Wespac Midstream LLC	Brownfield. Using existing infrastructure of FortisBC LNG storage facility. Received export license but for BCEAA and CEAA
	Triton LNG	2.3	Kitimat, BC	2020+	Alta Gas/Idemitsu (33.3%), Exmar (33.3%), EDF (33.3%)	Received export license. Not yet applied for environmental
	Goldboro	10	Nova Scotia	2020	Pieridae Energy Canada Ltd	Received all environmental approvals and U.S. DOE FTA export approval, waiting on NEB import and export approval. Signed a 20-year agreement to supply Germany's E.ON 5mtpa for 20 years.
	Bear Head LNG	4	Nova Scotia	2019	LNG ltd	FID in 2016. Reversal of a partially developed import site. Received U.S. FTA approval to export U.S. gas. Has all environmental approval and waiting on NEB import and export approval.

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