Comparative Economic Analysis of Coal & Gas in Vietnam

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Coal Markets

- Domestic supply and demand – coal imports?
- Asian coal markets
- Indonesia – key regional supplier
- Coal and transport pricing

Natural Gas Markets

- Domestic supply and demand
- LNG regasification development
- Global LNG supply and demand
- LNG pricing – convergence of US and Asian markets?
- Domestic gas pricing – marginal cost versus rolled-in

Case study: Gas development in Vietnam

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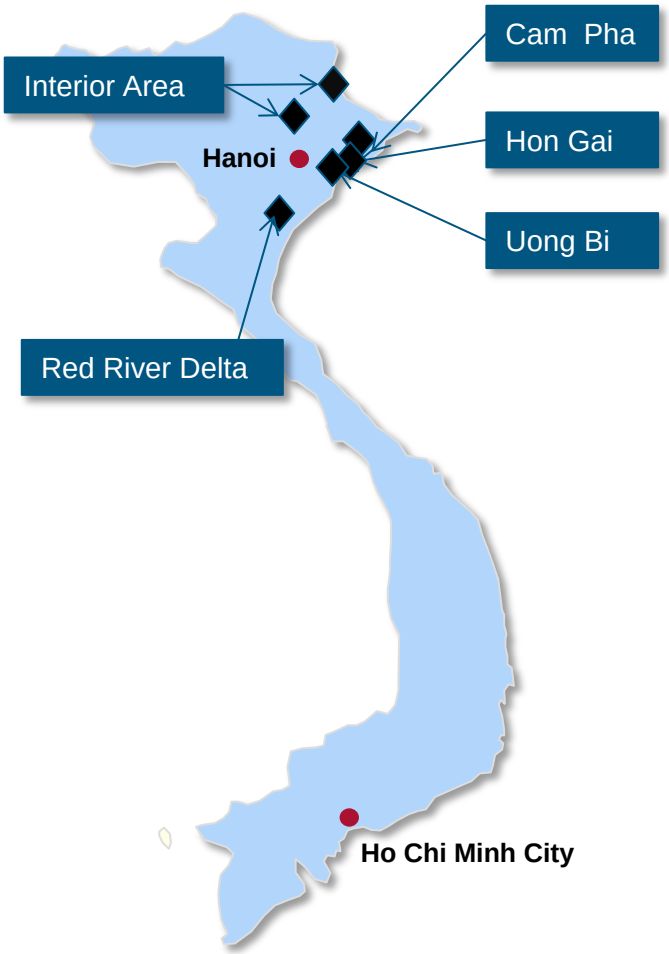
Case study: Gas development in Vietnam

Vietnam Coal Supply: coal mines and reserves



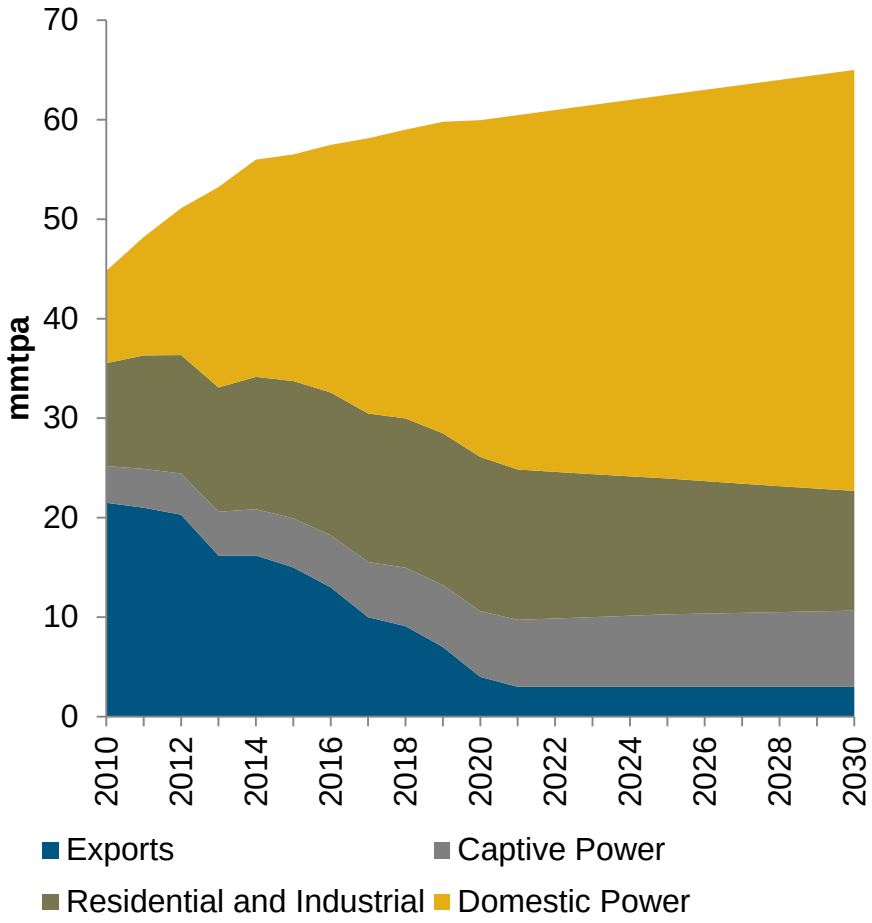
Reserve and Resources	Billion Tonnes
A+B	0.42
C1	2.39
Identified Resource	**2.80**
C2	2.65
P	43.3
Total Resource	**48.7**

Mining District	Capacity (Mtpa)	Reserve (Mt)
Cam Pha	43	875
Hon Gai	13	400
Uong Bi	40	1,420
Interior	3	90
Red River Delta	14	600

Source: Coal Development Master Plan 2012, reserve and resource as of December 2011

- Coal resource of Vietnam is concentrated in Quang Ninh coal basin and Red River coal basin in North Vietnam.
- Though Vietnam is endowed with abundant and good quality coal resources, the economically recoverable reserves of 2.80 billion tonnes only represent 6% of total reserves, and it is scattered across the north of the country making mining more costly.
- At current stage, exploration is not of high quality and mining conditions are harsh.
- If future coal demand is to be met from domestic coal sources, significant investment is required to increase reserves and develop coal mining.
- The Red River Delta coal seams are generally consider un-exploitable as they are too near the surface of the rice basket of Vietnam and display undulations making machine cutting difficult.

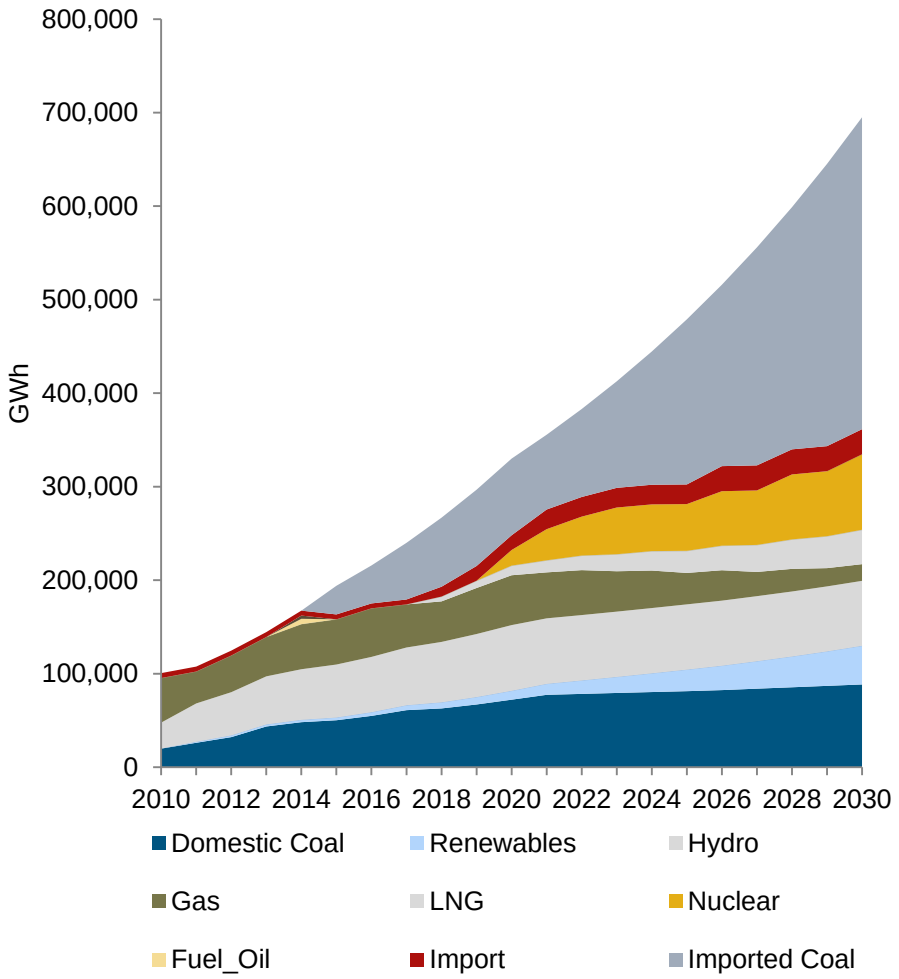
Domestic coal supply and demand



Source: TLG

- Local coal supply is expected to level off within the medium term. It is just a question of at what level will it level off.
- The latest official coal development plan indicates local production might top out at close to 70 million tonnes a year.
- Private consultancies such as The Lantau Group take a more conservative view and we forecast domestic coal production reaching 65 million tonnes by 2030.
- Most recoverable coal reserves lend themselves to open cast mining, with limited underground mining. There comes a limit to the number of opencast mines a certain land area can accommodate.
- We expected exports to be slowly clawed back as domestic demand grows.
- This raises upward pressure on domestic coal prices which have historically been cross subsidized by more expensive exports.

In order to replicate the PDP results, we had to “force-build” units

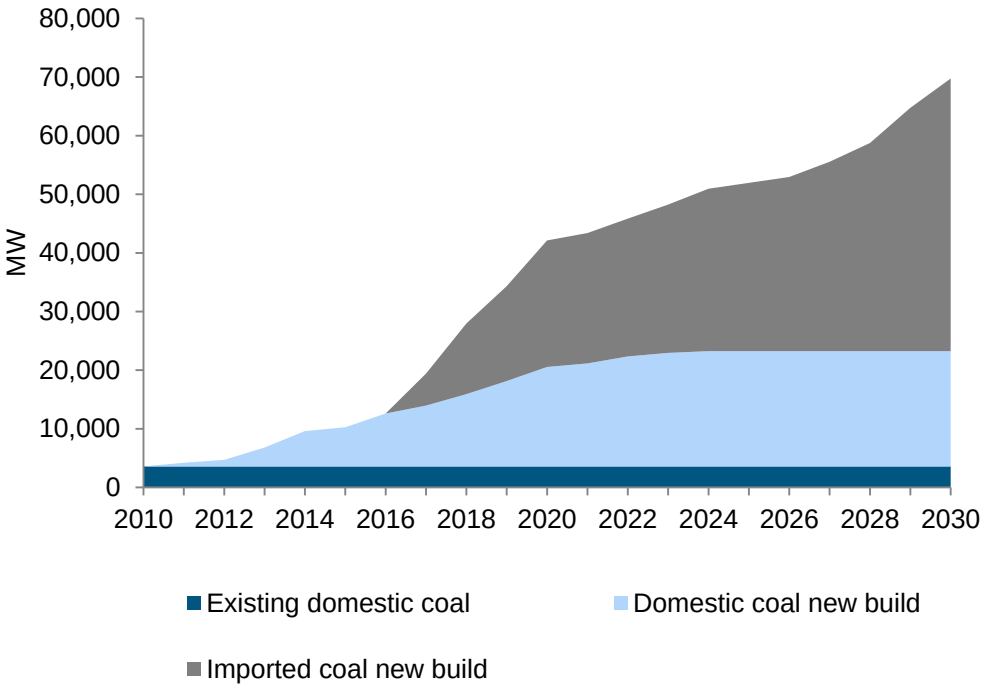


Source: TLG

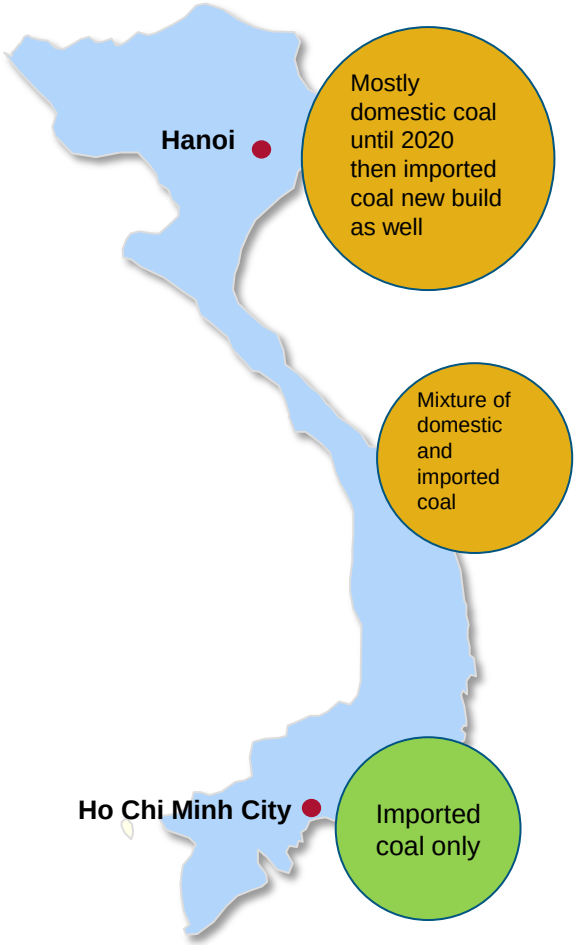
- Overall demand reaches a very substantial 695 TWh in 2030 (versus 442TWh in our projection)
- Domestic coal levels out after 2020 (similar to TLG forecast).
- Renewables mainly wind make a growing presence rising to 5 percent of generation (similar to TLG forecast).
- Hydro rises to 10 percent of power produced (similar to TLG forecast)
- Gas fired generation gets squeezed out by other plants especially nuclear and coal
- LNG is forced in starting in 2018, a few years later than in the PDP as no construction work has started.
- Nuclear contributes 10 percent of generation by 2030 (versus zero in TLG projections)
- Imports of power direct from China grows in the PDP forecast (versus flat outlook in TLG forecast)
- Imported coal accounts for almost half of generation by 2030 (versus 25 percent in TLG forecast).
- Competition from other types of generation and assumed LNG use results in lower demand for domestic gas (relative to the TLG forecast).

Vietnam Coal Demand: an array of planned coal-fired power plant

Coal-fired generation capacity: Existing and Planned



Source: PDP 7 revised and TLG



New build located in North Vietnam will be met by local supply until about 2020 when imports may be needed

New build in South Vietnam needs to use import coal due to lack of local coal supply and as it is uneconomic to transport domestic coal from the north

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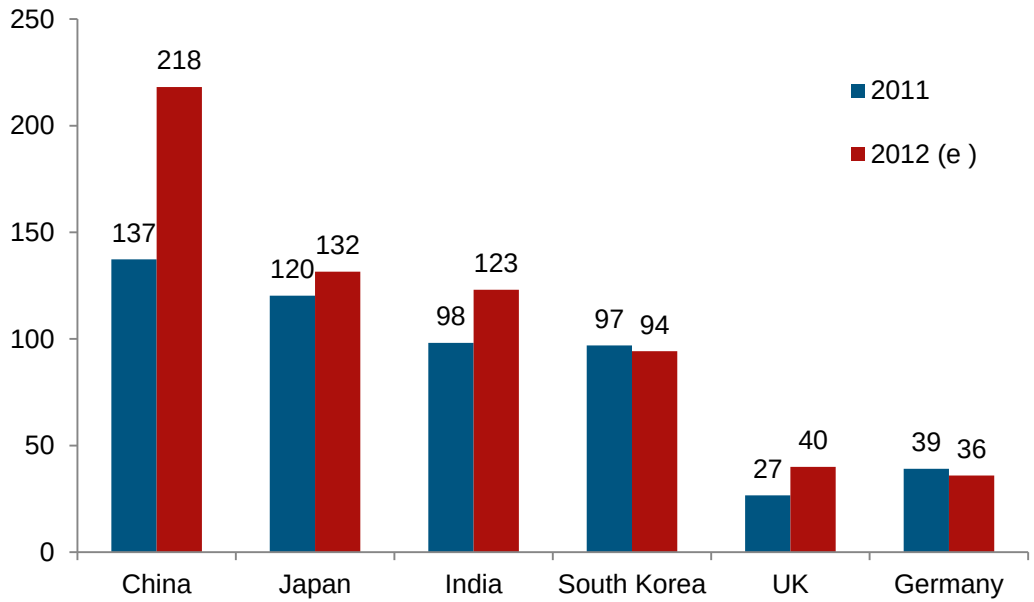
Asia coal markets: Demand

World's top thermal coal import countries 2011 and 2012 (e)



Source: IEA Coal Information 2013

China

- China is the world's largest coal importer, both in terms of thermal and coking coal
- China's power demand growth is expected to continue for the few decades to come
- Coal-fired generation will remain its dominant role in China's generation fuel mix
- Domestic production characteristic of declining energy content and inland rail infrastructure bottlenecks are expected not to be able to meet growth in coastal power demand.

Asia Coal Markets: Demand - Continued

Japan

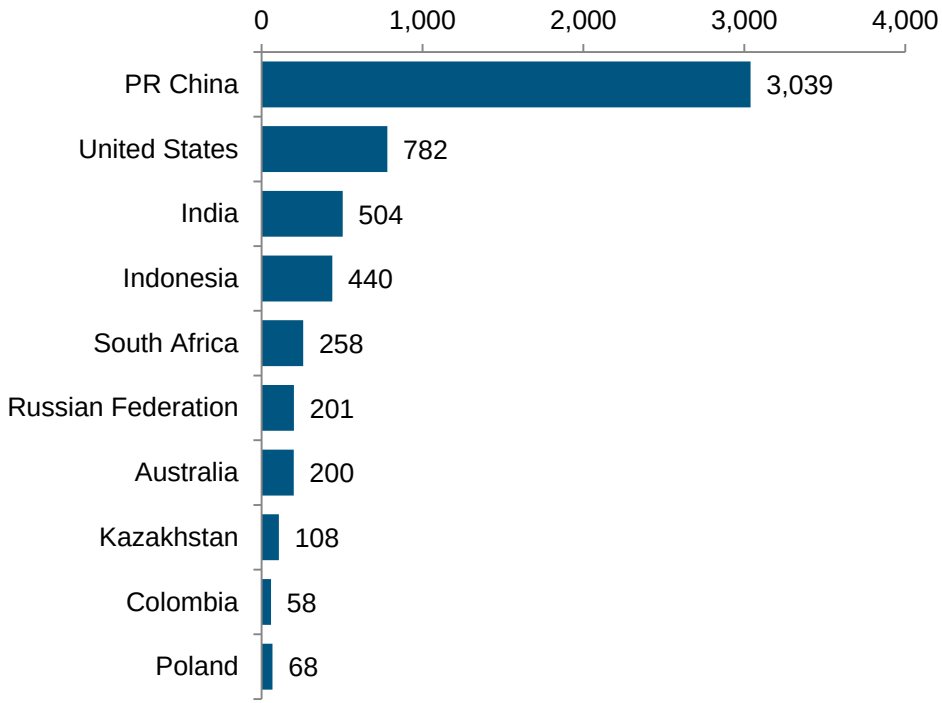
- Japan is the world's second largest thermal coal importer, surpassed by China in 2011
- Japan's power demand is expected to be flat on the back of matured economy, declining population and energy demand management efforts.
- Fukushima disaster is expected to change the landscape of Japan's energy supply from the June 2010 Revised Basic Energy Plan, which plans for nuclear to account for more than 50% of total power generation as both baseload and zero emission technology.
- New Basic Energy Plan is under drafting and its release is expected in Summer 2012, it is widely anticipated that nuclear will assume a much less important role due to safety considerations
- Renewables are anticipated to fill in the gap in the long run, whilst gas and coal will be utilized in the interim.

South Korea

- South Korea is the world's fourth largest thermal coal importer, behind China, Japan and India
- S. Korea's power demand growth and energy intensity are expected to fall as its economy matures and shifts towards lighter, high-tech manufacturing and service sectors
- Coal-fired power generation is expected to increase in the medium term through brownfield expansions in coal units according to the government's 5th Basic Plan for Long Term Electricity Supply and Demand
- However in the long run, renewables and nuclear will assume a more important role in power generation whilst that of coal's remains stable

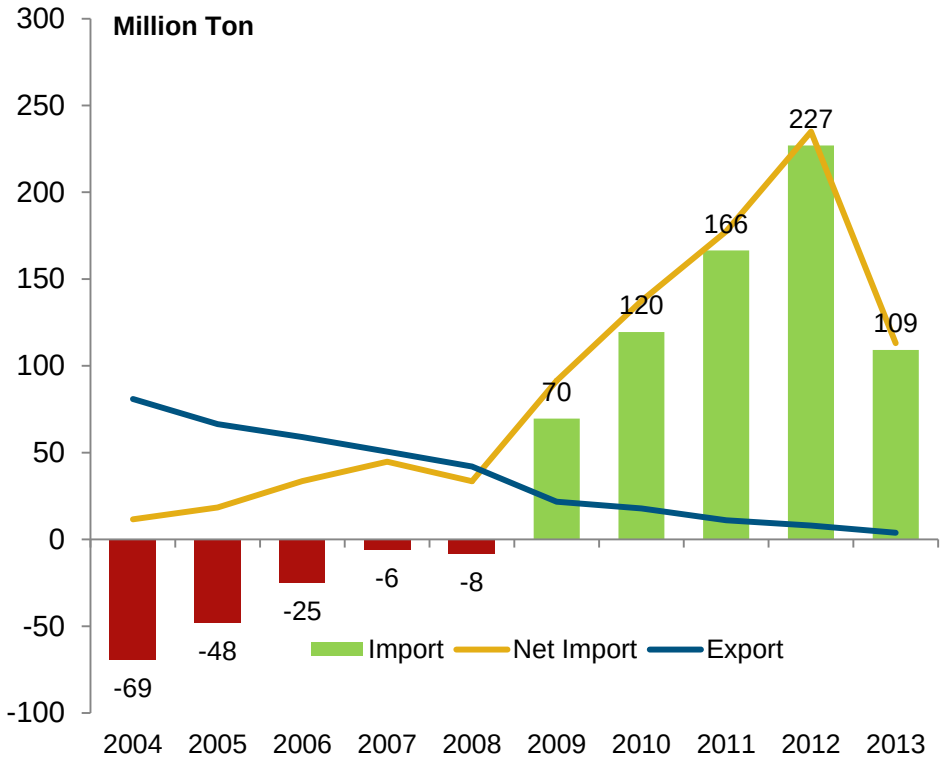
China: the world's leading steam coal producer and importer

2012 Steam coal production by country



Source: IEA Coal Information 2013

China Steam Coal Export and Import Volume 2004-2013

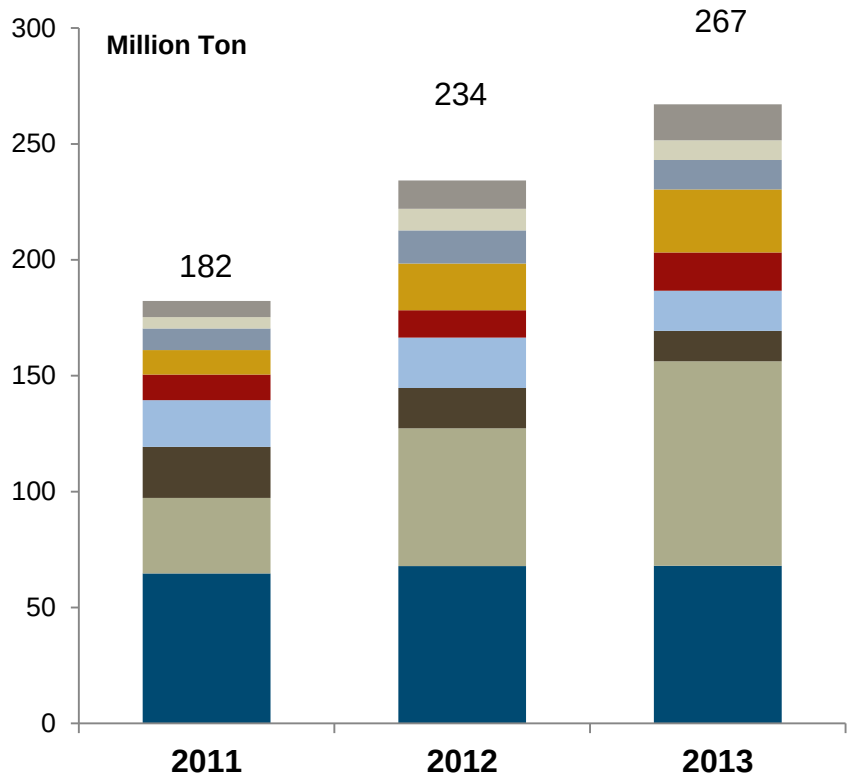


Source: China Custom

- China's the world's largest thermal coal producer
- China flips to become a net coal importer in 2009, and supplanted Japan as the world's largest coal importer in 2011

China's coal trading partners

China total coal import 2011-2013
(Including coking and steam coal)



	2013	CAGR % 2011-13
Others	6%	49%
US	3%	31%
South Africa	5%	17%
Russian Federation	10%	60%
North Korea	6%	22%
Mongolia	6%	-7%
Vietnam	5%	-23%
Australia	33%	65%
Indonesia	25%	3%

- Indonesia, Australia and Vietnam are China's main sources of coal supply
- Imports from Vietnam and Mongolia are falling, from Indonesia is levelling whilst that from RoW such as Australia, South Africa, Russia and USA have increased markedly to fuel China's growing energy demand and industrialization

Asia Coal Markets: Supply

Australia

- World's largest coal exporter, second in thermal coal export
- Existing infrastructure is expected to experience significant improvement with the completion of multiple large-scale port and rail capacity expansion projects
- Supply is expected to grow strongly in the medium term (2014-2016) with an array of significant thermal coal projects coming online in less developed Surat and Galilee basins of Queensland
- Carbon tax burden: A$25.4/tonne carbon tax and Mineral Resources Rent Tax

Indonesia

- World's largest thermal coal exporter, supplies a majority of coal production in the seaborne export market
- Lowest cost of production among major coal exporters but coal is lower quality medium-low rank coal
- However, future production faces challenges such as:

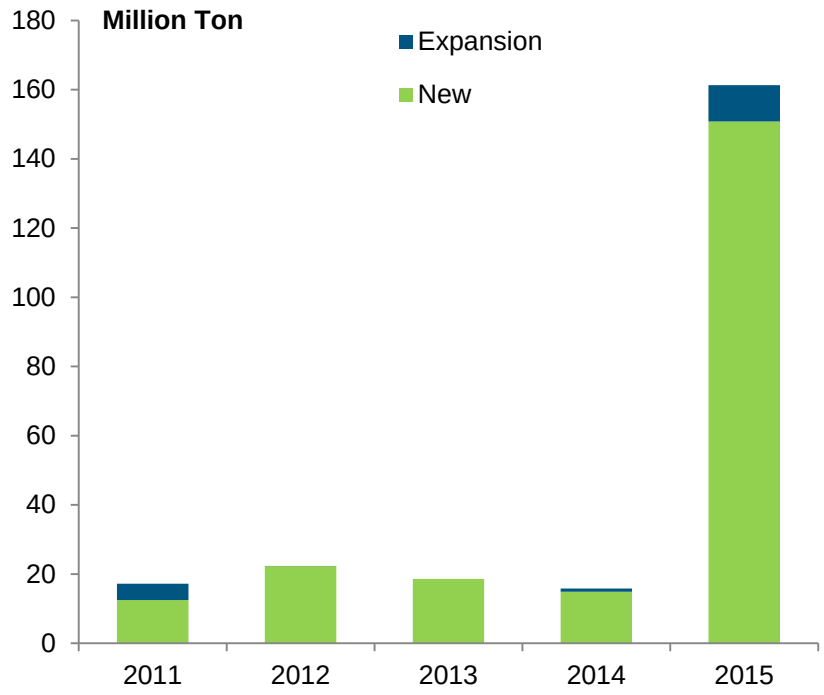
  i) Declining energy content of export coal as higher rank coal becomes exploited; and

  ii) Tightening government regulation to constrain coal export and set minimum price levels

  iii) Increasing transport costs as railway links are required to develop inland coal resources

Australia: Supply to grow strongly with an array of mega projects coming online in Surat and Galilee basins

Australia's total coal production capacity expansion



List of Post-2015 Mega Thermal Coal Projects

Company	Project	Capacity (Mtpa)
Xstrata	Wandoan	30
GVK Group; Hancock	Alpha	27.6
China First	Waratah Coal Inc	28
GVK Group	Kevin's Corner	21.7
Meijin Energy	China Stone	~30

However, the deliverability of expanded thermal coal production capacity depends on commensurate capacity expansions in railway networks and port facilities

Australia: Significant infrastructure debottlenecking with of multiple large-scale port and rail capacity expansion projects

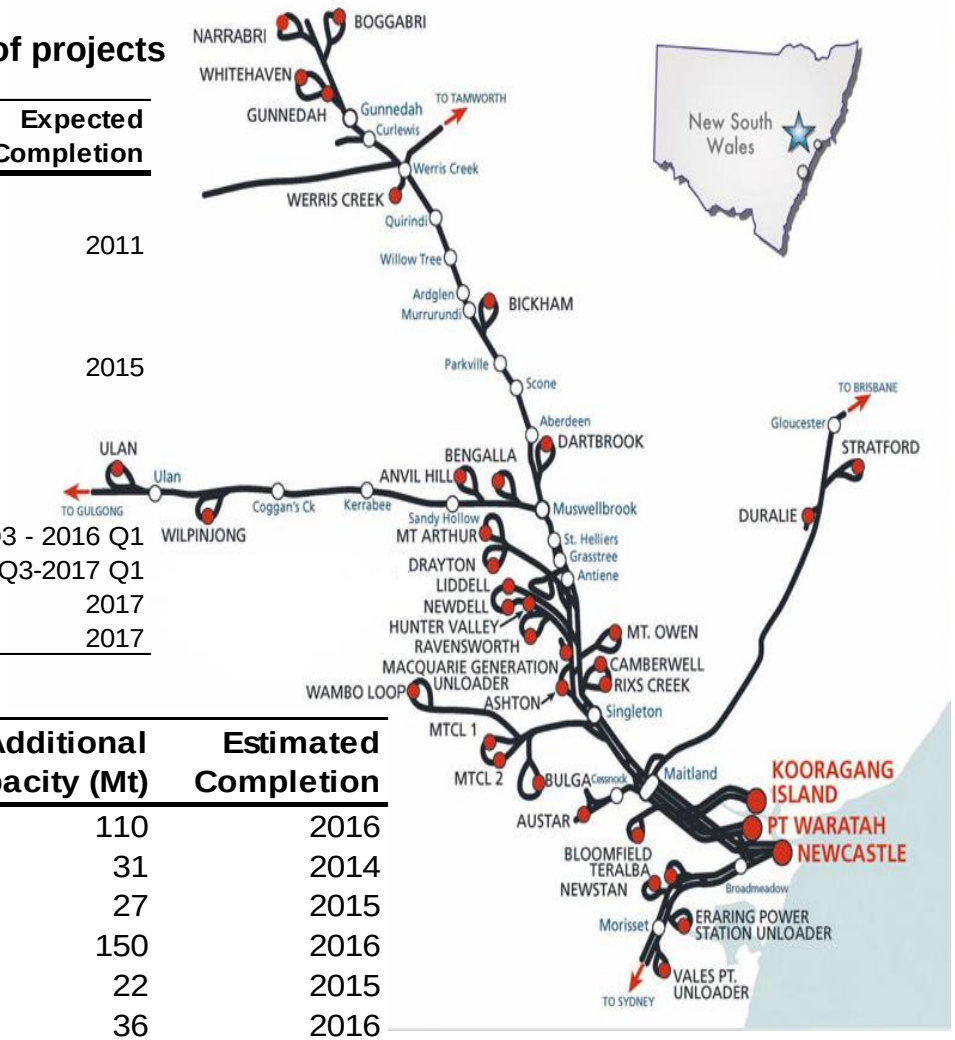
Ports and Railway expansions to align capacity with that of projects

Rail	Connectivity	Expected Completion
GAP Goonyella to Abbot Point Expansion	'Nothern Missing Link' connects Bowen Basin to expanding Port of Abbot Point	2011
Surat Basin Rail	Southern Missing Link' connects Surat Basin to the Port of Gladstone	2015
Hunter Valley Coal Chain (HVCC)	Connects coal mines in the Ulan, Central Coast and Gunnedah basin of NSW	
HVCC 1	Narrrabri--Muswellbrook	2012 Q3 - 2016 Q1
HVCC 2	Muswellbrook-Ulan	2015 Q3-2017 Q1
HVCC 3	Muswellbrook--Hexham	2017
HVCC 4	GAP--Narrabri (RIC)	2017

Source: Australian Rail Track Corporation (ARTC)

Port	Region	Additional Capacity (Mt)	Estimated Completion
Abbot Point Coal Terminal	Queensland	110	2016
Hay Point Coal Terminal	Queensland	31	2014
Wiggins Island Coal Terminal	Queensland	27	2015
Dudgeon Point Coal Terminal	Queensland	150	2016
Fitzroy Terminal	Queensland	22	2015
New Castle Coal Infrastructure Group	New South Wales	36	2016
Port Waratah Coal Services	New South Wales	120	2017

Source: Port Authorities and company reports



Hunter Valley Network on the east coast of Australia

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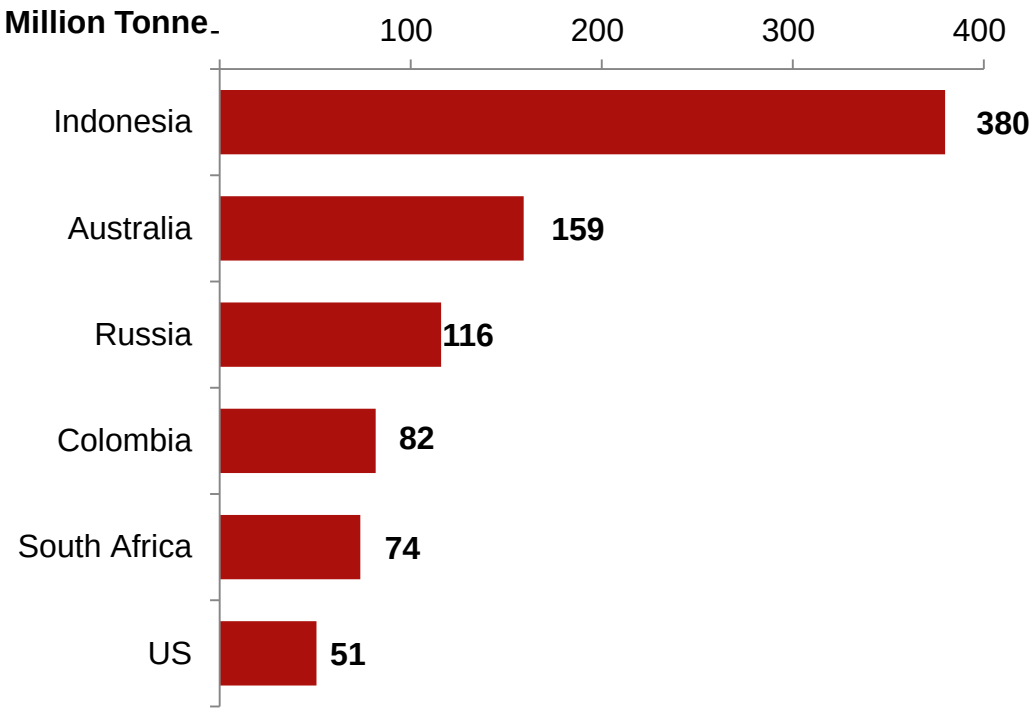
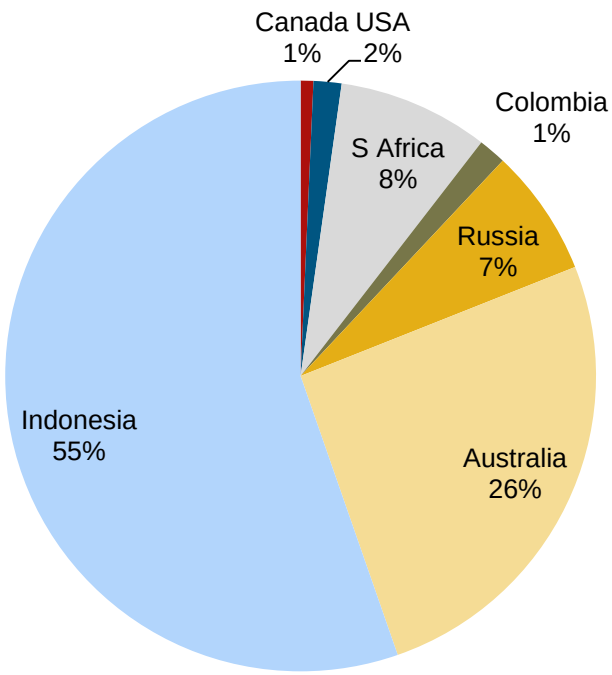
Indonesia – Key global and regional supplier

World's Top Thermal Coal Exporting Nations 2012(e)



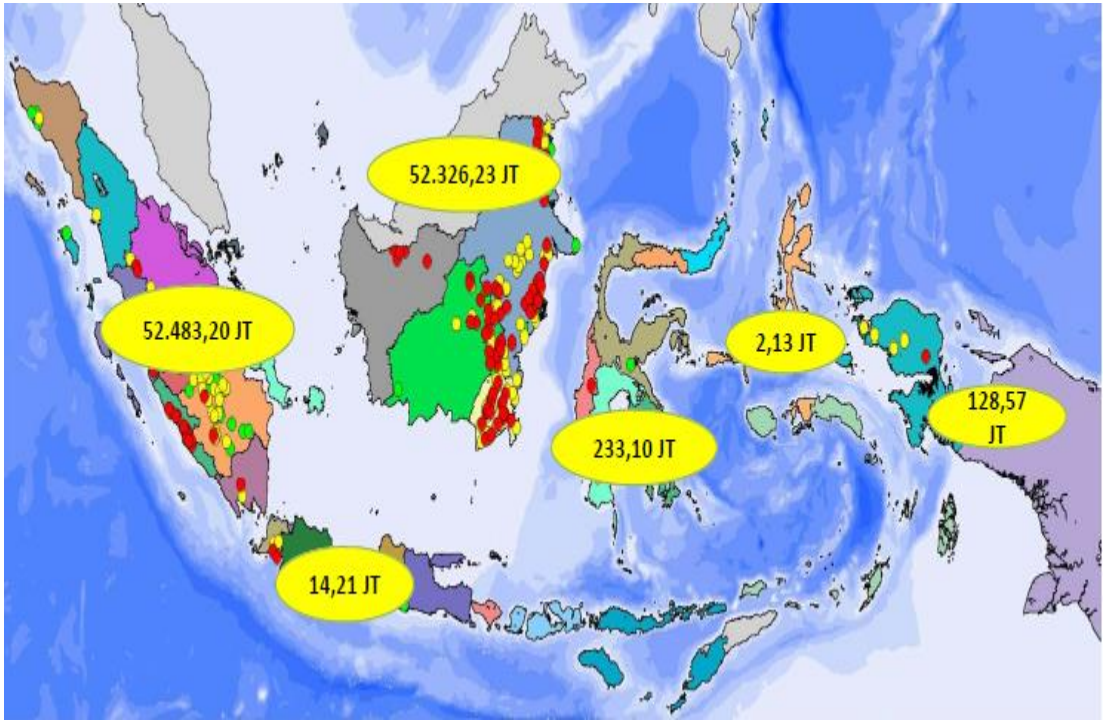
Source: IEA Coal Information 2013

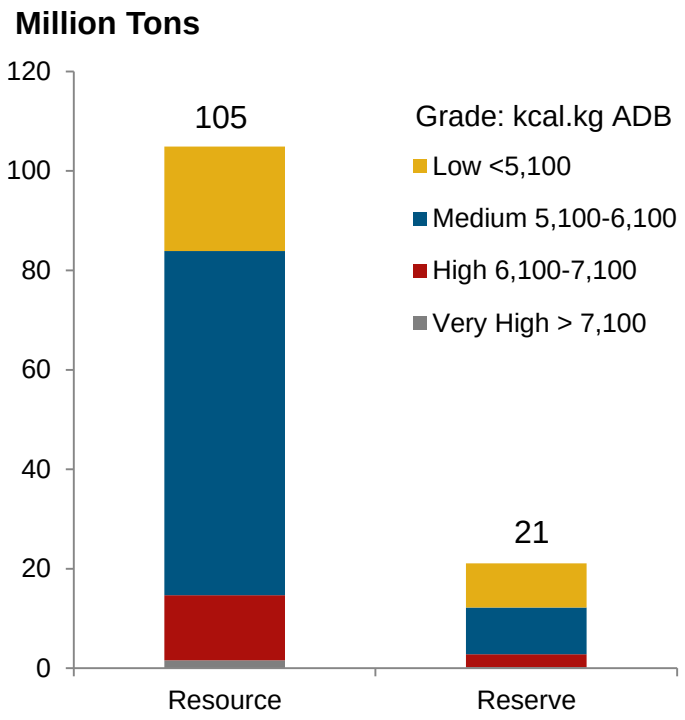
Thermal Export into Pacific Basin 2012



- Indonesia is the world's largest thermal coal exporter, exporting around 380Mt in 2012
- Indonesia supplies the largest portion of seaborne thermal coal in Pacific basin, at around 55%

Indonesia Coal Resource and Reserve



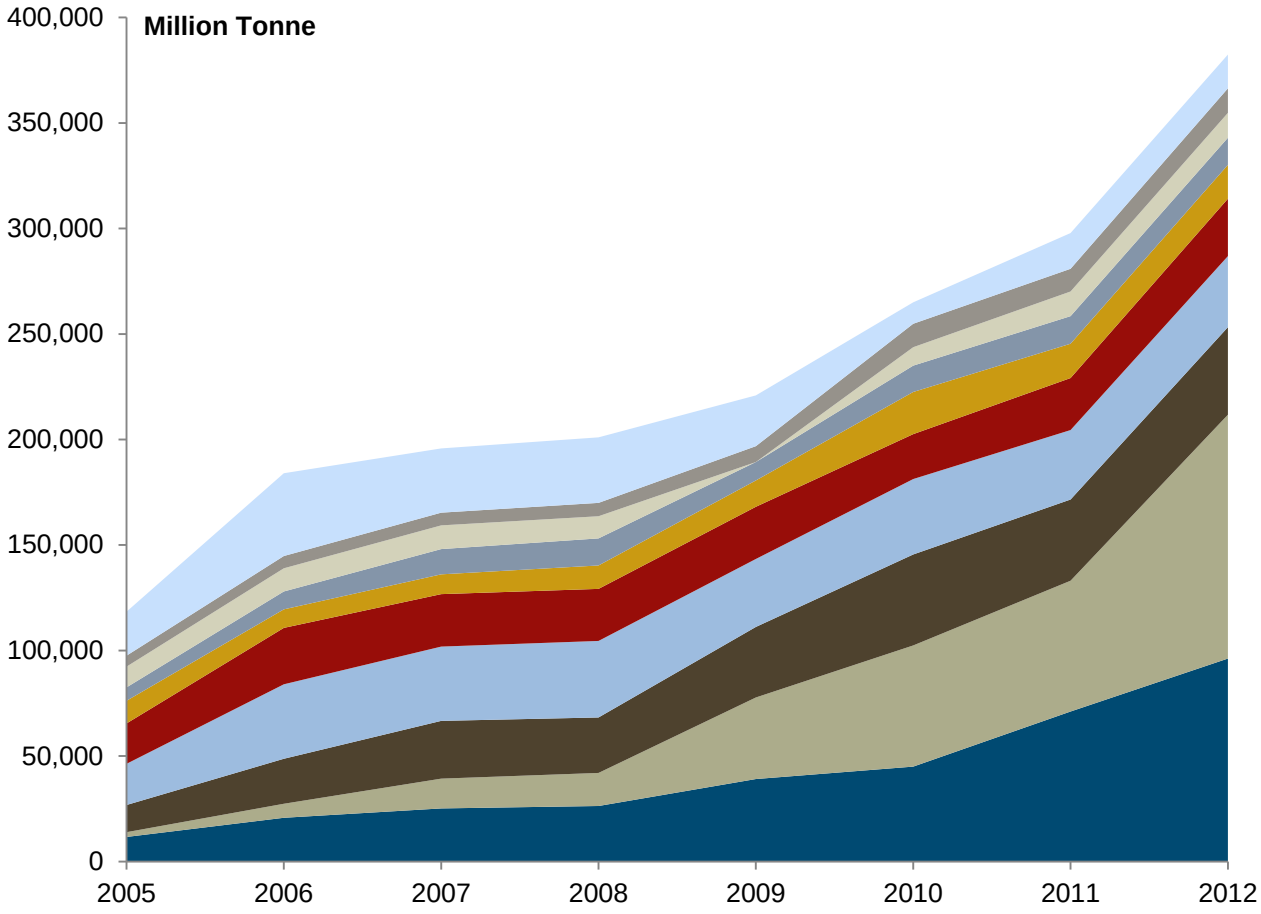


Source: Geology Agency – Ministry of Energy and Mineral Resources,

As of November 2011

- The majority of indonesia's coal resources is medium to low rank in calorific value
- This fits with the needs of coal-fired electricity generation facilities (5100-6100 kcal/kg ADB) to fuel Indonesia's growing energy demand

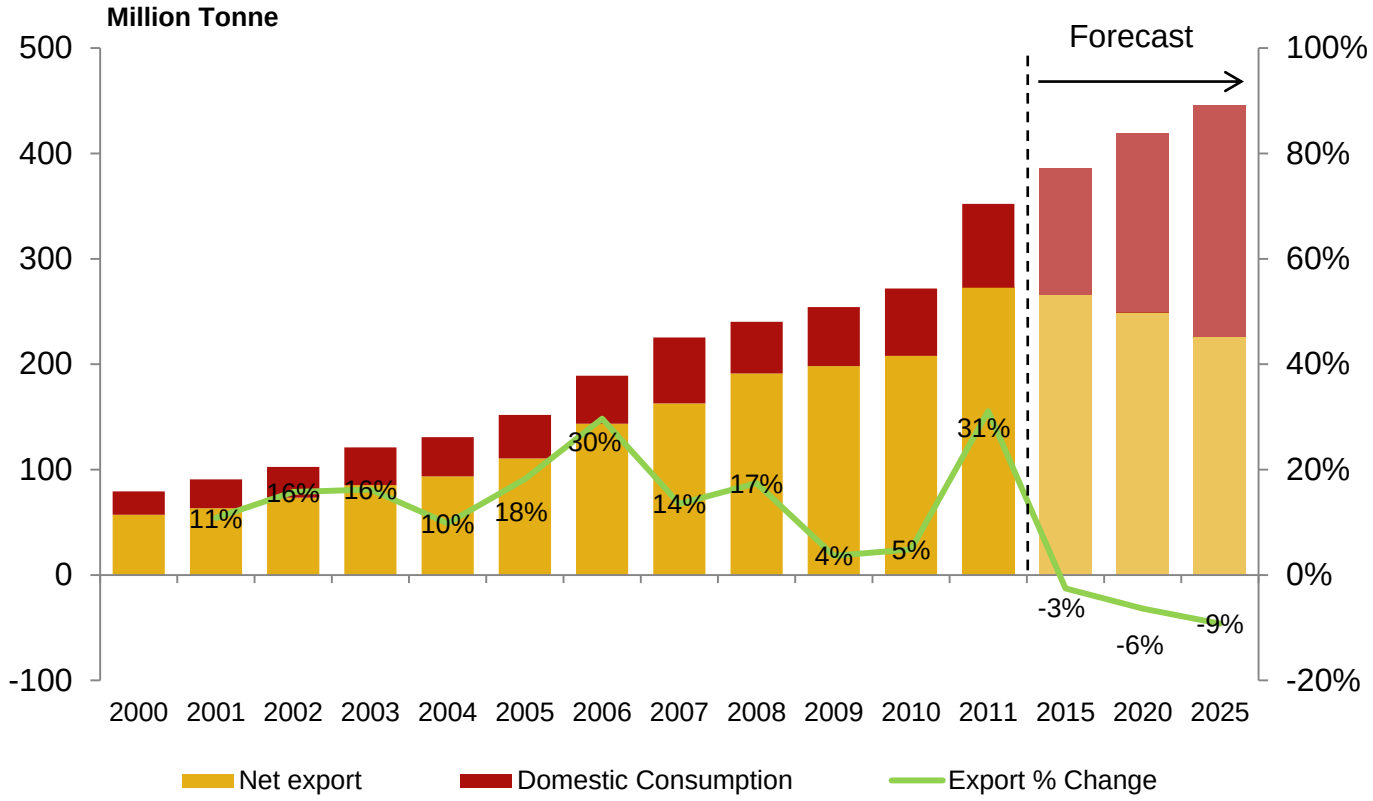
Indonesia coal export by destination countries



	% Total	2005-12 CAGR
Others	4%	-4%
Philippines	3%	12%
Hong Kong	3%	3%
Thailand	3%	11%
Malaysia	4%	6%
Taiwan	7%	5%
Japan	9%	8%
Korea, Republic	11%	18%
China	30%	75%
India	25%	35%

Asian countries account for over 95% of Indonesia's seaborne thermal coal export, and it is increasing

Indonesia Supply and Demand Balance 2000-2025



Source: Ministry of Energy and Mineral Resources

- Indonesia exports a majority of its coal production
- The proportion of export supply is projected to fall due to increasing energy demand at home

Indonesia Coal Mining Regulations

DMO Domestic Market Obligation

- In order to ensure sufficient coal supply for domestic coal consumption, Indonesia government introduced in 2009 under the new mining law, the Domestic Market Obligation ("DMO") requiring mining companies to sell a proportion of their production to the local market
- DMO is determined on an annual basis and a list of DMO for each company is published by the Ministry of Energy and Mineral Resources
- In 2014, DMO is set at 95.55Mt, estimated at around 25% of total production

Benchmark Price Regulation

- Under the Ministerial Regulation 17/2010, guidelines are provided to determine the minimum selling price of coal into both domestic and export markets
- The minimum benchmark price is determined on a monthly basis using the average of a combination of domestic and international price indexes, namely Argus Indonesia Coal Index (ICI), Platts, Newcastle Export Index and Newcastle globalCOAL Index
- This works to align domestic coal prices to prevailing international price levels and boost government's royalty income as this forms the price basis at which royalties are collected

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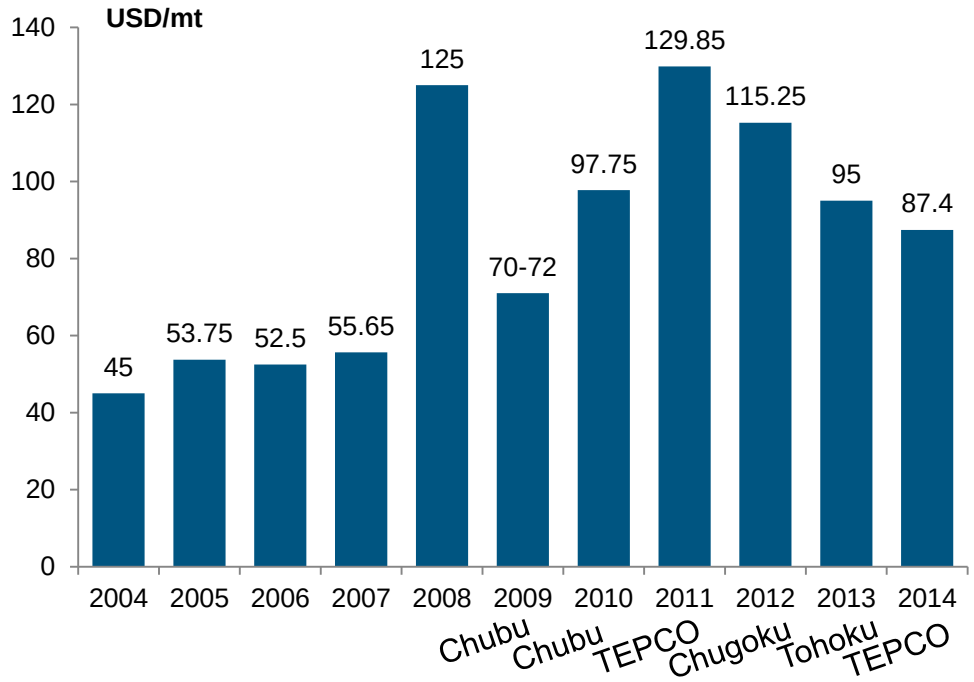
Coal Contracting and Pricing: Summary

- In Pacific basin, the majority of seaborne trade is settled through term contracts with the balance made up by spot market purchases
  - The annual Japan-Australia term contract negotiation in March-April sets the reference price for utilities in Japan and other Asian countries to follow
  - Taiwan and South Korea typically procure a larger proportion of coal on the spot market
- The long term trend has been moving from long term contracts to the spot market
  - The increasingly competitive electricity supplier market, the volatility of major reference index and the inflexibility of traditional procurement arrangements are drivers behind the trend of larger spot market purchases
  - Three major spot market price references in Indo Pacific region are Australia Newcastle FOB, Indonesia Kalimantan and South Africa Richards Bay
- Procurement Strategies
  - Strike balance between supply stability and economic purchasing
  - Diversification of sources in terms of supplier and country of origin

In Pacific basin, the price tone for the year is set by March/April Australian-Japanese annual term contract settlement

Historical Xstrata-JPU Annual Term Contract Reference Price 2004-2014

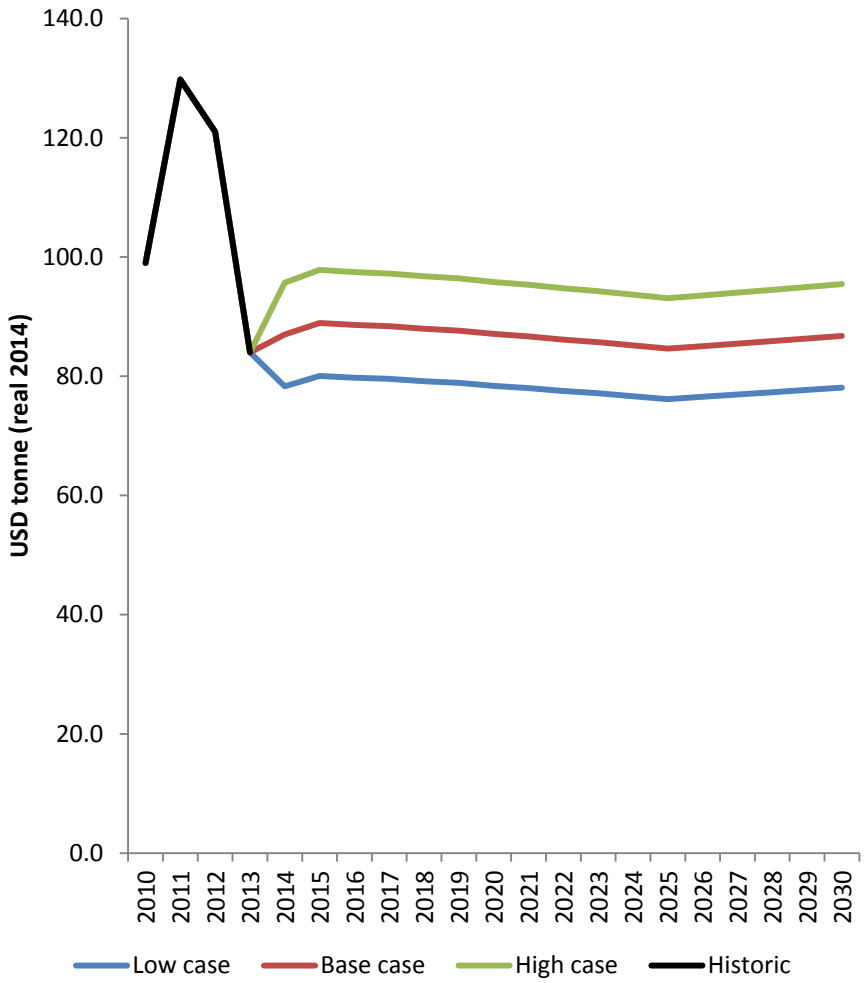


Source: Xstrata financial reports

- Since 1998, Japanese Power Utilities ("JPU") have negotiated individually based on reference prices instead of benchmark prices, a system under which coal prices were negotiated between the elected JPU and representative of Australian producers
- Australian-Japanese term contracts are settled four times a year with the largest volume settled in March/April, accounting for 70% of the total annual imports, followed by deliveries starting in October accounting for about 20%, and the rest is divided among July and January negotiations and spot purchases

The first contract price starting Japanese Financial Year (1st April) agreed between Xstrata(the world's largest thermal coal exporter) and JPU serves as price indicator across Pacific Basin

International coal price forecast



Coal prices are likely to see only a slow recovery from current lows in the short term as suppliers respond to low prices by delaying capacity expansions. In the medium term the coal price is expected to trend down before market adjusts back to balance post 2020-2025 period.

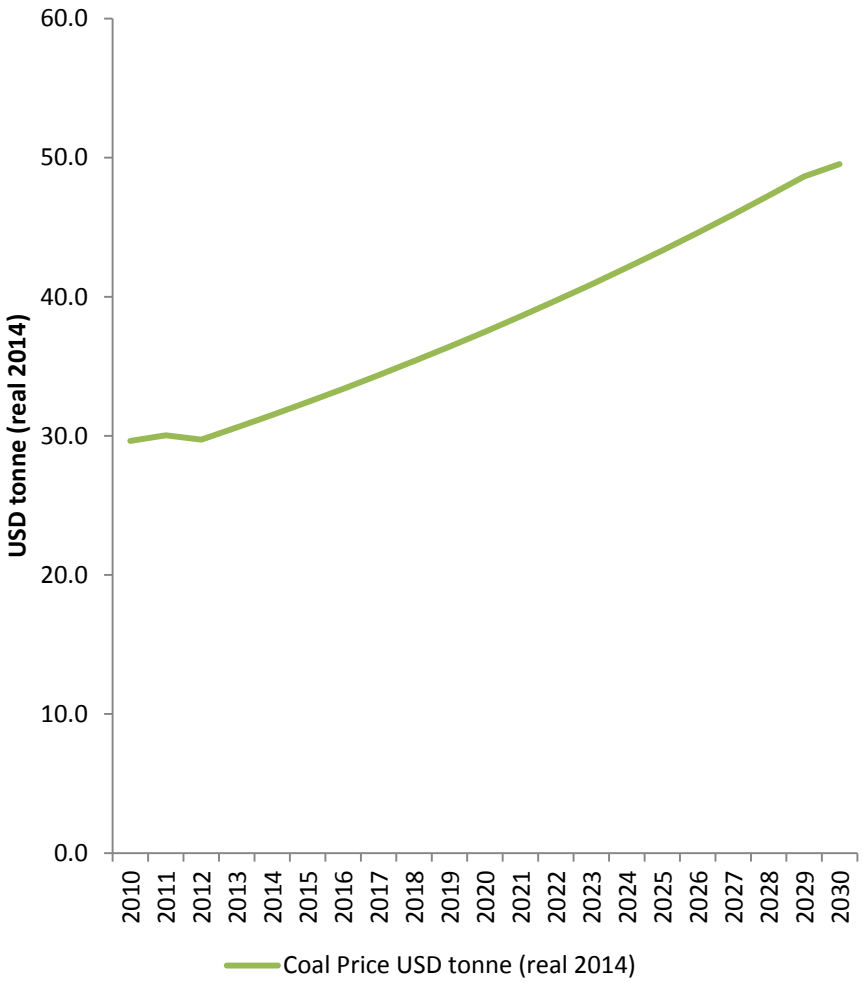
Demand side:

- Chinese demand for coal is likely to rise due to underlying economic expansion however the growth is likely to be subdued - China needs to invests in infrastructure that enables domestic coal transportation.
- The level of fuel switching away from gas to coal in power generation Europe witnessed in Spain and UK is unlikely to continue further due to environmental concerns
- India has strong demand for import thermal coal, however, price sensitivity will likely keep pressure on prices.

Supply side:

- There are plentiful supplies from Indonesia, Australia and US on the horizon.
- Major infrastructure debottlenecking projects and brownfield expansion projects in Australia are coming on line.
- US continues to switch to gas due to the attractive gas price relative to coal. The US exports excess coal abroad.

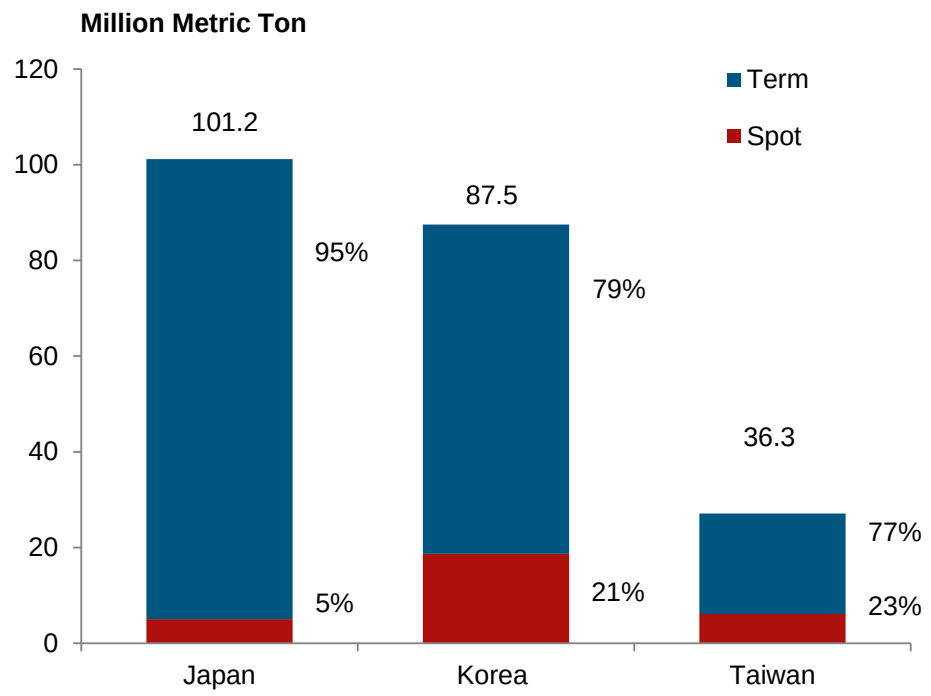
Domestic coal price forecast



- We forecast that the domestic coal price will gradually rise.
- Imports of coal are set to be reduced to meet local demand in power.
- In order for Vincomin to remain viable the artificially low domestic coal prices will have to rise to compensate for a reduction in volumes of higher priced exports.

In Pacific basin, the majority of seaborne trade is settled through term contracts with the balance made up by spot market purchases

Major thermal coal importing nations 2011 import split by term contract/spot purchases



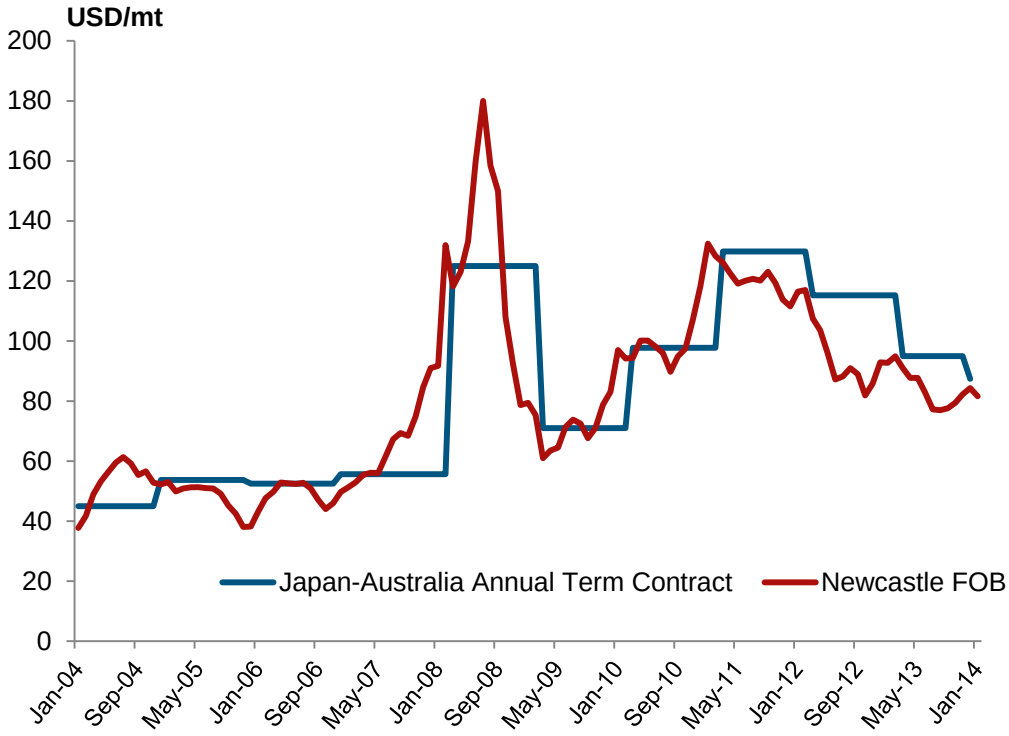
Source: Company presentations, custom data, TLG Analysis

- Japan, South Korea and Taiwan import 100% of thermal coal requirement
- Procurement strategy gravitates towards supply security and a diverse supply portfolio is maintained
- JPUs are the most conservative and procure almost 95% of its coal imports from term contract.
- This is however a significant improvement from the non-existence of spot procurement before 1996, the liberalization of Japan's electricity market
- Power utilities in South Korea and Taipower acquire larger portion of coal imports on the seaborne spot market

Import dependent Japan, Korea and Taiwan acquire a majority of thermal coal requirements from term contracts and maintain a diverse supply portfolio in terms of countries and supplier companies

The long term trend has been moving from long term contracts to the spot market

Price comparison between annual term contract and spot market 2004-2014



Source: Xstrata financial reports, World Bank Commodity Prices

Traditional take-or-pay contracts worked well during times of stable coal prices but not in current volatile markets

- Spot market prices are particularly volatile around the time of annual term contract negotiation, making the process long and difficult
- For the past two years, spot market prices have been consistently below that of fixed contract price, making prices uncompetitive for term contract buyers
- Fixed-price coal deliveries are not always secure. Regular delays are experienced during times when spot market prices rise above contract prices

Therefore, short term contracts and spot market purchases are increasingly used to complement long-term contracts for better procurement flexibility and cost competitiveness.

Procurement strategies: the need to balance between stable supply and economic purchasing

- **Diversification of coal import sources**

  - Taipower applies supply limits of

  i) Country 35% supplier 15% to term contracts

  ii) China: 30% for both term and spot
- **Coordination among Gencos**

  - Korea power utilities cargo swaps
- **Enhancing relationship with suppliers**
- **Investment in overseas coal mine**

  - Secure off-take contract

  - Taipower holds 10% interest in Bengalla coal mine in Australia

Stable Supply

- **Diversify pricing policy**

  - Development of index-linked, option embedded pricing mechanism
- **Competitive bidding**

  - Taipower's coal tender
- **Increase low rank coal blending**
- **Securing more dedicated vessels for distant sourcing**

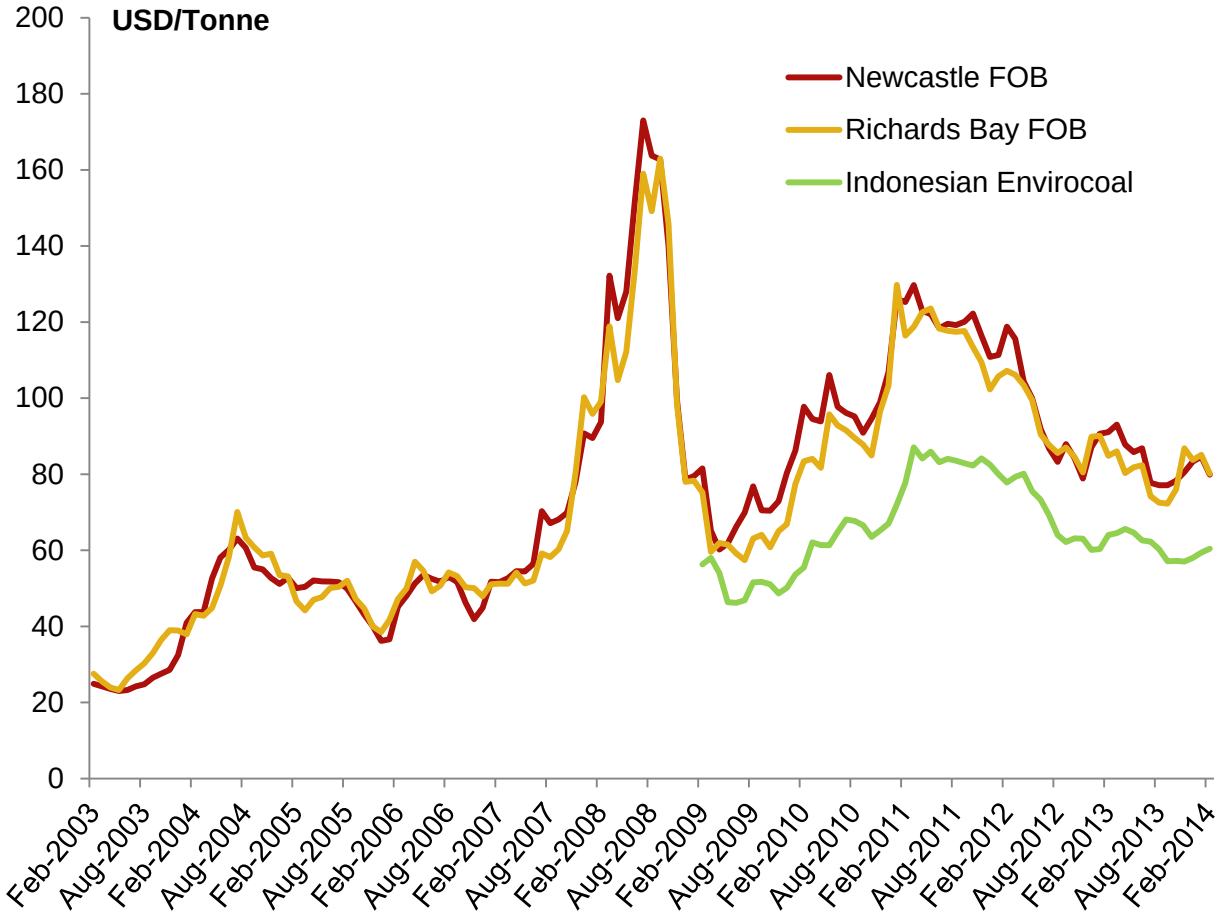
  - Shipment of Taipower-owned coal vessels reaches 30%

Unified coal procurement and negotiation

  - In 2009, 5 Korea Gencos formed fuel procurement union for 2.6Mt Chinese coal

Economic purchasing

Major Spot Market Reference Prices



Source: McCloskey, Indonesian Government

- Spot market price indexes are influential in their respective parts of coal importing countries
- Newcastle FOB price is commonly used as reference price for coal imports in Japan and South Korea
- Richards Bay FOB is commonly used as reference price coal imports in India
- Indonesia Kalimantan coal prices are commonly used as reference price for coal imports in China and Southeast Asian countries such as Philippines

Indonesian coal is priced with reference to government's monthly pricing guideline

Harga Batubara Acuan (HBA) on the basis of 6,322kcal/kg, TM of 8%, TS of 8%, 15% ash FOB vessel

HBA=25%ICI1+25%Platts59+25%NEX+25%globalCOAL NEWC Index

Harga Patokan Batubara (HPB)

Brand	Typical Quality			
	Calorific Value (kcal.kg GAR)	Moisture (%, ar)	Sulphur (%, ar)	Ash (%, ar)
Gunung Bayan I	7,000	10	1	15
Prima Coal	6,700	12	0.6	5
Pinang 6150	6,200	14.5	0.6	5.5
Indominco IM_East	5,700	17.5	1.6	4.8
Melawan Coal	5,400	22.5	0.4	5
Envirocoal	5,000	26	0.1	1.2
Jorong J-1	4,400	32	0.3	4.2
Ecocoal	4,200	35	0.2	3.9

Source: Directorate General of Mineral, Coal and Geothermal at The Ministry of Energy and Mineral Resources

- Indonesia government introduced Indonesian Coal Price Reference (HPB) for 8 brands of coal of varying quality to align domestic coal prices to international levels
- HPB is arrived at by adjusting differing coal quality to a general price reference (HBA). HBA is linked to both domestic and global prices, determined using a formula based on Indonesia Coal Index (ICI), Platts-1, Newcastle Export Index(NEX), and globalCOAL Newcastle Coal Index
- HBA and HPB are published monthly
- Price for term contract is the average HBA over the past three months and is fixed over a 12-month period, preventing Indonesian coal discount by setting an effective floor price

Ocean freight rates

Representative freight rates for major coal import routes

USD/Metric Ton	2011	2012	2013
Newcastle-> Japan Panamax	$17.13	$14.76	$15.09
Indonesia -> India Panamax	$10.20	$9.33	$9.91
Richards Bay ->Amsterdam-Rotterdam-Antwerp (ARA) Capesize	$10.78	$8.00	$9.12
Queensland -> Japan Capesize	$10.33	$8.82	$10.14

Source: Clarkson

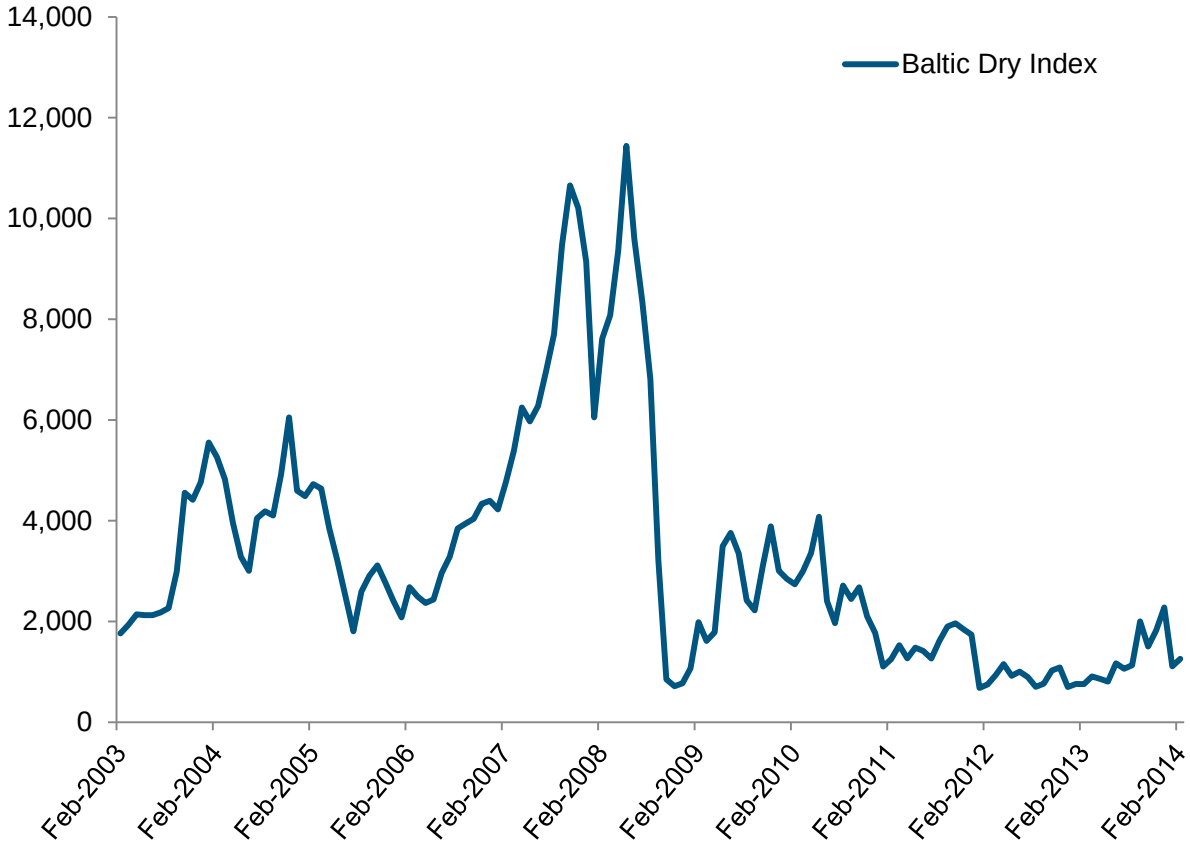
Ocean freight rates estimated between potential coal export and Vietnam

Panamax	USD/Metric Ton
Indonesia -> Vietnam	$4.89
Russia -> Vietnam	$11.47
Queensland-Vietnam	$13.48
Newcastle -> Vietnam	$15.34

Source: TLG Analysis

Freight rates will be the cheapest for Vietnam to import from Indonesia due to the geographical proximity, followed by Russia and Australia

Dry bulk freight rates: historical trend and outlook



Source: Baltic Exchange

- In 2013, freight rates slowly recovered from 2012 lows on the back of steadily improving global economy
- In the short term, freight rates will continue to be weighted down by oversupply caused by large amount of new vessels on the order book
- Oversupply will moderate post 2015, when increase in trade volumes and old vessel scrapping drive market back to balance
- Meaningful increases will be registered when demand starts to overtake the slowing vessel tonnage growth, driven by growing coal demand in China and India, improving harvests in Latin America and a recovery in minor bulk trade

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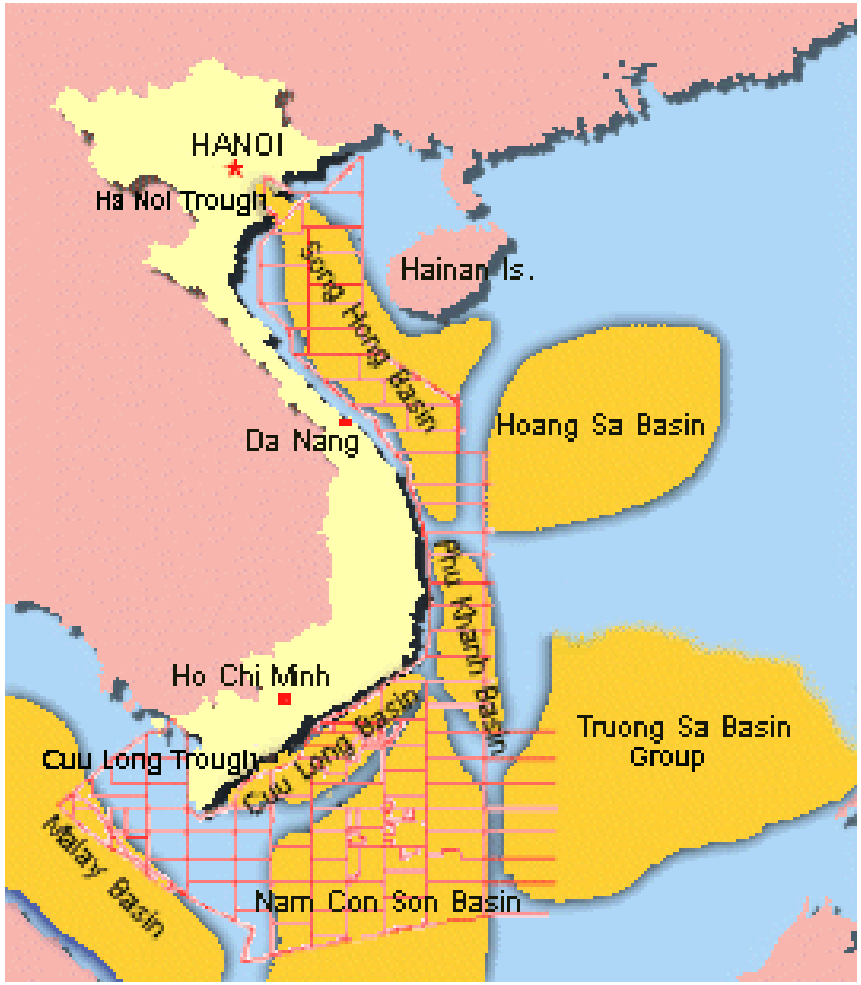
- Global LNG supply and demand
- LNG pricing – new dynamics led by disruptive influence of US LNG
- Impact of shale gas
- Domestic gas pricing – marginal cost versus rolled-in

Case study: Gas development in Vietnam

Vietnam natural gas supply: reserve and gas fields



Source: PVN, PVGAS

	Tcf
Total proved reserves	**12.6**
Cuu Long Basin	3.5
Nam Con Son Basin	6.6
Malay-Tho Chu Basin	4.8
Song Hong Basin	9.6
Total potential resources	**24.4**
Total reserves and unrisked resources	37.0

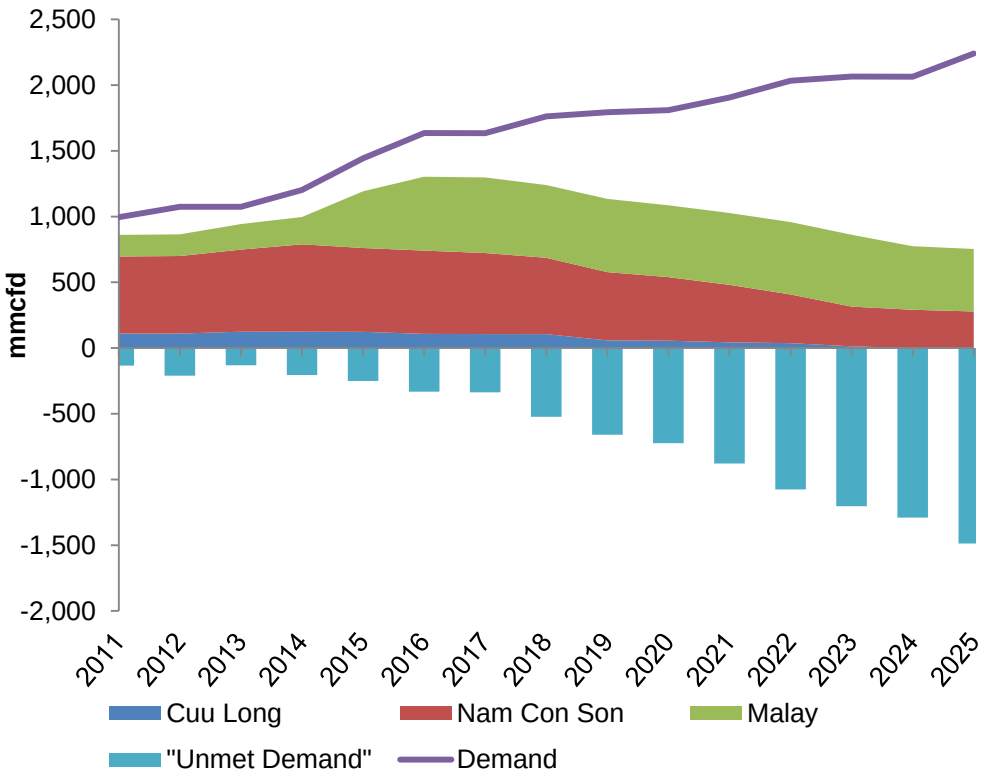
Source: PVN, PVGAS

Note that in Vietnam as a whole PVN and PVGas figures indicate 12.6 Tcf of proven reserves, and 24.4 Tcf of resources.

To upgrade resources to reserves requires exploration and appraisal drilling.

Moreover it requires the expectation of receiving a fair to generous return on risky expenditure – the E&P companies of course may make uncommercial discoveries or hit dry wells.

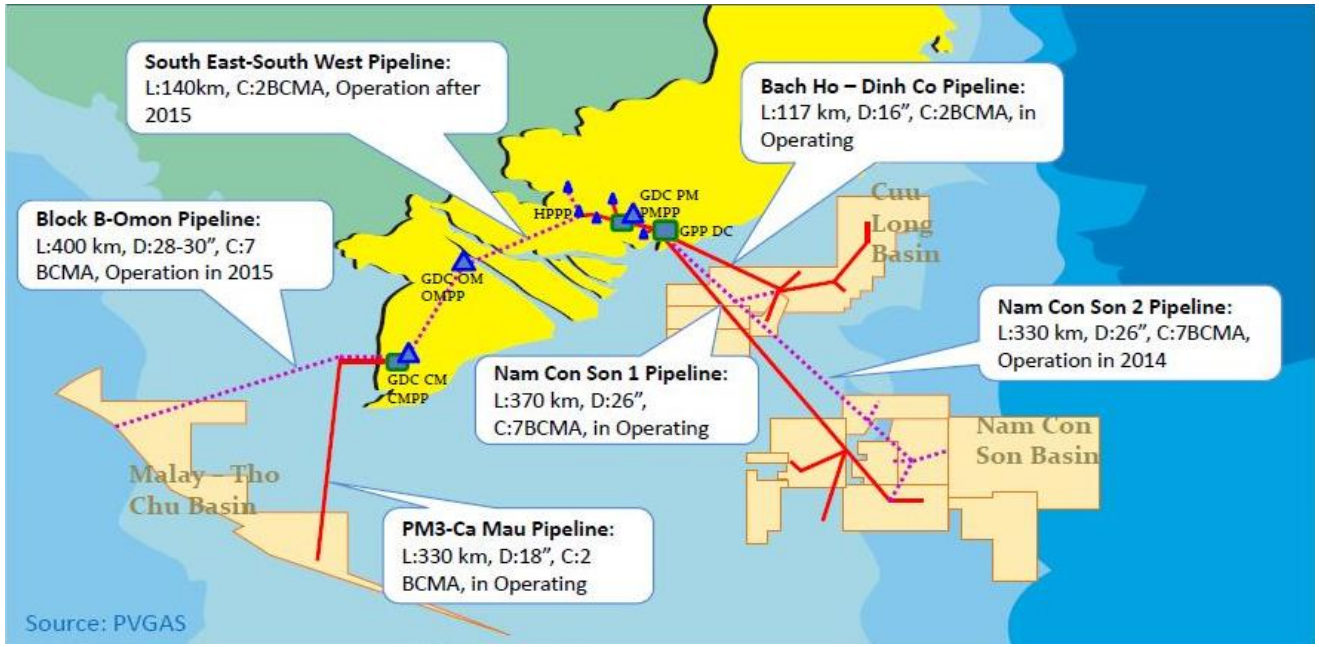
Official Vietnam natural gas southern supply and demand balance



Source: EVN, Vietnam PDP VII (2011)

- Through to 2025 this amounts to 6 Tcf of gas, but proven reserves, which we expect will mostly be located in the south, are already double this figure.
- With some **correct price signals** some of the 24.4 Tcf of resources should be able with some exploration and appraisal to be firmed up to probable or possible reserves.
- This gas could then close the demand supply gap.

Southern Vietnam natural gas supply: pipelines



Existing

Vietnam has three gas pipelines connecting offshore fields in the south with power plants and onshore gas distribution systems.

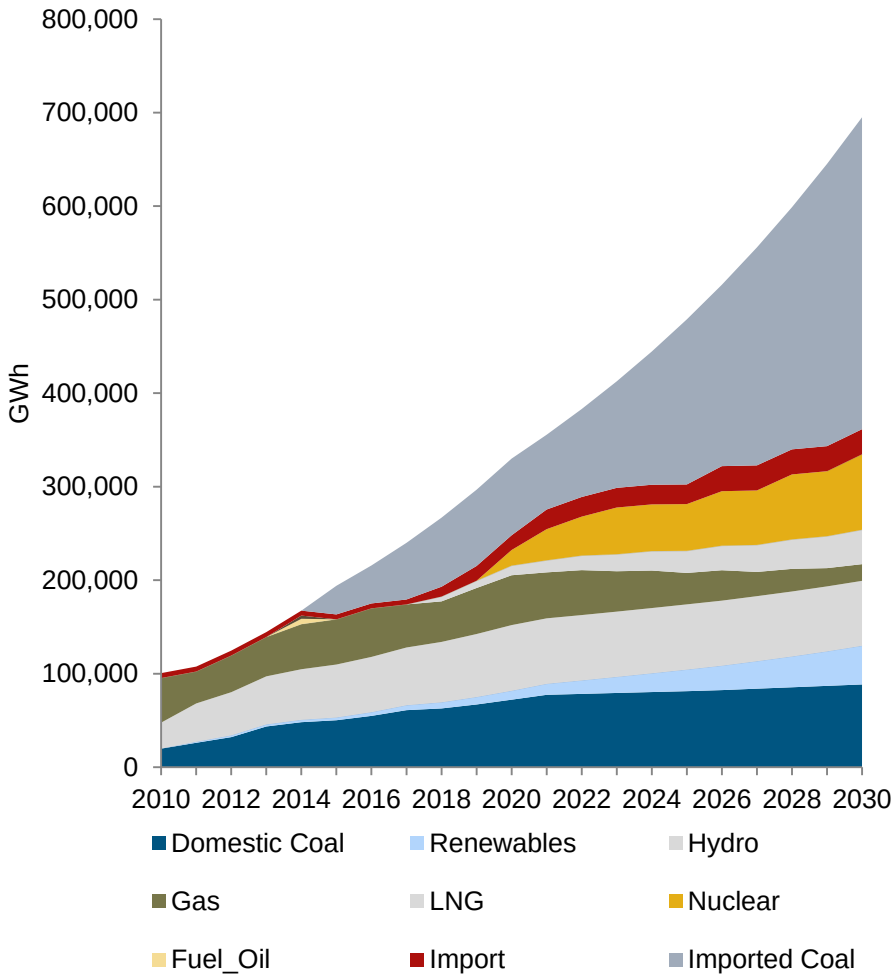
- The key pipeline is the 250-mile Nam Con Son pipeline, which accounts for a majority of Vietnam's gas supply and has a capacity of 700 mmcfd.
- The Bach Ho pipeline, with a capacity of 200 mmcfd, transmits associated gas from fields in the Cuu Long basin which are mostly associated gas.
- The third pipeline (200 mmcfd of capacity) runs from the PM3 Commercial Arrangement Area to the Ca Mau combined-cycle power plant and fertiliser plant.

Planned

A second Nam Con Son pipeline, with a capacity of 600 mmcfd is nearing development and slated for completion by 2017. PV Gas is at the FEED phase.

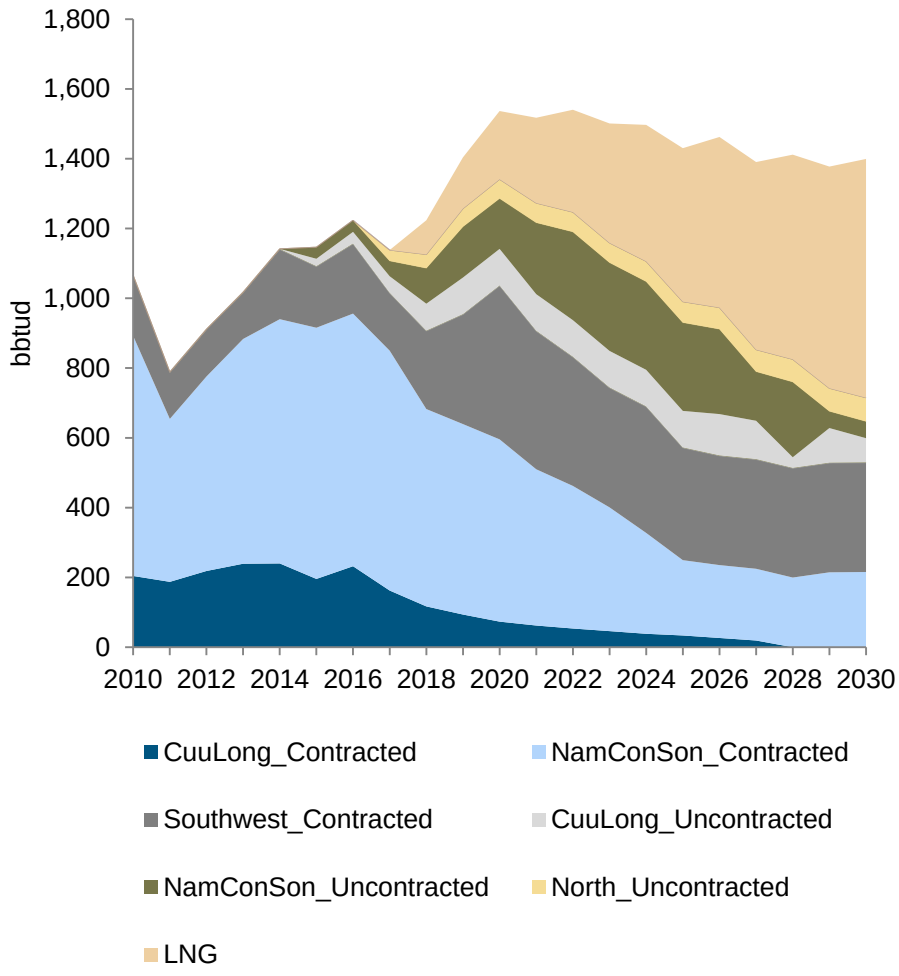
The Block B&52 to O Mon Pipeline with 600 mmcfd capacity is uncertain although and EPC contract has been inked. But it is intended to connect offshore blocks in the north Malay Basin (that Chevron is exiting) to the existing Ca Mau and the planned O Mon power plants.

PDP generation



- Overall demand reaches a very substantial 695 TWh in 2030 (versus 442TWh in our projection).
- Domestic coal levels out after 2020 (similar to TLG forecast).
- Renewables mainly wind make a growing presence rising to 5 percent of generation (similar to TLG forecast).
- Hydro rises to 10 percent of power produced (similar to TLG forecast).
- Gas fired generation gets squeezed out by other plants especially nuclear and coal.
- LNG is forced in starting in 2018, a few years later than in the PDP as no construction work has started yet on terminals.
- Nuclear contributes 10 percent of generation by 2030 (versus zero in TLG projections).
- Imports of power direct from China grows in the PDP forecast (versus flat outlook in TLG forecast).
- Imported coal accounts for almost half of generation by 2030 (versus 25 percent in TLG forecast).
- Competition from other types of generation and assumed LNG use results in lower demand for domestic gas (relative to the TLG forecast).

PDP gas demand forecast



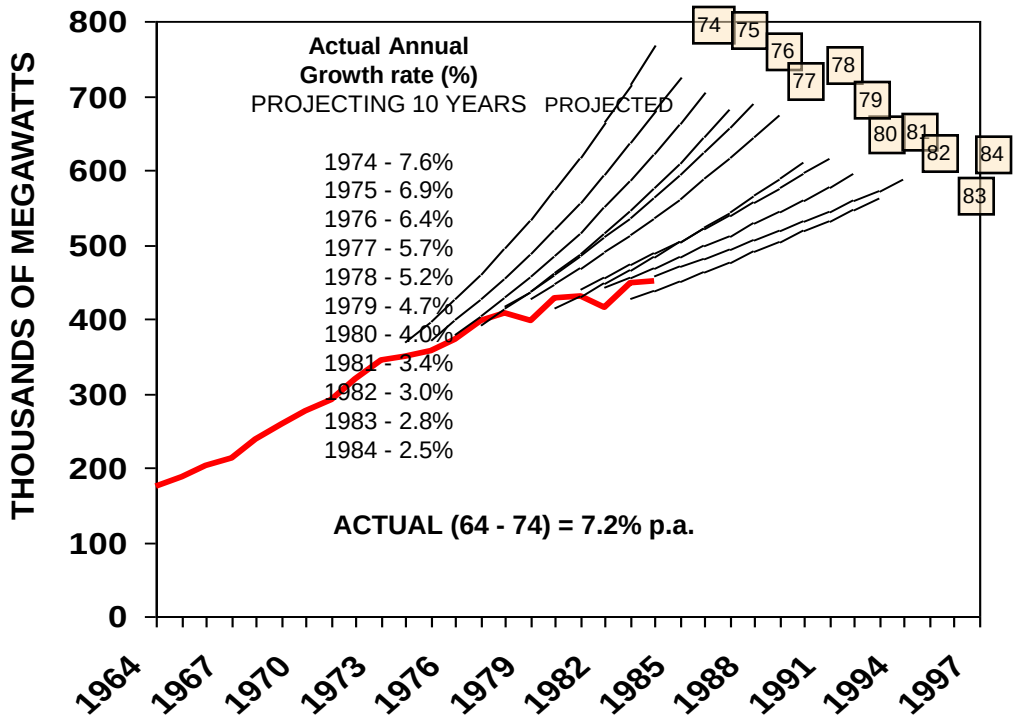
- Demand for piped gas is hampered by forcing in LNG from 2018 onwards.
- The rise in generation from imported coal in particular hampers growth in domestic gas into power.
- There is no need for any gas in the central area from new offshore discoveries as imported coal-fired generation is less expensive.
- There is some demand for gas in the north as we see some demand in the industrial sector.

We see three fundamental flaws in the PDP

- The load growth forecast is wildly optimistic
- Capacity expansion plan (at least implicitly) uses LNG to meet incremental load growth – but LNG is not economic relative to alternative resources (and also assumes nuclear development starting in 2020)
- Ability to pass on LNG costs to consumers appears dubious – and certainly does not justify use of LNG for baseload power

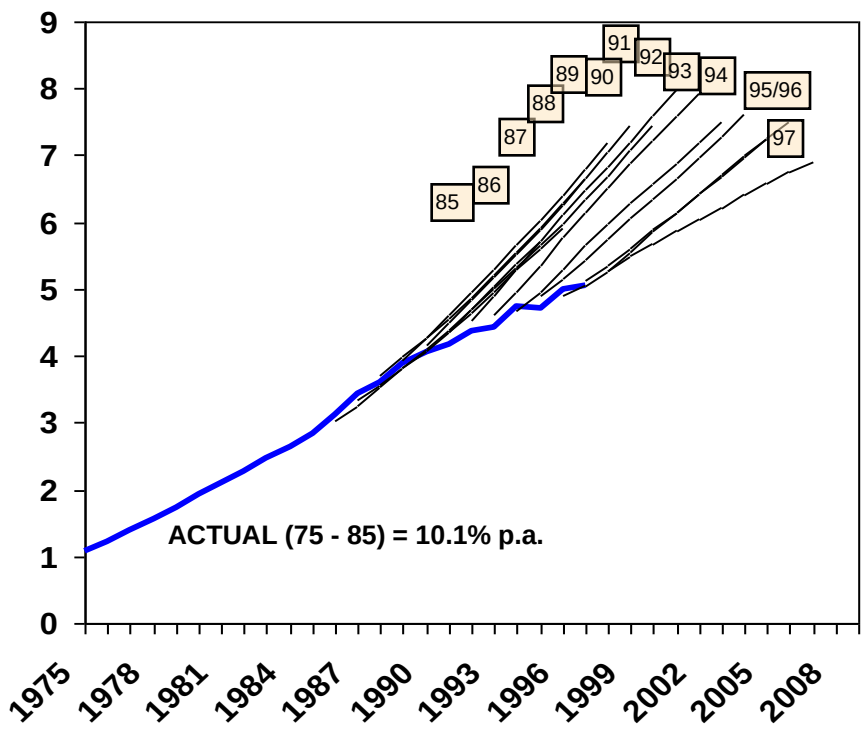
Balancing supply and demand is a dark art
– forecasts often look a lot like wild guesses when viewed with hindsight

USA



Source: North American Electric Reliability Council, *Electric Power Supply & Demand 1984, p.5*

Asian Country

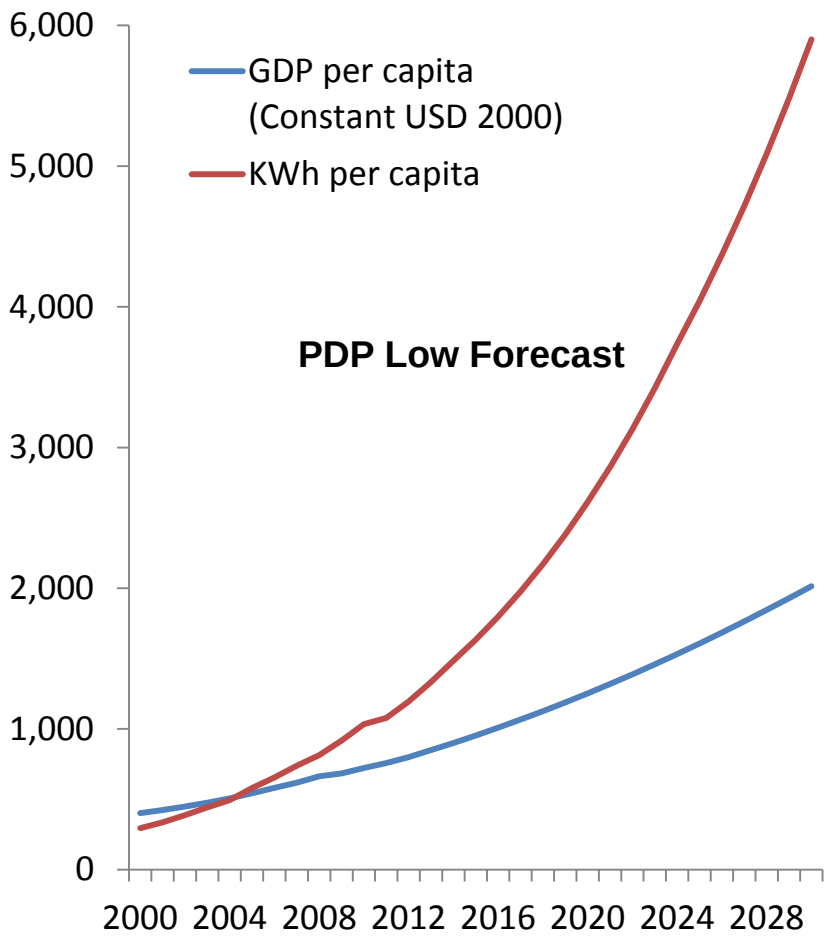


Source: Client Confidential

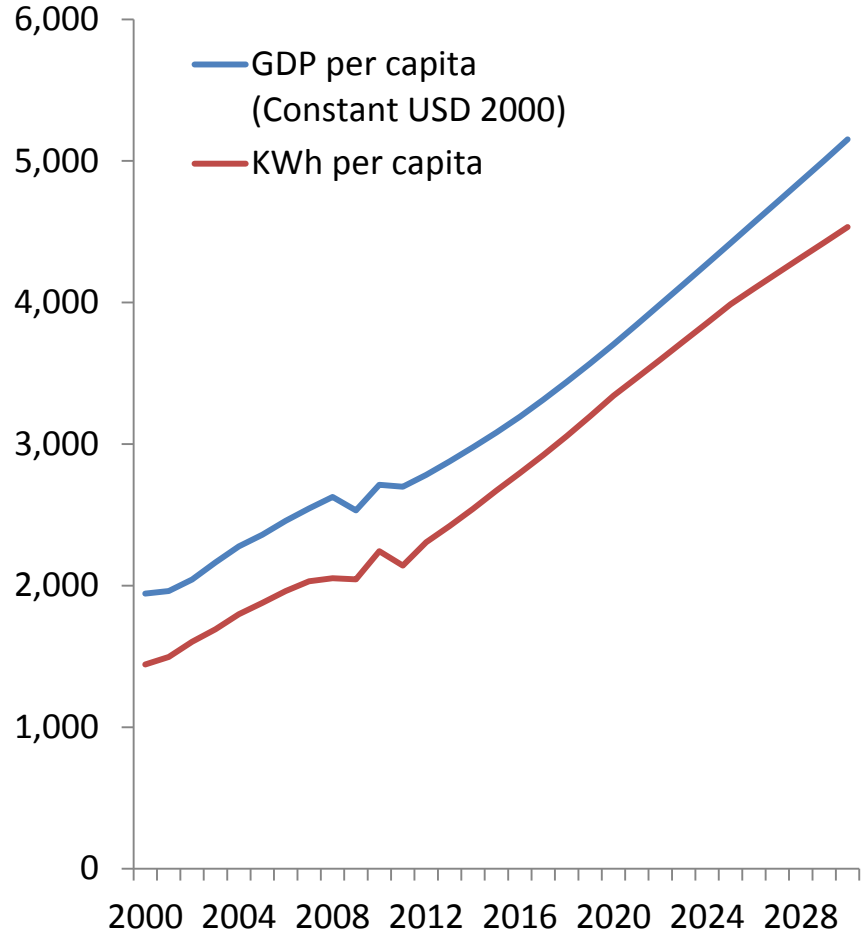
Warren Buffet: “Forecasts tell you little about the future, but a lot about the forecaster”

Vietnam projects much higher load than Thailand, despite much lower GDP

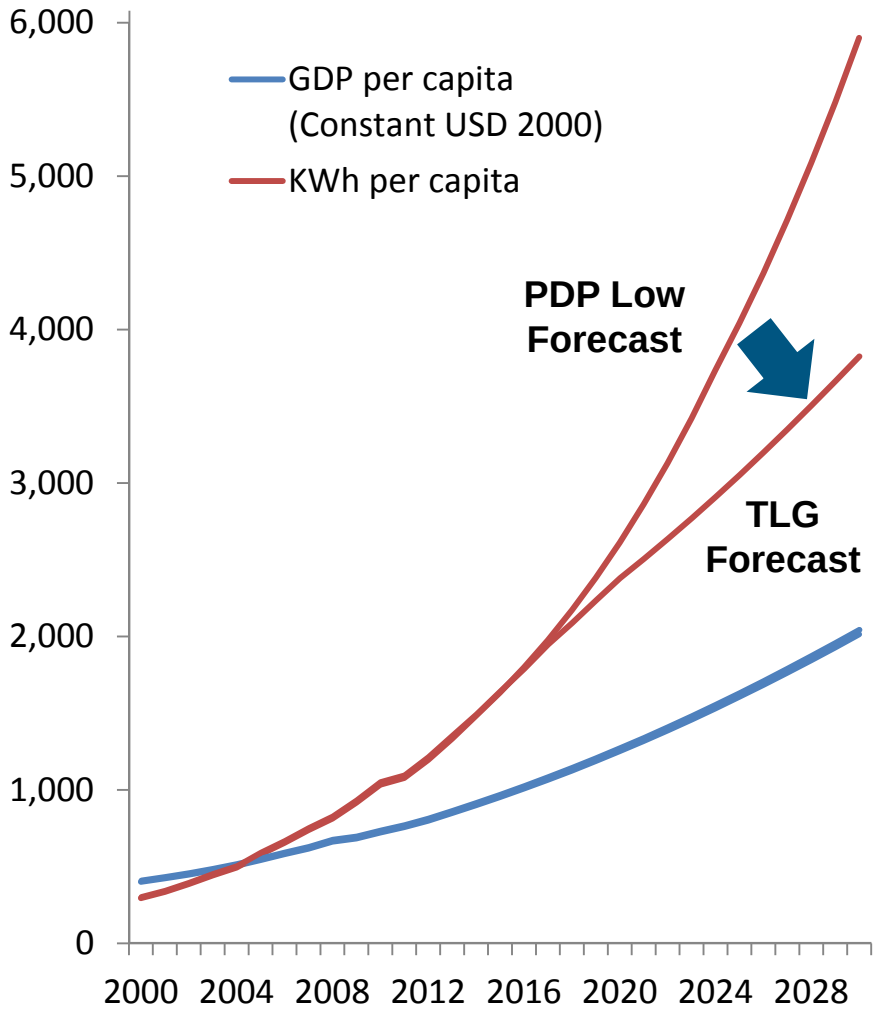
Vietnam



Thailand



Our TLG forecast reduces the load growth rate substantially



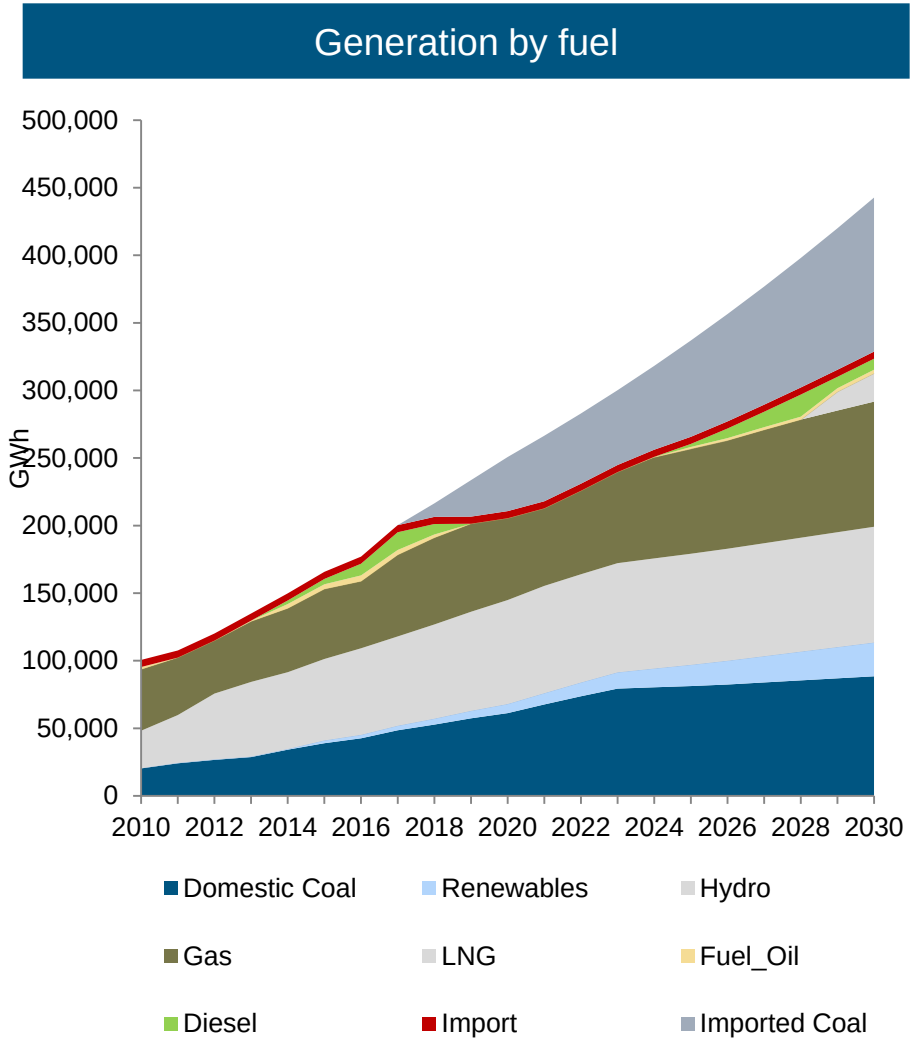
- The low PDP generation forecast looks way over-ambitious compared to economic growth
- We have assumed the same underlying GDP growth rate (6.5% average annual expansion the economy to 2030) as assumed for the low PDP forecast
- We have assumed an average elasticity of power generation growth to economic growth of 1.2 times through to 2030 (versus an average of 1.6 times for the low PDP forecast) – and we feel even this assumption is aggressive.

Gas prices will be limited by the competition between coal and gas economics

Plant Type	Gas CCGT	Coal Greenfield State of Art
Plant Details and Capital Cost		
Generic USD/kW	800	1,600
Economic Life (years)	25	30
Capacity Factor (%)	**85**	**85**
Fixed Cost		
Capex (USD/MWh)	15	32.2
Fixed O&M per MWh	2	3.4
Fixed (USD/MWh)	**17**	**36**
Fuel Costs	Gas	Coal
Gross Fuel Cost (HHV) (USD/mmbtu)	8.00	3.65
Heat Rate (mmbtu/MWh)	6.7	9.0
Variable Costs		
Variable O&M per MWh	2	4
Fuel per MWh	54	34
Variable (USD/MWh)	**56**	**38**
LRMC (USD/MWh)	**73**	**73**

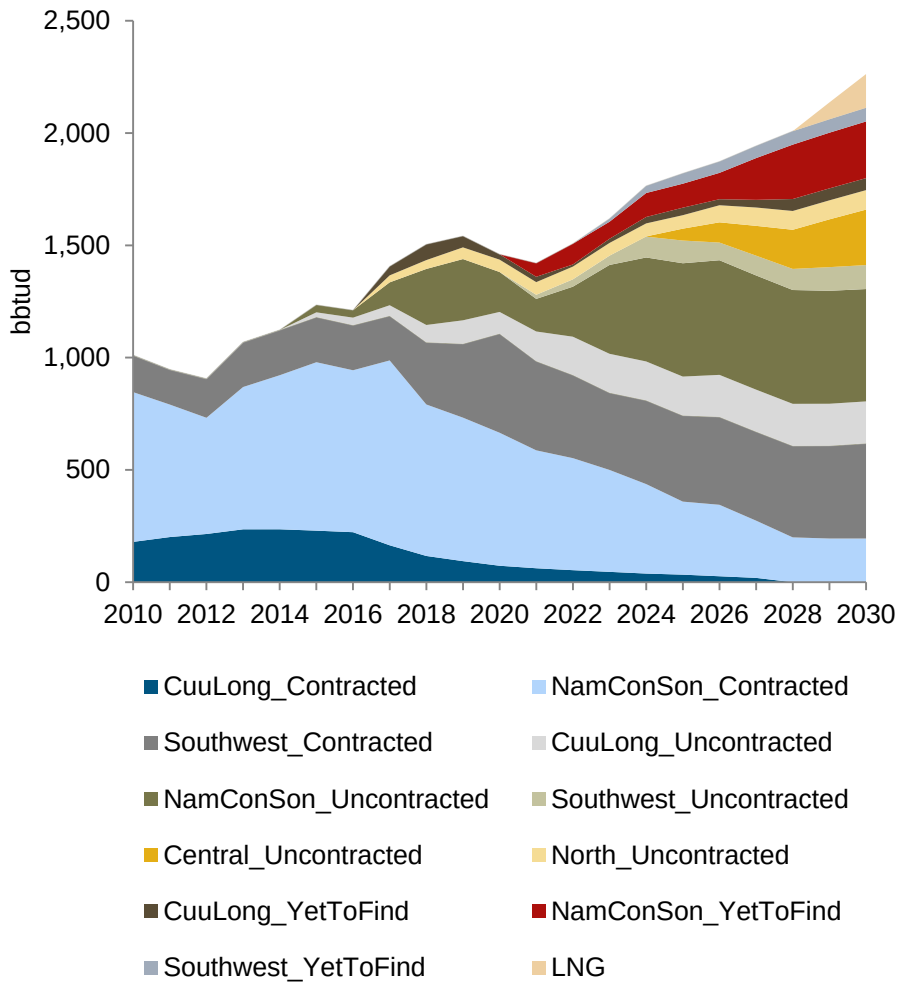
- State-of-the-art technology and coal fired plant
- Plant competing for base load with average capacity factor of 85 percent
- Use the economics of the new build coal plant to determine the competing price for delivered gas
- This would be gas delivered to a new build combined cycle gas turbine
- Should be willing to pay up to USD 8 per mmbtu delivered for gas.
- This indicates a range of USD 6.25 to 6.50 per mmbtu upstream.

TLG generation forecast



- Domestic coal generation levels out after 2020 due to plateau in local supplies.
- Renewables mainly wind show steady growth but will need to sort out feed in tariffs.
- Hydro is an important source of generation but shortage of new sites hampers growth after 2020
- Generation from gas fired plants rises despite, in some cases, being slightly higher cost than power from imported coal, due to siting problems for coal fired plant. We imposed some constraints on new build imported coal to let in more gas.
- LNG arrives at the end of the horizon to supplement local gas.
- There is some fuel oil and diesel needed for peaking.
- Large rise in generation from imported coal starting in 2018 and rising to account for 25 percent of total by 2030 (versus 50 percent in PDP).

TLG gas balance



- Southwest contracted rises by 2018 reflecting the rise in supplies from block B&52, which although not contracted we view as committed.
- Cuu Long uncontracted is needed to back fill the existing pipeline by 2014 and later on gets access to market via a T-in to the Nam Con Son 2 pipeline.
- Nam Con Son uncontracted gas can only get into market once the Nam Con Son 2 pipeline is completed, we estimate commissioning in 2017.
- Southern yet to find gas is not needed until 2017 from associated and inexpensive gas in the Cuu Long basin and by 2021 from the more expensive generally non-associated gas in the Nam Con Son basin.
- We force in Central uncontracted gas by limited new build generic imported coal fired plant in that region due to siting problems.
- North uncontracted gas goes to industry not power due to the large amount of new build coal fired plant in that area.

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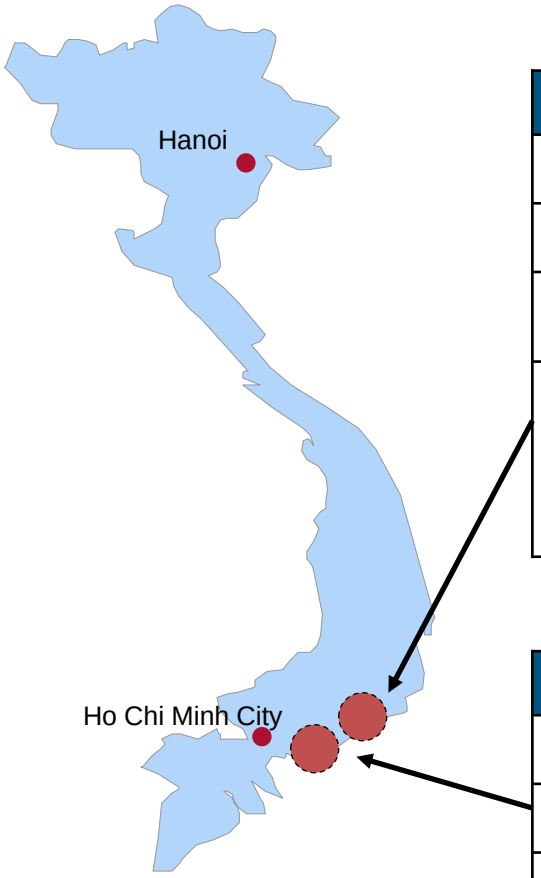
Case study: Gas development in Vietnam

Official LNG regasification development plan



Son My LNG receiving and regasification terminal	
Location	Binh Thuan province
Investment	>U$1.3 billion
Capacity	3.6 mmtpa (Phase I) 6-9.6 mmtpa (Phase II)
Operational Expansion	2018 (Phase I) – 1.8mmtpa 2019 – receiving first LNG 2020 (Phase I) – 3.6mmtpa 2023 (Phase II) – 6mmtpa 2026-2030 (Phase II) – 9.6mmtpa

Thi Vai LNG receiving and regasification Terminal	
Location	Ba Ria Vung Tau province
Investment	Est. U$246 million
Capacity	1-2 mmtpa
Operational	Mid-2016- receiving first LNG

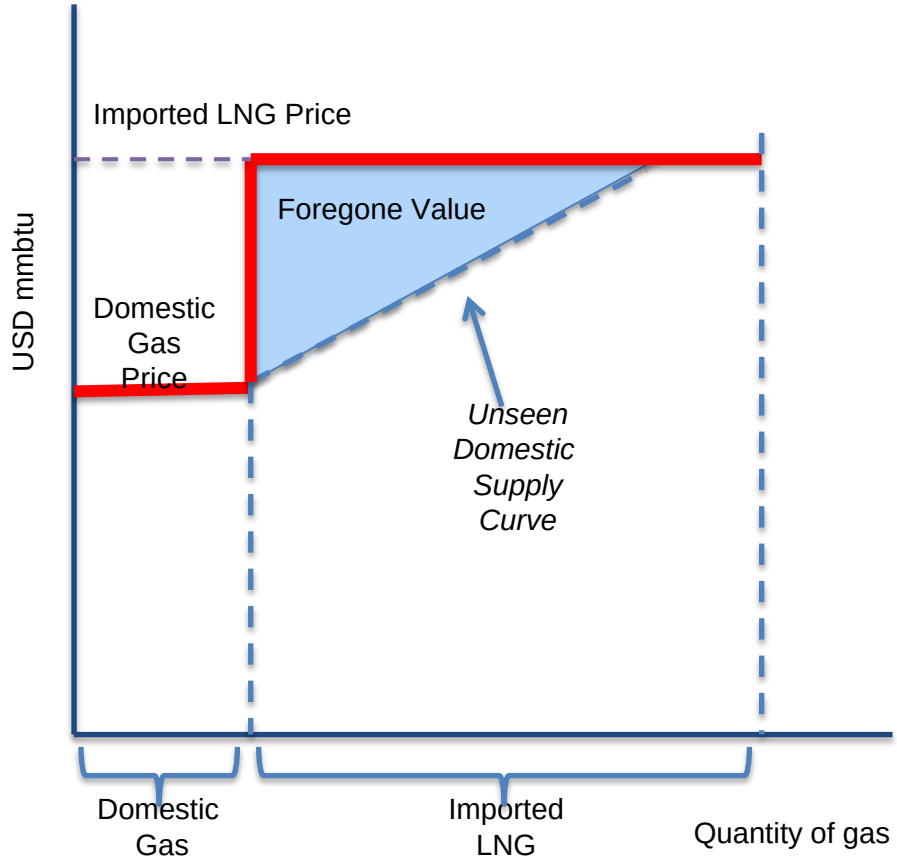
- Vietnam's 2016-2025 gas development plan gives priority to LNG imports and cutting LPG imports.
- Vietnam's state run Petrovietnam Gas Corp (PV Gas) will be in charge of constructing the first two LNG terminals in Vietnam
- In March 2012, Tokyo Gas Co. Ltd has entered into MOU with PV Gas to design the first LNG terminal as well as develop the LNG value chain in Vietnam
- In July 2012 Russia's Gazprom and PetroVietnam had signed a memorandum of understanding on Russian LNG deliveries to Vietnam. PV Gas is believed to be also in talks with QuatarGas and Australian suppliers for potential supply.

Comments on official LNG development plan

- Subject to endless delays as the plan to import of LNG has several serious short-comings
- The state power utility has trouble passing on costs of its existing fuel costs, far less the jump in costs that would come with large supplies of LNG at a premium to domestic gas prices
- Ignores potential supply that could come from offering a better price to domestic gas. But breaking through into the high single digits far less double digits per mmbtu has proved an insurmountable mental hurdle, so far……
- The global LNG suppliers will check to see if the buyer of LNG under a long term contract has the ability to pay for it. While PVN and PV Gas are viable and bankable entities the same is not so far true for the power company EVN. This will make buying any LNG under long term contract very difficult.
- So what to do?

Raise domestic gas prices first to get more domestic supply

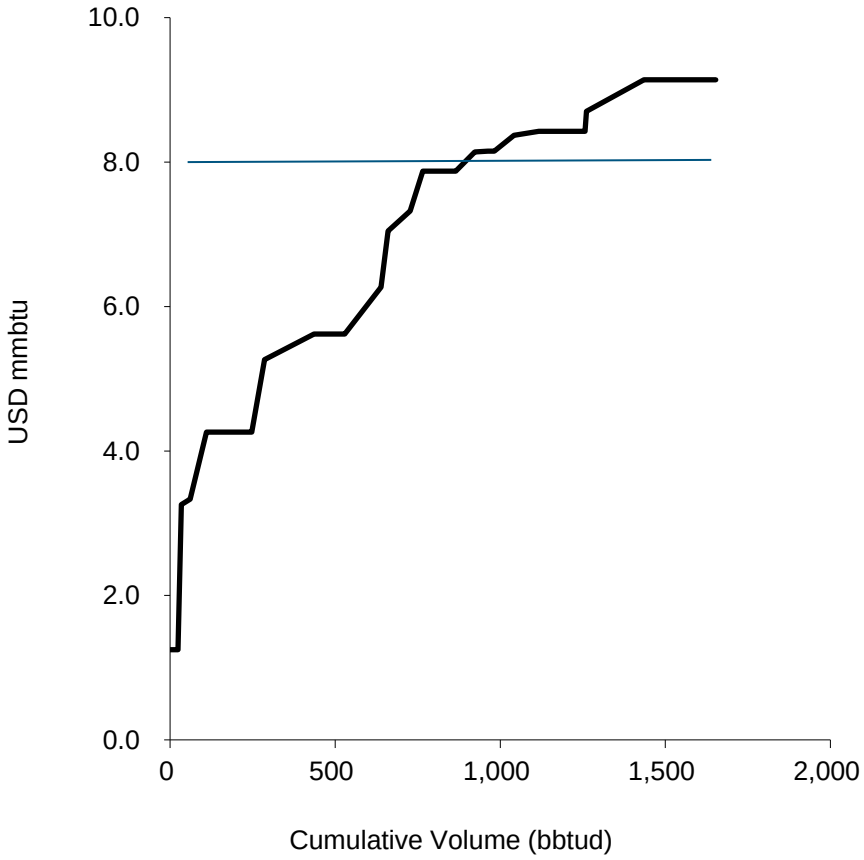
Kinky gas price curves



- A kink arises at the point where there is no more domestic gas available at the acceptable domestic price. Consequently, the country imports LNG to fill the gap to meet demand. Without access to the imported LNG price, gas developers do not explore or develop domestic resources to the extent that they might otherwise. The result is foregone value.
- Vietnam is one of the countries in Asia with the most pronounced 'kinky' gas price curve. The last non-associated gas price contract signed was almost a decade ago from block 11-2 for gas from the Rong Doi field.

Supply curve for domestic gas

Delivered gas at breakeven cost in 2020



- In this diagram we stack up uncontracted and estimates for yet to find gas by breakeven cost.
- Any gas above USD 8 mmbtu delivered, or in the range USD 6.25 to USD 6.5 mmbtu ex-platform would be displaced by less expensive generation from new build imported coal fired plants.
- There is a fairly large amount of gas that can compete with new imported coal fired plant. But also a substantial volumes of gas that would come in above the tipping delivered price of USD 8 mmbtu.
- In the PDP run none of that higher priced gas gets to market, but in the TLG run to recognize the siting constraints that some new imported coal fired plants might face, we allow in some of this higher cost gas.

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Case study: Gas development in Vietnam

The gas decision in Asia is particularly complex

LNG supply glut with global prices converging

Supply: US LNG export and Australian projects are executed as planned; shale gas production in US continue to increase significantly

Demand: China develop their shale gas resources and scale up production and investment in the near term, leading to less LNG demand

Prices: Both buyers and sellers accept new pricing mechanism and more LNG contracts are linked to HH, with more contractual flexibility

Which world?

Why?

How to manage if wrong?

Seller's market as Asia still pays premium for LNG

Supply: US LNG export and Australian projects are delayed because of various challenges

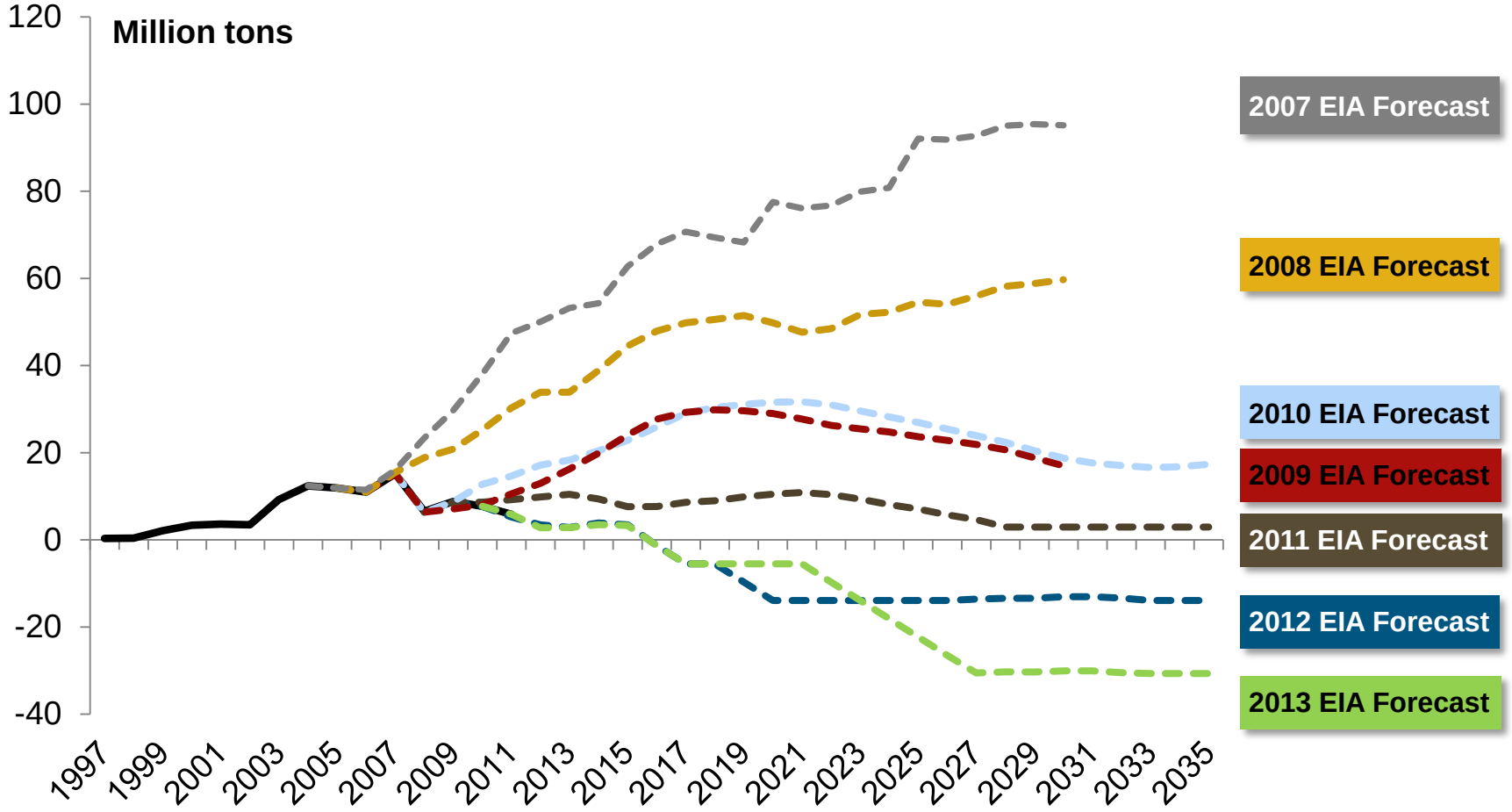
Demand: Chinese LNG demand is unexpectedly high as its domestic gas resource (especially shale gas) are developed very slowly; LNG demands in new markets are unexpectedly high

Prices: Asian buyers have to pay higher premium for LNG than other regions

Either way, gas in Asia is likely to struggle to compete with coal in the near and medium term, without a strong environmental agenda and robust government support

The USA, a previously anticipated major growth market for LNG imports, is expected to become a net LNG exporter as early as 2016

Evolution of US Net LNG Imports Forecast by EIA



Source: US Energy Information Administration (EIA), AEO 2007-2013

Out of the total of about 200 mmtpa of capacity applied to the DOE, 63 mmtpa has been approved for export to non-FTA countries

Group	Project	Requested volume, bcfd	DOE application			FERC application			Capacity, mmtpa	
			FTA approved	Non-FTA application submitted	Non-FTA approved / DOE order	Pre-filling completed	Filing completed	Filing approved	Terminal total	Group total
Non-FTA approved	Sabine Pass 1-4	2.2	✓	✓	✓	✓	✓	✓	18.0	62.8
	Freeport 1-2	1.4	✓	✓	✓	✓	✓		8.8	
	Lake Charles	2.0	✓	✓	✓	✓	✓		15.0	
	Dominion Cove Point	1.0	✓	✓	✓	✓	✓		4.6	
	Freeport 3	1.4	✓	✓	✓	✓	✓		4.4	
	Cameron	1.7	✓	✓	✓	✓	✓		12.0	
Non-FTA pending, filed with FERC	Jordan Cove Point	1.2	✓	✓	1	✓	✓		6.0	37.9
	Oregon LNG	1.3	✓	✓	2	✓	✓		9.6	
	Corpus Christi	2.1	✓	✓	3	✓	✓		13.5	
	Excelerate	1.4	✓	✓	4	✓	✓		8.8	
Non-FTA pending, pre-filed with FERC	Southern	0.5	✓	✓	6	✓			2.5	21.6
	Gulf LNG	1.5	✓	✓	7	✓			2.1	
	Sabine Pass 5-6 Total	0.3	✓	✓	12	✓			2.0	
	Sabine Pass 5-6 Centrica	0.2	✓	✓	13	✓			1.8	
	Sabine Pass 5-6 Uncommitted	0.9	pending	✓	17	✓			5.3	
	CE FLNG	1.1	✓	✓	8	✓			8.0	
Non-FTA pending, no FERC pre-filing	Gulf Coast	2.8	✓	✓	5				20.6	73.2
	Golden Pass	2.6	✓	✓	9				15.6	
	Pangea	1.1	✓	✓	10				8.0	
	Main Pass	3.2	✓	✓	11				24.0	
	Venture	0.7	pending	✓	14				5.0	
Only applied for FTA license	Waller	0.2	✓						1.3	6.8
	Magnolia	0.5	✓			✓			4.0	
	Gasfin	0.2	✓						1.5	
										202.3

US LNG – it's not about the price as much as it is about the flexibility….

A NEW MODEL

US LNG buyers contract for liquefaction capacity. When they want LNG they buy it at Henry Hub prices. Then they can take it anywhere they want – resell or for own use. Tap can be turned on and off at will. The LNG price is not linked to oil.

AROUND FOR THE LONG TERM

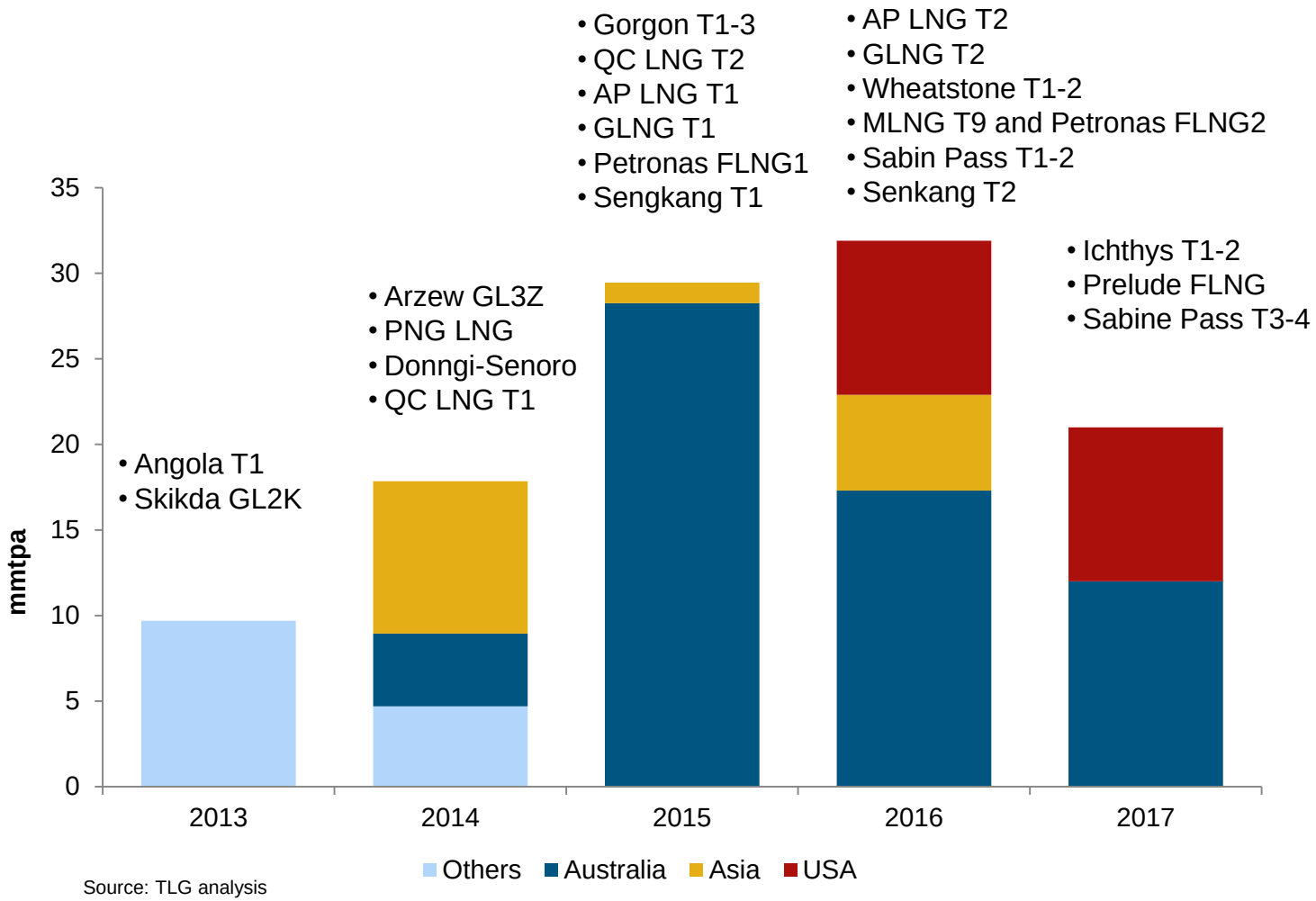
US domestic demand for natural gas is close to 24 Tcf/year and the nation has recoverable resources of some 2,200 Tcf, according to EIA data. A rise in demand for gas from US transport and petrochemicals could add some 6 Tcf to demand by the start of next decade. If all 200 mmtpa of LNG export plants go ahead (which is unlikely) then this would require close to 10 Tcf of gas per year. So even 40 Tcf per year of demand still gives the US some 55 years of gas in the ground.

NOT EASILY REPLICATED

This contrasts with the Western Canadian LNG projects which are more typical in that they specify a source of gas, will build dedicated new long pipelines to get the gas to the coast, and develop liquefaction plants and then sell the LNG. Projects have some buyer participation but at the moment are led by traditional LNG majors and aspirants. Pricing might be oil linked or linked to AECO (Canadian version of Henry Hub).

Australia developing traditional LNG for Asia, with US LNG coming a few years later

LNG liquefaction projects under construction/reached FID, 2013-2017

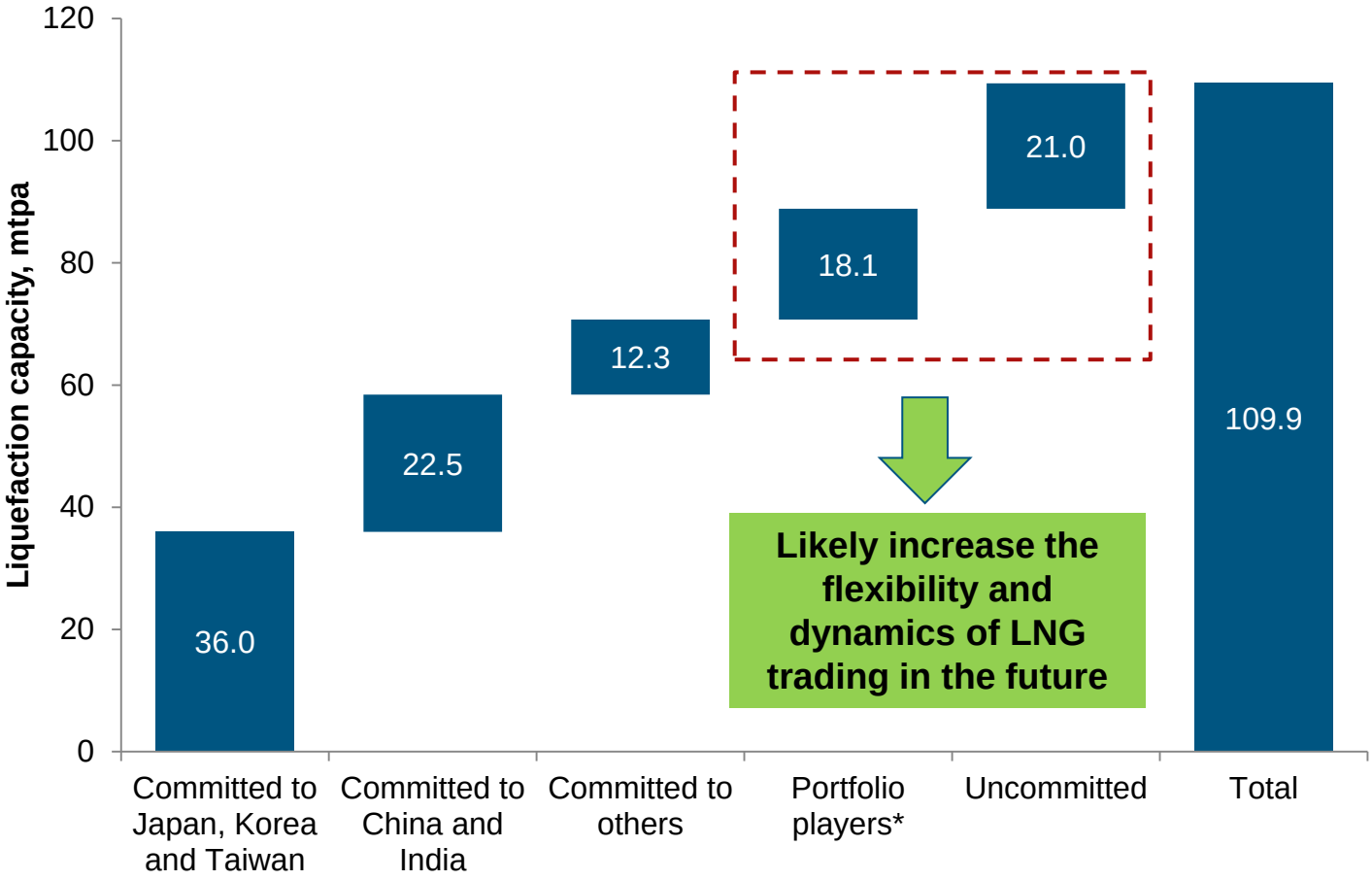


Source: TLG analysis

- The near term LNG capacity will be mainly from Atlantic basin, which used to export LNG to Europe and US. With the low demand in Europe and no demand in US, most of the new Atlantic LNG is expected to be directed to Asia.
- Large amount of new committed LNG volumes from Australia will start to enter the market from 2015 onwards.
- US LNG will start to export to Asia from 2016

The flexible and swing segment of the Asian LNG market reaches nearly 30% of new capacity by 2017

LNG liquefaction projects under construction/reached FID, 2013-2017



- Portfolio players (such as BG, BP, Shell and Total etc) have contracted 18.1 mmtpa of LNG from the committed LNG capacity, which have no firm destination.
- 21.0 mmtpa of LNG is also uncommitted for the committed LNG liquefaction capacity.
- **All these could lead to more flexible LNG trading in the future**

Note: Portfolio players' share exclude the volumes that are committed to buyers in a specific project
Source: TLG analysis

The North America LNG projects in 2018-2025 are poised to amplify the disruptive influences of Japan (demand uncertainty) and Australia, East Africa (new supply)

LNG Liquefaction Capacity, mmtpa

	Under Construction or reach FID (2013-2017)	Likely projects (2018-2025)	Other announced projects
Australia	61.8	12	36.0
US	18	53.8	130.5
Canada		17	52.6
Africa		30	41.4
Others	14.5	15	75.5
Asia	15.7	5.8	5.5
Total	**110.0**	**133.6**	**341.5**

- US LNG exports will be free on board and so be more flexible on destination restrictions and allowing re-exports and diversions. (Pertamina and Corpus Christi contract).
- Canadian LNG exports will be more like traditional LNG projects with developers investing from upstream, pipelines and liquefaction plant.

- Buyers have bought over 30% in the acreage supporting the Mozambique LNG project, and Pavilion Energy some of the acreage directed at Tanzania LNG

The large volume of potential flexible Henry Hub-linked LNG from US and maybe Canada could have disruptive force in long term LNG trading, new contract negotiation and re-negotiation of contracts.

But Australian projects have many challenges

High costs

- High labour cost with skills shortage
  - Tight immigration
  - Small population
- High construction materials' costs
- Technically difficult upstream projects
- Remote locations with little existing infrastructures

Environmental

- Tight regulation (BTEX fracking chemicals banned and drilling buffers around towns)
- Strategic cropping land
- Water resource issues

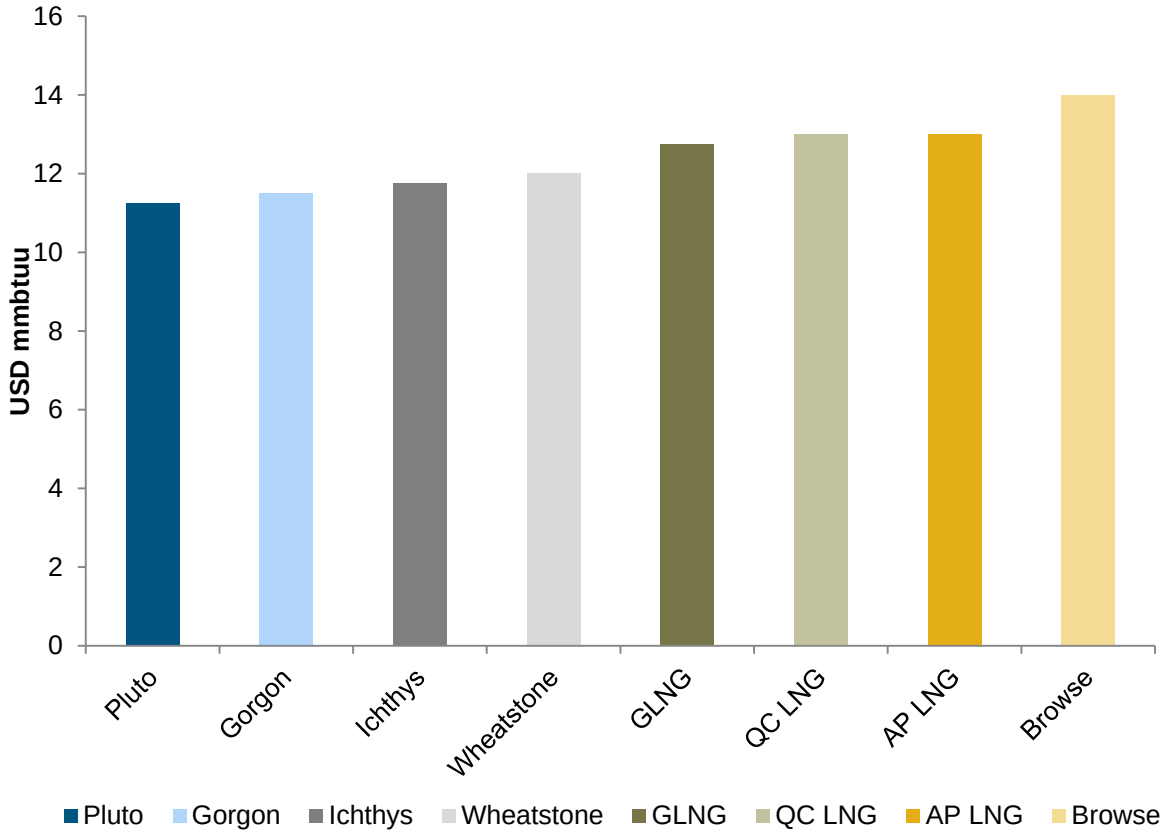
Fiscal and Political

- Fiscal uncertainties
  - Carbon tax
  - Extended Petroleum Rent Tax
- Political uncertainties
  - Domestic/Export
  - JPDA – E. Timor
  - Native title

While supply projects in other countries face *some* of these challenges, the <u>combined</u> impact in Australia could delay or keep supply from coming online

And Australian projects are relatively expensive compared to North American LNG export potential

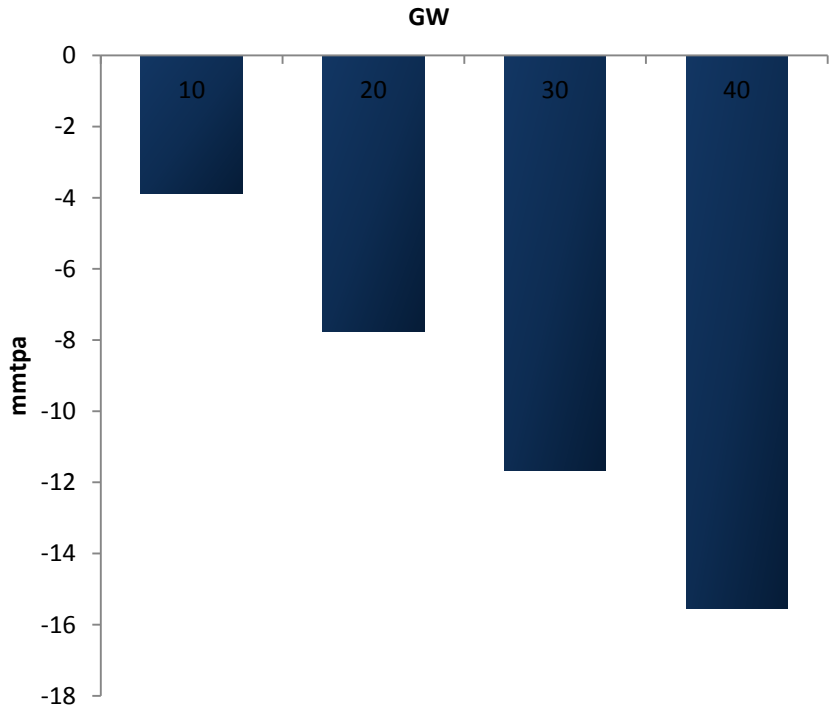
Australian LNG projects are at the high end of the cost curve



- Browse onshore LNG plant cancelled and Woodside and Shell assessing FLNG option to bring down costs, or else just wait until new build costs fall in Australia

Japan - the more nuclear restarts, the less LNG imports require so flexibility on LNG is key

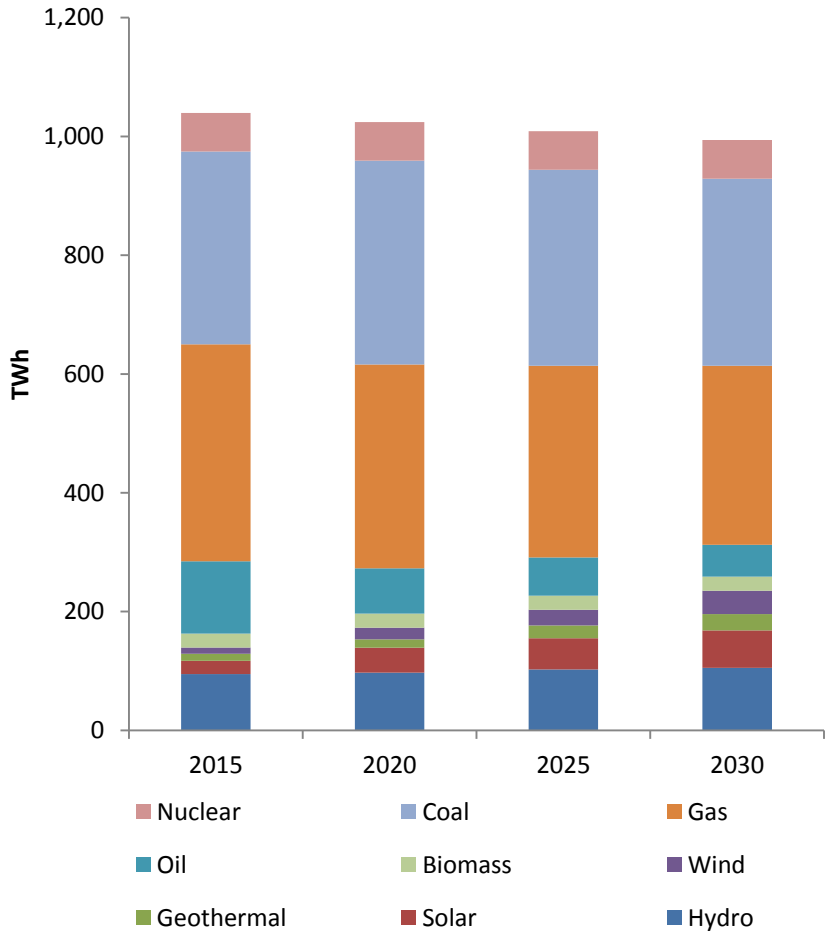
Nuclear capacity and change in LNG demand



- Half of Japan's post Fukushima fuel response has come from LNG and a quarter from fuel oil and a quarter from crude oil
  - Japan has turned LNG into a flexible fuel source like oil
- For every ~10 GW of nuclear restarts LNG import requirements fall by about 4 mmtpa
- But how much and when?
- **Uncertainty requires flexibility!**

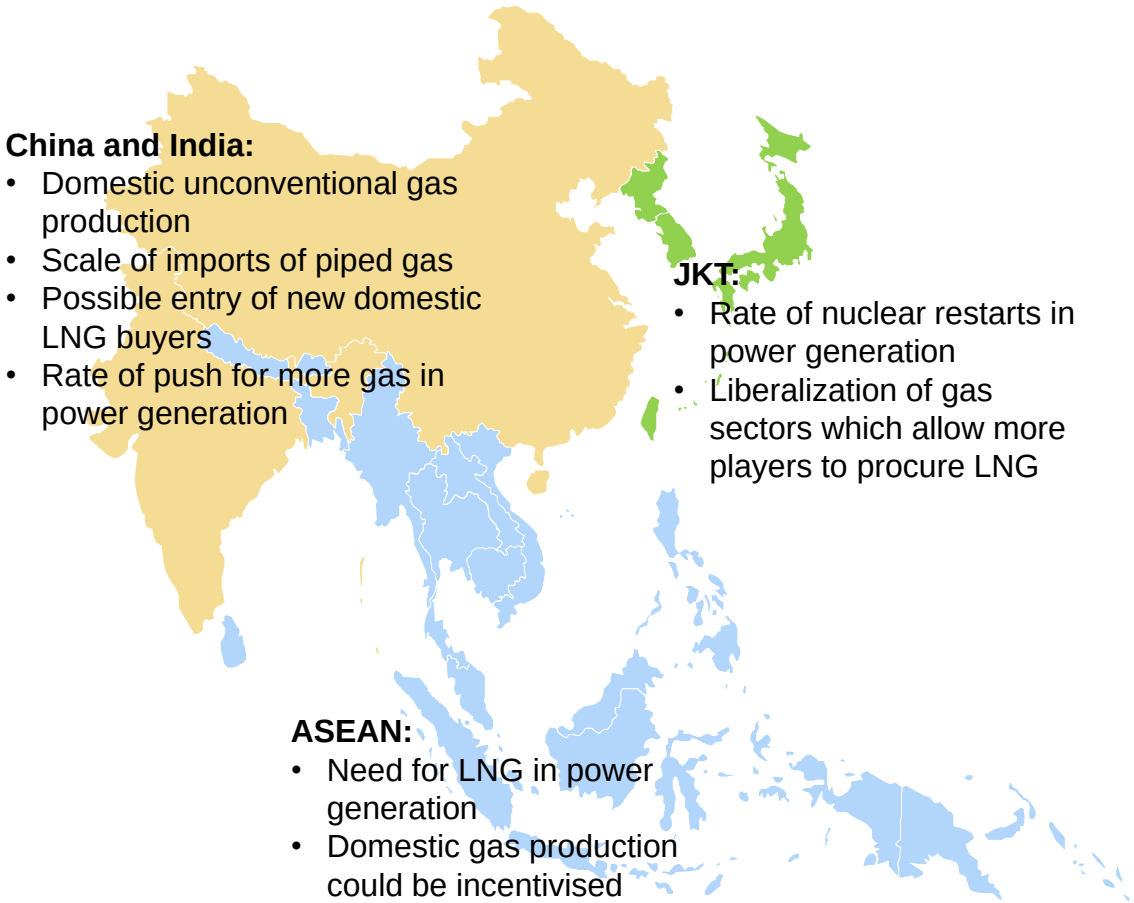
Japan's renewables uptake is another story

Power generation by fuel type



- Avoiding higher oil and LNG import costs makes renewables more attractive
- Japan has proceeded aggressively – having attracted 3.5 GW of solar power to date
- There are various plans afoot to raise renewables to close to 25 percent of generation by 2030.
- While these have extra value due to environmental and a fuel displacement economics – they also require flexible system support
- **More uncertainty and more need for flexibility!**

With uncertainties in future fuel mix, regulation and domestic gas production, most Asia countries are looking at LNG, but with more flexible terms



China and India:
- Domestic unconventional gas production
- Scale of imports of piped gas
- Possible entry of new domestic LNG buyers
- Rate of push for more gas in power generation

JKT:
- Rate of nuclear restarts in power generation
- Liberalization of gas sectors which allow more players to procure LNG

ASEAN:
- Need for LNG in power generation
- Domestic gas production could be incentivised
- Regional Hub LNG trading

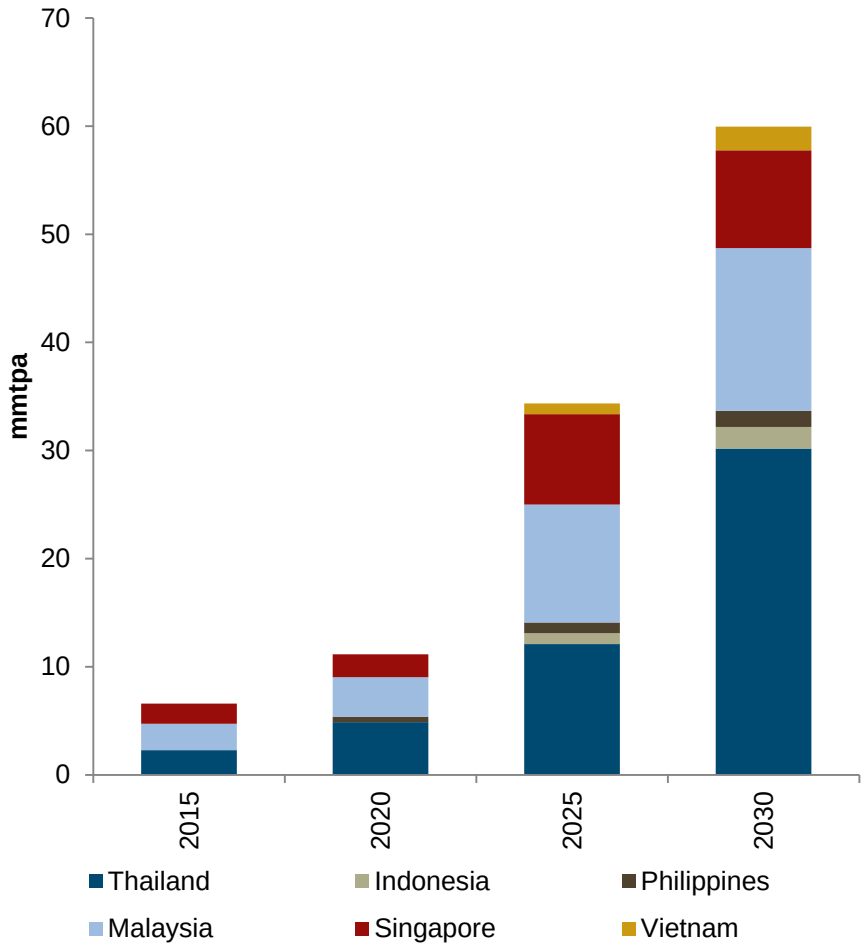
There are many inherent uncertainties in the buyers' domestic gas sector, which could incentive the buyers to negotiate for **more volume flexible and shorter term LNG contracts**

- **LNG Demand uncertainties.** In countries that have significant domestic gas production such as China and India, LNG demand in the long term would depend on how successful their unconventional gas production will be, and also by piped gas imports.

- **Liberalization of the gas sector in the domestic buyers' market**. It is possible that some buyers will have a more liberalized gas and power sectors in the medium and long term, which allow more domestic players to procure LNG. Thus, the risks of over-contracting could be high for the current incumbent LNG buyers committed to a 20 or 25 years long term contract with little volume flexibility.

Huge volume uncertainties for which emerging LNG supply infrastructure capability is poised to assist

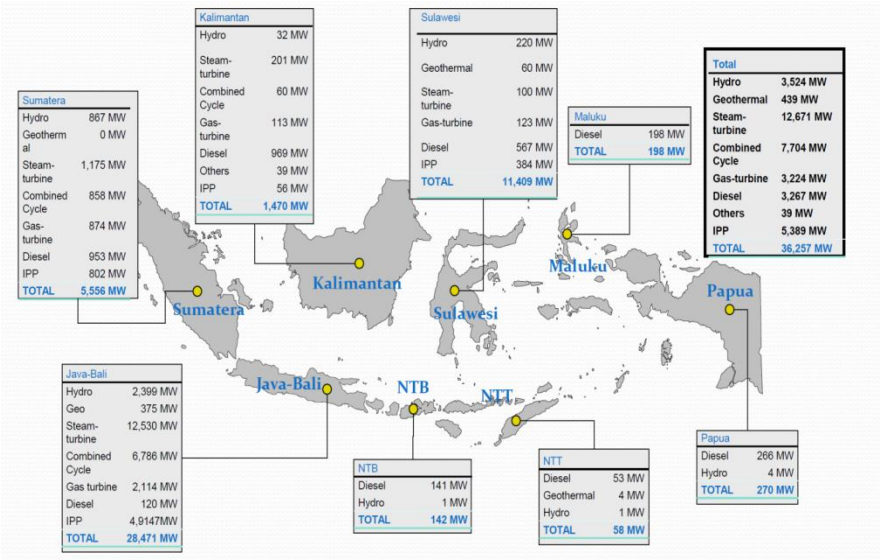
LNG demand by country



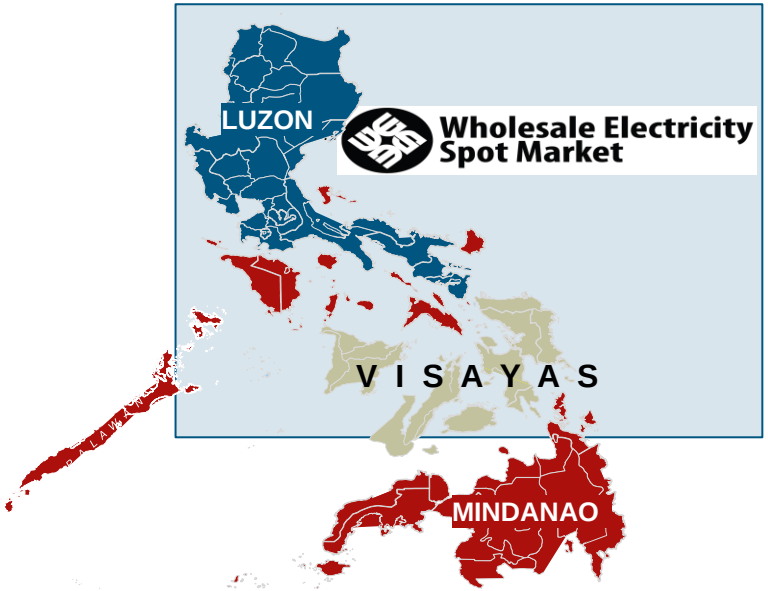
- Thailand could probably delay the steep rise in LNG imports by offering a higher price for domestic piped gas.
- Philippines might start importing limited quantities by 2020 which would be affected by seasonality and rate of coal build which would require flexibility in supplies.
- Malaysia demand could be hampered by delays in domestic gas pricing reform.
- New supplies of LNG to Singapore might undercut the price of contracted supplies.
- **All of which adds up to uncertainty which will require flexibility.**

New markets for LNG can even take higher LNG prices if necessary – the key is flexibility and lower volumes

- Indonesia
  - There is about 2,000 MW of effective diesel-fired power plants outside the island of Java.
  - These consumer the diesel equivalent of over 3 mmtpa of LNG
  - If only the infrastructure could serve them, the savings against diesel would likely pay for smaller scale and break-bulking type operations

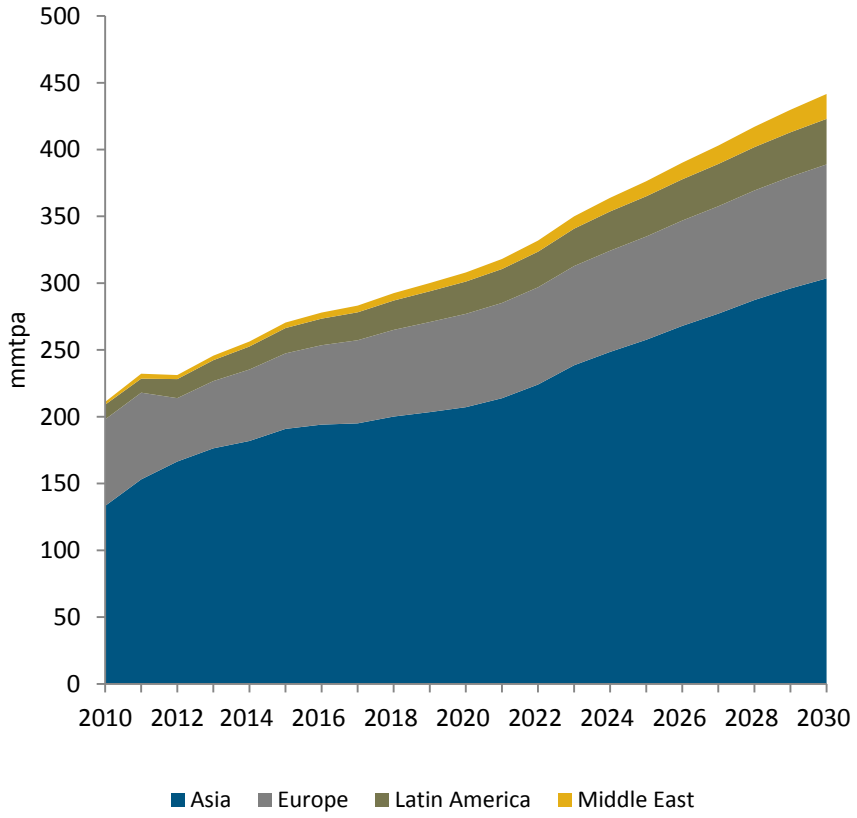


- Philippines
  - The Philippines has 3,000 MW of on-grid diesel and fuel oil power stations
  - Furthermore, off-grid and micro-grid capacity exists given the isolated nature of some regions
  - These oil-fired plants consume the equivalent of nearly 1 mmtpa of LNG.

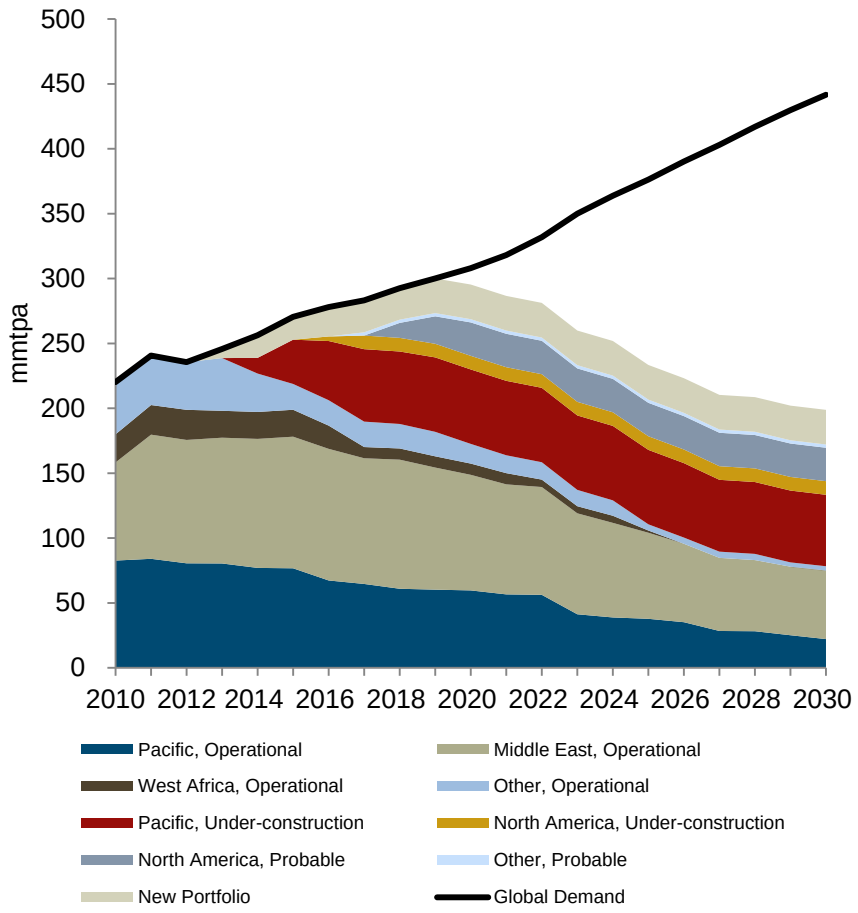


Global LNG demand supply balance

Global LNG demand

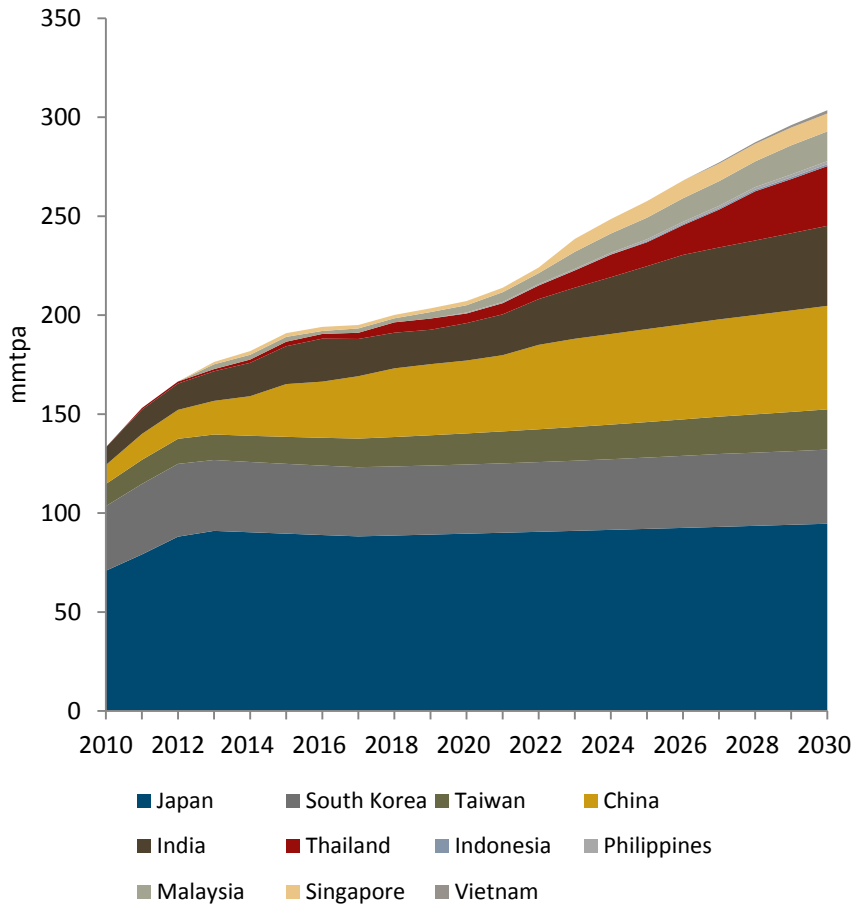


Global LNG supply

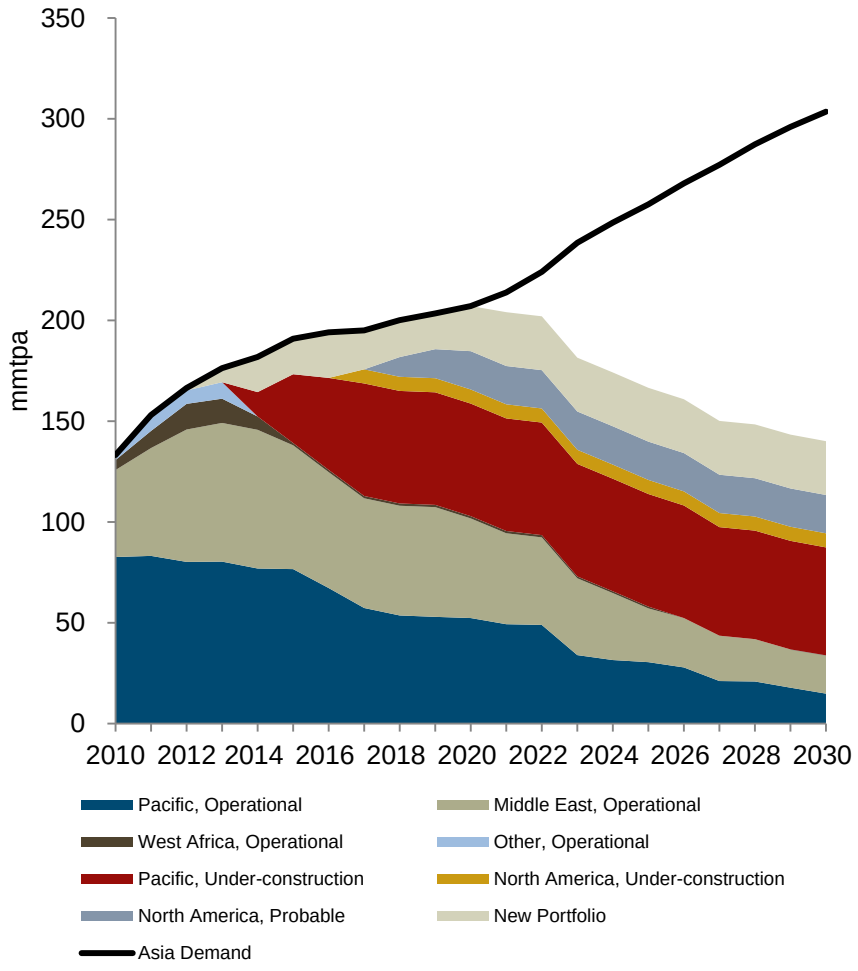


Asia LNG demand supply balance

Asia LNG demand



Supply of LNG to Asia



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Coal Markets

Natural Gas Markets

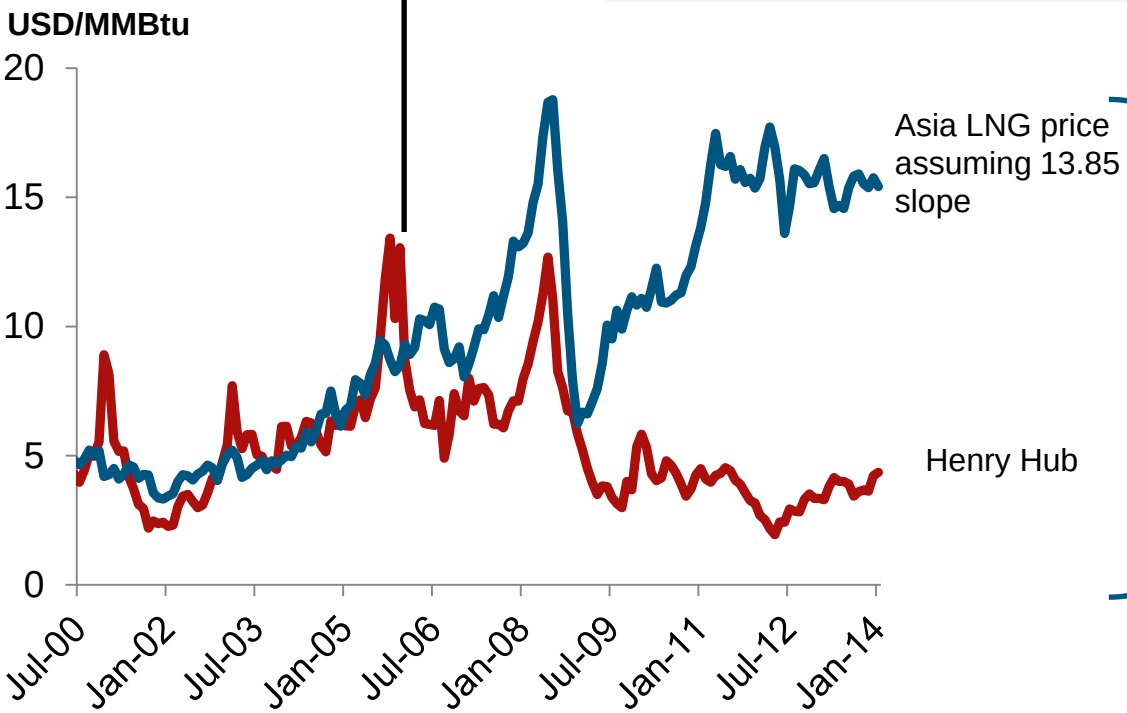
- Domestic supply and demand
- LNG regasification development
- Global LNG supply and demand
- LNG pricing – new dynamics led by disruptive influence of US LNG
- Domestic gas pricing – marginal cost versus rolled-in

Case study: Gas development in Vietnam

The US shale gas revolution has “disrupted” pricing

HH and Asian LNG prices

- In 2005, HH price increased to ~$15/MMBtu because of strong demand and supply disruption (Hurricanes Katrina). In response, many LNG receiving terminals were planned and some quickly built in US
- Now, most are idle as the US has 134 mmtpa of LNG import capacity but imported only ~3 Mt in 2012
- Many import terminals plan to convert into export terminals

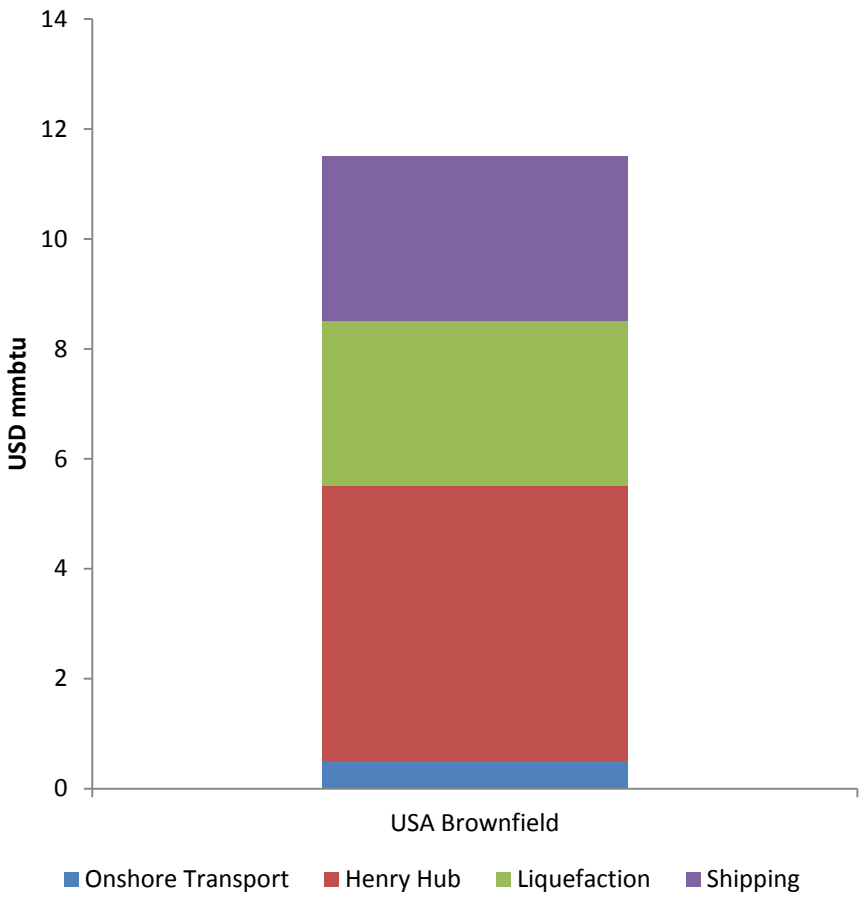


Regional pricing gap has widened to unprecedented wide level – more LNG is likely to be diverted to higher pricing region (i.e. Asia)

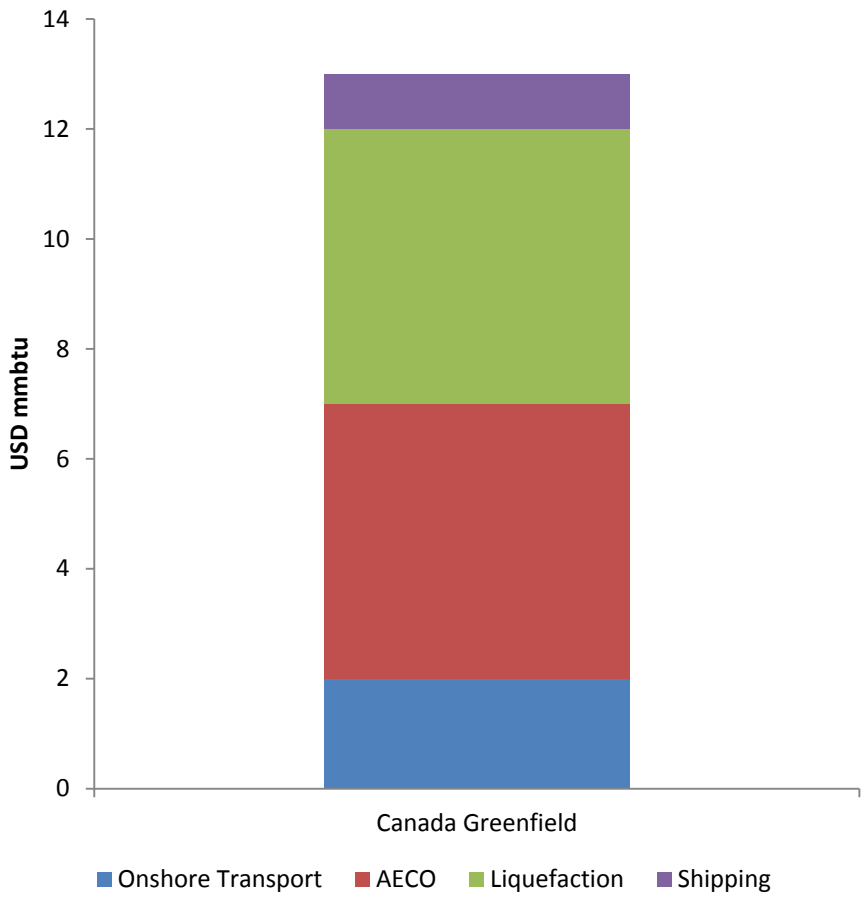
- Qatar’s original LNG export strategy: 1/3 for US, 1/3 for Europe and 1/3 for Asia; But this strategy is unlikely to be sustainable and Qatar is diverting more LNG cargos to Asia and Europe
- Trinidad & Tobago used to have 86% of its export to US, but it has to seek new customers now, likely in Asia

Delivered prices of US gulf coast LNG versus west coast Canada

US LNG



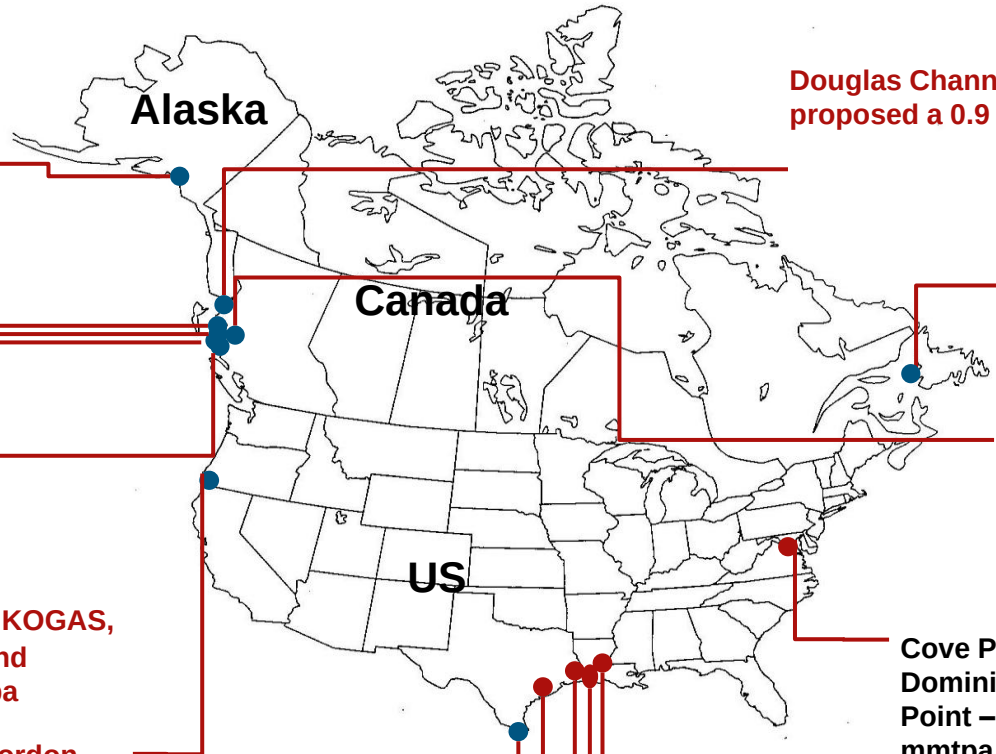
Canadian LNG



US gulf coast and Canada west coast delivered to Asia

- **The pricing gap:** is not as large you might think once liquefaction and shipping are added on. Based on Henry Hub at USD 5 mmbtu then the delivered price to Asia is shy of USD 12 mmbtu for US LNG and USD13 mmbtu for Canadian LNG, assuming it is sold at breakeven.
- **Pricing more than about cost:** But if it is a seller's market then higher pricing might be expected. Unless the buyer has contracted for US LNG, which many have done. In addition, many Canadian LNG projects are expected to favour a more traditional pricing mechanism linked to crude oil although they maybe forced to accept a linkage to the Canadian version of Henry Hub, AECO (Alberta Energy Company) spot price.
- **US LNG and Canadian LNG:** A major difference between the two sources needs re-emphasized. Buyers of US LNG are not buying LNG but buying liquefaction capacity rights, they can use it or lose it. Buyers of Canadian LNG are the end point on a build out of new liquefaction plant, new pipelines, and exploration and development of dedicated supply reserves, usually shale.
- **Buyers take a slice in liquefaction capacity** : Major LNG buyers such as KOGAS, GAIL, Tokyo Gas, Kansai Power, Osaka Gas, Chubu Power, have signed HH linked long term contracts with US LNG plants. Many new LNG buyers are also interested to get HH linked contracts, although the quality of some of the latest buyers of US liquefaction capacity has been declining.

The many LNG export projects planned in the US and Canada could further disrupt global LNG pricing, depending on timing and demand



Valdez LNG by Alaska Gasline Port Authority and others – 18 mmtpa

Kitimat LNG Chevron, Apache – 10 mmtpa

Prince Rupert – BG - 14 mmtpa project

West Coast Canada – ExxonMobil - 10 mmtpa project, expansion to 30 mmtpa

LNG Canada Shell, KOGAS, Mitsubishi, CNPC and Petrochina 12 mmtpa

Jordan Cove by Jordon Cove Energy – 8.7 mmtpa

Gulf Coast LNG by Gulf Coast LNG Exports– 23 mmtpa

Freeport by Freeport LNG and Macquarie Energy – 9 mmtpa; Expand by another 10 mmtpa by using FLNG

Sabine Pass T1-4 by Cheniere – 18 mmtpa, with T5-6 adding another 9 mmtpa

Cameron by Sempra – 12.4 mmtpa

Lake Charles by BG & Southern Union – 15 mmtpa

Cove Point by Dominion Cove Point – 7.8 mmtpa

Pacific Northwest - Petronas and Inpex - 12 mmtpa

Douglas Channel Energy Partnership proposed a 0.9 mmtpa

Pieridae Energy 10 mmtpa

- Existing terminals with proposed liquefaction
- Greenfield proposed liquefaction

Competition between US and Canadian export projects has increased

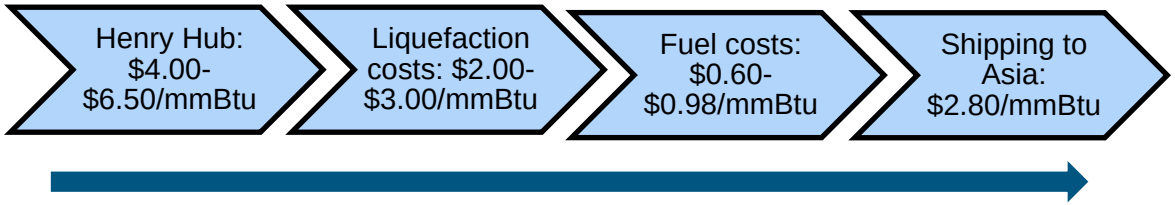
US DOE will grant approval for exporting LNG to non-FTA countries based on "accumulative effect" of LNG exports on US energy security

First mover advantage: many players have been quick to file applications for LNG exports and push for approvals

Competition also exist between the exports from US and those from Canada
LNG exports: US vs British Columbia (BC) in Canada

Liquefaction cost	**US Gulf Coast**: CAPEX for converting regasification terminal US$500-600/tonne **Canada British Columbia**: CAPEX for greenfield development is US$900-1,200/tonne
Shipping cost	**US Gulf Coast**: US$2.8/MMBtu to Asia, and maybe lower after the expansion of Panama Canal in c.2014 – depends on the rent the canal extracts from the LNG carriers. **Canada British Columbia**: Not cheaper than US Gulf despite shorter route to Asia as all equipment is new build – LNG plant, pipelines, exploration and development of gas fields.
Other costs	**Canada British Columbia**: BC government intends to levy LNG tax.

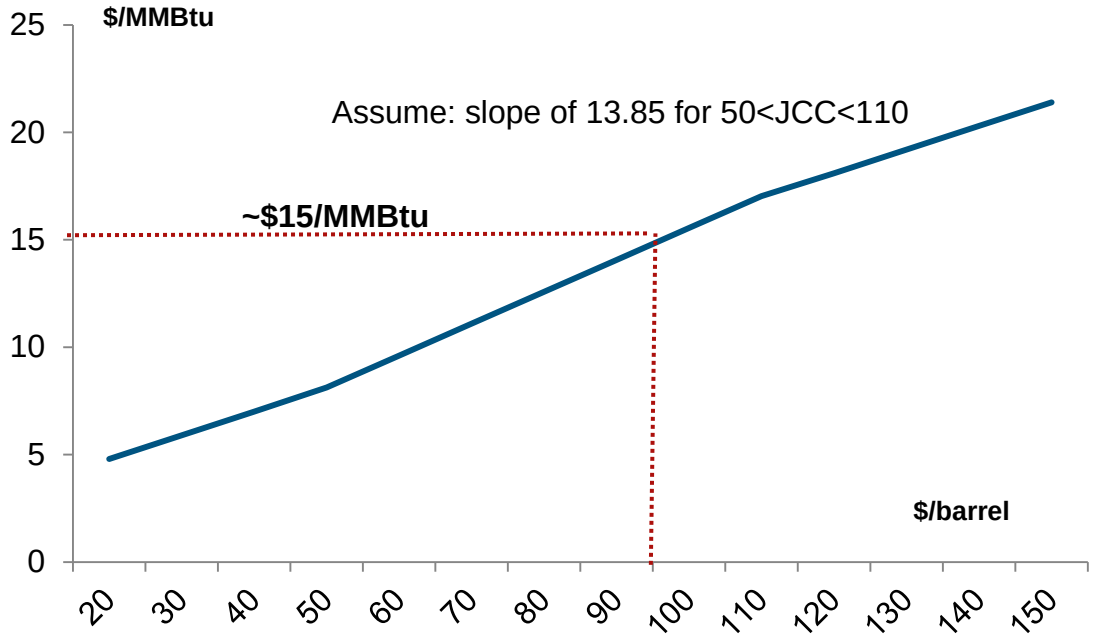
US LNG exports – cheaper with more flexibility, but not without risk

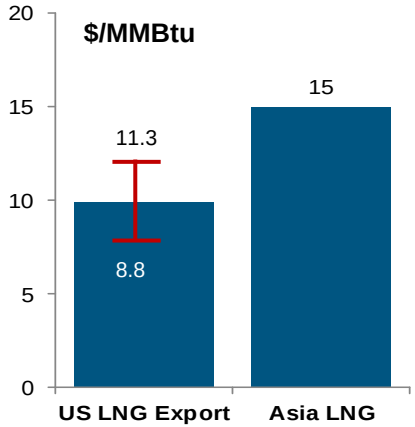


Sabine Pass LNG DES Price to Asia: $8.8-11.3/MMBtu

Source: Cheniere Energy, Annual Report

Approximate Cost of New Asian LNG Contracts





US LNG export price 20-40% less than other Asian LNG

But with new risks:

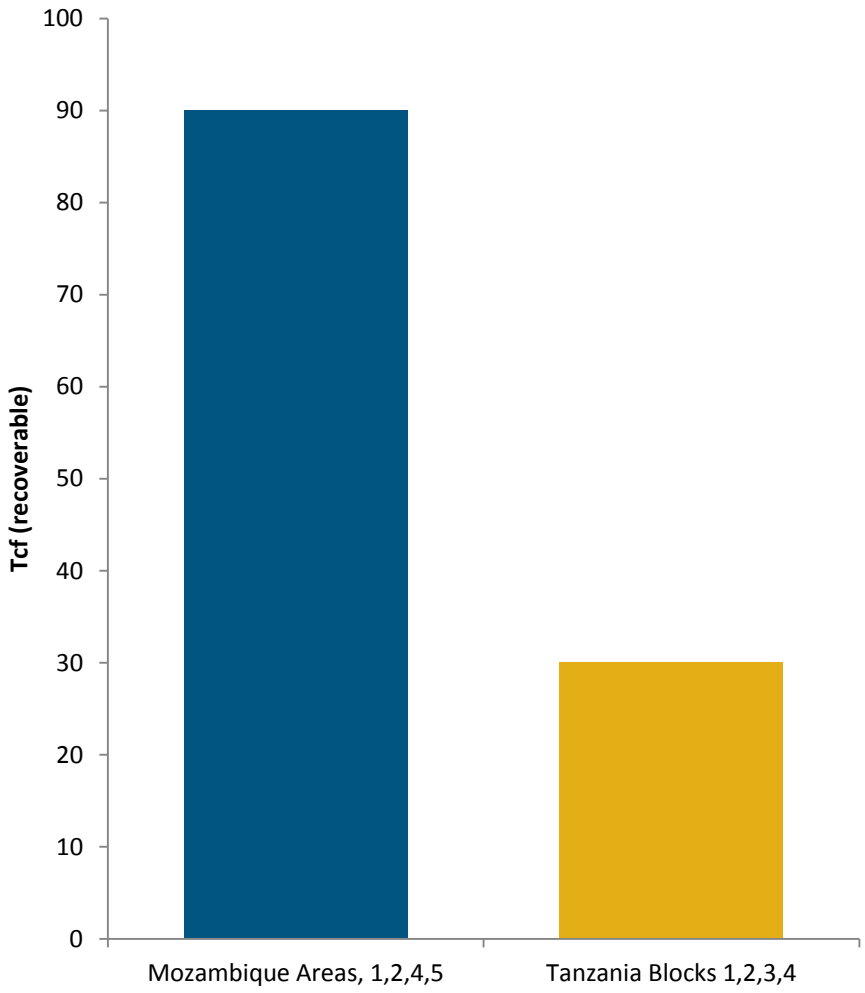
I) Timing/ Regulatory Risk

- Prospects of LNG export authorization delay or withdrawal by DOE

II) Commercial Risk

- Will supply-side competition allow LNG importers to capture the savings?
- Henry Hub price volatility
- Shale industry dynamics

East Africa LNG – marketing indicates some linkage to Henry Hub



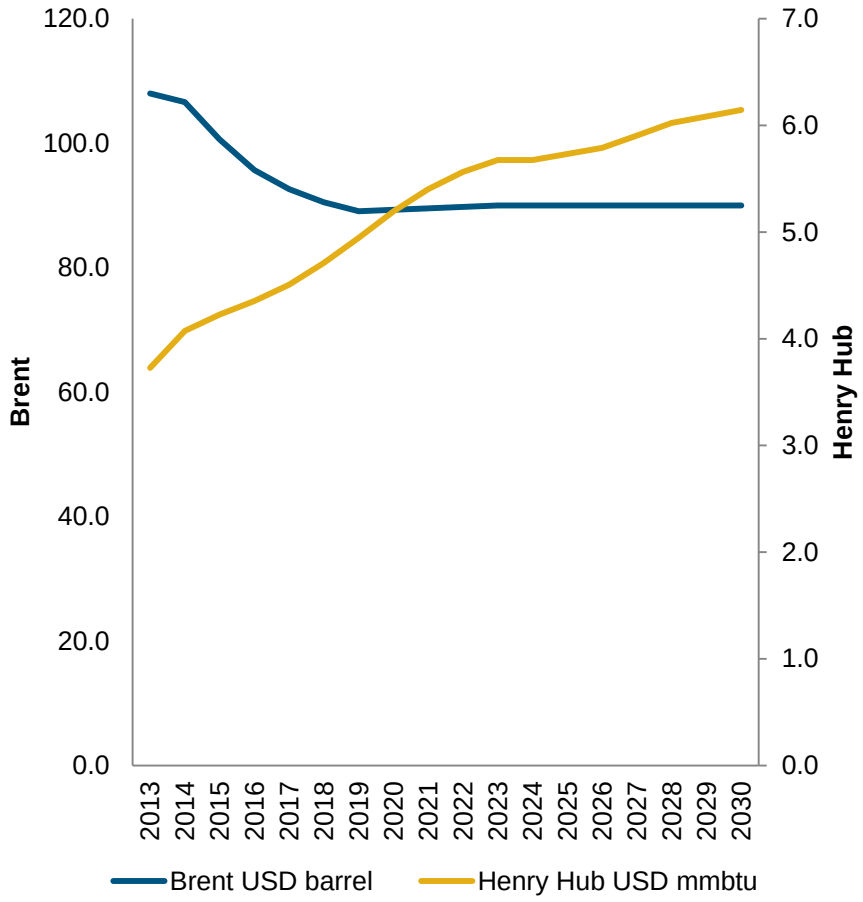
- Mozambique LNG led by Anadarko will probably be first to market by 2020 with an initial 10 mmtpa. With reserves (25 to 50 Tcf) from Area 1 in the Rovuma basin to support a rise to 50 mmtpa. Pricing has been offered that is part linked to Henry Hub and part to crude oil.
- Tanzania LNG we expect will come later perhaps by 2022 due to a lack of regulatory transparency, confusion over the role of the mooted new National Oil Company and existing de-facto upstream regulator Tanzania Petroleum Development Corp, and requirements for gas and infrastructure to support domestic industry. BG Group, Ophir and Statoil have together some 30 Tcf of recoverable gas from their four blocks.

LNG pricing round up

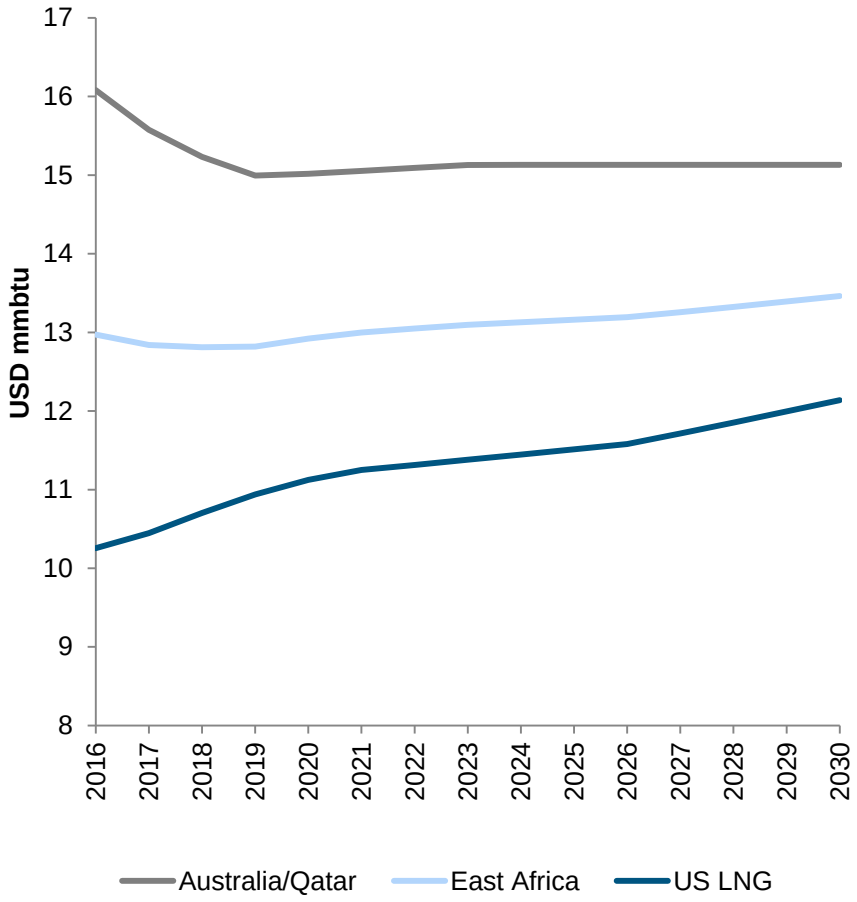
- **US LNG:** The gap is not as large you might think once liquefaction and shipping are added on. Based on Henry Hub at USD 5 mmbtu, then the delivered price to Asia is shy of USD 12 mmbtu, assuming it is sold at cost.
- **Canada**: Less expensive shipping than US LNG but a large build out of new infrastructure and field development adds to costs and complexity. They are like a traditional LNG projects with the need for new liquefaction plant, in most cases new pipelines and gathering pipelines, field exploration, appraisal and development. We believe these projects will favour a strong linkage to crude oil in pricing. This might partly explain why marketing efforts to date have been slow. So perhaps they have to accept some component of domestic gas spot pricing in the LNG contract?
- **East Africa** : Marketing of new LNG with a partial linkage to Henry Hub has been noted, but too early in the development phase to sign any firm sales agreements.
- **Qatar:** Up until recently it was the marginal LNG supplier and held fast on pricing, recently some compromise on pricing has been noticed, in response to greater competition.
- **Australia:** Mostly linked to crude oil but, CNOOC bought more shares in Queensland Curtis LNG and this we believe was accompanied by a LNG sales agreement that is partly linked to Henry Hub.
- **More trading and arbitrage**: A surplus in supply might be looming after 2020, this might lead to more spot trading and arbitrage.
  - Will Singapore become an LNG trading hub as more LNG is diverted to Asia and more trading companies such as BP, Gazprom, Gunvor and Vitol set up their LNG trading teams in the island?

Commodity pricing outlook – whether the marginal price is set by Australia/Qatar, or East Africa, or US LNG will depend to some extent on demand supply balance

Brent and Henry Hub



LNG delivered price forecast



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- LNG pricing – convergence of US and Asian markets?
- Domestic gas pricing – marginal cost versus rolled-in

Case study: Gas development in Vietnam

Vietnam Natural Gas: the need for a generic pricing strategy

- PetroVietnam is the dominant player and is both industry regulator and project participant. It signs back-to-back gas purchase and sales agreements and negotiates wellhead prices on a cost-plus basis. Transmission and Distribution tariffs are approved by GoV at project stage. Gas sales prices are negotiated between PetroVietnam and each end user.
- The absence of a gas pricing methodology handicaps gas development in Vietnam and it is also difficult to guide economically efficient development for its critical energy resources
  - ➢ Upstream investors cannot confidently evaluate their probable returns from exploration and development
  - ➢ Government cannot assess and optimize its fiscal revenues from gas development
  - ➢ Consumers have no basis to estimate their costs for gas supplies
- Twin Objectives for the gas pricing methodology

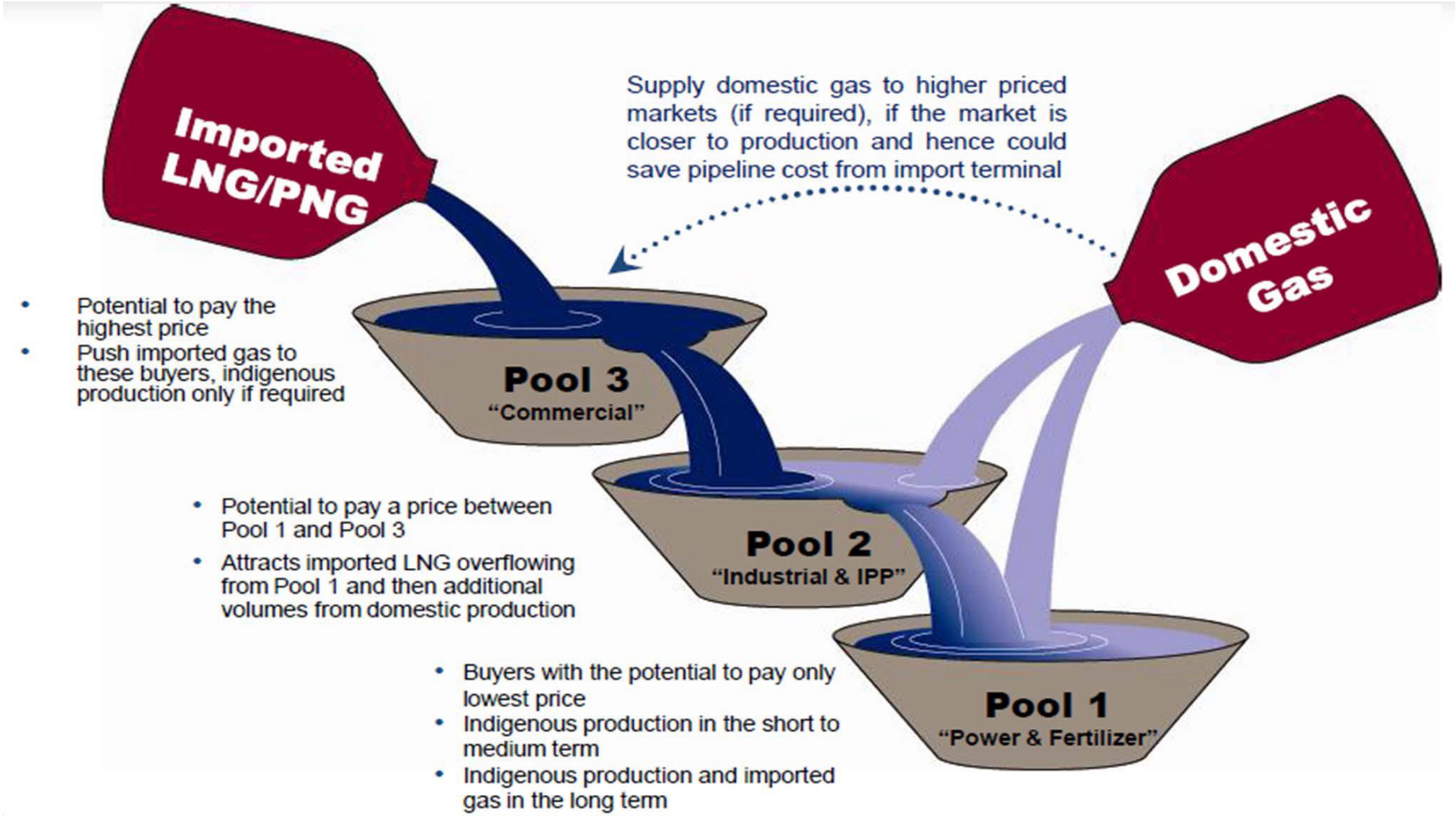
➢ At the supply side, it needs to provide the appropriate financial incentives to gas developers to invest in exploration, development and production activities. This should lead to optimal investments in the upstream sector and ensures only those gas fields should be developed which are economically competitive in Vietnam's main gas consuming sectors

➢ At the demand side, it needs to provide the right signals to investors to choose gas as the economic, lower-cost fuel when supply increments become available. This should lead to optimal investment in the consuming sectors, i.e. gas should only be used in those gas-consuming projects in which is it competitive with its alternative. For example, coal as an alternative fuel to gas in the power generation sector.

Natural Gas Pricing: Marginal Cost versus Rolled-in

Marginal Cost	Rolled-In
• Marginal cost mechanism prices natural gas at the cost of supplying one extra unit to meet increase in demand • The cost of incrementing gas production is typically higher as gas resources become more scarce and exploration and development become more expensive • The price incentivizes exploration and development of new reserve • However, charging all consumers at the marginal cost let suppliers operate below marginal cost reap all the economic rent, which is considered inequitable • Current cost-plus mechanism for Nam Con Son and Bach Ho have led to lengthy negotiations and long delays	• Another option is to allow wholesale prices to include the markup for historical average costs plus profit for the pipelines and historical average field price for gas at the wellhead • This “rolled-in” price at wholesale is thus changed by an increased field price only to the extent that the new price changes the historical average of all field prices • Rolled-in rate requires the costs of new gas into the line are spread equitably amongst existing shippers • This prevents explorers shoulder the entire cost of expansion • Therefore, rolled-in pricing incentivizes the opening of the entire basin for generations of exploration and development

PVN's plan is to create WACOG pools so as to direct subsides to specific users



Source: PetroVietnam Gas, *Challenges for Balancing Gas Supply and Demand*, 4 July 2012

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Natural Gas Markets

Coal Markets

Case study: Gas development in Vietnam

Block 52/97 , 48/95 & B Project Description (B&52)

Block B & 52 Gas Project		
Location	Offshore, Vietnam	
Investment	~U$4.3 billion	
Partners	Chevron Vietnam Mitsui Oil Exploration (MOECO) PetroVietnam PTTEP Kim Long Vietnam Company ltd	42.38% 25.62% 23.5% 8.5%
Operator	Chevron Vietnam	
Capacity	Gas: 450 mmcfd Condensate: 6000-7000 barrels per day	
Phase	Exploration	

- The project is supposed to provide gas for a planned cluster of power plants are located in O Mon in southwest Vietnam.

Development of Gas Block B&52 Project

- In July 2009, Chevron and three partners signed a basic agreement for front end engineering and design (FEED) with Vietnam Oil and Gas Group (PetroVietnam).
- The EPC for the pipeline from Block B, by subsidiaries of PVN and Vietsovpetro, to the shore site at O Mon started in late November 2009 ahead of any gas sales agreement.
- Chevron has prepared a development plan to produce gas from the block but hasn't started work over a dispute with Vietnam's national oil firm PetroVietnam about the price of gas.
- However, after many years of negotiations, the parties came close to agreeing on gas sale price in mid 2012 but then stalled again.
- We believe Chevron wanted a gas price of between $8 to $10 per million British thermal units while PVN and the government was unwilling to pay this amount.
- Chevron has indicated it will exit the project and has invited other partners to buy its stake. Existing partners of the project have the first right to buy stakes from others in the project.
- This said it was reported that India's ONGC Videsh Ltd (OVL) and Russia's Gazprom expressed an interest in buying a stake in B&52, but to date no details have been revealed by the parties.
- To add to the competition the Vietnamese government recently gave PetroVietnam the go-ahead to buy Chevron's stake in the B&52 gas project.

Block B – O Mon Gas pipeline project description

Block B – O Man Gas Pipeline Project	
Length	406km, including 246km offshore and 160km onshore
Investment	~U$1 billion
Operator	PV Gas
Capacity	600 mmcfd
Status	Construction started in November 2009 Expected to be completed by Q4 2014

- The Block B - O Mon gas pipeline system is currently under construction in order to transport gas from Blocks B&52 to supply for consumers in Ca Mau and O Mon area.
- The cooperation for this project marked a milestone in Vietnam's long-term partnership with foreign counterparts in constructing gas pipelines.

Development of Gas pipeline project for Block B&52 to O Mon

- A FEED design contract was signed with Worley-Parsons and PetroVietnam in July 2009.
- An EPC contract has been signed; and the contractor venture (including Vietsovpetro, PVC and PTSC) is preparing construction ground of GDC station in order to start construction.
- Site clearance and compensation have been coordinated with local authorities. Entire area for the construction-commencing celebration is handed over to the Venture.
- Petrovietnam Safety and Environment R&D Center is completing a final EIA report.
- Construction started in November 2009 but we believe that the lack of progress on a gas sales agreement has caused work to slow down.
- March 2010, Petrovietnam Gas Corporation (PV Gas), Chevron Vietnam Ltd. (US), Mitsui Oil Exploration Company Ltd. (MOECO) (Japan) and PTT Exploration and Production Public Company Limited (PTTEP) (Thailand) signed a Business Cooperation Contract (BCC) for the Block B Gas Pipeline Project. We understand that none of the upstream partners were willing to invest in the pipeline without a gas sales agreement being in place first.

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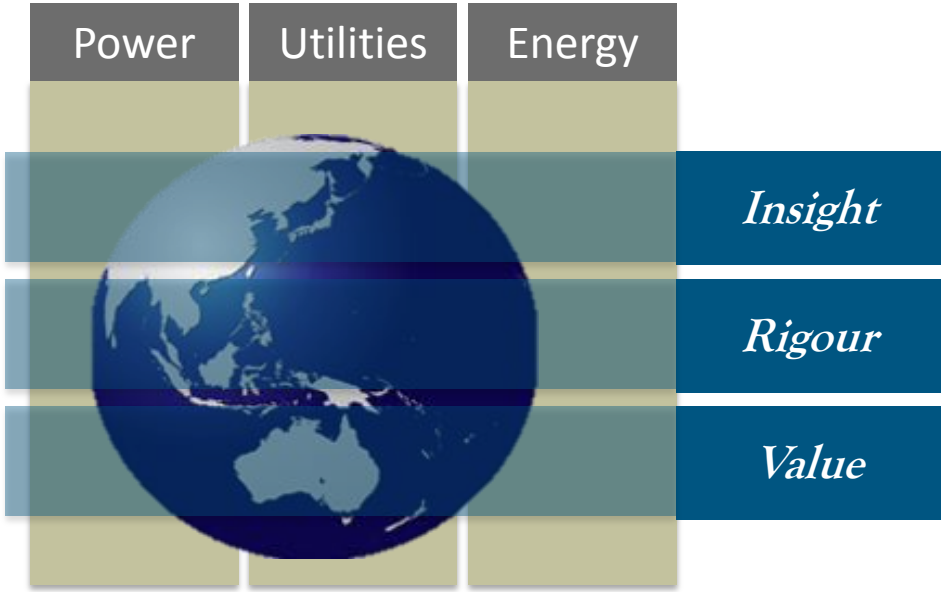

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