The Rise of Gas to Power

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Agenda

- Global LNG Market Developments
- Why Gas to Power?
- Key Issues and Considerations
- Case studies – South Africa and Morocco
- Q&A
Global LNG Market Developments
Global LNG Market - Developments

- Historically LNG projects were very high capex developments based on fields in one location selling to an incumbent and monopoly utility.
  - Structures generally inflexible in terms of resource, risk allocation, quantities and delivery models.
  - Pricing based on seller’s production costs
- Key developments – gas on gas competition in Europe
  - Gas prices set by fundamentals of supply and demand – producers required to market prices (development of market based pricing model).
  - Development of aggregators using multiple supply sources to provide for flexibility in supply terms, rather than linked to single field / liquefaction facilities.
  - Led to large differentials between Atlantic Basin prices and Asian prices (where linked to oil prices e.g. JCC) not justified by delivery costs alone.
Global LNG Market - Developments

- Key developments – US shale gas:
  - Fall in hydrocarbon prices and oversupply of gas in the market, plus greater competition
  - Ability to acquire US gas on Henry Hub linked pricing bases at a fraction of historical JCC prices
  - Japanese utilities buying mixture of JCC linked and Henry Hub linked prices – break the assumption of an immutable link between LNG and oil prices
  - Global oil price slump has also seen JCC linked pricing dropping below Henry Hub linked prices
  - In addition, US surplus provides potential for greater quantity flexibility – US gas and shipping can be acquired at levels of LNG actually required
Market Conditions

Recent History: Projections

- Since 2000 (Deutsche Bank):
  - Global natural gas demand: increased by 2.7% p.a.
  - Global LNG demand: increased by 7.6% p.a.

- Future growth:
  - Global natural gas demand: to increase 1.6% p.a. to 2035 (twice the rate expected of oil) (IEA)
  - Global LNG demand: predicted to increase 5/6% p.a. to 2020, thereafter circa. 2/3% p.a. as markets mature

BUT:

- 2015 – reduction of demand in South East Asia has led to oversupply and falling prices (demand down 6.7% in Japan and China in 2015)
- Sellers will still evaluate deals carefully (buyers / new markets are still competing for LNG supply, e.g. Brazil, Chile, Morocco and South Africa, and traditional buyers - EU, Japan, Korea, China)
- Buyers’ market at present, and buyers are seeking greater flexibility:
  - Fluctuations in ACQ have been accepted
  - Destination flexibility and price review provisions increasingly seen
World LNG Pricing (November 2013)

LNG Estimated Landed Prices

- Altamira: $16.40
- Lake Charles: $3.15
- Cove Point: $3.26
- Spain: $10.90
- UK: $10.66
- Belgium: $10.40
- Korea: $15.65
- China: $15.65
- Japan: $15.65
- India: $13.75
- Rio de Janeiro: $14.65
- Bahia Blanca: $15.65
World LNG Pricing (May 2016)

LNG Estimated Landed Prices

- Cove Point: $1.78
- Canaport: $2.66
- Lake Charles: $2.04
- Belgium: $4.30
- UK: $4.27
- Spain: $4.46
- Korea: $4.55
- Japan: $4.55
- India: $4.50
- China: $4.40
- Rio de Janeiro: $4.74
- Bahia Blanca: $4.73
World LNG Pricing Outlook

– Oil indexation will become more difficult
– Gradual migration away from oil-linked pricing – recent oil price slump has seen JCC linked pricing dropping below Henry Hub linked delivery prices (but this will not always be the case - oil price rises). Japanese utilities are currently diversifying their supply portfolios away from purely oil-linked contracts.
– Lowering of contract “slopes”
– Possibility of spot / hub gas-linked contracts for North American LNG, a “Henry Hub plus” pricing structure
– Buyer’s onsale / deferral rights are increasingly important – to take advantage when spot prices are high
– Development of Singapore SLNG – spot price index for Asian LNG
– Spot rates do not necessarily mean cheaper LNG prices
– Narrowing of regional differences – truly global, rather than regional pricing?
Why Gas to Power?
Use of Gas to Power Projects

- Gas to power projects used globally as a key element of diversified power networks:
  - In the US – plentiful indigenous gas and extensive pipeline network
  - In Europe – diversified supply – pipeline gas from Russia / North Africa plus indigenous reserves (e.g. Norway / UK) plus LNG (e.g. Spain)
  - In Japan / South Korea – no indigenous reserves, but LNG imports since the 1960s have been used to establish extensive gas network and infrastructure
- Relatively cheap up-front opex, and quicker to install and commission than coal-fired plant
- Current over-supply of gas in the market and low prices
Objectives of Gas to Power Projects

- Add significant capacity on an expedited basis
- Addition to long-term planned power generation mix
  – security of supply and fuel diversification considerations
- Grid stability – address inflexibility or intermittency of other generation sources (e.g. nuclear, renewables)
- Use of power to anchor development of gas markets
  – potential catalyst for development of domestic gas reserves, or industrialisation
- Address environmental concerns
- Potential for fuel switching from existing diesel / fuel oil-fired plants
Key Issues and Considerations
Key Issues & Considerations

Project / Infrastructure Issues

1 – **Existence of a gas market**
- Does the proposed jurisdiction have an established gas market?
- Reconciling LNG sales with power consumption
- Is there an alternative source of gas available or alternative customers for excess gas?
- Does the gas supply or power offtake address imbalances?
- Potential to trigger development of a domestic gas market – e.g. South Africa
- Regulatory issues, particularly as to retail gas pricing/ third party access

2 – **Availability of infrastructure**
- Reception / pipeline facilities available?
- Infrastructure effect on project economics and risk
- Types of infrastructure – land based or floating terminals?

3 – ‘**Project on Project**’ Risk
- Inter-connectivity risks associated with broad range of project components and participants
- Are projects fully integrated or are separate projects interconnected?
- Steps that can be taken to mitigate particular project on project risks
Key Issues & Considerations

Financing / Economic Issues

4 – Long term economics and fuel price risks
- Fuel price fluctuations can be steep and unpredictable
- LNG gas to power projects require very high capex and are inherently of a long term nature
- Pricing economics need to be reflected in the PPA, with appropriate levels of indexation to address fuel price rises
- Consider need for government guarantees to back offtaker payment obligations

5 – Bankability and project financing
- How are risks to be addressed in the project documentation?
- Availability of support from ECAs?

6 – Dollarisation / FX concerns
- Very large proportion of LNG gas to power costs (both capex and opex) will be payable in US Dollars (e.g. turbine acquisition and maintenance, fuel costs)
- What currency will the power be sold in? If local currency, what is the historic relationship between this currency and the US Dollar?
- Investors unlikely to take currency risk – will need to be passed through in the PPA.
- Currency denomination of project financing? Is there sufficient capacity within the local lending market to support a project of this nature?
Key Issues & Considerations

Local and Regulatory Issues

6 – Creditworthiness of PPA purchaser
- Entire project hinges on PPA, and ability of offtaker to meet each of its payment obligations
- Who will be the offtaker? Is it a state-owned utility?
- Long term nature of project economics will require a long term (likely 20 year +) PPA
- Availability of government guarantees or other sureties may be central to bankability of project

7 – Environmental considerations
- More of a ‘clean’ fuel than coal or fuel oil – a key driver in South Africa, where the government is looking to reduce reliance on coal generated power
- But a broad variety of issues to be considered, including offshore and coastal effects of FSRU or FSU usage

8 – Local content requirements
- Nature of CCGT technology does not lend itself well to local content requirements
- Particularly the case in a country which is new to gas to power technology, without established ancillary or service sector
- Other considerations, such as BEE in South Africa need to be assessed by foreign investors and can effect project economics
- But, can be used as a catalyst for development of local skills and industry within the country
Case Studies – South Africa and Morocco
South Africa – gas infrastructure
South Africa

- LNG to power projects at three port locations (total of 3126 MW)
- The Department of Energy (“DOE”) confirmed plans to procure a new 600 MW gas-fired power generation project, to be developed as a public-private partnership. It is envisaged that the private ‘strategic partner’ will work with the State-owned companies (SoCs) to implement the project, with private sector partners playing the lead role in developing, financing, operating and maintaining the facility
- Use of FSRUs (one vessel at each of three port locations)
- Bundled project structure, but with proposed multiple IPPs at each location
- Development of indigenous gas reserves and a domestic gas market
- Key concerns – FX risks, lack of alternative gas supply, political risk?
Future Developments – Unlocking SA’s Domestic Gas Resources

- Indication that LNG projects will be used to develop a gas market in South Africa
- Intention is to use this as a trigger for the development of domestic gas resources. All three proposed sites are close to current offshore and shale exploration blocks
- LNG import (and associated costs) would be phased out if a reliable, economic, indigenous gas source could be used.
- How does this fit with proposed bundled structure? IPPs may not incentivised if project could directly benefit competitors. What protections/comfort can IPPs seek from Eskom/government?
Morocco – gas infrastructure
Morocco

– High economic growth (6% p.a.) is driving up power demand. Additional capacity required to meet these needs
– Low levels of existing gas production, potential shale gas development
– Some existing gas infrastructure (e.g. pipeline from Algeria to Spain)
– Objectives:
  ▪ fuel source diversification
  ▪ environmental concerns
  ▪ gas market development & industrialisation
  ▪ address power shortfall – grid stability – intermittances caused by renewables projects to be addressed
Morocco

- Project:
  - Land-based LNG import terminal at Jorf Lasfar (4 mtpa)
  - 400km gas pipeline
  - 2 x 1200MW CCGT power plants (IPPs) at Jorf Lasfar and Dhar Doum – coming on line in stages between 2021 and 2025.
  - Conversion of two existing 450 MW oil fired plants to CCGT
  - 1.5 bcm of gas to be used directly by industry (3.5 bcm for gas to power)

- Unbundled: 2 elements:
  - terminal, pipeline & IPPs as a single project
  - LNG import

- Project cost: estimated $4.6bn.
Asia Pacific gas to power story

3 broad trends

- Increasing gas to power generation capacity (but cf coal)
  - More competition for traditional LNG buyers
    - Indonesia slated to be a net gas importer by 2020
- Changing price dynamics
  - But, impact of transportation costs
  - Traditional buyers still want to maintain LNG supply mix, to mitigate different risk profiles
- Interconnectedness
  - Increasing moves to supply power cross-border
  - Geographical restrictions – LNG break bulk models
## Electricity generation - S.E. Asia TWh

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*Compound average annual growth rate. **Includes wind and solar PV.
Case study - Indonesia

- Mix of different gas to power project structures, e.g.:
  - PLN (state owned power co.) = genco
  - IPPs (IPP procures gas/PLN supplies)
  - e.g. Java 1

![Diagram of gas to power project structure]

NB:
- 2 x 800MW nett capacity gas Fired IPP project, West Java Province, Indonesia
- Gas receiving facilities, 500 kV transmission line to PLN’s Substation at Maura Tawar
- 25 year term, BOOT
- Only one FSRU, multiple uses of FSRU offtake gas, not just the IPP’s power station
- Issues: risk allocation / pass thru.; financial viability; land; supply FM and sourcing gas; FX; cabotage; procurement rules