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Memo

To: Interested Parties

From: Sarah Fairhurst, The Lantau Group

Date: 20 December 2013

Subject: First Report of the Philippine Natural Gas Master Plan

REQUEST FOR FEEDBACK

The DOE would like to request Feedback on the Options presented by the Lantau Group at the Consultation Meeting on Friday 13th December 2013.

In particular, we would like feedback on:

1. Which of the Options presented do you feel is most suitable, and why?
2. Are there any Options you think are not suitable, and if so, why?
3. Do you see any obstacles to implementation of the suitable Options?
4. Do you have any further comments on the Options or the process generally?

Please provide all feedback via email to sfairhurst@lantaugroup.com, copied to lsaguin@doe.gov.ph on or before 17th January 2013.

Thank you for your consideration.

Philippines Natural Gas Master Plan

Phase One Report:
Assessment of the role of LNG within
the Philippines energy market

Prepared for:

Department of Energy

Supported By:

World Bank and Australian Aid

Prepared By:

The Lantau Group (HK) Limited

4602-4606 Tower 1, Metroplaza

223 Hing Fong Road

Kwai Fong, Hong Kong

Date: 29 November 2013

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The views expressed in this report are those of the authors and do not necessarily reflect the views of other TLG staff.

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EXECUTIVE SUMMARY

The key findings of Phase One of the Natural Gas Master Plan study are as follows:

On the basis of the market modelling, we have identified that there is a reasonably robust economic case for a modest (600– 800MW) of LNG-fired CCGT that can economically dispatch at mid-merit capacity factors but still underpin investment of about US\$300m in an LNG import terminal somewhere in Luzon. If non-power use of the LNG can ultimately defray some of the initial investment costs, then that would permit more power capacity to be economically built.

The engineering assessment of the different locations identified by project proponents shows that the cost differentials between sites are much smaller than the potential differences in the option value of each site. None of the sites being pursued by active proponents are materially inferior to any other. Where electricity transmission constraints/issues exist they should be surmountable with a minimal cost burden. It is more cost effective and more practically effective to transmit electricity rather than gas, meaning that power stations located near the LNG terminals make sense in the first instance.

The option to replace the Malampaya gas during outages appears to be worth about US\$25m p.a. to the system, or US\$ 230m NPV.

There is considerable uncertainty as to how much gas would be needed in any year in the future. There is value in not contracting firmly for gas (in other words, not repeating the Malampaya contract structures) as this will allow flexible use of gas and the full value of the option to be realised.

There are a number of market failures, including failure to internalise the environmental benefits of gas, inefficiencies in the approval process of bilateral contracts, credit quality and general purchase skills of buyers and a lack of policy and regulations relating to gas that may be currently limiting the building of LNG terminals and new CCGT capacity in the Philippines. However there appears little evidence that these or other market failures are inhibiting new investment in power generation capacity and thus the risk of power outages due to insufficient new capacity (of any type) appears low. We put forward a number of options for managing the market failures that do exist in this report, noting that there is some possibility that the existence of the EWC Terminal and associated power station may well defer the need for further investment until the mid 2020's.

The uncertainty surrounding the future of Malampaya creates difficulties for the development of LNG options and there are a number of strategies that could be adopted to deal with this. These need to be explored in more detail and the upstream and downstream parts of the DOE need to be fully engaged in this process.

This will be the focus of the tasks in Phase Two when we study the transactional structures for LNG-to-power and optimise the contractual structure for the power plant.

1. BACKGROUND TO THIS REPORT

The Lantau Group, with Ove Arup & Partners, has been chosen by the World Bank Group to develop a Gas Master Plan for the Philippines in conjunction with the Department of Energy (DOE) after a competitive bidding process. The effective date of the contract is 16th September 2013.

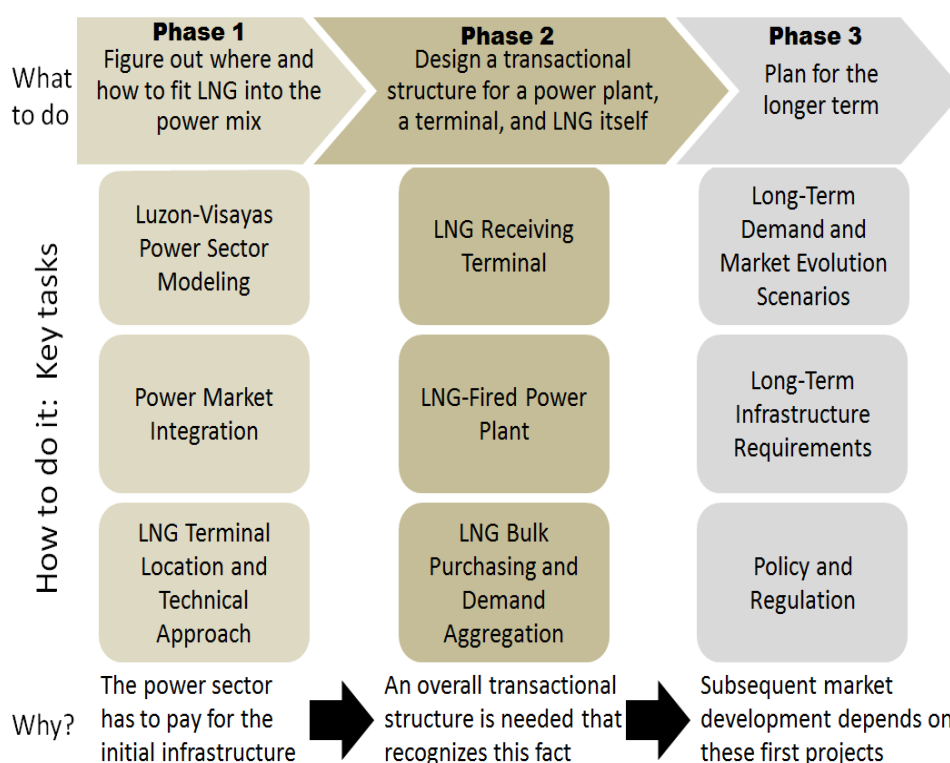
This report constitutes the Phase One Report – the second in a series of reports, following the Inception Report (dated 17th October 2013), that will document the progress of this project. From the Terms of Reference (TOR) of the study, the purpose of the Phase One Report is as follows:

Phase 1 report: covering Phase 1 of the Scope of Work, due 12 weeks after the effective date of contract.

This would normally have meant that this Report was due on the 8th January; however, because of the keenness of the World Bank Group and the DOE to conclude Phases One and Two before the end of 2013, in the Inception Report it was suggested that this Report would be delivered by close of business on the 29th November.

Phase One precedes the final two phases as illustrated in the high-level workplan schematic given in Figure 1. Phase Two shall be completed before Christmas.

Figure 1: High-level workplan schematic from the TOR



The Phase One Scope of Work, as described in the TOR, is:

- Task 1.1 Power sector modeling for Luzon-Visayas (a model for Mindanao is in hand and the results will be provided to the consultants)*
- Task 1.2 On the basis of modeling, translate the role identified for LNG-fired energy and capacity into contractual concepts that can form the basis for the regulatory underpinnings of new gas-fired power generation.*
- Task 1.3 Modeling needs to take into account transmission constraints that affect delivery of power in the greater Manila area. Consultants need to explicitly address the trade-off between moving gas by pipeline or by electricity transmission line, taking into account various institutional factors that might complicate construction of gas and power transmission lines in this area.*
- Task 1.4 Recommend one or two sites in Luzon, in addition to the northern Mindanao site, and the best technical options for those sites, for development as LNG terminals. This analysis should be done at a pre-feasibility level of analysis. Sites to be considered cover at a minimum the projects listed on page one of this TOR. Recommendations related to this task should explicitly address the concern of DOE to both avoid having too much generation capacity in the Batangas area, but to ensure that existing power plants there have access to back-up supplies. This can be accomplished by a combination of one terminal, one pipeline; or by having two LNG terminals, one primarily oriented on new capacity outside the transmission constraints, and one primarily oriented to providing gas supply security for existing plants (and perhaps allowing for limited expansion of current plans)*

Note: Modeling and site selection are mostly done for the Mindanao project. Most of the consultant input for Mindanao is requested for Phase 2 work, to define a suitable transactional structure in which the project can move forward.

In our proposal (dated August 11, 2013) we suggested a further task to examine the domestic gas situation including Malampaya:

- Task 1.5 Assess the current situation with respect to domestic gas including current finds, exploration activities and potential for future supplies of domestic gas, including any barriers to exploration or exploitation of finds.*

The remaining sections of this Report fulfil each of these tasks:

- Section 2, *Economic case for LNG in Luzon-Visayas power system*, achieves Task 1.1 by evaluating the extent to which LNG can be economically incorporated into the power generation mix of Luzon-Visayas and the optimal timing of the introduction of LNG;
- Section 3, *Regulatory structures for LNG-fired energy and capacity*, achieves Task 1.2 by first establishing the possible objectives for the DOE's gas strategy, considering the case for action, and then developing a range of options that are scored against criteria measuring the objectives.
- Section 4, *Assessment of the value associated with different sites*, achieves Tasks 1.3 and 1.4 by undertaking a site assessment survey of the sites in Luzon and Mindanao identified by proponents for development as LNG terminals.
- Section 5, *Domestic gas*, addresses Task 1.5 included in our proposal, as well as comments received from the EPIMB to our Inception Report, by looking at the future of the Malampaya field and the issues that it presents for LNG options.

As suggested in our original proposal, we have included incorporate preliminary thoughts on Task 2.3 in this Report (0), so that we might have a fulsome discussion with the DOE.

In our review of the previous work commissioned by the World Bank as part of the Inception Report, we highlighted that the rapidly changing situation in Mindanao over the past year has meant that the findings of the pre-feasibility power market modelling¹ are worth revisiting.

The Phase One study has been carried out over the past one to two months and has involved meeting the numerous sponsors of LNG projects and other stakeholders (Table 1). The study team has also visited the project site of Energy World Corporation (EWC) in Pagbilao, Quezon province.

Table 1: Meetings with project sponsors and other stakeholders

REDACTED

All meetings were confidential and will not be reported in this Report although issues raised are discussed without attribution.

All meetings were attended by members of the study team (TLG and Arup) and members of the DOE's Natural Gas Management Division. Members of the DOE's Electric Power Industry Management Bureau (EPIMB) were also present in some meetings.

¹ *Mindanao Power System Modelling*, Stephen Wallace (January 9, 2013)

Most of the project sponsors were also present at a dinner discussion in Manila at the invitation of the World Bank on 11th November.

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2. ECONOMIC CASE FOR LNG IN LUZON-VISAYAS POWER SYSTEM

Access to LNG has a variety of sources of value for power consumers in the Philippines. The option for the system to dispatch LNG-fired capacity when it is economical to do so – which we shall call ‘operational flexibility’ – and the option to build more LNG-fired plants when it is economical to do so – which we shall call ‘strategic flexibility’ – have the ability to lower the system costs by displacing less cost effective forms of generation. One of the first questions faced by the present study, as defined in the TOR, is to identify the economic role for LNG-fired energy and capacity.

Any commercial project structure that involves costs being passed onto captive customers has to be ultimately founded upon sound economic principals and justifiable ‘bullet-proof’ assumptions. Distribution Utilities (DUs) are obligated under EPIRA sec. 23 to supply electricity in the ‘least cost manner’ to their captive markets, which practically implies that the ERC in undertaking review of bilateral power supply contracts for that market has to be convinced of the least cost nature of LNG-fired energy if it is to be contracted on behalf of captive customers.

Nevertheless, under the EPIRA the generation sector shall not be considered a public utility and shall not subject to national franchises. This entails that LNG import and LNG-fired generation projects do not necessarily depend upon ERC review and regulatory justification – a private project could sell into the spot market or the contestable market – although normally the necessities of debt and equity financing mean that in any case the project has to follow sound economic and financial principals.

Economically this section starts by seeking to answer three fundamental questions about the *conventional* case for LNG in the Luzon-Visayas power system:

1. Is there sufficient economic incentive to build an LNG-fired CCGT that would dispatch at its short-run marginal cost?
2. How many MW of such CCGTs could be built and when?
3. How much LNG would they use?

The required logic flow to answering these questions is essentially circular: the quantities of LNG passing through the terminal define its requirements and economics, and hence the price of LNG and its economic quantity. The potential flexibility of LNG import infrastructure and power projects implies that value of the assets could be much greater than the conventional value because of the real option to use more (or less) LNG when required. This is studied in Section 2.4.

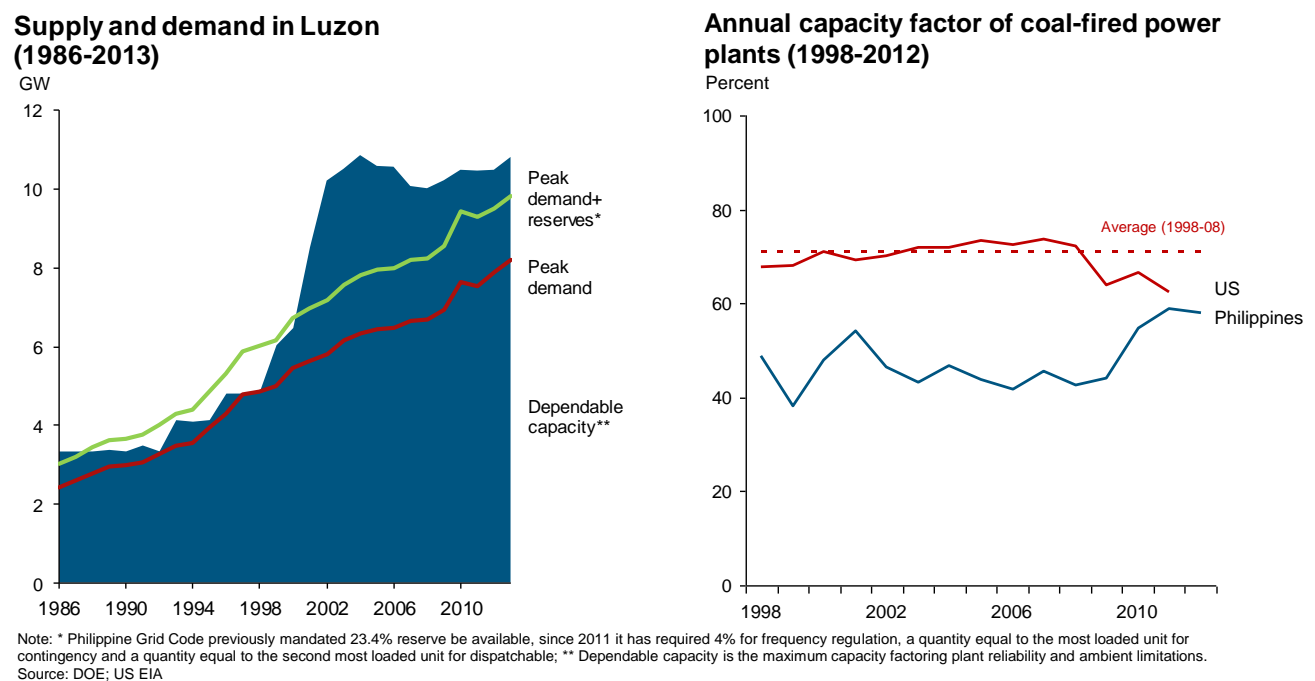
The preliminary modelling results were presented in the Inception Report and we have also sought feedback from market participants through our presentation at the dinner hosted by the World Bank on November 11, 2013.

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2.1. IDENTIFYING THE NEED FOR NEW CAPACITY IN LUZON

Prior to the EPIRA reforms, system planning and the procurement of new capacity was a responsibility of the Government through the National Power Corporation (NPC). The power crisis in the Philippines in the late 1980s/early 1990s prompted a significant expansion of the generation capacity based upon more than forty contracts² between Government and Independent Power Producers (IPPs). The economic downturn in 1991-93 followed by the Asian crisis in 1998-99 meant that growth power demand slowed so that by the beginning of the 2000s there was a significant excess of capacity. Since then it has taken more than ten years for demand growth to work through this surplus (Figure 2), as indicated by the rising coal-fired plants annual capacity factors, which have historically been significantly below those in other countries such as the US.

Figure 2: Supply and demand in Luzon and annual capacity factor of coal-fired plants



Peak demand growth in Luzon has averaged about 3.0 percent p.a. between 2004-13 driven by a growth of regional GDP growth of 4.8 percent p.a. in real-terms. Looking forwards, the Government has set ambitious GDP growth targets³ and independent forecasters, whilst not being as optimistic, expect growth of between 6 and 7 percent p.a., which would imply peak demand growth of between 3.9 and 4.6 percent p.a. on average. This implies that over the forthcoming years new generation capacity is required to continue to ensure that demand is met.

² World Bank, Philippines Power Sector Study: Structural Framework for the Power Sector (1994)

³ The Government targets GDP growth of 7.0% p.a. between 2013-15 and then 8.0% p.a. 2016-20.

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The DOE have previously identified a capacity shortfall in Luzon of 184 MW in 2015 and up to 635 MW in 2016 beyond those projects that were committed before August 2013⁴, although this high-level analysis does not take into account some details that will change the overall findings⁵. Nevertheless, the DOE's list of private-sector initiated power projects (which is not intended to be exhaustive) contains more than 10,000 MW of projects beyond those that were committed in August 2013. This is only slightly less than 2012's dependable capacity of 11,349 MW and suggests that the private sector is at least prepared to consider significant investments in new capacity. Many of these indicative projects (totalling c.3,179 MW) are intended to be commissioned in or before 2016; so the real issue for the Government may be the identification of potential market failures and how it should facilitate the private sector to deliver the most economic market outcomes (see Section 3

The economic dispatch of LNG is principally reliant upon displacing higher cost generation sources. Under most conceivable scenarios of fuel price evolution, LNG is only placed to displace higher cost generation from oil-based plants⁶ (Figure 3). As shown in Table 2, oil-based plants have contributed about 1.3 – 1.9 TWh p.a. in recent years without significant El Niño effects and as much as 3.3 TWh in 2010 when El Niño is stronger. These levels of oil-fired generation are equivalent to LNG demand 160 – 240 kilotonnes p.a. and 410 kilotonnes p.a. and they do not include the liquids used in Saints/Ilijan to replace their natural gas supplies, which has averaged about 350 GWh p.a. or 50 kilotonnes p.a. of LNG demand over the past seven years⁷.

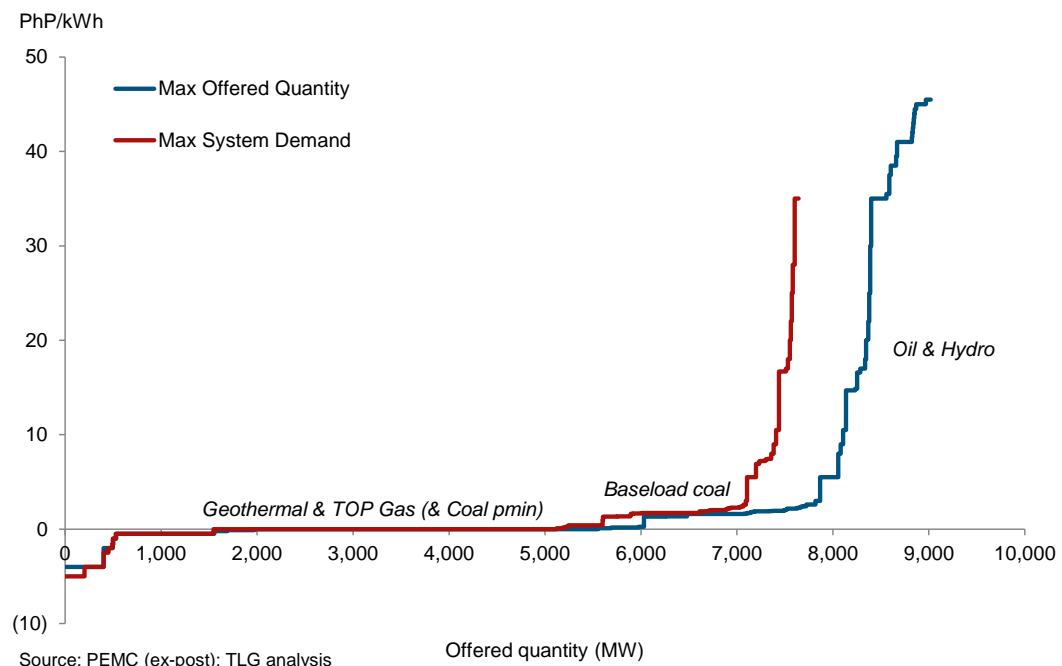
Nevertheless, LNG would not be expected to economically displace all oil-fired generation. Just as gas has a role supplementing coal at lower capacity factors, the low fixed costs of existing oil-fired plants means that they have a role supplementing gas at lower capacity factors.

⁴ See, for example, the Secretary's presentation to the 2013 Mindanao Business Conference on August 9, 2013.

⁵ For example: 1) The possible delay / cancellation of 'committed' projects that remain contingent to the final approval of the FIT scheme by the ERC; 2) The intermittent nature of some types of capacity (such as wind), which means that they may not be able to be maximally available in the peak hour; 3) Plants' capability to provide different classes of ancillary services; 4) Power exports to / imports from Leyte; 5) Decrease in the required amounts of ancillary services under the draft Second Amendment of the Grid Code; and 6) The potential economic entry of new capacity that can lower system costs by displacing more expensive existing capacity.

⁶ Here the value of the water, as reflected in the hydro plant offer strategies, is closely related to the marginal value of the oil-based generation with which they are competing during peak hours.

⁷ Estimate based upon examination of WESM schedules (Nov 2006-Oct 2013) during the periods of Malampaya supply outages.

Figure 3: Typical Luzon offer curves in 2013 annotated with illustrative plant types**Table 2: Gross generation in Luzon by plant type (TWh)**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Wind	-	-	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Geothermal	5.3	2.6	3.0	2.7	3.5	3.6	3.7	3.5	3.3	3.5	3.6
Natural Gas	8.8	13.1	12.4	16.9	16.4	18.8	19.6	19.9	19.5	20.6	19.6
Coal	15.8	14.4	15.5	14.7	14.1	14.4	13.5	14.1	20.0	19.7	21.9
Hydro	2.9	3.8	4.3	4.3	5.5	4.6	5.4	5.5	4.0	4.8	5.3
Biomass	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
Oil-based	3.6	3.6	4.6	2.0	1.7	2.2	1.9	1.9	3.3	1.3	1.8
Total	36.4	37.5	39.9	40.6	41.2	43.6	44.2	45.0	50.3	50.0	52.3

Note: Liquids used to replace natural gas in Saints/Ilijan are included under Natural Gas
Source: DOE Power Statistics

Whilst private sector project sponsors will normally undertake the kinds of economic and financial analysis we will describe in the rest of this section, the market prices provide the initial signals of the ability of generators to economically dispatch into the market.

2.2. ECONOMIC INCENTIVES TO BUILD AN LNG-TO-POWER PROJECTS

One of the basic illustrations of the ability of the market to accommodate LNG-fired generation is its price-duration curve, i.e., the prices from a period ordered from highest to lowest. In principle, whenever the market price is at least equal to the Short-Run Marginal Cost⁸ (SRMC) of a generator, then it would be economic from a system

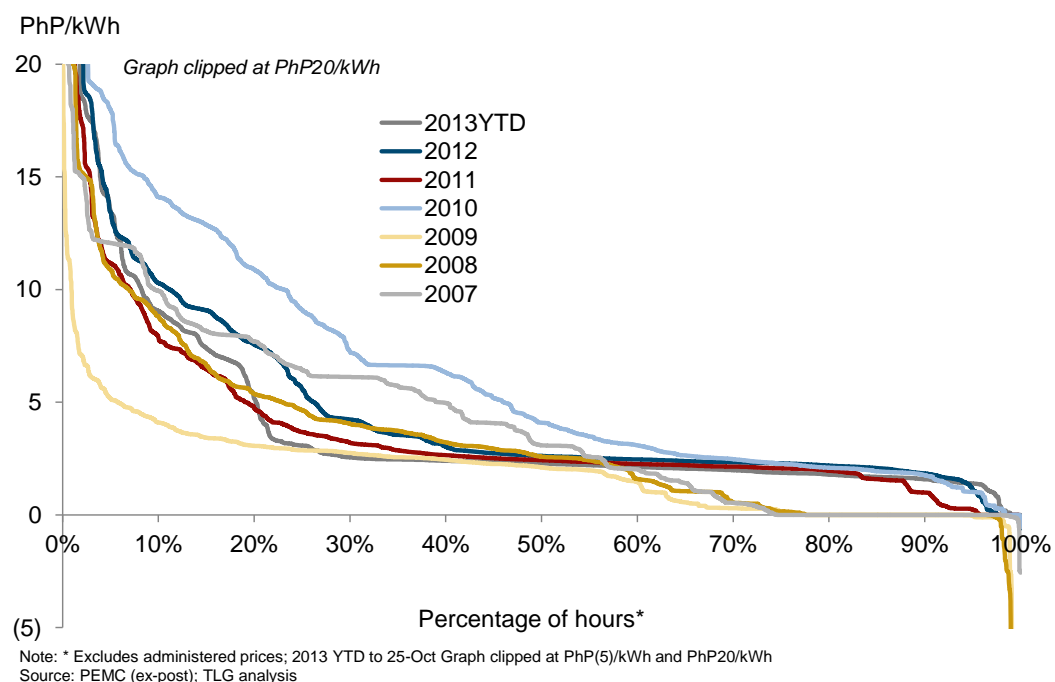
⁸ The Short-Run Marginal Cost at its simplest is equal to the sum of the marginal fuel cost and the variable operations and maintenance (VOM) costs.

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perspective – and profit-maximising from the generator's – for that generator to offer into the market such that is dispatched⁹.

Inspection of the price-duration curves from each year since the first full year of the WESM (Figure 4) suggests that a new generator with a dispatch cost of between 4 and 5 PhP/kWh would have been dispatched between 20 and 50 percent of hours. If costs were higher (equivalent to raising the horizontal threshold), then the proportion of hours would be less, and vice versa. If demand were higher or supply were limited (as say in 2010), then the PDC is translated to the right and the proportion of hours would be higher.

Figure 4: Price-duration curve for Luzon in 2007-13



The economic incentive to generators would be the net revenue¹⁰ they are able to generate from selling into the market. For example, as shown in Table 3, an SRMC of PhP4.23/kWh would have been sufficient to achieve a 30% annual capacity factor in 2012. Assuming that the generator was small, it would be infra marginal for those hours and earn economic rent to cover its capital and fixed costs. With an SRMC of c.PhP4/kWh that rent would have been about US\$414/kW, which after Fixed O&M (FOM) costs, would in present value terms cover an investment of nearly US\$3,000/kW with a 25 years lifetime at real discount rate of 12%.

⁹ This does not disregard the ability of generators to enter into contracts to settle payments for their generation at fixed prices. A risk neutral generator would enter into contracts with a fixed price at their expected market price; whereas a risk adverse generator would accept a small discount to their market price expectations.

¹⁰ Net Revenue = Revenue /less Fuel cost /less Variable O&M

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Table 3: Price deciles from price-duration curve for Luzon in 2012 along with net cash and NPV of net cash

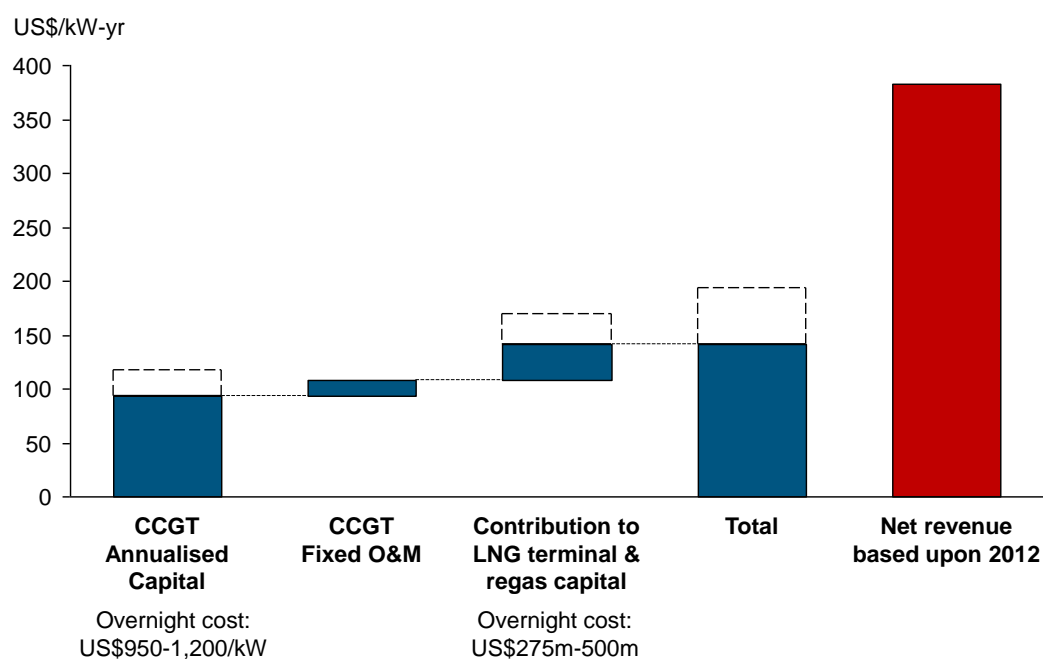
	Price deciles		Net Cash	NPV*
	(PhP/kWh)	(US\$/MWh)	(US\$/kW p.a.)	(US\$/kW)
90%	10.29	244	145	809
80%	7.56	179	230	1,474
70%	4.23	100	398	2,790
60%	3.02	72	485	3,476
50%	2.62	62	521	3,759
40%	2.46	58	539	3,898
30%	2.34	55	556	4,030

Note: * Net Present Value (NPV) after FOM cost of USD42/kW p.a. discounted at real rate of 12% over an economic lifetime of 25 years

Source: PEMC (ex-post); TLG analysis

If the overnight cost of the power plant was \$950-1,200/kW and the contribution towards the LNG infrastructure was \$275m-\$500m, then the net revenue from 2012 would have been sufficient to support the required investment, as illustrated in Figure 5.

Figure 5: Sources and uses of net revenue



In addition to revenues from the energy market, under existing arrangements generators are able to enter into contracts – called Ancillary Service Procurement Agreements (ASPAs) – with NGCP to supply ancillary services. These provide additional short-term incentives and compensation for generators able to provide flexibility. The commencement of the trading of reserves in the WESM, which is targeted for March 2013, is expected to permit certified generators to offer ancillary services to NGCP through a formal market mechanism.

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Whilst the above discussion using historical price-duration curves is illustrative¹¹, it serves as preliminary evidence to establish that sufficient economic incentives exist for developers to build LNG-fired generation plant. This is confirmed by market modelling in the next subsection, which seeks to evaluate the economic size and timing the introduction of LNG-fired generation.

2.3. ECONOMIC SIZE AND TIMING OF THE INTRODUCTION OF LNG-FIRED GENERATION INTO THE POWER MARKET

In this section we evaluate the conventional market entry of LNG-fired generation into the power market in Luzon. The sensitivity of the market clearing prices to the dynamics of supply and demand means that we generally use our QUAFU market model¹² to understand our the market could evolve economically. This is important because the impending entry of new coal baseload (and potentially much more if 'coal overbuild' happens – see Section 2.3.1) as well as increasing amounts of flexible supplies that potentially fill some of the gap in the market for LNG, such as development at San Roque¹³ and other hydro plants in addition to re-commissioning of Therma Mobile's four diesel-fired power barges.

If peak demand in Luzon grows at c.4.5 percent p.a. as the DOE expect and if entry of new coal-fired capacity is unrestricted (in terms of acceptable sites and availability of financing), then in the absence of uncertainty modelling of the least-cost capacity expansion plan under base case assumptions¹⁴ suggests that it would include about 800MW of LNG-fired CCGT in 2017/18 beyond those committed plants listed in **Error! eference source not found..** That is, the inclusion of the LNG capacity and generation acts to reduce the present value of future system costs and that capacity is able to recover its fixed costs including a reasonable capital return over the course of its lifetime through sales at market prices. The net revenue of the CCGT is able to support a capital investment of US\$300m in the LNG import terminal.

¹¹ Firstly, the market-clearing price in any hour is very sensitive to the instantaneous supply-demand situation. The composition of the Philippine market, like many others around the world, means that, depending on the residual supply, relatively small changes in demand can produce significant changes in clearing prices (even before changes in bidding strategies are considered). Hence, the price-duration curve for future years will be different to 2012 depending upon how demand grows, new capacity that is committed (e.g., the 1,170MW of committed coal-fired capacity due to enter between 2013-15), and the cost of competing technology options. In fact, the very addition of capacity will depress market-clearing prices if it changes the marginal (price-setting) plant.

Secondly, and less importantly, since the price-duration curve ignores the chronology of the hourly prices, it effectively ignores any temporal constraints (such as ramping), which may mean that generation plant is unable to take advantage of particular price opportunities. The operational flexibility of the gas-fired plant and correlations between hours mean that this assumption has less impact.

¹² An overview of the QUAFU modelling framework along with a detailed description of the assumptions is given in Appendix A.

¹³ San Roque's regulation pond is near completion. This will largely remove the need for the 411MW plant to run inefficiently (low turbine loads) and uneconomically (low market prices) during off-peak hours in order to serve irrigation requirements, and it will provide more peaking generation for the system.

¹⁴ The assumptions underpinning the modelling are described in Appendix A.

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Table 4: Committed entry in Luzon and the Visayas

	Location	Rated capacity (MW)	Commissioning date	Notes
Puting Bato coal	Batangas, Luzon	2 x 135	Unit I – Q3 2014 Unit II – Q4 2015	Under construction Financial close of unit II in July 2013
Southwest Luzon coal	Batangas, Luzon	2 x 150	Unit I – Q4 2014 Unit II – Q1 2015	Under construction Financial close in Feb 2012
Maibarara geothermal	Batangas, Luzon	20	Q4 2013	Under construction
Concepcion coal	Iloilo	2 x 135	Unit I – Q3 2016 Unit II – Q3 2016	
TPC coal expansion	Cebu	82	Q3 2014	Financial close in Mar 2013
Nasulo geothermal	Negros Oriental	50	Q2 2014	Plant moved from Northern Negros
Villasiga HEP	Antique	8	Q1 2014	
Consolacion landfill	Cebu	3.6	Q2 2015	Loan approval from DBP in May 2011
San Carlos biomass	Negros Occidental	16	Q1 2015	

Source: DOE (as of 12 August 2013)

This analysis does not include the Energy World Corporation LNG-fired plant in Pagbilao as 'committed', although we understand that the EPIMB has changed the EWC project's status from 'indicative' to 'committed' as of October 31, 2013. This reflects the evidence (which includes financing of the project) submitted by the company to the DOE¹⁵. The implications of EWC's project proceeding on the subsequent economic demand for further LNG-fired capacity are explored in Section 2.3.4.

Under our base case assumptions, if coal sites are available, developers of coal-fired have access to finance and no attempt is made to internalise the external costs associated with power generation, then the vast majority of the growth in demand would be accommodated by new coal-fired capacity (Figure 6). This assumes that the average slope of LNG contracts falls to 13.0 by 2020, although the associated constant increases to \$2/mmbtu such that it more realistically reflects the cost of transport from Australia or Middle East (average delivered price 2020 = US\$13.6/mmbtu in 2013 dollars).

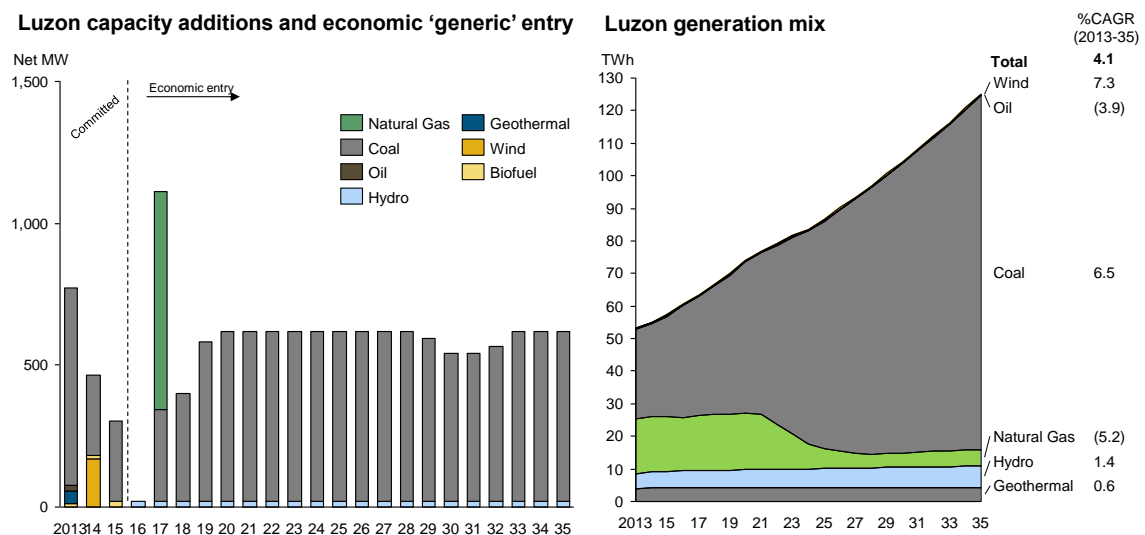
¹⁵ Confirmed by Dir. Capongcol in a communication on November 13, 2013.

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Table 5: Base case delivered fuel cost (2013 US\$/mmbtu)

	2014	2015	2016	2017	2018	2019	2020	2030	2035
Coal	4.18	4.25	4.35	4.44	4.54	4.58	4.59	4.59	4.59
Saints gas	12.52	12.06	11.28	10.93	10.40	10.23	10.16	n/a	n/a
Ilijan gas	10.62	10.28	9.65	9.39	8.97	8.83	8.78	n/a	n/a
LNG¹⁶	15.97	15.23	14.54	14.15	13.86	13.69	13.69	12.90	12.90
Bunker oil	15.75	14.90	14.19	13.74	13.43	13.21	13.24	13.34	13.34
Distillate	23.78	22.48	21.40	20.71	20.25	19.92	19.97	20.11	20.11

Note: LNG price includes terminal VOM (US\$0.15/mmbtu) but not capital cost

Figure 6: Luzon capacity additions and generation mix (2013-35)

For the reasons explored illustratively above, the associated annual capacity factor of the CCGTs is initially expected to be 15 – 25 percent, although more favourable fuel prices would see this increase to 30 – 50 percent. The sensitivity of annual LNG consumption to changes in fuel price¹⁷ is illustrated in Figure 7. The shape of this curve reflects the dynamic market issues of supply-demand:

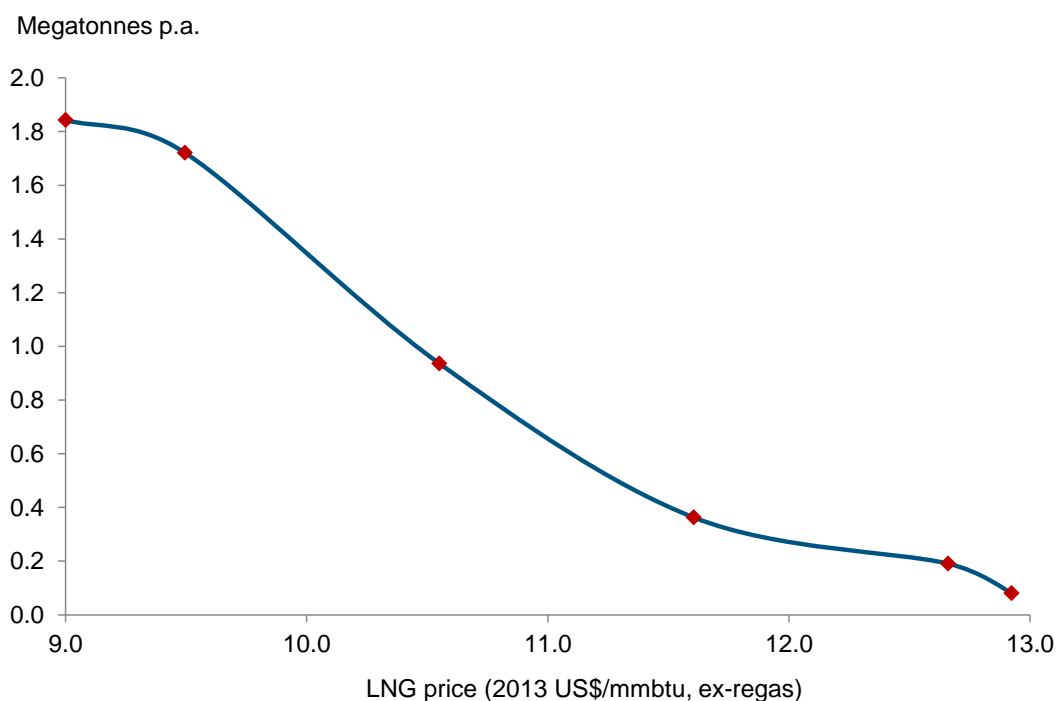
- Annual demand for LNG is potentially very high if LNG prices turn out to be favourable;
- Unfavourable LNG prices mean that less LNG can be economically dispatched in the market, and are therefore compounded by the fixed costs of the LNG import terminal;

¹⁶ This assumes that the import duty on LNG is removed. This option is to be validated as part of the options available to the DOE (see Section 3).

¹⁷ For ease of reference to absolute amounts, the modelling of this curve assumes that LNG prices are fixed from 2017 onwards.

- iii) Nevertheless, peak prices are expected to be sufficiently high to support investment in the LNG terminal and power plant.

Figure 7: Sensitivity of LNG consumption in 2020 assumed a fixed LNG price



In Section 2.4 we address the sources of uncertainty that give rise to option value for LNG-fired capacity.

2.3.1. Implications of 'coal overbuild'

The significant amount of coal capacity under various stages of development in Luzon has prompted comment from a number of parties. According to the EPIMB as of August 12, in addition to the 570MW of committed coal capacity in Luzon, there is a further 4,140MW of coal capacity under development with target commissioning by 2020.

It should be recognised that announcing new build/expansion is a beneficial strategy for existing market participants as it may deter other participants from entering and therefore protect their position from increased competition. Not all of the announced projects will be built on time, if ever. The development processes, if they are worthy, will cause some projects to be deferred or cancelled. This has been evident historically – for example, the 11th Status Report on EPIRA Implementation, which covers May-Oct 2007, lists 1,250MW of indicative coal projects, none of which have yet to graduate to 'committed' status.

From the DOE's perspective, so long as it is private money at risk and captive customers are not obliged to pay for underutilised capacity, then it should have no *market-based* concerns over the risks faced by private sector initiated projects and potential overbuild. This, however, requires that the DUs take informed power procurement decisions (as reviewed by the ERC) and do not contract expensive capacity for serving mid-merit /

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peaking needs if other forms of capacity or the spot market are offering more cost effective prices.

The 'space' for LNG-fired capacity and generation in the least-cost mix is reasonably robust to additional coal-fired capacity in the medium-term. If significant amounts of coal plant are commissioned then the quantum of LNG capacity required is relatively consistent, albeit it may be partly shifted from 2017 to 2018 or even 2019, as shown in Table 6. Notably, it would require all of the coal projects classified by the DOE as "indicative" (4,140MW installed capacity) to be built on the targeted schedule for the economic timing of LNG to be pushed back to 2022/23, that is, near to the expiry of the existing GSPAs.

Table 6: Impact on the economic quantity and timing of LNG capacity with different

Indicative coal build scenario	Economic LNG-fired net capacity*	Impact on additional economic coal build
None (only committed and economic)	765MW in 2017	325MW in 2017
+300MW in 2016	758MW in 2017	Delayed to 2018
+600MW in 2016	583MW in 2017 157MW in 2018	Delayed to 2018/19
+750MW in 2016	440MW in 2017 287MW in 2018	Delayed to 2019
+900MW in 2016	292MW in 2017 429MW in 2018	Delayed to 2019
+1,200MW in 2016	605MW in 2018 61MW in 2019	Delayed to 2019/20
+1,500MW in 2016	324MW in 2018 310MW in 2019	Delayed to 2020
All indicative coal projects (4.1GW between 2016-20)	414MW in 2022 392MW in 2023	Delayed to 2024

Note: * For the purposes of illustration of the impact in this table, the non-discrete numbers of MW that are economic are shown. Practically, as considered elsewhere, the discrete unit size of commonly available CCGTs means that entry will be more 'lumpy'.

Hence, the DOE's *non-market* concerns should be on the value and costs that the market does not internalise, for example, environmental emissions and physical energy security (as distinct from financial energy security).

From an energy security perspective, coal is a globally traded commodity and steam coal is exported by many countries, the largest of which in the Asia-Pacific market are Indonesia, Australia, South Africa, Vietnam, Russia and Colombia¹⁸. Much like oil (although perhaps to a lesser extent) it is almost inconceivable that coal would not be available *at some price*. The nature of the energy security issue is therefore less of a

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physical threat and more of a financial threat in terms of the possibility of high price shocks. The greater reliance on any particular fuel means that the 'portfolio' benefits of diversity are lessened, although correlations between the prices of substitutive fuels would decrease these benefits.

From an environmental cost perspective, the EPIMB confirmed to the Study Team¹⁹ that there are no current plans to introduce environmental policy actions (e.g., a carbon tax) that intervene or internalise these costs. Any realistic policies are, however, likely to only shift the balance between coal and gas rather than exclude one or other, since the carbon price implied by a shift from baseload coal to gas exceeds US\$70 per tonne of CO₂. This is greater than international benchmarks that exist such as the current Australian carbon tax (about US\$23 in 2013-14) and the social cost of carbon estimated by the US Government of US\$13 – US\$65²⁰.

In Section 3 we identify the potential market failures and discuss the implications for the options available to the DOE.

2.3.2. Value of reconfiguring Malampaya usage

Absent any changes in the contracted quantities of Malampaya gas, changing the power generation capacity that is served by those supplies has the potential to reconfigure the economic use of the gas.

It is well known that the relatively high ToP quantities in the GSPAs to Sta. Rita and San Lorenzo (119 mmscfd and 57-65 mmscfd, respectively) compel those plants to run at baseload capacity factors in order to consume that gas²¹. Additional power generation capacity would mean that more of this gas could be consumed during peak hours if a technical solution (e.g., line compression) was available to ensure a higher coincident supply. Less gas, therefore, would be burned 'uneconomically', that is, consumed at times when the market price is less than the gas cost absent of the ToP constraint. Fuel prices for Santa Rita / San Lorenzo averaged US\$13.4/mmbtu in 2012²² which is below the economic value of the gas including the shadow price of the ToP constraint, estimated to be about US\$7.3/mmbtu in 2012.

FirstGen has publicly announced its intention to build new gas-fired generation capacity near its existing plants in Batangas that will be initially supplied through its existing rights to Malampaya gas²³. These plans are said to include a 100MW aero-derivative gas

¹⁹ Meeting between TLG and the EPIMB on September 17, 2013

²⁰ 2015 averages updated to nominal values from 'Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866' (May 2013); available from http://www.whitehouse.gov/sites/default/files/omb/infoereg/social_cost_of_carbon_for_ria_2013_update.pdf

²¹ The same arguments generally apply to Ilijan, although since the purchaser of the gas (PSALM) supplies the gas to the IPPA (South Premier Power Corp., SPPC) under different terms the plant theoretically has more dispatch flexibility.

²² First Gen Annual Report 2012, p12

²³ See, for example, the President's Report to the Annual Stockholders' Meeting (May 8, 2013)

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turbine (San Gabriel Avion) and a 400MW plant (San Gabriel Phase II), targeted at 2014 and 2016, respectively, and followed by a third phase of 2 x 400MW. FirstGen has a proposal to accompany the third phase with an LNG import terminal to serve the needs of all their gas-fired plants. (We note at this point that the San Gabriel project is classed as “Indicative” by the EPIMB as it has yet to reach financial close and it has been included in the DOE’s Power Development Plans since at least 2006.)

Our modelling of the proposed San Gabriel Phase I and II suggests that they would lower the system costs by reconfiguring the usage of the ToP quantities of gas from Malampaya. Based on our assumption, they appear to be able to economically burn about 1PJ of Malampaya gas p.a. between 2016 and 2023. At Malampaya gas prices, Phase II can operate as genuine mid-merit plant and our modelling suggests it will have an average net capacity factor of 40 percent. Their net effect is to reduce the capacity factor of the Saints plants and permit cheaper baseload plants (including existing coal units) to more economically serve a greater proportion of the off-peak demand.

The aggregate size of the CCGTs in San Gabriel Phases II and III (400MW + 800MW), along with the 100MW of peaking capacity, appears to preclude the economic entry of additional LNG-fired generation in the medium-term.

2.3.3. Additional supplies from Malampaya

According to the DOE NGMD²⁴, the Malampaya gas field’s recoverable reserve end of field life is 3.08 to 3.29 tcf, whereas the total committed quantity under the current GSPAs is 2.7 tcf and total production as of June 2013 was 1.3 tcf.

In October 2013 Shell Philippines Exploration BV (SPEX) publicly disclosed details of the Malampaya Phases 2 and 3 (MP 2 and 3) of the Malampaya Deepwater Gas-to-Power Project in SC38. These involve the drilling of two additional production wells (MP2) and installing a second platform to house additional compressors for depletion compression (MP3). The two phases have been estimated to cost US\$250m and US\$750m respectively, and are targeted for completion by February 2014 and December 2015. The shutdown of Malampaya in November 2013 was partly to tie-in the MP2 infill wells and the tie-in of the depletion compression platform (MP3) is due to necessitate a shutdown in late Q1/early Q2 2015.

SC38 will expire in 2024 since GSEC 47 was entered into by Oxy in 1989. Pursuant to Presidential Decree 87, Service Contractors can operate for a maximum of 50 years so the Malampaya Consortium has a pending request (filed in 2011) with the DOE to extend its contract for 15 years. No matter whether the Malampaya Consortium, the Government or a third party operate SC38, the recoverable reserves beyond the current GSPAs are 0.38 to 0.59 tcf (according to the NGMD’s figures).

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Private communication from Laura Saguin, October 24, 2013

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Should Malampaya gas be priced up to that of LNG less the avoided cost of transport and regasification (assumed to be about \$2/mmbtu in real-terms), then the existing 2,700MW could economically consume about 0.03 tcf p.a. (if LNG were also present), that is about thirty percent of the total annual ToP level. This level would consume the recoverable reserves within about 11 to 18 years. If the current pricing formulae are continued, then more gas can be economically consumed by the power plants, about 0.04 tcf p.a. (if LNG were also present), and the recoverable reserves would be depleted in about ten to 15 years.

2.3.4. EWC power plant

Energy World Corporation (EWC) are developing a 3 x 200MW gas-fired power plant [2xCCGT + 1xST] accompanied with an LNG terminal in Pagbilao, Quezon province. The EPIMB has recently graduated the project's status to 'committed' (Figure 8) and the two gas turbines, already purchased from Siemens, will reportedly be delivered to the site by the end of 2013.

Figure 8: Private sector initiated power projects – natural gas (as of October 31, 2013)

Committed / Indicative	Name of the Project	Project Proponent	Location	Rated Capacity (MW)	Project Status	Target Commissioning
	NATURAL GAS			5,600.00		
Committed	Pagbilao 600 MW Combined Cycle Gas Fired Power Plant Proposed 3x200 MW CCGT Power Plant	Energy World Corporation	Brgy. Ibabang Polo, Grande Island, Pagbilao, Quezon	600	Various permits obtained; Granted permits by DOE on the LNG terminal on January 24, 2011; Financing equity will be 100% sourced from EWC but still engaging other banks such as DBP & Standard Chartered Bank; CoE from the DOE for CoC for the 300MW obtained on 9 December 2011; Issued Clearance to Undertake a GIS for 300 MW on 8 August 2013 and revised on 3 July 2013 for the 600MW. Land is already secured with a long lease entered into since 2007; Secured SEC Registration. ECC still on process; GIS still on process; LGU Permits still on process; Building permit still on process; Certificate of Endorsement still on process; EPC Contractor is Slipform Engineering International (Philippines, Inc.) Entered into a Sale and Purchase Agreement last October 2012 with Siemens Energy for two 200 MW gas turbines; Financing arrangements is completed documents will be provided to DOE within the month for reference ; Intended to supply power into the Wholesale Electricity Spot Market but is also open to discussing potential off take arrangements as well; Commencement of Construction will be on December 2013; Target Testing and Commissioning (2014: 1st Unit -200MW, 2015:2nd Unit-200MW, 2016:3rd Unit-200MW); Target Commercial Operation: (2014: 1st Unit -200MW, 2015:2nd Unit-200MW, 2016:3rd Unit-200MW); Project cost is \$300M	2014:1st Unit -200MW, 2015:2nd Unit-200MW 2016:3rd Unit-200MW

Source: DOE ('Comments of TLG Inception Report on LNG Investment Framework.doc')

Notwithstanding how EWC chooses to trade the power plant in the WESM and the exact timing of their project, the 600MW of capacity that they intend to commission over the next few years appears to fit within the realm of what is economic. Depending on how it is operated, it could also nearly completely fill the identified space of the peaking/mid-merit requirement in the WESM.

Based on our market modelling, if the EWC units enter as currently planned then under our base case assumptions, then there is no economic role for an additional LNG terminal until imports are required for the existing CCGTs supplied by Malampaya. The economic CCGT capacity above the 600MW planned by EWC would appear to be too small to underpin the investment in another LNG terminal unless relative fuel prices or demand growth were particularly favourable and/or there was sufficient bankable non-power off-takers willing to sign long-term contracts (which is thought to be unlikely ahead of validation in Phase Three of this Study).

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2.3.5. Displacement of liquids generation in Malampaya loss of supply incidents

Since 2,700 MW of capacity that normally runs as baseload is dependent upon Malampaya for its principal fuel source, any gas supply interruptions have significant impact on the whole electricity market. The on-going scheduled maintenance of Malampaya, which coincides with other plant outages²⁵, was expected to have produced a prolonged period of high market prices even before the impact of typhoon Yolanda²⁶.

The market's price sensitivity is exacerbated because of the material cost difference (currently about \$9/GJ) between replacement liquid distillate fuels and the Malampaya gas in addition to the 3 percent higher heat-rate and higher equipment wear-and-tear for liquids-fired generation. Nevertheless, we understand from the NGMD that during unscheduled interruptions, if the power plant decides to switch over to liquid fuel, under the GSPA SPEX is obliged to cover the cost difference of the liquid fuel against natural gas. Under the terms of the First Gen's PPAs with Meralco the incremental fuel cost in Sta. Rita / San Lorenzo due to use of condensate for the period of the shutdown is passed-through to Meralco consumers.

The line pack volume of natural gas if all three gas power plants are in use is estimated by the DOE to be about 18 hours, which – in the event of an offshore interruption – would give operators time to switch fuels. However, we recognise that Ilijan has only one fuel line, which means that a switch to liquids necessitates a five day shutdown to clear up the fuel line prior to use of natural gas and therefore acts as a disincentive to switch unless a prolonged outage is expected. The fuel hot-switching process also puts the plant at risk of a forced outage; for example, as suffered by San Lorenzo unit 2 in Oct 2011 that led to a four hour outage to restart the unit²⁷.

According to the NGMD, since the commencement of the WESM in Luzon (26 Jun 2006) up to before the 30 days of maintenance that started on 11th November 2013, there have been 74 days of scheduled maintenance periods for Malampaya gas supply, that is an average 10.6 days per year. Table 7 summarises the recent record of Malampaya outages and their estimated impact on system costs. Note that the additional generation from the coal plants, which have historically been the marginal plants for the majority of hours and not operating at their full availability, has the effect of reducing the system cost.

²⁵ Maintenance of Pagbilao unit 2, Ilijan unit 2, Calaca unit 2 and San Lorenzo unit 50. San Lorenzo unit 60 is still undergoing repair until Q1 2014.

²⁶ For example, Meralco forecast WESM rates in November 2013 of PhP18.9728/kWh in a submission to the ERC on September 30, 2013

²⁷ This event is recorded in PEMC's Monthly Market Assessment Report. The Study Team asked the NGMD whether they were able to provide a full record of the failed hotswitch events so that we might be able to quantitatively assess this risk but they were unable to so.

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Table 7: Estimated additional system cost for historical Malampaya outage events

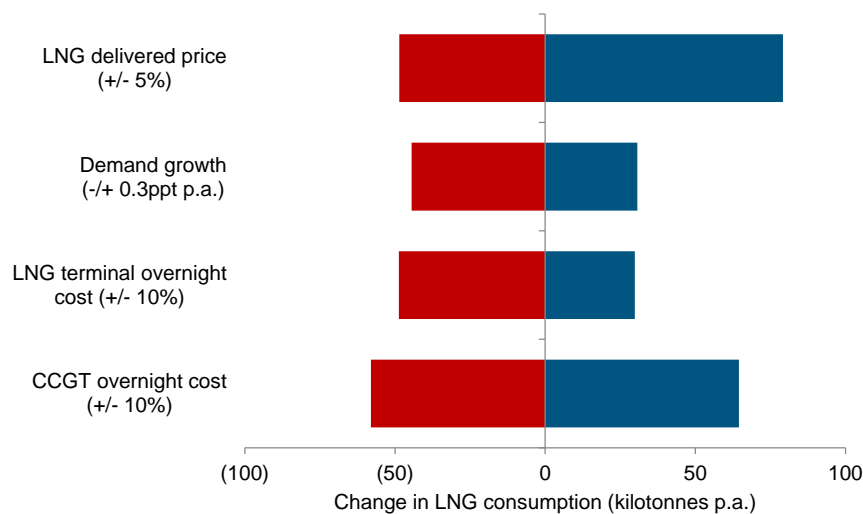
	Start date	Duration*	Additional generation (GWh)			Additional system cost (mPhP)
			Liquids replacement	Other oil plants	Coal plants	
Scheduled Malampaya maintenance outage	22 Nov 2006	25 days	797	332	130	2,500
	27 Jun 2008	4 days	152	13	65	1,000
	10 Feb 2010	30 days	929	10	483	1,300
	20 Oct 2011	7 days	257	39	95	900
	13 Jul 2012	8 days	298	17	166	600
	11 Nov 2013	30 days	1,051	106	366	4,000
Subtotal:						10,300
Unscheduled Malampaya supply outages	12 Mar 2007	30 hours (2,300MW)	27	4	13	40
	9 May 2009	30 hours (1,300MW)	9	1	9	0
	10 Mar 2010	27 hours (2,000MW)	<i>Delayed start-up coincident with scheduled outage data (above)</i>			
	22 Sep 2011	76 hours (1,800MW)	115	16	18	400
	2 Oct 2011	48 hours (1,300MW)	31	7	8	100
	8 Jun 2012	76 hours (1,500MW)	53	15	7	200
Subtotal:						740

These estimates suggest that the system should be willing to pay around US\$25 million p.a. to avoid the additional system costs associated with scheduled outages. At a discount rate of 10 percent over 25 years, the present value of these avoided costs is nearly US\$ 230 million.

Electricity consumers may actually be willing to pay more than this because of the rent transfer from consumers to generators during the supply outages.

2.3.6. Other sensitivities

The sensitivity of the LNG consumption in 2020 to changes in the key assumptions is illustrated in Figure 9.

Figure 9: Sensitivity of the LNG consumption in 2020 to key assumptions

2.4. SOURCES OF UNCERTAINTY AND THE DRIVERS OF REAL OPTION VALUE

One cannot deny that uncertainty exists – and that it has a major impact on investment outcomes in the power sector. Nonetheless, the vast majority of all electricity planning is done using deterministic models. There are several reasons for this seeming mismatch between planning methodology and operational reality – all of which relate to the fact that doing probabilistic planning well is difficult.

- First, at a purely conceptual level, uncertainty is hard to characterize and define. There are different approaches for representing uncertainty (e.g., scenarios, binomial trees, etc.), all of which have their analytical limitations.
- Second, human beings are notoriously bad at processing probabilistic information, often preferring to toil within the more comfortable, if inherently wrong, domain of deterministic analysis.²⁸
- Third, uncertainty is inherently forward-looking and thereby subjective – and most decision-making processes (and decision-makers) reject reliance on subjective assessments for which they have little understanding and even less intuition. Basically decision-makers are often quite uncertain about how to evaluate a particular representation of uncertainty, and are often more comfortable ignoring uncertainty completely than to risk relying on an inherently subjective representation – notwithstanding the fact that ignoring uncertainty completely is itself a subjective representation of future uncertainty.
- Lastly, the investment decision rules that work well in the deterministic planning world often do not work well in the probabilistic planning world. We must modify the tools accordingly in order to yield unbiased forecasts and valuations.

²⁸

These biases are well-noted in the literature. Amos Tversky and Daniel Kahneman collaborated on research in the psychology of prediction and probability judgment, for which Kahneman received the Nobel Prize in 2002.

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Nonetheless, while probabilistic planning is difficult, it is essential in order to quantify the benefits of strategic and operational flexibility.

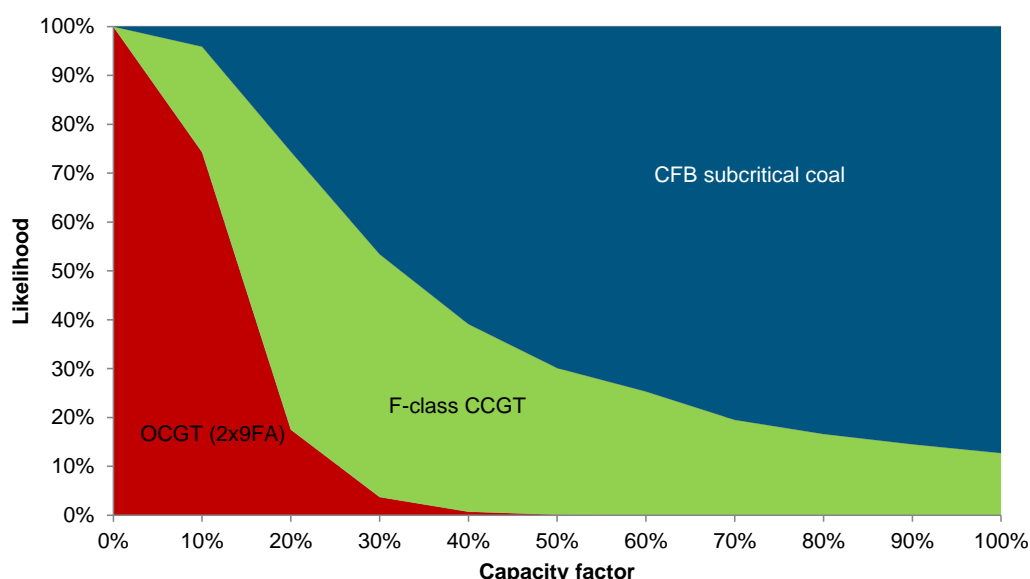
2.4.1. Key sources of uncertainty

The level of economic dispatch of LNG-fired generation is dependent upon a wide range of factors. The critical ones being:

- Fuel cost of LNG relative to coal;
- Capital cost of CCGT relative to coal plant;
- Technological efficiency of CCGT relative to coal plant; and
- Availability of baseload plant and hydro resources.

There appears to be a broad consensus that, at least in the medium-term, LNG has higher Long Run Marginal Cost (LRMC) compared to coal at baseload capacity factors. Nevertheless, the uncertainty in the key inputs means that in practice the choice of which technology/fuel would be 'least-cost' in the future is uncertain. In the Inception Report we introduced an approach using screening curves as a way of illustrating the nature of this uncertainty and the value of flexibility that it creates. In our example, as illustrated in Figure 10, applying the historical long-term volatilities and short-term variances to the projected assumptions allows the quantification of the likelihood that each option is least-cost.

Figure 10: Illustrative likelihood of technology options being least-cost at different capacity factors (2016)



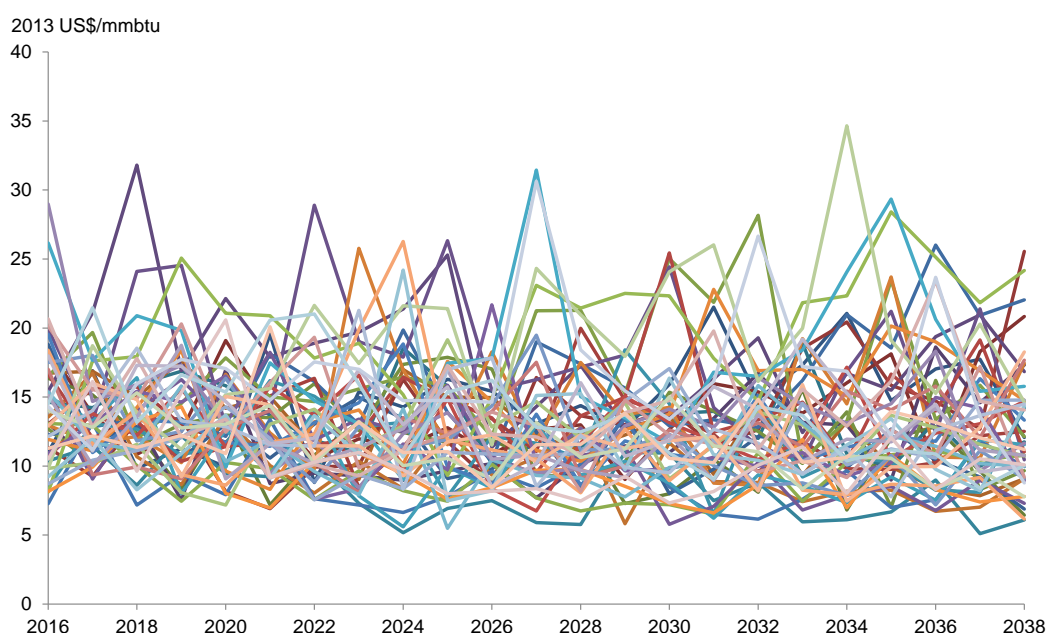
In Section **Error! Reference source not found.** we describe our approach to quantifying the volatility of the key uncertain parameters.

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2.4.2. Quantification of the value of operational and strategic flexibility

Given the forward projections of the key uncertain parameters, estimates of the volatility of those parameters, and the short- and long-term correlations between those parameters, we use a Latin hypercube sampling technique to produce an appropriately large set of scenarios (200 in this case) whose parameters have these characteristics. Each of these scenarios defines a possible outcome of the world for each year between 2014-2038 for the set of uncertain parameters. Crucially, these scenarios capture the dependencies of each year on the previous year so that the rate that an 'in-the-money' option moves 'out-of-the-money' (and vice versa) depends upon the volatilities of the underlying parameters. Example price paths for LNG are given in Figure 11.

Figure 11: Example scenario price paths for LNG given historical oil price volatility



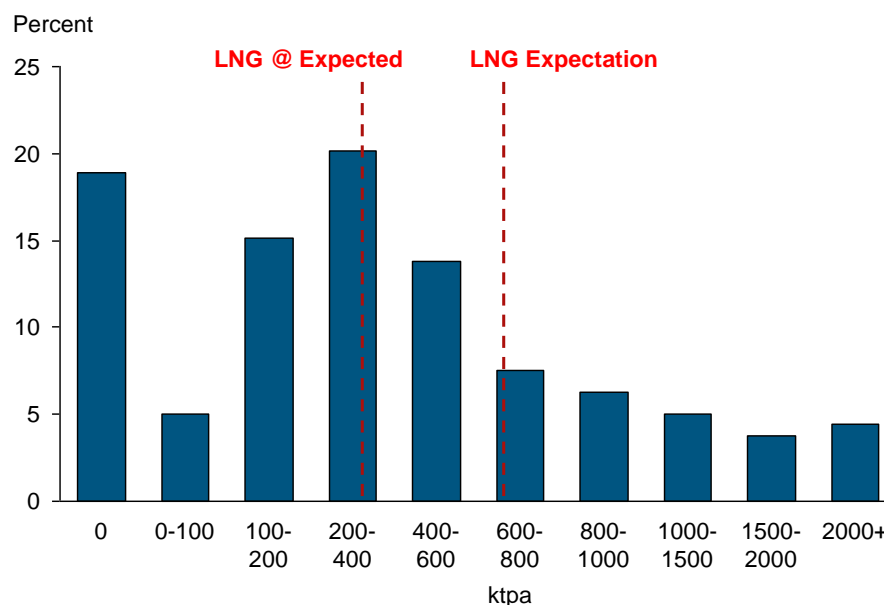
If we optimise the investment decision to build the terminal²⁹ and associated power plant, then, given an allocation of US\$300m to the power customers, they will be built in scenarios and in years whenever economic, that is, whenever they can fully recover their fixed and annualised capital costs. In scenarios where the outcome is favourable, perhaps because the price of LNG falls relative to coal, then we observe higher levels of LNG-fired dispatch and greater LNG demand (reflecting operational flexibility). In scenarios where the outcome is very advantageous for LNG, then we additionally observe that additional LNG-fired capacity is economically added. The probability distribution of LNG demand, for example as is given in Figure 12, reflects the likelihood of the different outcomes (as represented by the population of the scenario set) and the manifestation of those outcomes on the economic quantity of LNG demand. This figure also highlights the implications of the option value since the expected LNG demand

²⁹

For clarity, here we are the decision to build the terminal is represented by its own binary variable and it contributes its investment directly to the system costs.

at about 600 ktpa is materially higher than the LNG demand at the expected values (labelled as 'LNG @ Expected').

Figure 12: Probability distribution of economic quantities of LNG in 2020



Of course, the world does not always unfold in a propitious way. As with any investment, decision to build in a market environment carries the risk that once the investment is committed, prices will take an unfavourable turn and the amount of capital recovered in one or more years will not be as great as envisaged. This is reflected in the 'investment asymmetry' – once committed, the expected value of returns will be less than value of the returns at the expected values. Given our assumptions on the volatility of uncertain parameters, we can evaluate how this risk affects the investment decision.

If we consider how the investment in the LNG terminal and LNG-fired capacity contribute to the least-cost capacity expansion plant, we postulate a risk premium as a means to identify the "diversity benefit" associated with the marginal contribution of an investment to the overall electricity portfolio (see Section **Error! Reference source not found.** for a mathematical description).

The impact on system costs across our set of 200 scenarios implies a risk premium that is equivalent to a reduction in the overnight capital cost of about 5 to 10 percent, depending on the year of investment. This is principally the option value that an LNG-fired CCGT can capture if its contractual arrangements are sufficiently flexible to respond to the dynamics of the fuel markets. This highlights one issue for consideration in the later sections: how can private sector investors be incentivised to make the investment decisions that are most valuable to the system?

2.5. CONCLUSIONS FROM THE POWER SECTOR MODELLING

The issue of what form of fuel for power generation is needed to address the Philippine's growing demand is more complex than the discussion of "coal or gas" to which some

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parties try to reduce the debate. The future economics of both are uncertain and system costs should be lower if options are not excluded ex-ante. Nevertheless, it is clear that different forms of capacity can contribute to the 'least-cost' outcome, and it is likely that the least-cost outcome involves both new coal plant and new gas supplies (at some point).

On the basis of the market modelling, we have identified that there is a reasonably robust economic case for a modest (600– 800MW) of LNG-fired CCGT that can economically dispatch at mid-merit capacity factors but still underpin investment of about US\$300m in an LNG import terminal somewhere in Luzon. The engineering assessment of the different locations identified by project proponents (Section 4) will show that the cost differentials between sites are much smaller than the potential differences in the option value of each site. In particular, the option to replace the Malampaya gas during outages appears to be worth about US\$25m p.a. to the system, which is an order of magnitude greater than the cost differences on a present value basis. Section 4 will also show that any electricity transmission constraints/issues, if they do exist, should be surmountable with a minimal cost burden.

The fundamental uncertainty over key drivers of LNG demand creates flexibility value. If the LNG infrastructure investment is going to realise that option value, the import terminal and the supply chain needs to be flexible and able to cope with relatively large swings in demand. The economic demand for LNG in occasional years is likely to be low (maybe 100-200 ktpa), but the expected demand is greater than the demand at the expected circumstances since the upside potential is significant. In the event of low relative fuel prices, high demand (recognising also that gas plants are quicker to build) or supply outages then the terminal will potentially 'leave money on the table' if it's unable to technically, contractually or otherwise serve demand in excess of 1mtpa in the long-term. This will be the focus of the tasks in Phase Two when we study the transactional structures for LNG-to-power and optimise the contractual structure for the power plant.

Finally, if non-power use of the LNG can ultimately defray some of the initial investment costs, then that would permit more power capacity to be economically built.

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3. REGULATORY STRUCTURES FOR LNG-FIRED ENERGY AND CAPACITY

The TOR describes Task 1.2 as:

On the basis of modeling, translate the role identified for LNG-fired energy and capacity into contractual concepts that can form the basis for the regulatory underpinnings of new gas-fired power generation.

3.1. INTRODUCTION

The modelling has highlighted that the main role for gas fired generation in Luzon and Visayas (together, the WESM) is one of a modest capacity of mid-merit plant. This section outlines a wide range of options that could be considered to enable this using LNG. It covers contractual concepts, regulatory suggestions as well as other actions that DOE could perform to act as an enabler of LNG.

Firstly, we clarify and confirm the objectives of this process. Next, we outline the range of options that could be considered. These have been drawn from suggestions by market participants, DOE, World Bank and other stakeholders as well as from our own experience and from how similar questions have been addressed in other markets. Finally, we review the options against some criteria aimed at deciding which are most likely to be practical and meet the objectives.

This section discusses the issues at a relatively high level. The detail of how to implement any ideas will be covered in Phase Two under Task 2.1: *Recommend a transactional structure for an integrated LNG-to-power project.*

3.2. OBJECTIVES

In order to develop a useful Master Plan for gas in the Philippines, it is important to have clear objectives for the outcomes we wish to see as part of this Plan. On any journey, how can you tell if you have reached your destination if you do not know where you are heading in the first place? This subsection sets out our understanding of the objectives of this process, as previously presented to the DOE/WB in a memorandum dated use this memo to discuss and agree these with DOE. The memo consists of the formation of a proposed set of objectives. Following memos will include discussion of possible hypothetical outcomes that can be used to assess the consistency of the proposed objectives with the DOE's true objectives.

In the Inception Report, we summarised the Objectives as set out in the TOR:

We understand that the objectives of this framework are to develop one or two LNG terminals for Luzon, and one in Mindanao, that:

- *Can be developed and brought into operation in the medium term (within five years);*

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- *Will meet the needs of the power sector and be least-cost from the perspective of power sector customers; and*
- *Will provide for cost recovery of LNG import facilities and the LNG itself.*

However, these objectives pre-suppose the desirability of gas entry without explaining why gas is required. They are, therefore, lower-level objectives; we feel it is also important to be clear on the higher-level objectives as these may be important when developing criteria against which different options can be scored.

From our meetings, discussions, the TOR etc., we believe that the following summarises the DOE's higher-level objectives:

1. To ensure that there is gas to fuel the existing gas-fired power plants in Luzon after the end of the Malampaya gas contract;
2. To ensure that there is gas to fuel the economic entry of new CCGT into the Philippines; and
3. To encourage infrastructure to be built (and under contractual terms) that creates options for incremental expansion and other non-power opportunities

These objectives are still quite specific and define the "what" of what is hoped might happen. We note, however, that these objectives do not explicitly mandate a role for LNG. Accordingly, these higher-level objectives provide an ostensibly level playing field between domestic and imported gas. Any preference for LNG would therefore be based on the potential for LNG to yield gas infrastructure and gas volumes in a timely and predictable fashion.

It is also common for markets and regulators to define over-arching objectives that guide the overall way the industry should develop. For example, the NZ market objective is for the "electricity industry and markets to ensure electricity is produced and delivered to all consumers in an efficient, fair, reliable and environmentally sustainable manner." Similarly, the Australian NEM market objective is: "The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system."

We note that the declared NG policy in the *Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas*³⁰ has some objectives. These are outlined below:

Pursuant to the general provisions of RA 7638, it is hereby declared the policy of the State to:

³⁰ http://www2.doe.gov.ph/Downloads/IRR_for_Nat_Gas_26_AUG__SIGNED.pdf

- (a) *Promote Natural Gas as an environment-friendly and economically efficient source of energy for the country by creating conditions for the establishment of a Natural Gas industry that will enable the country to achieve greater energy self-sufficiency and at the same time serve the interests of the broad variety of industry participants including Customers, Gas Distribution Utilities, Gas Transmission Utilities, operators of Transmission- and/or Distribution related Facilities and Suppliers.*
- (b) *Facilitate the participation of the private sector in the Natural Gas industry. The State will primarily confine itself to policy direction and regulation, but may engage in strategic activities that will catalyze the development of the Natural Gas industry and enhance economic benefit to the people.*
- (c) *Promote competition by liberalizing entry into the industry and by adopting pro-competition and fair trade measures with due regard to the financial viability of industry participants.*
- (d) *Ensure compliance with international safety standards and with Philippine environmental and other laws and regulations.*

We also looked at the EPIRA to guide our thinking in this area. EPIRA has a long list of objectives in its statement of Policy:

Section 2. Declaration of Policy. - It is hereby declared the policy of the State:

- (a) *To ensure and accelerate the total electrification of the country;*
- (b) *To ensure the quality, reliability, security and affordability of the supply of electric power;*
- (c) *To ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippine products in the global market;*
- (d) *To enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors in order to minimize the financial risk exposure of the national government;*
- (e) *To ensure fair and non-discriminatory treatment of public and private sector entities in the process of restructuring the electric power industry;*
- (f) *To protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power;*
- (g) *To assure socially and environmentally compatible energy sources and infrastructure;*
- (h) *To promote the utilization of indigenous and new and renewable energy resources in power generation in order to reduce dependence on imported energy;*
- (i) *To provide for an orderly and transparent privatization of the assets and liabilities of the National Power Corporation (NPC).*
- (j) *To establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market; and*

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(k) To encourage the efficient use of energy and other modalities of demand side management.

Not all of the interim Gas or the EPIRA objectives are directly relevant or necessary for the Natural Gas Master Plan; moreover, having too many objectives makes it hard to score different options. Thus we now have two types of objectives – those from the interim gas rules/EPIRA, which focus more on “how” something should be done (process), and the objectives in the TOR/discussions that focus more on “what” it is we need to be doing. Both aspects are necessary to be able to evaluate different options.

Having objectives at the level of interim gas rules/EPIRA are very broad, somewhat repetitive and overlapping and not directly actionable. Therefore, we have decomposed what appear to be the key drivers behind these objectives, and combined these with some practical requirements in order to come up with a list of objectives for this project that is actionable and capable of being used as the basis for creating criteria to decide how to proceed given a variety of possible options. These are outlined below:

1. To provide necessary natural gas commodity and infrastructure:
 - To ensure that there is gas to fuel the existing gas-fired power plants in Luzon after the end of the Malampaya gas contract (recognizing, however, that these plants would not run in baseload mode, absent the existing take-or-pay contracts, and therefore may require far less gas);
 - To ensure that there is gas to fuel the economic entry of new CCGT into the Philippines; and
 - To encourage infrastructure to be built (and under contractual terms) that creates options for incremental expansion and other non-power opportunities.
2. To carry out the above in a way that:
 - Relies on private sector development whenever possible;
 - Is based transparently on free and fair competition – so as to provide full public accountability and to ensure non-discriminatory treatment of all market participants;
 - Provides price signals and incentives that contribute to operational, allocative, and consumption efficiency;
 - Can be implemented successfully by the DOE with minimal assistance from other government entities;
 - Broadens the ownership base so as to reduce the potential for the exercise of market power in the natural gas and electricity sectors;
 - Creates or utilizes contractual mechanisms that offer a high probability of commercial success (i.e., financial close of both gas production or regasification and CCGT generation); and
 - Can be demonstrated to be economically “least-cost” when taking into account all relevant considerations.

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In the next section we consider a number of options that may be capable of meeting these objectives.

3.3. THE CASE FOR ACTION

The objectives outline what the DOE would like to achieve. A key question that should be posed – if not answered at this stage of the process – is whether or not these objectives will actually be achieved without any (or with minimal) action.

Another way of posing this question is: Has there actually been a market failure that warrants intervention?

Market failures occur when the benefits of an activity are diffuse and unable to be captured by commercial parties such that although an activity is economically sensible, it's commercially unviable. An example of this is often a transmission line: which may add to the stability of the grid and which may allow many different customers to connect, but there are so many different benefits to so many different customers that collecting them all together in one commercial contracting structure is infeasible. This is why we have Grid Codes and regulation to cover expansion of the transmission network.

Is the potential LNG terminal in the same category? Or is it possible that the right amount of LNG will enter the Philippines without Government intervention at all?

The potential market failures that we have observed in the course of this project include:

- Environmental impacts of coal not being fully included in any costs for coal fired power plants. This market failure tends to advantage coal over gas options.
- The regulation of power contracts does not recognise the different roles of plant in the market. (Although we note some limited evidence that this appears to be changing, -see the discussion on the approval of the Therma Marina peaking plants below). This tends to disadvantage all forms of mid-merit and peaking (such as gas, storage hydro and diesel plants) compared to baseload plants (such as coal, geothermal and run-of-river hydro).
- Transmission pricing in the WESM does not reflect the deep costs of upgrading the network when generation connects (meaning that there is no incentive for new power plants to locate at places where connection is cheaper). This does not impact any particular plant type, but generally introduces inefficiencies into the industry however as it is not directly affecting gas we would not be considering options to change that at this stage.
- Some retailers are of poor credit quality, meaning that using them to underpin large scale capital investments funded by bank debt is difficult. This tends to disadvantage generators wishing to build in Mindanao (and to some extent Visayas) more than those in Luzon because of the presence of Meralco in Luzon. However, it does act to give Meralco a near monopsony buyer status and mean it can (alone) dictate which projects may go ahead. Given Meralco also has a generation business, and it interested in building an LNG terminal, highlights significant competitive issues within the current market structure.

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- Many retailers are used to buying power from the PSALM “Transition Supply Contracts” whose structure was highly unsuitable for a merchant environment. Power could be taken at any time (and in almost any quantity) for the single contract price meaning there was no value to intermediate or peaking capability. Therefore, buyers of power are struggling to understand power pricing and many have not yet internalised the differences between the price and the roles of different kinds of power stations. This tends to disadvantage specialist generation options – such as peaking or mid-merit plants – anything that cannot offer a “one-stop-shop” contract to cover full needs of the retailer. This tends to disadvantage mid-merit gas options.
- There are no rules surrounding gas or LNG in the Philippines, leading to uncertainty with respect to open access. Some concern has been expressed that a private sector party may build a terminal at some risk, but once built it could be “regulated” after the fact down to a utility level asset and the risk associated with the original decision not compensated. This directly impacts gas infrastructure projects – such as terminals.

The above list highlights that one of the key benefits of gas – that of flexibility and optionality – may not be commercially accessible to market participants (for example, due to transaction costs, free ridership, rent-seeking or merely numbers of people involved etc.).

Other market failures related to the inability of the market to fully capture the value of specific events. For example, a “back-up terminal” at Batangas whose sole role is to provide backup for Malampaya outages would have around US\$25m p.a. value to the power industry (see Section 2.3.5). However, some of this value accrues because of a general lowering of market prices during periods of outage: whereas now the price is set by more expensive oil-fired generation during outages and is higher, if LNG were available it could be set at relatively lower gas prices. This benefit accrues across the market as all retailers can buy cheaper power (or to use contracting as an example, the average WESM price over the year is lower which should lower contract prices in the medium to longer term). However, this benefit is indirect: only the direct cost of fuel purchases is easy to capture in a contract. The indirect benefit to everyone else in the market is not. Thus the benefit of this option is difficult to capture using a model of private sector rents only and some centrally implemented infrastructure could have value, in much the same way that transmission has some central planning (via the OATS Rules³¹) and ERC regulation.

However, none of the above are necessarily large enough market failures to prevent the entry of economic LNG. On the one hand, the terminal is under construction. We have viewed the site and note that there is indeed construction activity – albeit at a lower level than we might expect from the facility of this nature. We understand construction contracts for the tank and the power station have been signed and the DOE now considers the power station to be committed.

31 Open Access Transmission Service (OATS) Rules

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This is possible evidence of no market failure or may indicate that correct commercial outcome may occur, despite the existence of market failures of various types – if the market failures are not large. The EWC power station (600MW) is about the size that our modelling suggests is economic for new entry in the next few years. It would not necessarily solve the Malampaya replacement problem, but a pipeline from the terminal to Batangas would. The siting of the power station is in a location that currently has sufficient electricity transmission access to cope with another 600MW.

On the other hand, EWC's commercial strategy is unusual. They have no contracts for the sale of their power and intend to operate on a merchant basis. This increases the risk of their project and thus it may result in commercial failure. If such failure occurs, LNG may not flow into the Philippines in the near term however it would still be possible to construct a replacement for Malampaya in good order before 2024. In other words, even if EWC fails, it may not be catastrophic.

It may be that other proponents plans are not capable of going forward not because of market failures but because they are not economic projects. It would not be a good use of Government capital to underwrite projects that are not economic and complaints from proponents that they "need more" may be because their projects are uncommercial not a reflection of the potential of the Philippine market to support economic LNG entry.

There is also some (limited) evidence of changes in regulatory decisions that may highlight improved understanding of the role of different plants. See below. If this contract represents a valid point of reference, then mid-merit gas should be capable of approval by the ERC.

Figure 13: Implications of Approval of Therma Marine Peaking Plant

- Since the Inception Report the ERC has provisionally approved the PSA between Therma Mobile (TMO) and Meralco [1] for a maximum of 234MW of oil-fired capacity.
- This contract highlights the increasing maturity of DUs to power procurement – we believe it to be one of the first major contracts since EPIRA that is explicitly non-baseload – and thus provides evidence of increasing recognition of the value of flexibility.
- The ERC's order indicates that they are willing for the capacity costs to realise this value to be passed onto consumers. TMO's base rate for Meralco is PhP11.26/kWh at 40 percent capacity factor, although pursuant to Appendix B of the PSA in contract years 2-5 the maximum monthly capacity factor is 25 percent, which implies that the effective rate will be at least PhP12.67/kWh in subsequent years (at current fuel prices). The rates, which do not incur transmission charges owing to the direct connection, include a capital recovery fee of PhP4,190/kW-year and a FOM fee of PhP2,810/kW-year, the former of which gives TMO a return on capital of more than 15 percent.
- If we consider how the total fixed fees of PhP7,000/kW-year [2] might have otherwise been used, then with a net present value of about PhP75,000/kW (c.US\$1700/kW) at a discount rate of 10 percent they are sufficient to support an investment of about US\$1,200/kW and indexed FOM of US\$40/kW-year.
- This is about the level of investment required for a CCGT and LNG terminal (albeit at a size bigger than 234MW); so, even before the savings of lower fuel costs are considered, it demonstrates the contracting market's ability to bear and the ERC's willingness to provisionally approve contracts for non-baseload power.

[1] ERC case no. 2013-196 RC. Order dated November 4, 2013.

[2] Recognising that according to Appendix D of the PSA, the FOM component is subject to indexation of Philippine national CPI, which is assumed to be about 4% p.a.

It is also the case, in this as well as other electricity markets, that the cheapest and least risky way to solve a commercial problem is to ask the Government to make the problem

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go away. In the context of this work, the “problem” of coal being cheaper than gas is a case in point. However, coal IS cheaper than gas for baseload power and in a market that does not price nor value the lower emissions of gas; it is therefore hard to see how this problem can be made to go away.

There is indeed a significant risk that any Government intervention merely opens the floodgates for more and increases the case for “petitioning the Government” as opposed to “developing a robust project” as a commercial strategy going forward.

These issues should be debated in the Phase One workshop as they are critical to deciding which options to pursue.

3.4. OPTIONS

Although the TOR talks only about contractual concepts for regulatory underpinnings, a wider range of options was proposed by participants or used in other markets.

Many of these options are infeasible or unlikely to succeed in the Philippines; however, it is better to look at the full range of possible options at the start of the process in order to ensure that nothing is forgotten before whittling the options down into something that might be closer to a possible solution. Such a wider approach is more likely to capture the right answer rather than a narrower approach that may miss an unexpectedly useful idea.

In our proposal, we outlined the following possible solutions:

- **Direct investment in LNG infrastructure.** The ToR notes that, under EPIRA, the NPC cannot make investments in electricity generation, but that the Government (e.g., via DOE or PNOC) might have greater latitude to make investments in LNG regasification and gas pipelines. The public policy rationale for such direct investment would be that access to gas provides broad-based benefits to the Philippines power sector. The costs of this infrastructure could then be recovered via a similarly broad-based charge (e.g., similar to the Feed-in Tariff Allowance subsidy from consumers for the environmental benefits of renewable energy). Absent some or all of the regasification costs, gas-fired CCGTs may be able to be financed on a merchant basis. The ToR, however, does note that we should assume that PNOC will approach investments on a commercial basis (which may limit the feasibility of this mechanism).
- **PPP investments.** The ToR cites the fact that the PPP Center associated with the National Economic Development Authority (NEDA) provides transactional support to government agencies that pursue public-private partnerships. But we note that the recent changes to the NEDA JV guidelines would appear to make such public-private partnerships even more difficult.
- **Tendering for LNG gasification capacity.** The DOE could establish a public policy goal to develop gas-fired capacity and run an associated tender process to procure a given quantity of capacity. This would be conceptually similar to the renewables

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feed-in tariff procurement, except that the tender process would more easily meet the “least-cost” test.³²

- **Targeted assistance.** Tax exemptions or holidays for LNG and CCGT infrastructure investments might skirt the definition of “subsidy” and enable these investments to be financeable. The analogy in the renewable energy sector would be the fiscal benefits (such as income tax holiday) available to certified renewable energy developers under the 2008 RE Act.
- **LNG vesting contracts.**³³ The DOE would provide vesting contracts for investors willing to develop LNG regasification capacity. The vesting contracts would be structured as variable-quantity swap contracts against the LNG price. The owner of the gasification facility would receive the difference between the actual LNG import price and a much lower strike price for some specific percentage of all LNG imported and regasified.³⁴ Since incremental LNG sales would yield incremental margin, the terminal owners would then have an incentive to sign up CCGTs in order to keep LNG import volumes high. And the margin on the vesting contracts would provide a source of value that would help to make the projects bankable,³⁵ The DOE would then recover its swap payments via a broad-based energy charge.
- **Electricity capacity markets.** The ToR notes that “The Philippines is considering creation of a capacity market in the WESM.” Capacity in an electricity market can be defined as the option to buy electricity at a fixed price. Accordingly, a well-functioning, non-distortionary, capacity market provides a fixed capacity payment in lieu of a highly volatile and uncertain stream of energy revenues. By reducing revenue volatility, such capacity payments would make it easier to finance mid-merit and peaking units. Whether risk reduction alone could induce investment in LNG infrastructure is another question. Depending on its design, however, a capacity market may also create transfers in value between generators and customers, or between different generation technologies. So it is indeed possible that a capacity market could provide enough additional value to make CCGTs bankable.
- **CCGT capacity obligations for Distribution Utilities.** Under this mechanism, the DOE would establish the requirement that all distribution utilities purchase “CCGT

³² It is similar in the sense that the procurement is triggered by an external capacity constraint. The feed-in tariff process, however, is a “first-come, first-served” solicitation for a fixed number of MW at fixed prices. We also note that the mechanism by which the above-market costs of these renewables investments are recovered is still an open question.

³³ The Singapore government used similar contracts to induce CCGT developers to build new capacity and sign long-term LNG contracts. But these contracts favoured baseload generation and would not necessarily be at all suitable for the Philippines. Moreover, given that the WESM is structured as a competitive market largely free of subsidies, it seems more sensible to apply the vesting contracts to the developers of the regasification terminal.

³⁴ Note that the incentive to purchase LNG efficiently would disappear if the vesting contracts were applied to the entire import quantity.

³⁵ Note also that if LNG were purchased via either Brent-linked or Henry Hub-linked contracts, this source of value could be hedged quite well via commodity futures markets.

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capacity credits” equal to some percentage of their peak load. CCGTs meeting certain eligibility tests would be granted these capacity credits, which they could then sell to distribution utilities. The sales of these credits might provide an additional revenue stream sufficient to make the CCGT investments (and the associated LNG infrastructure) bankable projects.³⁶

- **Carbon constraints.** Even modest limits on industry-wide carbon emissions by the electricity sector would force some shift in new generation investment from coal to gas (and possibly other low-carbon sources). Implementing this as a limit on the tonne/MWh average output of each generation companies’ portfolio would give rise to an implicit carbon price that would tilt the generation economics in favour of gas investments without noticeably affecting WESM prices.³⁷

In our meetings with proponents, a number of options were suggested. These included:

- A fuel mix policy (with no expansion on what this might contain or what impact it might have). At least three participants mentioned this as an option;
- A ban on coal fired power stations (perversely this was favoured by at least two proponents who already have, or are also building, coal fired power projects);
- Tax incentives for LNG terminals similar to renewable power stations. At least two participants favoured this as an option and others mentioned it;
- Changes to regulation to facilitate approval of mid-merit power contracts. At least one participant favoured this option and others mentioned it. However one pointed out that it only helps the franchise sector, not the contestable sector players;
- Do nothing (Government intervention in power is not necessary and rolls back the reforms of EPIRA – two parties held this view).

Taking our original views, the suggestions of market participants and also a review of the possible market failures, we have identified a number of possible options.

One way to view these options is to identify which, if any, of the market failures they address. This is summarised in Figure 14 below.

³⁶ A similar scheme was used in Queensland to require retailers to purchase electricity from gas-fired sources. The aim of the scheme was to underwrite the costs of a gas pipeline from Papua New Guinea – more interesting is the fact that the outturn encouraged domestic gas production and the current boom in Coal Seam Methane in Queensland. Sarah Fairhurst worked with the Queensland Government on these issues while at PHB.

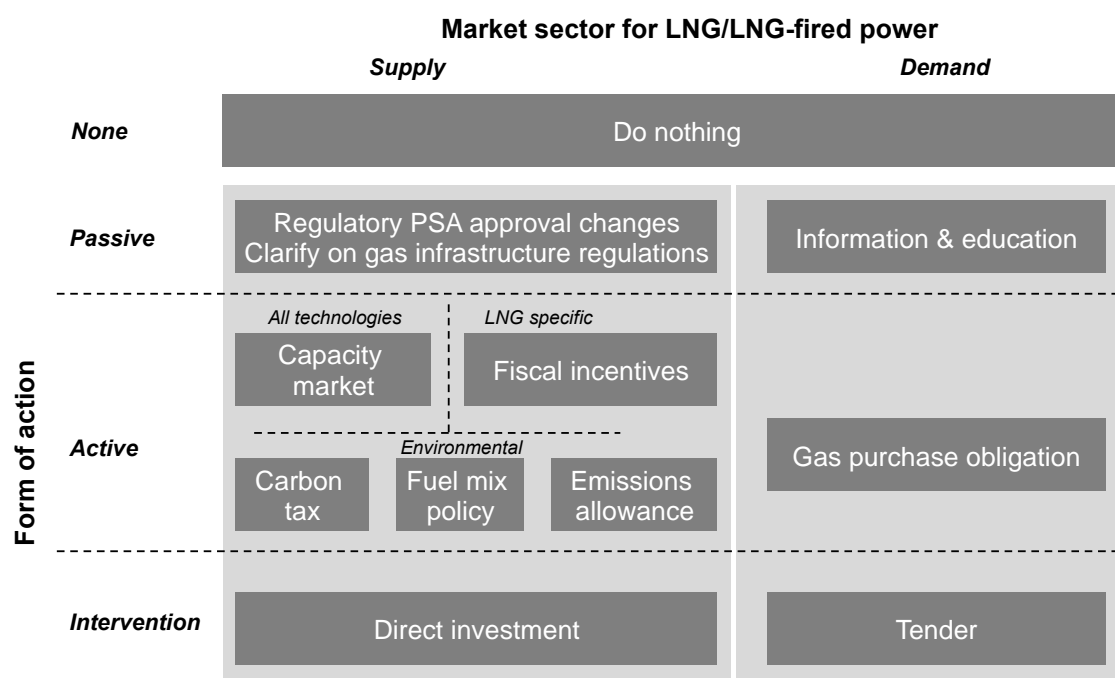
³⁷ Note that other forms of carbon policy – e.g., carbon taxes or constraints in the form of total tonnes of carbon output – would give rise to a marginal cost of carbon that the generators would build into their dispatch costs, thereby inflating bid curves and WESM market prices. By contrast, the tonne/MWh mechanism effectively allocates an incremental X tonne allowance to the generator for every MWh produced. This *implicit allowance* would thereby act as a credit to low-carbon generation sources; as a result, their effective dispatch costs would actually decrease. High-carbon sources would output more carbon than would be covered by the incremental allowance. Accordingly, their dispatch costs would rise. On balance, this would leave average WESM prices largely unaffected.

Figure 14: Relationship between Options and Market Failures

Market Failure → Option	Environmental impacts of coal not recognised	Failures in regulation of contracts	Retailers lacking knowledge and purchasing skills	Diffuse benefits of gas options unable to be captured commercially	Lack of LNG infrastructure rules / policies / regulations
Do Nothing					
Fuel Mix Policy	✓	✓			✓
Tax Incentives				✓	
Tender a gas offtake contract				✓✓	
Tender a regulatory approval		✓✓✓			
Tender a subsidy for terminal development				✓✓✓	
Tender a contract for terminal capacity				✓	
Gas Purchase Obligation	✓✓	✓	✓	✓	
Change to regulation of contract approvals		✓			
Carbon Tax	✓✓✓				
Grid Emissions Standards	✓✓✓			✓	
Direct Investment				✓	
Information and Education		✓✓✓	✓✓✓		
Capacity market				✓	
Clarify rules for access to terminal / pipeline					✓✓✓

Having identified the market failures, we then need to decide if the option needs to directly tackle the market failure (direct actions) or if there is some indirect mechanism that can be set up to bypass the failure (indirect or passive mechanisms).

Figure 15 gives an outline of how the various options can be categorised in relation to supply and demand vs. activity of the option. Some options tackle the demand for LNG (or LNG-fuelled electricity) – making demand for such LNG or power higher or more certain, which will enable contracts for such electricity to be increasingly desirable and entered into. Some options tackle the supply-side, making LNG-fired power cheaper or easier to implement.

Figure 15: Illustration of the different options under consideration

The options use a range of mechanisms – some are passive, working at a high level to improve the environment for the private sector to operate in – while others are active: soliciting proposals or tenders and actually driving particular outcomes. We have also, for completeness and because it may well be a viable option, included a “do nothing” option. Given the current committed status of the EWC terminal and power station and the low capacity of economic gas entry found from the modelling, it is possible that “do nothing” is sufficient. Indeed, doing anything always has a risk of unintended consequences whereas doing nothing does not.

We discuss these in more detail in the following subsections.

3.4.1. Do nothing

Although most proponents of an LNG terminal and associated power stations have suggested that something is needed to ensure their projects go ahead, not everyone has said it is essential. The Energy World Corporation, for example, is already building an LNG terminal and has ordered the turbines for its power station. The Meralco proposal arguably just needs to convince the ERC of the merits of mid-merit generation, something it is clearly well placed to do and has already started with public and private discussions. It clearly has the financial capability to underwrite the project alone if it believes it is in its commercial interest to do so.

It may well be the case, therefore, that doing nothing – or just doing minimal activities such as education – at this stage is the right answer. We believe it is important to evaluate a “do nothing” option as part of this Master Plan because sometimes if you do the wrong thing it is worse than doing nothing at all.

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3.4.2. Fuel Mix Policy

A “fuel mix policy” was the single most frequent action requested by a number of participants in the Study Team’s meetings with them. Almost everyone thought the DOE needed “a policy”. However, when questioned, there was no clarity as to what this would actually mean in practise or whether having a policy would actually achieve anything on its own. We therefore assume that a fuel mix policy is actually a shorthand statement for something more active, however given that few participants explained in detail what actions they actually wanted, we separate the “policy” from any active options that might flow from it.

In extremum, a fuel mix policy could be used to justify a Government mandated target for the capacity mix across grids or the country.

The experience of such explicit fuel mix policies in other countries (such as Malaysia and Hong Kong) highlights the risk associated with entering into very large capital commitments given uncertainties in the relative economics of competing options, demand projections and other factors.

Our interpretation is that flexibility has value for which a premium can be justified. If the right problem structure is developed and appropriate methodologies applied, this premium can usually be estimated. But it requires an appreciation of how quickly crucial assumptions can be proven wrong when dealing over the life of long-lived capital or fuel contractual commitments.

The other insight is that once a situation has transpired in which a large bet has gone bad, the tariff and other impacts can be long-lasting, with relatively few degrees of freedom for mitigation or response, despite often mounting criticism and pressure.

A fuel mix policy alone would not address any of the market failures that have been identified. We assume therefore that a “fuel mix policy” is a shorthand request for something else which does actually achieve the objectives as a pure policy alone, without operative functions, would appear to achieve little. As outlined in the case study attached below, fuel mix policies are often combined with other actions to achieve the desired outcome.

As explained in Figure 16, Hong Kong serves as a current example within South East Asia of a government using instruments within existing legislation to implement their fuel mix strategy. It also highlights the potential impact on consumer prices of imposing external constraints.

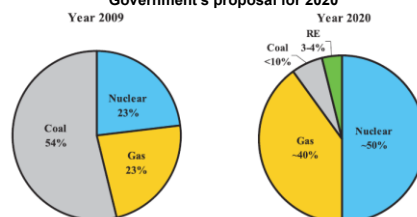
Figure 16: Case Study Hong Kong

The Government of Hong Kong's (GoHK's) *Climate Change Strategy and Action Agenda* consultation in 2010 proposed a fuel mix for power generation in 2020 of about 50 percent nuclear, about percent gas, less than 10 percent coal, and the rest being from renewable resources.

While the fuel mix target is yet to be formally enacted into policy, and will reportedly be subject to another public consultation in the forthcoming months, the GoHK has already used existing mechanisms – namely the emissions allowances under the Air Pollution Control Ordinance – to restrict the private sector utilities' degrees of freedom.

By decreasing the companies' allowance of SO₂/NO_x/PM that can be emitted by their plant portfolio, the companies are ostensibly obliged to switch most of the generation from coal to gas/nuclear from 2017 (even after significant investment in emissions reduction technologies) and therefore move most of the way towards the desired the target.

Hong Kong's fuel mix for power generation in 2009 and the Government's proposal for 2020



Since demand growth in Hong Kong is negligible, practically this implies the existing gas plants will have baseload operations and the existing coal plants will have much lower capacity factors and/or be partly decommissioned. The largest utility, CLP, have predicted that this will cause consumer prices to rise by about 40 percent over the next few years.

3.4.3. Tax incentives

Several proponents asked for tax incentives from the Government when we met and asked them what they needed to make their projects economic. Most said that something akin to what renewable energy is allowed.

Almost every participant expected that the current import duty on LNG would be removed. Some also suggested import duties on imported equipment should also be tax exempt.

We note that tax incentives are effectively a subsidy to a terminal, as they involve funds that would otherwise have flowed to the Government to stay with the private sector. They are, however, a more indirect form of subsidy that does not look like money is being given directly to the private sector. Further, the benefit of any income tax holidays is uncertain, because entities need to make profits before any benefit accrues.

It is worth therefore reviewing what tax incentives energy and renewables projects get and whether any of these are applicable.

The Board of Investments (BOI) already determines what tax incentives should be available for various different kinds of businesses. For projects related to energy, which covers the exploration, development, and/or utilization of energy sources adopting environmentally-friendly technologies, only power plants utilizing environmentally-friendly energy sources and technologies may qualify for income tax holidays (ITH). The general ITH is four years. However, only projects that have achieved financial closing for the project are qualified to apply for registration which reduces the certainty of any incentives and thus their ability to encourage such investment.

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Projects that can achieve “pioneer status” are able to gain a six year ITH. Any of the following may qualify for pioneer status:

- Power supply projects located in missionary areas or off-grid areas that are not receiving subsidies from PSALM;
- Projects that cost at least the Philippine Peso equivalent of US\$1.5 million per megawatt; or
- Projects with NVA of at least 30 percent.

For power generation projects, only revenues from power generated and sold to the grid, other entities and/or communities may be entitled to the ITH. Power projects that are built contiguous to existing generating facilities shall be considered as expansion projects. However, if the existing base load plant has consistently dispatched at least 80 percent of their registered capacity for the past three years, the project to be registered may be considered new. The amount of ITH to be granted shall not exceed 10 percent of the total revenue of generated power. Applications for registration must be endorsed by the Department of Energy (DOE).

As can be seen from the above, what current projects are entitled to is far less than renewable projects.

The Renewables Act (RE Act) grants a series of general incentives (sec. 15) to RE projects and activities including:

1. Income tax holiday (ITH) for the first seven years of commercial operations and a corporate tax rate of 10% on net taxable income thereafter;
2. Duty-free importation of RE machinery, equipment and materials within the first ten years;
3. Tax credit on domestic capital equipment and services equivalent to 100% of the value of the VAT and custom duties that would have been paid on the machinery, equipment, materials and parts had these items been imported;
4. Net operating loss carry-over during the first three years of commercial operations for the next seven consecutive taxable years;
5. Accelerated depreciation of up to twice the normal rate, if a project fails to receive an ITH before full operation;
6. Zero percent VAT on the sale of power and purchases of local supply of goods, properties and services needed for the development of the facilities; and
7. Special realty tax rates on equipment and machinery – realty and other taxes not to exceed 1.5% of net book value.

Extending these general incentives to developers of LNG projects presents at least two issues. Firstly, an issue recognized in the IRR of the RE Act, is the further erosion of the competitive nature of the generation sector under Section 6 of the EPIRA.

Secondly, the corporate tax rate of 10 percent is available *provided that* the developer “shall pass on the savings to the end-users in the form of lower power rates”. Pursuant to

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the RE Act IRR, the DOE shall determine whether savings are actually realized with respect to each RE Developer. In cases where the RE Developer charges generation rates that are lower than that of a non-RE facility, savings are deemed to have been passed on but only to the extent of the relevant supply contract. If a similar condition is to be applied to LNG projects, then potential investors will need a clear framework as to how the DOE will determine the amount of 'savings'. This may be complex given the lack of clear comparables that are analogues to non-RE facilities.

Even given the above, a tax incentive regime would need to be carefully structured to avoid over-compensating developers. It may be possible to model what tax benefits could swing an LNG terminal/CCGT project to be less expensive than coal however there is always considerable uncertainty as to the actual application of any such benefits and the outturn amount may be too little to change the outcome (in which case it is money wasted) or so much as to over-compensate (in which case, again money wasted).

3.4.4. Options which tender something of value

This option groups together a number of options, all of which fall into the category of offering something of value to a potential terminal builder. The different "things" which are offered tend to address different market failures and have different risk profiles and implications, however all would operate in the same way, by being tendered out by the DOE in return for specific actions – such as a terminal built.

Offering something of value by tender is a useful way of achieving a single defined outcome. It would not necessarily be a sensible long-term policy, but can be used to achieve the first step of a policy in a very direct manner by bypassing the main market failures, which is that of the diffuse benefits of the first terminal that are hard to capture commercially. The use of a tender would ensure that whatever is chosen is least cost, because the competition within the tender would result in a market outcome.

However, what should one tender? The devil is, as always, in the detail. In this section we give an overview of various ideas; these would be fleshed out in more detail in the Phase 2 report if this option is deemed viable.

Items of value vary and it would be important to find the thing that fits best with the objective. For example, it could be a site (if sites are rare and valuable); or a subsidy to underwrite some of the capital costs of the terminal if return on capital is the constraint (a direct way to support such a venture) or a contract to underpin the operation of a terminal (again, which is indirect support and which could, if properly structured, be on-sold to private sector users of the terminal).

Similarly, one could do the same for a CCGT with the terminal as an ancillary requirement/benefit. That is, if the CCGT were supported then the terminal would also be supported. Since a key market failure in the power market that we have identified is the lack of regulatory clarity regarding contracts for mid-merit plant, one option for example would be to tender an approval for a defined power sales contract (it would not necessarily need to have counterparties, but the terms and conditions of the contract would be fixed).

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The following lists a few of the more obvious ideas that tackle some of the identified market failures:

1. Tender a subsidy for terminal development.
2. Tender a contract for the capacity of the terminal.
3. Tender a Gas Purchase Contract.
4. Tender a regulatory approval.

Tender a subsidy for terminal development.

This directly solves the difficulty of bringing together commercial entities with diffuse benefits and the Government then takes the role, on behalf of all consumers who would benefit, of ensuring the terminal exists. It might thus work best for a terminal whose purpose was squarely aimed at reducing power prices – by cutting out the need for oil firing during Malampaya outages for example. Or one whose diffuse benefit is in the gas sector – supplying gas for transport or industry for example. It would therefore be important if this option is chosen to know exactly what market failure the subsidy is intended to address so that the tender could be specified precisely. The subsidy would be the tender variable and the lowest request for subsidy would be the winner. The terminal would need to be specified as a minimum size. A winner bidding zero would still “win” as they would lock out other competitors wanting more subsidy – thus if EWC could direct sufficient LNG to Batangas during Malampaya outages, they could still win this tender. This has the advantage of simplicity and is a direct incentive to get the terminal built. However, more complex options may be more valuable. The subsidy could be spread across all users of gas in the Philippines, much in the same way the Universal Charge is spread across all electricity consumers, or indeed over electricity consumers if they are the main beneficiaries of whichever options is chosen.

Tender a contract for the capacity of the terminal

This option is aimed at solving the same problems as the tender of a subsidy above. One benefit of tendering a subsidy is that there is the possibility that the subsidy would be low or zero. The downside is that it may be politically sensitive. Tendering for a capacity contract has the advantage of looking like the Government is buying “something”; however the downside is that this might be significantly more expensive than just the residual subsidy from a commercial activity.

Ideally the contract would be drafted to be tradable (i.e., not backed explicitly by the Philippine Government for its lifetime) but able to assigned to other parties wanting to use the terminal. The Capacity Fee would be the tender variable with the lowest capacity fee winning the right to build the terminal. The Government could then sell either rights to this contract, slices of the contract, slices of capacity or any other similar structures on a back-to-back basis to any party wishing to user the terminal. The sale of such capacity rights could also be tendered – with the Government either making a loss or profit on the sale. A loss would be incurred if the market value of capacity rights in an LNG terminal is less than the actual cost of the terminal – effectively the Government is paying the option fee to build the terminal and bearing the cost of this. A profit (possibly but less likely)

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would occur if the sale of capacity right exceeded the cost of building the terminal – more likely if the price of LNG falls in the market and the option to access the terminal has value.

However in any situation where you may have less of something that the market wants, you need a mechanism to allocate that prize. A tender is a good way to allocate the prize. It ensures that the best project wins rather than just the first project. Compare this to the current feed-in tariff for renewables: the scarce resource of “allowed MW of feed-in tariff” has been defined, but the allocation mechanism is “first to build gets the allocation”. This is actually undermining, rather than encouraging, renewable development because development of any infrastructure project (be it a wind farm or an LNG terminal) is costly and where there is uncertainty as to revenues, this tends to deter development.

Tender a gas purchase contract

This is a variation on the capacity contract above but includes both the gas as well as the capacity. This option allows us to define the gas purchase that we would be prepared to make, which may be larger than the economic gas requirements of a mid-merit station. The Government could then take the risk of swing on the gas (in a financial sense, by paying a take-or-pay style fee) while on-selling the actual gas in a shape suitable for the economic use in power stations. This is essentially a parallel of the current Ilijan IPPA arrangement.

Tender a regulatory approval

This is a variation on the option above: essentially a hybrid option linking changes to regulatory approvals (discussed below) with the “tender something of value” option. In this case, the point is that only a certain (reasonably small) amount of mid-merit plant is actually needed and thus even if regulatory change is used, it should only be for a constrained volume. That is, a rule change to approve all applications for mid-merit contracts may be inefficient – as only some are needed.

This option highlights that the need for the terminal is to supply power and the active component of the option is directly in the power sector. The power supply agreement could be drafted so that it is the most efficient terms and conditions and meets the economic market need for power.

The tender variable in this case could be electricity price in the power supply contract. This would ensure that only the lowest cost project goes ahead and thus ensure that the regulatory approval also meets the least cost criteria and thus is consistent with regulatory practise.

3.4.5. Gas purchase obligation

Under this mechanism, the DOE would establish the requirement that all distribution utilities purchase “CCGT capacity credits” equal to some percentage of their peak load; or have a requirement to purchase “CCGT energy credits” for some percentage of their total load. CCGTs meeting certain eligibility tests would be granted these capacity credits, which they could then sell to distribution utilities. The sales of these credits might provide

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an additional revenue stream sufficient to make the CCGT investments (and the associated LNG infrastructure) bankable projects.

This is somewhat similar to the Queensland gas purchase obligation. The Queensland Gas Scheme began in 2005. At the time, it was introduced to encourage a gas pipeline from Papua New Guinea to be built. However the actual impact has been to boost the state's domestic gas industry. It has also helped to reduce greenhouse gas emissions.

Under the scheme, Queensland electricity retailers and other liable parties are required to source a prescribed percentage (currently 15 percent) of their electricity from gas-fired generation.

The scheme has successfully acted to diversify the state's energy mix towards the greater use of gas. The scheme offered accredited gas-fired generators an additional revenue stream, which offset the higher cost of gas-fired generation (when compared with coal). This revenue was provided by electricity retailers who passed the cost onto their customers.

The scheme is now being amended because of changes to federal carbon legislation (the Carbon Pricing Mechanism) in Australia. There is some concern of a likely duplication of the expected impacts of the CPM plus a review also identified the scheme had met its key objective - to establish a mature gas industry in the state. It is expected that the scheme will end at the end of 2013.

The scheme helped to increase gas-fired electricity generation to almost 20 percent by 2012, exceeding the mandated 15 percent target. At the time of the introduction of the scheme, gas made up only 2.4 percent of the Queensland electricity mix. The associated development of new gas fields and infrastructure has also boosted the gas industry (in particular coal seam gas), and increased supply for electricity generation and other uses such as export to overseas markets.

Thus there are precedents for such a scheme to be set up to develop a gas industry. It would have no direct cost to Government – as retailers would pass the costs of purchasing (more expensive) gas on to consumers (thus some mechanism to ensure this has regulatory approval would also be needed). It is a market based mechanism with no winners or losers decided by Government and as a market mechanism has a high economic efficiency. It also has the added benefit of being gas-neutral – that is, would be equally beneficial to domestic gas as LNG. This may assist the domestic gas market to secure new gas (from Malampaya or elsewhere) which could be cheaper and more beneficial to the Philippines in the long term.

3.4.6. Changes to the regulatory approval of power sales agreements

Several of the power station developers highlighted regulatory issues as being a barrier to developing gas-fired generation capacity in the WESM. These developers/gencos appear to have little clarity over how the ERC will assess the rates in any proposed power supply agreement (PSA). In practice, as we outline in more detail in the Inception Report, the ERC has generally taken the approach of establishing base rates at the estimated

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long-run marginal cost (LRMC) of the generating plant in question, or at the proposed rates if they are below the ERC's assessment of the LRMC. Before 2013, if the proposed rates were below the NPC Effective Rates then they could be deemed as a cost effective. The ERC has explicitly rejected "market based pricing" for PSAs³⁸, arguing that there are insufficient levels of competition in the supply-side, even though the WESM is operating well, new entrants are entering and the Retail Competition and Open Access (RCOA) privatisation thresholds have been met.

This means, in practise therefore, that there is concern that the ERC will compare any gas fired power station to coal and deem it not cost effective. This fear would appear reasonably well founded given some of the decisions of the ERC in the past, where market based (sensible) solutions have been rejected as not cost effective. There appears to be little understanding of the role of different plant types (baseload, mid-merit and peaking) in the market. There appears to be little concern by the ERC about least-cost procurement of fuel, with the focus all on the construction costs and fuel being considered as "just a pass through" – even though best practise fuel procurement, even in a global fuel market, can achieve significant cost savings.

One option therefore is for the DOE to instruct the ERC that gas fired power project are a priority and PSAs from them should be approved. However, it is rarely that simple.

It would be uneconomic for a large capacity of gas fired projects to be built, so any instructions should not be of such a blanket nature. They should be more precise so that the correct approvals target the economic use of gas, which in Luzon has been identified as mid-merit.

Even then there are risks. A mid-merit plant would run only, say, 50 to 60 percent of the time so we would expect that the power supply agreement matches this.

However, because of the current tendency to use physical bilateral contracts very similar in design to PPA's³⁹, the whole of the capacity of the plant would be covered by this contract. This is unlike the situation in other market where financial hedges are the more common way to contract for power supplies and the plant would be free to generate in the market the actual amount that makes economic sense on any day.

The problem with using physical bilaterals that cover the whole plant is that there is a risk of mis-use of regulatory approvals. On the one hand, a contract that is approved may be then used to say such approval covers the whole output of the plant, and the plant run as baseload and passed through to customers even though this would be more expensive than purchasing coal (given that having an approved contract for an expensive plant is often just as good, from a retail perspective for captive customers, as a cheaper contract that is not approved). We would consider this a risk if the same entity owns the retail,

³⁸ For example, ERC Decision case no. 2012-118RC (issued January 28, 2013)

³⁹ There is a de facto "standard contract type" in the WESM which is not necessarily well suited to non-baseload plant

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generation and gas procurement infrastructure, as there may be ancillary benefits to one (say gas procurement) of running the plant flat out which are captured by that part of the company at the expense of the customers of the (regulated) retail part of the company. Put differently, the risk is of imposing a cost on captive customers that is then captured as private benefit by another part of the same company.

There are also risks of how regulatory approvals in the franchise market will affect the contestable market. If a company supplies both, this could result in all the low cost power migrating out for the franchise market into the contestable market while franchise customers (who have no choice) are burdened with even higher priced power. We already see that the lack of clear ring-fencing of contestable and franchise operations acting in this way in the market.

It is also the case that because of the way the contracts are structured, the trading of these power stations effectively lies with the retailer, not the generator. With Meralco's market share of the power market in Luzon, this means they actually have a monopoly control of generation in the market and can influence market prices by how they require that generation to run.

Therefore, the question of how to approve a mid-merit power contract in the WESM is far more complex than cost-plus and even simple economics. It requires analysis of contract structure, terms and conditions, identity of the proponents and market power.

It is also the case that only the "right" amount of mid-merit generation is required and thus contract approvals for more (or less) than this amount may also negatively influence the operation of the market. If there is a limited number of MW that could be approved, how should such approvals be allocated? On a "first past the post" system like the (not well functioning) FIT scheme or by having some way of finding the best projects to approve?

This tends to suggest that the option discussed above of "tendering a regulatory approval" where the DOE has control of the contract structure and amount of approval to be given has more attractions than a simple regulatory change. It would enable a much more targeted outcome, with far less risk of excessive gas being procured as a result and a greater chance of a competitive outcome if all potential retailers were competing for such approvals, with least cost as a tender variable, rather than just one passing through any cost it deems appropriate.

3.4.7. Carbon Tax

While we acknowledge that a carbon tax is probably outside the scope of this project, it should be on any list of possible options to encourage gas as it directly addresses the market failure that the carbon emissions of coal are not being recognised. However, we do not consider it further here.

3.4.8. Grid Emissions Target

Unlike an explicit carbon tax, even modest limits on industry-wide emissions by the electricity sector would force some shift in new generation investment from coal to gas

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(and possibly other low-carbon sources). Implementing this as a limit on the tonne/MWh average output of carbon of each generation companies' portfolio would give rise to an implicit carbon price that would tilt the generation economics in favour of gas investments without noticeably affecting WESM prices.

More importantly, such an option could tackle the non-carbon emissions of power stations. While coal can generate at low (non-carbon) emissions, more often they do not. With weak emissions regulations, or with existing regulations being weakly enforced, the local pollution of coal will increase. In particular, if coal displaces gas further in the mid-merit sector (in the future, we note currently coal is already mid-merit in the WESM) then NO_x emissions will rise as NO_x are much harder to control at the lower boiler temperatures associated with part-load operations.

This may be a more political and palatable "green" option without using the word carbon. It would also encourage renewables, which is already Government policy. However, we note that this overlaps considerably with existing policy on emissions in the Philippines and it may be more sensible to try and enforce and strengthen existing laws (such as the Philippine Clean Air Act) rather than attempt to impose new overlapping constraints.

3.4.9. Direct Investment

Although under EPIRA, the NPC cannot make investments in electricity generation, we understand that the Government (e.g., via DOE or PNOC) might have greater latitude to make investments in LNG regasification and gas pipelines. In practice this would mean that a Government-owned entity, most likely PNOC, would need to build the infrastructure. The public policy rationale for such direct investment would be that access to gas provides broad-based benefits to the Philippines power sector. The costs of this infrastructure could then be recovered via a similarly broad-based charge (e.g., similar to the Feed-in Tariff Allowance subsidy from consumers for the environmental benefits of renewable energy) or absorbed by PNOC as a reduced dividend to Government. Absent some or all of the regasification costs, gas-fired CCGTs may be able to be financed on a merchant basis. However, we note PNOC will approach investments on a commercial basis (which may limit the feasibility of this mechanism); that they must gain DOF funding and support (which may also limit the feasibility) and that they do have (albeit small) some private sector shareholdings which again may limit the ability of them to undertake uneconomic investments

Further, any actions undertaken by PNOC would need to be within the NEDA guidelines, which are very strict. Indeed, our experience with PNOC EC's coal mine-mouth project has highlighted a number of limitations of the NEDA guidelines and their ability to produce efficient investment outcomes.

Generally too investments made by Government may not necessarily be carried out in the most efficient manner. The whole thrust of electricity privatisation is predicated on this: that the private sector makes better, and more efficient, investments in infrastructure and that the risk of these is better borne by the private sector rather than the public purse.

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It is therefore possible that this could be undertaken by the PPP Center instead, although we note that the recent changes to the NEDA JV guidelines would appear to make such public-private partnerships even more difficult.

We believe that direct investment is probably always a secondary option to tendering something of value so that the private sector can make the investment. So this option tends to score relatively worse than any of these options when considered together making it hard to recommend.

3.4.10. Information & Education strategy

One barrier to development of power stations that we have noted (both previously and as part of this study) has been the general lack of understanding of market participants and the regulator of the basic economics of electricity. This was rather graphically demonstrated by Meralco's presentation to the LNG Terminal conference (and again to us the next day) where they started with "power economics 101" because they assumed nobody in the room knew anything about it. It has also been demonstrated repeatedly in ERC decisions, which favour cost plus approaches over market or economic based analysis even though such actions may actually be counter-productive to market efficiency in the long-run.

Further, a criticism of the excessive development of coal fired capacity is that, given the amount of such capacity being built, some of it will have to run at mid-merit which would be more expensive for the proponents than building gas. Leaving aside the obvious difficulties of building CCGTs to meet demand in the absence of any actual gas supply, this would also tend to highlight that coal fired power proponents may not be undertaking the right kind of analysis of their investments.

We have noted, in discussions generally with participants, that local sponsors of power stations rarely undertake market modelling and appear to do little fundamental analysis of supply and demand or the risks associated with their investment. This is in strong contrast to the international proponents that are also operating in the market and highlights that many of the lessons that international investors have learned by operating in other competitive markets (such as Singapore or Australia) are not being applied by local proponents.

To some extent, this may be assisted by education. So, one part of the Master Plan could be a strategy to assist both market participants and the ERC in understanding the fundamental economics of power and how to analysis projects in a power market.

This would also assist with the regulatory change option above (in respect of the regulator).

3.4.11. Electricity Capacity market

We understand that the DOE is considering creation of a capacity market in the WESM. Capacity in an electricity market can be defined as the option to buy electricity at a fixed price. Accordingly, a well-functioning, non-distortionary, capacity market provides a fixed

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capacity payment in lieu of a highly volatile and uncertain stream of energy revenues. By reducing revenue volatility, such capacity payments would make it easier to finance mid-merit and peaking units. Whether risk reduction alone could induce investment in LNG infrastructure is another question. Depending on its design, however, a capacity market may also create transfers in value between generators and customers, or between different generation technologies. So it is indeed possible that a capacity market could provide enough additional value to make CCGTs bankable.

However, where capacity markets have been introduced in other countries, they have not always had the outcomes expected at the start. For example, in Western Australia the capacity market has spawned an industry of installing cheap, sometimes second-hand gas turbines that may actually be incapable of running, just to earn the capacity payment. The costs of this scheme are now being borne by consumers while the amount of capacity that it has encouraged is multiple times the amount needed: we would not recommend such an option for the WESM.

The design of a well-functioning capacity market without unintended consequences is a challenge even in developed markets. It would therefore take quite some time to develop and implement and may not meet the timetables envisaged by this project.

It is also not something that directly benefits gas and it is questionable if it benefits the whole electricity market. Thus tends to score low in any relative ranking of options.

3.4.12. Clarify the rules surrounding LNG terminal and pipeline infrastructure

Some participants have highlighted concerns that there are no rules, regulations or policies on gas infrastructure. There is a concern that any terminal that sells to anybody other than a captive power station may become classified as a utility and become regulated by the ERC. Further concern has been expressed that if this was the case, then the rate of such regulation would not take into account the risk capital invested to build the terminal, but a low risk utility rate of return would be applied.

It may be useful to avoid this by clarifying how any terminal (and also any gas pipelines) would be regulated and set out what policies would apply. This could be done informally in the fuel mix policy, or more formally via regulations.

3.4.13. Summary

These options are not mutually exclusive. The information and education strategy, for example, is a stand-alone activity that may have significant benefits in its own right, is relatively low cost and would generally improve the functioning of the market.

Tendering something of value or direct investment or regulatory change would be direct and targeting. They may not all be alternatives, but complementary approaches.

3.5. COMPARING THE OPTIONS

In Section 3.2 we suggested the following objectives for the Gas Master Plan:

1. To provide necessary natural gas commodity and infrastructure:
 - To ensure that there is gas to fuel the existing gas-fired power plants in Luzon after the end of the Malampaya gas contract (recognizing, however, that these plants would not run in baseload mode, absent the existing take-or-pay contracts, and therefore may require far less gas);
 - To ensure that there is gas to fuel the economic entry of new CCGT into the Philippines;
 - To encourage infrastructure to be built (and under contractual terms) that creates options for incremental expansion and other non-power opportunities.
2. To carry out the above in a way that:
 - Relies on private sector development whenever possible;
 - Is based transparently on free and fair competition – so as to provide full public accountability and to ensure non-discriminatory treatment of all market participants;
 - Provides price signals and incentives that contribute to operational, allocative, and consumption efficiency;
 - Can be implemented successfully by the DOE with minimal assistance from other government entities;
 - Broadens the ownership base so as to reduce the potential for the exercise of market power in the natural gas and electricity sector;
 - Creates or utilizes contractual mechanisms that offer a high probability of commercial success (i.e., financial close of both gas production or regasification and CCGT generation);
 - Can be demonstrated to be economically “least-cost” when taking into account all relevant considerations.

In order to be able to compare different potential regulatory solutions to the problem of importing LNG, we need to use these objectives to develop criteria for how to score different possible options.

However, there are a long list of objectives and a long list of options. It would be impractical to score every option against every objective in the first instance. We have, therefore, cut down the objectives to focus on feasibility and capability of implementation first, in order to cull the options to a manageable number in order to review these in more detail against the remaining objectives.

Whether or not the option is possible is made up of a number of points.

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Firstly: Is the DOE capable of implementing it? If not, how would it be implemented and who else would need to be involved. Any option that requires broad agreement and broad actions across a range of counterparties is likely to be much harder to achieve than something that the DOE could do alone, or with the agreement of just one other body.

Secondly: Would it need changes in law to be implemented? Any option that requires changes in legislation or anything that requires congress to agree will, by definition, be much harder to implement than something that can be done by a DOE circular.

Thirdly: Is it capable of being implemented in the market? That is, would the private sector do it? Is it capable of being financed?

Finally: Does it require additional funds or incentives or other fiscal activities (such as a Guarantee). Options that do not require direct Government subsidies, funding, incentives or guarantees are much more likely to be capable of practical implementation.

We also include in this section the question: How certain are we of the answers to the above?

We discuss each option in relation to these questions below.

3.5.1. Do Nothing

Clearly there is no problem with the implementation of a Do Nothing strategy. The main difficulties with the Do Nothing strategy is explaining it and fending off the many demands from the private sector that the DOE should do “something”.

The variation of “Do Nothing” which is “Do Nothing Right Now” also requires no implementation, but whatever is done later would; however, that would be discussed in the other sections above.

3.5.2. Fuel Mix Policy

The DOE is clearly capable of drafting a Fuel Mix Policy alone and without any other Government department. It would not require any changes in law.

Nevertheless, as noted above, a “policy” alone would achieve nothing – it may merely act as an enabler for other, more active, options or legislation. Therefore, alone it is unlikely to achieve the objectives, but may be a necessary precursor to other actions.

3.5.3. Tax incentives

As noted in the earlier section, tax is not within the purview of the DOE. It is likely that the DOF (because of revenue implications); the Board of Investments (BOI, since this seems to be their job) and the Bureau of Inland Revenue (BIR) would need to be involved. Discussions with our legal team suggest that legislation would be required.

However, in order to enable gas projects to gain additional tax incentives, the DOE would need to work with the BOI to create a special scheme that was capable of giving

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additional tax incentives. Renewable projects get this by virtue of the Renewable Energy Act and thus it is clear that additional tax Incentives akin to those afforded to renewable projects would not be capable of being given by DOE alone. It would require additional legislation.

The Renewable Energy Act is clearly the precedent in this sector. However, it is worth noting that this is a piece of law that took some time to draft and pass, has still (after more than five years) not been fully implemented. Delays have been due to administrative bottlenecks and opposition – mainly because of perceptions of the additional costs that renewables would place on electricity consumers.⁴⁰

Compared to the Renewable Energy Act, LNG is not domestic (whereas renewables are); LNG is more expensive than competing fuels for baseload (similar to renewables) and LNG-fired power stations do not reduce environmental emissions as much as renewables. In other words, while LNG has some similar benefits, they are less than renewables, while the costs are high. We can therefore assume that there would be less will to pass an Act and more opposition to implementation even if passed. This will limit the feasibility of any options in this area.

Smaller actions that could assist along these lines would be greater clarity as to the tax incentives LNG could obtain within the existing BOI framework (some certainly of pioneer status, for example). These may be easier to implement.

3.5.4. Tendering something of value

Tenders are used in the Philippines as a way to implement a variety of outcomes, therefore designing some contractual construct through a tender process is highly feasible and indeed may be a necessity for many direct actions.

If the DOE attempts to procure any goods or services (giving out an LNG purchase contract, for example, would be construed as being a purchase of goods) then they will be bound by the Government Procurement Rules, which require competitive tendering.

One limitation on tenders that may impact this process is that the Procurement Rules are somewhat rigid and inflexible. It may be, for example, that a tender which compares things that are not identical is difficult to implement or is challenged (for example, a tender for an LNG terminal in different sites may struggle, or terminals of different sizes at the same site or different sites). This is not an insurmountable hurdle but would require careful structuring of the transaction at a later stage.

⁴⁰ This article summarises some of these issues. <http://technology.inquirer.net/26733/ph-warned-of-losing-2-5b-in-potential-renewable-energy-investments>

3.5.5. Gas purchase obligation

While there appears to be no direct reason why the DOE cannot implement this alone (no other Government departments would be required, for example) we have some concerns about whether or not it would actually be viable in practise.

A gas purchase obligation is by its nature discriminatory. Discrimination in favour of one option may be construed as discrimination against another (such as a coal-fired power station) and this could be a difficult concept.

Therefore, to be capable of withstanding legal challenge, a Gas Purchase Obligation may need to be legislated, or alternatively some agreement reached with the whole industry. This would add considerable time to the implementation of the option.

However, offsetting the potential difficulties, this option is an excellent way to drive exactly the outcome the DOE requires without additional expense. It would fit well with a Fuel Mix Policy; it is direct – it could be used to target exactly the economic (i.e., limited) amount of gas and it is not discriminatory against domestic gas: an argument that could be used to defend any general discrimination case. There are also precedents from other markets (Queensland) that highlight it works.

We would therefore recommend keeping this option in the mix at least for a while to assess against other feasible options.

3.5.6. Regulatory changes

Regulatory changes cover a variety of advice that the DOE can give to the ERC to improve the regulatory approvals process and ensure gas fired mid-merit contracts are adequately approved. The DOE is clearly able to offer the ERC this advice and we understand that informally this often occurs. We note that there is no formal mechanism whereby the ERC must take on board the DOE advice as they are, technically, an independent entity.

No other part of Government would need to be involved in this option and it would clearly work in the market as a number of market participants highlighted that regulatory certainty was a key prerequisite of their approach.

3.5.7. Carbon Tax and Grid Emissions Limits

We consider these together as they have many similar characteristics when it comes to feasibility.

Neither could be implemented by DOE alone – both overlap with the DENR and would require their co-operation to go forward. Similar to the Gas Purchase Obligation discussed above, both of these are inherently discriminatory in nature and would therefore have the same difficulties in implementation.

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Both are also bigger issues than just electricity or gas: we have seen in many markets that carbon taxes are key parts of Government policy and Governments have fallen when trying to implement them (the recent debacles in Australia are notable examples of this).

Further, the Philippines is a developing country and has already enacted the Renewable Energy Act. It would appear that both of these devices overlap to a considerable extent with this and would be criticised on this basis too.

Both are likely to require legislation.

Therefore, they cannot be implemented alone; require legislation and are likely to be high profile, discriminatory and subject to criticism and legal challenge. This makes both of these options practically infeasible for the purposes of this project.

3.5.8. Subsidy to terminal

This option is effectively covered in the discussions on tendering above, as it would appear inconceivable that the Government would offer a subsidy to any LNG terminal proponent without some mechanism to ensure that this subsidy went to the best option.

However, the DOE itself does not have any money, so the DOF would also need to be involved in any subsidy. As it runs counter to EPIRA, a strong case would need to be made for the DOF to sign off on any subsidies and thus it may be an unlikely option to proceed.

3.5.9. Direct Investment

Although the DOE could directly invest in LNG facilities, direct investment would also need funding, so it is unlikely the DOE can implement this alone. It would need to source the funding from DOF, or run the investment through a vehicle like PNOC that would itself need approval to spend the money from DOF.

Direct investment in power stations is another matter entirely as this is covered by EPIRA and it is unlikely that the DOE could undertake direct investment in the power sector without some change to EPIRA – which would be very difficult and time consuming.

3.5.10. Information & Education strategy

The DOE clearly has the ability to run an information and education strategy – for the ERC, for market participants, and for the public in general if required. No changes in law are required and no other departments are required. The cost of such a strategy is low and may be capable of funding by DOE or indeed external bodies such as ADB or WBG may be interested in helping with this strategy.

We would consider that information and education on economic generation of electricity and good decision making would be a benefit to the market generally and recommend some of this occur irrespective of which other options are chosen. However it is probably insufficient alone to result in LNG implementation.

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3.5.11. Electricity Capacity market

An electricity capacity market may improve the functioning of the electricity market, but implementation is likely to be difficult. It would require a change to the market rules, which are legislated rather than being procedures (as they are in most other markets). So it would require change in legislation. Given the high degree of potential unintended consequences (as evidenced by the failure of many other capacity regimes around the world) we would recommend that any capacity market be carefully thought through before implementation. As such it may not be a timely mechanism for the LNG terminal.

3.5.12. Summary

The discussions above are summarised below.

Table 8: Summary of Feasibility

Option	Can DOE implement alone?	Would it need a Law?	Would it work in the market?	Summary: Feasible?
Do Nothing	Yes	No	N/A	Yes
Fuel Mix Policy	Yes	No	No	Feasible but unhelpful alone
Tax Incentives	No	Yes	Maybe	Probably infeasible outside of existing arrangements
Tenders	Yes	No	Yes	Yes
Gas Purchase Obligation	Yes but probably challenged	Would be better	Yes	Problematic
Regulatory Change	Yes	No	Yes	Yes
Carbon Tax	No	Yes	Probably	No
Grid Emissions Limits	No	Yes	Probably	No
Subsidy	No	No	Probably	Problematic

Option	Can DOE implement alone?	Would it need a Law?	Would it work in the market?	Summary: Feasible?
Direct Investment	Unlikely	No for LNG; Yes (change in EPIRA) for power	Yes	Probably Feasible
Information and Education	Yes	No	Unlikely	Yes
Capacity market	Unclear	Unclear	Unlikely	No

The above discussion whittles down the options to the following for further consideration:

- Do Nothing (or Delay)
- Fuel Mix Policy
- Tax Incentives – but only within existing laws and incentives
- Tendering something of value – with further structuring required
- Gas purchase obligation – keep in for now but it's marginal
- Direct Investment – the least cost investment necessary that could be funded by DOF; LNG terminal only
- Subsidy - the least cost subsidy that could be funded by DOF; LNG terminal only
- Information and Education – to be included in addition to any other options

These fall into two categories:

- Activities that are enablers or useful things to do, but which do not actually achieve the objectives in full, and options which are aimed at bringing in LNG in their own right (i.e., achieving the main objectives).
- The activities that are enablers are useful but since they do not fully achieve the objectives it is not really necessary to discuss them further in terms of scoring.

These include:

- Fuel Mix Policy – this could be some policy document that may form a platform to introduce other options. This could be a section of our final report. However it achieves nothing on its own and could not sensibly be drafted until the other options are decided to ensure the whole policy fits together.
- Tax Incentives - we assume that the DOE will continue to assist any proponent to gain Pioneer Status with the BOI to maximise the tax incentives they could

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access. Further, removal of import duty on LNG is assumed to be an obvious and easy step. Neither of these is enough alone but may assist any project to become more viable.

- Information and Education – to be included in addition to any other options as it would generally enable better decision making and better regulatory decisions. But alone is insufficient.

The remaining viable options now need to be scored against the remaining criteria. This would occur in the Phase 2 report. However, before this can occur, each of the remaining options needs to be fleshed out in more detail.

3.6. SCORING AGAINST REMAINING CRITERIA

The first objective – *to provide necessary natural gas commodity and infrastructure* – relates to the actual infrastructure being proposed, so the scoring criteria should relate to what is actually proposed or possible as a result of what is proposed. We can score this according to what would result from the option as follows:

- Options that result in sufficient gas to fuel the existing power stations and new power stations, and involve additional infrastructure or create options for additional infrastructure would earn full marks – say 10/10;
- Options that result in sufficient gas to fuel the existing power stations and new power stations but do not involve additional infrastructure or create limited options for additional infrastructure – three-quarter marks – say 7/10;
- Options that result in sufficient gas to fuel the existing power stations only – half marks – say 5/10; and
- Options that may provide some of this, but it's very uncertain – a low score – say 3/10.

3.6.1. How does the option work?

The second objectives relate to how the option would be done, so the scoring for these objectives should be related:

1. *Relies on private sector development whenever possible*

This is relatively easy to score. Options that rely entirely on the private sector score top; options that have entirely public funding score zero while mixed (PPP-type) options score in the middle.

2. *Is based transparently on free and fair competition*

This objective is intended to provide full public accountability and to ensure non-discriminatory treatment of all market participants. Options that rely on competitive processes score top; options that have no

competitive processes are middle and options that actually undermine free market existing processes score zero.

3. *Provides price signals and incentives that contribute to operational, allocative, and consumption efficiency*

Options that provide price signals and incentives score top; options that have no such signals or incentives score zero.

4. *Can be implemented successfully by the DOE with minimal assistance from other government entities*

The issue of “Can be implemented successfully by the DOE with minimal assistance from other government entities” clearly relates to whether or not the option is actually possible and covers a wide range of issues; much wider than some of the other objectives.

Firstly, is the DOE capable of implementing it? If not, how would it be implemented and who else would need to be involved. Any option that requires broad agreement and broad actions across a range of counterparties is likely to be much harder to achieve than something that the DOE could do alone, or with the agreement of just one other body.

Secondly: Would it need changes in law to be implemented? Any option that requires changes in legislation or anything that requires congress to agree will, by definition, be much harder to implement than something that can be done by a DOE circular.

Finally: Does it require additional funds or incentives or other fiscal activities (such as a Guarantee). Options that do not require direct Government subsidies, funding, incentives or guarantees are much more likely to be capable of practical implementation.

Any option that meets all of the above would score top marks. Any options that meet none of the above would score zero. Any option that meets some of the above but not all would score medium marks, with some necessity for options to be compared against each other to decide which is easier to implement than others.

5. *Broadens the ownership base so as to reduce the potential for the exercise of market power in the natural gas and electricity sectors*

This option is relatively easy to score. Most options are likely to have a neutral impact on specific participants and would get middle scores. Any option that explicitly broadens the ownership base would score high; while any option that narrows the ownership base (that is, relies on existing participants for as key actors) would score low.

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6. *Creates or utilizes contractual mechanisms that offer a high probability of commercial success (i.e., financial close of both gas production or regasification and CCGT generation)*

Like the objective related to DOE implementation above, this objective is also very wide and relates to whether or not the option is practical in a commercial sense.

- Will it reduce commercial uncertainty? That is, does it have attributes that lock in revenues over a significant period of time?
- Is it probable that it will result in projects that will reach financial close?

Scoring of this will be somewhat subjective and based on a practical assessment of whether the option is likely to drive commercial projects.

7. *Can be demonstrated to be economically “least-cost” when taking into account all relevant considerations.*

The scoring of this objective will need to be determined analytically by modelling the option against other options. Those that can be demonstrated to be least cost score highest while the most expensive options score least.

3.6.2. Weighting of the objectives

The discussion above scores everything out of an arbitrary total of ten; however, not all objectives are equal. We need, as part of the discussion and confirmation of the objectives, to weight objectives in order of importance. Once this has been done, the scoring criteria too can be weighted in order of importance.

Implicitly, the “what” is probably equal to the “how” – but within the “how” some aspects are clearly more important than others. Some of the objectives – such as those related to practical implementation by DOE or commercially – are clearly more important than others. We would suggest that these two are weighted much higher than lesser objectives (such as broadening the ownership base, which while “nice to have” may not be essential to success).

Also, within the scoring, we would need to deal with uncertainty. Thus options whose positive effects are less certain (or whose negative effects are more certain) would score lower than those with a higher degree of certainty.

We also include in this section the question: How certain are we of the answers to the above?

4. ASSESSMENT OF THE VALUE ASSOCIATED WITH DIFFERENT SITES

The TOR describes Tasks 1.3 and 1.4 as:

- Task 1.3 Modeling needs to take into account transmission constraints that affect delivery of power in the greater Manila area. Consultants need to explicitly address the trade-off between moving gas by pipeline or by electricity transmission line, taking into account various institutional factors that might complicate construction of gas and power transmission lines in this area.*
- Task 1.4 Recommend one or two sites in Luzon, in addition to the northern Mindanao site, and the best technical options for those sites, for development as LNG terminals. This analysis should be done at a pre-feasibility level of analysis. Sites to be considered cover at a minimum the projects listed on page one of this TOR. Recommendations related to this task should explicitly address the concern of DOE to both avoid having too much generation capacity in the Batangas area, but to ensure that existing power plants there have access to back-up supplies. This can be accomplished by a combination of one terminal, one pipeline; or by having two LNG terminals, one primarily oriented on new capacity outside the transmission constraints, and one primarily oriented to providing gas supply security for existing plants (and perhaps allowing for limited expansion of current plans)*

The remainder of this section constitutes the report on these tasks.

4.1. GENERAL

The purpose of the engineering reviews of the sites is to compare the different sites under consideration and determine the relative cost implications on the development of a baseline CCGT and baseline LNG terminal at each site.

This chapter outlines the six sites considered and the methodology employed by Arup in conducting this engineering review. Given the different LNG terminal development plans and configurations, this study considers the establishment of a baseline LNG terminal (both onshore and offshore FSRU considered) and baseline 800MW CCGT power plant at each site. For this case, consistent technologies, configurations and sizing are applied to all sites.

This allows a direct comparison and objective analysis of the different sites for a baseline LNG terminal and CCGT power plant development. Given that LNG terminal developers have chosen their sites and plant configurations to suit their requirements, it is not possible to compare the specific proposals by the LNG developers on a like for like basis.

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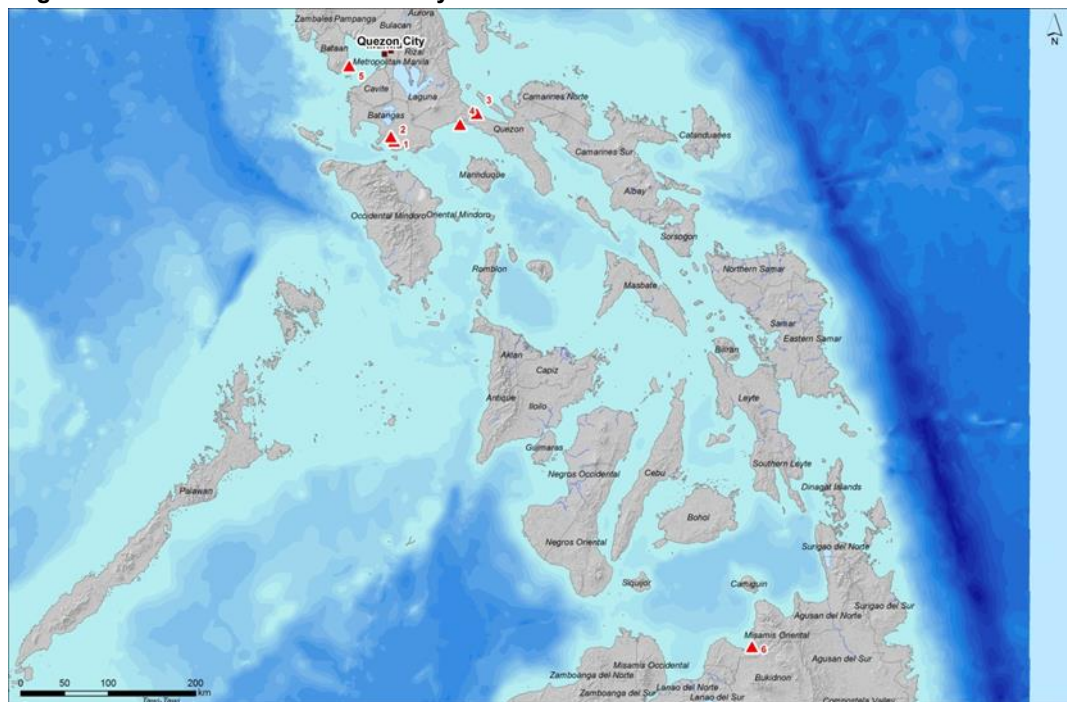
4.1.1. Sites Covered in this Review

An engineering review of the following sites has been conducted (numbered in the order stated in the TOR):

1. Batangas - Shell
2. Batangas - First Gen
3. Atimonan - Meralco
4. Pagbilao - Energy World
5. Limay - AG&P
6. Cagayan de Oro (Mindanao) - PetroleumBrunei

The locations of these sites are shown in Figure 17.

Figure 17: Sites covered in this Study



4.1.2. Overview of Methodology

This engineering review of potential LNG terminal and power plant sites has included the following methodology:

- Appraisal of infrastructure and scale required to support a baseline LNG terminal and baseline single 800MW Combined Cycle Gas Turbine (CCGT) Power Plant at each site (Section 4.2.2 and Section 4.2.3).
- Determination of the relevant preliminary siting criteria and associated infrastructure requirements (Section 4.2.4).
- Evaluation of existing electrical and gas transmission systems in the Philippines (Section 4.3).
- Presentation of natural hazards of the Philippines (Appendix D1).
- Engineering appraisal of the six selected sites against various criteria, including land and marine conditions and geophysical hazards (Section 4.4 to Section 4.9).
- Transmission network appraisal of the six selected sites (Section 4.4 to Section 4.9).
- To allow like for like comparisons of each site, baseline onshore and offshore configurations are positioned at each site and cost differentials against baseline assumptions are compared (Section 4.11).
- Comment on the proposed LNG terminal configuration and CCGT power plant at each site, including the risks, cost implications and future expandability (Section 4.4 to Section 4.9).
- For the sites in Luzon, the DOE concerns of electricity transmission constraints in Batangas area and the desire to have accessible back-up gas supplies to the existing CCGT plants are commented upon (Section 4.11).

4.2. LNG TERMINAL & CCGT POWER PLANT REQUIREMENTS

4.2.1. General

This chapter introduces the required baseline infrastructure for both Onshore and Offshore LNG terminals and CCGT Power Plants. Criteria such as siting, natural hazards and other parameters that determine the suitability of sites for the development of LNG terminals and power plants are also introduced here.

The cost comparison is solely based upon the reference baseline requirements. It does not reflect an absolute cost that any one site may incur as a number of factors such as the layout, size, method, scale and scope of construction will be different in each case. If each layout were to be replicated at each location then the relative cost of the facility would vary by the final percentage relative to the baseline case, to reflect the site specific conditions.

4.2.2. LNG Terminal

General LNG Terminal Requirements

In order to compare the cost variations associated with different sites they have been assessed for two 'typical' sites that may be commonly encountered for any proposed LNG terminal location. A number of assumptions have been made to derive the characteristics for the two 'typical' sites, which is largely governed by the cost, speed of development, space concerns, mobility and flexibility. The characteristics of the two "typical" types are as follows:

- **Baseline Onshore LNG Terminal:** Traditional onshore solution, with the LNG receiving facility wholly located on land. This facility is usually located at a suitably sheltered site close to a sufficient area of deep water in excess of 15m depth to allow for manoeuvring of a typical LNG carrier (140,000m³ to 170,000m³).
- **Baseline Offshore FSRU:** Conventional offshore floating terminal commonly known as a Floating Storage and Regasification Unit (FSRU) with an onshore gas receiving station.

Other common assumptions have been made to both configurations as follows:

- Close proximity of LNG terminal and associated power plant;
- Close proximity of the site to the coastline; and
- Suitable land available for terminal.

Further details of the baseline assumptions are contained within Appendix D.5.

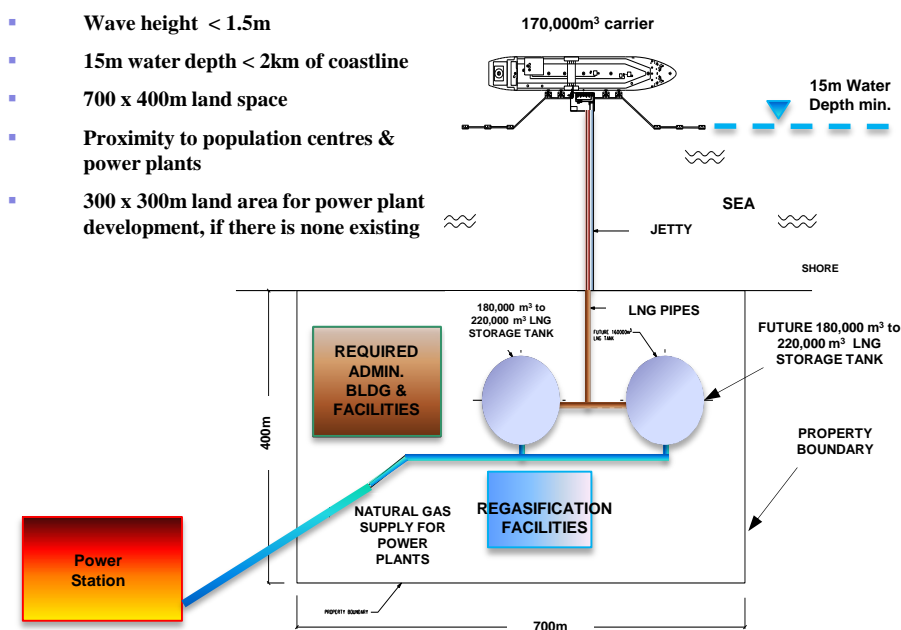
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Table 9 – Infrastructure Requirement for LNG Terminal

Item	Description	Onshore Technology Configuration / Options	Offshore Technology Configuration / Options
1	LNG Carrier berthing, jetty, mooring system	Precast or Trussed Deck supported on piles. Submerged pipeline could eliminate approach trestle.	Precast or Trussed Deck supported on piles for berthing FSRU in shallow water. Side-by-side or tandem mooring (deepwater flexible mooring could eliminate approach trestle).
2	LNG Unloading System	Articulated solid loading arm. Flexible pipe	Articulated solid loading arm. Flexible pipe
3	LNG Pipeline	Insulated stainless steel pipe Vacuum Insulated stainless steel pipe.	Insulated stainless steel pipe Vacuum Insulated stainless steel pipe.
4	LNG Storage Tank	Single or full containment with primary container in: 9% Nickel, Membrane, Concrete, Stainless Steel (Type C)	Single or double containment in: Moss Cylindrical, Membrane, Self-supporting Prismatic, Stainless Steel (Type C)
5	LNG Vaporisers.	Shell & Tube Submerged Combustion Open Rack Seawater Ambient Air	Shell & Tube Submerged Combustion
6	Other Process Equipment (Boil-Off Gas etc)	Additional process related equipment for the LNG terminal such as BOG re-liquefiers, compressors and pumps.	BOG handling equipment
7	Natural Gas Pipeline	Traditional onshore pipeline to power plant	Offshore pipeline with detachable connection to FSRU.

Baseline Onshore LNG Terminal Configuration

Figure 18 illustrates the traditional onshore solution, with the LNG receiving facility wholly located on land. This facility is usually located at a suitably sheltered site close to a sufficient area of deep water in excess of 15m depth to allow for manoeuvring of a typical LNG carrier (140,000m³ to 170,000m³).

Figure 18: Baseline Onshore LNG Terminal Configuration

For a typical LNG receiving terminal of this kind it is usually necessary and cost effective to provide sufficient storage capacity to receive a full load of LNG from a conventional oceangoing carrier. To accommodate a carrier size of 170,000m³, it is estimated that a site area of 400m x 700m (approximately 28ha) would be required.

This site area would house the one or two LNG storage tanks with a capacity of 180,000m³, regasification facilities, administrative and control buildings and other relevant facilities. Provision may also be made for future expansion with a similar sized storage tank to increase the overall storage and throughput as necessary.

The LNG would be transferred from the carrier to the storage tanks through a cryogenic pipeline which will be typically supported on a purpose built jetty and approach trestle structure. In order to achieve cost efficiency and to be competitive with other solutions, the trestle length should not generally be more than 2km.

The preferred site should be located a suitable distance away from population centres but as close as possible to the power plant that it serves in order to facilitate efficient and safe delivery of the natural gas. By being in close proximity the synergies between the respective processes for the power plant and LNG terminal can be utilised as much as possible even potentially removing the need for some components of the regasification plant.

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Offshore FSRU Terminal Configuration

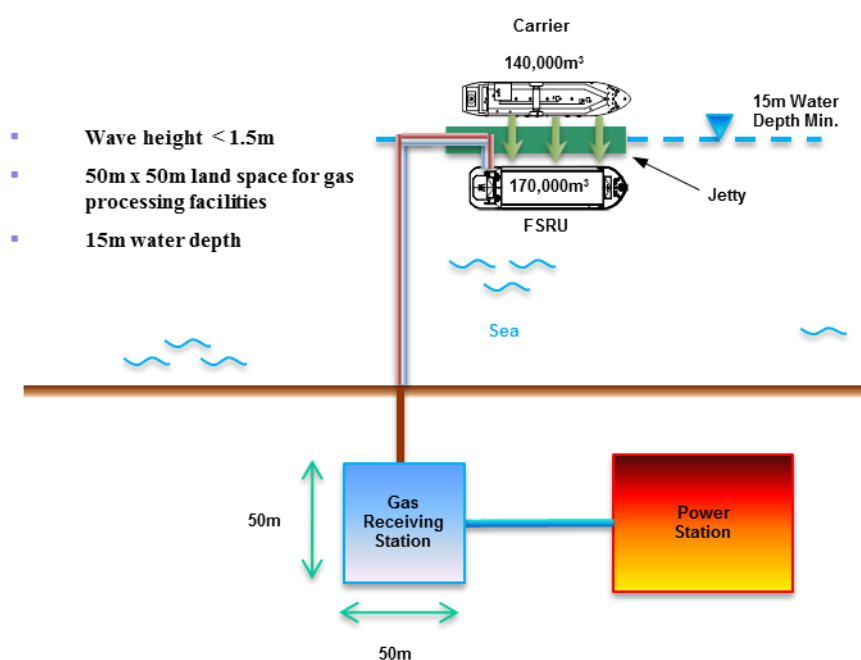
The conventional offshore floating terminal commonly known as a Floating Storage and Regasification Unit (FSRU) is illustrated in Figure 19.

Rather than have the LNG storage and regasification facilities on land, they are all installed on-board a floating vessel, which can be either a new-build bespoke FSRU or a converted LNG carrier.

For this solution, a smaller area of land (50m x 50m) will be required onshore to place the necessary gas receiving and administrative facilities to regulate and measure the rate of gas supply. The location of the FSRU and the distance from shore will depend upon the following factors:

- The prevailing water bathymetry close to shore
- The means by which the natural gas will be transferred to shore

Figure 19: Baseline Offshore FSRU Configuration



The Baseline Offshore FSRU configuration represents the situation where the water depth within a practical distance from shore is in excess of 15m (or can be made so within the economics for the project) and the distance to reach a water depth in excess of 50m is impractical. For this scenario it will be necessary to moor the FSRU, which should ideally have a capacity to take a full carrier cargo i.e. 170,000m³, against an offshore fixed jetty or platform within a water depth in excess of 15m.

The necessity to match the FSRU capacity with the carrier capacity is to allow full discharge of the cargo quickly and efficiently without the need for the delivery carrier to standby. The carrier will typically discharge the LNG at the jetty in a double berth arrangement to transfer its load across to the FSRU either via detachable loading arms or flexible hoses. When required, the FSRU will regasify and transfer the natural gas via a pipeline which, due to the limited depth of water, will be necessarily supported on the

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static trestle. This pipeline can either be connected to land above the sea on a trestle structure if it is sufficiently close to shore or as a sub-sea pipeline. It should be noted that the use of a sub-sea pipeline in such shallow water is only possible if the pipeline is attached to the static jetty rather than the moving FSRU.

4.2.3. Baseline CCGT Power Plant Requirements

This section describes the main characteristic of the power plant which should reach a capacity of around 800 MW, becoming the anchor user of the LNG.

General

The most favourable plant configuration to meet the 800MW in combined cycle, would be of 2 gas turbines coupled with 2 Heat Recovery Steam Generators (HRSG) plus 1 steam turbine which takes steam from the two Combined Cycle Gas Turbines (CCGT). This is deemed to be the simplest and generally most cost effective option.

An alternative would be 3 CCGTs plus 1 Steam Turbine, which is more complicated and with higher capital cost, but has the following advantages which lead to it not to be discarded:

- Higher efficiencies at part loads (e.g., maximum efficiency for 67% total load).
- In case of 1 plant offline more electricity can be generated.
- More suppliers can bid (some manufacturers cannot offer 2GT+1ST).

The technology of the HRSG is assumed to be 3 pressure levels plus reheating. Efficiency of an unfired single or double pressure HRSG is low and the payback of the more sophisticated 3 levels + RH (re-heat) is quick and well worth consideration, particularly when the LNG cost is on the rise. At 800 MW plant size the 3 levels plus RH is also the industry standard and the overall plant efficiency based on lower calorific value of about 60%.

Table 10 summarizes a preliminary research on the 4 main gas turbine suppliers for their 60 Hz machines. Performances are referred to ISO conditions (15°C, 60% humidity, 1.013 bar) and in the Philippines environmental conditions it is estimated that only around 95% of that nominal power can be generated. There may be some minor differences between costs and efficiencies among the suppliers and this will have to be investigated in the next stage.

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Table 10: Findings on gas turbine suppliers

Manufacturer	Configuration	Gas Turbine	GT output (MW)	Freq (Hz)	CC 1x1 Output (MW)	CC 2x1 Output (MW)
Siemens		SCC6-8000H	274	60	410	822
Alstom	KA24 -2 MS	GT24 (**)	230.7	60	280	>700
GE	S207FA	7FA	183	60	269	542
	S107H	7H (*)		60	400	TBD
Mitsubishi Heavy Industries		M501G	267	60	399	780
		M501J (*)	327	60	470	TBD

Note: (*) Gas turbine seemingly without many applications at the moment; (**) Need to investigate with Alstom the possibility of them to supply larger gas turbines for 60 Hz market.

During next stages the suppliers should be approached and further details shall be gathered regarding their products, to be customized for the specific application.

The steam is assumed to be cooled and condensed by a once through condenser fed by sea water. The alternative of air cooled condenser has not be considered as it reduces plant efficiency, due to the auxiliary consumption, and increases capital costs. In the event that sea water cannot be utilized due to temperature and regulatory constraints, then cooling towers would be utilized for condensing the steam. The length of the cooling sea water pipes has been estimated from the centre of the proposed site and the point where the sea water depth is approximately 10m.

LNG Demand for gas power plant

The design of the equipment and infrastructure for a LNG terminal will need to be determined to match the required LNG demand in order to achieve the optimum cost efficiency.

Assuming the LNG terminal serves a power plant with a capacity of 800MW, which would meet the local energy demand of small cities in a country such as the Philippines, it is reasonable to assume a throughput capacity of the LNG terminal to between 0.2MMTPA to 1.1MMTPA depending on whether the CCGT power plant operates as a baseload or mid-merit plant.

Depending on the operational requirement of the power plant and the LNG cargo procurement and shipment strategy, the optimum size of LNG storage for different scenarios may vary. Notwithstanding the above, it is expected that for a LNG terminal, storage of anything from 1 week to 20 weeks should be provided dependent on the availability and frequency of delivery of LNG to a particular site.

Summarising it can be said that the way of operating the CCGTs will largely affect the sizing of the LNG import terminal in these items in particular:

- Storage tanks;

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- Regasification system;
- Facilities to handle vapour and boil-off gas; and
- High-pressure LNG pumps.

Power Plant Requirements

In this study the power plant capacities for a typical LNG terminal are assumed to be 800MW which equates to an LNG throughput of between 0.1MTPA to 1.1MTPA depending on the mode of operation.

Table 11: Assumed Power Plant Capacities

	Power Plant Capacity (MW)		
	800	800	800
Operation Mode	Baseload	Mid-Merit	Peaking
Capacity Factor	48%-90%	14%-48%	0-14%
Minimum LNG Throughput Required (mmtpa)	0.6-1.1	0.2-0.6	0.1

Assumptions on the Power Plant Gas Demand

Receiving terminal infrastructure will need to be designed so as to meet the throughput capacity and match the demand for natural gas.

In this study the derivation of the throughput capacity has been made based on the assumption that the terminal will serve a nearby power plant, which consists of a two (or three) by one combined cycle facility with the following components:

- Two (2) or Three (3) combustion turbine generators (CTGs)
- Two (2) or Three (3) heat recovery steam generators (HRSGs)
- One (1) steam turbine generator (STG)
- A multi-cell mechanical draft cooling tower
- Associated auxiliary systems and equipment
- CTGs utilised will be General Electric, Siemens, Mitsubishi, Alstom or other acceptable technology
- CTGs will be fuelled by LNG
- CTG's will be equipped with dry low NOx (DLN) combustors and inlet air evaporative cooling

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- Standby components provided for key auxiliaries
- The figures given are referenced to 59°F, 14.7 psi and 60% RH. Corrections will have to be done for actual Philippines ambient data

4.2.4. General Siting Criteria

General siting criteria for both land based and offshore LNG terminals have been identified as follows:

- LNG carriers need deep water of between 12m and 15m and therefore sites with deep water close to shore are generally preferred. Sites with a shallow shoreline typically require long and expensive jetties. Water depths greater than 15m within 2000m of the coastline are considered viable for a land based terminal although a distance of less than 500m is preferred. It is possible that large LNG vessels with a shallower draft may be a solution for the sites that don't satisfy these criteria but these are not common and would likely need to be purpose built to suit the site conditions.
- FSRUs typically need to take a full cargo from an importing LNG carrier and hence would also need a minimum water depth of between 12m and 15m. However, the minimum depth of water required for operation will depend upon the means by which the natural gas is transferred to shore. If the gas pipeline from the FSRU is not fixed to a rigid platform then a minimum water depth of 50m is required to for the pipeline to be able to withstand the motions induced by met-ocean conditions. This can be mitigated by providing a fixed mooring for the FSRU such that the export gas pipeline remains static under met-ocean conditions which allow it to operate in 12m to 15m of water. The choice is governed by the relative costs to provide an export gas pipeline to shore which should ideally be as short as possible and located away from major shipping lanes to avoid snagging from anchors.
- Sufficient manoeuvring space for the LNG carriers including an approach channel and turning basin from either the open ocean or the nearest shipping navigation channels (if any) which would need to provide the required minimum water depth at all states of tide. The dimensions of the turning circle and approach channels being dependent on vessel size and manoeuvrability as well as met-ocean conditions and seabed material. For the purposes of this study it is assumed that the single approach channel bottom width should be five times beam length of the vessel and that the turning area required should be equivalent to a diameter four times the length of the vessel, based on the following assumptions:
 - FSRU/LNG Carrier: 345m Overall length, 54m Beam, 12m draft
- Suitable wave climate for the operation and unloading of the LNG carriers. Areas with wave heights less than 1.5m for most of the year are considered most favourable. Ideally, the following situations for a particular site should be avoided:
 - Waves approach from directly ahead or astern;

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- Wave heights exceeding 1.5 metres;
- Wave periods greater than 9 seconds.
- Proximity to population centres. Safety separation distances and potential ignition sources would need to be considered close to built-up urban areas.
- Proximity to existing power stations or suitable areas to build a power station, conversely avoiding interference on existing infrastructure and ease of connection to existing mains networks and transport access.
- Proximity to suitable flat land with sufficient area for each purpose:
 - Land based terminal = 700m x 400m plan area;
 - FSRU offshore terminal pipeline landing site = 50m x 50m plan area.
- Seismic, geological and natural terrain hazards associated with the particular sites.
- Ground conditions at each site and in particular the competency of the ground for tank foundations and susceptibility to seismic motions or liquefaction potential.
- The infrastructure costs will be driven by the location of any given site which will also be affected by the following:
 - Land prices;
 - Proximity to low-cost pre-fabrication centres; and
 - Availability of skilled and unskilled local labour force.

4.3. TRANSMISSION SYSTEMS IN THE PHILIPPINES

4.3.1. General

The key transmission vectors for energy from an LNG terminal in the Philippines are the High Voltage Electrical network and the proposed Gas network, due to the limited existing Gas network. In order to provide context with respect to the Philippines, both of these networks are summarised in the following sections, especially with commentary on how they could connect with the proposed LNG terminals, including possible constraints and issues.

4.3.2. The Current Electrical Transmission System

In 2012, the NGCP's managed transmission assets comprised 19,822 circuit kilometres (ckt-km) of transmission power lines.

- About half of these assets or 9,482ckt-km are in Luzon,

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- 4,979ckt-km form parts of the Visayas Grid, and
- The remaining 5,361 ckt-km are in Mindanao.

Roughly 76% (20,871 MVA) of the total 27,376 MVA substation capacity installed is located in Luzon, with 3,414 MVA in Visayas and 3,091MVA in Mindanao. (Source: NGCP Transmission Development Plan 2012)

Future power demand

Power demand for the country is expected to grow at an average annual compounded growth rate (AACGR) of 4.2 percent for the period of 2012-2016 and 4.1 percent for 2017-2021. This forecast is slightly higher than one made in the previous year and reflects the more optimistic outlook from the DOE. Overall, national non-coincident peak demand is expected to increase from 10,460 MW in 2011 to 15,660 MW in 2021, which translates to an AACGR for 2012-2021 of 4.1 percent.

Projected power demand from NGCP's Transmission Development Plan (TDP) is given in Table 12.

Table 12: Summary of projected peak demand per district

	Luzon	of which: Meralco	North Luzon	South Luzon	Visayas	Mindanao
2021 peak demand (MW)	11,165	7,852	10,488	677	2,331	2,164

Note: Based on DOE forecast (including embedded generation not monitored by NGCP)

Source: NGCP Transmission Development Plan 2012, p13

Transmission constraints

In the 2012 TDP, NGCP outlined that the siting of power plants near major load centres, i.e., Metro Manila, Metro Cebu and Davao, is preferable to reduce the need for extensive transmission reinforcement. Unfortunately, the existence of high density urban area (Metro Manila) or congested areas (the land area between the Manila Bay and Laguna Lake), coupled with high cost of real estate, make the implementation of generation solutions difficult.

Hence, the challenge is to manage transmission congestion, primarily due to the problem in acquiring right-of-way for new transmission lines and space limitations in existing substations.

To help address these constraints issue, the NGCP Transmission Development Plan 2012 outlines a proposed 500kV transmission line backbone to support electricity utilization of Luzon area through reinforcement of transmission capacity around metro Manila. This backbone project will need to be approved by the ERC and Government support via the DOE. This review, which undertakes the assessment of LNG terminals to support power generations, aims to consider possible immediate approach in delivering power to Manila.

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Connection of new power plant to NGCP transmission network

To connect a power plant to the NGCP network, it is necessary for an application to be submitted by the power plant developer and a clearance to proceed be given by the NGCP. NGCP will subsequently assess the application on technical basis through various studies, including System Impact Studies, Grid Impact Studies and Facility Study, to assess the impact of the power plant and its proposed connection capacity with the existing and future 230kV or 500kV transmission network.

Based on the studies, NGCP will recommend a connection point with the network. If a new substation is required, an approval and confirmation by the Energy Regulatory Commission (ERC) must be obtained. Generally, the power plant developer will fund all cost up to the point of connection with NGCP network, while NGCP will fund any cost associated with work required within its substation as well as any re-enforcement costs required to facilitate the new power station. Funding arrangement for new connection could deviate from this general norm and negotiation between relevant parties can be used to achieve an optimal cost model for all parties involved.

The capital cost of connecting from the proposed power plant to the NGCP network, the NGCP capital connections cost and an opinion of the cost of upgrades for re-enforcement have been factored into this review to give an overall commentary on the impact of the proposed connection to the Philippines.

Transmission network review assumptions

In order to provide a fair and comparative review of the transmission network, in the context of connecting a baseline 800MW CCGT Power Plant at the proposed LNG terminal, the following assumptions have been made:

- The power plants associated with the proposed LNG terminals for Luzon and Mindanao will be developed and brought into operation in medium term (within five years) and built with least cost.
- The transmission grid connection for the CCGT power plants that require equipment to be owned by the power plant company will also be considered in the same approaches.
- The review of transmission networks to the proposed locations in Luzon, Visayas and Mindanao are performed with reference to the proposed generation facilities in Table 13 and ERC-approved projects for those areas with list in Table 14

Table 13: Generation Projects assumed by the ERC for approval of the Calaca-Dasmariñas 230kV transmission line project

Commission Year	Proposed generation facility	Capacity (MW)
2014	Putting Bato, Batangas Stage-1	135
2015	Putting Bato, Batangas Stage-2	135
2014	Batangas Coal Stage-1	300 (2x150)
2017	Batangas Coal Stage-2	300 (2x150)
2015	San Gabriel Batangas	550 (2x225)

Source: ERC Decision case no. 2013-023RC (July 5, 2013)

Table 14: List of ERC-approved transmission projects

Name of Project	Location	Type of Project
Luzon Substation Expansion III	Batangas	2x300MVA 230/69kV substation
Luzon Substation Expansion III	Calaca	1x100MVA 230/69kV substation
New Calaca Dasmariñas 230kV Line	Luzon	230kv ST-DC 57 km transmission line
Luzon Substation Expansion IV	Limay	1x50MVA 230/69kV substation
Balo-i-Villanueva 230kV T/L	Balo-i-Villanueva	230kv ST-DC 120 km transmission line
Balo-i-Villanueva 230kV T/L	Villanueva	16x138kV PCB transformer
Balo-i-Villanueva 230kV T/L	Balo-i	5x138kV PCB transformer
Mindanao Substation Reliability I	Jasaan	1x100MVA 138/69-13.8kV substation
Villanueva-Maramag 230 kV Transmission	Villanueva-Maramag	230kV ST-DC 108 km transmission line

- Based on the information from Table 13, Calaca substation would have transmission congestion. The review has not considered connecting the proposed 800MW CCGT to the substation where total 1,470MW generation capacity will be accumulated by 2017. For additional generation capacity of 550MW from San Gabriel plant (by 2015), diversion of Sta. Rita 230kV transmission line from Calaca substation to Dasmariñas substation has been approved by the ERC. This modification of the network will be done in form of a diversion that will include the splitting of existing Sta. Rita and San Lorenzo with two 1,200MVA transmission lines.
- All electricity transmission related capacity information is estimated based upon the data acquired from the NGCP Transmission Development Plan 2012 as well as Luzon & Visayas network single line diagrams by Philippines Electricity Market Corporation (PEMC).
- Network data was not available for the review and therefore load flow study has not been undertaken. Load flow study is a significant component in evaluating transmission networks and therefore the conclusion drawn from the available data without the result from this study is subject to a high degree of variation and update from NGCP and PEMC.

Overhead Line (OHL) review assumption

The transmission Overhead Line (OHL) connection between the proposed power plant and the NGCP transmission substation was reviewed with the assumption that the connection will be compliant with power grid code and standard of NGCP, including;

- ACSR heat resistant conductors if the capacity augmentation is up to 50%;

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- Conventional large cross-sectional conductors if the capacity augmentation is about 75% and the line utilization hours is above 3,000 hours, or ACSR heat resistant conductors if the line utilization hours is below 2,000 hours;
- Line rebuild with conventional large cross-sectional conductors if the capacity augmentation is above 100%. Sizing of the cross-section depends on the extent of capacity augmentation;
- Choice of conductors will also depend on their procurement costs, bulk transmission tariffs, line utilization hours and local environment.
- Taking into consideration the 2,850MVA cable rating for existing transmission line, in order to set up a baseline to compare the various proposed locations, 3,000MVA cable rating for 500kV and 1,200MVA for 138kV or 230kV are adopted in this review.
- Protection schemes will be designed based on the requirements from NGCP and aligned with existing power grid systems. Digital relays compliant with IEC61850 are assumed to be used.
- The SCADA system, assumed to be centralized at the energy storage building, will control and monitor all station protection, telecom and metering systems or equipment.
- The connection of transmission Overhead Lines (OHL) from the proposed LNG power plants to existing NGCP substations is assumed to be installed along the existing transmission routing. For other transmission lines routing, the Right-Of-Way (ROW) is referenced from Google Earth maps and proposed to be away from congested areas.

Cost of transmission assets

The transmission cable cost comprises fixed building cost, variable cost and operation cost. The variable cost includes but is not limited to civil foundation, pylon materials, conductors and other electrical apparatus. The operation cost is divided into power losses, fuel source, which is LNG in our study, losses and normal operation and maintenance.

Estimated transmission line construction cost is around 0.75 and 1.5 million US dollars per kilometre per circuit for 1200MVA 138kV or 230kV and 3000MVA transmission OHL construction respectively. A factor of 1.6 will be added for line less than 5km, while a 1.2 factor will be taken into account for the line greater than 5km but less than 15km. No adjustment factor will be appended for line longer than 15 km.

For system upgrade by NGCP, it is assumed that it is necessary to have additional switchgear set including circuit breaker, disconnectors, protective device, metering & control equipment, other equipment and structural improvement which will cost 1 and 2 million US dollars per circuit for 138kV or 230kV and 500kV respectively. For 230kV

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connected to 500kV within the same substation, 600MVA auto-transformers installation cost of approximately 7 million US dollars per set will be taken into account.

4.3.3. Assumptions on the transmission network

The DOE has requested a view on the proposed LNG terminals and their associated power generation with respect to the existing and proposed electrical transmission network, in particular, the transmission constraint that affects the delivery of power to the load centre in and around greater Manila area and the mitigation and avoidance of excessive generation capacity in the Batangas area.

In addressing these requested DOE items, this review has made specific assumptions, including:

High Power Demand in Manila

- To address the high power demand at Manila (refer to Transmission Development Plan 2012), NGCP has proposed various 500kV and 230kV network upgrades or reinforcement which indicated projects requiring ERC approval and government support through the DOE.
- In support of these proposed network upgrades including existing and proposed power generation connection, it is assumed that one or two of the proposed LNG CCGT's will be connected into the transmission network within five years in Luzon area to supply electricity to Manila.
- The connection of additional proposed power generations and the proposed LNG CCGT's to the 230kV or 500kV substations of the existing systems has been considered. The substations considered in this review are the 230kV substations in Batangas and Limay as well as the 500kV substations in Tayabas and Ilijan.
- All substations are crucial to supply electricity from generators via various circuits to Manila where the power consumption accounts for 70 percent of total consumption in Luzon area.
- The substations capacity has been preliminarily assessed and is believed to have sufficient capacity for the integration of 800MW to the NGCP network at 230kV or 500kV voltage levels. This will help support electricity supply to Manila.
- Technically, connection of a generator to 500kV substation with subsequent stepping-down to 230kV is preferable, however, should the nearest substation to the generator is at 230kV transmission level, connecting at this level might provide an avenue for a cost and time effective solution to release some pressure for high electricity demand in Manila.
- For further confirmation of the feasibility of the connection scenarios to NGCP system, details system impact studies shall be conducted.

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Excessive Generation Capacity in Batangas area

- Only one site is recommended to be chosen in this area to support and supply electricity to Manila.
- A path with the best access, away from congested urban area, that provides right-of-way for implementation of new lines from proposed sites to the substation has been selected and taken into account in this review.
- The transmission networks including power lines and substations in the Batangas area will have enough capability to convey the electricity to Manila.
- Feasibility and reliability of the new connection to the system is subject to actual system impact studies results.

Option for Addressing Physical Congestion in Manila

The requirement for construction of new transmission line and substations in the congested areas in the vicinity of metro Manila, such as Pasay and Navotas and new 500kV lines from Hermosa to San Jose, the utilisation of underground cables and substations design can be considered. It should, however, be noted that the cost of the underground cable can be around five times more compared to that of overhead line over the same distance.

In addition to this, a more compact substation design with smaller Gas Insulated Switchgear (GIS) and SF6 transformer can also be adopted to mitigate issues with obtaining Right-Of-Way and building of new substation in congested areas. In extremely small and congested spaces, an underground compact substation design could also be considered as a possible solution.

4.3.4. Natural Gas Pipeline Grid Connection***Existing Natural Gas Pipelines***

The Philippines has a limited gas pipeline network at present, with the only notable example being the Malampaya Gas Field subsea link to Batangas. The Malampaya pipelines are over 500km in length and carry gas from the offshore fields to the three CCGT power plants (1,000MW Sta. Rita, 500MW San Lorenzo and 1,200MW Ilijan) located in the Batangas area.

Planned Natural Gas Pipelines

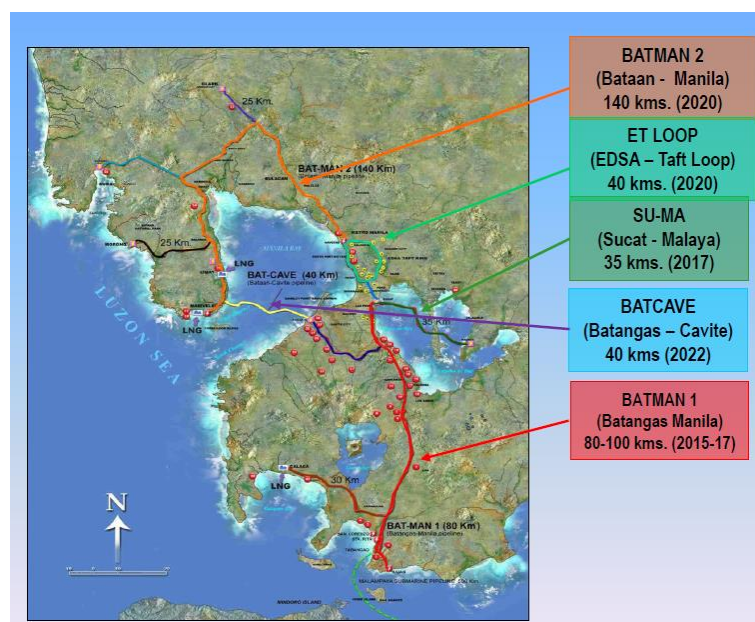
The DOE has devised a plan to develop a natural gas pipeline network in the Philippines, see Figure 20.

The proposed LNG terminals key planned pipeline projects are BatMan 1, which links Batangas to Manila, and BatMan 2, which links Bataan to Manila.

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Obviously, the presence or absence of pipelines will have implications on the operational configuration for the proposed LNG terminal projects in Limay and Batangas, as it will open up the possibility of distributing the gas to different types of consumers.

Figure 20: Natural Gas Pipeline Network Plan by the DOE



Potential Conversion of Petroleum Pipelines

In conjunction with the planned gas pipelines, it has been observed that there is an existing oil pipeline in the Philippines. This pipeline, which has two main lines, was established in 1967 to service fuel requirements for Meralco and oil refineries in Batangas. The 117km long white oil line transports refined petroleum products (diesel, gasoline, jet fuel and kerosene) from Batangas to Pandacan, whilst the 105km long black oil line carries heavier petroleum products (bunker fuel) from Batangas to Sucat.

The oil pipeline is owned by First Philippine Industrial Corporation (FPIC), which is 60% owned by First Holdings and 40% owned by Shell Petroleum Co.

It is understood that First Gen, an affiliate of FPIC, is currently examining the possibility of converting one of the oil lines to carry natural gas. The company expects that the pipeline will be capable of delivering the requirements for a 300MW gas fired power plant. The ultimate capacity of the pipeline will be dependent on the allowable operating pressure. If the conversion plan proceeds, the company expects to invest approximately US\$100million for the project, which will complete in 2-3 years.

Comment on the natural gas transmission

Each of the proposed LNG sites has been reviewed and a brief commentary has been provided based upon the applicability of its connection with the existing or proposed gas

network. The review will take into account the distance of connecting of the proposed LNG terminals to the gas network, especially its connectivity to Manila.

In particular, the Department of Energy has requested a view on the proposed LNG terminal capability to connect to the existing and proposed on shore gas networks, and its potential not only to support new power generation but also to serve as support to exiting power generators including acting as a back-up to the Malampaya system; noting that the Malampaya system is supplying gas to the Sta. Rita, San Lorenzo and Ilijan power plants.

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4.4. SITE 1, BATANGAS – SHELL

4.4.1. General

Shell are considering developing an offshore FSRU LNG terminal in Batangas Province, Luzon.

Table 15 Details of the proposed Shell LNG terminal

Shell Terminal	Units	Details
Location	n/a	Batangas, Luzon
Project Configuration	n/a	Offshore FSRU
Throughput	MTPA	Redacted
LNG Tank Size and No.	m ³	Redacted
CCGT Capacity	MW	Redacted
Project Status	n/a	FEED
Operational Target Date	Year	Information Unavailable

The proposed site is understood to be adjacent to the existing Shell Petroleum Refinery and faces Batangas Bay. It is located close to Batangas City, which is approximately 105km south of Manila, and is shown as Site 1 in Appendix D, Figure D3.1 and accompanying figures.

The city is a developed industrial city; however it is understood a 40ha site has been identified for development in the near existing Shell refinery to the South of the city. It is understood that a sufficient area of land has been identified and is available for the onshore development. Future development would possibly be limited by the existing plant and industrial zones adjacent to the site.

It is assumed that reclamation works would not be required.

The 2010 Philippines census has recorded the population of Batangas City as approximately 305,000 and the population density map in Appendix D, Figure D3.16 indicates this site is 20-50 people per 90km².

4.4.2. Commentary on proposed project

Detailed information from the site assessment can be found in Appendix D2. The key points on the site and proposed terminal configuration are:

- Offshore terminal proposed in an existing harbour with a relatively high level of marine traffic (although with control systems in place).
- Constrained site location in an industrial area requiring 1.35km subsea pipeline and 1.4km on land pipeline for piping gas from ship to shore.
- Future development of the terminal would be restricted by adjacent brownfield sites, however it is understood these are owned by Shell. The land area understood to be developed for the site appears to be larger than typically required for FSRU onshore requirements. There are a number of existing nearby jetties that would potentially restrict the locations available for future jetties.
- Nearby Batangas City is an industrial city where it is assumed that local skills and labour will be readily available.
- Although a populated city, given that a number of existing industrial plants are in the vicinity, it can be assumed any negative social views on the proposals would be minimal.
- This review has not considered the effects of any social unrest or security issues in its assessment and would assume that any issues with this would be addressed at a governmental level
- An Environmental Compliance Certificate has been issued for the project.
- The site has 'medium' geophysical risks with Tsunami susceptibility being a concern.
- Although the site is near Batangas area, transmission connection could be realized to both Batangas substation (with 1300MVA capacity) or Ilijan substation (with 1500MVA capacity). The connection to Ilijan at 500kV has more is technically more beneficial to the power system in supporting electricity demand of Manila, however, consideration should be given as this will nearly double overall cost compared to connecting at Batangas. The actual system impact studies e.g. load flow needs to be carried out to confirm the feasibility with respect to the whole system.
- The planned BatMan 1 gas pipeline is in the vicinity of this site. This gives the opportunity for gas from this proposed site to be utilised not only to provide gas to the proposed CCGT power plant but also as a source to the planned gas network.

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4.5. SITE 2, BATANGAS – FIRST GEN

4.5.1. General

First Gen are considering developing an onshore or offshore LNG terminal in San Lorenzo, Batangas Province, Luzon.

Table 16 Details of the proposed First Gen LNG terminal

First Gen Terminal	Units	Details
Location	n/a	Batangas, Luzon
Project Configuration	n/a	Onshore (Possibly Offshore) LNG Terminal with estimated 250m Jetty and CCGT Power Plant Expansion (San Gabriel) in 3 Phases
Throughput	MMTPA	Redacted
LNG Tank Size and No.	m ³	Redacted
CCGT Capacity	MW	Redacted
Project Status	n/a	In process of Phase 1 & 2 of San Gabriel
Operational Target Date	Year	As early as 2018

The proposed site is understood to be adjacent to the San Lorenzo Combined Cycle Power Plant, Sta Rita and faces Batangas Bay. The site is located close to Batangas City which is approximately 55km south of Manila, as shown in Map D3.1, site 2.

The city is a developed industrial city however it is understood a site has been identified for development and there will be sufficient available land.

The area of available undeveloped land and the target land rights requirements suggest that reclamation works would not be required. The identified site however, appears to be in a wetlands area and it is assumed that either substantial drainage or land upfill works would be required to protect the site.

The 2010 Philippines census has recorded the population of Batangas City as approximately 305,000 and the population density map in Appendix D, Figure D3.16 indicates this site is 20-50 people per 90km².

4.5.2. Commentary on proposed project

Detailed information from the site assessment can be found in Appendix D2 however key points on the site and proposed terminal configuration include:

- Onshore or offshore terminal proposed in an existing harbour with a relatively high level of marine traffic (although with control systems in place).

- The site appears to be located in wetlands area and would require significant upfill works or drainage to protect the site from flooding. This appears to be been undertaken on the nearby San Lorenzo Combined Cycle Power Plant.
- The site is located next to existing industrial plants which could potentially restrict the areas available for future development of the terminal. These areas would be located in wetlands.
- Nearby Batangas City is an industrial city where it is assumed that local skills and labor will be readily available.
- Although a populated city, given that a number of existing industrial plants are in the vicinity, it can be assumed any negative social views on the proposals would be minimal.
- This review has not considered the effects of any social unrest or security issues in its assessment and would assume that any issues with this would be addressed at a governmental level.
- The site has 'medium' geophysical risks with Tsunami susceptibility being the principle concern.
- The site is near Batangas area, which has around 1,300MVA spare capacity for new direct connection at the Batangas substation on preliminary estimation basis. The power plant can also be connected to the Batangas substation via Sta. Rita/San Lorenzo substation located next to the site, however, system upgrade, which might have to be funded by the NGCP, would be necessary to facilitate this connection. System impact studies e.g. load flow needs to be carried out to confirm the feasibility with respect to the whole system.
- The planned BatMan 1 gas pipeline is in the vicinity of this site. This gives the opportunity for gas from this proposed site to be utilised not only to provide gas to the proposed CCGT power plant but also as a source to the planned gas network.

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4.6. SITE 3, ATIMONAN – MERALCO

4.6.1. General

The Manila Electric Company (Meralco) are considering the development of an LNG receiving terminal at Atimonan, in Quezon Province, Luzon.

Table 17: Details of the proposed Meralco LNG terminal

Meralco Terminal	Units	Details
Location	n/a	Atimonan, Luzon
Project Configuration	n/a	Onshore LNG Terminal with estimated new 600m Jetty and CCGT Power Plant
Throughput	MMTPA	Redacted
LNG Tank Size and No.	m ³	Redacted
CCGT Capacity	MW	Redacted
Project Status	n/a	Feasibility Study Done
Operational Target Date	Year	3Q 2018

Atimonan is a coastal town facing the Lamon Bay and is approximately 20km East of Luzon City and 15km North-West of Gumaca. The town is approximately 130km from Manila and is shown as site number 3 on the map shown in Appendix D, Figure D3.1.

Although the town is developed, there appears to be adequate land available in the immediate surrounding areas and the site would be considered Greenfield. It is understood a target development of 64ha is required of which 60ha have been acquired already.

It is understood that there are no land availability issues; however, the topography of the area suggests that the site may be located on an area of sloping land. An LNG terminal would therefore require site levelling works (including cut & fill operations and slope works) and possibly areas of reclaimed land.

The 2010 Philippines census has the population of Atimonan municipality as approximately 65,000 and the population density map in Appendix D, Figure D3.16 indicates the area has a density of 0-1 people per 90km².

4.6.2. Commentary on proposed project

Detailed information from the site assessment can be found in Appendix D2. The key points on the site and proposed terminal configuration are:

- Onshore terminal proposed at a greenfield site in a rural region of Quezon Province.

- The exact location of the terminal is unknown however local topography suggests area of slopes to the coast. Site levelling works (including cut & fill operations and slope works) and possibly areas of reclaimed land are potentially required to provide a level area for the terminal.
- The site is located next to the town of Atimonan; however, it would be constructed on nearby greenfields. The site is further from major population areas and it can be assumed that skilled labour would need to be brought to the site.
- The area is less densely populated however given the construction would be greenfield, there may be some negative social views on the proposals to consider from local residents.
- This review has not considered the effects of any social unrest or security issues in its assessment and would assume that any issues with this would be addressed at a governmental level
- The site has 'low' geophysical hazard risks. Tsunami risk in particular may be reduced by Alabat Island across the Lamon Bay.
- The transmission capacity for connection of the proposed power plant to Tayabas substation is around 1,150MVA on preliminary estimation basis. The installation cost of the connection is comparatively high and it is believed that it would be beneficial for the transmission system to be upgraded by NGCP at Tayabas so connection can be made at 500kV level. System Impact Studies, e.g., load flow analyses, need to be carried out to confirm the feasibility with respect to the whole system.
- There is no planned gas pipeline in vicinity of the site.

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4.7. SITE 4, PAGBILAO – ENERGY WORLD

4.7.1. General

Energy World International are currently constructing an LNG terminal, jetty and processing area at a site on Pagbilao Grande Island/ Volcano Island, Pagbilao in Quezon Province, Luzon.

Table 18 - Details of the Energy World LNG Terminal Project

EWC Terminal	Units	Details
Location	n/a	Pagbilao, Luzon
Project Configuration	n/a	Onshore LNG Terminal with estimated new 300m Jetty and CCGT Power Plant
Throughput	MMTPA	Redacted
LNG Tank Size and No.	m ³	Redacted
CCGT Capacity	MW	Redacted
Project Status	n/a	Construction in progress for Jetty and 1st Tank
Operational Target Date	Year	Information Unavailable

The island itself is in the Tayabas Bay whilst the site faces Capulan Bay. The site is located to the East of Luzon City (and approximately 140km from Manila) and is shown in Appendix D, Figure D3.1, site 4. The site is immediately East of Pagbilao coal fired power station.

The site is under construction and various sections of the site have been levelled. A site visit was undertaken in November and found that the foundations for one of the proposed LNG tanks have been constructed and preparations are currently in place for slipform construction of the walls. Reclamation has been undertaken which is to be used for construction of the jetty.

The 2010 Philippines census has the population of Pagbilao municipality as approximately 85,000 and the population density map in Appendix D, Figure D3.16 indicates this site is 0-1 people per 90km².

4.7.2. Commentary on proposed project

Detailed information from the site assessment can be found in Appendix D2. The key points on the site and proposed terminal configuration are:

- Onshore terminal currently under construction at a greenfield site. Jetty construction underway and tank foundations for one tank complete.
- The site will be located in a low population, greenfield site however is in close proximity to the Bacungan Fish Sanctuary. An Environmental Compliance Certificate has been issued for the project and it is understood the jetty has been configured to avoid this area.
- The site appears to be sufficient greenfield land available for future expansions in the area, however these too would need to avoid the adverse impacts on the fish sanctuary.
- The site is further from major population areas and it can be assumed that skilled labour would need to be brought to the site from elsewhere.
- The local area is less densely populated and located near an existing coal fired power station which may suggest there any negative social views on the proposals would be minimal.
- This review has not considered the effects of any social unrest or security issues in its assessment and would assume that any issues with this would be addressed at a Governmental level
- The site has 'low' geophysical risks.
- The transmission capacity for connection of the proposed power plant to the Tayabas substation is around 1,150MVA on preliminary estimation basis. The installation cost of the connection is comparatively high and it is believed that it would be beneficial for the transmission system to be upgraded by NGCP at Tayabas so connection can be made at 500kV level. System Impact Studies, e.g., load flow analyses, need to be carried out to confirm the feasibility with respect to the whole system.
- There is no planned gas pipeline in vicinity of the site.

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4.8. SITE 5, LIMAY – AG&P (PNOC)

4.8.1. General

The AG&P site for onshore LNG terminal and processing area is proposed for the site in Limay municipality in the province of Bataan, Luzon.

Table 19 - Details of the AG&P LNG Terminal Project

AG&P Terminal	Units	Details
Location	n/a	PNOC-AFC Limay, Luzon
Project Configuration	n/a	Onshore Regas Terminal initially starting with FSU until Onshore Tanks are complete. 1,200m new Jetty and CCGT Power Plant in three phases
Throughput	MTPA	Redacted
LNG Tank Size and No.	m ³	Redacted
CCGT Capacity	MW	Redacted
Project Status	n/a	FEED
Operational Target Date	Year	2017

This 250ha site faces Manila Bay and is West of Manila itself. The site is approximately 40km across the bay from Manila but 140km by land via the City of San Fernando. The site is marked as number 5 in Appendix D, Figure D3.1 and accompanying figures.

The town is a developed industrial zone however it is understood a 250ha site has been identified for development. This area surrounds much of the existing industrial zones and is understood to require relocation of some existing buildings on the site. Further or future developments may be limited by the existing industrial zones adjacent to the site.

Considering the area of land available for development, it is assumed that reclamation works would not be required.

The 2010 Philippines census has the population of Limay municipality as approximately 60,000 and the population density map in Appendix D, Figure D3.16 indicates this site is between 5 to 20 people per 90km².

4.8.2. Commentary on proposed project

Detailed information from the site assessment can be found in Appendix D2. The key points on the site and proposed terminal configuration are:

- Onshore terminal proposed in industrial park facing Manila Bay. This has relatively high level of marine traffic (although with control systems in place)

- The site will be located in a low population, industrial area; however, it is in close proximity to the Bataan National Park. The existing industrial plant can be assumed to have overcome any objections on these grounds.
- The site is located although be based in an existing industrial area, there appears to be land available for future expansions in the area.
- The site is close to a major population area and it can be assumed that skilled labour is locally available.
- The local population density can be considered 'medium'; however, given that the construction would be located in an existing industrial area, there may be a minimal number of negative social views on the proposals.
- This review has not considered the effects of any social unrest or security issues in its assessment and would assume that any issues with this would be addressed at a governmental level.
- The site has 'high' geophysical hazard risks with earthquake and tsunami effects potentially of concern.
- The transmission capacity for connection of the proposed power plant to the Limay substation is around 1,100MVA on preliminary estimation basis. This proposed site is a significant distance away from either Batangas or Manila. From the preliminary assessment, it is believed that there is limited capacity to utilize power generated from this site to relieve some electricity demand in Manila. System Impact Studies, e.g. load flow analyses, need to be carried out to confirm the feasibility with respect to the whole system.
- The planned BatMan 2 gas pipeline is in the vicinity of this site. This gives the opportunity for gas from this proposed site to be utilised not only to provide gas to the proposed CCGT power plant but also as a source to the planned gas network.

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4.9. SITE 6, CAGAYAN DE ORO - PETROLEUMBRUNEI

4.9.1. General

PetroleumBrunei are understood to have identified a number of sites for either an onshore LNG terminal or offshore FRSU near Cagayan de Oro in the province of Misamis Oriental, Northern Mindanao.

Table 20: Details of the PetroleumBrunei LNG Terminal Project

PetroleumBRUNEI Terminal	Units	Details
Location	n/a	Cagayan de Oro, Mindanao
Project Configuration	n/a	Onshore or Offshore Terminal with estimated 250m new Jetty and CCGT Power Plant
Throughput	MMTPA	Redacted
LNG Tank Size and No.	m ³	Redacted
CCGT Capacity	MW	Redacted
Project Status	n/a	Feasibility Study Started
Operational Target Date	Year	2018

These sites are located near Tagaloan and Villanueva on the coast of the Macajalar Bay, approximately 170km from Davao City. The site is marked as number 6 in Appendix D, Figure D3.1 and accompanying figures.

The sites are understood to be under the PHIVIDEDEC Industrial Estate Special Economic Zone A and between 12 to 29ha are available for development. Despite being based in industrial areas, the sites appear to have available land for future developments.

It is understood that reclamation works would not be required, regardless of which terminal configuration is adopted.

The 2007 recorded population of Misamis Oriental is approximately 750,000 and the population density map in Appendix D, Figure D3.16 indicates this area has a population of between 20 to 50 people per 90km².

4.9.2. Commentary on proposed project

Detailed information from the site assessment can be found in Appendix D2. The key points on the site and proposed terminal configuration are:

- Onshore or offshore terminal proposed in industrial park.

- The site will be located in a low populated, industrial area and there appears to be land available for future expansions in the area.
- The site is close to a major population area in Mindanao but may still need to source skilled labour from elsewhere.
- This review has not considered the effects of any social unrest or security issues in its assessment and would assume that any issues with this would be addressed at a governmental level.
- A new jetty would be needed to position such at it avoided the nearby Poblacoin Subgongoon Marine Sanctuary
- Compared to the Luzon sites considered in this study, the risk of typhoons is reduced, however there is a local risk of flooding.
- The site has a 'medium' risk to geophysical hazards.
- There is insufficient transmission network information for the proposed site. From preliminary assessments, it was found that majority of the power plants in Mindanao are hydropower plants with low transmission capacity. To accommodate the new 800MW CCGT, it is necessary for NGCP to upgrade the capacity of existing network. All connection in the existing network in Mindanao is at 138kV, which is not preferable from a power systems point of view.
- There is no planned gas pipeline in vicinity of the site.

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4.10. SUMMARY OF SITE ASSESSMENTS

A summary of the engineering assessment of the six sites described in Sections 4.4 to 4.9 is included in Appendix D.5

World Bank Philippines Gas Masterplan Engineering Review										ARUP
Site Reference		All	Baseline Site Assumptions	1	2	3	4	5	6	
Developer		Appendices		Shell	First Gen	Meralco	Energy World	AG&P (PNOC Site)	FB	
General Information										
Location		D3.1	-	Batangas (Luzon)	Batangas (Luzon)	Aklan (Quezon)	Paghalo (Quezon)	Lamay (Luzon)	CDO (Mindanao)	
Latitude, Longitude			-	13.720, 121.066	13.766, 121.033	14.005, 121.917	13.894, 121.745	14.495, 120.605	8.514, 124.589	
LNG Tank Location			Onshore/Offshore	Offshore	Onshore	Onshore	Onshore	Onshore	Onshore or Offshore	
Regasification Location			Either	New build FSRU/Offshore	FSRU also considered/Onshore or Offshore	Onshore	Onshore	Onshore Regas with FSU lease in short term/Onshore	Onshore or Offshore	
Site Conditions (Land)										
Current Land Use			-	Industrial park	Industrial park	Greenfield sites available out of town	Greenfield	Industrial park	Industrial park	
Elevation (one point / 30m grid)	[mMSL]	D3.2	12	10.2	0	8.2	15	14	12.2	
Land Type		D3.3	Greenfield	Unclassified/ Present Agro-Industrial Lands/ Erodeble Lands	Fishponds/ Saltpads (EFL)/ Gently sloping lands (Irrigable)/ Abandoned Lands (Irrigable)	Industrial Lands/ Unclassified	Erodeble lands/ Present Agro-Industrial Lands	Build-up Area/ Expansion Area/	Present Agro- Industrial Lands/ Erodeble lands/	
Land Cover		D3.4	Greenfield	Crop land mixed with coconut plantation	Build Up Area/ Crop land mixed with coconut plantation	Barren land/ crop land mixed with coconut plantation	Coral reef/ arable land, crops mainly cereals and sugar/ coconut plantations	Cultivated area/ mixed with brushland/ grassland/ grass covering >70% open canopy/ mature trees	Crop land mixed with coconut plantation	
Geology		D3.5	Mid strength, semi weathered	Recent/ Pliocene- Pleistocene/ Pliocene- Quaternary	Recent/ Pliocene- Quaternary	Basement complex (pre jurassic)	Oligocene Miocene/ Limestone	Undifferentiated igneous rocks	Undifferentiated igneous rocks/ Pliocene- Quaternary	
Soil		D3.6	Non aggressive, mid strength	Iban kam	Taal sandy loam	Quingua silt loam	Clay & Highly weathered limestone	Antipolo clay	Beach sand	
Slope Class		D3.7	Level to nearly level	Level to nearly level	Level to nearly level	Steep/ very steep	Level to nearly level	Level to nearly level	Level to nearly level	
Reclamation Area	[m ²]						Small area			
Major Site Formation Area	[m ²]		Minor local levelling works only.	Assume minor local levelling works only.	Wetlands. Uplift or drainage required.	Steep slopes identified. Levelling works or reclamation required.	Rock cuttings into nearby mountain.	Assume minor local levelling works only.	Assume minor local levelling works only.	
Site Conditions (Marine)										
Distance to -15m Contour	[km]	D3.8	0.2	0.5	0.25	0.6	0.3	1.2	0.5	
Jetty Required			New	No	New	New	New	New	New (onshore only)	
Estimated Ties Length	[km]		0.2	0	0.25	0.6	0.3	1.2	0.5	
Normal Wave Heights			Small	Small	Small	Small	Small	Small to Medium	Small	
Typhoon Wave Heights			Small to Medium	Small to Medium	Small to Medium	Medium	Medium	Small to Medium	Small	
Ease of Navigation			Easy	Easy	Easy	Easy	Easy	Easy	Easy	
Environmental										
Industrial Area			Industrial	Part of Shell Refinery Land	Industrial Park	Greenfield sites available adjacent to Aklan town.	Greenfield	Part of Industrial Park	Part of Industrial Park	
Proximity to Sensitive Receivers (Land)			No protected parks in vicinity	Nearest protected area 25km (Taal Volcano national park).	Nearest protected area 25km (Taal Volcano national park).	Close proximity to Quizon National Park (lowland rainforest and vegetation).	No terrestrial protected areas.	Close proximity to Mt. Marikela watershed forest reserve. Bacan National Park 25km away.	Nearest protected area is Mahogano Watershed Forest Reserve, 25km away.	
Proximity to Sensitive Receivers (Marine)			No marine protected parks in vicinity	No NIPAS protection or marine protected areas. Nearest fish sanctuaries 20km (Mahini headland)	No NIPAS protection or marine protected areas. Nearest fish sanctuaries 20km (Mahini headland)	No marine protected areas.	Close proximity to the 20ha Bacungan Fish Sanctuary	No marine protected areas.	Close proximity to Poblacion Sugbongon Marine Sanctuary.	
Weather Hazard Risk										
Offline				Assumed 4-8 days/yr offline						
Tropical Cyclones	[km/ yr]	D3.9 + D3.10	100,000	30,000-100,000	30,000-100,000	100,000	100,000	30,000-100,000	3,000-10,000	
Flooding		D3.11	Medium	Low	Wetlands. High.	High	Low	Low	High	
Tectonic Hazard Risk										
Earthquake		D3.12	Medium	Medium	Medium	Low	Low	Medium	Low-Medium	
Earthquake (Rock)	[PGA]	D3.12		0.26	0.25	0.25	0.22	0.21		
Earthquake (Med soil)	[PGA]	D3.12		0.41	0.4	0.4	0.39	0.39	0.21	
Earthquake (Soft soil)	[PGA]	D3.12		0.7	0.65	0.7	0.69	0.6	0.35	
Landslide		D3.13	Low	Low	Low	Low (nearby High)	Low to Moderate	Low	Low	
Tsunami		D3.14	Medium	High	High	Medium	Medium	Medium	Medium	
Tsunami Rump	[mMSL]		2-5m	2-5m. Exposed.	2-5m. Exposed	2-5m. Likely protection from Alabat Island.	2-5m. Likely protection from Mindoro Island.	5m. Likely reduced on East coast of Batangas.	<2m. Exposed.	
Volcano		D3.15	Medium	Medium	Medium	Medium	Medium	Medium	No risk	
Combined Geophysical Risk		D3.16	Medium	Medium	Medium	Low	Low	High	Medium	
Social / Safety										
Population Density	[people/90km ²]	D3.17	5.1-20	20.1-50	20.1-50	0-1	0-1	5.1-20	20.1-50	
Distance to Population Centres			Low	Low	Low	Medium	Medium	Low/ Medium	Low	
Infrastructure										
Marine Traffic Safety			No issues	Batangas Harbour has a relatively high level of marine traffic but control systems are in place.	Batangas Harbour has a relatively high level of marine traffic but control systems are in place.	No issues identified	No issues identified	Manila Bay has a relatively high level of marine traffic but control systems are in place.	No issues identified	
Road			Good road access	Industrial city. Good road access.	Industrial city. Good road access.	<1 mile from Pan-Philippine Highway	10 miles from AH26.	<1 mile from Roman Superhighway	Batman - Cagayan de Oro-Iligan Rd	
Rail			No rail access.	No rail access.	No rail access.	No rail access.	No rail access.	No rail access.	No rail access.	
Transmission Lines										
NGCP Substations		D4.1		Batangas Lijian	Batangas Sta. Rita/San Lorenzo	Tayabas	Paghalo CFIPP Tayabas	Lamay	Tagakan	
Estimated connection distance		D4.1	11km	Batangas (10km) Lijian (11km)	Batangas (10km) Sta. Rita/San Lorenzo (0.1km)	Tayabas (36km)	Paghalo CFIPP (0.1km) Tayabas (33km)	Lamay (5km)	Tagakan (5km) Napcor Transco (0.1km)	
Required NGCP transmission lines reinforcement			No	No	Yes for Sta. Rita case	No	Yes for Paghalo case	No	Yes	
Gas Pipe Lines										
Connection Point				Batman 1	Batman 1	Batman 1	Batman 1	Batman 2		
Distance				5km	5km	110km	100km	5km		
Basis for Distance	1 - Assuming BAT MAN gas pipelines are constructed			Allow nominal connection length	Allow nominal connection length	Following road route to Tausan City for connection to Batman	Following road route to Tausan City for connection to Batman	Allow nominal connection length		
Connection Point				Manila	Manila	Manila	Manila	Manila		
Distance				105km	115km	190km	180km	42km		
Basis for Distance	2 - Assuming BAT MAN gas pipelines are not constructed			Following existing road route to Manila centre	Following existing road route to Manila centre	Following existing road route to Manila centre, by San Pablo, Tausan and Marikela cities.	Following existing road route to Manila centre, by San Pablo, Tausan and Marikela cities.	Subsea direct from Lamay to Manila.		
Programme/Cost										
Current Status				FEED Ongoing	Various	FS Done	Under Construction	GI & DED Ongoing	FS Starting	

The summary table presents an overview of the key technical findings of the study and has been referenced in preparing the capex analysis and conclusions of this report.

Cells have been shaded red or green to represent a difference from the assumed baseline criteria assumptions. Green cells indicate a positive impact (i.e., reduced cost compared to the baseline) and red cells indicate an adverse impact (i.e., increase cost).

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Information in Regular font text has been established in the course of this study. Where text is *italicised*, this indicates information that has been supplied by others.

4.11. CAPEX ANALYSIS

4.11.1. General

This section provides details of the capital costs of an LNG terminal, CCGT power plants and transmission infrastructure for each site. The findings are summarised into a table to provide relative costing, for ease of comparison, which is found in Section 4.10 and Appendix D.5.

4.11.2. Key Assumptions

Capital cost estimates are based on the following key assumptions. Other assumptions and unit rate costing data is included in Appendix D6.

- In order to ensure a like-for-like comparison all sites are assumed to comprise an LNG terminal serving an 800MW mid-merit power plant requiring 0.2 – 0.6 MTPA of LNG. The actual capacity of LNG terminal and power plant proposed by each developer are not considered by the capex estimates.
- Delivery of LNG to the terminals is by 170,000m³ carrier. The shipping costs or carrier acquisition costs associated with deliveries are excluded from the capex costs.
- The rates and costs assumed are those which provide the best estimate of the total contract sum which would be commanded by a reputable international contractor to complete the works in accordance with all relevant international and local standards.
- The figures quoted below are baseline costs. These baseline costs are adjusted by multipliers based on the exposure of the particular sites to risks from met-ocean conditions, typhoon winds, flooding and seismic effects (see Table 21).

4.11.3. Multipliers for Environmental and Seismic Factors

An allowance has been made in the cost of the main components of each site depending on the risk profile of the site determined by the site assessment. This allowance is an acknowledgement that there needs to be a cost adjustment to take account of environmental and seismic effects which differ at each site. The multiplier allows cost to act as a differentiator between the sites, but does not reflect the actual cost impact of the risk profile of each site.

The following multipliers have been applied to the above costs based on the information gained from the site assessment. The multipliers adopted are based on Arup experience of the design of infrastructure works in the Philippines and globally.

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Table 21: Cost multipliers based upon site specific risks

Effect	Site Specific Risk Rating			Multiplier applied to:
	Low	Medium	High	
Typhoon Waves	0%	7.5%	15%	Marine works costs *
Typhoon Winds	0%	5%	10%	Land based structures costs #
Seismic (Earthquake) on Structures	0%	5%	10%	Marine works costs * and land based structures costs #
Flooding	0%	17%	33%	Civil works costs
Seismic (Earthquake) on M&E Equipment	0%	5%	10%	Mechanical and Electrical Equipment

Note: * For marine works costs, the highest multiplier for typhoon waves and seismic (earthquake) on structures is adopted; # For land based structures costs, the highest multiplier for typhoon winds and seismic (earthquake) on structures is adopted.

4.11.4. Capex Summary

Table 22 summarises the expected capital costs for each site. All sites have been assessed on the basis of an onshore terminal or alternatively an FSRU moored alongside a jetty. Refer to Appendix D.6 for the original table.

Table 22: Cost estimate summary comparison REDACTED

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The costs have been split into three main components as follows:

- LNG Terminal cost (including FSRU if applicable);
- CCGT Power Plant cost;
- Electrical Transmission Connection costs.

Of these three components, the cost of the LNG terminal and electrical transmission network show the largest variation. The costs of the CCGT power plant are similar for each site and vary only due to the relative seismicity and flooding risk of the site.

As expected, the analysis shows that the FSRU option is the least expensive option for all sites. Costs of the FSRU based options vary from US\$ [X]m to [X]m. The cost differences arise primarily from the differing electrical transmission network costs for each site – the [X] site has the highest electrical transmission network costs at US\$ [X]m.

For the onshore terminal options, the cost differences between all the sites is relatively small and the overall costs vary from US\$ [X]m to [X]m. Again the cost difference is driven partly by the electrical transmission network costs but also by the cost of the LNG terminal. The LNG terminal costs vary from US\$ [X]m to [X]m. These costs are primarily driven by the marine works costs (length of jetty and shoreline protection) and the cost of site formation works (cut/fill and stabilisation works). The relatively high cost for the Meralco site reflects that the site is understood to be sloping requiring cut works and/or reclamation to form a suitable platform for the terminal and power plant.

4.11.5. Opex Cost Estimates

Not considered by this study.

4.11.6. Gas Pipeline Transmission capex

Site specific gas transmission capex

The capex costs above include for electricity transmission and distribution. Alternatively, natural gas may be distributed by underground pipeline to power plants or other users located closer to demand centres. Table 23 shows the expected costs of transmission by gas pipeline with Manila being the demand centre served by the pipelines. The costs presented below include purchase of land or any land rights issues which are assumed to be handled at Government level.

Table 23 – Capex of Gas Transmission network (US\$ millions)

Site Reference	1	2	3	4	5
Proponent	Shell	First Gen	Meralco	Energy World	AG&P*
Closest proposed DOE Gas Pipeline	BatMan 1	BatMan 1	BatMan 1	BatMan 1	BatMan 2
Assuming BatMan gas pipelines are constructed	13	13	290	264	13
Assuming BatMan gas pipelines are not constructed	277	304	502	475	370

Note: * For the AG&P site, gas distribution to Manila could be via submarine pipeline (across Manila Bay) or overland pipeline (around the North side of Manila Bay). For the purpose of this exercise only overland pipelines were considered. Submarine pipeline from Limay to Manila is not considered by this report.

Assuming BatMan 1 & 2 is constructed, sites 1, 2 and 5 would be located adjacent to the BatMan pipeline and therefore connection costs are minimal when compared to the other sites. Even if the BatMan is constructed, both Meralco and Energy World sites still have considerable connection costs associated with linking up to BatMan for onward distribution to Manila or Batangas. For these two sites, electricity transmission is a cheaper option and likely to be considered first by developers.

Alternatively, assuming BatMan is not constructed, gas transmission costs are assessed on the basis of total cost to the consumer. This scenario assumes that gas pipelines to Manila represent an additional cost to each site and it can be seen that these costs represent a large additional cost (perhaps a quarter of the overall cost of the terminal and power plant).

Commentary on transmission options

The following provides commentary on mitigating the Batangas/Manila Electrical Transmission Constraints in the context of the proposed gas network

If BatMan 1 is constructed, then this will enable both the Shell and First Gen LNG terminals to distribute natural gas by pipeline to power plants which are located outside of any transmission constraint areas, whilst providing backup gas supplies to the existing CCGT plants in Batangas. Based on the costs from Table 12, it is anticipated that BatMan 1 alone will cost in the region of US\$277-304 million, inclusive of land rights.

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In a scenario where BatMan 1 and 2 are constructed, this will allow the possibility for the proposed AG&P LNG terminal to distribute gas to Batangas to provide backup gas supplies for the existing CCGT plants. Based on the costs from Table 12, it is anticipated that BatMan 2 will cost around US\$370 million, inclusive of land rights.

If BatMan 1 is not built, the development of a LNG terminal in Batangas area can supply gas to the associated CCGT power plants nearby. The existing and committed electrical transmission network in the vicinity of Batangas has been assessed to a preliminary level and has shown to have a spare capacity to connect a proposed 800MW CCGT power plant.

When considering these issues, it is necessary to consider the holistic cost to the consumer. Based on this it would appear that upgrading the electrical transmission system will offer a more economical approach for addressing the power supply. Conversely, the availability of natural gas via pipelines could potentially have a large impact by opening up new markets in areas such as transportation and/or industrial facilities.

4.11.7. Conversion of an LNG Carrier to a FSRU

Some developers have suggested that they may convert an existing LNG carrier to an FSRU as part of the LNG receiving terminal. There are potential significant cost savings with the conversion of an existing carrier over a new build FSRU.

Carrier conversions to FSRUs can be achieved at around US\$70-100 million (including vessel acquisition) leading to significant capex reductions. The time required for conversion and retrofitting is likely to be substantially shorter than the construction of a new-build vessel or land based terminal.

There are several parameters that need to be investigated in detail when considering the conversion suitability of an LNG carrier to an FSRU including:

- Carrier capacity – smaller vessels restrict the LNG shipment size meaning that only smaller LNG carriers will be able to transport LNG to the terminal. The small capacity will also require more frequent shipments.
- Carrier age and condition – the material state of LNG carriers is usually good so options for life extension of even older carriers can be considered. Consideration must be given to whether to repair, replace or remove vessel systems. If the FSRU is not required to move under own power, the engine and other marine systems are no longer required and may be decommissioned and removed.
- Sloshing – carriers are not usually designed for partial loads and, depending on the met-ocean conditions at the FSRU site, sloshing may be an issue that can cause high structural loads and damage to containment systems. Smaller carriers will experience lower sloshing loads.

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- Mooring – mooring options (i.e., alongside a jetty, spread moored, turret moored, yoke moored, etc.) have a significant impact on the conversion requirements and mooring choice is driven by the met-ocean conditions, soil conditions, infrastructure, etc. at the site.
- Space constraints – constraints on the vessel deck will need to be considered for the regasification equipment and the preferred thermal energy source (combustion of gas, sea water or ambient air) bearing in mind the space constraints on the deck.
- Class – if the vessel is a permanent structure or does not leave territorial waters then it may not require classification. If classification is required, for insurance purposes or if it is required to leave territorial waters, there are cost and programme implications.

In summary, it is feasible to convert an existing carrier to an FSRU and the life extension is dependent on the carrier age and condition as well as specifics about the site and mooring.

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4.12. BULK ENERGY TRANSPORTATION STRATEGIES

Task 1.3, as defined in the TOR, required that the *“Consultants need to explicitly address the trade-off between moving gas by pipeline or by electricity transmission line.”*

The choice between different strategies for bulk energy transport – coal lumps vs. piped gas vs. transmitted electricity – is a pressing issues in many different countries, for example:

- In China, where energy from the coal mines of the north-central provinces (Shaanxi, Shanxi and Inner Mongolia) is needed in the coastal demand centres such as Beijing and Shanghai up to 3500km away.
- In the US, where coal from the Powder River Basin in Wyoming is transported by rail to feed coal power plants throughout the country, whereas it could be transmitted over wires or even gasified.

The economic issues are often similar; but the regulatory and institutional issues unique to each country. In this section we first examine the economics of transporting the energy different distances. We then explore the institutional factors that benefit one approach over another.

4.12.1. Economic comparison

The relative economics of the two options are defined by the investment cost, transmission losses and the power plant efficiency. Table 24 compares the cost over 100 km to build an underground pipeline that could serve 3,000 MW of newly built combined cycle gas turbine power plant with a heat rate of 7 mmbtu per MWh operating in mid-merit, with the cost to deliver a peak of 3,000 MW along a new 100 km above-ground power transmission line. The distance dependence is illustrated in Figure 21.

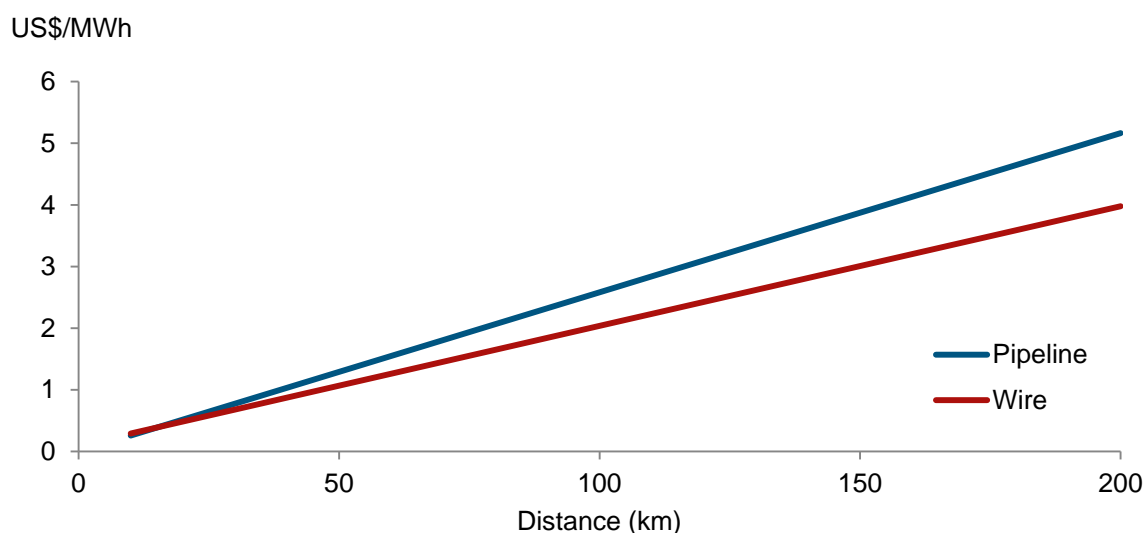
Our pipeline cost estimates are based upon the onshore pipelines under-construction or planned in Thailand and Indonesia and also take account of information from JICA on cost estimates for the BatMan pipeline. The power transmission line cost estimates (consistent with the earlier parts this section) include the purchase of land, and use a unit cost of US\$1/km/circuit. Since the Grid Code requires that there is N-1 contingency, the total unit cost is US\$2/km/circuit.

This is a high level comparison that shows it is less expensive to delivery power than to deliver gas for conversion to power. Other work we have done to date elsewhere has also come to this conclusion. We will delve deeper into the numbers in Phase Two of the Report.

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Table 24: Comparison of costs for transport over 100km

Onshore Pipeline (24 inch)		Wire (500kV)	
US\$/km/inch	110,000	USD/km/circuit	2
Peak mmcf/d	500	Peak MVA	3,000
Average mmcf/d	250	Average MVA	1,500
Average mmbtu/d	250,000	MWh per year	13,140,000
Average mmbtu year	91,250,000	Substation & Switching (US\$m)	10
Total cost (US\$m)	264	Total cost (US\$m)	210
IRR	12	IRR	12
Years	25	Years	25
Annual cost (US\$m)	34	Total cost (US\$m)	27
US\$/mmbtu	0.37		
US\$/MWh	1.26		
Efficiency at power	49		
US\$/MWh	2.58	US\$/MWh	2.04

Figure 21: Distance-cost relationship for pipeline and wire transport

4.12.2. Institutional factors in the Philippines

NGCP has a duty to ensure that generation companies are properly served by the electricity transmission grid, since one of NGCP's functions and responsibilities enumerated in Sec. 9 of the EPIRA is to:

... improve and expand its transmission facilities, consistent with the Grid Code and the Transmission Development Plan (TDP) to be promulgated pursuant to this Act, to adequately serve generation companies, distribution utilities and suppliers requiring transmission service and/or ancillary services through the transmission system: Provided,

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That TransCo shall submit any plan for expansion or improvement of its facilities for approval by the ERC” (Emphasis added)

Even though NGCP is authorised to exercise the right of eminent domain in so far as it may be reasonably necessary for the construction of the transmission grid (sec. 4, RA 9511), the practical exercise of gaining rights of way are difficult, costly and slow to obtain. The JICA study on BatMan (*Data Collection Survey on Utilization of Clean Alternative Energy in the Republic of the Philippines*, dated March 2012) highlighted that the issues of gaining access to building pipelines are, if anymore, more significant than those for wires.

Whilst the ERC has to approve the capex projects of NGCP, there has not yet been a major example of a generation company that was left stranded and unable to connect their new capacity. Even projects classified as ‘indicative’ by the EPIMB – such as RP Energy – appear to be catered for in terms of new transmission projects where it is beneficial for the wider grid.

A key difference in the Philippines between using wires or pipes is that, while not perfect, the way private sector proponents can connect to the existing transmission system, and the way the transmission system will be upgraded to deal with such connections, is relatively well known and understood. The construction of natural gas pipelines remains a big unknown. This alone gives transmission by wires a clear head start over gas pipelines on an institutional basis.

Where electrical systems need to be upgraded it is rare that there is no transmission at all in the area (the exception being where some of the new wind farms are being built in the North of Luzon). This means that there is often already an electrical easement pathway established and it is only a matter of upgrading the equipment to deal with more and higher voltages. This compares with gas pipelines where there are essentially no existing pipelines.

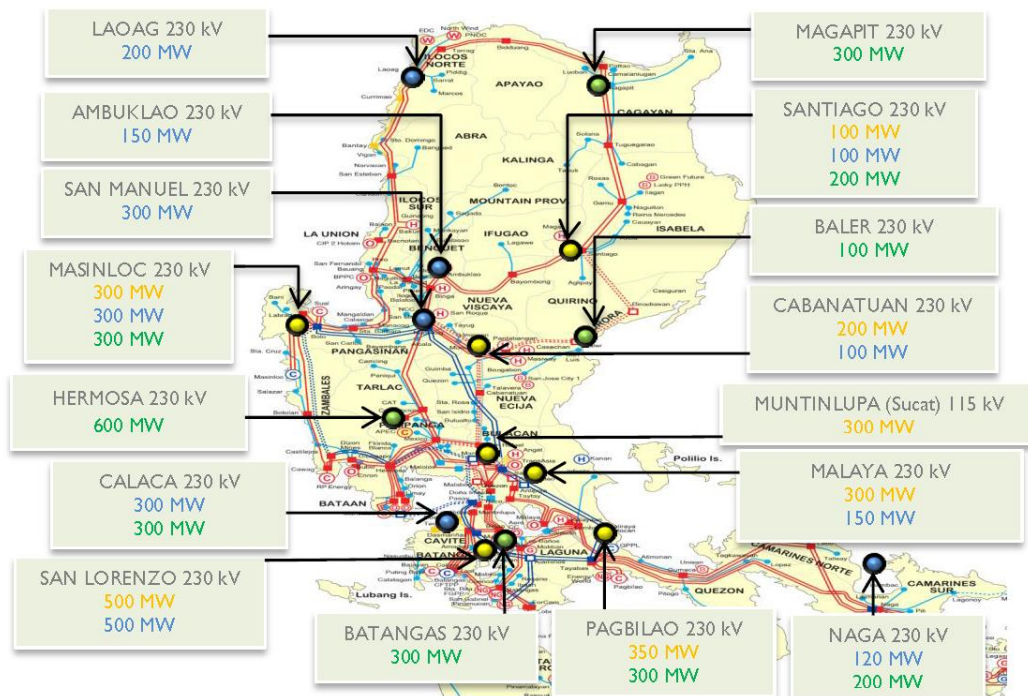
To put it another way, almost all transmission is a matter of upgrade (brownfield) development; pipelines are completely greenfield with no existing land easements and no history of how they will be obtained, priced or regulated.

Pursuant to the DOE Gas Circular (DC 2002-08-005), a permit from the DOE is required before anybody can undertake the construction of a gas transmission system. The DOE also reserve the right to permit applicants to submit the results of studies undertaken on alternative routes and options for expansion along these proposed routes. This implies that developers face the risk that the permitting process will be lengthy. Furthermore, since the route shall be “constructed following a route that will provide the greatest benefit to Customers”, it may not best serve the needs of any one project.

This tends to suggest that the power stations outlined in this report are best built in locations close to LNG terminals with the pipeline development being something that is not a critical path factor in the commercial development of any project.

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Figure 22: Locations where new power plants may connect without the need for any significant transmission reinforcement: yellow = 2011; blue = 2015; green = 2020



Source: NGCP TDP 2012

We will review in the Phase 2 report how this might impact on terminal development with respect to Batangas. Clearly, if “the” new terminal is NOT at Batangas, the first major pipeline that will have a commercial imperative will be a pipe from wherever the terminal is to Batangas. It may be that the EWC Terminal connections from Pagbilao to Batangas are the first to be tested in this manner.

If the first terminal is at Batangas, a fully replacement for Malampaya gas or an interim terminal being used mainly to displace oil, then there is no particularly strong need for a pipeline to support the power sector development for some time.

This gives time for the development of the Batman (or other) pipelines perhaps as a strategic investment and not necessarily with an anchor power load at one end.

These issues will be explored more in the later Reports.

4.13. CONCLUSIONS

4.13.1. Summary findings from the review

An engineering review has been conducted for six potential sites currently being considered for LNG terminal developments. The review has investigated the suitability of each site from a high-level engineering perspective and to provide factual information in an objective manner which can be used to inform the rest of the study. Commentary and assumptions have been made on the basis of the information provided and further study is required to verify the information.

The review considered the construction of a baseline LNG terminal and baseline CCGT power plant at each of the sites, with site specific parameters from the engineering review feeding into the capex analysis to determine relative cost differentials for all sites.

Based on the engineering review and the capex analysis, the conclusions are summarised as follows:

- From an engineering perspective, all sites are considered suitable for the development of an LNG terminal and/or associated power plant.
- The cost analysis undertaken adopting the assumptions described shows that the highest capex onshore site is around 14 percent higher than the lowest onshore capex site.
- Offshore FSRU options are cheaper at all sites, but there are potentially high risks relating to met-ocean and weather conditions (i.e., typhoons) which may require the FSRU to shut-down and/or move away from the terminal leading to supply disruptions.
- Electrical transmission costs vary significantly from US\$ 2 million for sites close to the existing network to US\$ 70 million for more remote sites. These costs include the likely expenditure by both NGCP and the power plant developer.
- If BatMan 1 and BatMan 2 are constructed, the cost of connecting the LNG terminal sites to the gas distribution networks varies from US\$ 13 million to US\$ 290 million. If BatMan 1 and BatMan 2 are not constructed, the cost of connecting the LNG terminal sites to the gas distribution networks varies from US\$ 277 million to US\$ 502 million.
- The DOE concerns on the transmission networks has been addressed within the individual site reviews, and summarised in the capex section above.

4.13.2. Further Analysis

As the engineering review was conducted at a pre-feasibility level of detail, further work is required to scrutinize some of the assumptions and to investigate the conclusions in further detail. It is recommended that any future analysis is to consider the following in greater detail:

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- Further power system analysis of the electrical transmission grid to confirm the connection options and system upgrades;
- Monitor the development of the gas transmission network;
- Further studies of the following risks at each of the sites are required including:
 - Tsunami risks
 - Social unrest
 - Resettlement issues
 - Variation in construction and labour costs in different parts of the Philippines.
- Investigate the expected cost variations of the developers preferred configuration for the LNG terminals; and
- Identification of demand and potential LNG consumers for each of the proposed sites.

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5. DOMESTIC GAS

5.1. INTRODUCTION

The TOR did not include a section on the domestic gas market in the Philippines; however, we proposed a review as part of our proposal. In our view, despite the overwhelming importance of LNG-related issues to the scope of this project and this report, it is not possible to do full justice to a review of options for LNG importation (including future magnitude of opportunity and risk) without at least considering the interplay between LNG opportunities and mechanisms and possible futures for the Malampaya field. This section therefore sets out a summary of our understanding of Malampaya and the issues that it represents for LNG options.

Details of the reconfiguring of the First Gen purchases from Malampaya are outlined earlier in Section 2.3.2 and our understanding of the current reserves situation at Malampaya is set out in Section 2.3.3.

As noted in Section 2.3.3, Shell has requested an extension of the Malampaya Service Agreement. Their rationale for the early request was that investments needed to firm up additional resources would take time to plan and implement and that they would need the certainty that the contract would extend beyond 2024 to make those investments. This section focuses on the implications for LNG of various options at Malampaya and how they inter-relate with the Shell LNG proposal (and other LNG terminal proposals).

5.2. CURRENT SITUATION

Firstly, it is worth summarising how the current agreement operates. All gas is owned by the Philippine government but extracted and marketed by Shell. The revenue from that gas is then split (simplistically) as follows: Firstly SPEX's costs are deducted. These can be up to 70 percent of the revenues and cover both operational costs and the costs of exploration needed to firm up additional supplies (cost component). Of the remainder, SPEX takes 40 percent while the Philippine Government takes 60 percent. The money accruing to the Philippine Government goes into the Malampaya Fund, which is managed by the Department of Finance and is primarily intended for energy-related projects, but it can also be used for other purposes approved by the President.

The revenues come from the sale of gas under (primarily) three gas sales agreements – one with PSALM (formerly NPC) for sale of the gas to Ilijan 1,200MW CCGT and two with First Gen for supply of gas to Santa Rita and San Lorenzo (together around 1,500MW) power stations. The gas for these three stations is sold on a take-or-pay basis that equates to a very high level of output from the stations. They must effectively operate at baseload or pay anyway. For much of the life of these plants, they have been running at levels higher than would be economically efficient: that is, without the take or pay, less gas would have been consumed and the power stations would have been running at mid-merit operation. More coal would have been burned and coal (the cheapest option) would have run baseload rather than mid-merit as it has since Malampaya gas started flowing.

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The cost to consumers of the Malampaya gas is born by consumers. First Gen sells all the output of Santa Rita and San Lorenzo to Meralco, who pass on all these costs to consumers in retail charges because these contracts have regulatory approval. Ilijan is an IPPA that was privatized. The residual costs of Ilijan to the Philippine Government are borne through the universal charge that PSALM collects from all consumers. Ilijan makes up a component of these stranded costs and debts, but not all.

We understand that the cost component of the Malampaya revenue flows is now very low – less than 15 percent of the total revenues and will not rise even with the additional development being done to enhance recovery in the field.

We understand that the contract was structured in this manner because of the high costs and difficulties of operating a deep field operation, however even taking into account the need for Shell to recover high cost and risky exploration investments through their share of the 40% gross profits, the residual 60 percent flowing into the Malampaya fund is effectively a wealth transfer from electricity consumers to the Fund. Presumably if the Fund is well managed, this money will flow back to consumers through energy related spending.

5.3. IMPLICATIONS FOR LNG OPTIONS

A key question is therefore:

How important is the continuation of the Malampaya Fund to the Government of the Philippines, or could the revenues from the (relatively small) volumes of gas left in the field be reduced to allow Malampaya to be used more “creatively” in the whole gas mix to help manage the entry of LNG?

In our discussions with SPEX, they highlighted that the Service Agreement did contemplate that extensions may have different commercial terms; however, no details have yet been discussed. SPEX indicated that they had been reviewing the potential for flexible operations at the facility, and their early conclusions were that flexibility would be best obtained through use of linepack in the pipeline rather than through changes to gas extraction profiles.

We understand that ramping gas fields up and down can compromise the reservoir and lead to a reduction in recoverable reserves.

SPEX have indicated that they would like to contract up the remaining gas in the field. For this to happen they would need certainty on the extensions to the Service Agreement in order to commit the investments in adjoining areas needed to firm up the reserves. SPEX believes that contracting up the remaining reserves to one party would resolve a key uncertainty in the market and assist the entry of LNG. The party who contracts for the gas is able to use it; everyone else wanting gas now knows they only have LNG as an option.

This raises a number of questions:

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1. At what price should Malampaya be contracted and who should decide that price?
2. When should such a contract be entered into and would it actually assist or deter LNG?
3. Given that the main role for gas economically (at world LNG prices) post 2024 is for mid-merit operation, flexibility is key. Malampaya has some potential to be flexible (at least in the short term if there is linepack that can be used). If SPEX are left unsupervised to contract up the remaining reserves, how can we be sure that flexibility will be used optimally?
4. As noted in Section 2.3.3, there is enough gas for about ten to fifteen years of operation in Malampaya. Presumably, if mixed with LNG, this could be extended and a mix of LNG and Malampaya gas may be a more flexible overall solution for the Philippines, particularly if a solution could be found whereby more LNG can be purchased if LNG prices fall while more Malampaya gas could be burnt during periods of relatively higher LNG prices. We discuss LNG purchasing strategies in the Phase 2 report but note that if LNG plus Malampaya are viewed holistically, there may be more options to buy economic quantities and would want to consider this further in the next Report. Strategically therefore, is Malampaya better as a strategic back-up for LNG after 2034, given its relatively small volume and short life?
5. If there were no gas contracted from Malampaya after 2024 (i.e., the Service Contract is not extended) then the market for LNG in the Philippines would be clear, and probably large enough to justify a terminal at that time commercially without any requirement for Government intervention as the commercial incentives on the owners of gas fired plant (of which there are only two, making decision making relatively easier) would drive action. SPEX note that contracting Malampaya provides certainty to the market to assist entry of LNG. Certainty of NO Malampaya in the market would achieve the same thing. However, this would probably be an inefficient use of a national resource. A similar outcome may be achieved if Malampaya is prevented from entering into any firm contracts and used solely as a back-up resource: for example, if FSRUs are used in Batangas, Malampaya could be used during typhoons or other outages although this is probably operationally infeasible.

We would need to understand the subsurface issues in order to know what level of swing is possible. Shutting in Malampaya for an extended period would probably not be viewed favourably by the subsurface people at SPEX.

6. How does the future of Malampaya impact on the proposed Shell LNG terminal? Shell is proposing an LNG terminal to be built at Batangas many years before (if Malampaya continues and if the plants no longer run baseload) it may actually be needed. Although a key advantage of a terminal at Batangas is that it could firm up Malampaya after it depletes (given the existing power station capacity there); a terminal not at Batangas may be more flexible and result in a less risky plant configuration where all the gas plants are in the same location.

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5.3.1. Operational Matters

Although SPEX have been the operator of Malampaya for some years, there is also the option to review this from 2024. We would not recommend giving up on an international operator all together as this is a complicated field and it is unlikely that the technical or managerial capacity to manage the depletion efficiently exists in PNOC. Nor does it necessarily imply the building up of a capability that can be used in other “similar” situations, as the move to LNG implies a very different gas future.

However, we do question whether or not SPEX should have an automatic right to continue or if the Government might wish to consider tendering out the operation to other suitably qualified operators. To do this they would have to have a clear contracting structure to reward risk and it is possible that SPEX (or Shell) may be the only bidders. This option may only have value if more innovative options for the use of Malampaya are considered and the existing operators are not co-operative.

We note, however, that any change in operator may result in a hiatus in field development and come with a risk that existing infrastructure is poorly maintained for the final years if the existing operator does not win the tender. These issues would need to be carefully balanced in any decision. Nevertheless, we understand that this is to be avoided as gas fields or their rate of production can be harmed if shut in for an extended period. So some mechanism should be decided on early to ensure continuous maintenance and care of the facilities and the gas field post-2024.

6. NEXT STEPS

The findings and options described in this Report will be discussed in a workshop held with the WB/DOE on December 13th.

APPENDICES

Appendix A: Power Sector Modelling Assumptions

Section 2 of this Report described some of our preliminary findings from modelling the evolution of the WESM in Luzon and the Visayas. In this Appendix we describe the development of our preliminary modelling assumptions that underpin these initial results.

A.1 Modelling framework

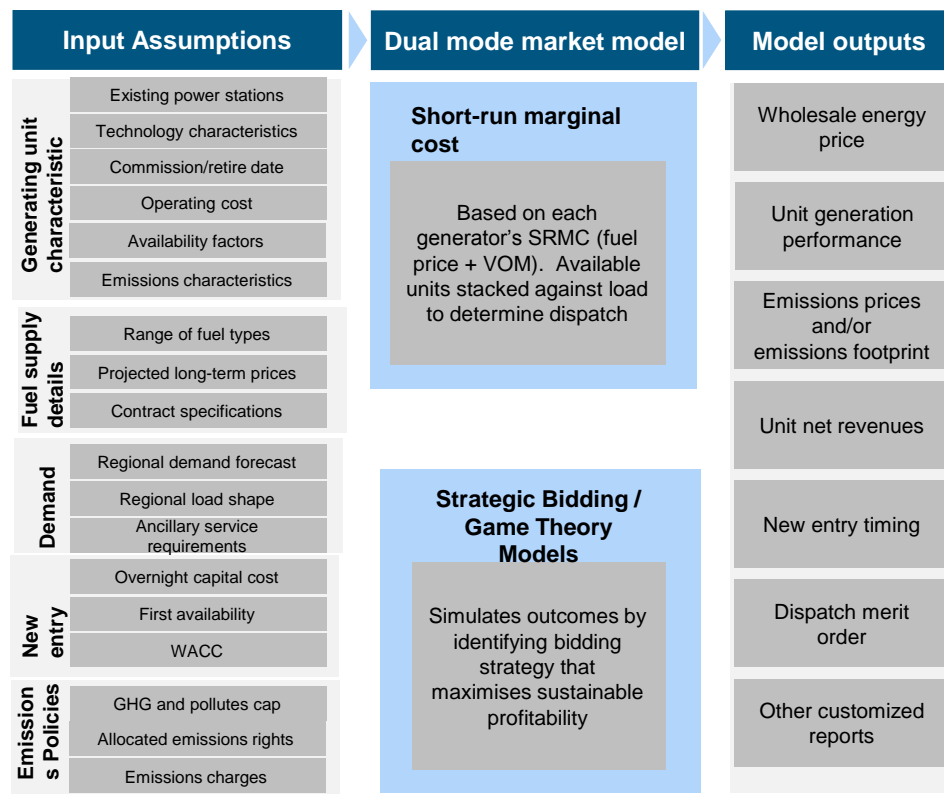
We are using our in-house proprietary QUAUFU market model to estimate the potential utilization of gas in Luzon and Visayas. QUAUFU has been used extensively over the past six years in the Philippines for a wide variety of clients and we have performed specific analysis on the WESM using QUAUFU for planning coal, gas, geothermal, hydro, wind, oil and diesel-fired units. It has proven to be both robust and adaptable to answering many different commercial and economic issues.

Fundamentally, QUAUFU is an integrated least-cost and bidding-based generation dispatch modelling tool that incorporates state-of-the-art optimisation theory grounded in proven techniques. It is based upon a security-constrained optimization linear / non-linear program (LP/NLP) in the General Algebraic Modelling System (GAMS) language and it is solved using CPLEX commercial solver.

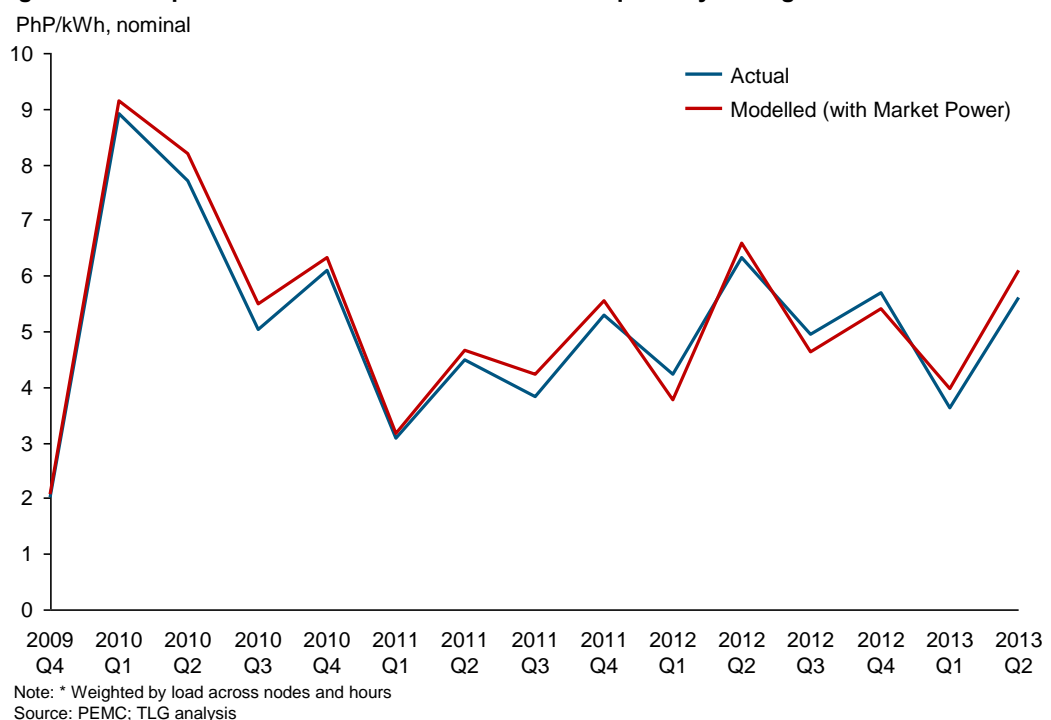
QUAFU provides a rigorous framework, as illustrated in Figure 23, to develop insights based on key drivers of value by:

- handling complex commercial and physical dynamics of an energy market;
- dealing with transmission constraints and other locational variables;
- incorporating strategic behaviour among competing suppliers; and
- supporting robust risk assessment associated with real-world uncertainties.

The model seeks to achieve the least-cost investment in, retirement of, and operation of generating units over the planning horizon which may span a few decades, while observing the physical realities and security policies necessary to operate the power system securely. Hence, rather than committing plants that are merely in the planning stages (and thus very uncertain), QUAUFU can develop a view of when and in what form it is most economic for capacity to enter the market.

Figure 23: Illustration of the QUAFU modelling framework

Using this approach, QUAFU is able to reproduce past price movements reasonably well without resorting to 'over-fitting' via unrealistic constraints, as illustrated in Figure 24.

Figure 24: Comparison of actual and modelled Luzon quarterly average LWAP*

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A.2 Factors included in dispatch modelling

In this section, we identify key factors that we incorporate in typical market modelling of the WESM. Relevant values for these key factors are discussed elsewhere in this Appendix. Not all factors are crucial to each analysis, but the following are accommodated in the modelling framework and dataset.

Generating unit characteristics

- Name and owner – allows us to associate groups of units by a common owner in the event that the owner's overall market share confers market power (in which case this information affects the optimal market-based bidding strategy calculated for that owner's portfolio).
- Technology characteristics (capacity, type, heat rate, auxiliary energy requirements) – establishes the basic technical performance characteristics relevant to establishing short-run marginal cost and the underlying merit order.
- Commissioning/retirement date for existing or committed new capacity – allows us to force capacity in or out at any point in the model horizon.
- Overnight capital costs, first availability date, associated weighted average cost of capital and pre-commissioning capital expenditure profile for relevant new technologies – allows us to specify the economics of new entry technologies so that the model can choose the appropriate new entry technology based on a commercial viability basis or for least-cost system expansion.
- Operating costs (variable and fixed operations and maintenance costs) – variable operating and maintenance costs influence the short-run marginal cost. Fixed operations and maintenance costs are captured but they are not used in the modelling of dispatch or bidding behaviour (although they will affect the amount and type of economic entry).
- Availability factor, net of scheduled and forced outages – allows the model to establish the maximum dispatch level achievable after taking the forced and unforced outage rate over the modelling period into account.
- Applicable energy limits for energy-limited plants such as hydro or fuel-constrained units (e.g., Malampaya gas) – energy limits determine the extent to which a unit is expected to generate over a period. A flexible energy limited plant (such as a gas-fired CCGT unit with a take-or-pay gas contract for an output level that is less than the unit's full "baseload" operational capability) will have the flexibility to generate during periods that confer the greatest profitability. An inflexible energy limited plant (such as wind or run-of-river hydro) will generate to a resource availability profile.
- Unit auxiliary consumption consistent with electricity demand data – depending on the measurement location of demand data, an adjustment may be required to account for a unit's "own" use of electricity during operation.

Fuel supply details

- Range of relevant fuel types – we specify the eligible fuel types for association with specific plants as well as new entry technologies. Fuel types can be plant specific or generic for a technology “class” (e.g., “coal” versus “Plant A Coal”).
- Corresponding projections of long-term market fuel prices and availability.
- Applicable terms of fuel supply contracts, including take-or-pay provisions and minimum and maximum quantities.

Demand (peak demand and energy)

- Regional demand forecast organised by relevant period or block – for long-term modelling we utilise a load duration curve which is represented using a number of load blocks ranked from lowest to highest. More load blocks are defined for those portions of the load duration curve that are particularly important determinants of prices and dispatch decisions. We create the load duration curve using historical data and estimates of the projected growth rate of maximum demand (MW) and total electricity consumption or generation (GWhs).
- Value of Lost Load (VoLL) – effectively the market price cap, which is used to set maximum market prices in the event of supply insufficiency (triggering additional entry for reliability or commercial reasons).

Transmission details

- Transmission limits and loss data – define the directional constraints between regions and the energy lost from flows between regions.

REST OF APPENDIX REDACTED, CONFIDENTIAL.

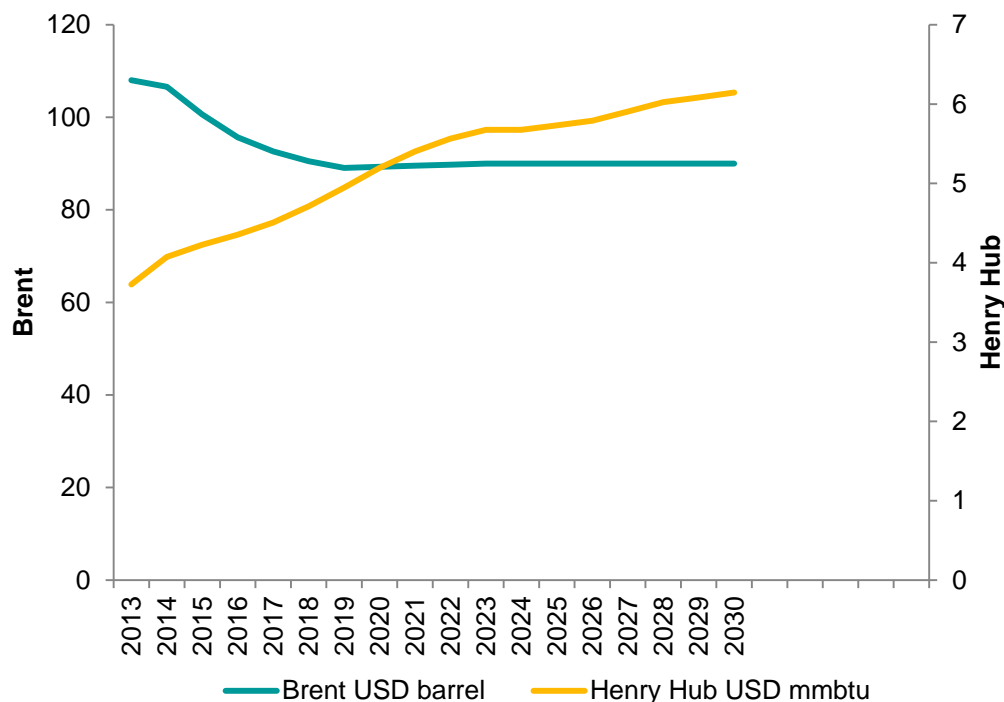
Appendix B: Preliminary thoughts on LNG bulk purchasing role and advice on how this should be structured

B.1 Summary

There are expected to be greater volumes of LNG traded on a short-term basis in future. This plays to the needs of LNG demand in the Philippines. Demand, at least in the first few years, will be determined by the requirements of combined cycle power plants competing in the mid merit part of the load curve. The level of demand could be subject to variation depending on the amount of water in the hydro power plants and the level of competing new build especially from coal-fired plants. If a power purchase agreement can be negotiated for a certain amount of electricity then this could underpin a back to back agreement for a fixed amount of LNG. But a feature that has emerged from investigations to date of the WESM power market on Luzon and Visayas is concern among the operators or retailers about the amount of mid-merit power that they need. Therefore the growing level of flexibility that we see in the LNG market will be helpful for the Philippines. The level of gas-fired mid merit power needed is subject to uncertainty and so flexibility on LNG supply is a benefit.

B.2 Key commodities

We summarise our outlook for Brent and Henry Hub in Figure 25. Through to 2020 the Brent price comes from the ICE forward curve and the same is true for Henry Hub to 2018 using NYMEX. Thereafter we assume flat real for Brent and a gradual rise in real terms for Henry Hub. These prices have an impact on the potential prices that different sources of LNG will be seeking.

Figure 25: Brent and Henry Hub forecasts (real prices)

B.2.1 LNG price scenarios

These key commodity forecasts result in three LNG pricing outlooks. If demand is tight then prices to Asia will tend towards the High Case and if there is oversupply and gas to gas competition in the short term market then prices in Asia will tend towards the Low Case. We chart a path through these possible pricing scenarios with our 'blended' LNG price forecast (Figure 26).

High Case

This reflects the premium that we believe reliable safe established sellers such as Qatar and Australia will aim to achieve: a slope of near 15 linked to Brent. Australia also needs this kind of price formula to justify investment in new LNG plant.

Mid Case

This is set by suppliers such as East Africa who will be new to the game will have to price themselves into the market. We assume a 13.5 slope half linked to Brent and the other half to Henry Hub.

Low Case

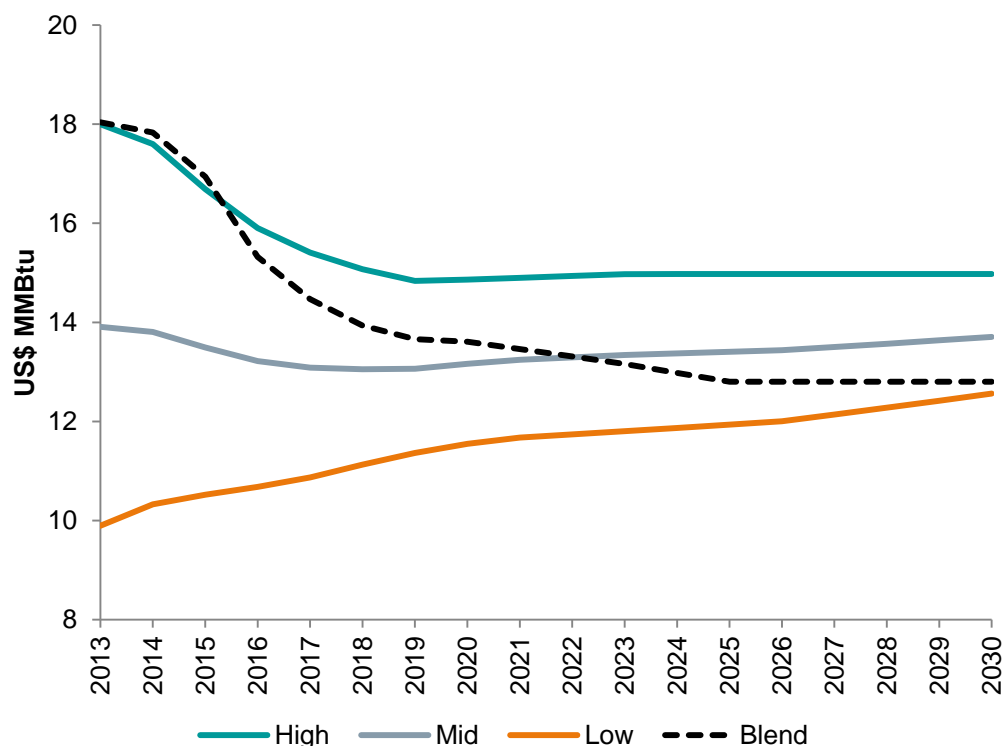
This is Gulf Coast USA Henry Hub times 1.15 and liquefaction of US\$3/mmbtu. For shipping we have assumed half goes via Panama and half goes east. This Low Case rises through to the middle of next decade as Henry Hub recovers due to LNG exports even as Brent is under pressure due to greater supply from US shale oil.

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Blend for Modelling

We have used a slope that declines from 14.85 in 2013 to 12.00 by 2030 and approximated a shipping cost of US\$2/MMBtu. This decline in LNG pricing captures the effect on the global market of US LNG exports.

Figure 26: LNG scenarios and LNG price used for modelling

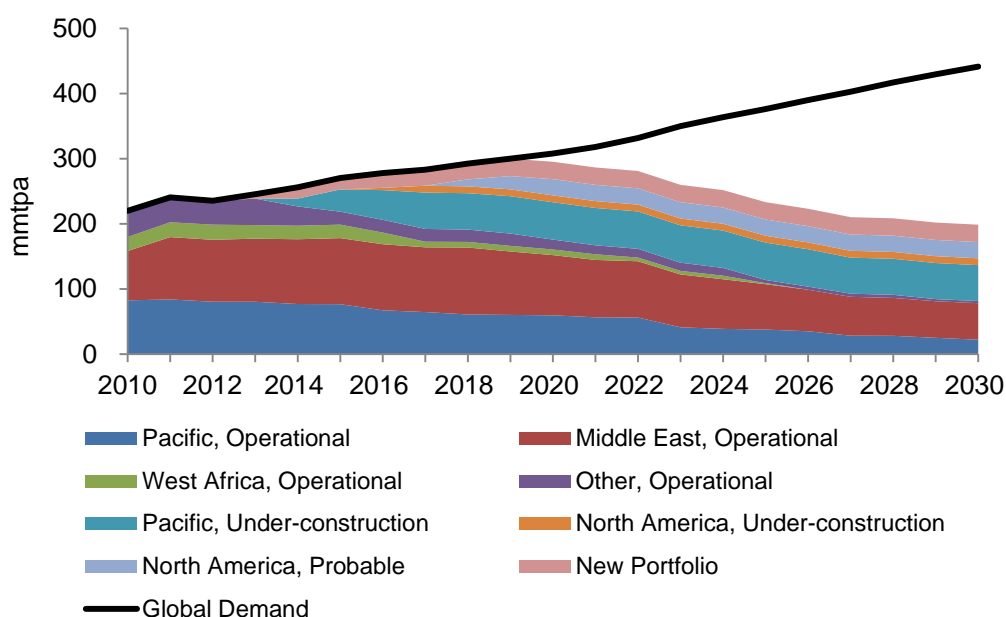


B.3 Supply-demand review

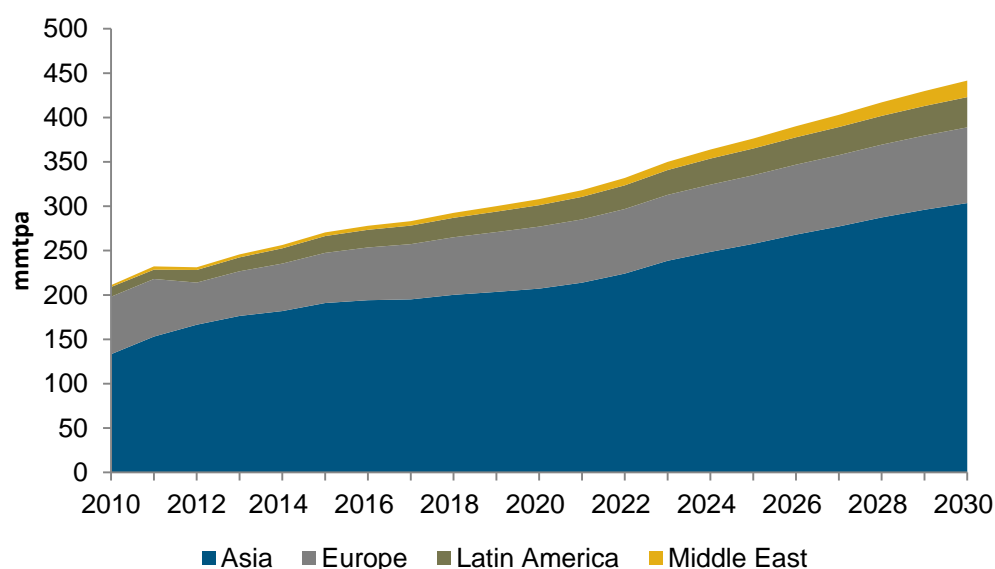
B.3.1 Global picture

We built up global demand for LNG by developing a global model for energy demand by country or regional block. This demand was split into power and non-power, which was further itemised for the larger markets into transport, industry, residential and commercial. We then drilled down to further to itemise the different types of fuel used by those sectors and separated piped gas from LNG.

We matched contracted supply to demand by country when there was specific contract. But a key feature of demand is the relatively large and growing amount that we expect to be met by portfolio players or from uncommitted supply. This is the grey area at the top of the graphic.

Figure 27: Global LNG demand supply

Asia dominates demand outlook and within that area China, India, Japan and Korea are the main users.

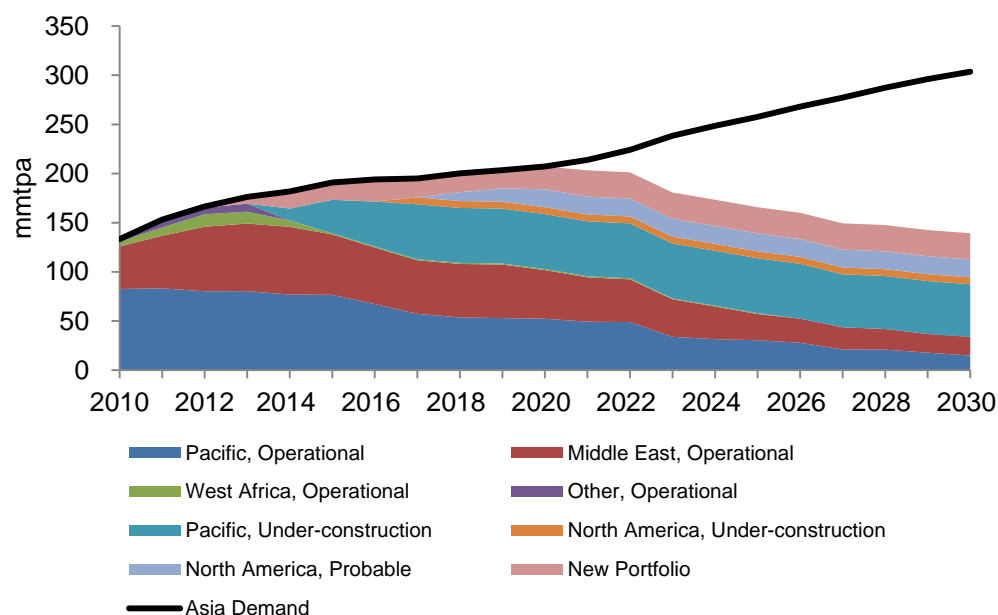
Figure 28: Global LNG demand

B.3.2 Asia outlook

We drilled down deeper on the demand supply balance side for Asia. Note again that portfolio supplies account for a large part of the market balance through to 2020. Supply is based on projects that are existing, under construction, or have reached final

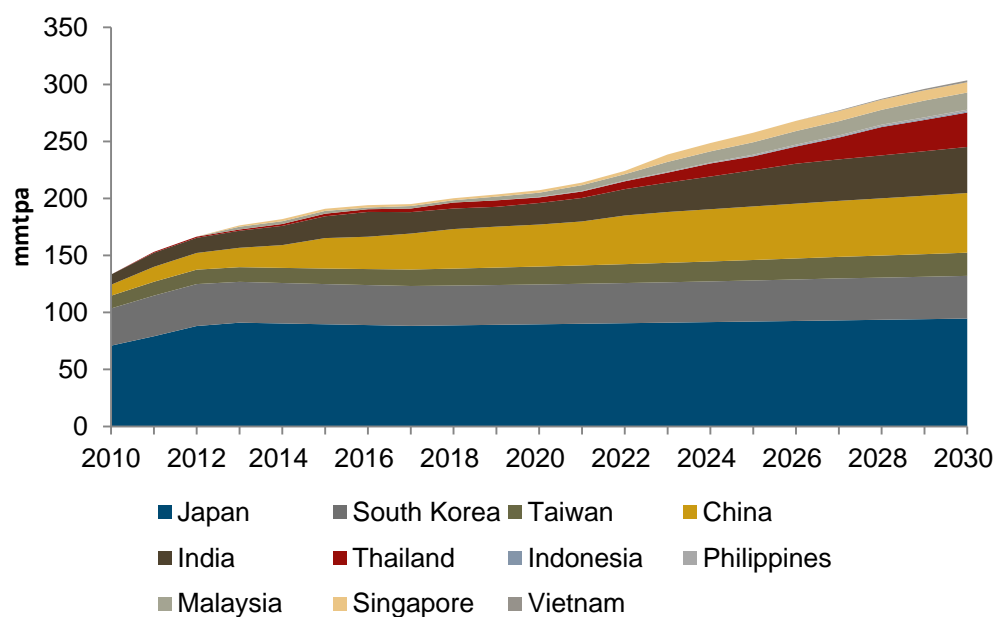
investment decision and a handful of projects we believe are likely to get final investment decision soon.

Figure 29: Asia LNG supply



Our Asia demand forecasts are shown in Figure 30. As we mention elsewhere in the report all forecasts especially for the larger markets of China, India, Japan and Korea are subject to a large amount of uncertainty. What is also of interest is the emergence of the nations of South East Asia as LNG importers. Singapore, Malaysia and Thailand already have operating terminals and later on come the Philippines and Vietnam.

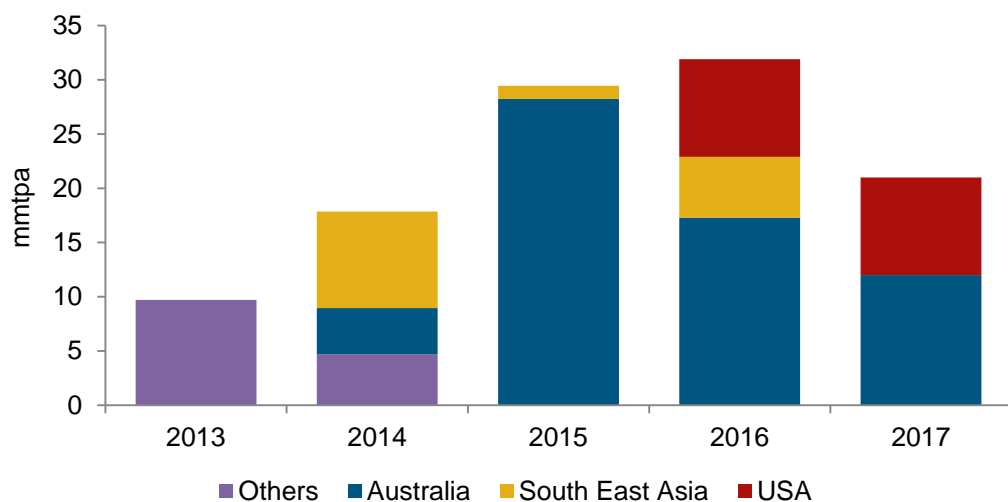
Figure 30: Asia LNG Demand



B.3.3 Growing presence of short term and portfolio in supplies

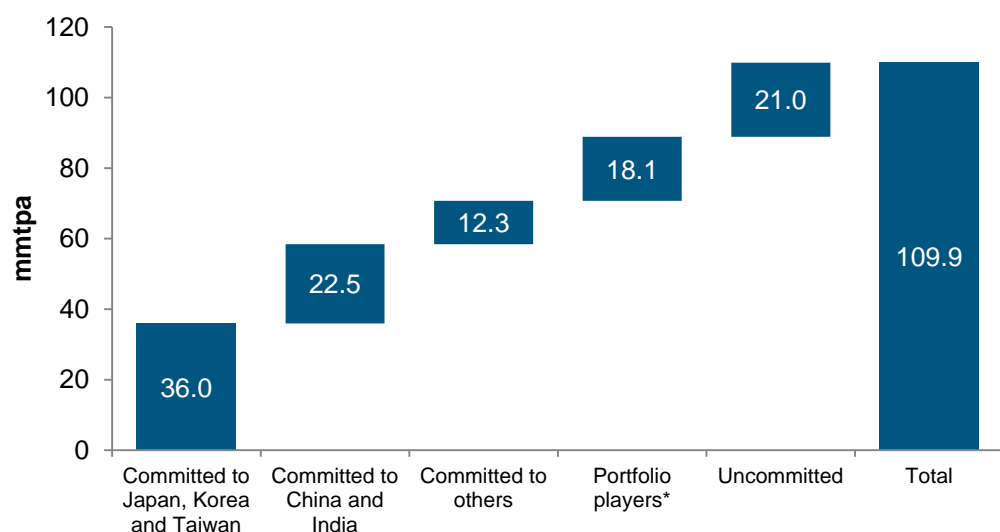
We calculate that there is just shy of 110 mmtpa of LNG plant under construction or at final investment decision. A large amount of expensive plant in Australia is expected to be commissioned between now and 2017. But also note the first US LNG plant is expected in 2016 (Cheniere at Sabine Pass). In addition, there are some LNG plants located in South East Asia in Papua New Guinea, Indonesia and Malaysia that are expected to start between 2014 and 2016. Within that South East Asia capacity is Sengkang LNG, led by Energy World Corporation.

Figure 31: LNG plant capacity under construction or at final investment decision



A key feature of the 110 mmtpa of LNG plant capacity that is coming to market by 2017 is that a good 40 percent of that total either goes to portfolio players or else at the time of writing is uncommitted. We believe this 39.1 mmtpa of LNG will mostly be sold on a short term basis.

Figure 32: LNG Plant volumes committed by destination, portfolio players, uncommitted



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B.4 Traditional contracts

These have been compared to a “virtual pipeline” linking a specified source of gas with a specified buyer at one receiving terminal. These contracts are usually delivery ex-ship, or if free on board, then will have diversion exclusions written into the contract to prevent the buyer from reselling the LNG elsewhere. Thus avoiding potential competition for new volumes of LNG that maybe marketed by the seller.

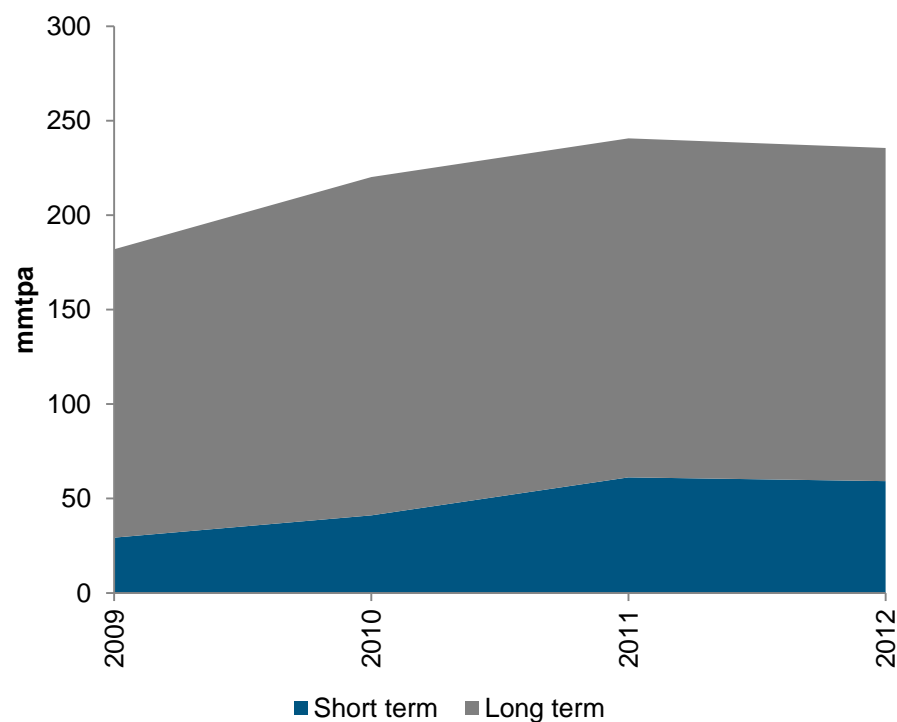
We would recommend that for the Philippines where demand is uncertain and given the other favourable dynamics that are evolving in the global LNG market that traditional LNG long term contracts, with high levels of take or pay, and destination clauses are avoided.

B.5 Short-term volumes

Short-term volumes have grown dramatically the last few years. In part this has been forced on the industry as demand in Europe fell dramatically. But by co-incidence demand for LNG by Japan rose by almost the same amount. The rise in demand by Japan is of course a result of the shut-down of nuclear plant in that country.

The experience of renegotiating and diverting committed and portfolio cargoes from Europe to Asia was described to us by one portfolio player as “a huge upheaval”. But we believe it has shown to both seller and buyer the value that exists in flexibility.

Figure 33: Mix of short-term and long-term LNG contracting (2009-12)



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B.6 Uncertainty

We have run various gas demand supply balance forecasts for the big LNG buyers in Asia such as China, India, Japan and Korea. Each one is the subject of large uncertainty. What this means for the LNG business is that like it or not the amount of LNG that will be traded on short term contracts must be set to grow in order to cope with this uncertainty. Some of the key demand uncertainties are listed below:

China

- Will shale and coal bed methane deliver significant amounts of gas or will they disappoint, leading to a greater need for LNG and/or Russian imports?
- Will the drive to clean up air quality really gather momentum? If so then there could be very significant demand for gas for power.

India

- Will the Rangarajan committee proposals that are set to double local gas prices result in greater supplies of domestic gas and thus lower the need for LNG?

Japan

- Each 10 GW of nuclear plant that is restarted lowers the demand for LNG by 4 mmtpa.
- Another initiative by the government is to try to significantly lift the amount of renewables in the power mix. If Japan really can lift renewables to 25 percent from 13 percent of generation then this could lower demand for LNG by close to 6 mmtpa by 2030. (Assuming only 10.6GW of nuclear is restarted).
- Just to further confused the outlook it was recently mooted by government that the de-facto ban on new coal-fired plant might be lifted.

Korea

- The last power plan contained a large push in favour of nuclear power plants.
- But this all changed just recently in favour of gas and coal. The existing nuclear power plants have been facing reliability problems and there are concerns about the lower quality of parts used for maintenance.

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B.7 US LNG

B.7.1 Flexibility enabler

The point that is worth driving home again is that US LNG is completely different in structure from any other source of LNG. What the buyers are signing up for are capacity liquefaction rights at the different plants on a tolling basis. They will typically sign up for 20 years with a fixed annual payment – this is a take it or lose it arrangement. Then there will be a small add-on charge for operations and maintenance charge and berthing based on usage. We expect that these liquefaction capacity rights will be transferable (as was the case with now largely worthless regasification terminal capacity rights).

Table 25 – US LNG export plants

Group	Project	DOE application				FERC application			Capacity, mmtpa	
		Requested volume, bcf/d	FTA approved	Non-FTA application submitted	Non-FTA approved / DOE order	Pre-filing completed	Filing completed	Filing approved	Terminal total	Group total
Non-FTA	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	29.1
	Oregon LNG	1.3	✓	✓	2	✓	✓		9.6	
	Corpus Christi	2.1	✓	✓	3	✓	✓		13.5	
Non-FTA pending, pre-filed with FERC	Excelerate	1.4	✓	✓	4	✓			8.8	30.4
	Southern	0.5	✓	✓	6	✓			2.5	
	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	
Non-FTA pending, no FERC pre-filing	CE FLNG	1.1	✓	✓	8	✓			8.0	73.2
	Gulf Coast	2.8	✓	✓	5				20.6	
	Golden Pass	2.6	✓	✓	9				15.6	
	Pangea	1.1	✓	✓	10				8.0	
	Main Pass Venture	3.2	✓	✓	11				24.0	
Only applied for FTA license	Waller	0.2	✓		14				5.0	6.8
	Magnolia	0.5	✓			✓			1.3	
	Gasfin	0.2	✓						4.0	
									1.5	

B.7.2 Pricing structure

The buyers will buy gas at Henry Hub (usually plus a small premium) as and when they want to, then liquefy the gas for export. The levelised real liquefaction tariff comes close to USD 3 per mmbtu in most cases. Then the final element is the shipping which to Asia is quite expensive and likely to come close to USD 3 mmbtu depending on route and engine technology.

B.7.3 Size of reserves

The Energy Information Agency, drawing on research from various other bodies such as the US Geological Survey, puts the size of US technically recoverable reserves at close to 2,200 Tcf. Demand in the US was 24 Tcf in 2012. There is expected to be a rise in demand for gas from US transport and petrochemicals as these sectors take advantage of low prices. This 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. Moreover most analysis points to there being further

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technically recoverable resources to be discovered as and when the Henry Hub price recovers.

B.8 Canadian LNG

6.1.1. Problems with experience and alignment of players

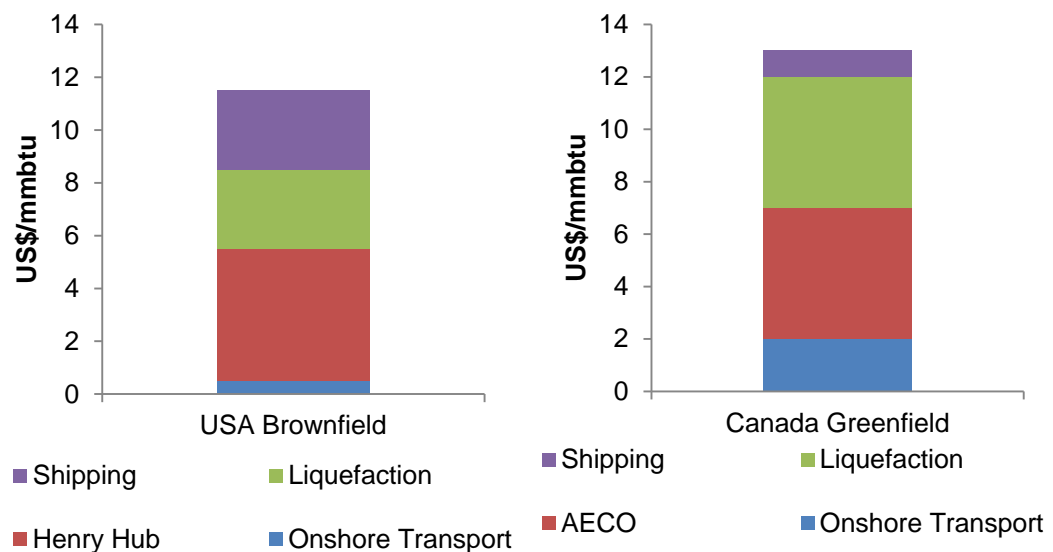
There has been some rationalisation in the shareholding of some proposed west coast Canadian LNG projects. Some more experienced heavy weight LNG players bought out the original shareholders.

- Chevron now leads the Kitimat LNG project, with Apache as a minority partner and with EOG Resources now departed. This project is located in Bish Cove.
- The Pacific North West LNG project was given a boost when Petronas bought the owner Progress Energy in an agreed takeover. Having JAPEX as a minority shareholder will assist with entry to the Japanese market. This is located in Prince Rupert Sound.
- The BG Group has plans for a large terminal in Prince Rupert Sound.
- Most recently ExxonMobil entered the list of those with grand ambitions for LNG exports from west coast of Canada either from Bish Cove near Kitimat or else Prince Rupert Sound.

Each of these projects has separate plans for pipelines to access mainly shale gas resources located further in land. With hindsight the three CBM LNG projects at Curtis Island in Australia realise they could have saved costs (and perhaps improved security of supply) by sharing infrastructure. We wonder if this lesson will be applied to those projects clustering around Prince Rupert Sound?

6.1.2. Closeness to Asia markets

All the west coast Canadian projects emphasise that they are only 9 to 10 days distant from Japan. Whereas US Gulf Coast LNG plants either face a 20 day trip if using the Panama Canal or 32 days if heading east. But we believe that the extra costs associated with green field new build LNG plants in Canada versus mostly brownfield in the USA, coupled with the need for new pipelines to access sometimes distant gas fields in Canada versus the shorter build out of pipelines needed to access the US pipeline network in the Gulf Coast, outweigh the extra shipping cost faced by US LNG to reach Asia. This is illustrated in Figure 34.

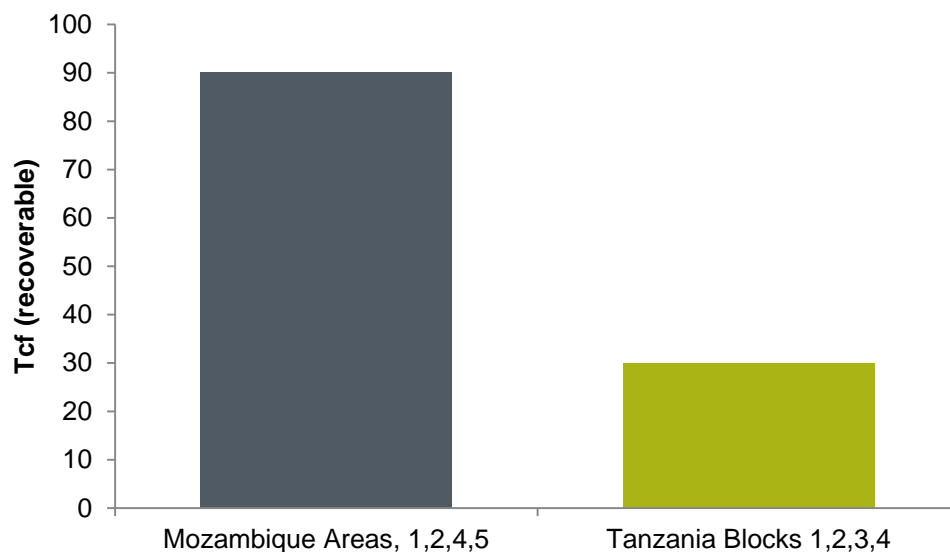
Figure 34: US versus Canada break-evens

6.1.3. Pricing probably linked to crude

Western Canadian LNG projects which are more typical in that they specify a source of gas, will build dedicated new, usually 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 some aspirants. Pricing might be oil linked or linked to AECO (Canadian version of Henry Hub). Less progress has been made marketing west coast Canadian LNG than is the case with US LNG.

B.9 East Africa LNG

There have been huge gas discoveries in reserves in Tanzania and Mozambique. These are very much a moving target but a summary is provided in Figure 35.

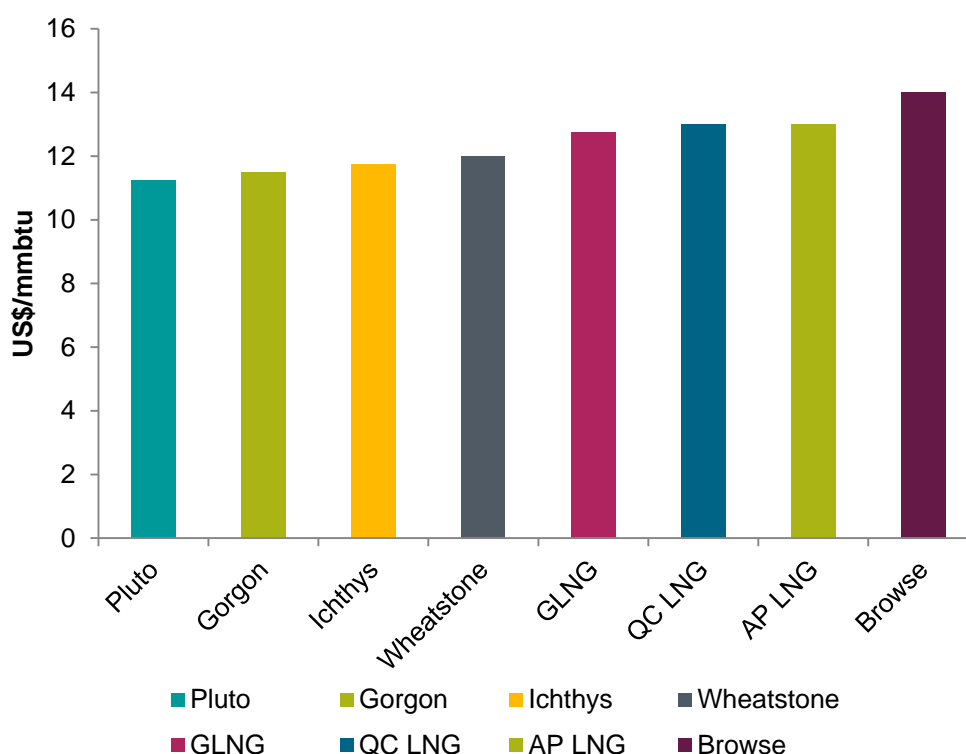
Figure 35: Mozambique and Tanzania gas resources

There are many challenges before this gas gets to market as LNG. Firstly, there is regulatory uncertainty which is particularly true for Tanzania. There is confusion over the role of the mooted new National Oil Company (NOC) and existing de-facto upstream regulator Tanzania Petroleum Development Corp, and requirements for gas and infrastructure to support domestic industry. This said, Tanzania has experienced LNG player leading developments in the shape of the BG Group.

Mozambique has less experienced LNG players. Anadarko is relatively new to LNG. ENI has experience via VICO at Bontang in Indonesia and Statoil has cut its teeth in its Snøhvit LNG plant. Some customers have bought in such as ONGC, Bharat Oil, PTTEP and Mitsui. On the plus side the country has a master plan sponsored by the World Bank and hopefully this will enable a balanced exploitation of resources. One that supports the build out of domestic industry while at the same time realising that large amounts of the gas will need to be exported as reserves totally eclipse local demand.

B.10 Australia LNG

The sharp rise in costs right across the LNG production chain has caused several upwards revisions to project costs as summarised in Figure 36. Negotiations by buyers with greenfield and even brownfield developers have quietened down as the focus among buyers has very much swung to getting US LNG.

Figure 36: Australian LNG plant all-in break-evens at 18% IRR

B.11 Creditworthiness of buyers

B.11.1 Power

An approved Power Sales Agreement would help convince LNG suppliers to sign a long term contract with the consortium running the power plant. As is noted elsewhere in this report convincing the Energy Regulatory Commission that a CCGT using LNG is a least cost method to serve mid merit demand does face some challenges.

On the other hand if some sales were also planned to be sold into the WESM on a spot basis then an analysis of the level of dispatch of the CCGT plant could be provided by simulation of the power market to justify a certain level of demand for LNG. Many of the proponents of LNG-to-power projects have done just such a study. In this case LNG could be bought on a short term basis under a master agreement as we discuss later.

B.11.2 Non-power

We expect demand for trucked LNG to industry and via LCNG into transport to emerge in time. A key player or players that will need to arise in order to get LNG to industry are gas aggregators. We have seen such new gas players or mini-aggregators emerge to supply gas to industry in Indonesia following the liberalising Oil and Gas Law 22/2001.

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B.12 Buying LNG directly

The LNG business is sometime compared to a country club. It is choosy about whom it lets in. Being accepted as a credible buyer of LNG and so let into the club is an informal hurdle to overcome.

B.13 Buying LNG from a portfolio player

An increasing amount of LNG comes from portfolio players such as Total, Shell, GdFSuez, BP and the BG Group. By this we mean that the source of the LNG is not identified in the LNG supply agreement nor is there a destination. It is usually taken onto their books and they will sell it on short term basis or else lock in longer term contracts as market conditions dictate. Delivery would usually be ex-ship so portfolio players are also attempting to optimize their LNG carrier fleet.

B.14 Buying LNG from an nearby LNG Hub

Singapore has clearly marked out its ambitions to become a LNG trading hub. It is building more storage capacity than it needs for its own domestic use. Moreover, it is adding jetties specifically designed for reloading LNG carriers. Normally offloading is twice as fast as reloading, but all you need to address this problem are the same capacity of cryogenic pipes along the jetty leading out of the tank as in.

Figure 37 – Singapore LNG with extra tanks for trading



Source: Singapore LNG

Singapore LNG will provide the hardware and Pavilion Energy together with some other yet to be selected LNG players will be granted access to bunkering facilities in Singapore. We note here that Pavilion Energy recently bought 20 percent of Blocks 1, 2 and 4 from Ophir Energy, although first LNG is at best only likely by late this decade.

Gunvor, an Amsterdam based oil trading company, with a large presence in Asia, has signed up for 2 mmtpa of tolling LNG capacity at the Magnolia terminal in USA. One

option is to bring it to Asia and trade it into the short term market. It has plans to supply some gas to Panama and/or else build a storage facility in that country.

In addition to Singapore LNG, there is the Vopak LNG terminal planned for Pengerang on the southeast tip of Malaysia. They have teamed up with the local energy logistics company Dialog. Phase one with a tank of 170,000 m³ is due for commissioning in 2016 and phase two with another 170,000 m³ in 2018. Designs have passed front end engineering and design (FEED) and requests for tenders have gone out to engineering companies for EPC.

Figure 38: Location of Vopak LNG terminal at Pengerang



Source: Vopak

The exact charging mechanism for Singapore LNG and Vopak LNG for the use of their facilities for bunkering of LNG are not clear at the moment. But based on initial discussions with Vopak the terms could be quite flexible. They will offer capacity rights for their two 170,000 m³ tanks. The capacity rights could be structured in many ways. But for example they might offer rights to one tank for three months of the year with a certain number of berthing slots spread over the entire year.

The final buyer of LNG in the Philippines would negotiate with the holder of the terminal capacity rights at Singapore LNG or Vopak LNG, which would mostly likely an LNG portfolio player. The LNG could then be shipped onwards to the Philippines on LNG carriers provided by the portfolio player or else on LNG carriers chartered by the buyer.

B.15 Terminal and shipping options

There has been a growth in orders for traditional small size LNG carriers over the past few years. In late 2012, for example, CNOOC ordered four carriers of 30,000m³ and ten carriers of 10,000m³ to serve small satellite LNG terminals situated up rivers. IM Skaugen (Norgas Carriers) and Anthony Veder are also active in the smaller LNG carriers. Norgas Carriers has an office in Singapore and conducts operations in the region. Anthony Veder has used some of its smaller vessels to transport LNG from Korea to Japan and between terminals in Japan. Another player in this field is Argent Marine Management from the USA, and so far as we are aware is not active in Asia at present.

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While it is true that these smaller carriers are more expensive per m³ to build than larger vessels, they have the advantage of delivering a cargo of LNG more appropriate to what is needed to fuel a 800 MW CCGT at peaking to mid-merit capacity factors (from our power market simulations) of around 400 to 600 kilotonnes per year.

Recently there has been growth in gas carriers using pressurized ISO (International Shipping Organisation) tanks for delivery of small amounts of LNG. Recently the US approved export permits for small volumes of LNG from some small terminals to Free Trade Agreement countries in the Caribbean and Latin America

Another option is to get LNG delivered by a multigas carrier that can carry LNG, ethylene, LPG and vinyl chloride monomer. That said, this latter option is on the expensive end of the range at above an estimated USD 3,750 m3. This option would be a last resort.

Table 26: Indicative costing of large- versus small-scale delivery and storage solutions

	Large Scale (2013 US\$/mmbtu)	Small scale via Hub (2013 US\$/mmbtu)
LNG 0.13*90	12.0	12.0
Large scale shipping	2.0	1.5
Portfolio player mark-up	-	0.5
Bunkering in Singapore or Malaysia	-	0.5
Small carrier from Hub to Philippines	-	1.5
Terminal	3.5	2.0
Others	-	-
Total	17.5	18.0

In our forecasts at the moment Brent approximates to real USD90 bbl in 2020 and we estimate a slope for LNG of 13. In Table 26, we assume that short term and long term LNG are priced the same. But long term comes with take or pay obligations and short term is just buying when needed from the Singapore-Malaysia LNG Hub. (Maybe Thailand is also trying to get in on providing LNG Hub services as they are building a second tank for which they have no immediate domestic use so far as we can tell).

Our large scale shipping cost is somewhat approximate and is a rough average for deliveries from Qatar, East Africa, and Australia to Manila for large scale carrier and with some small savings for delivery to the nearer destination of Singapore.

The bunkering cost is a guesstimate but based on holding inventory for about 10 days at a large scale LNG terminal. This is triangulates with Thailand and Singapore LNG terminal charges, after stripping out regasification, of close to USD 1 mmbtu which we calculate are predicated on an average inventory holding period of 20 days.

When shipping LNG on a small carrier the buyer would only need to charter the carrier for just over half of the year (20 round trips of ten days to and from Singapore to Philippines each year) and the rest of the time it would be doing other deliveries for the owner. The large carrier would be needed for deliveries to the Philippines for only 15 percent of the

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year, and so would be used on other tasks for a greater amount of time or 85 percent of the rest of the year. With the large carrier we assume that the LNG comes delivery ex ship (DES or as it is now called DAT, delivery at terminal). For the small carrier the buyer would probably buy the LNG free on board at the Hub and pay the charter separately for shipping.

The terminal charge is a levelised flat real tariff based on 800 MW power plant at 40% capacity factor needing 400,000 tonnes a year. Using our estimates for onshore terminals, this works out at close to USD3.5 mmbtu for a large terminal with a 170,000 m3 tank and USD2 mmbtu for a smaller terminal with a 45,000 m3 tank at the same level of throughput.

What this attempts to do is present a rough base case that the small terminal and small carrier option using LNG from a nearby Hub is not necessarily that much more expensive than the traditional large scale option. But the key feature of the smaller scale option is that it comes with flexibility. As an extreme position, no burdensome 20-year take or pay for LNG needs to be signed with purchases only on the short term market (less than four years). Or if a certain amount of power can be contracted to retailers then the corresponding amount of LNG could be contracted for on a more long term basis, and with the option to buy short term if needed, say to supply industry or if there was a hydro power shortage.

At this stage we have not factored in the working capital cost of holding LNG inventory in the large tank for a fifth of a year. Whereas the small tank holds the LNG for a less than a month.

Appendix C: Comments received on the Inception Report

NOT PUBLICLY AVAILABLE

Appendix D: Engineering Site Assessments

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