An Initial Assessment of the Economic Costs of Natural Gas for Myanmar's Domestic Market

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empowering people

e.Gen Consultants Ltd.

14A Chandrashila Suvastu Tower
69/1 Bir Uttam Qazi Nuruzzaman Road
Dhaka 1205, Bangladesh.
Phone: +88 02 964 1256-9
email: info@egenconsultants.com, Web: www.egenconsultants.com

Project Document

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November 2016

This report was written by Saad Agha, Evangelos Penglis (VIS Consultants),and David Roland-Holst, under the supervision of Faisal Rabbi. Report review, compilation and backstopping support was provided by Amit Datta Roy.

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e.Gen Consultants, Ltd.
14A Chandrashila Suvastu Tower,
69/1 Bir Uttam QaziNuruzzaman Road,
Panthapath, Dhaka 1205 Bangladesh
www.egenconsultants.com

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ABBREVIATIONS[1]

ADB - Asian Development Bank

AIC - Average Incremental Cost

ASEAN - Association of Southeast Asian Nations

CAPEX - Capital Expenditures

CCGT - Combined Cycle Gas Turbine

CDM - Clean Development Mechanism

CNG - Compressed Natural Gas

DCF - Discounted Cash flow

DMO - Domestic Market Obligations

EGAT - Electricity Generating Authority of Thailand

FSRU - Floating Storage Regasification Unit

FDI - foreign direct investment

FYP - Five Year Plan

GDP - Gross domestic product

GE - General Electric

GHG - greenhouse gas

GMS - Greater Mekong Sub-region

GOM - Government of the Union of Myanmar

HH - Henry Hub

ICT - information and communication technology

IEA - International Energy Agency

IMF - International Monetary Fund

IPP - Independent Power Producer

IRR - Internal Rate of Return

JICA - Japan International Cooperation Agency

LCOE - Levelized Cost of Electricity

LNG - Liquefied Natural Gas

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[1] A glossary of technical terms is available in an appendix at the end of this document.

LPG - Liquefied Petroleum Gas

LRAC - Long Run Average Cost

LRMC - Long-run marginal cost

MAGIC - Myanmar Aggregate Gas Industry Comparison

MC - marginal cost

MCP- Methylcyclopropene

MDGs - Millennium Development Goals

MIT - Massachusetts Institute of Technology

MOE - Ministry of Energy, Republic of Myanmar

MOGE - Myanmar Oil and Gas Enterprise

NG - natural gas

NTS - National Transportation System

NPV - net present value

OPEX - operation & maintenance expenses

PRC - People's Republic of China

PSA - Production Sharing Agreement

PSC - Production Sharing Contracts

PV - present value

PVPI - Profitability Index

SEAGP - South East Asia Gas Pipeline Company

SOE - Special Operations Executive

SMEs - small and medium-sized enterprises

TFP - Total factor productivity

TT - transition town

UREC - University Recreation at Washington State University

USAID - United States Agency for International Development

USEIA - US Energy Information Administration

WB - World Bank

$ - United States Dollars

EXECUTIVE SUMMARY

1. To support more effective evidence-based development strategies for Myanmar's energy sector, the World Bank commissioned this study of the economic costs of natural gas development and distribution in the domestic market. Natural gas can be a potent catalyst for economic growth and livelihoods improvement, both as a direct energy source and feedstock for relatively low emission electric power generation. For their part, Myanmar authorities are interested to review the economic cost of supplying natural gas for domestic consumption to better prepare for the rising domestic demand for gas. An updated gas costing exercise can support effective decision-making on leading energy policy decisions, including but not limited to balancing gas export and domestic consumption, domestic gas pricing, including tariffs and/or subsidies. The project comprised four primary tasks, each of which is summarized below.

Task 1: Review of Myanmar's Natural Gas Supply and Demand Balances

2. To support more effective strategic planning for Myanmar's gas sector, it is essential that long-term trends in demand and supply be elucidated, both with respect to the country's resource potential and in terms of opportunities for trade. As we shall see in the other components of this project, Myanmar's resource potential has enormous promise for meeting national development objectives, directly in terms of energy supply and indirectly in terms of foreign exchange earnings. Balancing gas supply to domestic and external demand will be essential if Myanmar is to support dynamic and inclusive domestic growth, but this will require foresight to avoid mismatches between domestic energy needs and supply, while maximizing export opportunities. Many other developing countries with ample energy endowments have experienced problems of this kind, including unsustainable subsidized domestic energy demand, adverse real exchange rate movements (Dutch Disease), and bottlenecks in both domestic and exported energy supply chains. To help avert such problems, a project began with a comprehensive assessment of relevant sector and economic data and developed a heuristic scenario tool to improve visibility for policy makers regarding consistency of energy supply and demand trends.

3. The first task of the project, called for review and assessment of all relevant data and information on reserves and gas supply and demand conditions for the next 10 years or longer. In the event, we carried out a data assessment to 2030. The task required a comprehensive survey of proven, possible, probable, and prospective gas reserves, export commitments, Production Sharing Agreements (PSAs) and domestic gas supply and demand conditions.

4. The first component of Task 1 entailed a comprehensive review of historical evidence on Myanmar's gas supply and demand balances. This activity-included discovery of 43 core data resources, documented below, as well as intensive data gathering from line ministry sources. The second activity synthesized this information with a new empirical decision tool developed in Task

1 for assessing future demand and supply patterns and balances via a user-friendly graphic interface.

5. The Myanmar Aggregate Gas Industry Comparison (MAGIC) model elucidates the relationship between the demand side of the real economy and energy supplies. This makes a valuable contribution to the MOE side of the dialog by giving the government a user-friendly scenario tool to better understand emerging supply-demand gaps and the two basic strategic alternatives to those gaps – reserve development and contract offsets ("swaps"). Time and resources on this contract did not support development of a more comprehensive economic forecasting tool (although the consultant for this task is a leading authority in this area), let alone the training requirements to transfer such a technology. MAGIC is a simple material balances model that takes no account of the pricing/valuation considerations referred to above. Neither does it need peer review by a panel of economists. This is a simple Excel accounting tool that compares input macroeconomic trends to official statistics on energy system resource potential.

6. Current demand for gas in Myanmar is around 300 mmcf/d on average (2014-15) and is expected to increase to around 750 mmcf/d on average by 2020-2021 and remain at such high levels onwards. The power sector accounts for the overwhelming majority of natural gas consumption (currently around 70%), while the rest is consumed mainly by industries, CNG filling stations and refineries. The country's plans for significant expansion of electrification through the construction of 10 new gas-fired power plants in the next 5 years, is expected to more than double current generating capacity, to over 3,400 MW by 2020-21. Additionally, industrial/commercial demand is expected to increase more than 2-fold from around 70 mmcf/d on average in 2014-15 to around 150 mmcf/d on average in 2015-16 onwards, driven primarily by existing paper and cement plants and oil refineries, as well as by new plants, mainly in metallurgy and cement industries.

7. The domestic gas market is currently supplied from domestic sources, primarily the 3 offshore fields of Yadana, Zawtika and Shwe, which altogether supply 81% of the domestic market supplies (2014-15) i.e. around 260 mmcf/d of the total supply of around 320 mmcf/d. The rest of around 60 mmcf/d is supplied by 7 onshore fields. Offshore fields provide the bulk of their production to the export market. The availability of indigenous gas supply for the domestic market is nevertheless decreasing, as production from both onshore and offshore fields is predicted to drop from 2020-21 onwards. Offshore fields' supply to the domestic market is expected to increase to 450 mmcf/d in 2016-17 and be maintained at those levels until 2019-20, and thereafter decrease every year until it reaches 280 mmcf/d in 2030-31. Thereafter, it is expected that new discoveries such as Badamyar and Aung Sinkha could bring additional supplies to the domestic market of the order of 140 mmcf/d from 2025-26 and 50 mmcf/d from 2029-30 respectively. Onshore fields' supply to the domestic market is expected to gradually decrease from current levels and reach 25 mmcf/d in 203-31.

8. Economy wide and sector projections show that there will be an overall gap of gas demand over supply, starting 2018-19 at around 50 mmcf/d and increasing significantly to over 300 mmcf/d in 2020-21, growing thereafter and reaching a peak of around 420 mmcf/d in 2024-25. From 2025-26 the gap decreases to around 300 mmcf/d and is predicted to remain stable until 2028-29, decreasing slightly in the next couple of years to around 260 mmcf/d. The largest supply gaps are predicted in the offtakes of Daw Nyein and Kanbauk, which start from 2016-17 onwards and peak at around 370 mmcf/d in 2014-25 for Daw Nyein and 50 mmcf/day in 2019-20 for Kanbauk.

Task 2: Methodology for Calculating Economic Costs for Domestic Gas in Myanmar

9. The first objective of the study is to determine the economic costs of supplying natural gas into the Myanmar domestic market at certain offtake points of the gas network. Economic costs encompass the true cost of all resources used to produce, transport and supply natural gas in the domestic market. The estimation of economic costs is nevertheless a complex and imprecise task that requires assessing many parameters, including externalities, and which requires availability of a wide range of data. In the absence of relevant studies and data in the gas sector of Myanmar, financial costs were used as a proxy for economic costs, whilst ensuring that the opportunity cost of resources is taken into account, assets employed and their values are realistic, and the rate of return on assets is in line with market norms.

10. A number of alternative costing methodologies or techniques were considered, to select the most appropriate one for calculating the economic costs for domestic gas supply in Myanmar. The cost-plus pricing method, currently applied in Myanmar, is static and not forward looking, with costs subject to wide year-on-year fluctuations, and this method provides no or weak incentives for companies to be efficient, as they can pass through to the customers' costs in excess of efficient operation. Economic theory suggests that efficient gas prices are set using marginal cost (MC), especially Long-run marginal cost (LRMC), since this results in sending appropriate signals to consumers and suppliers alike for the use/supply of gas and maximizes economic welfare. Marginal cost pricing is a forward-looking concept, whereby it is estimated how long run operating and future capital costs change if expected demand changes.

11. The two main methods for assessing LRMC are the Average Incremental approach and the Perturbation approach. The Consultant compared and contrasted the different approaches to economic cost estimation in Myanmar, across the following criteria:

a) to be forward and not backward looking
b) to be not overly complex to apply
c) the required data for their proper application to be available.

Both the AIC and Perturbation methods were found not to be applicable in Myanmar's gas sector, due to their complexity and current lack of underlying data requirements for their effective application. AIC requires a comprehensive least cost investment plan in place, encompassing all additional costs involved in satisfying future demand increments, whereas the Perturbation approach is even more demanding and complex, as it requires re-optimization of investment plans in response to what-if questions concerning successive marginal shifts in future gas demand.

12. The chosen approach, which is forward looking, simple to apply in view of current data availability limitations, and effective in approximating the cost effect of future annual changes in demand, is the Long Run Average Cost estimation (LRAC). The LRAC approach estimates the average forward looking cost required to meet future year-on-year demand. Although it does not capture costs at the margin, it provides a 'levelized' average long term cost that can be used as a 'proxy' to LRMC.

13. LRAC is calculated as the present values of the sum total of year-on-year costs, divided by the present values of the sum total of all relevant year-on-year volumes. All economic cost calculations are incorporated in an economic model, which is a flexible tool for the beneficiary to use. In future, as Myanmar adopts and implements comprehensive cost assessment techniques, and institutes relevant investment planning and data collection processes, a switch to meaningful calculation of LRMC can take place.

Task 3: Economic Costs at certain Offtake Points from the Gas System

LRAC estimation for each part of the supply chain

14. Economic costs of gas on a LRAC basis for each offtake point in the Myanmar gas network, is the sum total of gas supply costs (calculated at the inlet to the transmission system) and gas transportation costs (at offtake points from the gas network). Gas supply costs include the cost of gas produced in indigenous (onshore and offshore) gas fields in Myanmar, as well as the cost of sourcing additional supplies such as LNG imports, and the cost of LNG swaps or other agreements aimed at diverting gas quantities destined for the export market into the domestic market. Gas transportation costs include the cost of using 'export' pipelines to transport gas from offshore fields to designated offtakes, the cost using the national transportation network to transport gas to domestic offtakes and/or customers, and the cost of using an LNG import terminal and its infrastructure to process and transport gas to selected offtake points.

Gas supply LRAC

15. The LRAC of gas supply involves the assessment of the cost of different supply sources, namely the cost of onshore gas fields, offshore gas fields, the cost of supply from projected new

indigenous finds, the cost of physical swaps and other arrangements, as well as the cost of LNG imports.

16. In the absence of major new finds coming on stream, before 2025-26, and given the contractual difficulties of diverting gas from the export to the domestic market, the projected supply gaps at the offtake points that escalate to levels of over 400 mmcf/d, would have to be accommodated with supplies from external sources, namely LNG imports. It is assumed that the latter would be possible from 2020-21 onwards, when Myanmar could have the necessary LNG import infrastructure in place. Over the short to medium-term period until 2020, the supply gap estimated at 20 mmcf/d to 100 mmcf/d in the offtakes of Daw Nyein and Kanbauk, are assumed to be addressed by means of physical swaps between gas directed for exports with LNG supplies to Thailand, and/or other options.

17. Gas supply LRAC ranges between $ 3.47/mmbtu and $ 8.11/mmbtu. LRACs for onshore fields are 3% to 36% lower compared to the LRACs of the offshore gas fields, while the highest LRAC is for LNG. Charging customers in accordance to their geographic location and supply source, would therefore result in wide differences in the cost of gas between them. A fairer policy to be considered is a single uniform economic 'blended' cost of gas supply for all customers, based on the weighted average economic cost of gas supply of the different gas supply sources in Myanmar.The Consultant has estimated this blended or weighted average LRAC to be 5.98 $ per mmbtu.

LRAC for the use of export pipelines

18. The Consultant has estimated LRAC for the use of export pipelines connecting offshore fields to domestic offtakes, on the basis of respective PSA terms and other relevant agreements. For Shwe, the LRAC comprises separately the cost of using the offshore pipeline to the landing, as well as the costs of using the onshore South East Asia Gas Pipeline Company (SEAGP) pipeline to transport gas to each of the 4 Shwe offtakes (Kyauk Phyu, Belin, Taung Thar, Yenanchaung). For Zawtika, the LRAC comprises the single cost for using both offshore and onshore export pipelines to transport gas from the field to Kanbauk. In the case of Yadana, there is no cost for using the export pipeline, as the Yadana field is now connected to Daw Nyein with a pipeline that is part of the National Transportation System (NTS). The LRAC for the Shwe offshore pipeline is estimated at $ 0.83/mmbtu, while the LRAC for the Shwe onshore pipeline ranges between $ 0.11/ mmbtu and $ 1.56/ mmbtu depending on the offtake. The LRAC for the use of the Zawtika pipeline is estimated at $ 2.54/mmbtu.

19. It is noted that according to PSA terms, the charge for using the Zawtika export pipeline and the Shwe offshore pipeline is based on a percent of the gas contract price of the respective fields, rather than being a fixed charge or linked to distance. This is inconsistent with the underlying cost rationale for the pipeline transport and increases the risks of cross-subsidization between the

gas commodity and transportation components. The Consultant estimated the level of transportation charges for the use of Zawtika and Shwe pipelines that should have been, based oncost benchmarks of equivalent pipeline systems. These 'proxy' LRACs are significantly lower than the LRACs on the basis of current PSA pricing policies: for Zawtika the proxy LRAC is 0.73 $/ mmbtu and for Shwe the proxy LRAC is 1.06 $/ mmbtu.

Use of National Transportation System LRAC

20. There is no comprehensive development/ master plan for the NTS in Myanmar.The Consultants estimated the economic cost of the NTS by the offtake based on all available data, as well as own assumptions concerning the costs associated with the operation, maintenance, replacement and expansion of the network. This economic cost is allocated to offtakes in accordance with the length of the NTS associated with each offtake, as well as the volumes of gas transported from the field to the customers linked to the offtake. NTS LRACs range between $ 0.02/ mmbtu and $ 1.35/ mmbtu, with the highest LRACs in Kanbauk and Kyaukse offtakes and the lowest at Kyauk Phyu and Taung Thar offtakes.

FSRU and associated infrastructure LRAC

21. The economic costs include the construction and operation of an Floating Storage Regasification Unit (FSRU) terminal, with a capacity of approx. 440 mmcf/d (160,000 mmcf p.a.), set in the southern part of the country. The FSRU infrastructure includes an underwater pipeline of 80 km until the landfall and then 50 km of onshore pipeline, to connect to the national transmission system. The construction period is assumed to be 4 years. The PV of the required revenue for the FSRU terminal and associated infrastructure construction and operation over the 2020-21 to 2030-31 period, is approximately $ 660 mil. This required revenue is apportioned to all the offtake points that are projected to use the imported LNG to address their supply gaps (all except the 4 offtakes link to Shwe). The bulk of the costs are allocated to Daw Nyein and Kanbauk offtakes. Estimated LRACs for the FSRU and infrastructure range between $ 0.1/ mmbtu and $ 0.51/ mmbtu.

Total gas supply chain LRAC

22. Total LRACs per offtake, when applying proxy LRAC for the use of Shwe and Zawtika export pipelines, instead of the gas price linked transportation tariffs currently applied in PSA contracts(see Chapter7) range between 6.84 $ per mmbtu and 8.77 $ per mmbtu across the 14 offtakes. Cost differences between offtakes are accounted by differences in relation to costs for the use of the NTS and of export pipelines. Offtakes linked to the offshore fields incur higher costs for using export pipelines, compared to onshore fields. Additionally, all offtakes except those of Shwe incur additional costs linked to the use of the FSRU and associated pipelines, ranging between 0.10 $ per mmbtu and 0.51 $ per mmbtu. The weighted average total LRAC for all offtakes in Myanmar equals8.02 $ per mmbtu.

23. The above results can be contrasted with a gas "supply constrained" scenario in which gas demand can only be satisfied to the extent there is available indigenous gas supply. In other words, in this scenario there is no LNG import (physically through FSRU or by swaps) and domestic demand is only satisfied by onshore gas supply and the part of offshore gas which is not committed to exports. The estimated weighted average LRAC for gas supply in this case is 4.87 $ per mmbtu and the total weighted average LRAC is 7.17 $ per mmbtu.

Recommendations to MOE/ MOGE

24. The Consultant recommends the following:

- MOE/MOGE may conduct a comprehensive gas demand study and formulate gas demand projections, on the basis of country-wide economic and sectoral/regional development. Existing demand projections provided are not comprehensive (detailed demand for some of the new power plants is missing), whilst there is no explicit link of gas demand to economic growth indicators

- An energy and gas supply strategy to be formulated taking into account the relative cost of supply from alternative sources and the optimum energy supply mix. The supply options used in the frame of the study were discussed and agreed with the beneficiary and the World Bank (WB), but were not based on a least cost study for optimum sourcing and use of energy mix (e.g. cost-benefit of gas versus coal for power generation)

- A comprehensive action plan to be developed to implement the chosen strategy, as soon as possible, including actions that ensure Myanmar is in position to cover anticipated supply gaps, including:

    - Preparation for LNG swaps over the short term if required
    - Renegotiation of Domestic Market Obligations (DMOs) in Yadana, and elsewhere if feasible, with a view to increasing domestic gas supplies
    - Preparation for the option of importing LNG (LNG procurement strategy, feasibility studies for FSRU/importing infrastructure, including financing/ownership options etc.)

- A long range Gas Infrastructure Master Plan needs to be formulated in order to guide required investments and maintenance, ensure required capacity, minimize losses, enhance cost efficiency and guide costing assessments and pricing decisions.

- MOE/MOGE will be essential to make effective use of the economic costs estimation framework and model provided, as useful and flexible tools for cost assessment and policy decision making.

- MOE/MOGE needs to institute effective data collection and verification processes for all the costing and other parameters required in the economic costs estimation framework and model. The available data was insufficient, fragmented and not fully consistent.

- It is recommended to review domestic market gas pricing policies and to introduce gas tariffs based on economic costs, with transition strategies if necessary.

Task 4: Potential Impact of a Decline in Gas Prices and Increased Domestic Supply on the Value of Exports and Government Revenue

25. This study carried out a detailed analysis of the Myanmar PSC structure that includes the standard PSC terms for the deep water and shallow water regimes. The difference in the PSC terms between these two regimes is mainly on the Cost Recovery limit (the amount of revenue allowed to be used for recovering capital spend) and Profit Share (the sharing of the post cost recovery revenue between the Myanmar government and Contractor). When comparing the two regimes using a sample field, the deep water regime fares slightly better due to better cost recovery and higher profit split for the investor, however, it does not show strong economics for a typical gas field development. Further analysis shows that there is not a significant difference between the deep water and shallow water regimes as illustrated in the standard terms PSCs. As a result, the deep-water regime appears less attractive given the high risk and cost associated with deep-water development, especially for investors in the current low commodity price environment.

26. In this task, the consultants carried out a deeper analysis on the projection of government revenue from the upstream gas industry. This was done using a financial model capable of handling the two fiscal regimes. The intended use of this model is to help with capacity building in the Myanmar government and help them gain an understanding of projected revenue from the gas industry and make key policy decisions in a changing macro environment.

27. Results from the model show that in the base case gas price scenario ($6/mmbtu for shallow water and $9/mmbtu for deepwater), total point forward government revenue between 2015 and 2030 is 40.5 billion US dollars. Based on 2015 GDP figures, this would represent around 7-8% of Myanmar's GDP. There is a significant drop in revenue expected in 2016 from 2015, mainly due to the change in gas price, despite production expected to be around 1,920 mmcf/d.

28. The biggest contributor to government revenue each year is royalty and government profit share (defined as the share of revenue government receives as per the PSC terms post cost recovery),

approximately 90% of the revenue is generated from these sources. The average government take for both regimes is 88%. Deep-water regime government take is 86%, whilst shallow water regime take is 91%. Sensitivity analysis shows that the Government revenue stream is highly sensitive to gas prices. $1/mmbtu change in gas price impacts government revenue by approximately 6%. Profit share terms is the most sensitive element as it also the biggest contributor to government revenue.

29. Lastly, this task carried out a fiscal benchmarking exercise for the Myanmar PSC. Results show that the Myanmar PSC ranks amongst the highest total government take countries. Myanmar PSC's total deep water and shallow water take is higher than its peers in the Asia Pacific region. Deep-water terms in Myanmar appear to be less attractive for investors than most of the peer group based on current model PSC terms, however, actual signed deep-water PSCs may not reflect this. Nonetheless, the study would recommend a more detailed review of the current PSC structure with the view of making it more attractive in the prevailing commodity price environment.

1 INTRODUCTION

30. Myanmar's energy consumption is among the lowest in the world. About 70 percent of the population has no access to electricity, and the consumption per capita is 160 kWh per annum, twenty times less than the world average. Most rural areas lack electricity services - only 16 percent of rural households have access to grid-based power. Access to modern fuels for cooking (such as LPG) is limited to urban areas, with the countryside relying on traditional biomass (fuel wood and animal dung), comprising about two-thirds of Myanmar's primary energy consumption.

31. To support evidence based development strategies for the nation's energy sector, the World Bank has commissioned this study of the economic costs of natural gas development and distribution in the domestic market. Natural gas can be a potent catalyst for economic growth and livelihoods improvement, but as a direct energy source and feedstock for relatively low emission electric power generation. For their part, Myanmar authorities are interested to review the economic cost of supplying natural gas for domestic consumption to better prepare for the rising domestic demand for gas. An updated gas costing exercise can support effective decision-making on leading energy policy decisions, including but not limited to balancing gas export and domestic consumption, domestic gas pricing, including tariffs and/or subsidies.

32. The project comprised four primary tasks:

    a. Review and assess all relevant data and information on reserves and gas supply and demand conditions for the next 10 years or longer.

    b. Determine Methodology for Calculating Economic Costs for Domestic Gas in Myanmar

    c. Calculate the economic costs at certain offtake points from the gas network based on the methodology and modeling approach proposed under Task 2

    d. Estimate the potential impact of a decline in gas prices and increased domestic supply on the value of exports and government revenue

33. This Final Project Report details all four tasks with supporting appendices.

34. Three Excel decision tools were also developed as part of the project and are available separately with technical documentation.

2 Review of Myanmar's Natural Gas Supply and Demand Balance

2.1 Overview and Relevant Studies from other countries

2.1.1 Task Description

35. Task 1 of the project called for review and assessment of all relevant data and information on reserves and gas supply and demand conditions for the next 10 years or longer. In the event, we carried out a data assessment to 2030. The task required a comprehensive survey of proven, possible, probable, and prospective gas reserves, export commitments, PSAs and domestic gas supply and demand conditions.

36. All relevant data and information on the gas reserves, contractual arrangements and studies on current and future supply and demand conditions were provided by the MOE to the Consultant team after signing the appropriate confidentiality agreement. In addition, the Consultant reviewed all relevant publicly available information and data on the same and allied resource and market issues.

37. The Consultant did not audit gas reserves or carry out new gas demand and supply studies. The Consultant independently reviewed existing studies, contracts, and data and, based on its findings prepared an economic analysis proposing the most appropriate approach for calculating economic costs for selling natural gas into the domestic Myanmar market.

2.1.2 Overall Approach

38. This task was completed in two phases. The first entailed a comprehensive review of historical evidence on Myanmar's gas supply and demand balances. The second, and more intensive activity, developed an empirical decision tool to project future demand and supply patterns and balances via a used friendly graphic interface. This tool was based on an accounting model developed according to the standards of the most recent natural gas system information resources. This framework, implemented in MS Excel, will be delivered to Myanmar line ministry counterparts with technical documentation and an onsite training component.

39. In our overall supply-demand model review, the objective was to find studies that are relevant for assessing and comparing benefits of gas supply to both domestic and export markets, a key decision context for Myanmar authorities. Broadly, this methodology is situated in the realm of cost benefit analysis, financial modelling, and scenario assessments. These methodologies are broad enough that they can be applied to multiple commodities and geographies; in this

summary, we reviewed studies that focus on natural gas in countries that parallel Myanmar in terms of gas infrastructure and reserves. The summary is organized by country/region.

40. In this summary, we also describe the studies' use of the following information in their analysis, if at all, since such statistics are needed for the Myanmar study:

- Domestic gas pricing strategy
- Impact of international gas prices on gas export
- Government revenue from gas sector

2.1.3 Tanzania and Mozambique

41. In a study for the World Bank, Eberhard, Santley, and Schlotterer (2014) estimate what kinds of gas-to-power projects are economically viable in several key African countries. This summary focuses on their results for Tanzania and Mozambique over Nigeria, which differs from Myanmar very significantly in infrastructure.

42. The study estimates two prices, the minimum wholesale price and the LNG netback price, to recommend an export decision. The authors calculate the minimum wholesale price through a bottom-up discounted cash flow model that sums costs. The LNG netback price compares destination market price with total costs of distribution. For both Mozambique and Tanzania, the authors find that the LNG netback price is higher than the minimum wholesale price, indicating that export would be profitable. However, since Tanzania has a smaller resource base, the authors found that supplying gas to the domestic market would actually have a higher netback value. These findings on Tanzania are explored from a different perspective by Umeike (2014) below.

43. The World Bank study goes on to estimate the cost of electrification from natural gas versus other options, as well as the cost of building natural gas pipelines domestically and around the region. To estimate pipeline cost, which may be relevant for the Myanmar study, the authors assume a $64,300 per inch-kilometre heuristic for a simple discounted cash flow model. Demierre et al. (2015) also estimate the cost of regional distribution systems for gas from Tanzania and Mozambique; however, since export is assumed to be the most economical option, their methods are not summarized in detail here.

2.1.4 Tanzania

44. Umeike (2014) estimated revenue generating potential and direct economic value of various export and domestic consumption scenarios for Tanzania's recently discovered natural gas reserves. The paper considers three potential uses for Tanzania's natural gas: LNG export, urea manufacturing for export, or domestic electricity generation. These three scenarios were sub-models, each with three sub-scenarios, within the larger Excel-based scenario analysis model. In

this summary, we focus on LNG export and electricity generation, which parallels the options for Myanmar's natural gas.

45. For the LNG and electricity generation sub-models, Umeike estimates exploration costs, capital investments, and government revenue (no private sector). The sub-model uses forecasted prices in the Asian LNG market, which is where Tanzania's exports would likely go. It assumes that the domestic price and international price are the same. For government revenue, the sub-model adds revenue from royalty payments with tax revenue, as determined by a simple algorithm.

46. For the electricity generation sub-model, Umeike models business-as-usual, gas-only, and low carbon scenarios. These sub-scenarios were differentiated by specific Levelized Cost of Electricity (LCOE) and Discounted Cash flow (DCF) analyses. Also, instead of disaggregating transmission and distribution infrastructure costs, the sub-model uses energy prices to estimate the cost of power generation, as determined by Tanzania's tariff categories.

47. The paper projects that LNG export generates the greatest revenue, but that electricity generation produces the greatest direct economic value for Tanzania. This distinction is based on Umeike's additional calculation of 'value added per unit volume of gas produced', which the author states corrects for different end-use market sizes and is a good measure of contribution towards GDP.

2.1.5 Cyprus

48. The MIT Energy Initiative is conducting an on-going study on natural gas development in Cyprus. The first part of the study assesses project development options, all of which are export schemes, given the extremely small Cypriot gas market. Although Paltsev et al. (2013) do not conduct the study with an eye towards comparing domestic use versus export, they do provide a highly detailed discounted cash flow model (in Excel) that could be adopted to the Myanmar context[2]. The output of their DCF model is the breakeven gas price ($/MMBtu), or the price at which the net present value of the project is zero and above which the project should be undertaken.

[2] http://mitei.mit.edu/publications/reports-studies/interim-report-study-natural-gas-monetization-pathways-cyprus

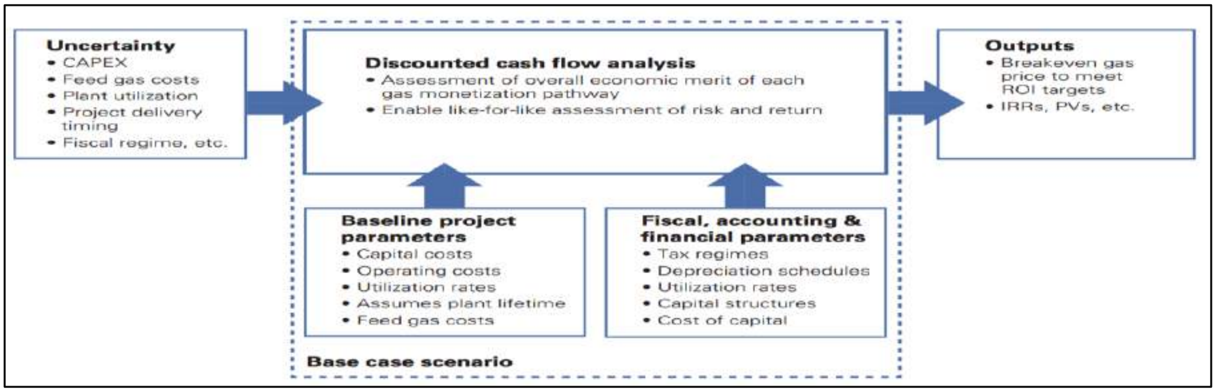


Figure 2.1 Estimating Gas Monetization Pathways with Discounted Cash Flow Techniques

2.1.6 Peru

49. Leung and Jenkins (2014) undertook a cost-benefit analysis for Peru to assess the difference in economic benefits for Peru with and without the Camisea gas fields LNG export project (which is already operating). Although Peru has a significantly more developed natural gas and electrification infrastructure than Myanmar, the methodology used here is the most advanced and relevant to the Myanmar project.

50. Leung and Jenkins calculate costs as a sum of tax revenue from the project, forgone tax revenues from domestic sales, and cost of energy to replace the natural gas once it is depleted. Government revenues and final consumer price of Camisea gas are sub-costs within these larger terms, with data available from project information. In both the with-project and without-project scenarios, the amount of natural gas supplied to the domestic market is the same; however, in the case of natural gas export, the gas reserves are depleted more quickly. Their financial model does not model the Peruvian natural gas distribution system in detail, but rather assumes a flat efficiency rate and heating value across the system. Off-take points are captured as aggregate demand in million cubic feet by client type – residential, industrial, electricity generation, etc.

51. The authors used the model to evaluate three scenarios. The first scenario simulates the information conditions in 2007, when Peru first decided to approve the Camisea project. The second scenario uses information at the time of the study, which showed that new reserves have been discovered but also that the domestic demand for natural gas was increasing dramatically. Finally, the third scenario assumes implementation of oppositional policies that restrict export to certain blocks in the Camisea field.

52. Cost estimation for natural gas scenarios in Myanmar can benefit from the discounted cash flow modelling that others have used for similar scenarios. Fortunately, the open-source MIT DCF model and the financial model constructed by Leung and Jenkins (2014) can serve as starting points. Exact methodology will depend on data availability in Myanmar, in particular data on capital costs, domestic demand, prices, and government revenue policies. The DCF model output

should use an end metric that goes beyond gross revenue (value added per unit, for example), which should support the case for domestic use, according to Umeike (2014).

53. After consultation with Myanmar counterparts, it became apparent that a descriptive accounting and scenario tool was a higher priority at this state of strategic planning than a more complex optimization or mathematical programming model. For this reason, we developed the Myanmar Aggregate Gas Industry Comparison (MAGIC) model as a platform for integrating the diverse and complex streams of gas industry data that are relevant to sector planning in MOE and allied ministries.

54. Although this approach does not support more complex scenario development and optimization tools, it provides a solid basis to support current sector planning and can be extended in that direction if time and resources permit. This could include accommodation of more complex strategic planning such as LNG hedging for domestic import and/or export substitution.

2.2 MAGIC: A Gas Sector Scenario Assessment Tool

55. To support more effective strategic planning for Myanmar's gas sector, it is essential to improve visibility regarding long-term trends in energy demand and supply, both with respect to the country's resource potential and in terms of opportunities for trade. As we shall see in the other components of this project, Myanmar's resource potential has enormous promise for meeting national development objectives, directly in terms of energy supply and indirectly in terms of foreign exchange earnings. Balancing gas supply to domestic and pipeline gas exports.

56. MAGIC is a scenario tool for elucidating the relationship between the real economy, domestic energy needs and production potential. It was designed to support MOE in sectoral strategic planning and dialog with other line ministries and international energy and development partners. Embedding a macroeconomic accounting tool in a user-friendly scenario interface, MAGIC helps identify supply-demand gaps and elucidates the two basic strategic alternatives to those gaps – reserve development and contract offsets. The basic role of MAGIC is to help the government raise awareness of and promote policy dialog on the development potential and opportunity cost of existing gas resources. One of the main strategic policy challenges facing the nation will be to reconcile domestic development priorities with current and prospective energy opportunities. Both at the aggregate level captured by MAGIC, as well as from a bottom up assessment elsewhere in the study, suggest that these demand and supply trends will give rise to gas supply gaps sooner than is generally expected.

2.2.1 Introduction

57. The introductory worksheet of the MAGIC model is devoted to branding, authorship, rights, and caveats regarding scope and usage. In particular, all MAGIC results are indicative only and do not provide a basis for official policy. Moreover, constituent data and calculations of this model

are provided without warranty regarding accuracy or applicability. In other words, the MAGIC model is an accounting and scenario development tool to support evidence based policy and strategic planning.

2.2.2 Baseline Growth

58. The first results-oriented worksheet of MAGIC (Figure 2.2) provides descriptive gas sector trend information for the Business as Usual growth of real GDP (red), total (domestic and export) natural gas demand (green) and total electricity demand (yellow). This scenario is based on consensus international estimates (WB, IMF, Oxford Econometrics) of macroeconomic growth for Myanmar. Of course there is considerable uncertainty regarding the ultimate pathway of Myanmar's economic growth, as well as energy supply and demand patterns supporting this. For exante purposes, however, the Baseline Scenario is considered to be indicative, and cost estimates associated with this can be considered robust against reasonable levels of uncertainty.

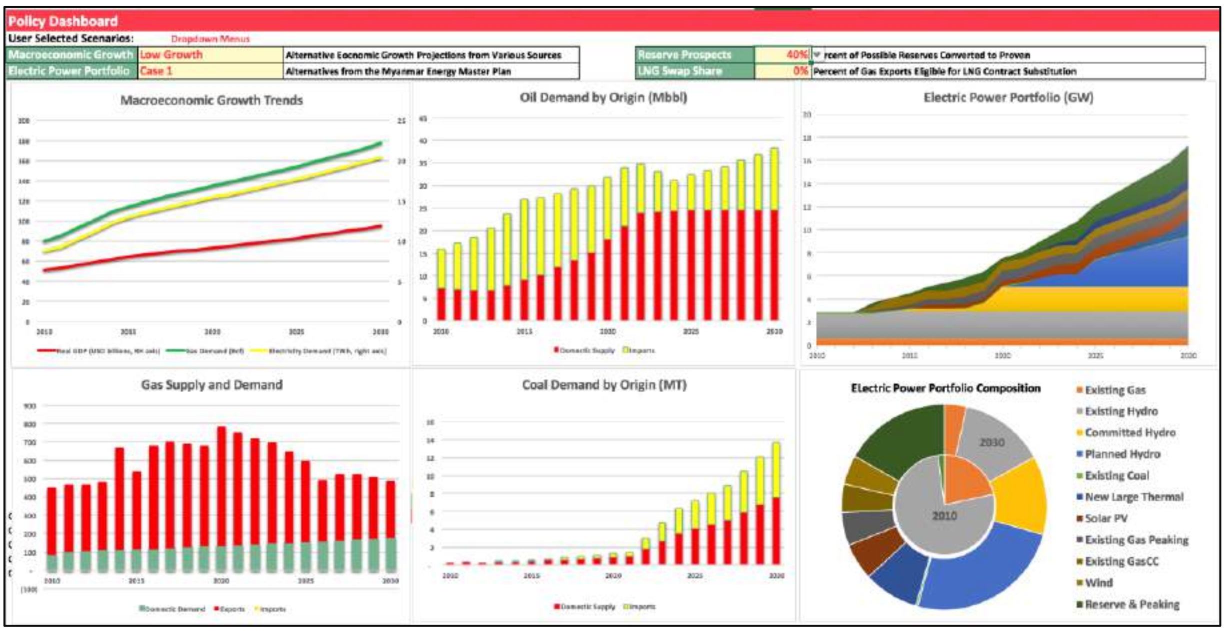


Figure 2.2 MAGIC Policy Scenario Dashboard

59. Several other aspects of the Dashboard worksheet are of interest for descriptive policy analysis. On the upper right side of this sheet are two drop down menus, one labelled Reserve Prospects and the other LNG Swap Share. The first of these recognizes that Myanmar's gas reserves, especially offshore, are uncertain, and the disparity between Proven and Possible reserves is substantial in some cases. The Reserve Prospects drop down menu allows the user to evaluate Myanmar's gas supply and trade patterns as these might be affected by proving additional offshore reserves, i.e. a change in Reserves Available. Reserves Available are calculated based on the degree to which Possible Reserves become Proven Reserves. Ex ante, this assumption is reflected in the Reserves Prospects percentage in cell (N3) of the Dashboard, measuring the percent of the difference between Possible and Proven that become available. These incremental

reserves are assumed to be exploited for production, beginning in 2020, at a decadal depletion rate. By choosing in the interval 0-100%, the user can see the implications of proving additional offshore gas reserves (up to the Possible Reserves limit).

60. A second scenario tool in this MAGIC worksheet allows the user to experiment with different ways of offsetting existing gas export commitments. Myanmar's gas exports are to a significant extent obligated by long-term contracts. Established offshore resources in the Yadana, Zawtika, Shwe and Yetagun fields have significant majorities of their current production contracted for export, and new reserves could be implicated in export contracts to meet joint venture investment requirements. For this reason, growth Myanmar domestic demand for gas faces and implicit domestic supply constraint.

61. If domestic demand outstrips the residual of actual and export-obligated production, there are two alternatives to contract renegotiation or demand curtailment. The first would direct imports of LNG, requiring significant investments in terminal infrastructure over several years. Alternatives, Myanmar could avail itself of a commodity market solution, buying LNG contracts for its export partners to offset diversion of its own gas diverted to the domestic market. Given that its primary export partners, Thailand and China, have well-developed coastal LNG facilities, this would be a relatively simple substitution. Indeed, given the cost of new LNG landing facilities to Myanmar, as well as the distance Shwe gas travels to some of its destination uses in Southern China, it might be very cost effective to substitute derivative contracts for some direct exports. Finally, it should be noted that, because MAGIC is a material balances model, the cost of LNG contracts needed to offset export diversions to the domestic market are not taken into account.

62. In any case, both new reserves and LNG export offset swaps could alter Myanmar's energy balances, and this would be quite important if the country's economic growth led to domestic energy constraints. In the Reference Case, for example, a net gas supply "gap" emerges post 2017 with substantial LNG import requirements.

63. While many energy-producing countries find themselves in a situation of two-way trade, this is not a necessary outcome for Myanmar. As the next figure shows, if we assume as an illustrative scenario that 50% of the countries Possible Reserves are Proven by 2020, and 30% of contracted exports are offset by LNG swaps, the net gas import requirement is eliminated, obviating the cost of LNG landing facilities and the risks of long-term import dependence.

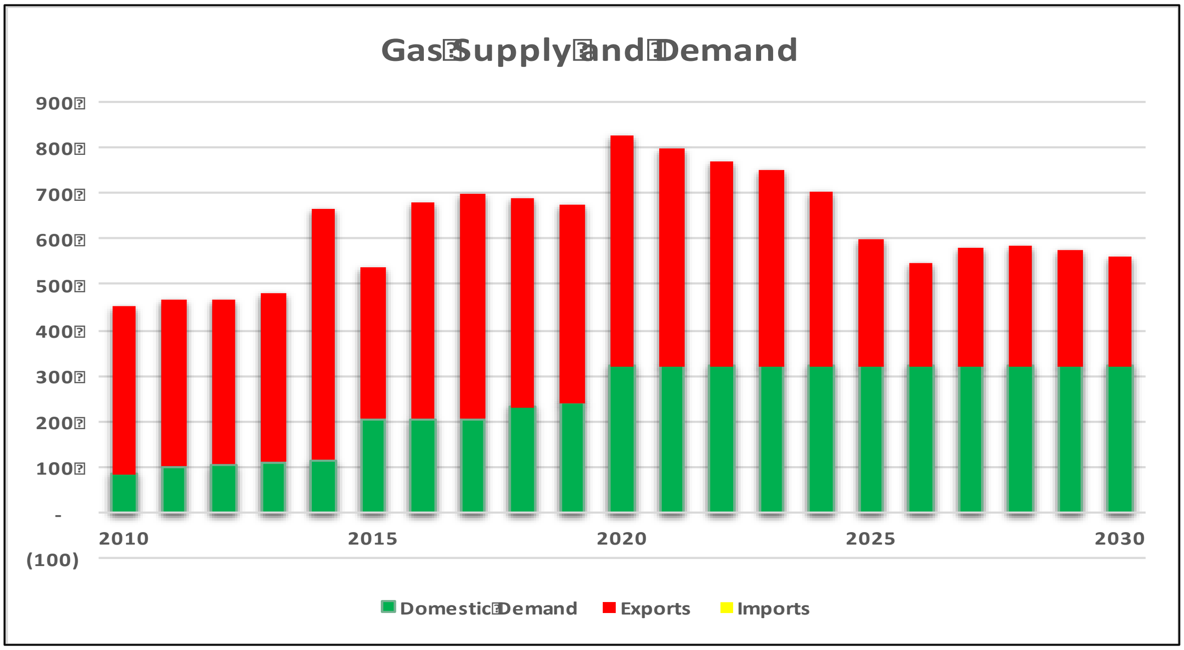


Figure 2.3 Reference Demand Growth with 50% of Possible Reserves Proven by 2020 and 30% of Contracted Exports Offset by LNG Swaps

64. In addition to the two left panels focused on the gas sector, the Reference worksheet contains detailed trends on other energy fuel balances (Oil and Coal) as well as detailed long-term composition of the electric power source portfolio. Myanmar's current electricity generation mix is dominated by gas and hydro, but the country is contemplating a much more diversified approach to generation, including significant expansion of renewable capacity.

65. The alternative electric power portfolios are described in detail in the National Energy Plan for Myanmar, published last year and summarized in five Cases, which can be examined using the left-side drop down menu labelled "Electric Power Portfolio." In any case, a full spectrum of options, from continued heavy reliance on new thermal capacity (Case 4, Figure 2.4) to much more renewable diversification (Case 5, Figure 2.5) are evaluated in detail.

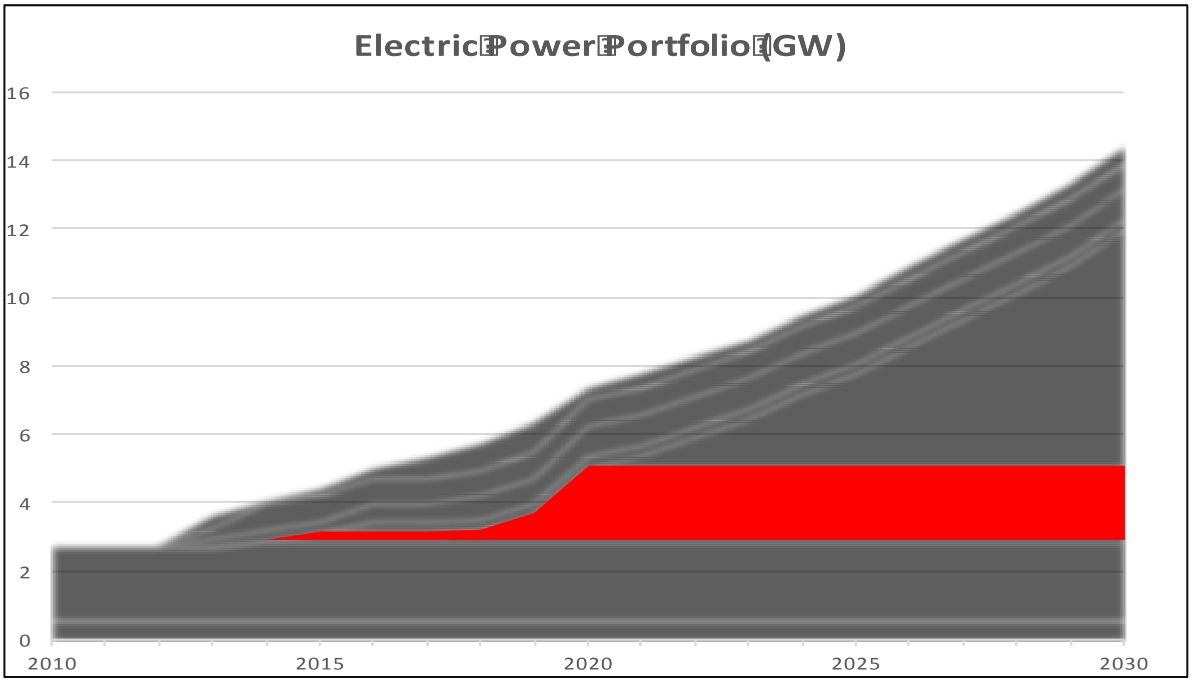


Figure 2.4 Case 4 – New Thermal-intensive Electric Power Portfolio

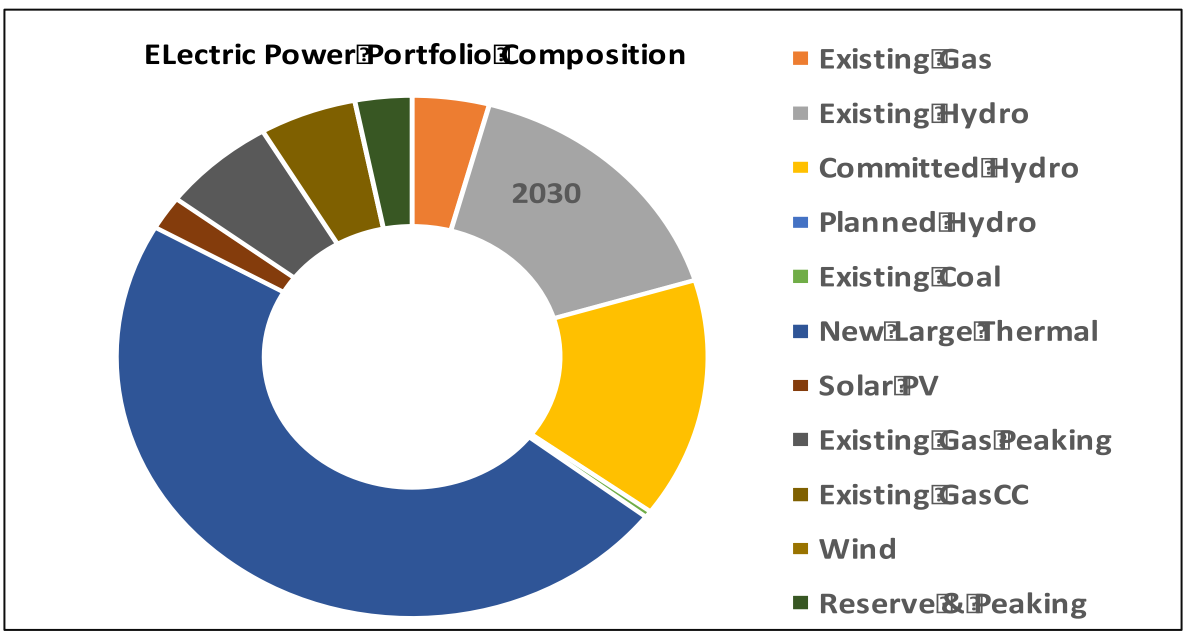


Figure 2.5Case 5 – Diversified Renewable Electric Power Portfolio

2.2.3 Scenarios

66. The next worksheet departs from the Reference framework to examine a more diverse set of macroeconomic growth scenarios for Myanmar. Any country undergoing institutional transition

of such depth and scope must accept reasonable uncertainty regarding the detailed characteristics of the process of economic growth and development, and Myanmar is no exception. Although the Reference Scenario is the basis for this project's cost calculations for the natural gas sector, the MAGIC framework supports heuristic assessment of a larger universe of policies and outcomes. To illustrate this, we have instrumented the Scenarios worksheet with nine representative economy wide policy scenarios. Including the Reference case, we examine long-term projections of Baseline real GDP growth that conforms to pre-reform experience, Low and High alternatives, and macroeconomic growth trends under a variety of structural policy reforms, summarized in Table 2.1.

Table 2.1 Comparison Scenarios for Macroeconomic Growth

	Name	**Description**
	Reference	Official and Consultant Estimates of Gas Demand and Electric Power Growth
2	Baseline	Pre-reform growth rates
3	Low Growth	Lower Bound on Consensus Growth Expectations
4	High Growth	Upper Bound on Consensus Growth Expectations
5	Agriculture	Rice yield growth of 2% annually, closing half the gap with highest yield Asia by 2030, other agricultural productivity grows by 3% annually, including other crops and livestock
6	Industry	For Myanmar industrial sectors, assume TFP growth for sector groups comparable to other lower income Greater Mekong Sub-region (GMS) economies.
7	Education	Assume that Myanmar sustains growth rates of Labor Productivity comparable to the rest of the GMS economies, with rates for all countries converging to the sub-regional average by 2030.
8	Transport	In addition to Scenario 4, assume that investments and institutional changes effect a 50% reduction in trade, transport, and transit (TT) margins for lower income Asian countries.
9	Financial Liberalization	Assume that Myanmar's the stock of FDI sustains 10% of GDP to 2030.

67. These scenarios provide rich descriptive information regarding Myanmar's policy options, with important implications for the gas and allied energy sectors. In the most dynamic scenario, for example, the country is estimated to triple real GDP by 2030, and can achieve this goal without importing gas as long as 100% of its possible offshore reserves are proven and half its contractual exports are offset by LNG swap contracts (see Figure 2.6 and Figure 2.7 below).

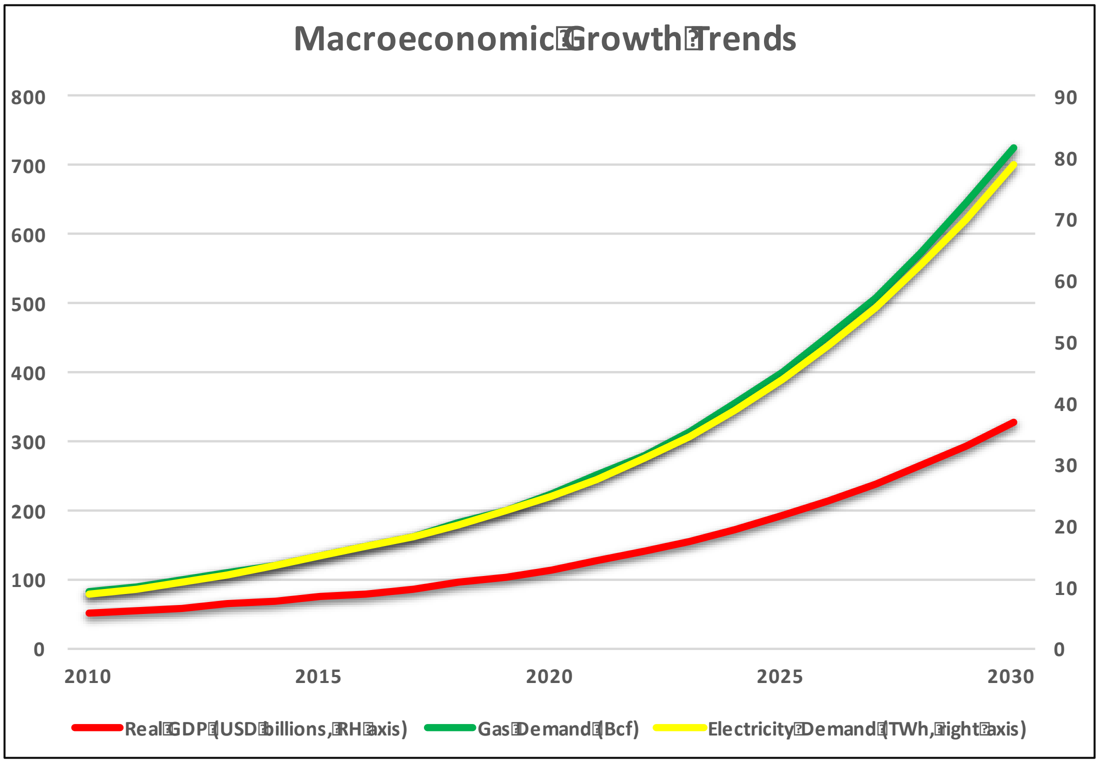


Figure 2.6 Growth of Economic and Energy Aggregates under Financial Liberalization

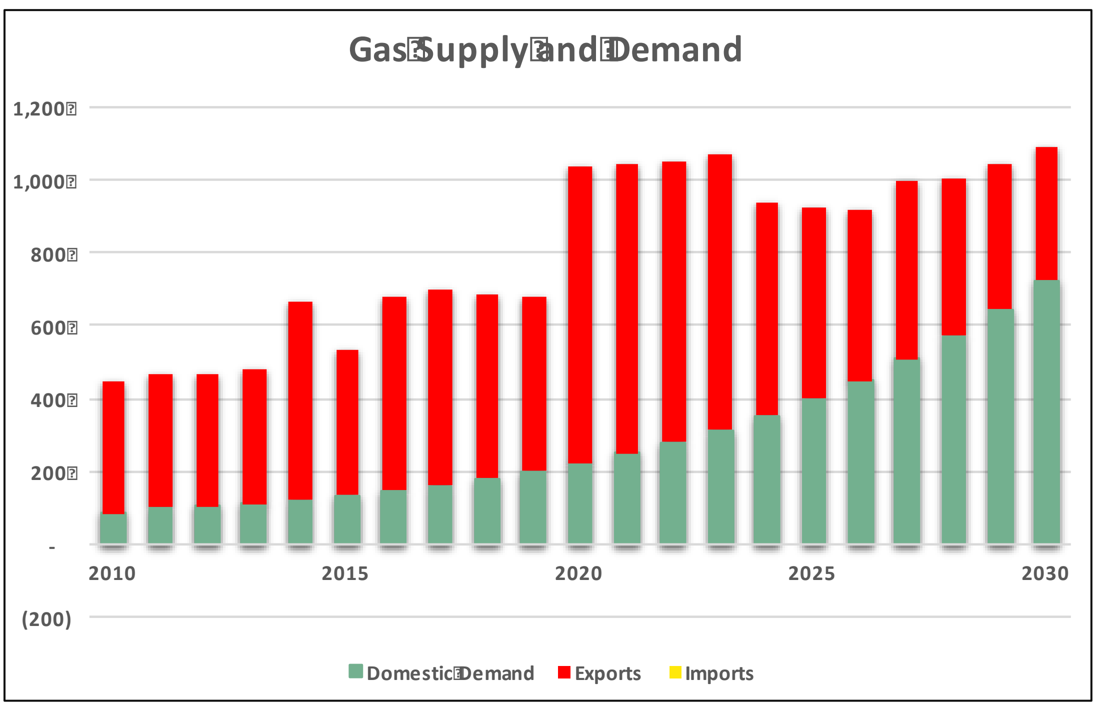


Figure 2.7 Gas Demand by Destination: Financial Liberalization (bcf)

2.2.4 Assumptions

68. This worksheet contains a variety of parameter values assumed to hold in base year and baseline ("Business as usual") calculations. Included are initial values for exchange rates, initial year level variables, interest and discount rates, and a variety of pricing indices. These values should not be confused with the financial variables used in the gas system cost and government revenue assessments that follow. They are used here for counterfactual analysis of demand and supply trends.

2.2.5 Demand

69. All the basic demand side data of the Myanmar energy system are contained in this spreadsheet, including trends for aggregate demand (GDP), domestic electricity requirements, and a variety of fossil fuel types including gas. These demand trends are centred on the Reference Scenario, reflecting official expectations and the basis for calibrating gas system costs and government revenue in this report. In addition to the Reference case, a number of other possible growth scenarios are detailed for comparison (see Section 2.2.3) above. These reflect the potential of changing policies and external events to change the trajectory of overall demand growth, offering both opportunities and challenges to the Myanmar economy and public/private stakeholders.

70. In addition to these indicative growth scenarios, it is possible for MAGIC users to specify their growth paths for real GDP as well as aggregate domestic natural gas and electricity demand. Growth trends are input in index form, with the year 2010 as a base value of 100 for each of the three series. A total of five places have been provided for User Scenario inputs, beginning with Row 63 in the Demand Worksheet. Once the trend indexes are entered, users can see their scenario in the context of national energy balances by returning to the Scenarios worksheet and selecting their scenario from the drop down menu in Cell C3.

2.2.6 Supply

71. The Supply worksheet contains all the information complied on reserves, production, and trade for primary energy fuels (gas, oil, and coal). Reserves of four kinds are specified for natural gas: Proven, Probable, Possible, and Available. The last category is a combination of Proven reserves and user-input expectations regarding ultimate proving of Possible reserves from 2020. As explained in Sections 2.2.2and 2.2.3above, users can experiment with different prospects in this regard to see how they would affect Myanmar's national energy balances in the context of given demand growth scenarios. Taken together, these features offer better insight into risk management with respect to gas exploration and development. In the present version, we do not allow for new reserve discoveries or augmentation of Possible reserves. This feature could be added to a future version of MAGIC.

2.2.7 Trade

72. This worksheet compiles the trends in energy demand and supply from the previous two worksheets and calculates national energy fuel balances for gas, oil, and coal over the period 2010-2030. In addition to direct computation of net import/export trends, this sheet takes in account the possibility of using LNG swaps to offset contractual gas export obligations. The degree of swapping is specified in the Reference and Scenarios sheets, but computations of net trade implications are carried out in this worksheet.

2.2.8 Portfolios

73. The Portfolios worksheet contains detailed information on the five Cases or alternative electric power portfolios set forth in the Myanmar National Energy Plan (ADB: 2015). Of course, these only represent a small subset of a much larger variety of electric power generation plans that may emerge over the next fifteen years, but since they are published in one of the government's most detailed, up-to-date and authoritative energy plans, they provide a convenient reference for policy dialog.

2.2.9 FYP

74. This worksheet summarizes the energy system statistics from the latest Five Year Plan of the Government of Myanmar.

2.3 Data Reconnaissance

75. This project was initiated with a comprehensive review of information resources needed for the cost assessment, supported by an initial data reconnaissance mission to Nay Pyi Taw in November 2015. Time and resource constraints for this project did not allow for primary data development, so we focused on existing secondary sources in public and private hands. Our first objective was to catalogue all publicly available data, with some rapid assessment of its completeness and reliability.

76. Among the public sources, the primary source was the Ministry of Energy (MOE) of the Government of the Union of Myanmar (GOM), but other public sector contributors included other line ministries, the Central Statistical Office, and a variety of multilateral and bilateral institutions. For the private sector, independent national operators are limited, but GOM has some large foreign partners who could make data available.

77. Three generic types of information were sought, corresponding to different stages of the energy supply chain, as well as some data on the overall national, regional, and global economies. In all cases, sourced data on actual and historical volumes, capacity, and as much cost/price detail as possible:

1. Exploration, extraction, and refining.
2. Distribution, storage, and logistics, in terms of location, volumes, and capacity, with attendant infrastructure investment and O&M costs.
3. Demand side data by detailed end user type (electric power, industry, household, etc.).

78. We also considered the five most significant types of institutional actors associated with Myanmar's energy system, listed in the table below.

Table 2.2 Primary Data Sources

Data Sources	Description
Government of Myanmar	Our first line of enquiry, since GOM line ministries and SOEs may hold much of the data developed by others
Multilaterals	WB, ADB, and some other multilateral development banks may have researched Myanmar energy in support of development policy or lending (particularly for energy infrastructure). We should review their commitments and attendant information resources.
	IEA: We reviewed the reporting standards for Myanmar and the data available
Bilaterals	A number of Myanmar's leading development partners (JICA, USAID, USEIA, China Development Bank, etc.) have researched the country's energy system for their own investment interests or to support lending. We conducted a rapid review of these sources and information they may have produced.
Private sector	This group can be challenging because of incentives to limit disclosure, but we can begin with Myanmar line ministries who may be auditing the activities of energy system investment partners. Either they would have records of joint and individual venture investment and operations or they could help us request this information.
Demand side sources	In this case, the primary source would be the utilities who are delivering gas. As part of our reconnaissance of publicly available data, this was a high priority. Despite uncertainties regarding the level and (especially) composition of gas allocation to industry and households, we hoped the electric power distributors have accounts that can be audited. For leading industries and institutions (e.g. the military), specific requests could also be helpful. For household use, we acquired a very good nationally representative household survey of Myanmar for 2012. Of course, the reason for this WB project is that Myanmar has extremely low HH gas use, so this cannot be a big factor in calibrating our models. It would, however, support detailed assessment of gas policy's livelihoods potential.

3 Economic cost of gas methodology

79. A number of alternative costing methodologies to calculating the economic costs for domestic gas supply in Myanmar were considered, which are presented and analysed in Annex 6: Economic cost of gas methodology. The LRAC (Long-Run Average Cost) approach is selected as the most appropriate for Myanmar under the present circumstances. LRAC is forward looking, yet simple and effective in capturing the cost effect of future annual changes in demand. The LRAC approach estimates the average forward looking cost (operating and capital expenditure) required to meet future year-on-year demand and is a good proxy to long-run marginal costs. Further analysis of the LRAC approach is provided in Annex 6: Economic cost of gas methodology.

80. The LRAC approach is applied to all segments of the gas supply chain as depicted in Figure 3.1. The estimation of LRAC for each offtake point in the Myanmar gas network involves adding up LRAC of relevant gas supply costs (calculated at the inlet to the transmission system); and LRAC of relevant gas transportation costs (at offtake points from the gas network).

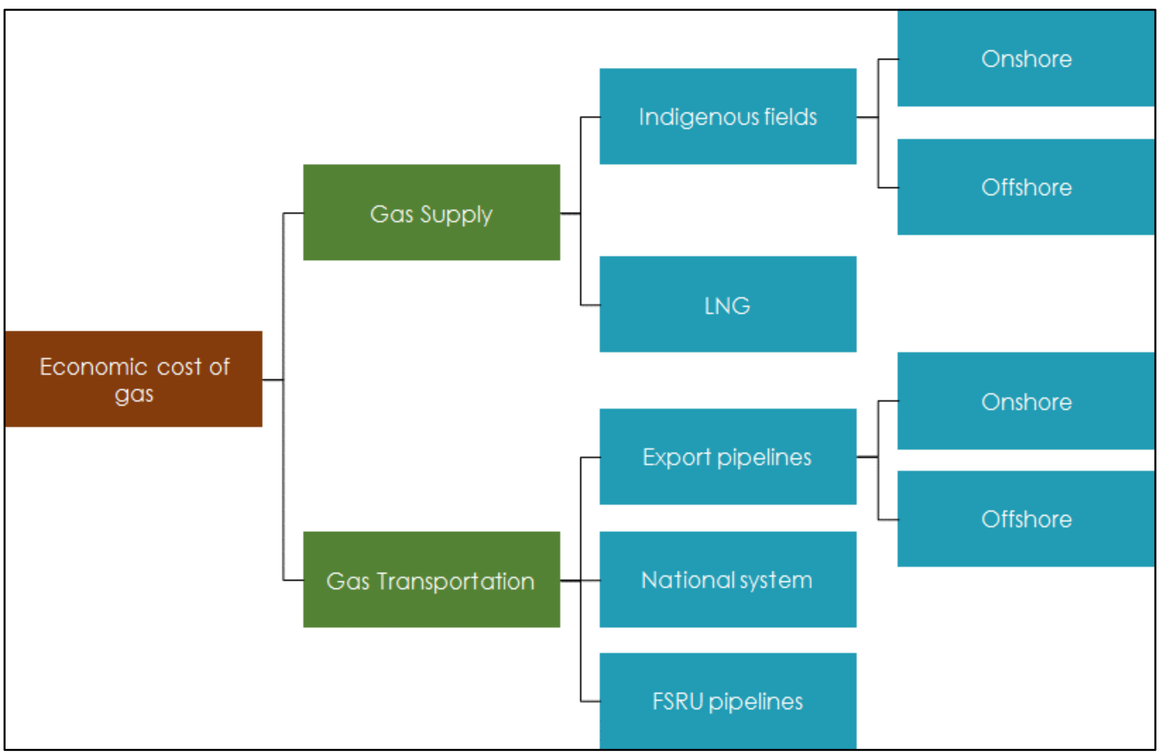


Figure 3.1 Supply and transmission sub-components of gas economic cost in Myanmar

81. The economic costs are calculated on the same unit cost basis ($ per mmbtu) and are additive, i.e. they can be summed up by offtake to provide a total economic cost per offtake. Depending on

the offtake's location and sourcing of gas, the estimation of its LRAC may involve some or all of the below components of gas supply and gas transportation.

Gas supply costs encompass:

- the cost of gas produced in indigenous (onshore and offshore) gas fields in Myanmar;
- the cost of LNG swaps i.e. LNG procured by Myanmar and provided to countries with which Myanmar has export contracts for natural gas through pipelines, in lieu of its obligations, so that the equivalent natural gas quantities can be diverted to Myanmar's domestic customers;
- the cost of LNG imports i.e. LNG imported and regasified in facilities located in Myanmar, for supplying its domestic market.

Gas transportation costs encompass:

- the cost of transporting gas from the offshore fields to designated offtake points in the gas network, through 'export' offshore and onshore pipelines;
- the cost of transporting gas through the national transportation network:
  - from the onshore fields to designated offtake points in the gas network;
  - from the offshore field of Yadana to its designated offtake point Daw Nyein;
  - from the offtake points to the customers.
- the cost of transporting gas from the LNG import terminal to the offtake points, through offshore and onshore pipelines.

82. The broad steps to LRAC estimation are the following:

- Forecast average annual volumes of gas corresponding to the gas supply chain segment being costed, for e.g. volumes of gas supplied by a field when assessing the gas costs of that field, volumes of LNG demanded when assessing LNG import costs, volumes of gas transported through the domestic transport system when assessing the domestic gas transportation costs, etc.
- Develop an investment plan for capacity and infrastructure expansion that ensures that the gas volumes pertaining to the segment of the gas supply chain examined can be accommodated e.g. investment plan for a gas field when assessing the gas costs of that field, investment plan of LNG terminal and infrastructure when assessing LNG terminal and infrastructure costs, investment plan for rehabilitation or upgrade or expansion of the domestic transport system when assessing domestic gas transportation costs, etc.

- Estimate year-on-year economic costs pertaining to the segment of the gas supply chain examined over the examined horizon. The components of economic costs are provided in detail in Annex 6: Economic cost of gas methodology.

- Calculate LRAC as the present values of the sum total of year-on-year economic costs, divided by the present values of the sum total demand satisfied year-on-year. The real discount rate used in our economic cost analysis is 6.5% (see Annex 7: Discount Rate Estimation for details).

Table 3.1Indicative example of estimation of LRAC for domestic gas transport system

Indicative example of estimation of LRAC for domestic gas transport system

	Years							
	0	1	2	3	4	5	6	7 – 14
Volume of gas transported via domestic transport system (mmbtu million)	1,500	1,800	2,300	2,700	2,900	3,300	3,900	4,500
Economic cost of domestic gas transportation system ($ million)	1,000	1,500	2,000	2,300	2,600	3,000	3,500	4,000

Note: Year 0 is the present year

Real discount rate: 6.5%

$$\text{LRAC} = \frac{\text{PV of } \mathit{Economic\ cost\ of\ domestic\ gas\ transportation\ system}\ (\$\ \mathit{million})}{\text{PV of } \mathit{Gas\ Transported\ via\ domestic\ transport\ system}\ (\mathit{mmbtu\ million})}$$

Whereas

PV of *Economic cost of domestic gas transportation system ($ million)* =

$$\text{Cost at Year 0} + \sum_{k=1}^{14} \frac{\mathit{Economic\ cost\ at\ Year\ k}}{(6.5\% + 1)^k} = \textbf{29,376\$ million}$$

PV of *Gas volume transported via domestic transport system (mmbtu million)* =

$$\text{Volume at Year 0} + \sum_{k=1}^{14} \frac{\mathit{Volume\ at\ Year\ k}}{(6.5\% + 1)^k} = \textbf{33,567 mmbtu million}$$

Thus **LRAC = 0.88 $/ mmbtu**

83. The above steps were applied for the calculation of LRAC for the domestic gas transportation system and for the LNG FSRU terminal and pipelines infrastructure. In these cases, although investment plans were lacking, the Consultant nevertheless was able to produce estimates of

required investments. In the case of domestic gas transportation system, we estimated pipelines replacement programs, reinforcement and expansion investments. In the case of LNG FSRU terminal and pipelines infrastructure we used data from a recent feasibility study and international benchmarks.

84. As far as calculation of LRAC of offshore gas fields' gas supply, we used wellhead prices under existing PSA contracts as a proxy to revenue requirement. For these fields, there is no available data on investment and development plans or operating expenditures, and their estimation is not possible. In these cases, the wellhead price included in the contract terms for gas supplies from these fields can be taken as a good proxy to the economic cost, as this 'commodity' set-by-contract price is linked to the traded/market price for gas.

85. As far as calculation of LRAC for onshore gas fields, there is limited available data on investment and development plans as well as historical asset values and depreciation. Additionally, there is absence of a market/traded linked contract price for gas supplied from these fields (as is the case with offshore PSA contracts). On the basis of complete available historical data for two of the seven onshore fields, Kyaukkwet and Mann, we projected the required revenue for the remaining five fields.

86. The resulting economic cost of onshore fields were found to be low compared to that of offshore fields, due to low OPEX and CAPEX values, low asset values and low return on assets. Thus there is a case for including in the costs of onshore fields a 'depletion premium' to reflect the 'economic rent' associated with the exhaustion of a non-renewable resource. The economic rent reflects the cost of sourcing gas from more expensive sources(sources in costlier development areas – further offshore and deeper – or the cost of imports) following depletion of these fields, and thus provides domestic customers with a signal for efficient use of resources. The cost of LNG imports is taken as a proxy to the opportunity cost of gas following depletion of existing sources i.e. the depletion premium. This depletion premium is added post 2030, when it is assumed that production levels from current onshore fields could be phased out, and forms part of the calculation for onshore gas supply fields' LRAC.

87. In years where demand exceeds available supply, the cost of additional gas supplied to the customers can be taken as the cost of alternative sources, namely LNG, either swapped for export gas obligations or physically imported, regasified and used in Myanmar after the construction and operation of relevant facilities. LRAC is also applied separately to estimate the cost of additional gas sources e.g. LNG, that are required to satisfy demand over and above the assumed production levels of onshore fields and the available domestic supply of offshore fields.

88. The detailed approach to LRAC application and estimation in each segment of the gas supply chain is described in Chapters 6 to 9.

4 Overview of Myanmar's key gas production and transportation infrastructure

89. In this section, we provide an overview of outline of key gas production and transportation infrastructure in Myanmar.

4.1 Offshore gas fields

90. Myanmar has four offshore gas producing fields, operating under PSA framework:

- Shwe
- Yadana
- Zawtika
- Yetagun

The first three fields supply both the export and domestic markets, whereas Yetagun is exclusively oriented to exports.

91. Yadana started production in 1999, with annual production volumes ranging between 200,000 and 300,000 bcf until today. Production is expected to decline henceforth, reaching levels below 100,000 bcf by 2025/26. The majority of Yadana gas has been and will continue to be exported to Thailand. Historically, domestic consumption accounted for 1% to 26% of production, averaging at around 11%. Forecasts of available supplies for domestic use are from 31% of production declining to 22% of production, in the period to 2025/26, averaging at around 26% of production.

92. Zawtika started production in 2014, with annual production volumes in the years until today ranging between 84,000 and 118,000 bcf. Production is expected to increase to 126,000 bcf in 2016/17, with levels maintained until 2023/24, declining to around 77,000 in 2025/26.The majority of Zawtika gas is exported to Thailand. Forecasts of available supplies for domestic use range between 23% to 47% of production, in the period to 2025/26, averaging at around 30% of production.

93. Yetagun started production in 2000. Production is assigned only to exports. Yetagun production is nevertheless expected to decline significantly, reaching around 13% of today's production levels by 2025/26.

94. Shwe also started production in 2014, with annual production volumes in the years until today ranging between 42,000 and 174,000 bcf. Production is expected to increase to around 182,000 bcfin 2016/17, with these levels maintained until 2025/26.The majority of Shwe gas is exported to China. Historically, available supplies for domestic use ranged between 1% to 9% of

production. It is forecasted that domestic use will account for around 20% of production in the period to 2025/26.

95. Detailed description of demand and supply from offshore fields is provided in Section 5.

4.2 Onshore gas fields

96. There are 7 onshore fields listed below (in parentheses the start of production date) whose production is exclusively oriented to supplying the domestic gas market:

- Mann (1970)
- Htauk Sha Bin (1978)
- Apyauk (1991)
- Kyaukkwet (1995)
- Nyaung Don (1999)
- Thar Guyi Taung (2001)
- Ma U Bin (2006)

97. Total production of these fields was about 46 bcm in 2004/5 and rapidly declined over the years reaching about 19 bcm in 2015/16.It is forecasted that production from these fields will be around 17 bcm p.a. in the period 2016/17 to 2024/25.Of the 7 onshore fields, Nyaung Don has the largest gas production, accounting for 36% of total onshore gas production, followed by Kyaukkwet (21%), Ma U Bin (17%) and Apyauk (15%).

98. Detailed description of demand and supply from onshore fields is provided in Section 5.

4.3 Export pipelines

99. The export pipeline, carrying gas from the offshore Shwe field to the border with China, stretches for 552 miles within Myanmar's territory. This pipeline is connected with the national transmission system, supplying 4 offtake points of Kyauk Phyu, Taung Thar, Yenanchaung and Belin (Mandalay).The export gas pipeline has an annual capacity of twelve billion cubic metres of gas, and is comprised of two parts:

- The Daewoo owned subsea pipeline with a length of 60 miles and a 40-inch diameter;
- The 492 miles long onshore pipeline with a 32-inch diameter, named South East Asia Gas Pipeline Company (SEAGP), is operated by CNPC and owned by CNPC, MOGE, Daewoo International, KOGAS, Indian Oil and GAIL companies.

100. The 1998 built export pipeline linking the Yadana offshore field to the border of Thailand has a length of 216 miles of offshore pipeline with a 36" diameter and a length of 39 miles of onshore pipeline with a 36" diameter. This pipeline is nevertheless not used for supplying gas to the

domestic market. In 2009-2010, a new Yadana-Yangon domestic offshore pipeline with a 24 inch diameter 40 and length 180 miles was built for this purpose. It is comprised by a 94.5 miles long subsea pipeline and an 85.4 onshore pipeline connecting the Yadana field with the Daw Nyein offtake.

101. The 2012-2013 built export pipeline linking the Zawtika offshore field to the border of Thailand has a length of 143 miles of offshore pipeline with a 28" diameter and a length of 43 miles of onshore pipeline with a 28" diameter. This pipeline connects to the national transportation system at the Kanbauk offtake.

102. Finally, there is a 170-mile-long export pipeline linking the Yetagun offshore field to the border of Thailand, built in 2000. This 24" diameter pipeline comprises 126 miles of offshore pipeline and 44 miles of onshore pipeline. This pipeline though is used exclusively for exports and does not supply the domestic market.

4.4 National Transportation System

103. The pipeline network of the national transportation system (NTS) has a total length of 2,500 miles and average age of 14 years. The diameter of the pipelines comprising the NTS ranges from 6 to 30 inches. The first pipeline was constructed/ commissioned in 1969, while the network grew significantly in the 1990s when more than 800 miles of pipelines (or 33% of the current network) were added to the system. More than 60% of the current network was constructed/ commissioned after 2000. Figure4.1 shows the NTS network in Myanmar, as well as export transmission pipelines, and the connections to gas fields and offtake positioning.

104. A key part of the system is the recently constructed pipeline connecting Yadana field to Daw Nyein offtake with a total length of 180 miles and diameter of 24 inches, mentioned in the preceding Section. This is the only one section of the NTS that includes an offshore segment and the only one pipeline of the NTS that is directly connected to an offshore field. The latest segment that has been added to the system is a 30-inch pipeline, connecting Ywama, Hlawga and Tharkayta, which was commissioned in 2015.

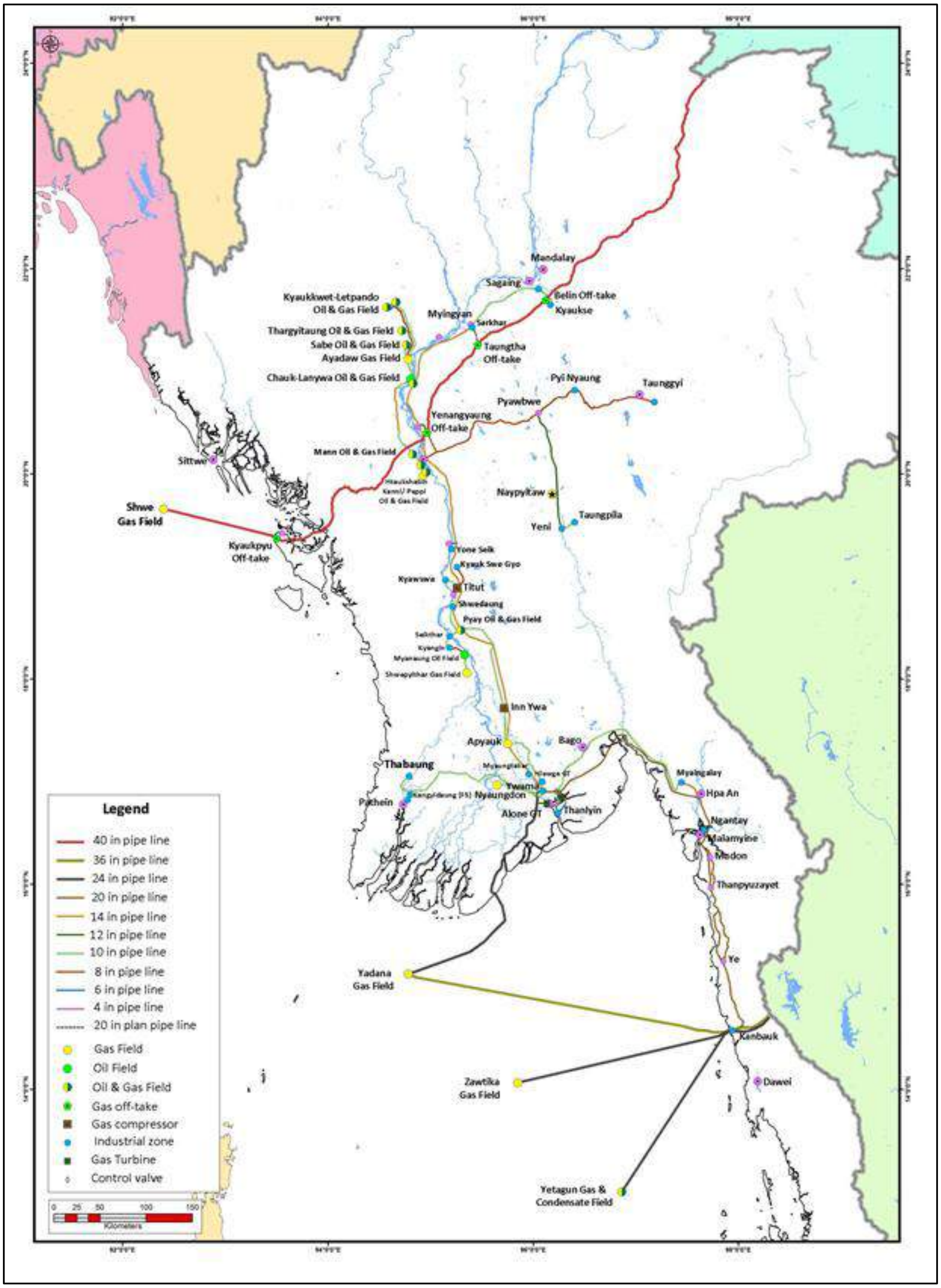


Figure4.1Map of Myanmar gas network

4.5 Offtakes

105. Table 4.1 Main offtakes and corresponding gas fields supplying each offtakebelow details the 14 main offtake points in the Myanmar gas network designated by MOE, for each of which the Consultant undertook to estimate the economic costs of gas supply. The table also provides information on the gas field(s) currently supplying each offtake, according to MOE. Figure 4.2 highlights the location of each offtake on the gas network of Myanmar.

Table 4.1 Main offtakes and corresponding gas fields supplying each offtake

No	Offtake	Supplied form field(s)
1	Ayadaw	Kyaukkwet and Thar Gyi Taung
2	Chauk	Kyaukkwet and Thar Gyi Taung
3	Kyaukse	Kyaukkwet and Thar Gyi Taung
4	Htauk Sha Bin	Mann and Taung Htauh Sha Bin
5	Mann	Mann and Taung Htauh Sha Bin
6	Nyaung Don	Apyauk, Nyaung Don and Ma U
7	Myaungdagar	Apyauk, Nyaung Don and Ma U
8	Ywama	Apyauk, Nyaung Don and Ma U
9	Kyauk Phyu	Shwe
10	Taung Thar	Shwe
11	Yenanchaung (for Tanguyi and Ney Pyi Taw)	Shwe
12	Belin (for Mandalay and also Kyaukse)	Shwe
13	Daw Nyein (for Yangon)	Yadana
14	Kanbauk (also for Malamyine)	Zawtika

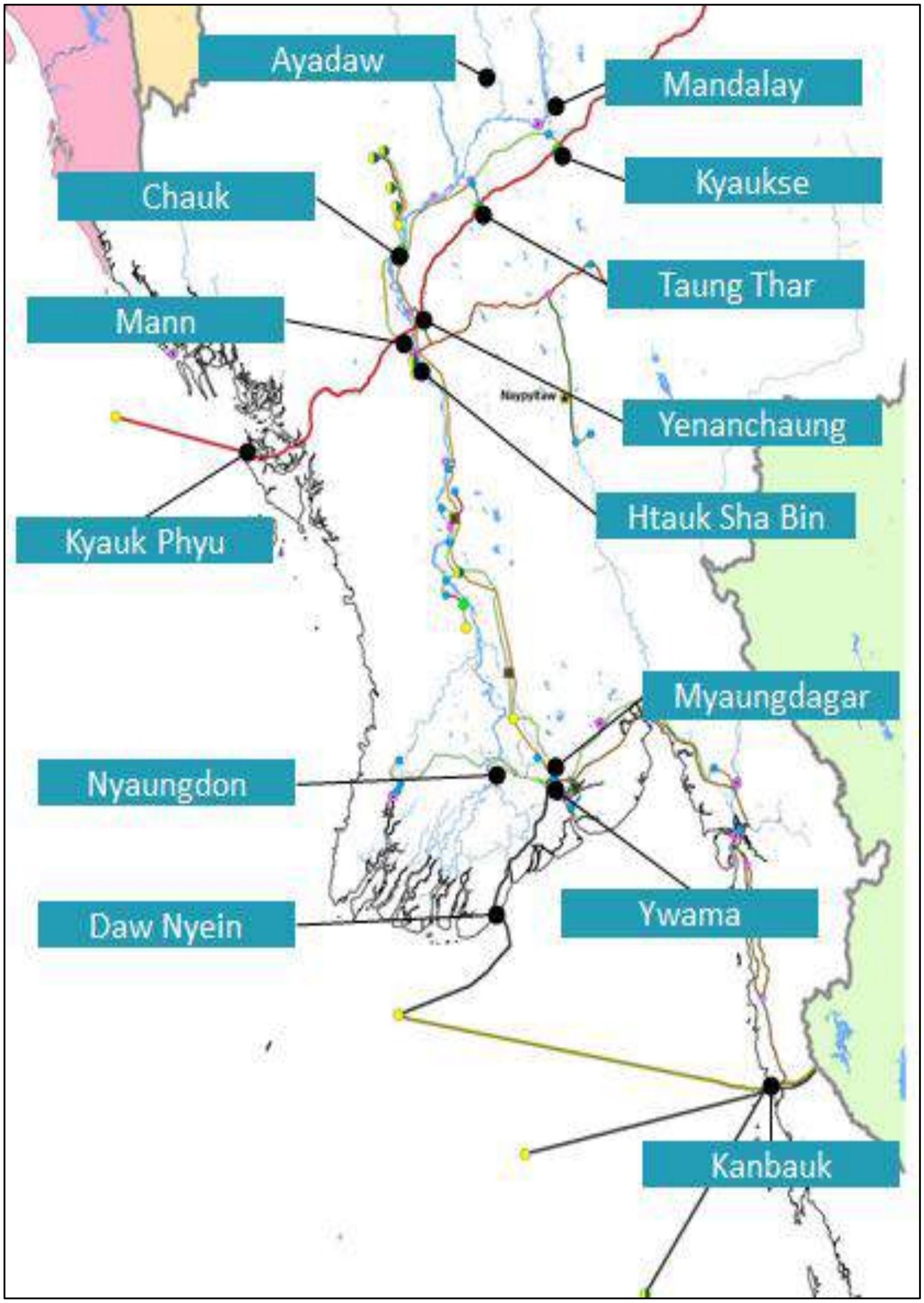


Figure 4.2 Geographic location of offtakes

5 Demand and Supply of gas in Myanmar

5.1 Introduction

106. Myanmar is a net natural gas exporter, supplying gas to China and Thailand. Domestic gas consumption has been historically limited, and driven by the available gas volumes indigenously produced that were not exported. The power sector accounts for the overwhelming majority of natural gas consumption (currently around 70%), while the rest is consumed mainly by industries, CNG filling stations and refineries.

107. The country's plans for electrification, and the subsequent need for additional power generating capacity, is expected, according to the Ministry of Electricity, to lead to the construction of new gas-fired power plants. The commissioning of these new plants, which is planned until 2021, will lead to a strong growth in domestic gas consumption, and result in 2.5-fold increase in demand from current levels (around 300 mmcf/d on average in 2014-15) to around 750 mmcf/d on average in 2020-21 onwards (Figure 5.1). The largest part of this increased demand will be attributed to a limited number of offtakes of the gas system, which will serve the new power plants.

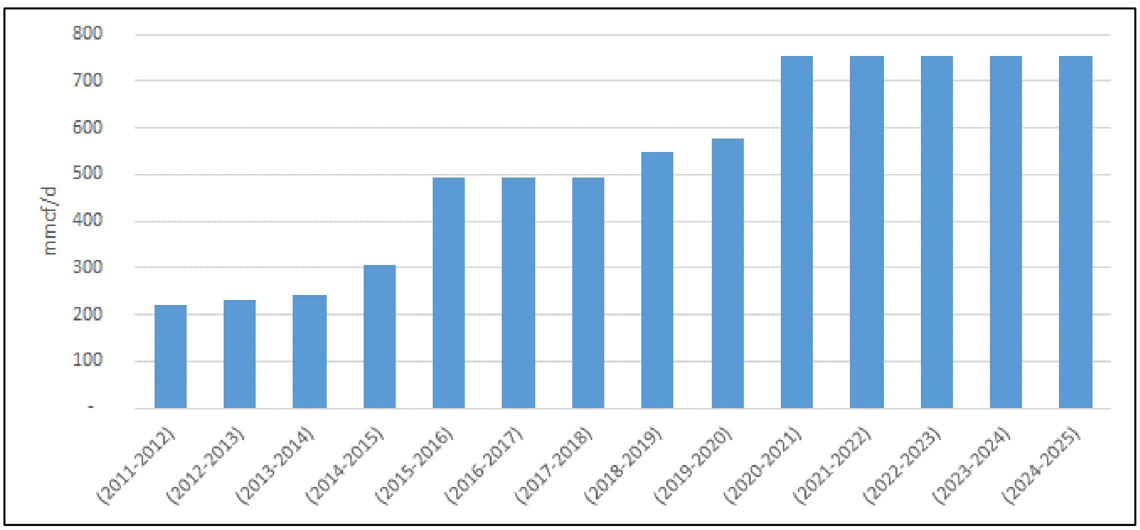


Figure 5.1 Historic and forecasted growth of gas demand in Myanmar (Source: MOGE, Consultant's estimations)

108. Domestic market is currently supplied from indigenous sources, primarily offshore fields which supply 81% of the domestic market supplies (2014-15). Offshore fields provide the bulk of their production to the export market. The availability of indigenous gas supply for the domestic market is nevertheless decreasing, as production from both onshore and offshore fields is predicted to drop from 2020-2021 onwards (Figure 5.2).

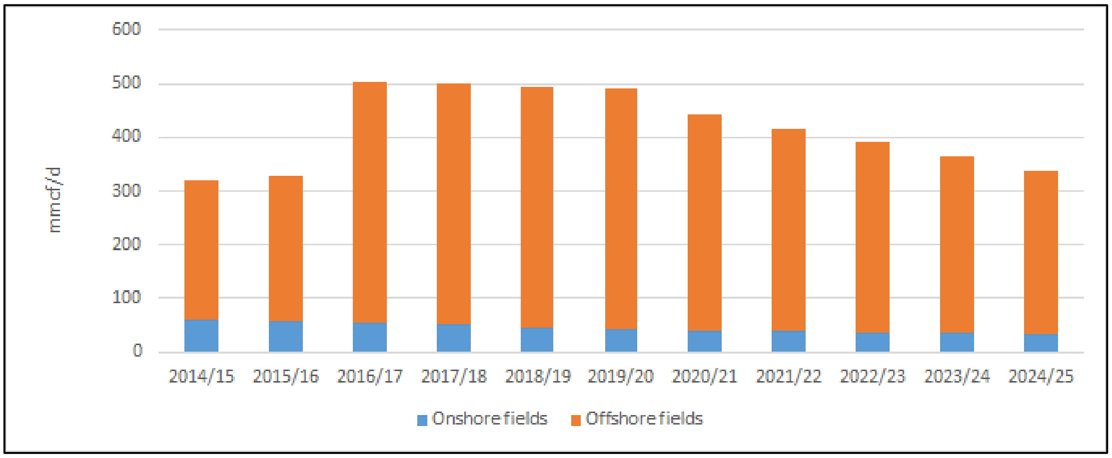


Figure 5.2 Domestic gas supply from existing indigenous fields in Myanmar

(Source: MOGE, Consultant's estimations)

5.2 Approach for estimation of future demand and supply

109. Future demand at each of the offtake points is estimated using a bottom-up approach, aggregating the consumption of the final customers served from the respective offtake. The indigenous gas supplies available for each off-take are estimated the same way, aggregating the forecasted production of the gas fields connected to the offtake. The data used for the estimations are primarily based on inputs provided by MOGE for projections of supply and of future consumption at existing final customers, as well as on Consultant assumptions for expected consumption at new gas-fired power plants. The supply gap or surplus of each offtake is estimated by comparing the available supply with the demand at the offtake (Figure 5.3).

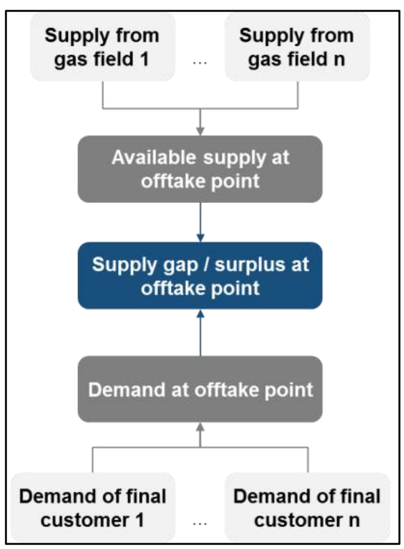


Figure 5.3 Approach for estimation of demand, supply and supply gap

5.3 Demand for gas overview

5.3.1 Industrial/commercial demand

110. The industrial and commercial demand examined mainly includes gas used in Myanmar industries for energy and feedstock, oil refineries and CNG filling stations. The projections for industrial/commercial demand for the period from 2015-16 up to 2024-25 were provided by MOGE. According to these projections, demand is expected to increase more than 2-fold from around 70 mmcf/d on average in 2014 – 15to around 150 mmcf/d on average in 2015 – 16 onwards (Figure5.4), driven primarily by demand from existing paper and cement plants and oil refineries, as well as by new plants, mainly in metallurgy and cement industries.

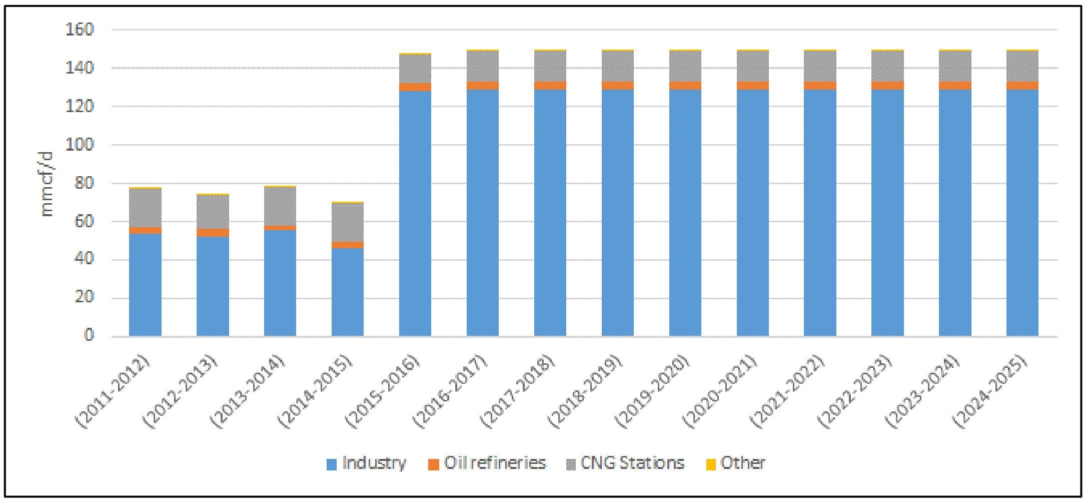


Figure5.4 Historic and forecasted growth of industrial/commercial demand (source: MOGE)

111. As the estimation of the economic cost of gas supply is carried out for the period of 2015 – 2030, while demand forecasts from MOGE were provided up to 2025, gas demand is assumed to remain constant for the period 2026 – 2030.

5.3.2 Electricity sector demand

5.3.2.1 Current plants

112. Currently there are 19 gas-fired power plants in operation in Myanmar with total installed capacity of 1,680 MW. Ten of these plants (installed capacity 906 MW) are owned by the Ministry of Electricity, 6 (installed capacity 512 MW) owned by Independent Power Producers (IPPs) and 3 (installed capacity 264 MW) are rented gas engines. The vast majority of power plants (with the exception of the Kyaung Chaung Gas Turbine) are being supplied by the off-shore fields Yadana, Shwe and Zawtika.

113. Table 5.1 below summarizes the existing power plants, their installed capacity, year of commissioning and supplying gas field.

Table 5.1 Existing gas-fired power plants in Myanmar (source: Ministry of Electricity)

Power plant	Owner	Installed Capacity (MW)	Year built/ commissioned	Supplying field
Kyaung Chaung Gas Turbine	MOE	54,3	1974	Kyaukkwet + Thar Guyi Taung
Kyauk Phyu Gas Turbine (V-Power)	Rental	50,0	2013-2015	Shwe
APR GEG (Kyauk Se)	Rental	110,6	2014	Shwe
Ahlone Gas Turbine	MoE	154,2	1995-1999	Yadana
Toyo Thai Gas Turbine (Ahlone)	IPP	121,0	2013-2014	Yadana
Ywama Gas Turbine	MOE	70,3	1980	Yadana
Ywama EGAT CCGT	MOE	240,0	2014	Yadana
Hlawgar Gas Turbine	MOE	154,2	1996-1999	Yadana
MCP Gas Engine (Hlawgar)	IPP	54,6	2013	Yadana
Shwe Taung Gas Turbine	MOE	55,4	1982	Yadana
Mayan Aung Gas Turbine	MOE	34,7	1975	Yadana
Mawla Myaing Gas Turbine	MOE	12.0	1980	Zawtika
Tha Htone Gas Turbine	MOE	51,0	1975, 1985, 2001	Zawtika
Tha Ke Ta Gas Turbine	MOE	92,0	1990, 1997	Zawtika
Max Power (Tha Ke Ta)	IPP	50,0	2013	Zawtika
UPP (Ywama) GT/GE	IPP	50,0	2014	Yadana
Myanmar Lighting (Malamyine)	IPP	230,0	2014	Zawtika
Kanbauk GE	IPP	6,0	2015	Zawtika
Aggreko (Tanintharyi) GE	Rental	103,0	2015	Zawtika

5.3.2.2 Planned power plants

114. Within the next 5 years the installed capacity of gas-fired power plants in the country is expected to more than double, with the commissioning of new plants by the Ministry of Electricity and IPPs (Figure 5.5). All the planned plants will be supplied by the off-shore fields, and in particular Yadana and Zawtika.

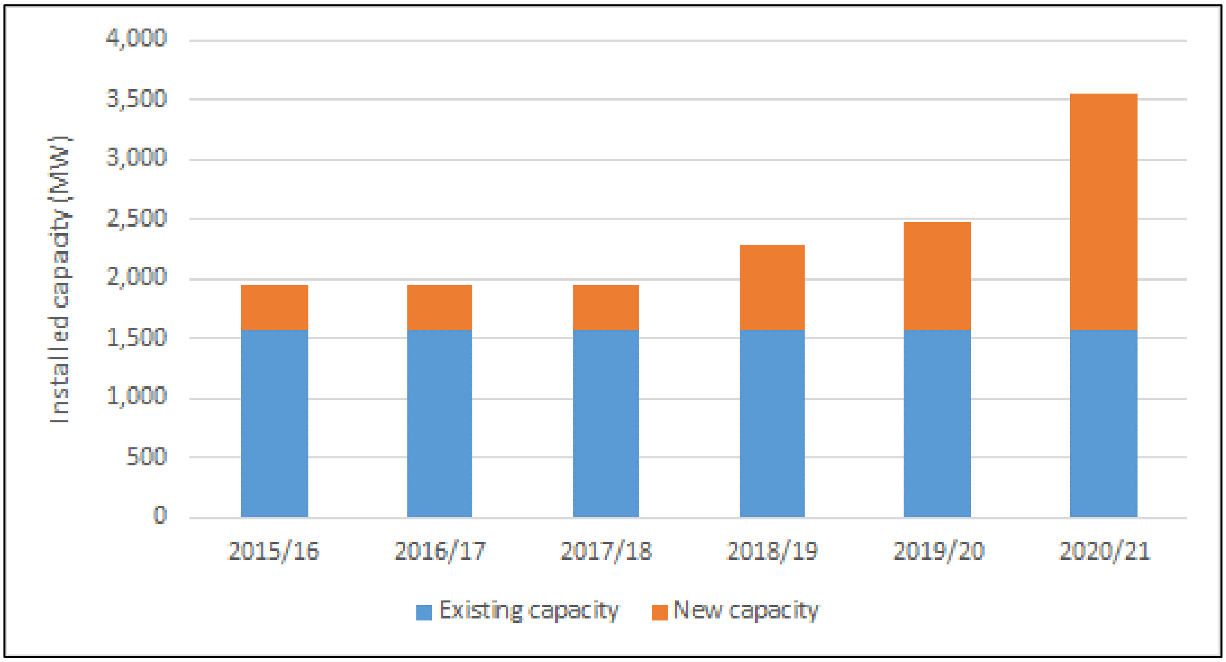


Figure 5.5 Growth of gas-fired installed capacity (Source: MOE, Ministry of Electricity)

Table 5.2 summarizes planned power plants as defined by the Ministry of Electricity and the Myanmar Electricity Master Plan, their installed capacity, expected year of commissioning and supplying gas field

Table 5.2 Planned gas-fired power plants in Myanmar (Source: Ministry of Electricity)

Power plant	**Installed Capacity (MW)**	**Year built/ commissioned**	**Supplying field**
Myinchan	225	2015-16	Shwe
Thilawa (Yangon) GT	50	2018	Yadana
Be One CCGT (Hlawga)	200	2020-21	Yadana
HDL CCGTs (Hlawga)	200	2020-21	Yadana
IPP CCGT (Ayeweyarwdy)	400	2020-21	Yadana
Thaton CCGT	120	2018-19	Zawtika
Eden (Thaketa) CCGT	80	2020-21	Zawtika
BKB CCGT (Thaketa)	200	2020-21	Zawtika
UREC CCGT (Thaketa)	109	2018-19	Zawtika
Kanbauk CCGT	200	2019-20	Zawtika

5.3.2.3 Estimation of future gas demand of power plants

115. MOGE has provided forecasts for the future gas demand of the existing power plants owned by the Ministry of Electricity and for some of the IPPs. The Myanmar Electricity Master Plan was

also used by the Consultant as a source for future consumption of plants. For particular cases of planned power plants for which no consumption data was available, the Consultant performed estimated based on the assumed operation and efficiency of the plants. The following parameters are taken into consideration, to estimate gas consumption of the power plant, as depicted in Figure 5.6:

- Installed capacity of the power plant;
- Average load factor of the power plants annual operation (assumed 85% for all plants)[3];
- Efficiency factor of the plant, depending on its type (CCGT, Gas Turbine, Gas Engine). The assumptions for efficiency factors used in the Myanmar Electricity Master Plan have been applied;
- Gross calorific value of gas. Differs depending on the source of gas supplying the plant.

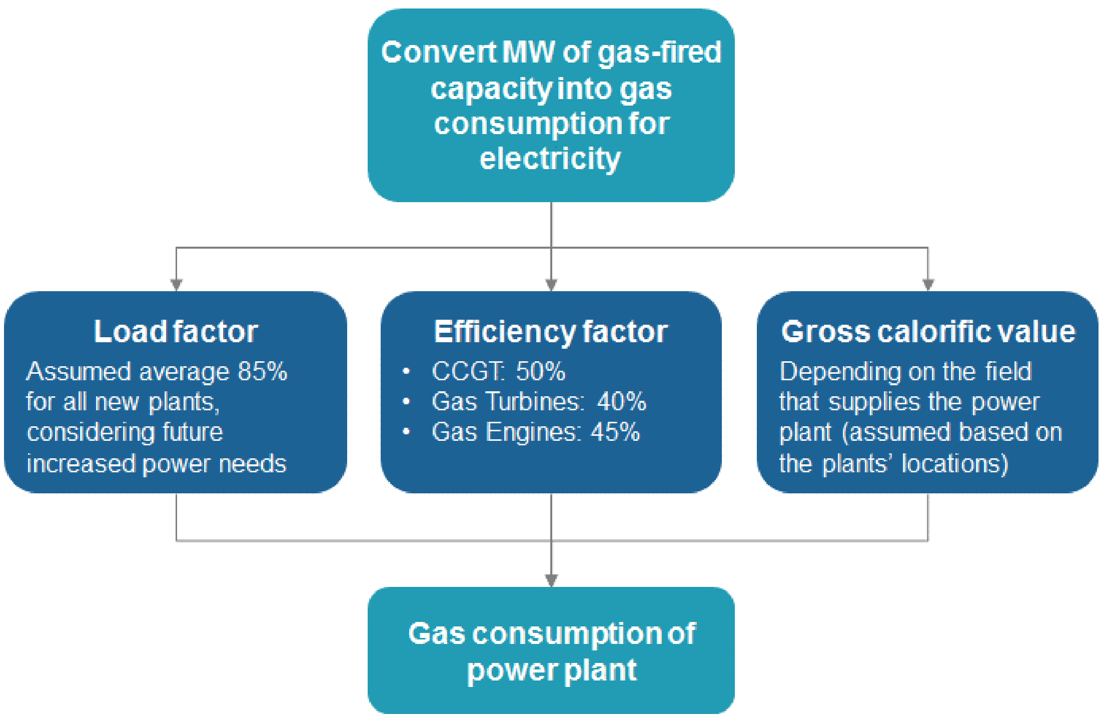


Figure 5.6 Approach for estimation of gas consumption of power plants

[3] The 85% average load factor for all plants was adopted in the absence of detailed demand plans for the power sector and a gas master plan. The 85% load factor reflects the high anticipated utilization rate of gas power plants in the context of intensified Myanmar electrification, and the low rate of hydro plants utilization during the dry season, whilst allowing for a reasonable downtime and contingency factor for gas power plants' operation.

116. The table below presents the source used for the projection of gas demand in each existing and planned power plant, and the estimated consumption in 2020-21 (for some plants MOGE has provided aggregated consumption).

Table 5.3 Future gas demand in power plants in Myanmar (source: Ministry of Electricity, Electricity Master Plan, Consultant's estimations)

Power plant	Source of data/ estimates	Average daily consumption in 2020-21 (mmcf/d)
Kyaung Chaung Gas Turbine	MOGE	2.1
Kyauk Phyu Gas Turbine (V-Power)	MOGE	8.8
APR GEG (Kyauk Se)	MOGE	0
Ahlone Gas Turbine Toyo Thai Gas Turbine (Ahlone)	MOGE	66.0
Ywama Gas Turbine Ywama EGAT CCGT	MOGE	59.5
Hlawga Gas Turbine MCP Gas Engine (Hlawga)	MOGE	50.0
Shwe Taung Gas Turbine	MOGE	13.3
Myan Aung Gas Turbine	MOGE	2.9
Mawla Myaing Gas Turbine	MOGE	2.3
Tha Htone Gas Turbine	MOGE	9.7
Thaketa Gas Turbine Max Power (Thaketa)	MOGE	27.0
UPP (Ywama) GT/GE	Electricity Master Plan	12.0
Myanmar Lighting (Malamyine)	Electricity Master Plan	43.7
Kanbauk GE	Consultant's estimates	1.0
Aggreko (Tanintharyi) GE	Consultant's estimates	16.0
Myinchan	MOGE	31.5
Thilawa (Yangon) GT	Consultant's estimates	12.0
Be One CCGT (Hlawga)	Electricity Master Plan	38.3
HDL CCGTs (Hlawga)	Electricity Master Plan	38.3
IPP CCGT (Ayeweyarwdy)	Consultant's estimates	56.0
Thaton CCGT	Consultant's estimates	18.2
Eden (Thaketa) CCGT	Consultant's estimates	12.2
BKB CCGT (Thaketa)	Consultant's estimates	30.4
UREC CCGT (Thaketa)	Consultant's estimates	16.6
Kanbauk CCGT	Consultant's estimates	30.4
Total		**598.2**

117. The expected growth of gas demand in the electricity sector is presented in Figure 5.7.

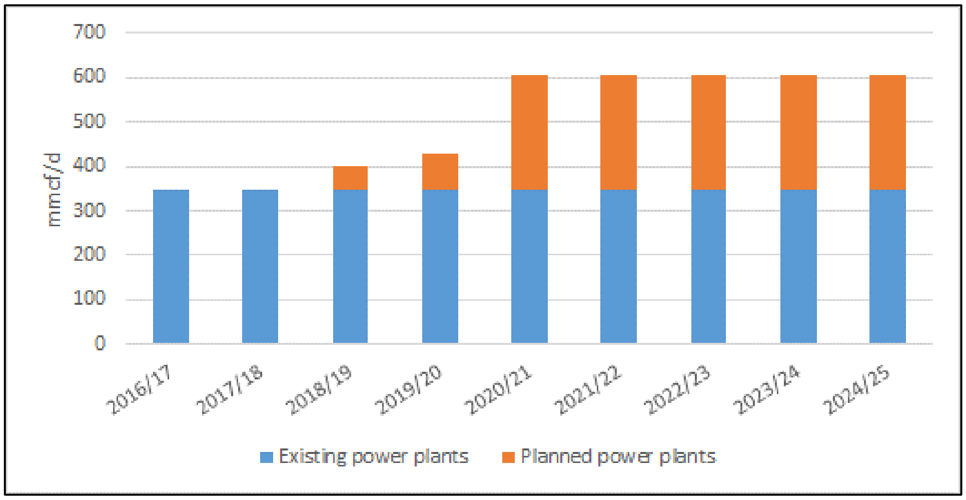


Figure 5.7 Historic and forecasted growth of power plants demand (sources: MOGE, Ministry of Electricity, Electricity Master Plan, Consultant's estimations).

118. Gas consumption at each power plant is assumed to remain constant following its commissioning. Detailed projections of gas demand for each power plant are presented in Annex 1: Gas supply and demand per offtake.

5.4 Allocation of demand for gas to each offtake

119. As described in Section 5.2 above, the demand of gas at each offtake point is estimated bottom-up, as the sum of the forecasted consumption of every final consumer served by the offtake. Demand varies significantly, depending on the number of final consumers, their size and type of consumption. The Daw Nyein and Kanbauk offtakes have by far the largest gas demand, as they serve the largest consumption centres in which most of the gas-fired power plants and large industries are concentrated. Daw Nyein and Kanbauk will also have the highest demand growth, as the vast majority of new power plants will be connected to these offtakes.

120. Table 5.4 presents the expected gas demand per offtake in selected FYs 2016-17, 2019-20 and 2020-21. It is noted that post 2020-21 gas demand is constant.

Table 5.4 Gas demand per offtake (sources: MOGE, Consultant's estimations)

	Gas demand 2016-17 (mmcf/d)	Gas demand 2019-20 (mmcf/d)	Gas demand 2020-21(mmcf/d)
Ayadaw	2.1	2.1	2.1
Chauk	1.5	1.5	1.5
Kyaukse	1.6	1.6	1.6
Htauk Sha Bin	0.8	0.8	0.8
Mann	1.5	1.5	1.5
Nyaung Done	9.2	9.2	9.2
Myaungdagar	7.7	7.7	7.7
Ywama	15.6	15.6	15.7
Kyauk Phyu	8.8	15.1	15.1
Taung Thar	31.5	31.5	31.5
Yenanchaung	33.2	33.2	33.2
Belin	11.6	11.6	11.6
Daw Nyein	253.8	300.6	475.9
Kanbauk	115.7	146.1	146.1
Total	**494.6**	**578.1**	**753.5**

121. Gas demand projections by customers at each offtake point are presented in Annex 1: Gas supply and demand per offtake.

5.5 Supply of gas overview

5.5.1 Supply of gas from existing onshore fields

122. In section 4.2 we described the seven onshore gas fields in operation in Myanmar, supplying the domestic market. All gas produced from these fields is exclusively used in the domestic market. Figure 5.8 - Figure 5.14 below provide historic and projected gas production per field, on the basis of data provided by MOGE, for the period 2015-16 to 2030-31.

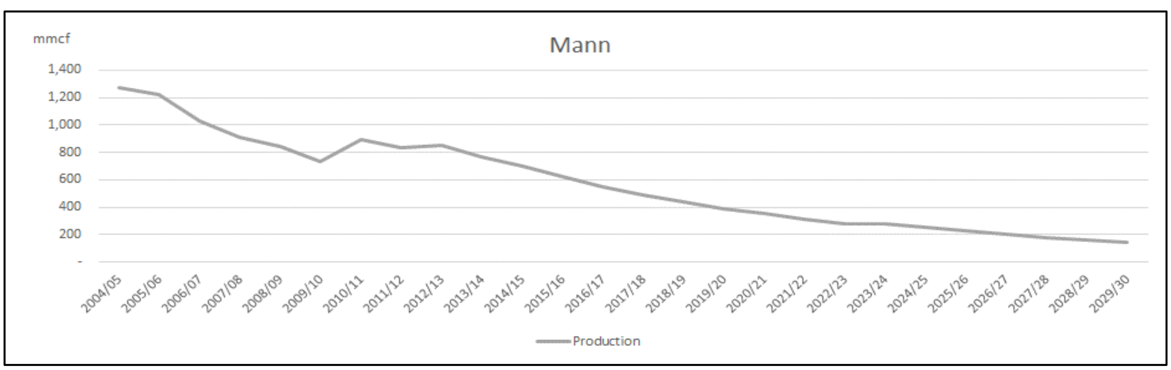


Figure 5.8 Historic and projected gas production of Mann field

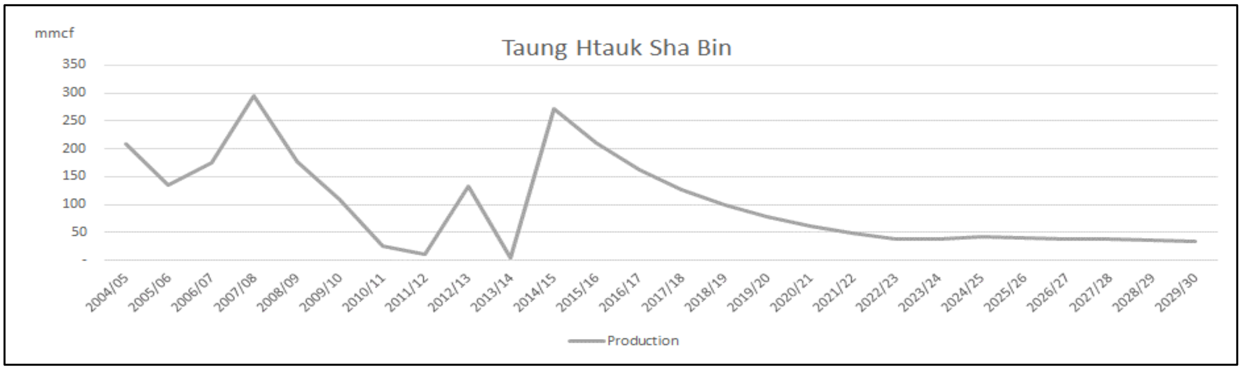


Figure 5.9 Historic and projected gas production of Taung Htauk Sha Binfield

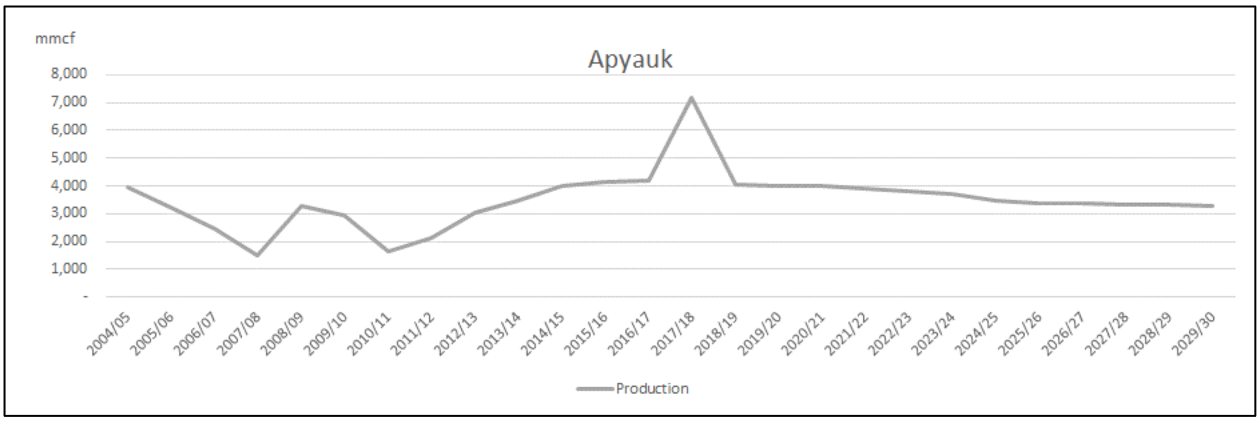


Figure 5.10 Historic and projected gas production of Apyauk field

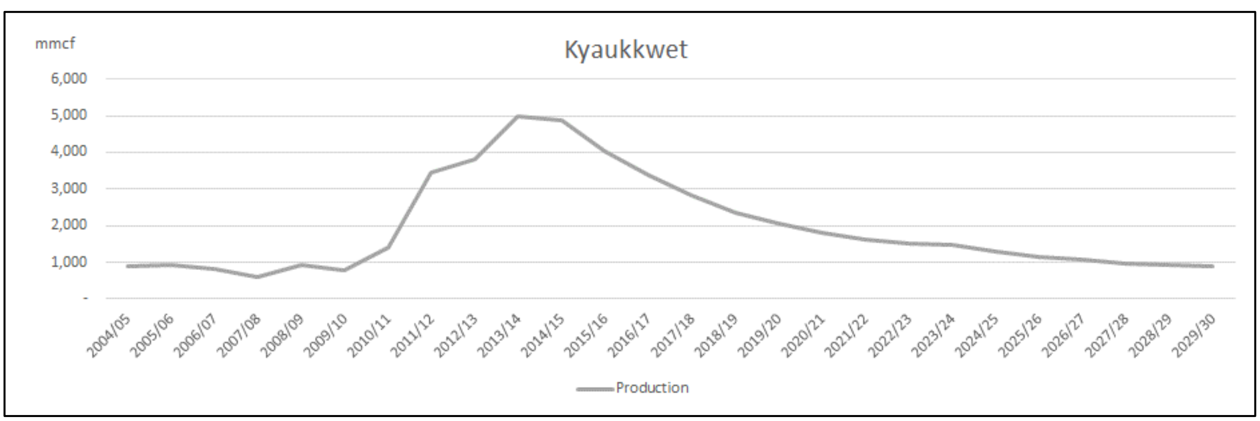


Figure 5.11 Historic and projected gas production of Kyaukkwet field

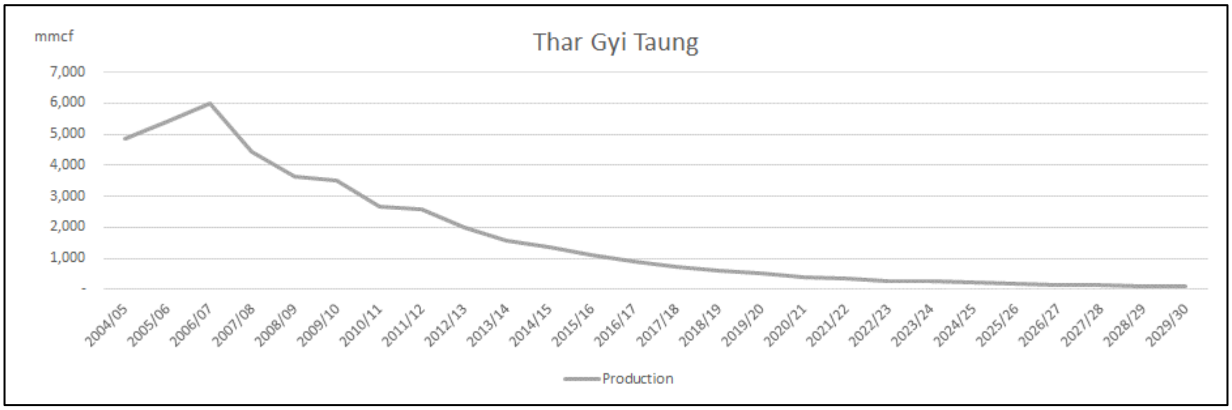


Figure 5.12 Historic and projected gas production of Thar Guyi Taung field

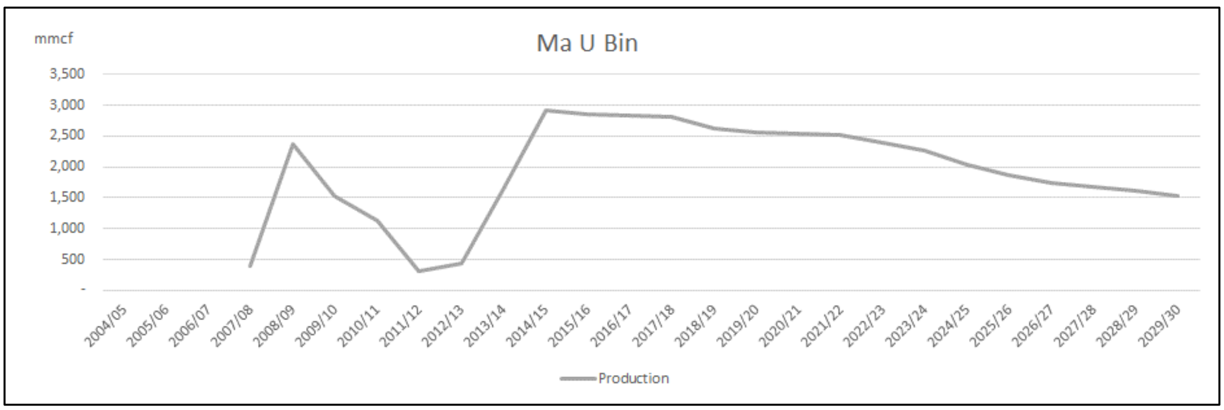


Figure 5.13 Historic and projected gas production of Ma U Bin field

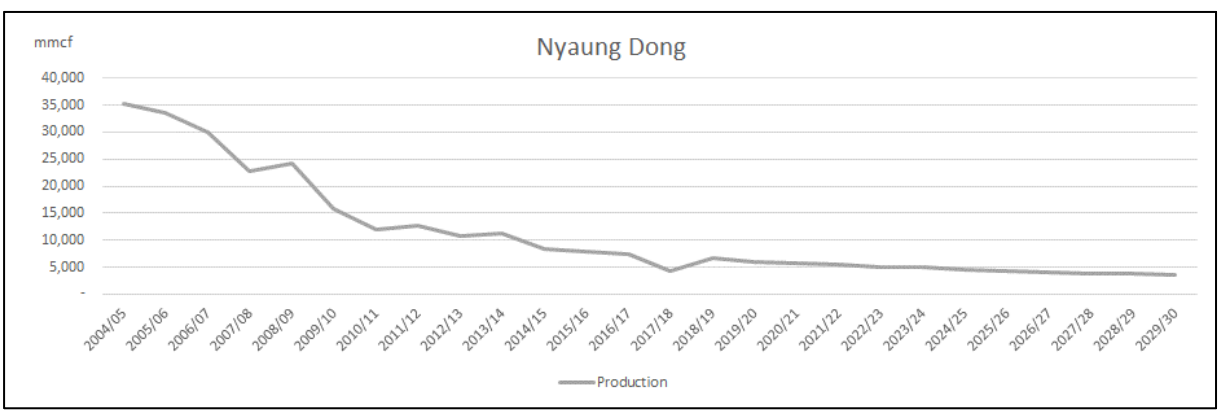


Figure 5.14 Historic and projected gas production of Nyaung Dong field

123. The consumption profile of each field is different, depending on the field's characteristics, such as its time of development and recoverable reserves. However, overall production from the onshore fields is expected to decrease in the next decade, as seen in Figure 5.15.

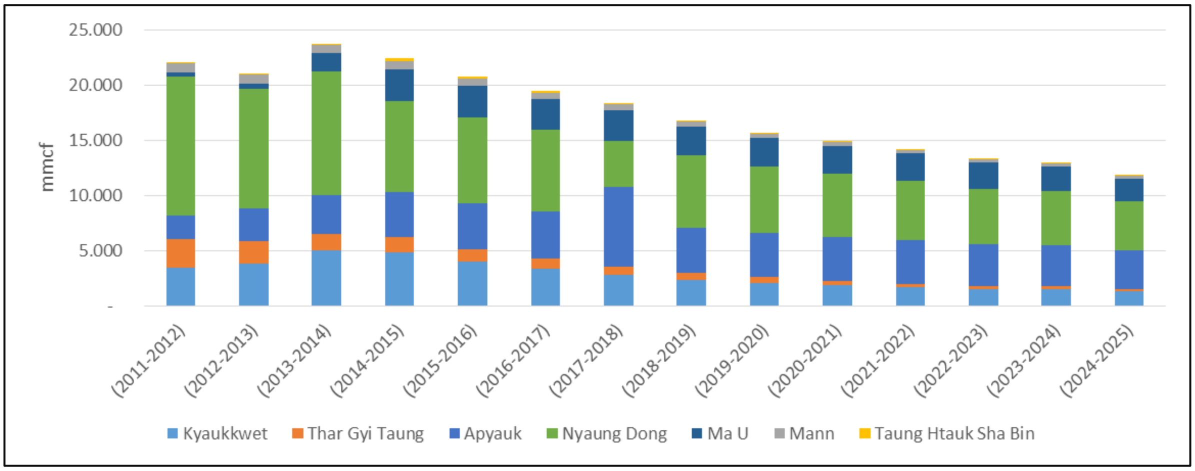


Figure 5.15 Historic and forecasted growth of gas production in onshore fields of Myanmar (sources: MOGE, Consultant's estimations)

Forecasted gas production by each onshore field is presented in Annex 1: Gas supply and demand per offtake.

5.5.2 Supply of gas from existing offshore fields

124. Most of the gas produced in Myanmar originates from the country's offshore fields of Yadana, Zawtika, Shwe and Yetagun. However, in accordance with the PSA for development of these fields, the largest part of production is exported, and only a small part is supplied to the domestic market. Specifically, the domestic market receives 31% of gas produced in Yadana, 29% of gas from Zawtika and 20% of Shwe, while Yetagun is fully export oriented. Figure 5.16 – Figure 5.18 provide production, exports and domestic supply historical and projection information for the three offshore fields (Yadana, Shwe, Zawtika) supplying the domestic market, on the basis of data received from MOGE.It is noted that MOGE provided production forecasts for the offshore fields until 2025, and thereafter it was assumed that supply directed to the domestic market would remain constant for the period 2026 – 2030. Figure 5.19 provides production information for Yetagun, for completeness purposes.

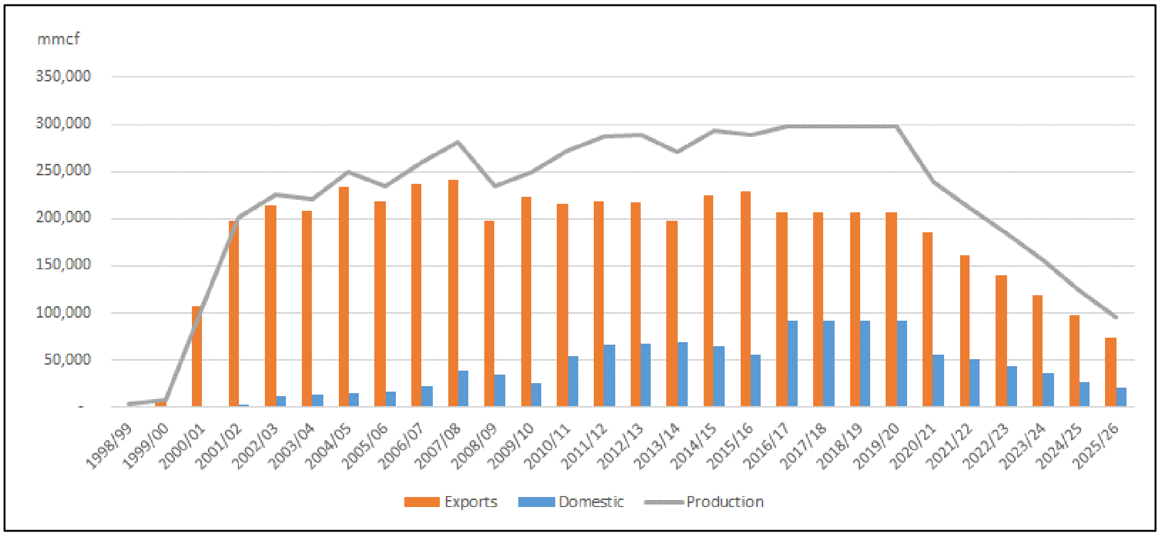


Figure 5.16 Historic and projected production, exports and domestic supply of Yadana

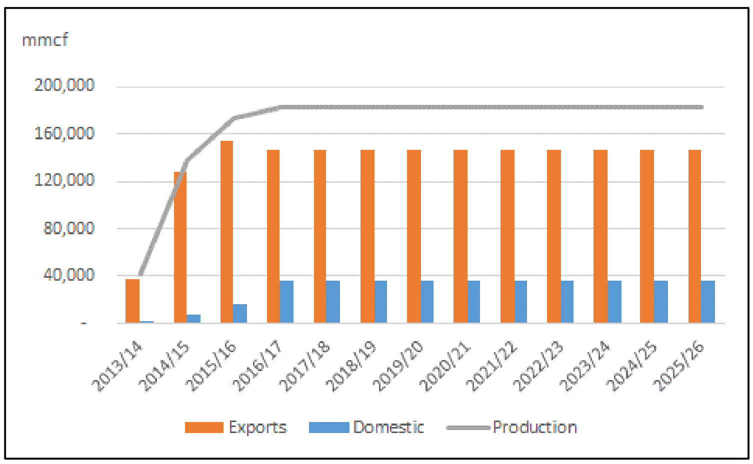


Figure 5.17 Historic and projected production, exports and domestic supply of Shwe

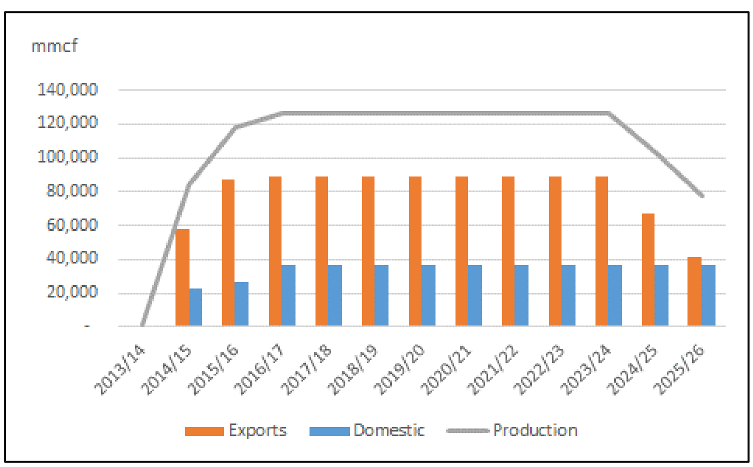


Figure 5.18 Historic and projected production, exports and domestic supply of Zawtika

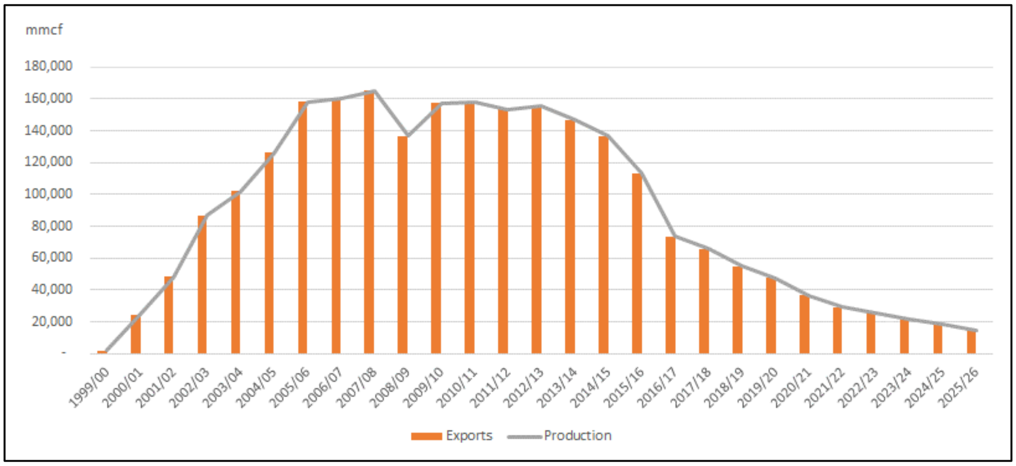


Figure 5.19 Historic and projected production and exports and domestic supply of Yetagun

125. A drop in the output of offshore fields is expected in the coming years, and especially in Yadana, which is the largest producing field. For the Yadana field, for which the PSA will end in 2020-21, it is assumed that the renegotiation of the PSA's Domestic Market Obligations (DMOs) in 2020-21, could lead to exports' share of production thereafter to be maintained at current percentage levels (69%); this would allow 31% of production to be directed to domestic use, thereby increasing volumes to the domestic market.

5.5.3 Supply of gas from new discoveries

126. Apart from the existing onshore and offshore fields, there is the prospect of enhancing supplies to the domestic market from development of new fields. According to MOGE, such prospect is uncertain and difficult to quantify. It is expected that any new discoveries cannot effectively commence production before 2025-26. Potential new discoveries that could come on stream to provide additional production of gas for the domestic market, could encompass Aung Sinkha (M3)from 2025-26 and Badamyarfrom 2029-30.

127. For Aung Sinkha (M3), reserves in line with MOE estimates are assumed to be 519 bcf, and production levels over a 10-year exploitation period are assumed to be around 52 bcf p.a. (around 140 mmcf/d on average) starting 2025-26. Badamyar is assumed to have reserves around 170 bcf, and production levels could be around 17 bcf p.a. (around 45 mmcf/d on average) starting 2029/30.Both Aung Sinkha and Badamyar are assumed to supply 100% of their production to the domestic market. The expected supply to the domestic market from new discoveries is presented in Figure 5.20.

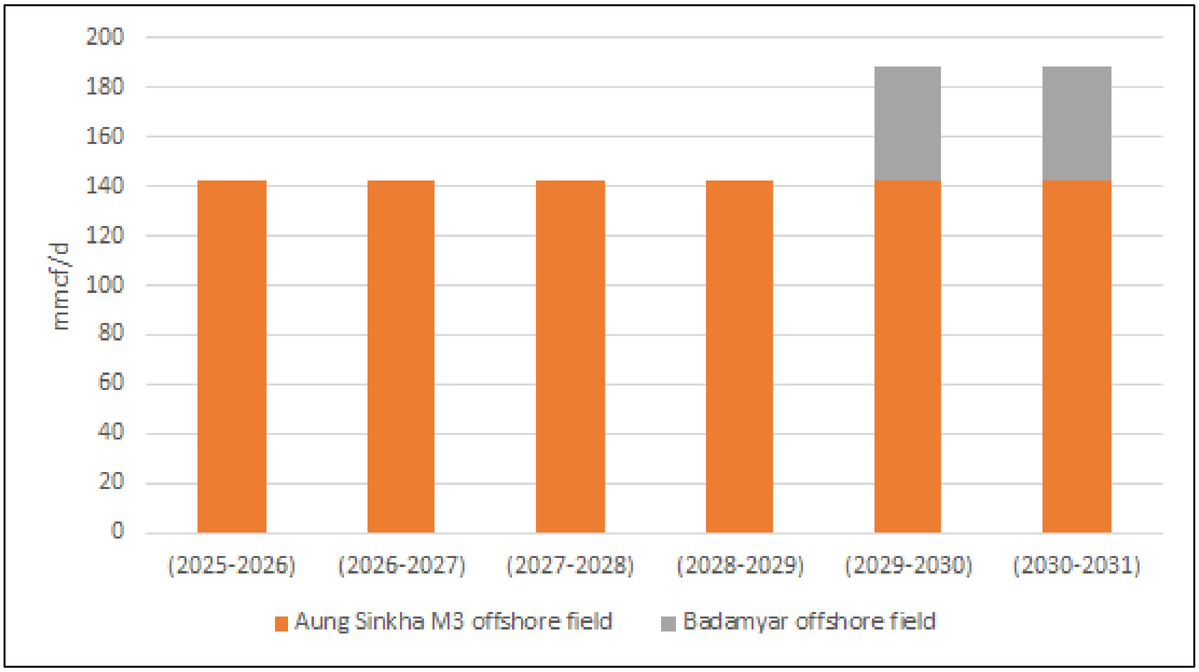


Figure 5.20 Forecasted gas production of new discoveries directed to the domestic market (Source: MOGE, Consultant's estimates)

128. Forecasted gas production from potential new fields is included in Annex 1: Gas supply and demand per offtake.

5.6 Allocation of gas fields to each offtake

129. The onshore and offshore fields are currently linked to specific offtake points, according to MOGE, as shown in section 4.5. In case a gas field is connected with more than one offtakes, it is assumed that the fields supply is allocated to each offtake proportionally to the offtake's gas demand.

130. The table below presents the allocation of fields to each offtake, with a differentiation in the gas fields supplying the offtakes of Groups 1 and 2 based on improved gas flows on the premise of geographic proximity and availability of sufficient interconnections (additional investment for Yenanchaung to Mann interconnection was taken into account in the NTS capex discussed in section 8.2). Specifically, offtakes Ayadaw, Chauk and Kyaukse can be supplied not only by Kyaukkwet and Thar Guyi Taung fields but also by Taung Htauk Sha Bin and Mann fields. Similarly, Htauk Sha Bin and Mann offtakes can be supplied not only by Taung Htauk Sha Bin and Mann fields but also by Kyaukkwet and Thar Gyi Taung fields. This would enable any surpluses in gas supply from one or more sources to be directed and utilized to offtakes that require them.

131. The new discoveries (Aung Sinkha (M3) and Badamyar), on the basis of their location, are assumed to supply the Daw Nyein offtake.

Table 5.5 Allocation of gas fields to offtake points

Groups of fields / offtake points	Gas fields	Connected offtake point(s)
Group 1 (onshore)	Kyaukkwet Thar Gyi Taung Taung Htauk Sha Bin Mann	Ayadaw Chauk Kyaukse
Group 2 (onshore)	Kyaukkwet Thar Gyi Taung Taung Htauk Sha Bin Mann	Htauk Sha Bin Mann
Group 3 (onshore)	Apyauk Nyaung Don Ma U	Nyaung Done Myaungdagar Ywama
Group 4 (offshore)	Shwe	Kyauk Phyu Taung Thar Yenanchaung Belin (Mandalay)
Group 5 (offshore)	Yadana Aung Sinkha M3 Badamyar	Daw Nyein
Group 6 (offshore)	Zawtika (including extension)	Kanbauk

5.7 Supply gaps – overall and by offtake

132. The growing gas demand, driven by consumption in the power sector, and the decreasing supply from indigenous fields, results in an increasing supply gap (Figure 5.21). The gap grows significantly after 2019-20, when the bulk of new power plants are commissioned.

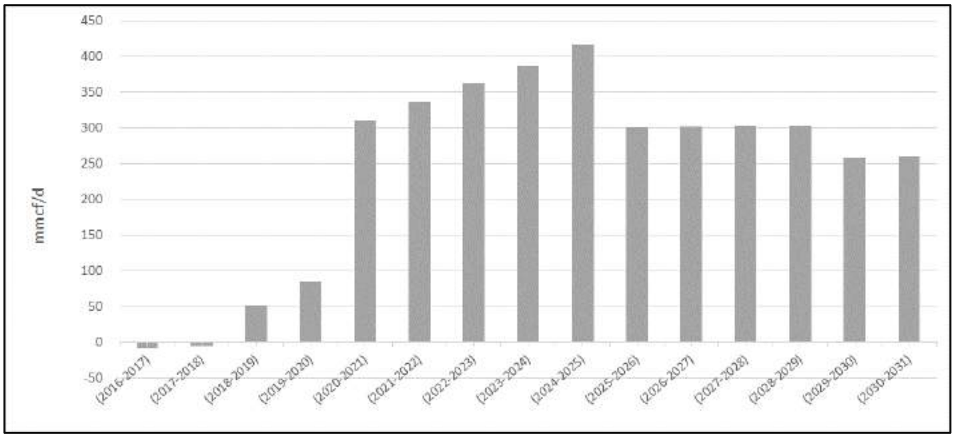
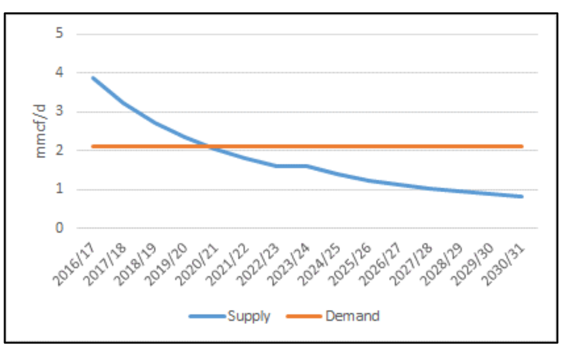


Figure 5.21 Supply gap in the domestic market (sources: MOGE, Consultant's estimations)

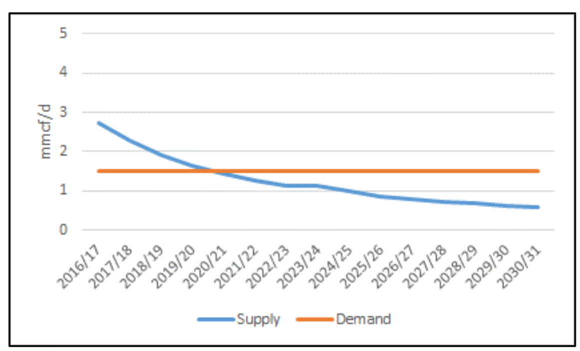
133. Figure 5.22 below provides the projected supply surplus/ deficit for each of the 14 offtake points. It can be seen that the 5 offtakes of Groups 1 & 2 (Ayadaw, Chauk, Kyaukse, Htauk Sha Bin and Mann) have a deficit of supply over demand from 2020-21 onwards. Supply gaps are nevertheless small in absolute terms (1-2 mmcf/d). Offtakes of Group 3 (Nyaung Done, Myaungdagar and Ywama) have deficits from 2021-22 onwards. Supply gaps range between 2.5-5 mmcf/d. Offtakes of Daw Nyein and Kanbauk that are supplied by offshore fields of Yadana and Zawtika respectively, have deficits of supply over demand from 2016-17 onwards peaking at around 370 mmcf/d and 50 mmcf/day respectively. The only offtakes which do not have a projected supply gap are the 4 offtakes supplied from Shwe field, namely Kyauk Phyu, Taung Thar, Yenanchaung and Belin (Mandalay).

Figure 5.22 Supply gap at each offtake point (sources: MOGE, Consultant's estimations)

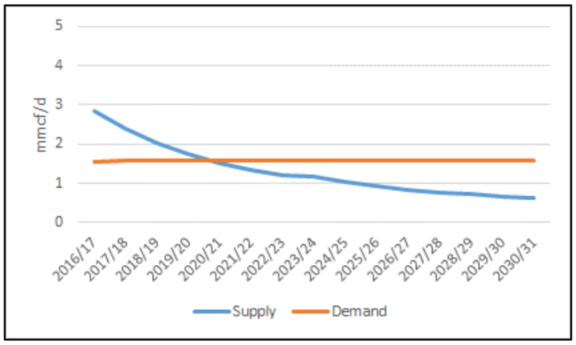
Ayadaw



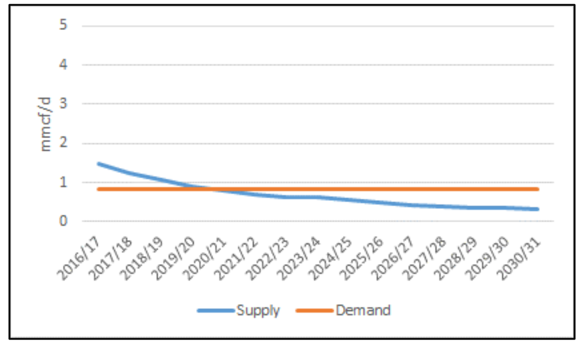
Chauk



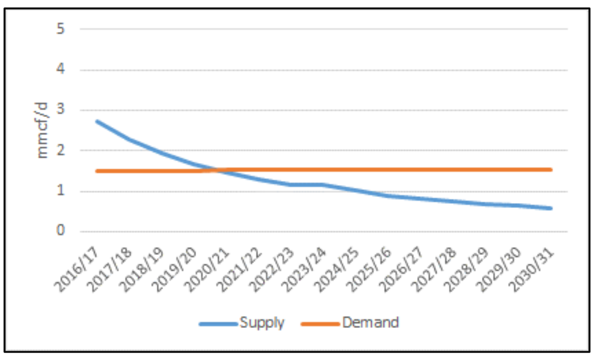
Kyaukse



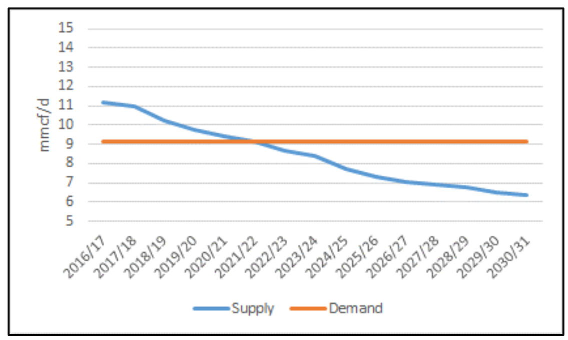
Htauk Sha Bin



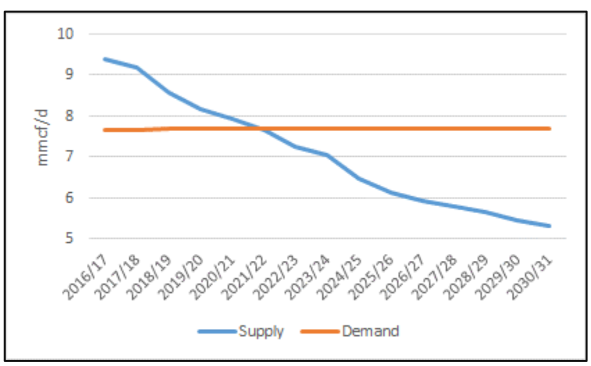
Mann



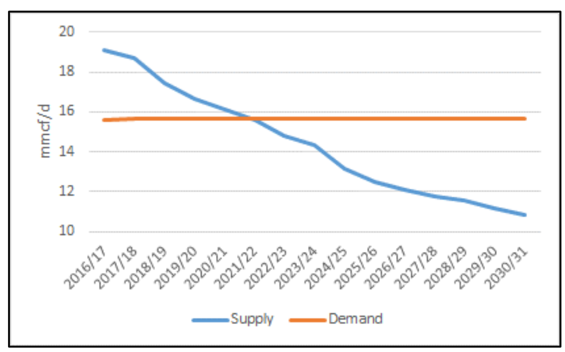
Nyaung Done



Myaungdagar

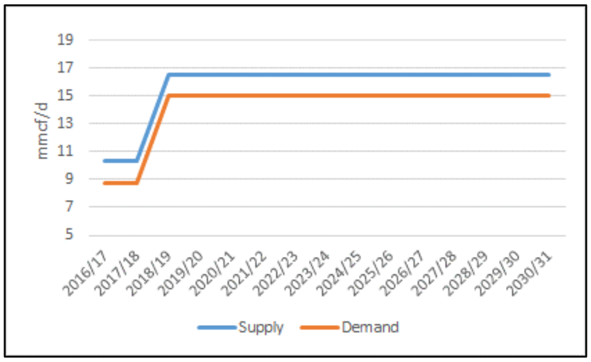


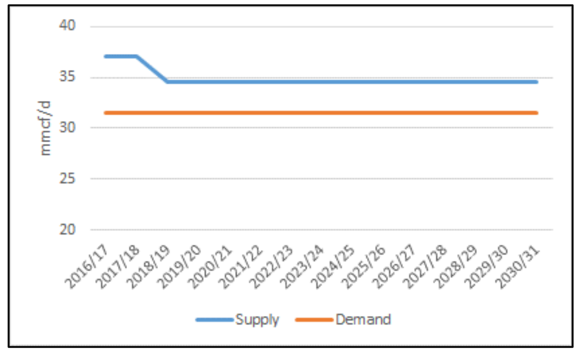
Ywama



Kyauk Phyu

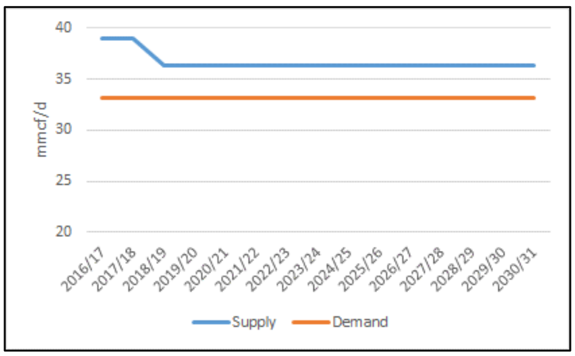
Taung Thar

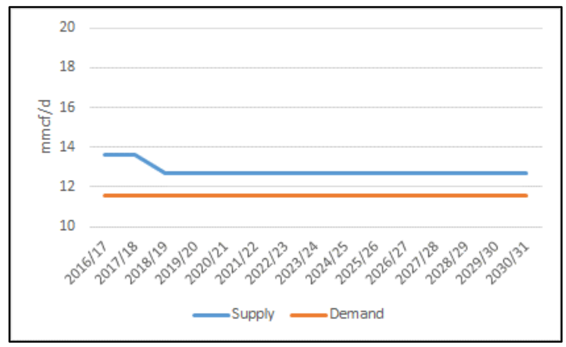




Yenanchaung

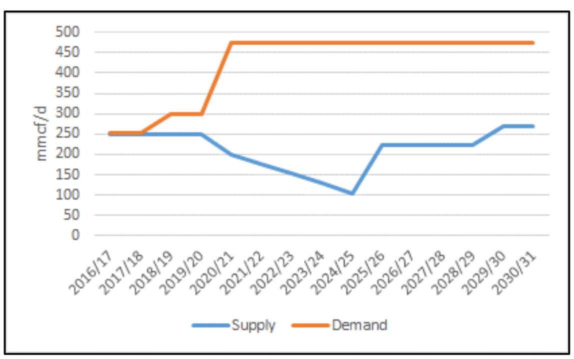
Belin

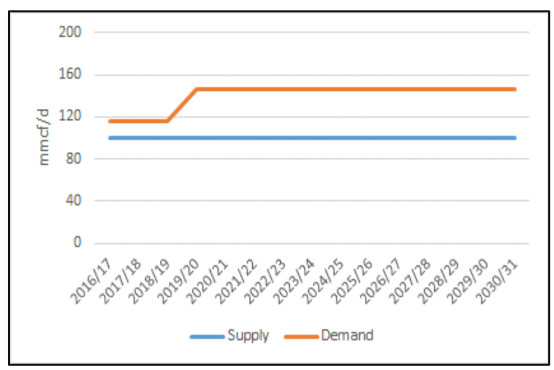




Daw Nyein

Kanbauk





5.8 Addressing supply gaps – LNG swaps and imports

134. In the absence of major new finds coming on stream over the short to medium term, and given the contractual difficulties of diverting gas from the export to the domestic market, the projected supply gaps at the offtake points would have to be accommodated with supplies from external sources.

135. Over the short to medium-term period (2016-17 – 2019-20) it is not possible to develop in-country permanent gas import infrastructure so as to enable the import of LNG for domestic use. During this period, the supply gap which totals 20 mmcf/d to 100 mmcf/d in Daw Nyein and Kanbauk, could be addressed by a number of alternative options, to be investigated:

- Physical swaps between gas directed for exports with LNG supplies to Thailand. This would involve an agreement between Myanmar and Thailand, the former to withhold gas volumes contractually destined for export to Thailand, and divert these to the domestic market, in exchange for equivalent LNG volumes that would be paid for by Myanmar and delivered to Thailand at an LNG receiving terminal (Map Ta Phut). The cost to Myanmar of this physical swap of LNG for natural gas would be the cost of LNG purchase and regasification, together with any premium that could be required by the Thai authorities, less the price paid by Thailand for the equivalent natural gas export.

- Increase in flexibility of the gas purchase agreement between Myanmar and China that could for example involve the latter accepting to reduce gas quantities purchased from Myanmar for 2-3 years, in exchange for a rump-up of gas deliveries in subsequent years, possibly with a penalty.

- The above flexible arrangement could involve Myanmar in a parallel barter agreement to purchase electricity from China. This arrangement however would require an assessment of the adequacy of transmission capacity, otherwise if investments are required it could unattractive as a short-term supply option.

136. For the purposes of economic cost calculations, we have assumed that LNG swaps with Thailand could be feasible and would be used to cover short to medium-term needs, and have included the relevant cost in the calculation as detailed in section 6.1.4.

137. In the long-term (2020-21 onwards), Myanmar could have in place the necessary LNG import infrastructure so as to be in position to cover the supply shortage, which is projected to escalate to over 400 mmcf/d. This infrastructure could take the form of a FSRU, implemented in proximity to the demand centres in the south part of Myanmar. Implementing this option would require adequate preparation in terms of studies, contracting, financing, etc. so that the LNG terminal could be commissioned by 2020-21.

138. The additional gas needs that could be covered with LNG swaps or other short-term agreements, and with LNG imports over the middle to longer-term come at an additional and high cost compared to indigenous supplies. It is noted that sourcing of additional gas at a higher cost, stems from the need to address the fuel requirements of a rapidly expanding power generation programme in Myanmar, which is taken as granted to be implemented; a cost-

benefit study for the use of gas compared to other fuels for new power plants was not undertaken, as this is strictly outside the scope of the present study.

6 Estimation of the economic cost of gas supply in Myanmar

6.1 Estimation of the economic cost of offshore fields gas supply

6.1.1 Overview of approach

139. When we contrast economic and financial costs in Annex 6: Economic cost of gas methodology, we highlight that prices should reflect as much as possible the opportunity cost of resources, especially in case of tradable commodities, and we indicate that financial charges paid to offshore field PSA operators can be a good proxy for the economic costs of gas supply in Myanmar. The field or wellhead price of gas for each offshore field, as stipulated in relevant PSA operators gas export contract prices, can be considered as the opportunity cost of using available indigenous gas supplies for fulfilling domestic market needs.

140. An alternative method to estimating economic costs, would involve a bottom up assessment of the present values of all costs associated with exploration, development and production stages, from the discovery of the field to its depletion, at the value of the time they occurred, and the apportionment of costs to the present values of volumes of gas produced each year over the lifetime of the field. Firstly, this is a difficult approach to apply in the Myanmar circumstances, due to the lack of required data. Moreover, even if data were available the applicability of the derived economic costs would be dubious; the contractual obligation is for field operators to be compensated on the basis of the agreed gas contract prices on the basis of the PSA agreements, and not on notional economic costs. Furthermore, as stressed before, opportunity costs i.e. financial costs based on traded price of gas, would be more appropriate to use in the case of gas supply compared to economic costs.

141. As an example, to illustrate the above, in case economic costs were estimated to be higher than PSA wellhead gas prices, indicatively as a result of high field development and production costs vis-à-vis low regionally traded prices of gas, it will not be allocative efficient to oblige domestic customers to pay a higher (economic cost) gas price compared to the low price (gas traded price) they can source regionally. Vice-versa, in case economic costs were proven to be lower than PSA wellhead gas prices, indicatively as a result of low field development and

production costs vis-à-vis high regionally traded prices of gas, it is not allocative efficient to charge domestic customers a lower gas price (based on economic cost) compared to the high price gas can fetch regionally (export/traded price).

6.1.2 Wellhead/field gas prices according to PSA contract terms

142. In each three offshore fields supplying both the export and domestic markets, respective PSA terms stipulate how the gas contract price is set i.e. the total price paid by the importing country at the border, for gas exported from Myanmar. The contract price fluctuates according to variations in the constituent components on which it is indexed. The contract price includes, as separate components, the field gas price or gas price at the wellhead and the transportation cost of gas from the field to the border. The transportation to the border involves a combination of offshore and onshore export pipelines. The charges for transportation using offshore and onshore pipelines could be bundled or charged under separate components.

143. Although the contract price formula is confidential and has not been provided to the consultant, it is understood that it includes a reference/base price of gas at the time of the PSA contract entering into force, in $ per mmbtu, adjusted on a quarterly basis by the average preceding 12 month values of the following indices: Singapore fuel oil index (weight 50%), US Consumer Price Index (25%) and US Oil Equipment Index (25%).

144. Figure 6.1 below illustrates the historic contract prices and the field/wellhead prices in $ per mmbtu for each of the three fields.

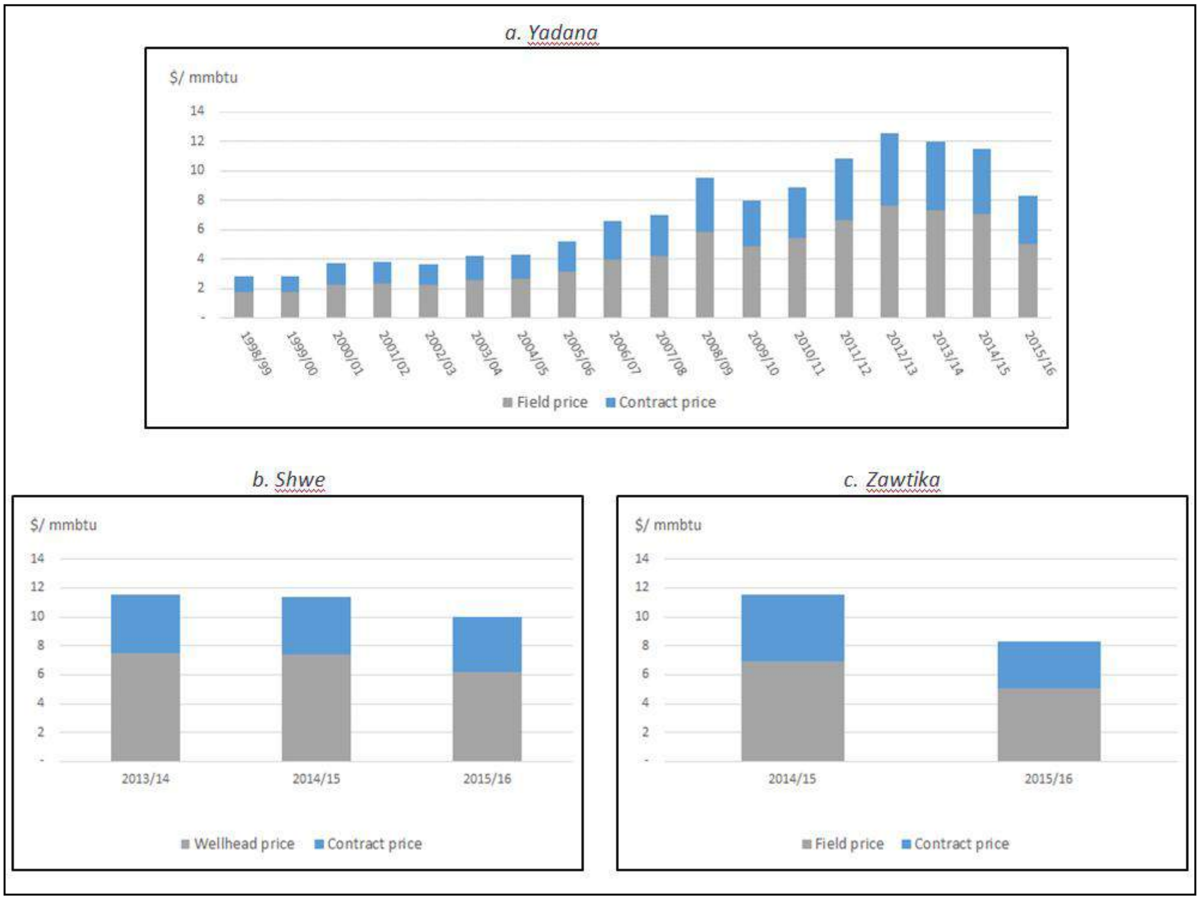


Figure 6.1 Historic contract & field/wellhead prices of offshore fields

145. For Yadana, the field price of gas, according to PSA terms, accounts for 61.2% of the contract price, with the balance 38.8% of the contract price accounted for by transportation charges to the Thai border. The PSA terms stipulated that gas destined for the domestic market would pay the field price and 86.8% of the transport charge attributed to export gas. However, since 2010 when the new 24 inch pipeline connecting the Yadana field with the Daw Nyein offtake Yangon pipeline was built, as part of the national transmission system, domestic users do not have to pay the Yadana PSA operator the above transport charges.

146. For Zawtika, the field price of gas, according to PSA terms, accounts for 60% of the contract price, with the balance of 40% of the contract price accounted for by transportation charges to the Thai border. The PSA terms stipulated that gas destined for the domestic market would pay the field price and 80.2% of the transport charge attributed to export gas.

147. For Shwe, there is a wellhead price of gas that fluctuates according to a formula set in the PSA.The charge for the subsea transportation from the field to the landing is then calculated as 15.2% of the wellhead price. The sum of the wellhead price and the subsea transportation constitutes the 'sale price' of Daewoo, the operator of the Shwe field and the subsea pipeline.

In addition to this sale price, there is the charge for transport of exports from the landing to the Chinese border via the SEAGP pipeline. This charge is paid to the operator of the SEAGP pipeline and is a fixed price of 2,927 $ per mmcf, which varies when it is applied on a mmbtu basis according to the calorific value of gas produced at any given quarter.

6.1.3 Gas field/wellhead price projections

148. The consultant has formulated projections of gas field prices for Yadana and Zawtika, as well as projections of gas wellhead prices for Shwe, as the underlying basis for the calculation of LRACs for each of these offshore supply fields. For Yadana and Zawtika these gas field price projections are based on projections of the respective contract prices, given that Yadana and Zawtika field prices are 61.2% and 60% respectively of their relevant contact prices, according to the PSA contract conditions for these two fields. The consultant was informed by MOE that contract/wellhead prices are based on the following underlying indices: Singapore Fuel Oil index (50% weight), the US Consumer Price Index (25% weight) and the US Oil and Gas Field Machinery and Equipment index (25% weight).

149. The consultant used linear regression analysis to model the relationship between, on the one hand, actual historical gas prices (gas contract prices in the case of Yadana and Zawtika, and historical wellhead prices in the case of Shwe), and on the other hand, historical prices that would have been derived by applying the three abovementioned indices. The relationship modelled was then used to project gas contract prices (for Yadana and Zawtika) and gas wellhead prices (for Shwe), on the basis of projections for the three aforementioned indices.

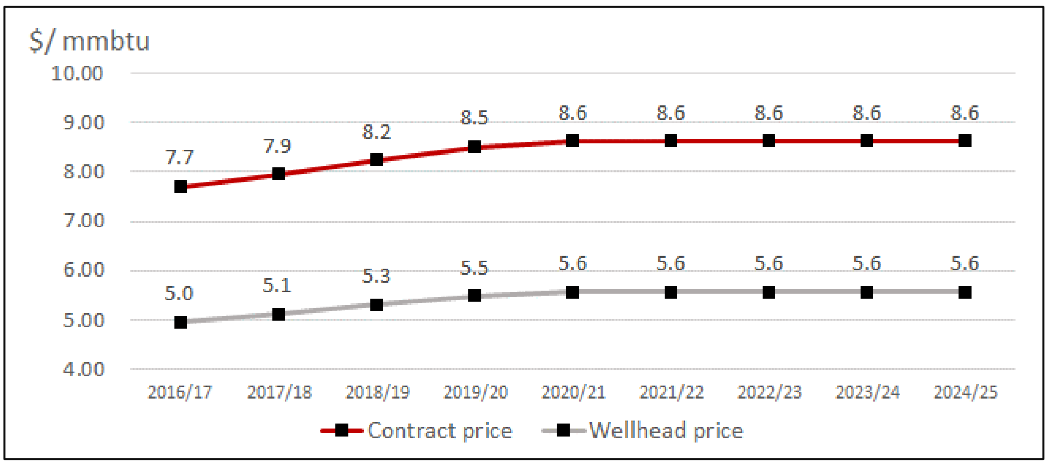
150. The historical contract/wellhead prices were sourced from MOE: January 2010 – March 2016 for Yadana, January 2014- March 2016 for Zawtika and January 2010 – March 2016 for Shwe. Historical and projected values of the aforementioned three indices were sourced by the consultant from www.bunkerindex.com (for the Fuel Oil index), and the US Department of Labor Bureau of Labor Statistics (for the US CPI Index and the US Oil and Gas Field Machinery and Equipment Index). The values of the three indices used for the gas field/wellhead price projections are provided in Annex 4: Indices used for projections of field/ wellhead prices.

151. The regression line that resulted from the linear regression analysis carried out by the consultant, showed a very good fit of the data to the derived regression lines for each field, as manifested by the coefficient of determination R-squared. In other words, the 'predicted' historical contract/wellhead price for each field for each quarter of a year on the basis of the base value of the preceding quarter and the subsequent movements in the 3 aforementioned indices with the weights stipulated by MOE, is very close to the actual historical contract/wellhead values. In the case of Yadana and Zawtika the coefficient R2 was 0.9743, and for Shwe 0.9934.

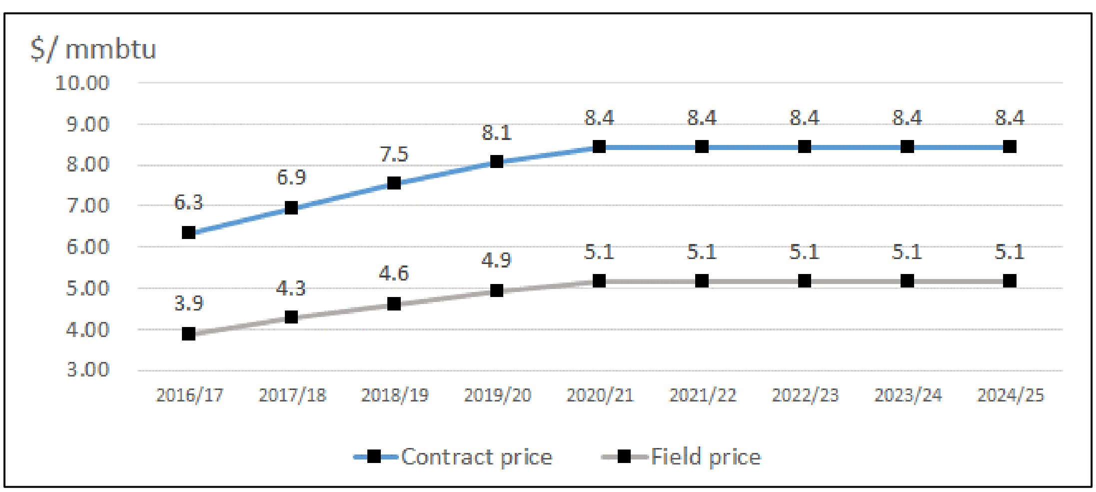
152. We have used the derived regression lines for each field to forecast $ per mmbtu contract prices (for Yadana and Zawtika) and $ per mmbtu wellhead price (for Shwe) for the period starting in the second quarter of 2016 until the first quarter of 2022, on the basis of available datasets of forecasted values for the three underlying indices. The forecasted contract prices in real terms, for Yadana and Zawtika, together with the derived respective field prices, as well as the forecasted wellhead prices in real terms for Shwe are shown in the following Figure.

Figure 6.2 Forecasted wellhead/ field prices of gas for offshore fields

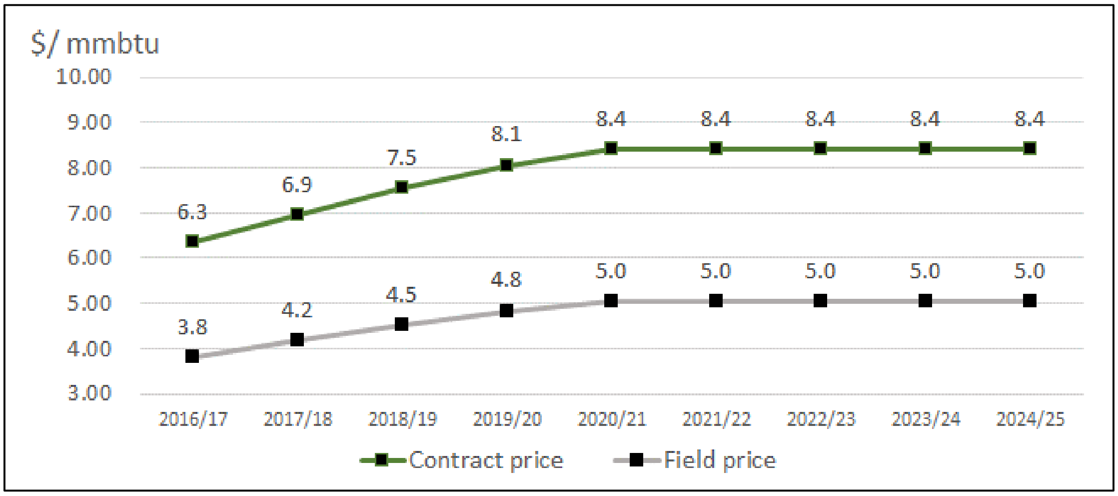
a. Shwe



b. Yadana



c. Zawtika



6.1.4 Additional cost due to LNG Swaps

153. Further to the above described costs of gas supply, there is also a need to estimate the additional gas cost due to the gas swaps with Thailand in the period 2016-7 to 2019-20, as mentioned in Section 5.8 of this report. Specifically, in these years there is a shortfall in supply over domestic demand in the offtakes linked to the Yadana and Zawtika fields, and which cannot be covered by new sources such as LNG. Myanmar is assumed to procure and pay for LNG which is provided to Thailand in lieu of equivalent natural gas export obligations, with the respective natural gas volumes diverted to Myanmar's offtakes which require the additional supply.

154. The additional unit cost of LNG Swaps is calculated as the difference between the costs of LNG procurement and re-gasification for delivery to Thai customers, and the offshore field wellhead/field price. LNG swaps could also potentially include other costs, such as an incentive/bonus payment to Thailand in order to authorize the LNG swaps, and/ or additional costs for delivering gas from the Thai terminal to the Thai customers. These costs are nevertheless uncertain and difficult to quantify in this case, so we have not included them in the calculations.

155. Section 6.4 of this report provides the LNG price projections used for costing LNG procurement for the swaps. For the re-gasification costs, to convert liquid gas into natural gas for infusion into Thailand or Chinese system, an approximate unit cost based on the price list of a major Spanish LNG import terminal (Source: http://www.enagas.es/enagas/en/Transporte_de_gas/Servicios_ofrecidos_y_contratacion/SimuladorServicios) on the basis of the projected LNG volumes to be regasified. This unit cost is

0.208 $ per mmbtu. This unit cost is assumed to be constant in real terms throughout the 3 years involving the swaps.

156. The year-on-year additional costs of LNG swaps is then calculated by multiplying in each year the additional costs of LNG swaps (i.e. LNG cost plus LNG regasification cost less the field/wellhead price representing the revenue received from sales to domestic customers in Myanmar) with the supply volumes provided to the aforementioned domestic offtakes through the LNG swaps.

157. The additional cost on a LRAC basis is then calculated as the present values of the sum total of year-on-year additional costs, divided by the present values of the sum total of all volumes supplied year-on-year to the aforementioned offtakes (planned and additional).For estimating the present values, a real discount rate of 6.5% is used(see Annex 7: Discount Rate Estimation).The resulting additional LRAC gas supply costs are 0.018 $ per mmbtu for Yadana and 0.10 $ per mmbtu for Zawtika.

6.1.5 Economic cost of gas supply by offshore field

158. Following the estimation of field and wellhead prices in Section 6.1.2 to 6.1.3, and the additional cost of gas supply in the early years through LNG Swaps in Section 6.1.4, the derivation of the economic costs of gas supply by offshore field, is carried out in two steps:

- Firstly, the assessment of the gas supply costs by year and by field. In each year in the forecasted period, the projected volumes of gas to be supplied from each field to the domestic market are multiplied by the field/wellhead price of that respective year. The economic cost on a LRAC basis is then calculated as the present values of the sum total of year-on-year field/wellhead prices, divided by the present values of the sum total of volumes supplied year-on-year. The resulting LRAC gas supply costs are 4.74 $ per mmbtu for Yadana, 4.75 $ per mmbtu for Zawtika and 5.44 $ per mmbtu for Shwe.

- Secondly, the economic costs of additional gas supply through LNG Swaps is added to the previous costs in order to derive the total economic costs of gas supply for each of the three offshore fields. The resulting total LRAC gas supply costs are therefore 4.92 $ per mmbtu for Yadana, 4.86$ per mmbtu for Zawtika and 5.44$ per mmbtu for Shwe.

6.2 Estimation of the economic cost of onshore fields gas supply

6.2.1 Overview of approach

159. Onshore gas fields supply is exclusively directed to the domestic market. Onshore fields are state owned, they are not operated on a PSA basis and do not have specific contract prices for gas sales. Furthermore, there is lack of comprehensive historical data to enable estimation of

all costs involved in the lifecycle of the onshore fields, and no projections of cost data for the future.

160. Historical data were only available for two of the seven onshore fields supplying the domestic market: Kyaukkwet and Mann.For these two fields and for the period 2010-11 to 2014-15, in addition to production costs (drilling, development and operation & maintenance costs) provided by MOGE, data was received on asset values, new investments and depreciation pertaining to these fields. For the remaining five fields, only data on historical production costs were available.

161. To approximate economic costs pertaining to onshore fields, the following assumptions were adopted:

- The total gas supply costs pertaining to each field in each year of the projected period equal the sum of production costs, depreciation and rate of return on the field assets corresponding to that year. The rate of return adopted is 6.5% real on $ values, equivalent to 15% nominal (see Annex 7: Discount Rate Estimation)

- For the five onshore gas fields for which data on depreciation and assets is not available, a proxy is adopted for depreciation and rate of return on assets. This proxy is based on the average value of the ratio of production costs to total gas supply costs, derived for Kyaukkwet and Mann fields for the years 2013-14 to 2014-15.For Kyaukkwet field, the average value of this ratio is 1.54 and for Mann field the average value is 1.63.It is therefore assumed that the total gas supply costs for the five other onshore fields would be 1.6 times their production costs.

- The economic cost on a LRAC basis for each field is then calculated as the present values of the sum total of year-on-year gas supply costs for the field, divided by the present values of the sum total of volumes supplied year-on-year by the field.

6.2.2 Depletion premium

162. The economic gas supply costs derived from the application of the above approach, shown in Table 6.1, range between 0.30 $ per mmbtu (Mau U Bin) and 1.43 $ per mmbtu for Thar Guyi Taung and Kyaukkwet, and are substantially lower compared to the equivalent costs of offshore fields shown in Section 6.2.1.

Table 6.1 Economic cost of supply of supply of onshore fields (without depletion premium)

Field	LRAC ($ per mmbtu)
Kyaukkwet	1.43
Thar Guyi Taung	1.43

Htauk Sha Bin	0.43
Mann	0.93
Apyauk	0.71
Nyaung Dong	0.66
Ma U Bin	0.30

163. With the exception of Kyaukkwet, Apyauk and Ma U Bin, which showed some increases in production in the last 3 years, onshore fields' production is significantly declining over the last decade.MOE cannot provide data concerning expected depletion dates. Although these fields account for a small portion of current and projected supply of gas, in case these fields are depleted in the near future, gas supplies from these fields would have to be replaced by alternative sources. We therefore consider that there is a case for including to the costs of onshore fields a 'depletion premium' so as to reflect the opportunity cost of sourcing gas from more expensive gas following depletion of these fields.

164. The opportunity cost chosen to reflect the depletion premium is the cost of LNG imports, which is added to the calculations in 2030-31.This amounts to 8.1 $ per mmbtu in real terms. The derivation of the LNG import price projections is discussed in detail in Section 6.4.The depletion premium is then discounted with a real rate of 6.5% to arrive at its present value of 3.16 $ per mmbtu. Charging domestic customers, the gas supply costs plus the depletion premium, provides signals for efficient use of resources and enables the full recovery of costs as well as the collection of funds to cover exploration costs for new fields replacing the ones being depleted.

6.2.3 Economic cost of gas supply by onshore field

165. Table 6.2 below shows the LRAC of gas supply for each onshore field, including the afore discussed depletion premium. It can be seen that costs range 3.47 $ per mmbtu to 4.59 $ per mmbtu. These unit costs are 3% to 36% lower compared to the unit costs of the offshore gas fields.

Table 6.2 Economic cost of supply of supply of onshore fields (with depletion premium)

Field	LRAC ($ per mmbtu)
Kyaukkwet	4.59
Thar Guyi Taung	4.59
Htauk Sha Bin	3.59
Mann	4.09
Apyauk	3.87
Nyaung Dong	3.82

Ma U Bin	3.47

6.3 Estimation of the economic cost of gas supply from new offshore fields

166. As discussed in Section 5, domestic gas supply projections included supply from two new offshore fields, Aung Sinkha M3 and Badamyar, expected to be come on stream from 2025/26 and 2029/30 respectively. Both these fields are in close to the existing Yadana field. As a proxy to the economic costs of gas supply from these new fields, in the absence of any data, the consultant adopted the use of gas supply contract prices from the Yadana PSA contract, and has calculated an LRAC of 5.15$ per mmbtu for Aung Sinkha M3 and Badamyar taking into account the timing and volume of their production.

6.4 Estimation of the economic cost of LNG

167. The economic cost of LNG on an LRAC basis, is calculated as the present values of the sum total of year-on-year gas LNG regional prices, divided by the present values of the sum total of volumes to be supplied year-on-year by LNG imports.

168. Projected LNG regional prices are sourced from World Bank LNG Japan delivery (released 19th April 2016) nominal $ per mmbtu forecasts to the calendar year 2025 (Source: http://go.worldbank.org/4ROCCIEQ50), as shown in the figure below. It is assumed that post 2025 the LNG prices will remain constant.LNG forecasts have been converted into real $ per mmbtu values for each calendar year using the US CPI index (http://www.imf.org/external/pubs/ft/weo/2016/01/weodata/weorept.aspx?sy=2014&ey=2021&scsm=1&ssd=1&sort=country&ds=.&br=1&pr1.x=22&pr1.y=0&c=111&s=PCPI&grp=0&a=).Calendar LNG real prices are then converted into financial year LNG prices, using a 75% weight corresponding to the LNG price of the calendar year on which the financial year commences (first 9 months of the financial year) and 25% weight corresponding to the LNG price of the calendar year on which the financial year ends (last 3 months of the financial year).For example, the LNG price for the financial year 1st April 2016 – 31st March 2017 is calculated as 75% of the LNG projected price for the calendar year 2016 and 25% of the LNG projected price for the calendar year 2017. The resulting year-on-year LNG real price $ per mmbtu projections, on a financial year basis, to 2030/31, are shown in the figure below.

169. The volumes to be supplied year-on-year by LNG imports are detailed in Section 5.8.The LRAC of LNG imports is then calculated, in accordance with the aforementioned approach, as 8.11 $ per mmbtu.

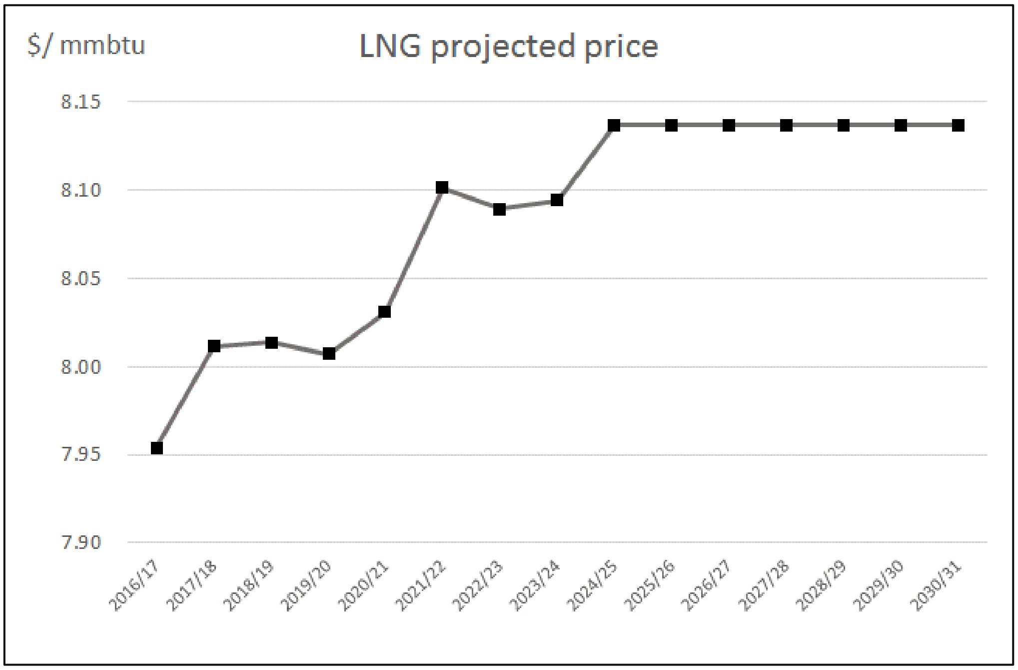


Figure 6.3LNG real projected price

6.5 Weighted average or blended economic cost of gas supply

170. As can be seen from the previous sections, the cost of gas supply by offtake differs considerably depending on whether the supply source to the offtake is an offshore field or an onshore field, and whether customers of specific offtakes would have to shoulder the high costs of LNG imports. Charging customers in accordance to their geographic location would therefore result in wide differences in the cost of gas between them. This charging policy would result in 'punishing' customers linked to offtakes supplied by higher cost fields, compared to customers linked to offtakes supplied by lower cost fields.

171. An alternative policy would be to derive a single uniform economic 'blended' cost of gas supply applying to all customers i.e. an average of the economic cost of gas supply of the different gas supply sources in Myanmar that is weighted by the significance of each supply source in terms of volumes supplied to the domestic market. The weights to be used to calculate this blended economic cost are based on the present values of the volumes of gas supply for each source over the forecast period. Table 6.3shows the LRAC by supply source, the present values of the volumes of gas supplied, and the resulting weights attached to the LRAC of each source. The % weight for each sources is calculated on the basis of the PV of volume for that source, divided by the sum total of PV of all sources. The blended or weighted average LRAC is then calculated as the sum total of the LRAC for each source times its weight. The blended or weighted average LRAC that could be potentially applied to customers of all offtakes is thus estimated at 5.98 $ per mmbtu.

Table 6.3 LRAC of gas supply by supply source

Source	LRAC ($ per mmbtu)	Volumes PV ($)	Weights (%)
Kyaukkwet	4.59	15.0	0.7%
Thar Guyi Taung	4.59	3.2	0.2%
Htauk Sha Bin	3.59	0.6	0.0%
Mann	4.09	2.7	0.1%
Apyauk	3.87	38.1	1.8%
Nyaung Dong	3.82	48.1	2.3%
Ma U Bin	3.47	21.5	1.0%
Shwe	5.44	333.1	15.8%
Yadana	4.92	470.2	22.4%
Zawtika	4.86	362.4	17.2%
Aung Sinkha M3	5.15	109.9	5.2%
Badamyar	5.15	10.5	0.5%
LNG	8.11	687.4	32.7%
Weighted average	5.98		

172. The LRAC of gas supply per offtake is shown in Table 6.4 below. It can be seen that the LRAC varies widely between the different offtakes, as a result of some offtakes having access to lower cost gas supply sources (e.g. Kyauk Phyu supplied from Shwe field) and others drawing from more costly sources (e.g. Daw Nyein supplied from Yadana field and LNG). Note that slight variations between offtakes supplied from the same single source (e.g. offtakes supplied by Shwe field) are observed due to differences in gas demanded over time in each offtake. The weighted average LRAC of gas supply for all offtakes is 5.98 $ per mmbtu, the same as the weighted average LRAC of gas supply for all sources.

Table 6.4 LRAC of gas supply by offtake

Offtake	LRAC ($ per mmbtu)	Volumes PV ($)	Weights (%)
Ayadaw	5.21	7.5	0.4%
Chauk	5.21	5.3	0.3%
Kyaukse	5.22	5.6	0.3%
Htauk Sha Bin	5.21	2.9	0.1%

Offtake	LRAC ($ per mmbtu)	Volumes PV ($)	Weights (%)
Mann	5.22	5.4	0.3%
Nyaung Done	4.13	33.1	1.6%
Myaungdagar	4.13	27.8	1.3%
Ywama	4.13	56.6	2.7%
Kyauk Phyu	5.46	51.1	2.4%
Taung Thar	5.43	116.5	5.5%
Yenanchaung	5.43	122.6	5.8%
Belin	5.43	42.8	2.0%
Daw Nyein	6.50	1,168.7	55.6%
Kanbauk	5.57	456.7	21.7%
Weighted average	5.98		

7 Economic cost of use of export gas pipelines for domestic gas deliveries

7.1 Overview of approach

173. As detailed in Section 6.1.1, for the three offshore fields, respective PSA terms and agreements stipulate the gas contract price and the cost of transporting gas from the field to the border:

- For Yadana, according to PSA terms, the cost of gas transportation to the Thai border, using offshore and onshore export pipelines linking the field to the Thai border, is directly linked to the contract price (38.8% of the contract price).PSA terms stipulate that in case gas is destined for the domestic market, the transportation charge is less i.e. 86.8% of the charge applying to gas exported, which amounts to 33.67% of the contract price. However, since 2010 when the new 24 inch pipeline connecting the Yadana field with the Daw Nyein offtake Yangon pipeline was built, as part of the national transmission system, it was agreed that domestic users do not have to pay the Yadana PSA operator the above transport charges.

- For Zawtika, according to PSA terms, the cost of transportation to the Thai border, using offshore and onshore export pipelines linking the field to the Thai border, is also directly linked to the contract price (40% of the contract price).PSA terms stipulate that in case gas is destined for the domestic market, the transport charge is 80.2% of the charge applying to gas exported, which amounts to approx. 32.08% of the contract price.

- For Shwe, the charge for the offshore/subsea transportation from the field to the landing is calculated as 15.2% of the wellhead price. Additionally, the charge paid to the operator of the onshore SEAGP pipeline for gas exports transported from the landing to the Chinese border is a fixed price of 2927 $ per mmcf, which varies when it is applied on a mmbtu basis according to the calorific value of gas produced at any given quarter, but on average in the last 3 years it is approx. 2.89 $ per mmbtu. However, for the use of the onshore SEAGP pipeline for transport to domestic offtakes, a different charging system is in force, specifically:
    - $ 0.11/ mmbtu for the Kyauk Phyu offtake
    - $ 1.25/ mmbtu for the Taung Thar offtake
    - $0.84/ mmbtu for the Yenanchaung offtake
    - $ 1.56/ mmbtu for the Belin offtake

174. The economic cost of transportation of gas destined for domestic offtakes via an export pipeline is then estimated on an LRAC basis, by summing up the present values of year-on-year $ transportation costs, and dividing by the sum total of present values of volumes transported through that pipeline. In case the unit cost for transport is uniform across the whole pipeline (as is the case with Zawtika), the $ transportation costs through an export pipeline are calculated on a yearly basis as the product of the unit cost for transport ($ per mmbtu) and the volumes of gas transported (mmbtu) through the said pipeline. In case the unit cost for transport differs according to offtake destination (as is the case with Shwe),the $ transportation costs through an export pipeline, for each offtake, are calculated on a yearly basis as the product of the unit cost for transport ($ per mmbtu) for that offtake, and the volumes of gas transported (mmbtu) through the said pipeline destined for the specific offtake.

175. As a result of the above approach, we have estimated a single value for the economic cost on an LRAC basis for the use of export pipelines for the Zawtika offtake (Kanbauk), and two separate values for the economic cost on an LRAC basis for the use of onshore and offshore export pipelines by the 4 Shwe offtakes (Kyauk Phyu, Belin, Taung Thar, Yenanchaung).These are:

Table 7.1 Economic cost of use of gas export pipelines by offshore field

Offtake	Export pipeline – offshore ($ per mmbtu)	Export pipeline – onshore ($ per mmbtu)
Kanbauk	2.54	-
Kyauk Phyu	0.83	0.11
Belin	0.83	1.25
Taung Thar	0.83	0.84
Yenanchaung	0.83	1.56

7.2 Benchmarking export pipelines transportation costs

176. As shown in 6.1.2 the PSA agreement for Zawtika defines the charges for the use of the export pipelines as a % of the contract price. In the case of Shwe, the charge related to the use of the offshore export pipeline, which is an inherent part of the PSA, is similarly defined as a % of the wellhead price.

177. However, having transportation charges correlated with gas prices is not consistent with the underlying costing rationale: gas is a commodity whose price is driven by energy demand and supply, whereas pipeline transportation costs are driven by investment and operating costs as

well as capacity utilization factors. Having the gas price driving the transportation costs presents a skewed picture and increases the risks of cross-subsidization between the gas commodity and transportation components.

178. The Consultant proceeded to estimate the level of "proxy" transportation charges for the use of equivalent pipelines to those of Zawtika and Shwe, on the basis of benchmarks for investments, operating costs, reasonable return on the assets of such equivalent pipelines, for the same throughput as Zawtika and Shwe.

179. The assumptions used for the calculation of proxy unit transportation costs for a pipeline system (offshore and onshore) similar to that currently linking Shwe field to the Chinese border, using international cost benchmarks, are (all values in real $):

- 492 miles of 32 inch onshore pipeline at a cost of $ 2 million per mile
- 60 miles of 40 inch offshore pipeline at a cost of $ 5.3 million per mile
- 3 compressor stations at a cost of $ 21.3 million each
- 22 block valve stations at a cost of $ 0.28 million each
- 6 M&R stations at a cost of $ 2.87 million each
- A 25-year average lifespan of assets, and a 4% p.a. charge of asset value for depreciation
- Annual operating expenses equal to 5% of initial investments
- Pipeline throughput equal to production of Shwe field
- Real $ rate of return of 6.5%

180. The economic cost of pipeline transportation on an LRAC basis, by the present values of the sum total of year-on-year required revenues to cover all costs and the rate of return of the above proxy pipeline, divided by the present values of the sum total of volumes transported through the pipeline. The resulting LRAC cost is 0.81 $ per mmbtu for the onshore section of the pipeline and is 0.25 $ per mmbtu for the offshore section.

181. A similar exercise was done for the calculation of proxy unit transportation costs for a pipeline system (offshore and onshore) equivalent to that currently linking Zawtika field to the Thai border, using international cost benchmarks. The resulting LRAC cost is 0.73 $ per mmbtu.The main assumptions are (all values in real $):

- 43 miles of 28-inch onshore pipeline at a cost of $ 1.85 million per mile
- 143 miles of 28 inch offshore pipeline at a cost of $ 3.7 million per mile
- 1 compressor station at a cost of $ 21.3 million each
- block valve stations at a cost of $ 0.26 million each
- 3 M&R stations at a cost of $ 2.87 million each
- A 25-year average lifespan of assets, and a 4% p.a. charge of asset value for depreciation
- Annual operating expenses equal to 5% of initial investments
- Pipeline throughput equal to production of Shwe field
- Real $ rate of return of 6.5%

182. It can be seen that the above proxy transportation costs are significantly lower than the economic costs estimated in Section 7.1 for Shwe and Zawtika respectively on the basis of their current PSA pricing policies:

- for Zawtika LRAC on the basis of PSA pricing is $ 2.54 per mmbtu versus the proxy cost of 0.73 $ per mmbtu, and
- for Shwe LRAC on the basis of PSA pricing (including onshore SEAGP charge) ranges between 0.94 $ per mmbtu and 2.38 $ per mmbtu, versus the proxy cost of 1.06 $ per mmbtu.

183. The above proxy gas transportation costs for the use of export pipelines could be a better reflection of the "economic cost" than that prescribed in the PSAs.However, to charge customers for proxy costs would mean that transportation costs are under-recovered vis-à-vis PSA obligations, and that the gas commodity costs would have to be uplifted in compensation. Therefore, the proxy cost for export pipeline transportation is not taken to be the base case.

8 Estimation of the economic cost of the Gas National Transportation System in Myanmar

184. In this section, we describe the Consultant's approach to the estimation of the economic cost of the Gas National Transportation System (NTS) in Myanmar, and the results of our analysis. The section is organized in the following paragraphs:

- Assessment of current and projects costs of gas NTS
- Three step approach to estimating economic cost of the gas NTS by offtake
- Derivation of weights and allocation of NTS costs by offtake according to customer volumes and distances travelled by gas
- Estimation of economic costs by offtake

185. In the absence of a comprehensive development/ master planfor the NTS in Myanmar, the estimation of the economic cost of the NTS by offtake is based on all available data received from MOGE, as well as on Consultant's assumptions concerning the costs associated with the future development of the network, and specifically concerning the replacement, expansion and upgrades of pipelines, and additionally the allocation of costs across the different offtakes.

8.1 Assessment of current and projected costs of gas NTS

186. The economic cost of the NTS is approximated by estimating the required revenue for the development and operation of the NTS according to the approach described in Annex 6: Economic cost of gas methodology; this includes projections of the operation & maintenance expenses (OPEX) of the network, estimation of the depreciation of the assets utilized in the NTS (current stock of assets and new investments), as well as the assessment of the fair return that the owner of the network should enjoy on the NTS assets.

187. Concerning depreciation, it is necessary to estimate the net book value of assets over the projected period. The net book value of assets for the base year 2014-15 is provided in MOGE accounts. MOGE also provided to the Consultant a short-term plan for network reinforcement and expansion, amounting to a capital expenditure of approximately $ 133 mil. over 2016-17 to 2020-21.However, since the development plan has a short term horizon and does not fully address the requirements for network replacement and rehabilitation, including new connections to the planned power plant additions, the Consultant proceeded to estimate a proxy plan and necessary investments on the basis of international benchmarks. Specifically, the Consultant's estimates are based on the following assumptions:

- Replacement of existing and new pipelines every 25 years
- Network expansion for connection of new power plants amounting to approximately 190 miles of new pipelines (compared to the existing pipeline network of 2,600 miles), as well as some investments in pipelines to facilitate interconnections between offtakes in the north of the country supplied by onshore fields (e.g. Yenanchaung to Mann offtakes 15 miles)

188. The capital expenditure benchmarks, on the basis of which the costs associated with the above investments are calculated, are the following:

Table 8.1 Capital expenditure benchmarks

Pipeline diameter	CAPEX benchmarks
<10 inches	493,000 $/ km
10– 16 inches	563,200 $/ km
16 – 20 inches	577,500 $/ km
24 inches	660,000 $/ km
30 inches	701,250 $/ km

189. As shown in Figure 8.1, NTS capital expenditure plan comprising MOGE's plan and Consultant's additional estimates of expenditure associated with system replacements and expansions, results in significant growth in NTS nominal/ gross asset value over the next 10 years.

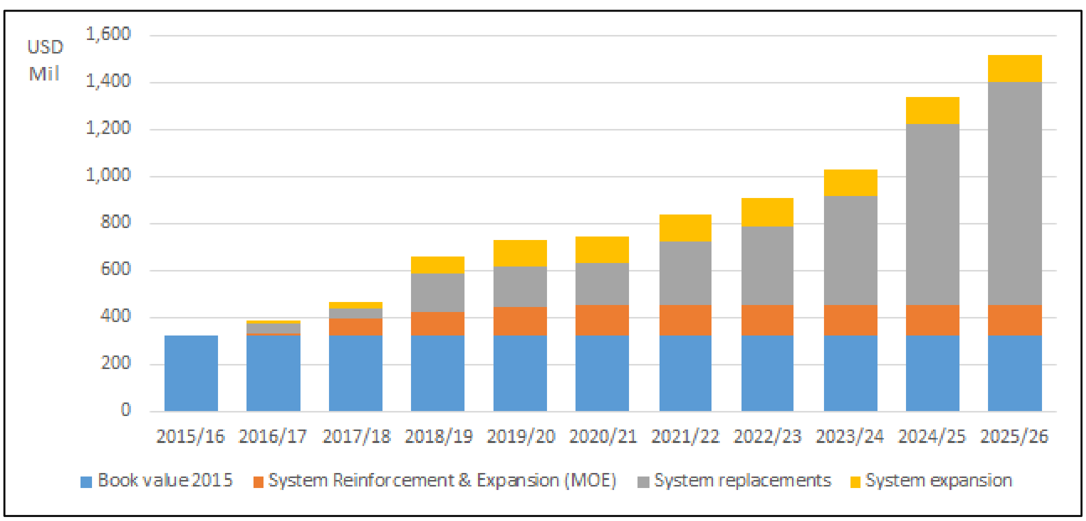


Figure 8.1 Cumulative growth NTS nominal/ gross assets

190. Annual depreciation is then calculated at a rate of 5% (implying assumed depreciation of new assets over a period of 20 years) of the gross book values of the NTS.

191. Concerning NTS OPEX, in the absence of projections from MOGE, the Consultant had to make estimates. The historical OPEX in the recent historical years amounted to 12% p.a. of the net book value of assets. The Consultant assumed that this % level of OPEX would continue until year 2023-24, principally on the basis that the underlying age and state of the network would continue to require significant maintenance expenses in spite of gradual replacement and rehabilitation of the network. From 2024-25 onwards and until 2029-30, it is assumed that OPEX would be around 10% the net book value of assets, since by 2024-25 a significant amount of the assets (30%) would have been replaced, assuming to require lesser maintenance. From 2030-31 onwards, it is assumed that OPEX would be 7.5% of the net book value of NTS assets, since approximately 65% of the assets would have been replaced.

192. Finally, a fair return on NTS assets employed is estimated at a 6.5% real rate on the net book values of the assets.

193. The total NTS costs in each year of the projected period are then estimated as the sum of operating costs, depreciation and return on net book value of assets corresponding to that year. The PV of total NTS costs is then calculated at 1.7 $ billion.

8.2 Allocation of NTS economic cost to offtakes

194. The three-step approach to allocate NTS costs to offtakes and derive LRAC by offtake, is presented in Figure 8.2 and detailed below.

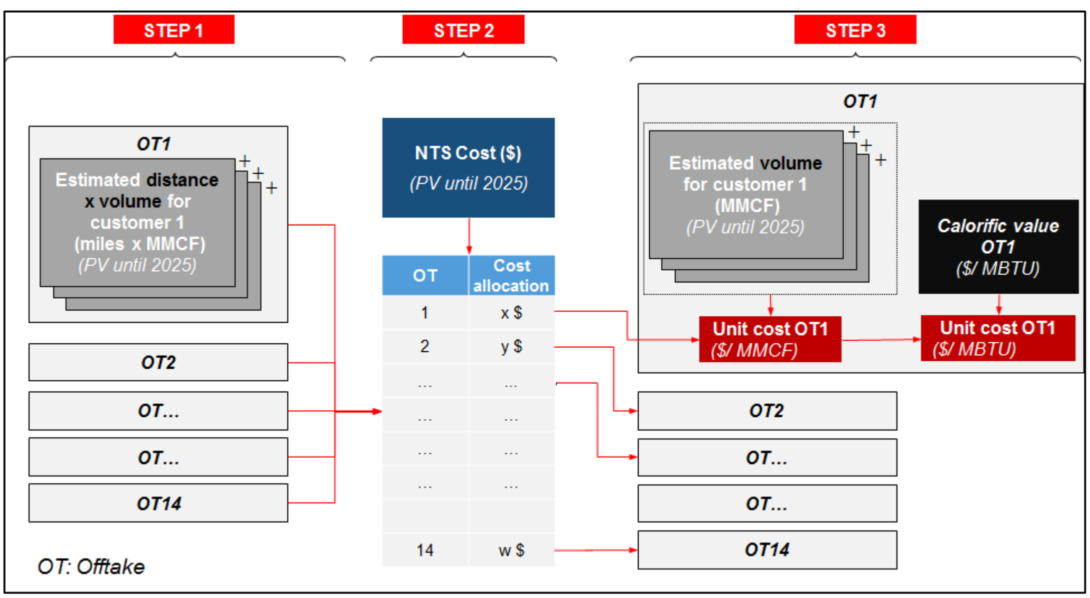


Figure 8.2 The three main steps for estimating the unit cost of NTS per offtake

Step 1

195. The Consultant assumes that the NTS costs should be allocated to each offtake in accordance with the length of the NTS associated with each offtake (length of NTS pipelines from field up to customers linked to the offtake) as well as the volumes of gas transported from the field to the customers linked to the offtake.

196. The underlying rationale is that costs are related to the volumes transported as well as the distances travelled, so that an offtake whose customers use larger volumes over longer distances, should bear a high proportion of the costs, compared to offtakes whose customers use smaller volumes over shorter distances.

197. The weights assigned to each offtake, for the allocation of NTS costs, are calculated by summing up, for all customers of each offtake, the product of:
Volume demanded by customer-i (mmcf) x estimated NTS pipeline length in use by customer-i (miles)

Step 2

198. In the second step, using the weights derived in step 1, the total NTS cost (PV in $) is allocated to each offtake.

199. According to Steps 1 and 2, the allocation of NTS cost to each offtake, according to the respective weights, is shown in Table 8.2. It can be seen that Daw Nyein and secondarily Kanbauk offtakes are allocated the bulk of the NTS cost, due to the high volumes of gas transferred to customers and the significant distances between the field and the customers.

Table 8.2 Weights and allocation of NTS costs by offtake

Offtake	Weight	Cost allocation ($ mil.)
Ayadaw	0.26%	4.5
Chauk	0.21%	3.6
Kyaukse	0.45%	7.8
Htauk Sha Bin	0.15%	2.6
Mann	0.24%	4.1
Nyaung Done	1.25%	21.5
Myaungdagar	0.40%	6.8
Ywama	1.02%	17.6
Kyauk Phyu	0.05%	0.9
Taung Thar	0.46%	8.0
Yenanchaung	6.29%	108.2
Belin	0.21%	3.6
Daw Nyein	53.13%	914.2
Kanbauk	35.87%	617.1

Total	100.00%	1,720.5

Step 3

200. In the third step, the LRAC (in $/ mmbtu) for the use of NTS for each offtake, is calculated. This is done by dividing the PV of the NTS cost that is allocated to each offtake, by the sum total of the PV of volumes transported to offtake customers.

201. The LRACs for each offtake are shown in Table 8.3 below. The weighted average LRAC of NTS for all offtakes is 0.86 $/ mmbtu. Kanbauk and Kyaukse offtakes have the highest LRACs due to the fact that the major part of the weights on which costs are allocated to them, was accounted for by distance travelled, and thus when PV of costs is divided by volume alone, unit costs are proportionately higher than the other offtakes. In contrast, in the case of Daw Nyein, although this offtake bears a higher allocation of NTS cost compared to Kanbauk, the volumes in Daw Nyein are significantly higher, thus leading to a smaller LRAC unit cost compared to Kanbauk.

202. The policy maker can either opt for a charging policy based on LRAC per offtake, or to charge a uniform weighted average LRAC across all offtakes.

Table 8.3 LRAC economic cost of NTS per offtake

Offtake	LRAC ($/ mmbtu)
Ayadaw	0.58
Chauk	0.65
Kyaukse	1.35
Htauk Sha Bin	0.88
Mann	0.74
Nyaung Done	0.64
Myaungdagar	0.24
Ywama	0.31
Kyauk Phyu	0.02
Taung Thar	0.07
Yenanchaung	0.88
Belin	0.08
Daw Nyein	0.86
Kanbauk	1.34
Weighted Average	**0.86**

9 Estimation of the economic cost of an FSRU terminal and associated infrastructure

9.1 Description and sizing

199. The steep increase of demand in the next decade cannot be addressed in full with the indigenous production, even if new offshore discoveries come online. Within the scope of this study it is assumed that in the mid and long-term this supply gap will be covered with imports of LNG through an FSRU terminal, which will operate from 2020-21 onwards.

200. The location of the FSRU terminal is set in the southern part of the country, in accordance with the results of the "Feasibility Study for Introduction of LNG Receiving Facilities in Myanmar"[4] (Figure 9.1), as this positioning is close to the large consumption centre of Yangon. The analysed infrastructure includes an underwater pipeline of 80 km until the landfall and then 50 km of onshore pipeline, to connect to the national transmission system.

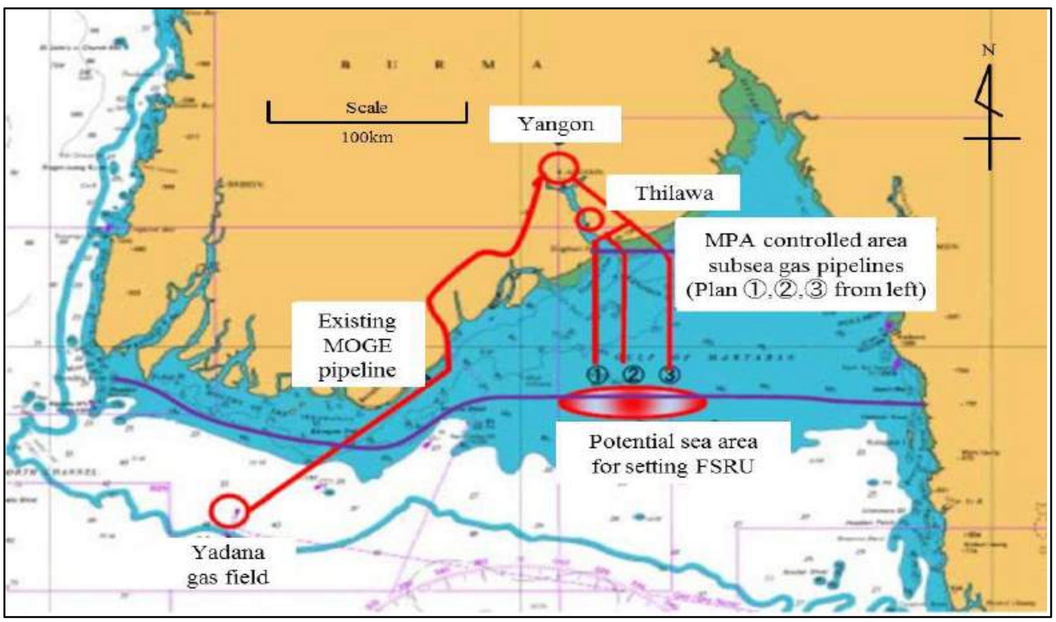


Figure 9.1 Positioning of FRSU terminal proposed by The Japan Research Institute, Limited et al.

201. The option of positioning the terminal near the Yadana field, so as to take advantage of the existing offshore infrastructure, is not feasible, as the pipeline will be fully used to transport

[4] "Feasibility Study for Introduction of LNG Receiving Facilities in Myanmar", prepared by The Japan Research Institute, Limited, Mitsui O. S. K. Lines, Ltd., JGC Corporation, Sumitomo Mitsui Banking Corporation, February 2014.

gas produced in Yadana to the Daw Nyein offtake, and consequently there would be no spare capacity to be used by the FSRU.

202. The examined FSRU terminal and associated infrastructure have been sized with a capacity of approximately 440 mmcf/d (160,000 mmcf per annum) to address Myanmar's supply gap at its peak which is predicted to be in 2024-25. This is shown in Figure 9.2 below.

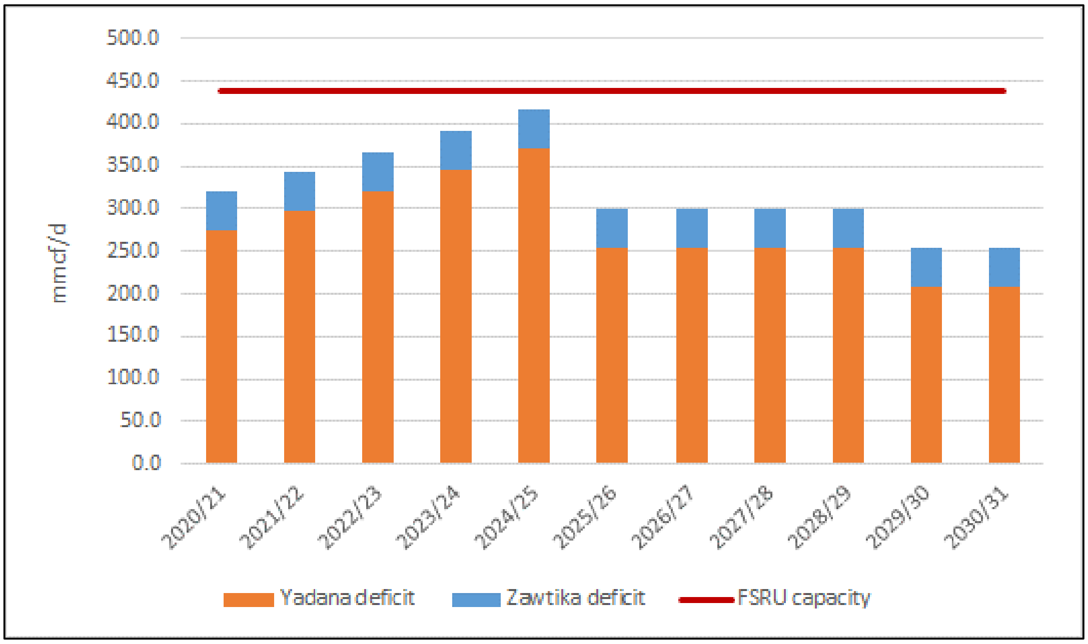


Figure 9.2 FSRU terminal sizing (Consultant's estimations)

9.2 Infrastructure costs

203. The major costs associated with the implementation of the LNG terminal are the procurement of the floating unit and the construction of the offshore section of the pipeline connecting the FSRU with the national transmission system. Table 9.1 below details the investment costs as well as the annual operating cost of the FSRU terminal. The sources used for these costs are the "Feasibility Study for Introduction of LNG Receiving Facilities in Myanmar" and the experience of the Consultant from similar infrastructure projects in Southeastern Europe. The construction period is assumed to be 4 years.

Table 9.1FSRU terminal CAPEX and OPEX

	Cost	Source
Floating Unit	$ 278,000,000	Source: "Feasibility Study for Introduction of LNG Receiving Facilities in Myanmar"
Jetty	$ 150,000,000	Consultant's estimates
Subsea pipeline (incl. installation works)	$ 154,000,000	Source: "Feasibility Study for Introduction of LNG Receiving Facilities in Myanmar"
Onshore pipeline (incl. installation works)	$ 35,062,500	Consultant's estimates
Technical studies - licenses	$ 15,000,000	Source: "Feasibility Study for Introduction of LNG Receiving Facilities in Myanmar"
Operating expenses	$ 24,000,000 p.a.	

9.3 Economic cost of the FSRU terminal and associated infrastructure

204. Estimation of the economic cost of the FSRU terminal and the associated infrastructure involves calculation of the required revenue for the infrastructure development and operation, that includes the depreciation of assets, the annual operating expenses and a return on the assets. The costs used in the calculation are those presented in Table 9.1. The lifetime of the project is considered to be 20 years, and accordingly the depreciation of the assets has been set at 5%. A return on assets (real) of 6.5% is applied.

205. Using this input and assumptions, the present value of the required revenue for the FSRU terminal and the associated infrastructure is approximately $ 660 mil. This required revenue is apportioned to all the offtake points that are projected to use the imported LNG to address their supply gaps, specifically all the Myanmar offtakes except the four Shwe offtakes. The apportionment is carried out based on the supply gap for each offtake (Figure 9.3). The bulk of the PV of the required revenue for the FSRU is allocated to Daw Nyein at approximately $ 550 mil., whereas Kanbauk is allocated approximately $ 96 mil. of the FSRU's PV.

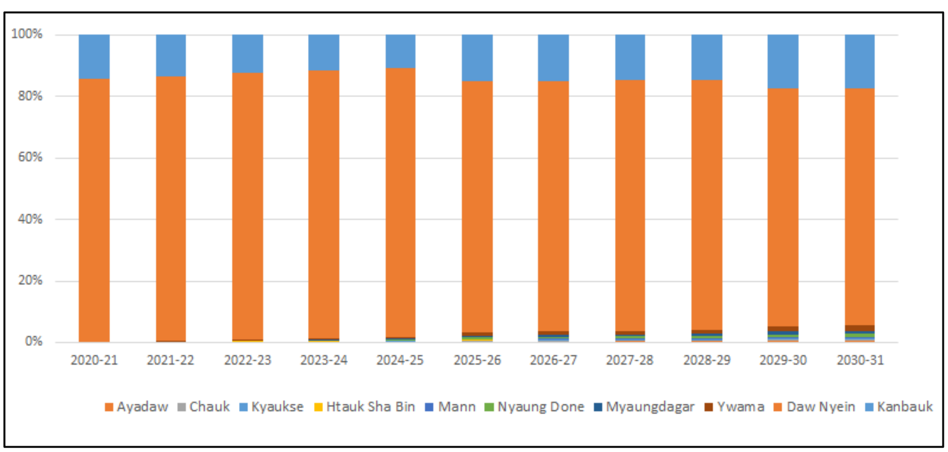


Figure 9.3 Weights used for apportionment of FSRU required revenue to offtakes.

206. The LRAC costs per offtake are shown in Table 9.2below. These costs have been calculated by dividing the PV of the FSRU allocated to each offtake by the PV of total volumes in the respective offtakes (LNG and natural gas). Estimated LRACs for the FSRU and infrastructure range between $ 0.1/ mmbtu and $ 0.51/ mmbtu, as the costs are apportioned to all customers of the relevant offtakes.

Table 9.2 FSRU and related infrastructure LRACs per offtake

Offtake	LRAC ($/ mmbtu)
Ayadaw	0.22
Chauk	0.22
Kyaukse	0.23
Htauk Sha Bin	0.22
Mann	0.23
Nyaung Done	0.10
Myaungdagar	0.10
Ywama	0.10
Kyauk Phyu	-
Taung Thar	-
Yenanchaung	-
Belin	-
Daw Nyein	0.51
Kanbauk	0.21

10 Overall economic cost and sensitivity analysis

10.1 Overall economic cost

207. Table 10.1 below shows for each offtake point LRACs on a $ per mmbtu basis for each part of the supply chain: LRAC for gas supply (the weighted average or blended cost of as supply applying equally to all offtakes), LRAC for the use of export pipelines (where applicable), LRAC for the use of the national transmission system, and LRAC for the use of LNG FSRU and associated infrastructure. These LRACs are additive and combine to produce the total LRAC by offtake.

208. It can be seen that LRACs vary amongst the 14 offtakes, ranging between 6.33 $ per mmbtu and 10.07 $ per mmbtu. Although LRAC for gas supply is common to each offtake, and accounts for the bulk of the total LRAC in each case, there are cost differences between offtakes in relation to LRACs related to transportation costs. Offtakes linked to the offshore fields incur higher costs for using export pipelines, compared to onshore fields. Additionally, all offtakes except those of Shwe incur additional costs linked to the use of the FSRU and associated pipelines, ranging between 0.10 $ per mmbtu and 0.51 $ per mmbtu.

Table 10.1 Overall economic cost ($ per mmbtu) with a single uniform economic 'blended' cost of gas supply

LRAC / Offtake	Supply	Export pipeline (offshore)	Export pipeline (onshore)	NTS	FSRU and pipeline	Total
Ayadaw	5.98	-	-	0.58	0.22	6.79
Chauk	5.98	-	-	0.65	0.22	6.86
Kyaukse	5.98	-	-	1.35	0.23	7.55
Htauk Sha Bin	5.98	-	-	0.88	0.22	7.09
Mann	5.98	-	-	0.74	0.23	6.94
Nyaung Done	5.98	-	-	0.64	0.10	6.73
Myaungdagar	5.98	-	-	0.24	0.10	6.33
Ywama	5.98	-	-	0.31	0.10	6.39
Kyauk Phyu	5.98	0.83	0.11	0.02	-	6.93
Taung Thar	5.98	0.83	1.25	0.07	-	8.13
Yenanchaung	5.98	0.83	0.84	0.88	-	8.53
Belin	5.98	0.83	1.56	0.08	-	8.45
Daw Nyein	5.98	-	-	0.86	0.51	7.36

LRAC / Offtake	**Supply**	**Export pipeline (offshore)**	**Export pipeline (onshore)**	**NTS**	**FSRU and pipeline**	**Total**
Kanbauk	5.98	2.54	-	1.34	0.21	10.07
Weighted Average						**8.02**

Note: the above table presents the LRAC per offtake on the basis of a single 'blended' gas commodity LRAC for all offtakes, and export pipeline LRACs derived on the basis of PSA contract provisions.

209. Table 10.1 also includes a weighted average total LRAC for all offtakes, equal to 8.02 $ per mmbtu, with the weighting factor being the gas volumes supplied to each offtake. By subtracting from the total weighted average LRAC the weighted average LRAC for gas supply of 5.98 $ per mmbtu, gives us a weighted average LRAC for all the remaining transportation and FSRU costs of 2.04 $ per mmbtu.

210. Applying a uniform weighted average LRAC to all offtakes would be a policy decision; the underlying rationale in favor of a flat 'postage stamp' charge, is that customers should not be favored or penalized according to their geographic location; on the other hand, a uniform flat cost involves a cross subsidy between customers with higher transportation costs and those with lower, that does not reflect true costs imposed.

211. The alternative approach of applying a varying LRAC of gas supply per offtake is shown in Table 10.2 below. It can be seen that the LRAC varies widely between the different offtakes, as a result of some offtakes having access to lower cost gas supply sources (e.g. Kyauk Phyu supplied from Shwe field) and others drawing from more costly sources (e.g. Daw Nyein supplied from Yadana field and LNG).

Table 10.2 Overall economic cost ($ per mmbtu) with a different gas supply cost per offtake

LRAC / Offtake	**Supply**	**Export pipeline (offshore)**	**Export pipeline (onshore)**	**NTS**	**FSRU and pipeline**	**Total**
Ayadaw	5.21	-	-	0.58	0.22	6.02
Chauk	5.21	-	-	0.65	0.22	6.09
Kyaukse	5.22	-	-	1.35	0.23	6.79
Htauk Sha Bin	5.21	-	-	0.88	0.22	6.32
Mann	5.22	-	-	0.74	0.23	6.18
Nyaung Done	4.13	-	-	0.64	0.10	4.87
Myaungdagar	4.13	-	-	0.24	0.10	4.47
Ywama	4.13	-	-	0.31	0.10	4.54

LRAC / Offtake	Supply	Export pipeline (offshore)	Export pipeline (onshore)	NTS	FSRU and pipeline	Total
Kyauk Phyu	5.46	0.83	0.11	0.02	-	6.41
Taung Thar	5.43	0.83	1.25	0.07	-	7.58
Yenanchaung	5.43	0.83	0.84	0.88	-	7.98
Belin	5.43	0.83	1.56	0.08	-	7.90
Daw Nyein	6.50	-	-	0.86	0.51	7.88
Kanbauk	5.57	2.54	-	1.34	0.21	9.66
Weighted Average						**8.02**

Note: the above table presents the LRAC per offtake on the basis of different gas commodity LRAC for each offtake (depending on cost of supply sources for each offtake), and export pipeline LRACs derived on the basis of PSA contract provisions.

212. The consultant performed sensitivity analysis on weighted average LRAC across all offtakes in respect to the following parameters:

- LNG price
- Offshore fields' wellhead/ field prices
- Domestic gas supply volume
- Demanded gas volumes
- NTS pipeline cost/ expenditure
- Offshore fields' transportation tariffs
- Onshore fields' operational costs
- LNG infrastructure construction costs
- LNG swap cost

213. The sensitivity analysis showed that the economic cost of gas is in general not very sensitive to changes in the above parameters. It is more sensitive in respect to changes in LNG price, projected offshore fields' wellhead/ field prices and domestic gas supply volume. Specifically, an increase/ decrease of 50% in the LNG price results in an increase/ decrease in economic cost only of +/- 19% (9.54 and 6.49 $ per mmbtu respectively). Similarly, it is observed that an increase/ decrease of 50% in offshore fields' wellhead/ field prices would lead to an increase/ decrease of weighted average LRAC of +/- 18% (9.48 and 6.56 $ per mmbtu respectively). If we apply both changes at the same time, the weighted average LRAC

increases/ decreases by +/- 37% (10.95 and 4.99 $ per mmbtu respectively). Finally, an increase/ decrease of 50% in domestic gas supply volumes would lead to a decrease/ increase of economic cost by -6%/ 11% (7.54 and 8.92 $ per mmbtu respectively). The detailed results of the sensitivity analysis, including all incremental variations of parameters examined, are provided in Annex 2: Sensitivities.

214. The consultant also estimated the overall economic cost in a scenario which assumes that gas demand can only be satisfied to the extent there is available indigenous gas supply. In other words, in this scenario there is no LNG import (physically through FSRU or by swaps) and domestic demand is only satisfied by onshore gas supply and the part of offshore gas which is not committed to exports. The estimated weighted average LRAC for gas supply in this "supply constrained" caseis4.87 $ per mmbtu and the total weighted average LRAC is 7.17 $ per mmbtu.

215. On a final note, we have estimated the impact of changing the pricing basis for the use of Shwe and Zawtika export pipelines, by using the Consultant estimated proxy LRAC (see Chapter 7), instead of the gas price linked tariffs currently applied in PSA contracts.

216. As shown in Table 10.3, the application of the above referenced proxy costs results in lower LRAC costs for export pipelines transportation for the offtakes linked to Shwe and Zawtika, compared to the current situation. For Kanbauk, LRAC on the basis of the proxy cost is 0.73 $ per mmbtu, and for Shwe offtakes, LRAC on the basis of proxy cost (including onshore SEAGP charge) is 1.06 $ per mmbtu. Also, it can be seen that the LRAC price of gas supply will have to increase in compensation for the application of the proxy cost, for the offtakes linked to Shwe and Zawtika. This is because the part of the contract price of gas for offshore fields that the offshore field operators cannot recover from the transport charges will have to be added to and recovered from the field/wellhead price operators charge for gas supply. It can be seen that the weighted average or blended gas supply LRAC increases, from $ 5.98 per mmbtu (reference case) to $ 6.49 per mmbtu. Therefore, the "saving" in export pipeline transport cost for Kanbauk and the Shwe offtakes, results in higher LRACs for gas supply for all offtakes.

Table 10.3 Overall economic cost ($ per mmbtu) with a 'proxy' export pipeline cost and a single uniform economic 'blended' cost of gas supply

LRAC / Offtake	Supply	Export pipeline (offshore)	Export pipeline (onshore)	NTS	FSRU and pipeline	Total
Ayadaw	6.49	-	-	0.58	0.22	7.30
Chauk	6.49	-	-	0.65	0.22	7.37
Kyaukse	6.49	-	-	1.35	0.23	8.06

LRAC / Offtake	Supply	Export pipeline (offshore)	Export pipeline (onshore)	NTS	FSRU and pipeline	Total
Htauk Sha Bin	6.49	-	-	0.88	0.22	7.60
Mann	6.49	-	-	0.74	0.23	7.45
Nyaung Done	6.49	-	-	0.64	0.10	7.24
Myaungdagar	6.49	-	-	0.24	0.10	6.84
Ywama	6.49	-	-	0.31	0.10	6.90
Kyauk Phyu	6.49	0.25	0.81	0.02	-	7.57
Taung Thar	6.49	0.25	0.81	0.07`	-	7.62
Yenanchaung	6.49	0.25	0.81	0.88	-	8.43
Belin	6.49	0.25	0.81	0.08	-	7.64
Daw Nyein	6.49	-	-	0.86	0.51	7.86
Kanbauk	6.49	0.73	-	1.34	0.21	8.77
Weighted Average						**8.02**

Note: the above table presents the LRAC per offtake, on the basis of export pipeline LRACs that were derived from estimated 'proxy' costs for the use of similar pipelines, and a single 'blended' gas commodity LRAC for all offtakes which includes, inter alia, an uplift to compensate for the reduction in export pipeline costs so as to maintain total level of PSA contract provision obligations.

217. Table 10.4 shows the result of applying the proxy cost to the Shwe and Zawtika offtakes, but having different LRAC supply cost for each offtake.

Table 10.4 Overall economic cost ($ per mmbtu) with a 'proxy' export pipeline cost and a different gas supply cost per offtake

LRAC / Offtake	Supply	Export pipeline (offshore)	Export pipeline (onshore)	NTS	FSRU and pipeline	Total
Ayadaw	5.21	-	-	0.58	0.22	6.02
Chauk	5.21	-	-	0.65	0.22	6.09
Kyaukse	5.22	-	-	1.35	0.23	6.79
Htauk Sha Bin	5.21	-	-	0.88	0.22	6.32
Mann	5.22	-	-	0.74	0.23	6.18

LRAC / Offtake	Supply	Export pipeline (offshore)	Export pipeline (onshore)	NTS	FSRU and pipeline	Total
Nyaung Done	4.13	-	-	0.64	0.10	4.87
Myaungdagar	4.13	-	-	0.24	0.10	4.47
Ywama	4.13	-	-	0.31	0.10	4.54
Kyauk Phyu	5.34	0.25	0.81	0.02	-	6.41
Taung Thar	6.45	0.25	0.81	0.07`	-	7.58
Yenanchaung	6.04	0.25	0.81	0.88	-	7.98
Belin	6.75	0.25	0.81	0.08	-	7.90
Daw Nyein	6.50	-	-	0.86	0.51	7.88
Kanbauk	7.38	0.73	-	1.34	0.21	9.66
Weighted Average						**8.02**

Note: the above table presents the LRAC per offtake, on the basis of export pipeline LRACs that were derived from estimated 'proxy' costs for the use of similar pipelines, and different gas commodity LRAC for each offtake (depending on cost of supply sources for each offtake) that include, inter alia, an uplift to compensate for the reduction in export pipeline costs so as to maintain total level of PSA contract provision obligations.

10.2 Conclusions

218. Domestic gas demand in Myanmar is expected to grow significantly over the next years, at an annual compound rate exceeding 19% and reaching 320 billion cubic feet of gas in 2020.Gas demand is mainly driven by power sector demand as Myanmar's electrification intensifies and new plants are constructed and planned to be built over the next five years, but also by higher industrial demand as the economy growth.

219. Historically, the priority of gas supply was to exports and not to the domestic market. Supply to domestic customers accounted for a fraction of what was exported and reportedly domestic customers, especially industrial, demanded more than what was actually supplied to them.In spite of increases in gas supplied to the domestic market in recent years and projected additional increases in the volumes of gas made available for domestic use, from existing offshore fields and from a number of new fields expected to come on stream, namely Aung Sinkha M3 and Badamyar, it is expected that a supply gap will remain. This supply gap is estimated at approx. 31 billion cubic feet in 2019/20 and growing thereafter reaching a peak of approx. 152 billion cubic feet by 2024/25 with a slight decrease thereafter.

220. In the absence of significant increases in domestic supply from new fields and/or diversion of exports to the domestic market, catering for the projected supply gap in the coming years stemming in particular from the annual additional gas needs at the Daw Nyein and Kanbauk offtakes, but also from other offtakes except those linked to Shwe, would necessitate Myanmar to import LNG. It is assumed that this LNG would be imported through an FSRU terminal of capacity 440 mmcf/d (160,000 mmcf per annum) operational by 2020/21.The investment cost of the FSRU, including all associated infrastructure and pipelines linking the terminal to the mainland gas transmission system, are assessed at 632 million $.

221. Given that the earliest time an FSRU terminal and its infrastructure could be ready and operational is in 2020/21, the projected supply gaps which total 20 mmcf/d to 100 mmcf/d over the four-year period 2016-17 to 2019-20, in Daw Nyein and Kanbauk, would have to be covered by additional supplies through agreements such as swaps of LNG for NG with Thailand. In other words, Myanmar swaps part of its NG export obligations to Thailand with LNG supplies, which are procured and paid for by Myanmar, whilst the equivalent NG is not exported but diverted to Myanmar's domestic market needs.LNG for NG swaps carry an additional cost for Myanmar, which would have to be passed on to the customers, which is the differential between the cost of LNG supplied to Thailand (at a minimum, cost purchase plus regasification costs) and the export proceeds from Thailand for the equivalent NG quantities. Further LNG for NG swap costs such as transmission cost and/ or premium for Thailand to agree with the swap, cannot be ruled out but cannot be specified at this stage.

222. Each offtake is supplied by different gas sources with different supply costs: Ayadaw, Chauk, Kyaukse, Htauk Sha Bin, Mann, Nyaung Don, Myaungdagar and Ywama offtakes are supplied by a combination of onshore fields, whereas Kyauk Phyu, Taung Thar, Yenanchaung and Belin offtakes are supplied by Shwe, Daw Nyein offtake is supplied by Yadana and Kanbauk offtake is supplied by Zawtika. Onshore fields have lower costs compared to offshore fields, even if we add to onshore fields a depletion premium 15 years from now to incorporate the higher opportunity cost of alternative gas supplies in case these fields are depleted.LNG costs are currently higher than the cost of gas supply from offshore fields, even though the LNG market price has been decreasing. Charging customers for the cost of gas in accordance to their geographic location and the gas supply sources associated with the customers' offtakes, would therefore result in wide differences in the cost of gas between them and will not equitable. A policy for consideration would be to charge all customers a uniform economic 'blended' cost of gas supply, based on the weighted average of all supply costs, in accordance with the volumes of supply by source.

223. Customers linked to offtakes supplied by offshore fields (with the exception of Yadana) are subject to higher transportation costs than other offtakes, because in addition to the costs of the

national gas transportation system, they have to incur costs for the use of export pipelines. In accordance to PSA terms, the charges for the use of export pipelines, are linked to gas prices and are thus subject to fluctuations. The Consultant calculated 'proxy' unit costs on the basis of international benchmarks, for the use of these export pipelines, and these estimations produce considerably lower charges than those charged under current PSA contracts for transportation.

224. Economic costs for the national transmission system were also approximated, in the absence of comprehensive gas transportation master plan, using MOGE estimates for projected investment costs of the system, additional Consultant estimates for long term replacement and expansion costs, as well as estimates for systematic annual operation and maintenance costs.

225. Finally, the estimated economic cost of the FSRU terminal and its associated infrastructure is calculated and then allocated to all offtakes, except those of Shwe. These costs include the construction of offshore pipelines linking the FSRU to the landing, as it was deemed not possible to utilize existing offshore pipelines, either from Yadana field or Zawtika field, for linking the FSRU terminal with either the Daw Nyein or the Kanbauk offtake; the reason being that already 180 mmcfd of the 250 mmcfd capacity of the Yadana-Yangon pipeline is currently utilized, whilst projected additional future supplies would bring capacity utilization to its limit. In the case of Kanbauk export pipeline, its capacity of 110 mmcfd seems to be in full utilization even today.

226. The weighted average total economic costs of gas of all offtakes in Myanmar, on an LRAC basis, is estimated at $ 8.02 per mmbtu. The economic costs differ by offtake, depending on the assumptions adopted. Total LRACs per offtake range between 6.84 $ per mmbtu and 8.77 $ per mmbtu across the 14 offtakes, in the case where a proxy cost is adopted for the use of Shwe and Zawtika export pipelines, instead of the higher gas price linked transportation tariffs currently applied in PSA contracts (see Chapter7), and a single uniform 'blended' commodity price of gas of $ 6 .49 per mmbtu for all offtakes is adopted (that includes an uplift in gas supply costs of the Shwe and Zawtika offtakes so as to compensate for the reduction in export pipeline costs and thus maintain total level of PSA contract provision obligations) – (see Table 10.3).

227. In the case where a proxy cost is adopted for the use of Shwe and Zawtika export pipelines, and a different commodity price of gas for each offtake is adopted, according to the cost of its gas supply sources (that still includes an uplift in gas supply costs of the Shwe and Zawtika offtakes so as to compensate for the reduction in export pipeline costs and thus maintain total level of PSA contract provision obligations) – (seeTable 10.4), total LRACs per offtake range between 4.47 $ per mmbtu and 9.66 $ per mmbtu across the 14 offtakes.

228. In the case where 'proxy' costs for export pipeline use is not adopted, the economic costs differ by offtake, depending on the whether a single 'blended' LRAC of gas supply ($ 5.98 per mmbtu) applying to all offtakes is used, or whether there are different gas commodity costs for each offtake, according to the cost of specific supply sources for each offtake.In the case of single 'blended' LRAC of gas supply (Table 10.1) the highest total LRAC per offtake is observed in Kanbauk offtake ($ 10.07 per mmbtu) and the lowest in Myaungdagar offtake ($ 6.33 per mmbtu).The 8 offtakes supplied from onshore fields tend to have lower LRACs than the rest ($ 6.33 per mmbtu to $ 7.55 per mmbtu) as they do not incur costs for the use of export pipelines. In contrast, offtakes linked to offshore fields tend to have higher LRAC costs, ranging from $ 6.93 per mmbtu to $ 10.07 per mmbtu).

229. By applying a variable gas supply LRAC per offtake, based on each offtake's sources of gas and their cost, we see that the total LRAC per offtake (Table 10.2) is higher for some offtakes linked to costlier supply sources (e.g. Daw Nyein that relies on LNG supplies), and lower for offtakes linked to less costly onshore fields(comparison of Table 10.1 and Table 10.2).For example, Daw Nyein customers would have to incur a cost of $ 6.50 per mmbtu compared to the case of having a uniform commodity LRAC of $ 5.98 per mmbtu; in contrast, Ywama offtake customers would incur a cost of $ 4.13 per mmbtu, instead of $ 5.98 per mmbtu. This arises from the fact that under the 'blended' weighted average LRAC for gas supply, there are cross-subsidies between offtakes with less costly supply sources and those with higher cost supply sources.

230. Sensitivity analysis has shown that the economic cost of gas is in general not very sensitive to changes in parameters with the exception of changes in LNG price, projected offshore fields' wellhead/ field prices and domestic gas supply volume, where the impact on the weighted average LRAC of changes in these parameters is relatively higher, but still limited (1 percentage point change leads to impact on LRAC ranging between 0.38 and 0.22 percentage points).

10.3 Recommendations

231. The consultant recommendations to MOE/MOGE are as follows:

- Conduct a comprehensive gas demand study and formulate gas demand projections, on the basis of country-wide economic and sectoral/regional development. The demand projections provided by MOE/MOGE to the Consultant were not comprehensive (demand for some of the new power plants was not included), whilst the underlying assumptions for customer gas demands were not provided and there was no explicit link to economic growth indicators

- Formulate an energy and gas supply strategy, taking into account the relative cost of supply from alternative sources and the optimum energy supply mix. The supply options used in the frame of the study were discussed and agreed with the beneficiary and the WB, but were not based on a least cost study for optimum sourcing and use of energy mix (e.g. cost-benefit of gas versus coal for power generation)

- Develop an action plan to implement chosen strategy, as soon as possible, to ensure that supply gaps are covered, including:

    - Preparation for LNG swaps over the short term if required

    - Renegotiation of Domestic Market Obligations (DMOs) in Yadana, and elsewhere if feasible, with a view to increasing domestic gas supplies

    - Preparation for the option of importing LNG (LNG procurement strategy, feasibility studies for FSRU/importing infrastructure, including financing/ownership options etc.)

The timeframe for developing a strategy, assessing and undertaking needed actions is short. In the case of LNG terminal, the construction period is 4 years, so preparation for the terminal has to commence as soon as possible, given the expected evolution of supply gaps.

- Prepare long range gas infrastructure master plans, investment and maintenance plans, so as to ensure required capacity, losses minimization, cost efficiency and guide costing assessments and pricing decisions. Myanmar does not currently have a Gas Master Plan in place. There is insufficient information concerning the development needs for the network and the associated CAPEX and OPEX.

- Make effective use of the economic costs estimation framework and model provided, as a tool to guide decisions. The model presents a useful and flexible tool for cost assessment and policy decision making.

- The available data was insufficient, fragmented and not fully consistent. To enable the timely collection of comprehensive data, there is a need to institute effective data collection and verification processes for the costing and other parameters required in the economic costs estimation framework and model

- The results of this study can support policy decision making for introduction of gas tariffs based on economic costs. It is recommended to review domestic market gas pricing policies, in line with economic costs, if necessary adopting transition strategies when cost changes are significant.

11 Estimate the potential impact of a decline in gas prices and increased domestic supply on the value of exports and government revenue

232. Myanmar's gas industry has historically been dominated by the Yadana and Yetagun fields which accounted for more than 90% of total production, with the bulk of production exported to Thailand. Myanmar's exports increased further with the Shwe and Zawtika field coming on stream in 2013 and 2014 respectively. As a result, the total gas production from Myanmar is expected to increase to over 2,000 mmcfd in 2016.The majority of gas from Zawtika will be used to meet Thailand's growing gas demand, while gas from Shwe is being exported to markets in southwest China through a newly constructed pipeline.

233. In the backdrop of new field developments and increasing exports, Myanmar's domestic gas demand has also been rising at a fast pace and is expected to outgrow supply in the near future. The current supply of gas to domestic market is limited to the contractual obligation under the Domestic Market Obligation (DMO) clauses in signed Production Sharing Contracts (PSC). However, Myanmar's national oil company, Myanmar Oil and Gas Enterprise (MOGE), have looked to the upstream producers to supply more gas domestically at market prices in addition to the DMO obligations.

234. In this study, we looked more closely at the domestic gas demand and supply situation in Myanmar. This helped assess the economic cost of increasing domestic supply and its financial impact for the Myanmar government in Tasks 1, 2 and 3. In this particular task, Task 4, we look more closely at the government revenue from the upstream production and key terms under the model PSCs. We analyze the current PSC structure against the backdrop of similar regimes worldwide, followed by an introduction to a tool designed to help forecast future government revenue and help shape key policy decisions.

11.1 Task Description and Background

11.1.1 Task Description

11.1.2 Proposed Approach and Methodology

235. In this task, we proposed a financial model capable of forecasting government revenue from tax receipts and other sources of revenue from the Myanmar gas industry. The model was to provide a financial mapping and trace all tax and non-tax incomes from gas sales and exports.

236. The purpose of this model was to help the Myanmar government gain an understanding of projected revenue from the gas industry and make key policy decisions in a changing macro environment. Thus, the model was to be designed to provide revenue forecasting under various pricing and policy scenarios. The model would help with, for example, setting the right tax rate in a particular gas price environment or the right gas price for domestic market supply whilst ensuring commercial viability for both the upstream and midstream business.

237. The model was proposed to be designed around two fiscal 'regimes' – namely the Export Gas regime and Domestic Gas regime. This was to help identify and analyse the two fundamental markets individually from a policy perspective, such as testing different tax rates and gas prices for domestic market, as they generally differ from the export market, to help support local development.

238. For the purpose of this model, a 'typical' Myanmar PSC was to be modeled for the export gas and domestic gas regimes, which were most representative of current and future terms. However, as the study progressed it became apparent that the agreed methodology of using the 'Export' and 'Domestic' regime was not an accurate representation of current Myanmar regime. Thus, a new methodology and approach was agreed which is detailed in the next section of the report.

239. The methodology and structure of the proposed revenue projection model is summarized in the following flow-diagram.

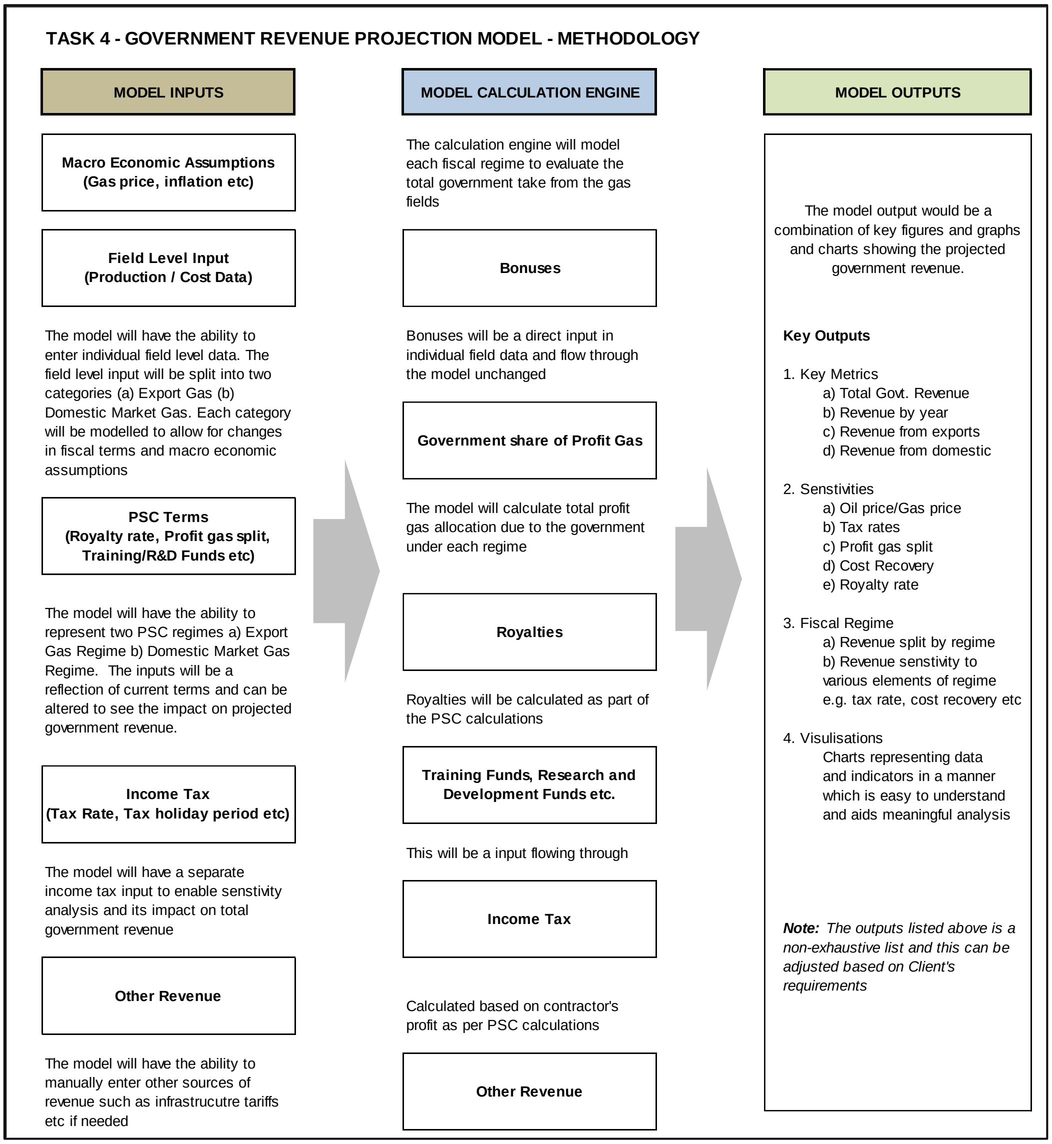


Figure 11.1 Schematic of the Proposed Government Revenue Model

11.1.3 Final Approach and Methodology

240. During the course of this study, data available on Production Sharing Contracts (PSCs) from government Ministries and MOGE showed that the structure of the regime was divided by the operating depth (shallow water and deep water) and not target market i.e. domestic or export. Thus, following discussions with the World Bank representatives, it was agreed that revenue forecasting tool/model will be built around the shallow water and deep water regimes as is the current structure of most recent sample PSCs.

241. Data on specific PSCs was not available due to confidentiality clauses inherent in such contracts, thus the model was built around the standard terms that were made available by the MOE. The remaining structure of the model remained unchanged and was implemented as proposed.

11.2 Production Sharing Contracts in Myanmar

242. The majority of licenses in Myanmar are governed by production sharing contracts (PSCs).The basic PSC includes the following fiscal elements:

- Bonuses (various)
- Royalty
- Domestic Market Obligation
- Research and Development fund contribution
- Training fund contribution
- Cost recovery
- Profit sharing
- State Participation (via MOGE)
- Income tax

243. A brief description of these fiscal elements and their application in a typical Myanmar PSC follows.

11.2.1 Bonuses

244. Under a typical Myanmar PSC, a negotiable signature bonus is payable. Signature bonuses are not recoverable cost and are payable within 30 days after entering into the exploration period. Production bonuses are also payable and not cost recoverable. Payments vary depending on the production rate and location of the blocks. Bonuses for onshore blocks are lower than those for the offshore blocks.

11.2.2 Royalty

245. For contracts signed prior to 2012, a royalty of 10% is payable on gross revenue less transportation costs from the wellhead to the point of sale. This payment can either be in cash or in kind. Royalty payments are not cost recoverable. In 2012, royalty was increased to 12.5% of available petroleum for all onshore and offshore contracts.

11.2.3 Domestic Market Obligation (DMO)

246. Domestic market obligation is 20% of contractors' share of oil production and 25% of gas production. DMO petroleum is typically supplied at a 10% discount to the fair market value.

11.2.4 Research and Development Fund

247. The contractor must contribute 0.5% of its share of profit oil or gas to a Research and Development fund.

11.2.5 Training Fees

248. The contractor is obliged to employ as many qualified Myanmar personnel as possible. For offshore blocks, a minimum expenditure commitment of US$50,000 per year in the exploration period, and US$100,000 in the development and production periods, should be spent to train and educate Myanmar citizens. For onshore blocks, a minimum commitment of US$25,000 per year in the exploration period, and US$100,000 in the production period is required. All costs are fully recoverable.

11.2.6 Cost recovery

249. In each year of production, a percentage of production is available to offset costs. The cost recovery ceiling is set at 50% for onshore blocks, 50% for offshore shallow water blocks (in water depths less than 600 feet) and 60% for offshore blocks in depths greater than 600 feet. In deep-water (above 2,000 feet) a 70% cost recovery ceiling exists.

250. Recoverable costs include all exploration, development and operating expenses as incurred over the life of the field. Contribution to training funds is also understood to be cost recoverable.

251. Depreciation treatment of development expenditure is typically over four years on a straight-line (SLN) basis, beginning in the year in which they are incurred or the year in which commercial production starts, whichever is later.

252. Any unrecovered costs can be carried forward for relief in subsequent years without limit. There is no indication of any uplift available for costs that are carried forward.

11.2.7 PSC Profit Sharing

253. Production remaining after royalty and cost recovery is termed profit share and is divided between the contractor and the government. The profit shares are a key element of each PSC and are generally competitively bid for by each participant in the licensing rounds. An indicative list is made available for the shallow water and deep water blocks by the Myanmar Ministry of Energy (MOE) which are discussed in detail in the next section of the report.

11.2.8 State Participation

254. MOGE has a negotiable carried interest in the exploration phase of any contract, which it can convert into a working interest in the event of a commercial discovery. This interest can be up

to 20% for offshore blocks, but if the discovery size is greater than five tcf, this interest can increase to 25%. If MOGE exercises its option, it must pay historic costs on a pro-rata basis.

11.3 Deep-water and Shallow-water Regimes

255. For the purpose of this study, the Myanmar shallow water and deep water standard terms PSCs were used to build the government revenue projection model. All the revenue forecasts and potential investor attractiveness is assessed on the basis of these terms.

256. Thus, it is important to analyse these PSCs in more detail and provide a comparison between them in order to better understand the revenue projection model developed around their terms.

11.3.1 Key Terms

257. The deep water and shallow water gas terms are very similar in relation to the components they are made up of. It is the variation in profit splits and cost recovery ceilings which highlight the major differences between the two regimes. Key terms of each regime are highlighted in the table below.

Table 11.1 PSC Key terms

Terms	Shallow Water	Deep Water
Royalty	12.5%; payable on gross production	12.5%; payable on gross production
Signature Bonus	Negotiable; payable within 30 days of signing agreement	Negotiable; payable within 30 days of signing agreement
Production Bonus	On plan approval - $1mm 150 MMSCFD - $2mm 300 MMSCFD - $3mm 600 MMSCFD - $4mm 750 MMSCFD - $5mm 900 MMSCFD - $10mm	On plan approval - $1mm 150 MMSCFD - $2mm 300 MMSCFD - $3mm 600 MMSCFD - $4mm 750 MMSCFD - $5mm 900 MMSCFD - $10mm
Cost Recovery	<600 feet – 50% >600 feet – 60%	<600 feet – 50% Between 600-2000 feet – 60% >2000 feet – 70%
Profit Split	See separate tables below	See separate tables below
Domestic Market Obligation	25% Gas of Contractor's Share at 10% discount to Fair Market Value	25% Gas of Contractor's Share at 10% discount to Fair Market Value
Training Funds	Exploration period - $50,000/year Production period- $100,00/year	Exploration period - $50,000/year Production period- $100,00/year
R&D Funds	0.5% of Contractor Profit Share	0.5% of Contractor Profit Share
Terms	**Shallow Water**	**Deep Water**
State Participation	20% at Commercial Discovery and up to 25% if reserves greater than 5 Tcf	20% at Commercial Discovery and up to 25% if reserves greater than 5 Tcf
Income Tax	25% on Net Contractor Profit	25% on Net Contractor Profit
Governing Law	Laws of the Republic of Union of	Laws of the Republic of Union of

	Myanmar	Myanmar

258. The tables below provide a more detailed description of the profit gas splits for deep water and shallow water blocks as per the standard terms PSCs.

Table 11.2 Profit Gas Splits (2013 shallow water offshore terms)

Production (mmcfd)	**600 feet or less** MOGE share (%)	**600 feet or less** Contractor share (%)	**more than 600 feet** MOGE share (%)	**more than 600 feet** Contractor share (%)
<300	65	35	60	40
<600	75	25	70	30
<900	85	15	80	20
>900	90	10	90	10

Table 11.3 Profit gas splits (2013 deep water terms)

Production (mmcfd)	**< 2000 feet** MOGE share (%)	**< 2000 feet** Contractor share (%)	**> 2000 feet** MOGE share (%)	**> 2000 feet** Contractor share (%)
<300	65	35	55	45
<600	75	25	65	35
<900	85	15	75	25
>900	90	10	80	20

259. As can be noted from the tables above, there is very little difference between the typical deep water and shallow water fiscal regimes in Myanmar. The highest contractor share from profit split varies between 35% to 45% whilst cost recovery ceiling can be anywhere between 50-70%. This would usually mean that projects which are in deeper water and require higher capital costs are unlikely to be developed in a low to mid gas price environment as they would struggle to recover costs in such tough fiscal terms. However, as mentioned these standard terms are only 'indicative' and given as guidance for competitive bidding during licensing rounds. A more detailed comparison of a typical project under these two regimes is given in the next section of this report.

11.3.2 Comparative analysis

260. When comparing fiscal regimes, most analyses focus on the level of "government take" as a tool for ranking. This is an oversimplification. Ranking by state take is only a proxy for what influences investment decisions — the value creation resulting from the deployment of investors' capital. In fact, most investor look beyond this simple metric of government take and are likely to invest in countries with high rate of return and profitability despite high government take.

261. It is important, therefore, to focus on more detailed fiscal analyses by applying different fiscal regimes to an example model field and comparing the resulting development economics and levels of state take. Our approach in the comparison of these two regimes is to consider what share of the barrel is left to the investor in each regime. Thus, the key comparison between the

two regimes is extent to which the difference in investor take justifies the added risk of exploration, development, production and eventual decommissioning in a deep-water environment in contrast to shelf or onshore opportunities in Myanmar.

262. To evaluate this, we used a sample gas field to run through the two different regimes and compared cashflows. As we know from the tables above, the key difference between the deep water and shallow water regime is profit share split and cost recovery ceilings. In relation to the impact on cashflows, these two elements are generally the dominant contributors to investor cashflow.

263. We used the maximum and minimum contractor profit share splits as per the standard terms PSCs i.e. 35% for shallow water and 45% for deep water gas fields, to evaluate the impact on investor take. Similarly, the cost recovery limit was set at 50% for shallow water and 70% for deep water to emphasize the contrast and understand the range of outputs. Gas price used is $9/MMBtu with 2% inflation 2017 forward.

264. The resulting post-tax cashflow and government revenue cashflow are illustrated in the chart below.

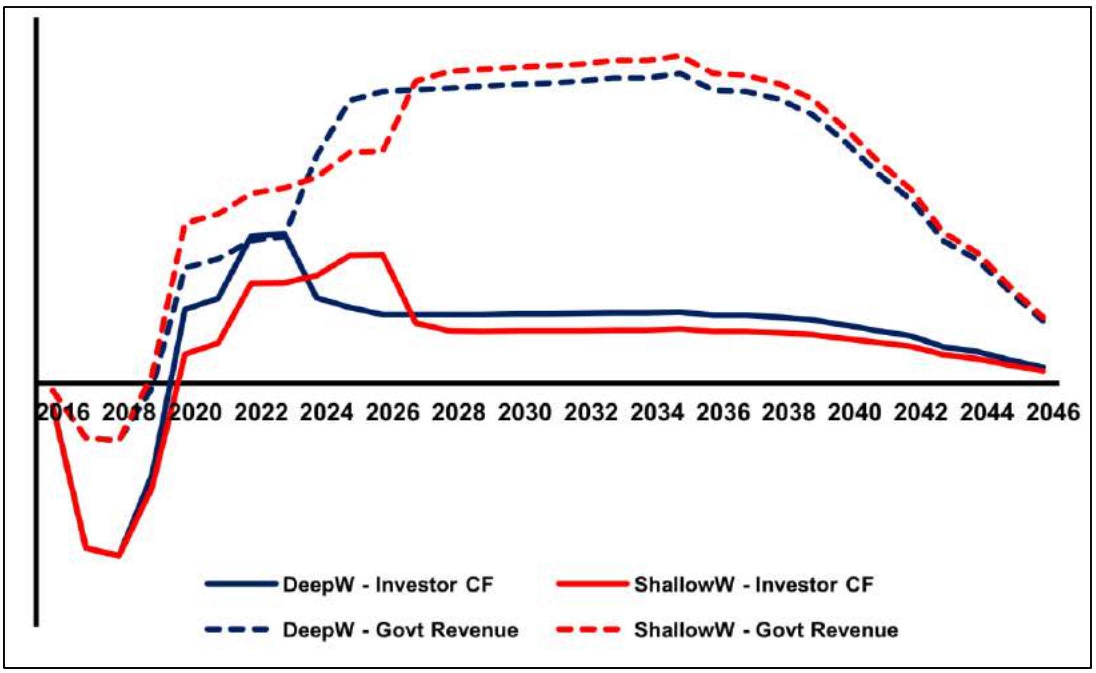


Figure 11.2 Cashflow Comparison - Myanmar Deep and Shallow water PSCs

265. The chart above highlights the impact of varying cost recovery limits and contractor profit share splits. Investor cashflow is boosted in the early years in the deep-water regime due to high cost recovery ceiling (70%) and high contractor take, whilst the shallow water regime is

more punitive in the early years. Nevertheless, as the project costs are recovered there is very little difference between the cashflows in two regimes as there is only a 10% difference in profit split and all other government take elements (royalty, funds, bonuses etc.) are fixed.

266. Investor NPV for sample project in deep water regime is boosted by 150% due to the high impact on early cashflows, however, other key indicators like Internal Rate of Return (IRR) and Profitability Index (PVPI) do not show significant improvement between the two regimes. The IRR is improved by three (3) percentage points and profitability index improves from 1.14 to 1.36. The difference in total government take is five (5) percentage points whereby shallow water regime has an 86% government take and it is around 81% for deep water regime.

267. The analysis shows that there is not a significant difference between the deep water and shallow water regimes as illustrated in the standard terms PSCs. Thus, the deep-water regime appears less attractive given the high risk and cost associated with deep-water development, especially for investors in the current low commodity price environment.

268. However, it is pertinent to mention here that these results are based on the 'indicative' terms for deep water PSCs and the investors are free to bid different profit splits and cost recovery limits as they consider appropriate. Further, as will be elaborated in the next section of the report, most deep-water regimes across the world show low returns on 'typical' sample projects as generally they attract investors with deep pockets with a "high risk-high reward" business model.

11.4 Fiscal Benchmarking

269. The Myanmar PSC contracts have all the salient fiscal elements of a typical PSC in the global oil and gas industry. However, to understand the attractiveness of Myanmar's fiscal terms it is vital to benchmark these terms against other countries around the world.

270. The traditional rank of a regime is calculated on the total government take (defined as the undiscounted revenues that accrue to the government as a percentage of the total undiscounted net revenues of a project) when compared against other regimes globally.

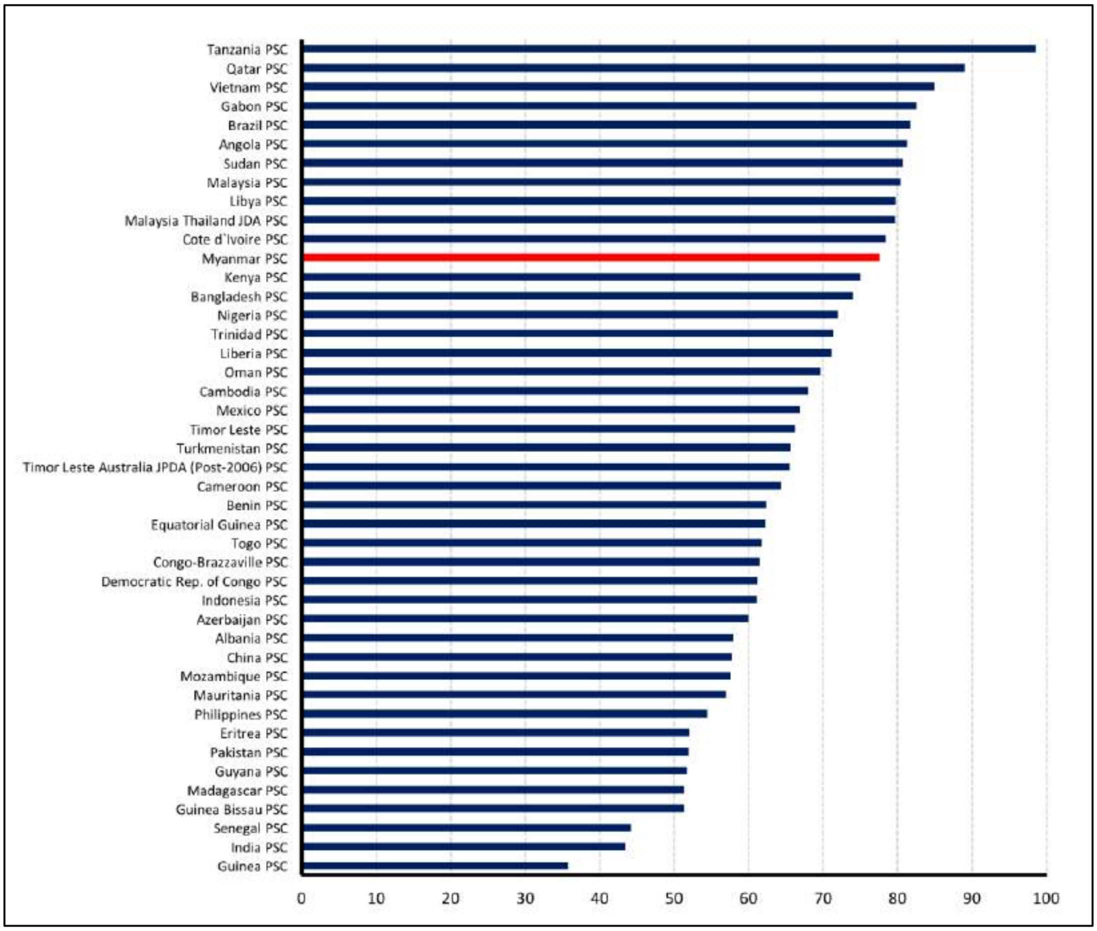


Figure 11.3 Myanmar PSC ranking by total government take
(Source: Industry Source 2016)

271. Figure 11.3 above illustrates the rank of Myanmar PSC amongst other PSC regimes globally ranked for gas projects. The average government take in this set of data is around 66% whilst Myanmar PSC sits at around 77% average government take. The countries amongst the highest take include Tanzania, Qatar, Gabon, Angola and Brazil which have had huge success rates historically and some more recently. On the low end of the scale are countries like India, Guinea Bissau, Senegal and Guyana, which are geologically mature or riskier and underexplored at present. Thus, analyzing Myanmar's position amongst such a large peer group is not representative of its position amongst the global fiscal systems.

272. To offer a fair comparison, a smaller peer group for comparison needs to be selected. For this study, the Asia-Pacific region was selected as the relevant peer group which has a mix of mature and frontier oil and gas provinces with varying level of country risk. Further, ranking only by government take is misleading and does not offer a comprehensive view of how investors might look at a particular country when making investment decision. Investors

typically also look at metrics like the rate of return, capital efficiency and country risk when making investment decisions on projects. Thus, in the analysis below we look at investor rate of return as well as total government take when comparing the Myanmar PSC to its peers.

273. Ranking of the Myanmar PSC by investor rate of return (IRR) is illustrated in Figure 11.4 below. The chart shows the average IRR for a mix of projects sizes, cost and gas prices within the regimes in Asia Pacific region. The results are displayed by the 'environment' of operation i.e. deep water, shelf or onshore.

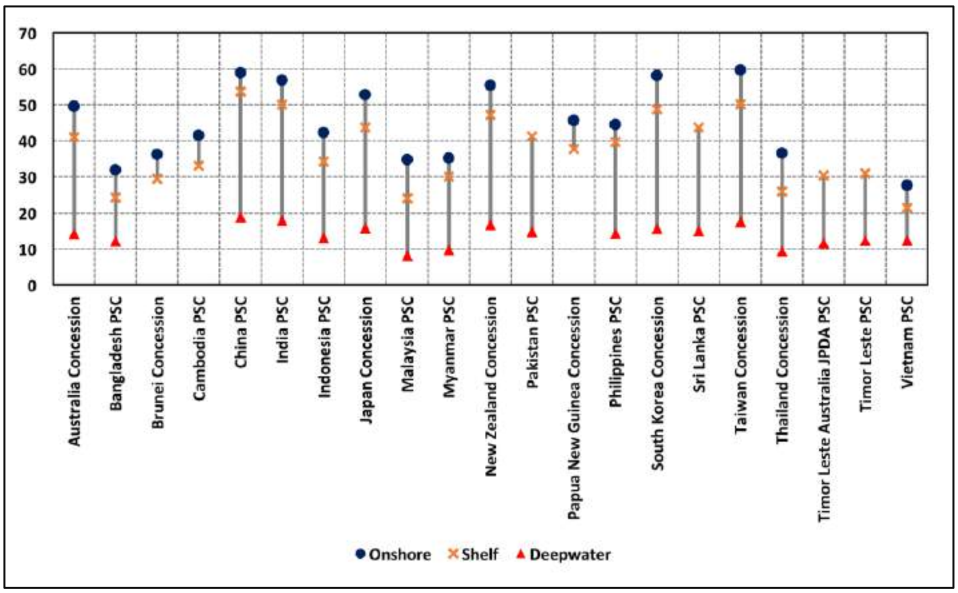


Figure 11.4 Investor IRR comparison for Gas Field Development in Asia-Pacific Countries (Source: Industry Source 2016)

274. A few conclusions can be drawn from the results in this chart:

- Deep water projects offer a very low IRR in all regimes, when compared to other environments
- Myanmar PSC offers a healthy rate of return for shelf (30%) and onshore (35%) projects, however, it falls below the average of the peer group (average for shelf and onshore project is 46% and 36% respectively)
- The highest rate of return for Myanmar projects are well below the peer group high range which sits around 50-60%, however, it must be noted that only countries like China, Taiwan and South Korea offer such returns which are less attractive oil and gas provinces from a geological and country risk perspective.

Further, looking at the Myanmar PSC from a government take perspective with a dimension of deep water and shallow water environment offers interesting insight amongst the Asia-Pacific region peer group.

275. Figure 11.5 below provides a breakdown of total government take in the deep water and shallow water environment.

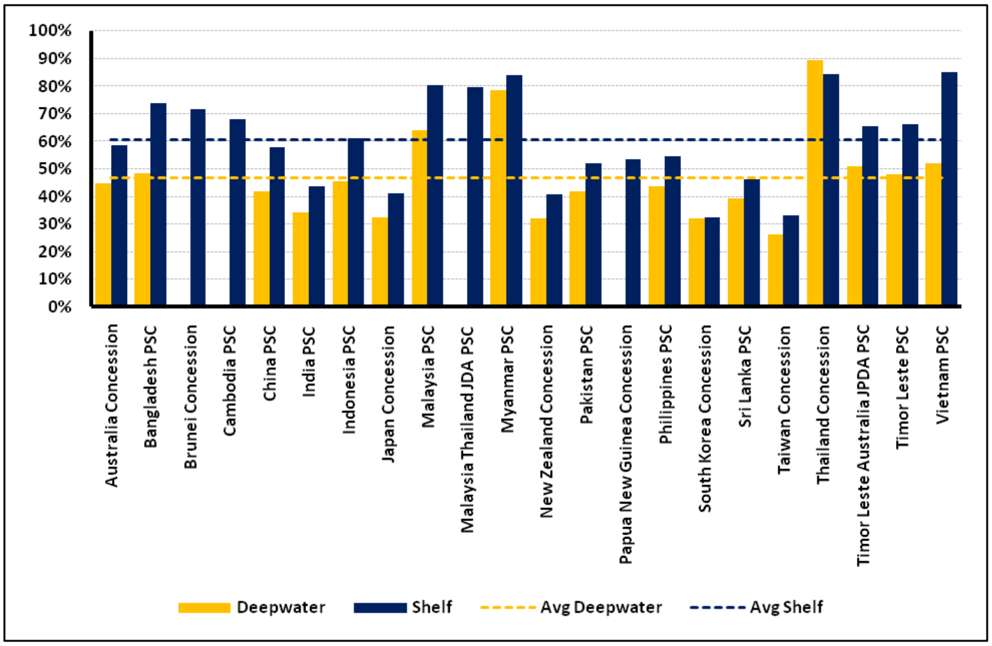


Figure 11.5 Comparison of Government Take in Asia Pacific Region (source: Industry Source 2016)

Analysing the data from

276. Figure 11.5 leads to the following conclusions:

- Myanmar ranks amongst the highest total government take countries as was the case in the wider global peer group
- Myanmar PSC's total deep water and shallow water take is higher than the group average.
- Deep-water terms in Myanmar are tougher than most of the peer group. This can be concluded by looking at the difference between deep water and shallow water government take. This was also noted in the two regime comparison in 4.2 of this report
- In conclusion, the Myanmar PSC sits in the high government take and low to mid investor return peer group when compared to most regimes globally. The deep-water terms seem more tough than the peer group and could benefit from some softening to attract more interest in the deep-water blocks. However, as caveated before, this

analysis is based on the standard term deep water PSC and does not reflect the actual signed PSCs which might, in fact, have favourable terms. There is always room for investors and Myanmar government to negotiate less harsh terms as they may deem appropriate. Further, it is pertinent to mention that a more detailed analysis of each regime needs to be carried out to truly understand the fiscal levers that make some regimes more attractive than Myanmar. The analysis shown in the charts above is not conclusive evidence as the cost and geological environments vary across each country.

11.5 Government Revenue Forecasting Model

11.5.1 Model Overview

277. In this task, we proposed a financial model capable of forecasting government revenue from tax receipts and other sources of revenue from the Myanmar gas industry. The model has been designed to provide a financial mapping and trace all tax and non-tax incomes from gas sales and exports.

278. The intended use of this model is to help the Myanmar government gain an understanding of projected revenue from the gas industry and make key policy decisions in a changing macro environment. Thus, the model has been designed to provide revenue forecasting under various pricing and policy scenarios. This model will help with, for example, setting the right tax rate in a certain gas price environment or the right gas price ensuring commercial viability for both the upstream and midstream business.

279. The model has been built in Microsoft Excel® software and is fully transparent and auditable. The user can enter inputs and follow the calculations through to the output to understand the impact of various fiscal terms and macro assumption settings. Advanced users will also be able to introduce new calculations and sensitivities as needed for future use.

11.5.2 Model Limitations

280. This model has been built around two fiscal regimes and has certain limitations which must be understood to ensure appropriate use and reliability of analysis provided by the model.

281. The model only captures government revenue from the production sharing contracts and does not take account for any mid-stream or down-stream activities.

282. Further, the model aggregates all field level data into a single field and calculates the outputs accordingly, thus there is a loss of granularity and calculations on tax pools and other field specific calculations are not captured by the model. However, single field data can be isolated and run through the model, which would correctly capture the outputs as expected.

283. As mentioned, corporate tax calculation in the model is not reflective of the business reality, as each company operating in Myanmar will have a different tax position and consequently individual tax liability.

284. Lastly, the production-sharing contract terms are based on Standard Terms PSCs provided by the MOE and are certainly not reflective of the actual signed confidential PSCs that currently exist in Myanmar. However, the ability to model these individual terms is available in the model, in so far as the key features are the same as calculated in the model.

11.5.3 Model Structure and Key Features

285. The model consists of three main components, namely a) the Input Module b) the Calculation Module and c) the Outputs Module. It has been designed in Microsoft Excel® with limited VBA code and macros to keep within the remit of a simple and easy to use model.

286. The model is designed around two fiscal 'regimes' – namely the Deep-water regime and Shallow Water regime. This is based on the standard terms contract sheets provided by MOGE and MOE during visits to Myanmar. Both regimes have independent fiscal settings which can be set the 'Control Panel' tab in the model. The user is also able to enter key input assumptions separately for each of the regime to compare and accurately forecast the projected revenue for the Myanmar government. Further, the model also can enter individual gas prices for each regime, as well as field specific gas prices as necessary. Details on how to correctly select and change these settings can be referred to in the user guide provided separately.

287. It is important to note that as the Myanmar government operates a Production Sharing Contract fiscal system, the ability to forecast and accurately history match government revenue will be difficult to achieve from this model. This is mainly due to the individual nature of PSCs as they have different terms and must be modeled on a field by field basis to generate the government take from individual contracts.

11.5.4 Input Module

288. The input module has the following four sheets:

- Control Panel
- Macro Assumptions
- Deep water Inputs
- Shallow water Inputs

Control Panel

289. The control panel is designed to contain all fiscal and model settings. Thus, settings such as PSC terms (cost recovery limits, profit split share percentages, DMO discount and obligation etc.), tax assumptions, model settings (days in year, sensitivities, gas to oil conversion rate etc.) as well as Strategy settings. The strategy settings section has been designed to allow flexibility of selecting individual or both regimes as well as flexibility on individual decisions like treatment of DMO in government revenue.

Macro Assumptions

290. Macro-economic assumptions like oil price, gas price, inflation and exchange rate can be set in the macro assumptions sheet. As mentioned earlier, the gas price in the input module is entered separately for the deep water and shallow water regimes. Users can alter input values in order to see the impact on government revenue projections.

291. The macro assumptions tab has the flexibility to define various macro assumption scenarios. Currently, the model has been pre-populated with three low, mid and high scenarios. Details of how to define a new scenario can be found in the user guide available separately.

Field level input (Shallow water/Deep water)

292. Field level input data has been designed to comprehensively capture the field data which will flow through the model. The following data can be entered for numerous fields:

- Production profiles
- Exploration, development and operating costs
- Field revenue (other)
- Field specific prices
- Field specific signature bonus
- Field specific production bonus (auto-calculation)

293. It is important to note that the field input area has some auto-calculation settings which must not be altered to ensure correct modeling of outputs. Specifically, the production bonus is calculated for each field based on settings in the Control Panel. Further details on this are available in the user guide.

294. The field revenue other input option is designed to allow the user to manually enter any other sources of government revenue by year, which they would like to see in the output reports. It will simply flow through the model with no calculations.

11.5.5 Calculation Module

295. The calculation module has been designed to project the revenue Myanmar government would expect from all the fields. The modules or sheets comprising of the calculation engine are:

- Deep water Regime
- Shallow Water Regime
- Charts Data

296. The prefix 'c' has been added to these sheets to easily identify them as calculation sheets. It is advised that only advanced users edit or review these sheets in order to ensure there are no unexpected errors in the model. The charts data sheet is designed to collate data from both calculation engines (Deep water and Shallow water regime) and provide summary tables for charts in the output module.

297. The chart in Figure 11.6 is a representation of a typical Myanmar PSC as provided by MOGE. The government revenue elements are highlighted in green and will form part of the proposed model. It is important to note that the total government revenue for the purpose of this model includes Royalty, Government's share of profit oil, DMO discount revenue (deemed), Taxes from the independent E&P companies and MOGE's equity share as well as MOGE's equity share net income.

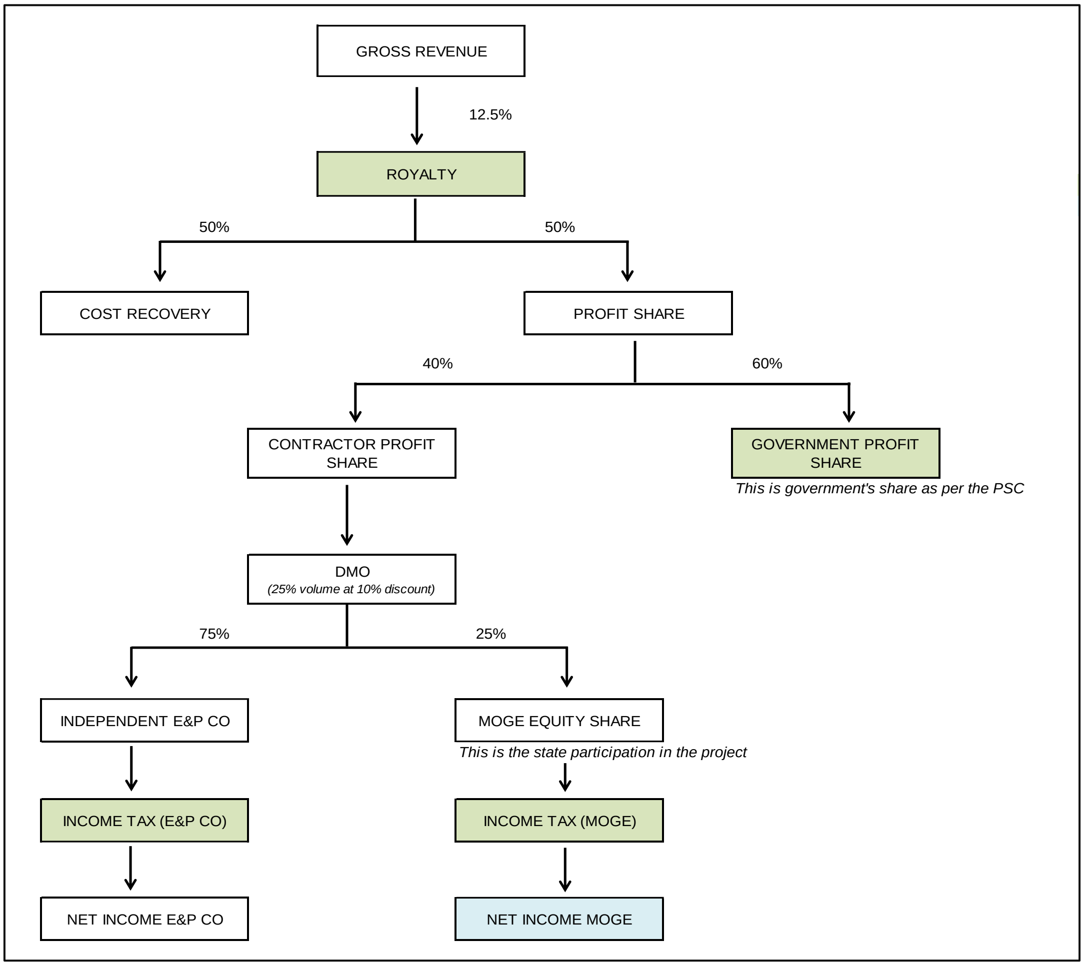


Figure 11.6 Myanmar PSC Revenue Flowchart

298. For this model, the aggregation of government revenue has been calculated based on the key Standard Terms PSCs as provided by MOE. Each regime has set values on key parameters like the cost recovery limit, profit share percentage, royalty rates, bonuses and state participation. This helps determine the expected revenue from each of these revenue sources. However, some settings which are common across the regimes, such as corporate tax, state participation and DMO rate has been set generic across both regimes at the input level. There are two calculation engines in the model; one for each regime. In each of the calculation engines, the model aggregates all the field level data into a single gas field which runs through the model for all PSC and tax calculations.

299. It must be noted that this methodology differs from real-life scenario i.e. typically each field or block will have individually negotiated PSC terms and potentially varying tax treatment. However, reflecting each field PSC terms individually is difficult to achieve in a single model and makes the model complicated, difficult to audit and run. Moreover, this approach would

require continuous modeling of new PSC terms for new fields in order to maintain accuracy of forecasts. Keeping in mind the request to keep the model simple, the methodology outlined above has been adopted.

300. A further simplification in the model is the taxpaying position of all fields. All field data will be aggregated and tax pool will be developed on an aggregate basis. This would enable the aggregation of all field data more plausible. The downside of this approach is that it will result in over estimation of government revenue in years where large capital spends occurs on individual fields which may have no tax liability.

301. Lastly, in the calculation module, the economic limit has been calculated based on cumulative operating cash flow (revenue minus operating costs) for all fields in each regime. This is not calculated on the individual field level.

11.5.6 Output Module

302. The output module has been designed to provide different perspectives of government revenue over a selected period. The output 'dashboard' sheet has the flexibility to choose a specific period, discount date, rate and macro-assumption scenario to adjust the output as required by the user. The aim of the output module is to represent the results of the model in a user-friendly manner using charts and tables.

303. The dashboard has been designed around four key outputs

- Revenue Projection – this section is designed to provide projected government revenue by year. Key metrics include PV total revenue; government take and revenue by source.
- Regime Analysis – this is designed to provide regime specific analysis. Output metrics which highlight the regime specific parameters are revenue by regime, total reserves by regime as well as revenue split by source for each regime
- MOGE Participation Analysis – this is designed to provide a view of MOGE cash flow as a participant in the fields as per State Participation settings
- Sensitivities – this has been designed to provide a view of government revenue sensitivity to fiscal terms as well as gas prices

11.6 Model Results and Findings

304. The model has been used to generate test results to demonstrate its capability and expected outcome for a given scenario. The scenario used for this purpose is the Reference Scenario as referred to in Tasks 1, 2 and 3.

305. Results from the Reference Scenario are discussed in detail with commentary on the sensitivity of these results on macro-economic assumptions as well as fiscal terms.

11.6.1 Reference Scenario

306. The Reference Scenario has been designed to reflect the near and long term gas supply and demand situation in Myanmar. It includes the key current producing fields in Myanmar as well as some fields expected to be developed soon. Details of the data used in this model to develop the results is given in the table below:

Table 11.4 Details of the data used in this model to develop the results

Field	Current Status	Production	Capital Investment	Operating Costs	Regime
Shwe	Producing	4.1 Tcf Reserves; Production start 2013	$2.8billion development cost between 2010-2016	$250mm per year on average including tariffs	Deep Water
Zawtika	Producing	1.8 Tcf Reserves; Production start 2013	$2.1billion development cost between 2010-2018	$310mm per year on average including tariffs	Shallow Water
Yetagun	Producing	2.2 Tcf remaining reserve between 2004-2030; Production included from 2004	$745mm ongoing development costs between 2004-2026	$380mm per year on average including tariffs	Shallow Water
Yadana	Producing	5.8 Tcf remaining reserves between 2004-2029; Production included from 2004	$1.7bn ongoing development costs between 2004-2022	$690mm per year on average including tariffs	Shallow Water
MOGE Onshore	Producing	540bcf remaining reserves between 2004-2029	No cost data available	No cost data available	Shallow Water
Aung Sinkha	Potential development	475 Bcf reserves; Production start 2021	$480 development cost between 2019-2023	$81mm per year on average including tariffs	Shallow Water
Mya	Potential development	450 Bcf resources; Production start 2035	$420mm development cost between 2033-2037	$31mm per year on average	Deep Water
Badamyar	Potential development	128 Bcf resources; Production start 2029	$165mm development cost between 2027 and 2030	$15-20mm per year on average	Shallow Water
Shwe future development	Potential development	1.3 Tcf resources; Production start 2033	$940mm development cost between 2031-2040	$50mm per year on average	Deep Water
Zawtika future development	Potential development	400 Bcf resources; Production start 2020	$550mm development cost between 2018-2022	$35mm per year on average	Shallow Water

307. The input data in table above has been sourced mainly from MOE and MOGE with cost data from public sources including operators plans for future development in Myanmar. The above

data has been run with certain macro-economic assumptions and fiscal terms settings. The table below summarizes the model settings used to generate the output results.

Table 11.5 Model settings used to generate the output results

Inputs	Deep water Regime	Shallow Water Regime
Cost Recovery Limit	60%	50%
Profit split share (contractor share)	upto 300mmcfd – 35% 301-600mmcfd – 25% 601-900mmcfd – 15% >900mmcfd – 10%	upto 300mmcfd – 35% 301-600mmcfd – 25% 601-900mmcfd – 15% >900mmcfd – 10%
General Inflation	2% - Base year 2016	2% - Base year 2016
Price Scenarios	2016 Low-Mid-High price of $7-9-11 per mmcf gas price respectively inflated at 2% thereafter	2016 Low-Mid-High price of $5-7-9 per mmcf gas price respectively inflated at 2% thereafter
Field Specific Gas Prices	Field specific prices not entered at this stage	Field specific prices not entered at this stage
Training Funds	Exploration Fund – assumed to be paid by each field from first spend Production Fund – assumed to be paid during production years	Exploration Fund – assumed to be paid by each field from first spend Production Fund – assumed to be paid during production years
Bonuses	Signature Bonus – none entered Production Bonus – calculated at field level	Signature Bonus – none entered Production Bonus – calculated at field level

11.6.2 Model Results

308. The inputs provided in section 4 were run through the Revenue Projection Model and results were obtained which are summarized the chart below:

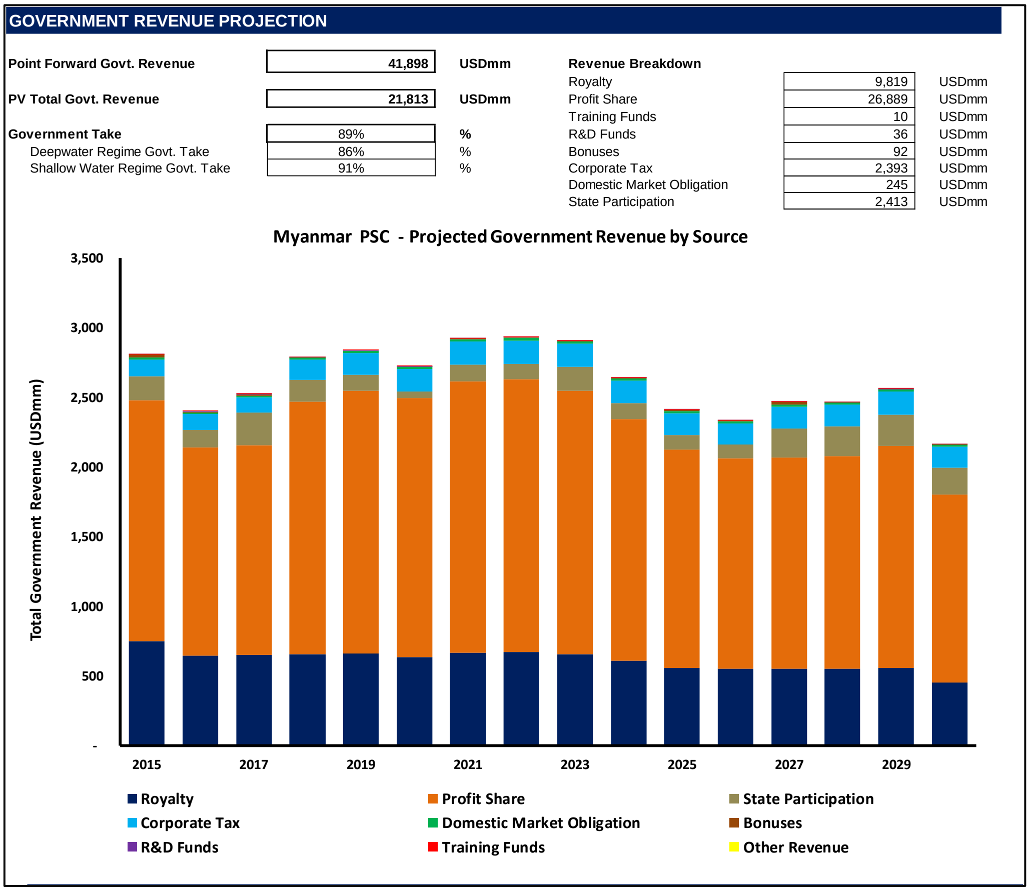


Figure 11.7 Government revenue projection - Mid Case

309. The following results can be deduced from this:

- In the mid-case gas price scenario, total point forward government revenue between 2015 and 2030 is 41.9 billion US dollars. Applying a 10% discount rate, the PV point forward revenue is 21.8 billion US dollars
- There is a significant drop in revenue in 2016 from 2015, mainly due to the change in gas price and total production. 2015 gas price assumption $10/mmcf, whilst 2016 price is $9/mmcf. Production forecast in 2015 is 704 bcf (gross) whilst in 2016 it is expected to be 699 bcf (gross)
- The biggest contributor to government revenue each year is royalty and government profit share, approximately 90% of the revenue is generated from these sources
- Profit share alone contributes around 64% of point forward government revenue between 2015 and 2030
- Participation through MOGE contributes approximately 6% of total point forward revenue

- Average government take is 89%. Deep water regime government take is 86%, whilst shallow water regime take is 91%

310. Reviewing the sensitivity of government revenue to various factors, the charts below provide a comprehensive picture of the outcome.

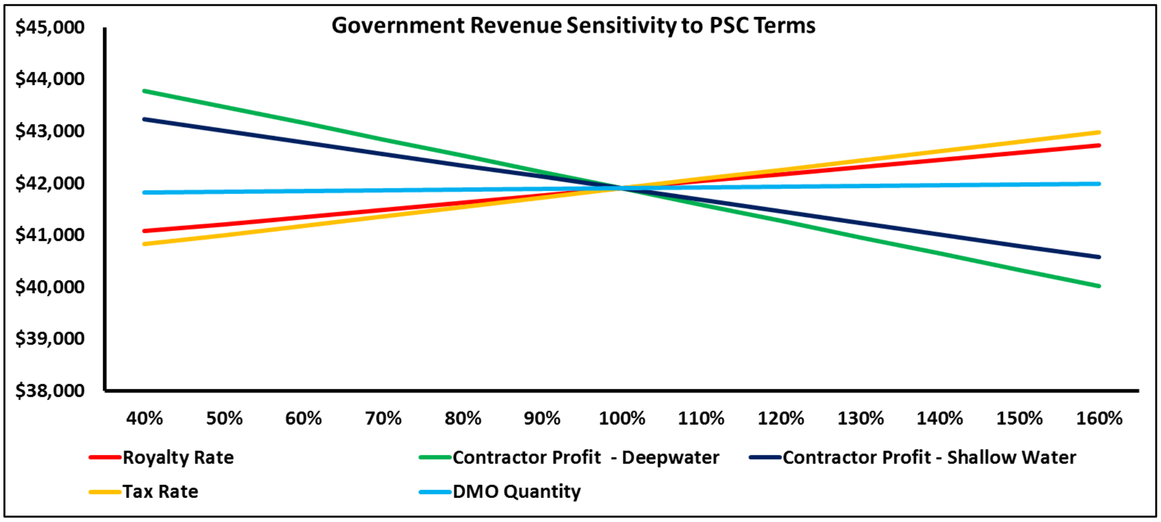


Figure 11.8 Government revenue sensitivity to PSC Terms

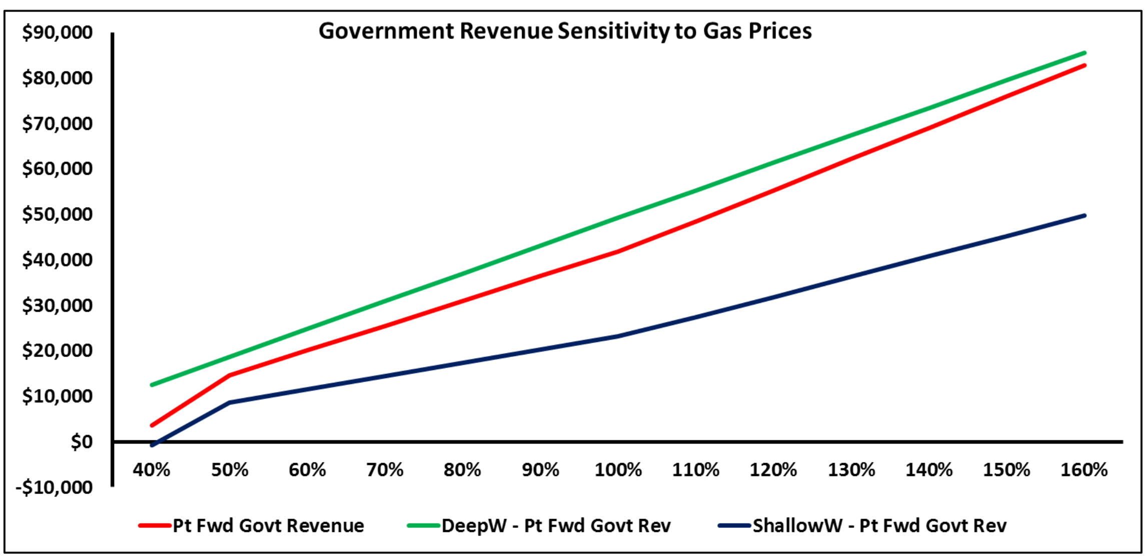
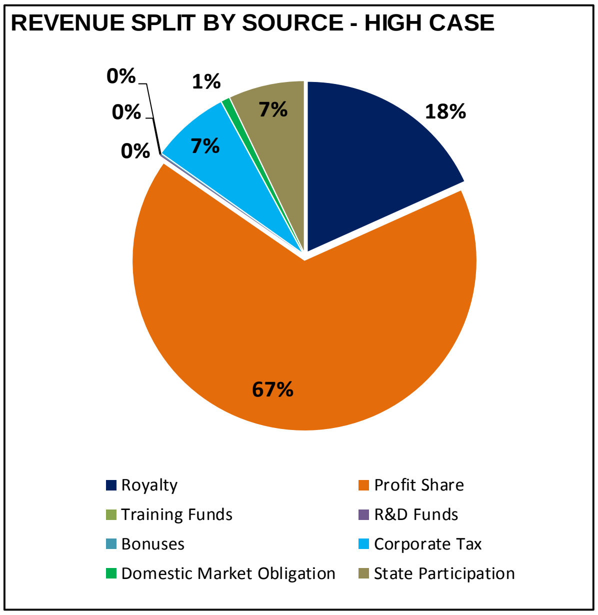


Figure 11.9 Government revenue sensitivity to Gas Prices

311. Based on these results it can be concluded that Myanmar government revenue is highly sensitive to gas prices as would be expected. Further, the PSC terms most sensitive to government revenue is profit share as it is the largest contributor to the total revenue. However, in a low price environment, the share of fixed PSC terms like royalty are expected to contribute

more. The chart below shows the total government revenue by source in a high and low gas price environment.



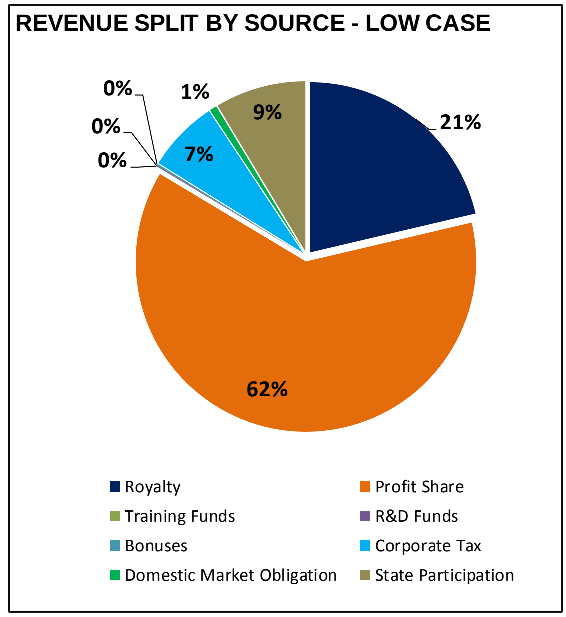


Figure 11.10 Revenue split by source in Low and High Case

312. Thus, the total contribution to government revenue changes between a high price environment when compared to low price environment. The contribution of royalty increases from 18% to 21% whilst profit share contribution drops from 67% to 62%.This example shows the benefit of having fixed fiscal elements in PSC contracts like royalty, which are not directly linked to commodity price.

313. Lastly, the model results dashboard also provides analysis on MOGE participation in the fields. The chart below summarizes the output.

NPV	138	USDmm	Capex per boe	3.39	
PVPI	1.97		Opex per boe	15.38	
Total Revenue	14,481	USDmm	Economic Reserves	394	mmboe
Total Capex	1,335	USDmm	Economic Reseerves - Gas	2,294	bcf
Total Opex	6,053	USDmm	Economic Reseerves - Oil	-	mmbls

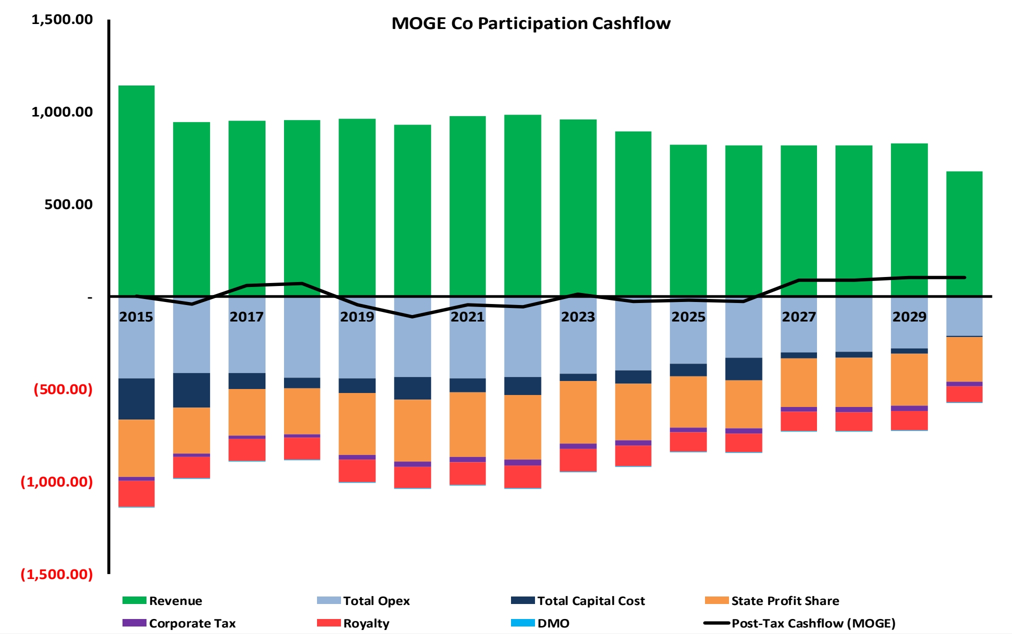


Figure 11.11 MOGE Participation Analysis

11.7 Conclusion and Recommendations

314. The purpose of this task was to better understand and forecast the Myanmar government's revenue from the upstream gas industry. In order to achieve this, a model was built to help forecast expected government revenue and understand better the two main PSC contracts currently operational in Myanmar.

315. A detailed review of Myanmar PSCs concluded that the current standard terms PSCs sit in the high government take and low investor return bracket when compared to several peer groups. The deep water regime in particular has harsher terms when compared against similar PSCs worldwide. This conclusion was based on publicly available data and with no access to actual contracts in both Myanmar and the comparison countries.

316. Looking more closely at the expected revenue for the Myanmar government, we concluded that the revenue stream is highly sensitive to gas prices as would be expected being the single revenue source in our model. Amongst the fiscal term elements, profit share split percentage is the most sensitive element as it also the biggest contributor to government revenue. Thus, it is

expected that the profit share split would be the most important component when negotiating individual PSC contracts in the future.

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Annex 1: Gas supply and demand per offtake

Group 1& 2: Onshore gas fields Kyaukkwet, Thar Gyi Taung, Taung Htauk Sha Bin & Mann / Offtake points: Ayadaw, Chauk, Kyaukse, Htauk Sha Bin &Mann

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
A. Supply (mmcf)															
Kyaukkwet field	3,369	2,816	2,368	2,055	1,818	1,638	1,501	1,462	1,303	1,155	1,069	981	937	883	844
Thar Guyi Taung field	910	748	618	507	415	340	279	278	228	187	153	126	103	83	67
Taung Htauk Sha Bin field	162	127	99	78	62	49	39	39	42	41	39	38	37	34	32
Mann field	551	489	438	392	351	315	282	282	253	226	202	182	162	145	128
Total	**4,992**	**4,181**	**3,523**	**3,032**	**2,647**	**2,342**	**2,100**	**2,061**	**1,826**	**1,609**	**1,463**	**1,327**	**1,239**	**1,145**	**1,070**
B. Demand (mmcf)															
Ayadaw Offtake															
Kyaung Chaung Gas Turbine	767	767	767	767	767	767	767	767	767	767	767	767	767	767	767
Fertiliser plant	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Ayadaw	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**	**772**
Chauk Offtake															
Chauk refinery	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Yenangyaung CNG	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
CNG CHK Chauk	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Total Chauk	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**	**546**
Kyaukse Offtake															
Cement Mill	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360
Pleik CNG	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
Textile KSE	31	32	33	34	35	36	37	38	39	39	39	39	39	39	39
Paper Mill Paleik	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
KSE Slipper factory	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
VAST KSE	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Kyaukse	**573**	**574**	**575**	**576**	**577**	**578**	**579**	**580**	**581**	**581**	**581**	**581**	**581**	**581**	**581**
Htauk Sha Bin Offtake															
ThanPayaKan Refinery	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Total Htauk Sha Bin	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
Mann Offtake															
Minbu LPG	360	360	360	360	360	360	360	360	360	360	360	360	360	360	360
Pwint Phyu Textile	3	4	5	6	7	8	9	10	11	11	11	11	11	11	11
Wazi Heavy Industry	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Minbu Army	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total Mann	**549**	**550**	**551**	**552**	**553**	**554**	**555**	**556**	**557**	**557**	**557**	**557**	**557**	**557**	**557**
Total all offtakes	**2,741**	**2,743**	**2,745**	**2,747**	**2,749**	**2,751**	**2,753**	**2,755**	**2,757**	**2,757**	**2,757**	**2,757**	**2,757**	**2,757**	**2,757**
C. Supply – Demand Surplus or (Deficit) (mmcf) (A) – (B)															
Supply – Demand Surplus or (Deficit)	***2,251***	***1,438***	***778***	***285***	***-102***	***-409***	***-653***	***-694***	***-931***	***-1,148***	***-1,294***	***-1,430***	***-1,518***	***-1,612***	***-1,687***

Group 3: Onshore gas fields Apyauk, Nyaung Don & Ma U / Offtake points: Nyaung Done, Myaungdagar, Ywama

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
A. Supply (mmcf)															
Apyauk field	4,215	7,181	4,038	3,996	4,016	3,918	3,789	3,698	3,481	3,397	3,372	3,351	3,335	3,264	3,209
Nyaung Dong field	7,439	4,166	6,574	6,060	5,688	5,388	5,021	4,919	4,476	4,220	4,045	3,905	3,792	3,639	3,518
Ma U field	2,826	2,819	2,629	2,551	2,531	2,517	2,387	2,266	2,027	1,861	1,747	1,668	1,614	1,536	1,483
Total	**14,479**	**14,166**	**13,242**	**12,608**	**12,235**	**11,824**	**11,197**	**10,884**	**9,983**	**9,478**	**9,164**	**8,924**	**8,741**	**8,438**	**8,210**
B. Demand (mmcf)															
Nyaung Done Offtake															
Kangyisaaungt Fertiliser	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Nyaung Done LPG	341	341	341	341	341	341	341	341	341	341	341	341	341	341	341
Total Nyaung Done	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**	**3,341**
Myaungdagar Offtake															
Myaungdagar Fertiliser	2,801	2,802	2,803	2,804	2,805	2,806	2,807	2,808	2,809	2,809	2,809	2,809	2,809	2,809	2,809
Total Myaungdagar	**2,801**	**2,802**	**2,803**	**2,804**	**2,805**	**2,806**	**2,807**	**2,808**	**2,809**	**2,809**	**2,809**	**2,809**	**2,809**	**2,809**	**2,809**
Ywama Offtake															
CNG YNG 1	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475
Small factories	221	221	221	221	221	221	221	221	221	221	221	221	221	221	221
CNG YNG 2	11	12	13	14	15	16	17	18	19	19	19	19	19	19	19
Total Ywama	**5,707**	**5,708**	**5,709**	**5,710**	**5,711**	**5,712**	**5,713**	**5,714**	**5,715**	**5,715**	**5,715**	**5,715**	**5,715**	**5,715**	**5,715**
Total all offtakes	**11,849**	**11,851**	**11,853**	**11,855**	**11,857**	**11,859**	**11,861**	**11,863**	**11,865**	**11,865**	**11,865**	**11,865**	**11,865**	**11,865**	**11,865**
C. Supply – Demand Surplus or (Deficit) (mmcf) (A) – (B)															
Supply – Demand Surplus or (Deficit)	***2,630***	***2,315***	***1,389***	***753***	***378***	***-35***	***-664***	***-979***	***-1,882***	***-2,387***	***-2,701***	***-2,941***	***-3,124***	***-3,427***	***-3,655***

Group 4: Offshore gas field Shwe / Offtake points: Kyauk Phyu, Taung Thar, Yenanchaung, Belin

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
A. Supply (mmcf)															
Shwe field	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500
B. Demand (mmcf)															
Kyauk Phyu Offtake															
Kyaung Chaung Gas Turbine	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196	3,196
Fertiliser plant	-	-	2,301	2,301	2,301	2,301	2,301	2,301	2,301	2,301	2,301	2,301	2,301	2,301	2,301
Total Kyauk Phyu	**3,196**	**3,196**	**5,497.6**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**	**5,498**
Taung Thar Offtake															
Myinchan Gas Turbine and Steel Mill	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507	11,507
Total Taung Thar	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**	**11,507**
Yenanchaung Offtake															
Yeni Paper Mill	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278
Nay Pyi Taw Cement Mill	876	876	876	876	876	876	876	876	876	876	876	876	876	876	876
Pinpet Steel Mill	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153	3,153
Chauk refinery	730	730	730	730	730	730	730	730	730	730	730	730	730	730	730
Sa le fertiliser plant	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825
Kanbawza cement plant (near Taunggyi)	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548
YCDC Cement plant (Pyay Nyaung)	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Tatmadaw canopy factory (Pyay Nyaung)	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Magwe Tyre factory	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
Cement plant NPT Development	876	876	876	876	876	876	876	876	876	876	876	876	876	876	876
Cement plant Max Myanmar	986	986	986	986	986	986	986	986	986	986	986	986	986	986	986
Total Yenanchaung	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**	**12,114**
Belin Offtake															
Kyauk Se Glass factory	730	730	730	730	730	730	730	730	730	730	730	730	730	730	730
Sin Min 11 cement plant	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008	2,008
Sin Min cement plant spare factory	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548
Kyaukse Industrial group	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Cement Factory (MOI [1]) (Paleik area)	657	657	657	657	657	657	657	657	657	657	657	657	657	657	657
Paleik Industrial group	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
Belin Alcohol	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Belin Tyre factory	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Total Belin	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**	**4,231**
Total all offtakes	**31,048**	**31,048**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**	**33,349**
C. Supply – Demand Surplus or (Deficit) (mmcf) (A) – (B)															
Supply – Demand Surplus or (Deficit)	***5,452***	***5,452***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***	***3,151***

Group 5: Offshore gas fields Yadana, Aung Sinkha M3, Badamyar / Offtake points: Daw Nyein

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
A. Supply (mmcf)															
Yadana field (incl. renegotiations)	91,250	91,250	91,250	91,250	73,448	65,051	56,541	47,696	38,291	29,110	29,110	29,110	29,110	29,110	29,110
Aung Sinkha M3	-	-	-	-	-	-	-	-	-	51,900	51,900	51,900	51,900	51,900	51,900
Badamyar	-	-	-	-	-	-	-	-	-	-	-	-	-	17,000	17,000
Total	**91,250**	**91,250**	**91,250**	**91,250**	**73,448**	**65,051**	**56,541**	**47,696**	**38,291**	**81,010**	**81,010**	**81,010**	**81,010**	**98,010**	**98,010**
B. Demand (mmcf)															
Daw Nyein Offtake															
Ahlone Gas Turbine (Ahlone plus Toyo Thai)	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074	24,074
Ywama Gas Turbine (Ywama GT + EGAT)	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715	21,715
Hlawga Gas Turbine	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261	18,261
Nitrogen removal unit (future)	3,650	3,650	3,650	3,650	3,650	3,650	3,650	3,650	3,650	3,651	3,652	3,653	3,654	3,655	3,656
Shwe Taung Gas Turbine	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842
Myan Aung Gas Turbine	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050
Kyan Kinn Cement Mill	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745	4,745
Tha Yet Cement Mill	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190	2,190
Pyay area small factories	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713	4,713
Inywa ceramic	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Shwe Taung Textile factory(Finishing)	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Tyre factory (MEC)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Ohnne Compressor (Kawa)	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Thaketa area small factories	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Thanlyn area small factories	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399	1,399
Mayangon area small factories	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Hlain area small factories	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Insein area small factories	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
Shwe Pyi Thar area small factories	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Golden sea seafood factory (Hlaing Tharya)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Mingaladon area small factories	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hwambe area small factories	465	465	465	465	465	465	465	465	465	465	465	465	465	465	465
UPP (Ywama)	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374
Thilawa (Yangon) GT	0	0	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374	4,374
Hlawga power plants	0	0	0	0	27,992	27,992	27,992	27,992	27,992	27,992	27,992	27,992	27,992	27,992	27,992
IPP CCGT (Ayeweyarwdy)	0	0	0	0	20,456	20,456	20,456	20,456	20,456	20,456	20,456	20,456	20,456	20,456	20,456
Thaton CCGT	0	0	6,659	6,659	6,659	6,659	6,659	6,659	6,659	6,659	6,659	6,659	6,659	6,659	6,659
Thaketa power plants	0	0	6,048	6,048	21,585	21,585	21,585	21,585	21,585	21,585	21,585	21,585	21,585	21,585	21,585
Total Daw Nyein	**92,622**	**92,622**	**109,703**	**109,703**	**173,688**	**173,688**	**173,688**	**173,688**	**173,688**	**173,689**	**173,690**	**173,691**	**173,692**	**173,693**	**173,694**
Total all offtakes	**92,622**	**92,622**	**109,703**	**109,703**	**173,688**	**173,688**	**173,688**	**173,688**	**173,688**	**173,689**	**173,690**	**173,691**	**173,692**	**173,693**	**173,694**
C. Supply – Demand Surplus or (Deficit) (mmcf) (A) – (B)															
Supply – Demand Surplus or (Deficit)	***-1,372***	***-1,372***	***-18,453***	***-18,453***	***-100,240***	***-108,637***	***-117,147***	***-125,992***	***-135,397***	***-92,679***	***-92,680***	***-92,681***	***-92,682***	***-75,683***	***-75,684***

Group 6: Offshore gas field Zawtika / Offtake point: Kanbauk

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
A. Supply (mmcf)															
Yadana field (incl. renegotiations)	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500	36,500
Total	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**	**36,500**
B. Demand (mmcf)															
Kanbauk Offtake															
Mawla Myaing Gas Turbine	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832
Myaing Ga Lay Cement Mill	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840	5,840
Tha Htone Gas Turbine (=sum of 3 Thaton gas turbines, Thaton, Thaton new and Thaton old)	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534	3,534
Tha Ke Ta Gas Turbine	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849
Ceramic Mawla Myaing	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Myanmar Lighting (Malamyine)	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953	15,953
Kanbauk GE	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Aggreko (Tanintharyi) GE	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853	5,853
Kanbauk CCGT	-	-	-	11,098	11,098	11,098	11,098	11,098	11,098	11,098	11,098	11,098	11,098	11,098	11,098
Total Daw Nyein	**42,235**	**42,235**	**42,235**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**
Total all offtakes	**42,235**	**42,235**	**42,235**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**	**53,332**
C. Supply – Demand Surplus or (Deficit) (mmcf) (A) – (B)															
Supply – Demand Surplus or (Deficit)	***-5,735***	***-5,735***	***-5,735***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***	***-16,832***

Annex 2: Sensitivities

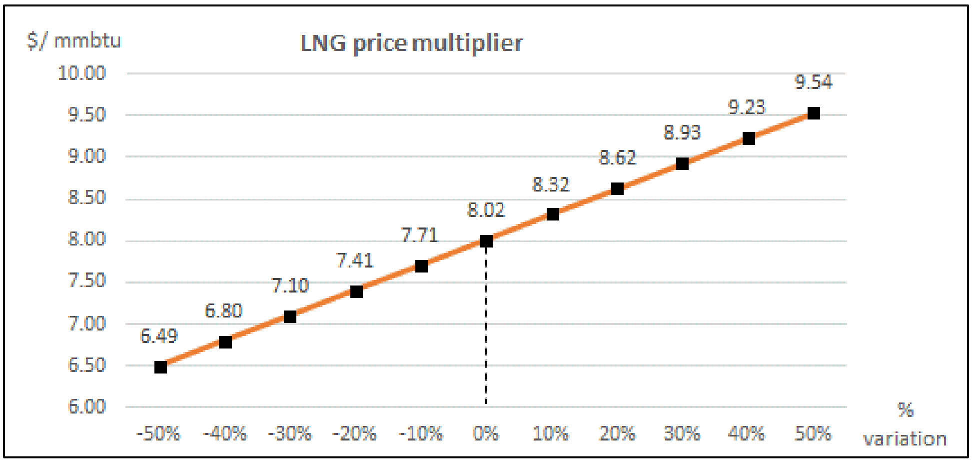

Figure 0.1: Weighted average economic cost sensitivity to LNG Price

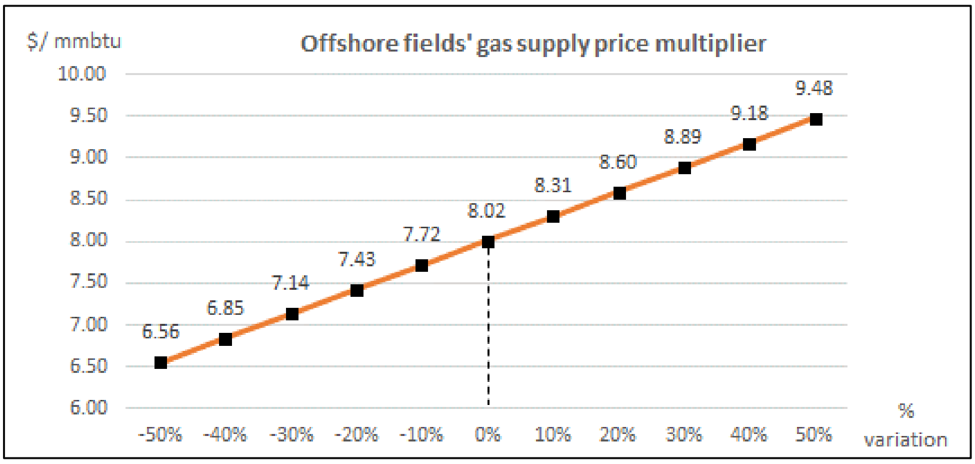

Figure 0.2: Weighted average economic cost sensitivity to offshore fields' wellhead/ field prices

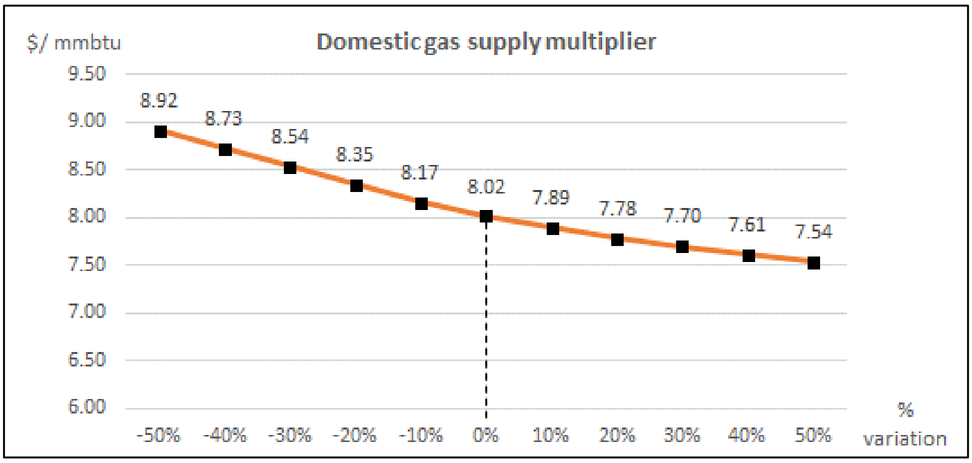

Figure 0.3: Weighted average economic cost sensitivity to gas supply

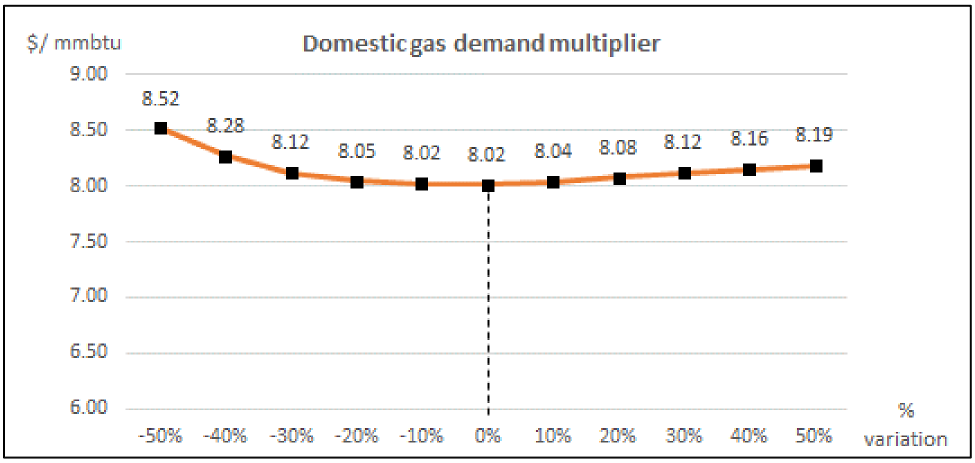

Figure 0.4: Weighted average economic cost sensitivity to gas demand

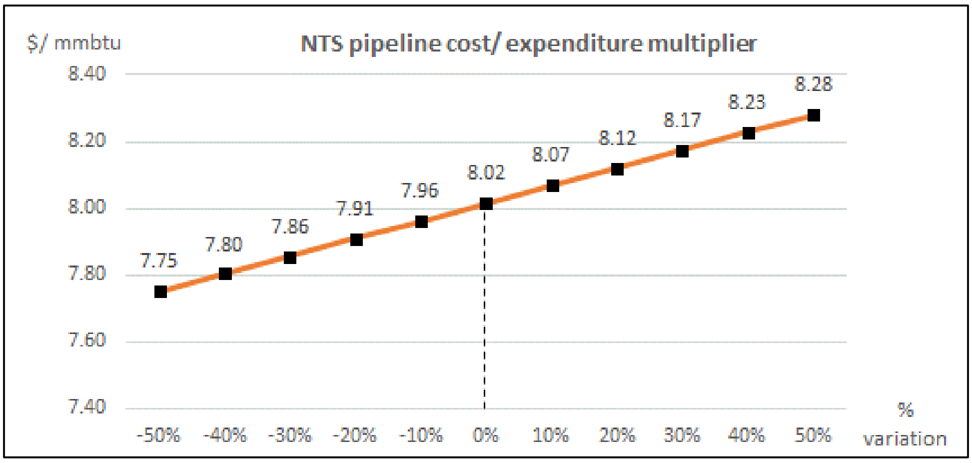

Figure 0.5: Weighted average economic cost sensitivity to NTS pipeline construction cost

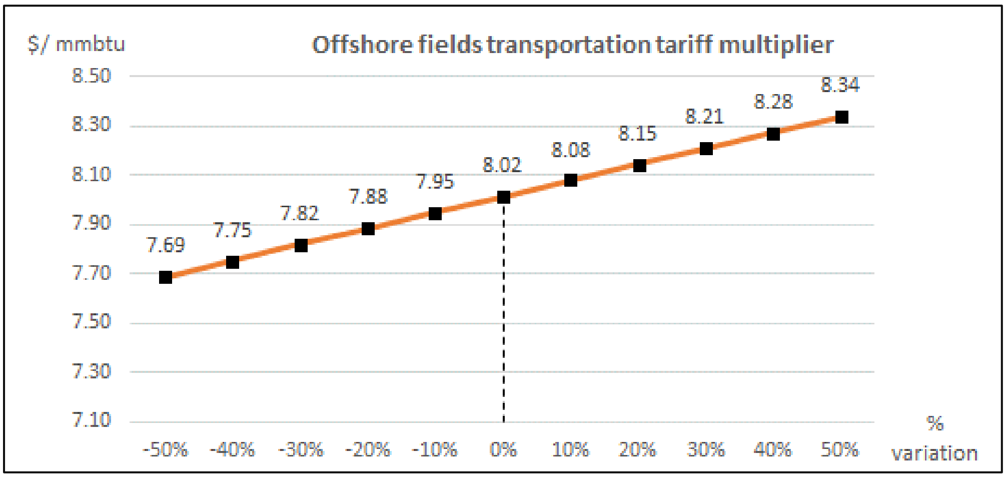

Figure 0.6: Weighted average economic cost sensitivity to offshore fields' transportation tariff

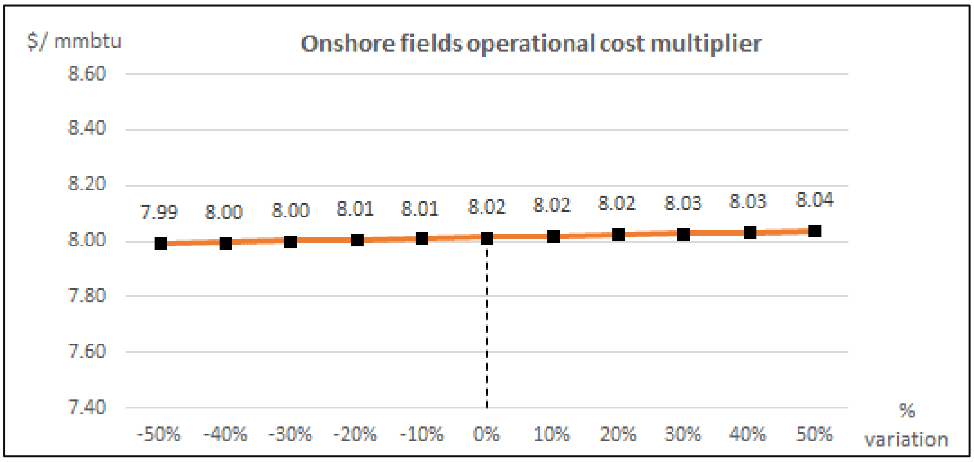

Figure 0.7: Weighted average economic cost sensitivity to onshore fields' costs

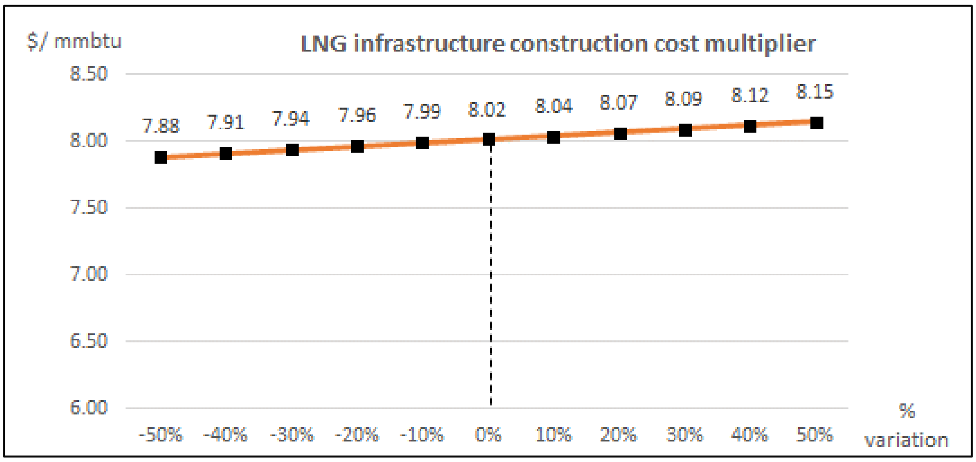

Figure0.8: Weighted average economic cost sensitivity to LNG infrastructure construction cost

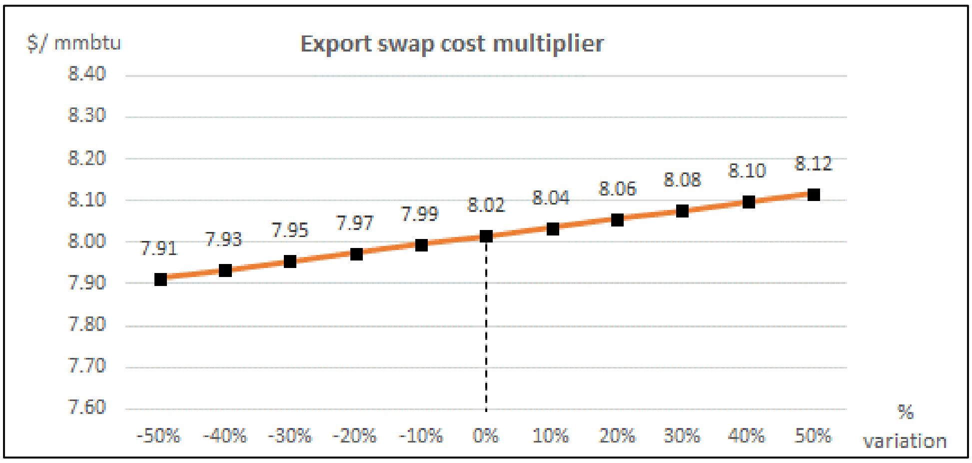

Figure 0.9: Weighted average economic cost sensitivity to export swap

Annex 3: Economic cost model overview and user manual

1. Overview of economic costmodel and basic parameters

1. The economic model was designed and built in order to calculate economic costs of gas for each offtake point in the Myanmar gas network, on a LRAC basis, in accordance with the adopted methodology described in Annex 6: Economic cost of gas methodology, and the parameters and approach to calculation of costs, described in Sections 6 to 9 of this report. In this Section, we provide the outline structure and basic parameters of the economic cost model.

2. The model's output are estimates of the following five economic cost elements, on a LRAC basis, for each offtake (where applicable):
   a. Weighted average or blended economic cost of gas supply ($ per mmbtu)
   b. Economic cost of (offshore)export gas pipelines per offtake ($ per mmbtu)
   c. Economic cost of (onshore) export gas pipelines per offtake ($ per mmbtu)
   d. Economic cost of National Transportation System per offtake ($ per mmbtu)
   e. Economic cost of FSRU terminal and associated infrastructure ($ per mmbtu)

3. Each of the cost elements is additive, thus their sum total provides a total economic cost estimate on a LRAC basis for each offtake.

4. The economic model is organized by thematic areas as shown in Figure 0.1below. The level of detail of required input, and associated key assumptions, have been designed, to accommodate for the type of data that is currently available to the consultant and MOE. The thematic areas are:
   a. Control panel
   b. Input areas
   c. Output/ calculation areas
   d. Dashboard

5. In the 'Control Panel', the user defines the basic parameters of the model. These include the model's first economic year and the horizon of the examined period (i.e. number of subsequent economic years to be examined). These parameters feed through the entire model and define the period for which the user is required to provide input, on an annual basis/ frequency, as well as the period for which all calculations in the model are carried out.

6. The other key parameter that is defined by the user in the 'Control panel', and feeds through to all calculations in the model (specifically all PV and required revenue calculations) is the discount rate. Finally, in this section the user defines the names of relevant offshore fields, onshore fields and offtakes to be examined in the model, and determines which of the defined fields, supply each offtake.

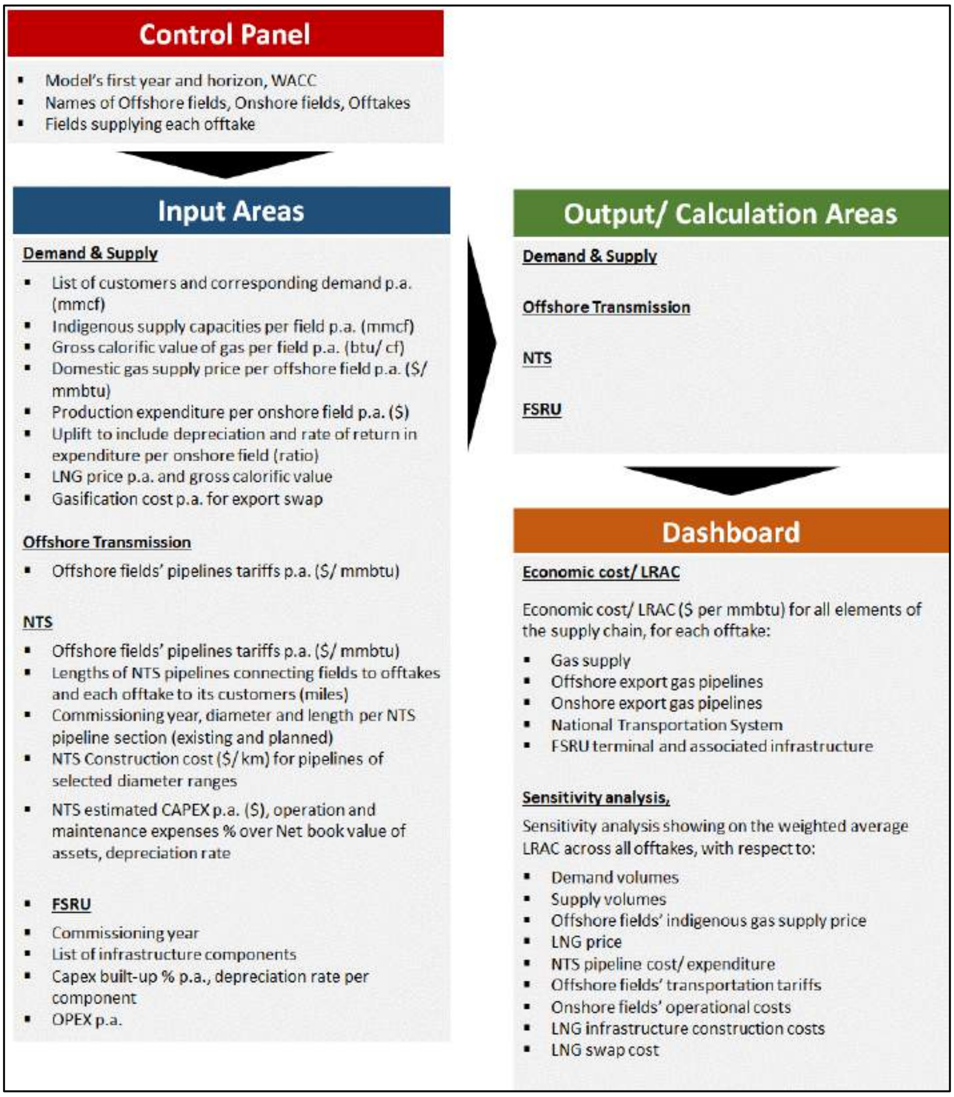

Figure 0.1: Economic model architecture

7. In the 'Input Areas', the user provides all required input for the operation of the model's calculations. There are several separate 'Input Areas' clearly identified in the model:

a. In the 'Demand & Supply' input area, for each of the defined offtakes the user inserts a list of customers and their corresponding expected demand per annum, over the examined period. In relation to supply volumes, the indigenous supply capacities, and corresponding gross calorific value of gas supplied per field, are also input by the user on an annual basis. In relation to supply costs, the user is required to insert the following:

- Domestic gas supply price per offshore field per annum ($ per mmbtu).
- Production expenditure forecast per onshore field per annum ($).
- Uplift to include depreciation and rate of return in expenditure per onshore field (ratio).
- Forecasted trading price of LNG ($ per mmbtu) in the region per annum and corresponding gross calorific value.
- Forecasted LNG gasification cost ($ per mmbtu) in the region, in order to calculate the cost of the 'export swap' option for diverting additional production of offshore fields to the indigenous market.

b. In 'Offshore Transmission' input area the user provides input concerning the tariffs ($ per mmbtu)for transmission of gas via offshore fields' pipelines.

c. In 'NTS' input areas (there are 3 separate areas) the user provides the following technical and financial inputs:

- Lengths of NTS pipelines connecting fields to offtakes and each offtake to its customers (miles) in NTS input area 1
- Commissioning year, diameter and length per NTS pipeline section (existing and planned) in NTS input area 2
- NTS Construction cost ($/ km) for pipelines of selected diameter ranges in NTS input area 2
- NTS estimated CAPEX p.a.($), depreciation rates, operation and maintenance expenses % over net book value of assets in NTS input area 3

d. In the 'FSRU' input area the user defines the FSRU infrastructure's commission year and its components, as well as associated CAPEX values ($) and CAPEX built-up profile (%), depreciation rates and OPEX per component, on an annual basis.

8. There are several separate 'Calculation Areas' clearly identified in the model: 'Demand & Supply', 'Offshore Transmission', 'NTS' (2 calculation areas) and 'FSRU'.

9. The 'Dashboard' presents the LRACs for all elements of the supply chain (gas supply, export pipeline – offshore, export pipeline – onshore, NTS, FSRU & pipeline) by offtake, as well as the total LRAC by offtake. Additionally, the 'Dashboard' provides a weighted average LRAC for all offtakes.

10. The 'Dashboard' also includes tables showing sensitivity analysis, showing the impact on the weighted average LRAC across all offtakes, with respect to incremental percentage variations in the following parameters: demand volumes, supply volumes, offshore fields' indigenous gas supply price, LNG price, NTS pipeline cost/ expenditure, offshore fields' transportation tariffs, onshore fields' operational costs, LNG infrastructure construction costs, LNG swap cost.

11. The model's first year is set to be the current economic year of 2016/ 2017, which commenced in April 2016. The time horizon of the model is 15 yearsending in 2030/2031, which is a reasonable period to allow consideration of significant/ material variation in forecasted input (volumes, costs etc.). The user has the flexibility to change the time period to make it shorter or longer.

12. The model input and output is all in real terms and in $. In cases the Consultant received nominal $ money flows, the inflation rate used to convert flows into real terms was sourced from the following:
http://data.worldbank.org/indicator/FP.CPI.TOTL.ZG/countries/MM?display=default.

2. Economic cost model – user manual

2.1 General points

13. As a general guide, all input to the model, shall be entered by the user in the cells marked/ formatted with light blue background:

All other cells are locked and should not / cannot be altered by the user.

14. All financial/ economic input to the model shall be entered in real terms (i.e. no adjustments shall be made over time for inflation) as the whole analysis is carried out in real terms. The relevant discount rate that is applied for the calculation Present Values (PVs) and Required Returns shall also be in real terms.

15. In cases where no input is applicable, corresponding cells shall be left empty, as shown in the example below.

Snapshot 1: Indicative example of input cells that shall be left empty when no input is applicable (i.e. in the first two cells, the user input the two fields supplying Ayadaw, remaining cells are left empty)

Offtake Sources		
Offtake	**Fields supplying Offtake**	**Comments**
Ayadaw	*Kyaukkwet*	
	Thar Guyi Thaung	

2.2 'Control panel' sheet

16. In this section the user defines:

a. The basic parameters of the model: the first economic year ('**First year'**), the horizon of the examined period, that is the number of subsequent economic years to be examined ('**Time horizon additional years'**). These parameters feed through the entire model and define the period for which the user is required to provide input, on an annual basis/ frequency, as well as the period for which all calculations in the model are carried out.

> **<u>Notes</u>:**
> (1) year N refers to financial year starting April 1st in year N-1 and ending March 31st in year N
> (2) max 'Time horizon additional years' value is 50 years

b. The '**Real WACC/ discount rate**' which feeds through to all calculations in the model, specifically all Present Value (PV) and Required Revenue calculations.

c. The currency of the financial input/ output ('Currency') which feeds through to all calculations in the model.

d. The universe of fields and offtakes, specifically names of:

   i. **'Offshore fields'**
   ii. **'Onshore fields'**
   iii. **'Offtakes'**

e. The '**Offtake sources'**, that is the names of fields (already defined in 2.2.c.) supplying each offtake, via a drop down menu.

f. The values of sensitivity multipliers in '**Sensitivities - Manual mode input'**which allow small adjustments to the value of key input data. The adjustments feed through to model calculations and thus enable the user to examine the changes in the model's outputs that result from small variations in key model input. The sensitivity multipliers which the user can modify are:

   i. **'Domestic gas demand multiplier'**
   ii. **'Domestic gas supply multiplier'**
   iii. **'Domestic gas supply price multiplier'**
   iv. **'LNG price multiplier'**
   v. **'NTS pipeline cost/ expenditure multiplier'**
   vi. **'Offshore fields transportation tariff multiplier'**
   vii. **'Onshore fields operational cost multiplier'**
   viii. **'LNG infrastructure construction costs'**

> **<u>Note</u>:**
>
> (1) A value of "1.0" denotes no adjustment to the value of the input data, a value of "1.1" denotes a 10% increase and a value of "0.9" denotes a 10% decrease to the value of the input data.
>
> (2) The **'Sensitivities - Mode switch'** needs to be set to 'Manual' in order for this feature (described in 2.2.d. to operate). When the switch is set to 'Automatic', all sensitivity analysis, is carried out automatically and is presented in the 'Dashboard' sheet.

2.3 'Demand & Supply input' sheet

17. In this section the user inputs:

a. In the '**Demand per offtake**' subsection, for each of the offtakes that have been defined in the 'Control panel' section, the user inserts a list of customers and their corresponding expected demand per annum (mmcf), over the examined period, as shown in the example below.

Snapshot 2: Extract from the 'Demand per offtake' subsection where the user inserts a list of customers and their corresponding expected demand per annum, over the examined period, for each of the offtakes

	Unit									
Year	yr	2017	2018	2019	2020	2021	2022	2023	2024	2025
DEMAND										
Demand per offtake										
Ayadaw	mmcf	1,830	1,830	1,830	1,830	1,830	1,830	1,830	1,830	1,830
Kyaung Chaung Gas Turbine (=KCHG MEPE)	mmcf	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825
Fertiliser plant (=KCHG F/P)	mmcf	5	5	5	5	5	5	5	5	5
	mmcf									
	mmcf									
	mmcf									

b. In the '**Indigenous supply capacities per field**' subsection, for each of the fields that have been defined in the 'Control panel' section, the user inserts the maximum gas volume (mmcf) that each field can supply to the domestic market per annum, over the examined period, as shown in the example below.

Snapshot 3: Extract from the 'Indigenous supply capacities per field' subsection where the user inserts the maximum gas volume that each field can supply to the domestic market per annum, over the examined period

Year	Unit yr		2017	2018	2019	2020	2021	2022	2023	2024
SUPPLY										
Indigenous supply capacities per field		**Total**								
Kyaukkwet	*mmcf*	24,199	3,369	2,816	2,368	2,055	1,818	1,638	1,501	1,462
Thar Guyi Thaung	*mmcf*	5,041	910	748	618	507	415	340	279	278
Htauk Sha Bin	*mmcf*	918	162	127	99	78	62	49	39	39
Mann	*mmcf*	4,398	551	489	438	392	351	315	282	282
Apyauk	*mmcf*	58,259	4,215	7,181	4,038	3,996	4,016	3,918	3,789	3,698
Nyaung Dong	*mmcf*	72,851	7,439	4,166	6,574	6,060	5,688	5,388	5,021	4,919
Ma U Bin	*mmcf*	32,462	2,826	2,819	2,629	2,551	2,531	2,517	2,387	2,266
OS_8	*mmcf*	0								
OS_9	*mmcf*	0								
OS_10	*mmcf*	0								

c. In the '**Gross Calorific Value'**, subsection, for each of the fields that have been defined in the 'Control panel' section, the user inserts the gross calorific value (btu per cf) of gas that each field supplies to the domestic market per annum, over the examined period.

d. In the cell '**Field deficit level requiring sourcing of additional gas**' the user defines the maximum level of annual deficit for each offtake (mmcf), beyond which the sourcing of additional gas from alternative sources will be required. For example, if Offtake 1 has a deficit of -3,500 mmcf during a particular year, it is implicitly assumed that this deficit is not significant enough to require sourcing of additional gas through 'LNG export swaps' or LNG through the FSRU. It is rather assumed rather that this deficit will be covered through other means, that are not examined in the model.

e. In the '**Field/ Wellhead price**' subsection under the 'OFFSHORE FIELDS' group, for each of the offshore fields that have been defined in the 'Control panel' section, the user inserts the field/ wellhead price (real $/ mmbtu) of gas that each field supplies to the domestic market per annum, over the examined period.

f. In the '**Production Expenditures'**subsection under the 'OFFSHORE FIELDS' group, for each of the onshore fields that have been defined in the 'Control panel' section, the user inserts the annual production expenditure/ cost (real $) of gas that each field supplies to the domestic market per annum, over the examined period.

g. In the '**Expenditure uplift**' subsection under the 'OFFSHORE FIELDS' group, for each of the onshore fields that have been defined in the 'Control panel' section, the user inserts the uplift ratio by which production expenditure shall be increased in order to estimate total required revenue of onshore fields (including not only production cost/ expenditure, but also depreciation and a reasonable rate of return) for gas that each field supplies to the domestic market per annum, over the examined period, as shown in the example below.

Snapshot 4: Extract from the 'Expenditure uplift' subsection where the user inserts the uplift ratio by which production expenditure shall be increased in order to estimate total required revenue of onshore fields for gas that each field supplies to the domestic market per annum, over the examined period

	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025
Year	*yr*	2017	2018	2019	2020	2021	2022	2023	2024	2025
Period	*no.*	0	1	2	3	4	5	6	7	8
Year multiplier	*no.*	1	1	1	1	1	1	1	1	1
Expenditure uplift										
Kyaukkwet	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Thar Guyi Thaung	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Htauk Sha Bin	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Mann	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Apyauk	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Nyaung Dong	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
Ma U Bin	*n/a*	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
OS_8	*n/a*									
OS_9	*n/a*									

h. Under the 'EXPORT SWAP/ LNG' group, the user inserts:

i. the forecasted **trading price** of LNG (real $ per mmbtu) in the region, per annum, over the examined period;

ii. the corresponding **gross calorific value** of LNG supplied in the region, per annum, over the examined period;

iii. the forecasted **LNG gasification cost** (real $ per mmbtu) in the region, over the examined period.

Snapshot 5: Extract from the 'EXPORT SWAP/ LNG' group where the user inserts the forecasted trading price and gasification of LNG and the corresponding gross calorific value of LNG in the region

	Unit		2017	2018	2019	2020	2021	2022	2023	2024	2025
Year	*yr*		2017	2018	2019	2020	2021	2022	2023	2024	2025
Period	*no.*		0	1	2	3	4	5	6	7	8
Year multiplier	*no.*		1	1	1	1	1	1	1	1	1
EXPORT SWAP/ LNG											
LNG price (Japan estimated price)	*real USD/ mmbtu*		7.95	8.01	8.01	8.01	8.03	8.10	8.09	8.09	8.14
Gasification cost estimate	*real USD/ mmbtu*		0.208	0.208	0.208	0.208	0.208	0.208	0.208	0.208	0.208
Gross calorific value of LNG	*BTU/ cf*	880									

2.4 'Offshore transmission input' sheet

18. In this section the user inputs:

a. In the '**Export pipeline transportation tariff**' subsection, for each of the offshore fields that have been defined in the 'Control panel' section, the user inserts the tariffs (real $ per mmbtu) of 'export pipelines' (i.e. pipelines which are not owned by Myanmar's state, are interconnected with neighbouring countries' systems but are also used for transporting gas domestically) per annum, over the examined period. For pipelines which are part of the National Transmission System (NTS) (i.e. are owned by Myanmar's state), the value of tariffs to be entered in this section shall be zero, as the NTS LRAC is calculated in a separate sheet/ section.

b. In the '**Export pipeline additional transportation tariff**' subsection, for each of the offshore fields that have been defined in the 'Control panel' section, if applicable, the user inserts the additional tariffs (real $ per mmbtu) of 'export pipelines' (i.e. pipelines which are not owned by Myanmar's state, are interconnected with neighbouring countries' systems but are also used for transporting gas domestically) per annum, per offtake over the examined period. Additional tariffs apply only to pipelines which have a 'two-part' tariff, such as the Shwe pipeline which has separate tariffs for the offshore and the onshore pipeline segments.

Note:

As noted above, the cells where no input is applicable shall be left empty. For example, no value shall be entered in the cells of the 'Export pipeline additional transportation tariff' subsection, for those fields' pipelines that are not subject to a 'two-part' tariff.

2.5 *'NTS input' sheets*

19. This section consists of three sheets ('NTS input 1', 'NTS input 2', 'NTS input 3').

20. In sheet 'NTS input 1', the user inputs the NTS miles usage per customer, i.e. the lengths of NTS pipelines connecting offtakes to their supplying fields, and each offtake to its customers. Specifically:

   a. In the cells titled '**Fields to offtake distances'**, the user inputs the total length of the NTS network pipelines (miles) connecting each of the relevant fields (supplying the offtake) to the offtake. The relevant routes for which data must be input, appear automatically on the basis of input already provided by the user. For example, in the snapshot below, the user has already specified in the 'Control panel' sheet that the fields supplying Ayadaw offtake are Kyaukkwet and Thar Guyi Taung. This information appears automatically in the input table (horizontal axis), prompting the user to input the length of NTS network pipelines that are connecting each of the relevant fields (supplying the offtake) to the offtake.

   b. In the cells titled '**Offtake to customer distance'**, the user inputs the total length of the NTS network pipelines connecting the offtake to each of the offtakes' customers. The customers for which data must be input, appear automatically, as shown in the example below. For example, in the snapshot below, the user has already specified in the 'Demand & Supply' sheet, all customers of Ayadaw offtake. This information appears automatically in the input table (vertical axis), prompting the user to input the length of NTS network pipelines that are connecting the offtake to each of its customers.

Snapshot 6: Extract from the 'NTS input 1' subsection where the user inputs the NTS miles usage per customer, i.e. the lengths of NTS pipelines connecting offtakes to their supplying fields, and each offtake to its customers

NTS miles usage per customer

Ayadaw

Fields supplying Ayadaw
Kyaukkwet
Thar Guyi Thaung
-
-
-

‘Fields to offtake

‘Offtake to customerdistance’ce

Customers	Unit	Fields to offtake distances					Offtake to customer distance
		Kyaukkwet --> Ayadaw	Thar Guyi Thaung --> Ayadaw	-	-	-	Ayadaw --> customer
Kyaung Chaung Gas Turbine (=KCHG MEPE)	miles	44.52	27.00				0.00
Fertiliser plant (=KCHG F/P)	miles	44.52	27.00				0.00
-	miles						
-	miles						
-	miles						

21. In ‘NTS input 2’ sheet, the user inputs key technical specifications and costs of the NTS network. Specifically:

a. In the cells titled ‘**Pipelines construction cost (CAPEX) levels’**, the user inputs benchmark costs (CAPEX) for the construction of gas network pipelines, for each of the following pipeline diameter ranges: <10 inches, 10 – 16 inches, 16 – 20 inches, 24 inches and 30 inches.

b. In the cells titled ‘**Pipeline replacement frequency’**, the user determines the “economic life” of the pipelines, i.e. the period over which a newly commissioned pipeline is expected to be usable, with normal repairs and maintenance. This period determines the frequency of replacing pipelines by incurring corresponding investments.

c. In the cells titled ‘**Existing pipelines technical specifications’**, the user inserts a list of all existing NTS network pipelines, and their corresponding commissioning year, diameter (inches) and length (miles). An indicative extract is provided below.

Snapshot 7: Extract from the ‘NTS input 2’ sheet where the user inserts a list of all existing NTS network pipelines, and their corresponding commissioning year, diameter and length

Existing pipelines technical specifications

	Unit	Commissioning yr.	Unit	Diameter	Unit	Length
Chauk - Sale	yr	1969	inches	8	miles	13.30
Ayadaw - Lan Ywa	yr	1983	inches	10	miles	23.00
Lanywa - Chauk	yr	1980	inches	8	miles	2.00
Myanaung - Shw Pyi Thar	yr	1977	inches	10	miles	13.70
Myanaung - Kyankin	yr	1975	inches	8	miles	13.50
Myanaung - Kyankin	yr	1986	inches	10	miles	10.03
Seik Thar - Htantabin - Kyankin	yr	1985	inches	10	miles	9.28
Pyay - Seik Thar	yr	1994	inches	10	miles	9.50
Pyay - Shwedaung	yr	1981	inches	10	miles	22.00
Shwedaung - Ti Tute	yr	1984	inches	10	miles	14.00
Ti Tute - Kyaw Swa	yr	1984	inches	10	miles	15.00
Aphauk - Oat Kan	yr	1995	inches	10	miles	12.25
Oat Kan - Pyay	yr	1979	inches	10	miles	78.48
Aphauk - Shwe Pyi Thar	yr	1992	inches	10	miles	47.99
Shwe Pyi Thar - Hlawga	yr	1995	inches	10	miles	2.52
Aphauk - Shwe Pyi Thar (Yangon)	yr	1994	inches	14	miles	41.14
Ywama - Pho Pae Hlaw Su	yr	1999	inches	14	miles	9.40

d. In the cells titled '**Network expansion pipelines technical specifications**', the user inserts a list of all NTS network pipelines that are foreseen to be constructed as part of a network expansion plan, and their corresponding commissioning year, diameter (inches) and length (miles).

22. In 'NTS input 3'sheet, the user inputs financial data/ assumptions concerning the NTS. Specifically:

a. In the cells titled '**MOE plan for pipeline investments'**, the user inputs estimated costs (CAPEX) associated with network expansion/ improvement plans per annum, over the examined period, in addition to those specified in the previous sheet ('NTS_input_2').

b. In the cells titled '**O&M as % of net assets'**, the user sets assumption for estimating NTS Operation and Maintenance costs (O&M) as a percentage of NTS net assets.

c. In the cells titled '**Assets**', the user inserts the closing balance ($), at year end, prior to the examined period of: Nominal assets, Accumulated depreciation and Depreciation charge for 'said' year.

d. In the '**Asset depreciation rate'**, the user inserts the annual depreciation rate for NTS assets.

2.6 'FSRU input' sheet

23. In this section, the user inputs financial data/ assumptions concerning the NTS. Specifically:

a. In the cells titled '**FSRU and associated infrastructure CAPEX per unit'**, the user inputs the infrastructure's components and the corresponding estimated construction cost (CAPEX) per unit of component, for each component as shown in the example below.

Snapshot 8: Extract from the 'FSRU input' sheet where the user inputs the infrastructure's components and the corresponding estimated construction cost (CAPEX) per unit of component, for each component

FSRU and associated infrastructure CAPEX per unit	Unit	
FSRU	*real USD mil*	224.4
Turret, Mooring, Anchoring, PLEM (incl. installation works)	*real USD mil*	55.0
Subsea pipeline (incl. installation works)	*real USD mil*	117.3
Onshore pipeline (incl. installation works)	*real USD mil*	0.7
Technical studies - lisences	*real USD mil*	12.0
	real USD mil	
	real USD mil	
	real USD mil	

b. In the cells titled '**FSRU and associated infrastructure no. of units'**, the user inputs the number of units required for each of the infrastructure's components that are defined above.

c. In the cell titled '**FSRU Commissioning Year**', the user inputs the commissioning year of the FSRU unit.

> **<u>Note</u>:**
> year N refers to financial year starting April 1st in year N-1 and ending March 31st in year N

d. In the cell titled '**Capex build-up in 2 yrs preceding commissioning'**, the user is prompted to input the percentage (%) build-up of construction progress (and associated CAPEX) for each type of infrastructure component that has been already defined above, in the two years preceding commissioning. A snapshot of this is shown below.

Snapshot 9: Extract from the 'FSRU input' sheet where the user is prompted to input the percentage build-up of construction progress (and associated CAPEX) for each type of infrastructure component that has been already defined

	Unit	2017	2018	2019
Year	yr			
Capex build-up in 2 yrs preceding commissioning				
FSRU		40%	60%	
Turret, Mooring, Anchoring, PLEM (incl. installation works)		40%	60%	
Subsea pipeline (incl. installation works)		40%	60%	
Onshore pipeline (incl. installation works)		50%	50%	
Technical studies - lisences		100%		
-				
-				
-				

a. In the cell titled '**Depreciation rates'**, the user inputs the annual depreciation rate (%), for each type of infrastructure component that has been already defined above.

b. In the cells titled '**Operating costs'**, the user inputs the estimated annual FSRU operating costs ($), over the examined period (and following the FSRU's commissioning), as shown in the example below.

Snapshot 10: Extract from the 'FSRU input' sheet where the user inputs the estimated annual FSRU operating costs ($), over the examined period (and following the FSRU's commissioning)

	Unit	2017	2018	2019	2020	2021	2022	2023	2024	2025
Year	yr									
Operating costs	real USD mil			24.0	24.0	24.0	24.0	24.0	24.0	24.0

2.7 'Dashboard' sheet

24. This is the main sheet where the outputs of the model are presented, namely:

    a. The **LRACs per offtake**, in terms of gas supply, transmission via 'export pipelines' (this includes two components: the main tariff, which corresponds to "offshore" transmission and the additional tariff, where applicable, which corresponds to "onshore" transmission), transmission via NTS, and the FSRU infrastructure. The total LRAC per offtake is presented, as well the weighted average LRAC across all offtakes is also calculated.

    b. **Sensitivity analysis on weighted average LRAC** across all offtakes, with respect to eight key parameters: demand volumes, supply volumes, offshore fields' indigenous gas supply price, LNG price, NTS pipeline cost/ expenditure, offshore fields' transportation tariffs, onshore fields' operational costs, LNG infrastructure construction costs.

> **Note:**
>
> Sensitivity analysis in this section is carried out automatically. In order for the calculation to performed, the **'Sensitivities – Mode'** switch in the 'Control panel' sheet needs to be set to 'Automatic'.

Annex 4: Indices used for projections of field/ wellhead prices

Month	Singapore fuel oil Index	US Oil and Gas Field Machinery and Equipment Index	US Consumer Price Index
Apr-09	288.74	249.60	213.2
May-09	319.33	250.80	213.9
Jun-09	366.30	246.80	215.7
Jul-09	425.69	249.90	215.4
Aug-09	428.71	246.80	215.8
Sep-09	464.91	246.70	216.0
Oct-09	457.63	246.90	216.2
Nov-09	469.87	246.80	216.3
Dec-09	497.13	246.80	215.9
Jan-10	493.24	246.90	216.7
Feb-10	507.19	247.40	216.7
Mar-10	488.81	246.20	217.6
Apr-10	494.72	246.90	218.0
May-10	511.45	247.00	218.2
Jun-10	498.84	247.30	218.0
Jul-10	479.61	246.80	218.0
Aug-10	479.84	246.80	218.3
Sep-10	491.78	247.20	218.4
Oct-10	490.06	247.50	218.7
Nov-10	513.57	246.50	218.8
Dec-10	528.13	248.10	219.2
Jan-11	543.08	248.50	220.2
Feb-11	564.34	249.30	221.3
Mar-11	623.50	249.40	223.5
Apr-11	679.01	251.00	224.9
May-11	713.80	251.90	226.0
Jun-11	693.35	254.60	225.7
Jul-11	698.97	255.40	225.9
Aug-11	710.95	255.50	226.5
Sep-11	697.18	256.20	226.9
Oct-11	703.28	256.20	226.4
Nov-11	719.24	256.30	226.2
Dec-11	702.57	256.40	225.7
Jan-12	740.17	257.50	226.7
Feb-12	763.32	257.90	227.7
Mar-12	787.48	258.40	229.4
Apr-12	772.23	260.70	230.1
May-12	727.28	261.00	229.8
Jun-12	657.26	261.40	229.5
Jul-12	662.16	261.80	229.1
Aug-12	704.95	261.90	230.4

Month	Singapore fuel oil Index	US Oil and Gas Field Machinery and Equipment Index	US Consumer Price Index
Sep-12	723.48	261.90	231.4
Oct-12	702.12	261.90	231.3
Nov-12	683.70	262.30	230.2
Dec-12	674.42	262.30	229.6
Jan-13	691.35	263.50	230.3
Feb-13	710.07	263.60	232.2
Mar-13	691.47	263.90	232.8
Apr-13	672.02	264.00	232.5
May-13	668.00	263.20	232.9
Jun-13	666.38	263.20	233.5
Jul-13	666.10	263.20	233.6
Aug-13	667.90	263.60	233.9
Sep-13	665.07	263.80	234.1
Oct-13	659.71	264.10	233.5
Nov-13	652.58	264.40	233.1
Dec-13	660.49	264.70	233.0
Jan-14	656.00	266.80	233.9
Feb-14	661.62	268.40	234.8
Mar-14	660.76	267.80	236.3
Apr-14	657.53	267.50	237.1
May-14	657.67	267.50	237.9
Jun-14	664.47	267.60	238.3
Jul-14	657.25	267.70	238.3
Aug-14	650.12	267.80	237.9
Sep-14	637.72	268.20	238.0
Oct-14	582.32	268.00	237.4
Nov-14	529.26	268.00	236.2
Dec-14	440.36	268.30	234.8
Jan-15	364.84	268.40	233.7
Feb-15	394.90	267.90	234.7
Mar-15	395.49	268.20	236.1
Apr-15	400.90	268.10	236.6
May-15	429.57	269.70	237.8
Jun-15	416.98	269.60	238.6
Jul-15	382.02	267.50	238.7
Aug-15	330.62	267.40	238.3
Sep-15	315.16	267.20	237.9
Oct-15	316.47	267.20	237.8
Nov-15	300.93	266.90	237.3
Dec-15	261.32	266.90	236.5
Jan-16	227.76	266.90	236.9
Feb-16	229.89	266.60	237.1
Mar-16	241.31	266.70	237.0
Apr-16	243.17	266.70	237.0
May-16	260.60	267.00	238.93
Jun-16	263.11	267.00	238.93
Jul-16	266.64	267.00	238.93

Month	Singapore fuel oil Index	US Oil and Gas Field Machinery and Equipment Index	US Consumer Price Index
Aug-16	270.16	267.00	238.93
Sep-16	273.29	267.00	238.93
Oct-16	276.42	267.00	238.93
Nov-16	279.54	267.00	238.93
Dec-16	282.59	267.00	238.93
Jan-17	285.63	267.00	242.61
Feb-17	288.67	267.00	242.61
Mar-17	290.48	267.00	242.61
Apr-17	292.29	267.00	242.61
May-17	294.10	267.00	242.61
Jun-17	295.70	267.00	242.61
Jul-17	297.29	267.00	242.61
Aug-17	298.89	267.00	242.61
Sep-17	300.48	267.00	242.61
Oct-17	302.08	267.00	242.61
Nov-17	303.67	267.00	242.61
Dec-17	305.27	267.00	242.61
Jan-18	306.86	267.00	248.36
Feb-18	308.45	267.00	248.36
Mar-18	310.05	267.00	248.36
Apr-18	311.64	267.00	248.36
May-18	313.24	267.00	248.36
Jun-18	314.83	267.00	248.36
Jul-18	316.21	267.00	248.36
Aug-18	317.59	267.00	248.36
Sep-18	318.96	267.00	248.36
Oct-18	320.34	267.00	248.36
Nov-18	321.71	267.00	248.36
Dec-18	323.09	267.00	248.36
Jan-19	324.46	267.00	254.54
Feb-19	325.84	267.00	254.54
Mar-19	327.21	267.00	254.54
Apr-19	328.59	267.00	254.54
May-19	329.97	267.00	254.54
Jun-19	331.34	267.00	254.54
Jul-19	332.37	267.00	254.54
Aug-19	333.39	267.00	254.54
Sep-19	334.41	267.00	254.54
Oct-19	335.44	267.00	254.54
Nov-19	336.46	267.00	254.54
Dec-19	337.48	267.00	254.54
Jan-20	338.51	267.00	260.49
Feb-20	339.53	267.00	260.49
Mar-20	340.56	267.00	260.49
Apr-20	341.58	267.00	260.49
May-20	342.60	267.00	260.49
Jun-20	343.63	267.00	260.49

Month	Singapore fuel oil Index	US Oil and Gas Field Machinery and Equipment Index	US Consumer Price Index
Jul-20	344.22	267.00	260.49
Aug-20	344.82	267.00	260.49
Sep-20	345.41	267.00	260.49
Oct-20	346.00	267.00	260.49
Nov-20	346.60	267.00	260.49
Dec-20	347.19	267.00	260.49
Jan-21	347.71	267.00	266.12
Feb-21	348.29	267.00	266.12
Mar-21	348.87	267.00	266.12
Apr-21	349.45	267.00	266.12
May-21	350.03	267.00	266.12
Jun-21	350.61	267.00	266.12
Jul-21	351.19	267.00	266.12
Aug-21	351.77	267.00	266.12
Sep-21	352.35	267.00	266.12
Oct-21	352.93	267.00	266.12
Nov-21	353.51	267.00	266.12
Dec-21	354.09	267.00	266.12
Jan-22	354.09	267.00	266.12
Feb-22	354.09	267.00	266.12
Mar-22	354.09	267.00	266.12
Apr-22	354.09	267.00	266.12
May-22	354.09	267.00	266.12
Jun-22	354.09	267.00	266.12
Jul-22	354.09	267.00	266.12
Aug-22	354.09	267.00	266.12
Sep-22	354.09	267.00	266.12
Oct-22	354.09	267.00	266.12
Nov-22	354.09	267.00	266.12
Dec-22	354.09	267.00	266.12
Jan-23	354.09	267.00	266.12
Feb-23	354.09	267.00	266.12
Mar-23	354.09	267.00	266.12
Apr-23	354.09	267.00	266.12
May-23	354.09	267.00	266.12
Jun-23	354.09	267.00	266.12
Jul-23	354.09	267.00	266.12
Aug-23	354.09	267.00	266.12
Sep-23	354.09	267.00	266.12
Oct-23	354.09	267.00	266.12
Nov-23	354.09	267.00	266.12
Dec-23	354.09	267.00	266.12
Jan-24	354.09	267.00	266.12
Feb-24	354.09	267.00	266.12
Mar-24	354.09	267.00	266.12
Apr-24	354.09	267.00	266.12
May-24	354.09	267.00	266.12

Month	Singapore fuel oil Index	US Oil and Gas Field Machinery and Equipment Index	US Consumer Price Index
Jun-24	354.09	267.00	266.12
Jul-24	354.09	267.00	266.12
Aug-24	354.09	267.00	266.12
Sep-24	354.09	267.00	266.12
Oct-24	354.09	267.00	266.12
Nov-24	354.09	267.00	266.12
Dec-24	354.09	267.00	266.12
Jan-25	354.09	267.00	266.12
Feb-25	354.09	267.00	266.12
Mar-25	354.09	267.00	266.12
Apr-25	354.09	267.00	266.12
May-25	354.09	267.00	266.12
Jun-25	354.09	267.00	266.12
Jul-25	354.09	267.00	266.12
Aug-25	354.09	267.00	266.12
Sep-25	354.09	267.00	266.12
Oct-25	354.09	267.00	266.12
Nov-25	354.09	267.00	266.12
Dec-25	354.09	267.00	266.12
Jan-26	354.09	267.00	266.12
Feb-26	354.09	267.00	266.12
Mar-26	354.09	267.00	266.12
Apr-26	354.09	267.00	266.12
May-26	354.09	267.00	266.12
Jun-26	354.09	267.00	266.12
Jul-26	354.09	267.00	266.12
Aug-26	354.09	267.00	266.12
Sep-26	354.09	267.00	266.12
Oct-26	354.09	267.00	266.12
Nov-26	354.09	267.00	266.12
Dec-26	354.09	267.00	266.12
Jan-27	354.09	267.00	266.12
Feb-27	354.09	267.00	266.12
Mar-27	354.09	267.00	266.12
Apr-27	354.09	267.00	266.12
May-27	354.09	267.00	266.12
Jun-27	354.09	267.00	266.12
Jul-27	354.09	267.00	266.12
Aug-27	354.09	267.00	266.12
Sep-27	354.09	267.00	266.12
Oct-27	354.09	267.00	266.12
Nov-27	354.09	267.00	266.12
Dec-27	354.09	267.00	266.12
Jan-28	354.09	267.00	266.12
Feb-28	354.09	267.00	266.12
Mar-28	354.09	267.00	266.12
Apr-28	354.09	267.00	266.12

Month	Singapore fuel oil Index	US Oil and Gas Field Machinery and Equipment Index	US Consumer Price Index
May-28	354.09	267.00	266.12
Jun-28	354.09	267.00	266.12
Jul-28	354.09	267.00	266.12
Aug-28	354.09	267.00	266.12
Sep-28	354.09	267.00	266.12
Oct-28	354.09	267.00	266.12
Nov-28	354.09	267.00	266.12
Dec-28	354.09	267.00	266.12
Jan-29	354.09	267.00	266.12
Feb-29	354.09	267.00	266.12
Mar-29	354.09	267.00	266.12
Apr-29	354.09	267.00	266.12
May-29	354.09	267.00	266.12
Jun-29	354.09	267.00	266.12
Jul-29	354.09	267.00	266.12
Aug-29	354.09	267.00	266.12
Sep-29	354.09	267.00	266.12
Oct-29	354.09	267.00	266.12
Nov-29	354.09	267.00	266.12
Dec-29	354.09	267.00	266.12
Jan-30	354.09	267.00	266.12
Feb-30	354.09	267.00	266.12
Mar-30	354.09	267.00	266.12
Apr-30	354.09	267.00	266.12
May-30	354.09	267.00	266.12
Jun-30	354.09	267.00	266.12
Jul-30	354.09	267.00	266.12
Aug-30	354.09	267.00	266.12
Sep-30	354.09	267.00	266.12
Oct-30	354.09	267.00	266.12
Nov-30	354.09	267.00	266.12
Dec-30	354.09	267.00	266.12
Jan-31	354.09	267.00	266.12
Feb-31	354.09	267.00	266.12
Mar-31	354.09	267.00	266.12
Apr-31	354.09	267.00	266.12
May-31	354.09	267.00	266.12
Jun-31	354.09	267.00	266.12
Jul-31	354.09	267.00	266.12
Aug-31	354.09	267.00	266.12
Sep-31	354.09	267.00	266.12
Oct-31	354.09	267.00	266.12
Nov-31	354.09	267.00	266.12
Dec-31	354.09	267.00	266.12

Annex 5: Data Inventory

Summary of Data Availability by Format/ Medium		Online	Electronic	Hardcopy	A	B	C	Value	Unit	Source(s)	Time Period	Source Link 1 (Dropbox/website)	Source Link 2 (Dropbox/website)	Source page	Remarks
1. Studies and data requirements regarding gas supply and demand	1. Proven, possible and probable gas reserves.	1						Proven = 9.996, Probable = 16.72*, Possible = 18.549*	TCF	CIA Factbook, US Dept. of Energy, ADB Energy assessment	1/1/2014, *09/01/2011	https://www.cia.gov/library/publications/the-world-factbook/geos/bm.html	http://www.eia.gov/beta/international/data/browser/index.cfm#?iso=MMR&c=00000000000000000000000001&ct=0&ord=SA&cy=2015&v=H&vo=0&so=0&io=0&start=2010&end=2015&vs=INTL.43-1-MMR-BCF.A&pa=g1q0000g0000100001004&f=A&ug=g&tl_type=p&tl_id=3002-A	http://www.adb.org/sites/default/files/institutional-document/33719/files/myanmar-energy-sector-assessment.pdf	E&D Offshore: They have the soft copy and will send us later.
	2. Latest gas reserves audit report. If a recent audit is not available, then up-to-date unaudited information on the proven, possible and probable reserves in Yadana, Yetagun, Shwe and the smaller on-shore fields. Information, inter alia, should include for each gas field reservoir depth, water depth, total reserves, expected peak production, ultimate gas recovery, estimate of developed and undeveloped field potential		1					Yadana Gas Field: The Yadana field has estimated gas reserves of more than 5.7 TCF, with an expected field life of 30 years. It is operated by Total and started production in 1998. Gas from Yadana is transported via a 346-kilometer subsea pipeline and a 63-km onshore pipeline to the border with Thailand at Ban I Thong. At the border, the Yadana pipeline connects with a pipeline built by Thailand, which carries the gas to its destination near Bangkok, providing fuel to the Ratchaburi and Wang Noi power plants. Gas from the Yadana field covers an estimated 15%–20% of Thailand's demand for natural gas. The Sein field, located south of the Yadana field, is estimated to have recoverable reserves of 200 BCF	TCF, BCF	ADB Energy assessment	9/1/2011	http://www.adb.org/sites/default/files/institutional-document/33719/files/myanmar-energy-sector-assessment.pdf			Do

Summary of Data Availability by Format/ Medium		Online	Electronic	Hardcopy	A	B	C	Value	Unit	Source(s)	Time Period	Source Link 1 (Dropbox/website)	Source Link 2 (Dropbox/website)	Source page	Remarks
1. Studies and data requirements regarding gas supply and demand			1					The Yetagun field has estimated reserves of 3.16 TCF. Following the withdrawal of Texaco in 1997 and Premier Oil in 2002, Yetagun has been operated by Petronas, in partnership with MOGE (20%), Nippon Oil (19%), and PTTEP (19%). The gas is transported via a 210-km subsea pipeline and a 67-km onshore pipeline to Thailand.	TCF	ADB Energy assessment	9/1/2011	http://www.adb.org/sites/default/files/institutional-document/33719/files/myanmar-energy-sector-assessment.pdf			
			1					In August 2000, Daewoo International partnered with MOGE to explore and develop offshore natural gas deposits in the Bay of Bengal off the coast of Arakan. In 2004, Daewoo International announced the discovery of the Shwe field, off the coast of Sittwe, the capital of Arakan State. Test drilling in blocks A-1 and A-3 has indicated gas reserves of 3.56 TCF or more.	TCF	ADB Energy assessment	9/1/2011	http://www.adb.org/sites/default/files/institutional-document/33719/files/myanmar-energy-sector-assessment.pdf			
	3. Current and planned Production Sharing Agreements (PSAs) with gas producers		1					The Yadana project was developed by a consortium composed of Total (31%), Unocal (28%), PTTEP of Thailand (26%), and MOGE (15%).		ADB Energy assessment	9/1/2011	http://www.adb.org/sites/default/files/institutional-document/33719/files/myanmar-energy-sector-assessment.pdf			Depends on the level of confidentiality
			1					PETRONAS 40.75 % NIPPON 19.40 % PTTEP 19.40 % MOGE 20.45 %		ministry_of_energy_myanmar_2_27_13.ppt	2/27/2013				
			1					DAEWOO 51 % ONGE 17 % GAIL 8.5 % KOGAS 8.5 % MOGE 15 %		ministry_of_energy_myanmar_2_27_13.ppt	2/27/2013				
	4. Historical, current and forecasted gas production. Historic data for gas production (annual and yearly peak) should be by field		1												Available

Summary of Data Availability by Format/ Medium		Online	Electronic	Hardcopy	A	B	C	Value	Unit	Source(s)	Time Period	Source Link 1 (Dropbox/website)	Source Link 2 (Dropbox/website)	Source page	Remarks
1. Studies and data requirements regarding gas supply and demand	5. Historical, current gas exports, forecasted exports based on commitments/contractual arrangements and plans/targets		1												Available
	6. Historical, current gas exports in spot markets		1												Finance
	7. Historical, current domestic gas supply, and projected availability of gas for domestic use		1												Available
	8. Historical and current commercial and technical losses in gas production, transportation and distribution. Potential changes in commercial and technical losses as result of relevant actions			1											Available
	9. Historic data for the operation of the gas transmission and distribution systems (daily inflows at each injection point and outflows at each off-take point)		1					**I have the data on their pipeline network and their lenth, capacity. Nothing about daily inflow and outflow							Available
	10. Historic data for the operation of the export pipelines (daily outflows)		1					**I have the data on their pipeline network and their lenth, capacity. Nothing about daily inflow and outflow							Annual Data available, monthly and quarterly would have been nicer

Summary of Data Availability by Format/ Medium		Online	Electronic	Hardcopy	A	B	C	Value	Unit	Source(s)	Time Period	Source Link 1 (Dropbox/website)	Source Link 2 (Dropbox/website)	Source page	Remarks
1. Studies and data requirements regarding gas supply and demand	11. Detailed description and technical characteristics of gas infrastructure in Myanmar (including map). Infrastructure will include production platforms and gas processing plants, gas transmission and distribution systems (length and diameter of pipelines, compression stations, metering & regulation stations, maximum and operating capacity of pipelines, location and capacity of injection and off-take points), export pipelines (length and diameter of pipelines, compression stations, metering &regulation stations, off-take points, maximum and operating capacity)		1												Some are available, some are not. Need to specify our needs. Offshore, pipline and the production departements are needed to be involved from the MOE.
	12. Investment plans for development of new gas infrastructure (transmission and distribution systems, export pipelines, LNG terminals, storage facilities), with information including inter alia planned maximum and operating capacity, status of implementation, planned date commissioning. Available studies (e.g. pre-feasibility, feasibility studies) for each planned infrastructure			1											Management Level decision. Has to come from the top. Some information are in PSA.
	13. Description of Myanmar’s key gas consumers (electricity production, industry, transport, distribution), their location, their typical daily load profiles in different months, monthly consumption		1					**information about key consumers and yearly consumption							Annual Data, MoG can provide bi monthly data.

Summary of Data Availability by Format/ Medium		Online	Electronic	Hardcopy	A	B	C	Value	Unit	Source(s)	Time Period	Source Link 1 (Dropbox/website)	Source Link 2 (Dropbox/website)	Source page	Remarks
1. Studies and data requirements regarding gas supply and demand	14. Gas demand forecasts per sector, including all scenarios, key policies and drivers.			1											Energy Master Plan, Energy Policy Draft
	15. Agreed off-take points for calculation of gas supply costs to customers			1											to be decided
	16. Gas production (dry) historic and future costs for each gas field (existing or new) broken		1					**information about the total investment on the project							Finance
	17. down by main cost component (exploration & development costs, O&M costs (materials and labor), gas processing and treatment costs (wet to dry), capex, assets depreciation rates, net book value, royalties and taxes (if not included in the PSAs))			1											Finance
	18. Thailand and China border with Myanmar gas prices	1									-	http://www.lexology.com/library/detail.aspx?g=858b5de9-43c4-4926-9e87-cc7d9b032fd9			Finance
	19. Gas transmission system capex/investment program			1											Finance
	20. Gas transmission system assets (gross, depreciation, net)			1											Finance
	21. Gas transmission system O&M costs			1											Finance
	22. Gas export pipelines capex/investment program			1											Finance

Summary of Data Availability by Format/ Medium		Online	Electronic	Hardcopy	A	B	C	Value	Unit	Source(s)	Time Period	Source Link 1 (Dropbox/website)	Source Link 2 (Dropbox/website)	Source page	Remarks
1. Studies and data requirements regarding gas supply and demand	23. Gas export pipelines assets (gross, depreciation, net)			1											Finance
	24. Gas export pipelines O&M costs			1											Finance
	25. Gas distribution system capex/investment program			1											Finance
	26. Gas distribution system assets (gross, depreciation, net)			1											Finance
	27. Gas distribution system O&M costs			1											Finance
2. Other energy fuel and system data	1. Description of electricity sector of Myanmar (gas-fired power plants [type, capacity, year of commissioning, annual hours of operation, efficiency factor], other power plants [including RES]. Electricity peak demand, generating capacities, gross electricity production, transmission and distribution losses (commercial/technical), own power sector consumption		1												From World Bank
	2. Electricity sector investment plans, and underlying rationale and drivers behind the investments to be made (efficiency of existing plants, new CCGTs, Open Cycle plants, network extensions etc) for validation of gas demand forecasts in the electricity sector (e.g. commissioning/decommissioning of plants, upgrades of existing plants, electricity system extensions, loss reduction plans, etc)		1												From World Bank
	3. Description of use of CNG in transport (number of filling station and Natural Gas Vehicles, CNG price evolution, policies promoting the use of CNG)		1												Production and Engineering Department

Summary of Data Availability by Format/ Medium		**Online**	**Electronic**	**Hardcopy**	**A**	**B**	**C**	**Value**	**Unit**	**Source(s)**	**Time Period**	**Source Link 1 (Dropbox/website)**	**Source Link 2 (Dropbox/website)**	**Source page**	**Remarks**
3. Mayanmar Economic/financial/fiscal data requirements:	1. GDP, nominal, real, PPP, projections Inflation rate (CPI), projections		1												WB
	2. Population, growth rate and projections, urban vs rural		1												WB
	3. GDP per head, average monthly salary		1												WB
	4. Monthly average energy cost, absolute terms and as a % of income), households vs industry			1				**information about household vs industry energy consumption but not in % income, that data can be calculated with enough information							WB
	5. Corporate tax rate, projections			1											WB
	6. Local currency exchange rate to USD, projections	1									-	http://www.xe.com/currencycharts/?from=MMK&to=USD	http://www.tradingeconomics.com/myanmar/currency/forecast		WB
	7. Depreciation rates for assets			1											WB
	8. Historic and current proportion of debt and equity in total liabilities of the gas operations of			1											Finance
	9. Myanma Oil and Gas Enterprise, as well as the cost of debt and equity, broken down at production, transmission and distribution levels (for WACC calculation). In case WACC is regulated, the regulated WACC is sufficient for the analysis.			1											
	Financial data														
	Fiscal accounts														
	NIPA (C+I+G+X+M) by sector, commodity														
	Labor market data														
	Demographic data														
	Myanmar Economic and Foreign Trade Banks, audited accounts														
Totals	**43**	**3**	**21**	**19**											

Annex 6: Economic cost of gas methodology

1. Economic versus Financial Cost

1. Economic cost is important as the underlying basis of efficient pricing, enabling the gas companies and their customers alike to make decisions leading to efficient resource allocation and welfare maximization.

2. Economic costs encompass the true cost of all resources used to produce a given good or service, including the cost of resources that are not charged against the good or service e.g. free land, voluntary labor etc. as well as the cost of externalities related to the good or service e.g. environmental costs such as the cost of pollution. Furthermore, the economic cost of resources used to produce a good or service concerns the cost that is free of price distortions e.g. rebates, cross-subsidies etc. and other market imperfections e.g. labor market restrictions and externalities.Using economic costs to value the gas will help to provide the correct investment signals particularly for growing demand when forecast demand exceeds current supply, and guide the allocation of gas to new sources of demand, thus promoting sustainability of the sector.

3. The estimation of economic costs is nevertheless a complex and imprecise task that requires assessing many parameters often from diverging viewpoints, and collecting a wide range of data.In the absence of comprehensive environmental, social and economic impact studies and data in the gas sector of Myanmar, it is not possible (and in the scope of this study) to identify and incorporate costs related to all externalities in the economic cost analysis.

4. In contrast, financial or accounting costs refer to the costs that have to be actually paid for the production of the given good or service.The financial costs may be distorted e.g. resources used are priced at over/under their true costs, or financial costs may include payment for items that have no direct relation to the given good or service e.g. taxes. However, in practice, financial costs are easier to obtain compared to economic costs, and can therefore be used as a proxy for economic costs provided it is ensured that certain key economic principles apply and/or relevant adjustments are made:

   - Prices reflect as much as possible the opportunity cost of resources.For example, financial charges paid to offshore field PSA operators can be a good proxy for the economic costs of gas, as they are linked to traded price of gas (export price).It would not be allocative efficient to charge customers on the basis of what it costs to produce domestically when the traded price of the gas is lower, or vice-versa.

   - In the case of aged domestic onshore fields, cost recovery is ensured if the assets used to produce the good or service are valued at their true cost and the rate of return on these assets is in line with market norms.The inclusion of a 'depletion premium' to be paid by gas customers can be used to reflect the economic rent for the use of a finite resource, and thus better approximate the true value of the assets

- Taxes and other transfer payments are excluded from calculations.

2. Cost-Plus Pricing approach

5. Cost-plus pricing is a well-known, simple and additive approach, whereby the company providing the good or service is allowed to pass-through to the customers each year all the costs required to perform normal operation of its company along with a desired mark-up or profit margin, so as to arrive at a minimum price for the product or service that enables the company to break even financially. Under cost-plus pricing, prices can be adjusted to the company's changing conditions.This provides assurance to investors because risks (and the cost of capital) are lower.

6. However, cost-plus pricing has severe limitations. It is static and not forward looking, as costs are calculated each year.Costs can be also subject to wide fluctuations, depending on the stage of company development and the yearly mix of costs. Cost-plus pricing is not a suitable method for pricing a product or service that is sold in a market with competing products or services to the one in question; cost-plus pricing does not take into account whether the product or service is overpriced compared to what is charged by competitors.Cost-plus pricing provides no or weak incentives for companies to be efficient, as they can pass through to the customers' costs in excess of efficient operation.For assessment of economic costs, we therefore focus on the marginal cost methodologies that follow.

3. Alternative methodologies for estimating economic cost

7. According to standard economic theory, prices should be set at marginal cost (MC) since, in the absence of externalities, this maximizes economic welfare. This is because such prices reflect the costs involved in providing an additional amount of output. Setting prices equal to MC means that users will continue purchasing extra units until it is no longer economically efficient to produce them at that price. MC based pricing therefore send signals to consumers and producers encouraging them to balance the benefits obtained by consuming a good or service with the costs of providing it.

8. Marginal cost pricing is a forward-looking concept. It depends on using estimates of future capital costs (or capital costs looking-forward) to calculate gas charges, rather than historical costs. However, a forward-looking perspective implies the existence of a long-term capital plan for the supplier.

9. Marginal cost can be estimated in either a short-run (SRMC) or a long-run (LRMC) perspective. The fundamental difference between SRMC and LRMC is the period under consideration and the implications for the supplier's ability to adjust its

production process to minimize costs. LRMC is used to signify the cost effect of a change in demand, which would involve future investments for infrastructure and capacity, whereas SRMC takes capacity as given, and relates only to changes in operating costs. LRMC is approximated by estimating how long run operating and future capital costs change if expected demand changes. LRMC is generally preferable over SRMC as the appropriate basis for cost-reflective pricing.

10. There are two main methods for assessing long run marginal costs:

- Average Incremental approach; and
- Perturbation approach.

11. The Average Incremental approach (AIC) approach estimates LRMC as the average change in forward looking operating and capital expenditure required to meet future demand. It can be summarized as follows:

- Forecast average annual and maximum demand for each year of the future time horizon;
- Develop an optimum investment plan for capacity and infrastructure expansion that ensures that supply can satisfy demand in each year;
- Calculate AIC as the sum total of the present values of the year-on-year investments and of the increments in other costs, divided by the sum total of the present values of the incremental demand satisfied year-on-year.

12. The AIC approach is commonly used to approximate the LRMC for network businesses because it can be estimated using pre-existing expenditure and demand forecasts. The principal shortcoming of the AIC approach is that it estimates average capital costs that are needed to satisfy a given demand forecast as proxies for likely marginal costs associated with changes in future demand. It goes without saying that estimation of AIC requires an investment plan to be in place, containing all the additional costs involved in satisfying future demand increments on a least cost basis.

13. The perturbation approach (also known as the ‘Turvey’ approach) is also used to calculate LRMC.This approach shares many of the same steps as the AIC approach, but focuses on estimating how future capital costs can vary as a consequence of an increment or decrement of demand.The principal feature of the perturbation approach is that it directly estimates the change in demand as a consequence of small changes in demand, which most closely ensembles the theoretical ‘marginal cost’.

14. The perturbation approach can be summarized as follows:

- Forecast average annual and maximum demand over the future time horizon;

- Develop an optimum investment plan for capacity and infrastructure expansion that ensures that supply can satisfy demand;

- Increase or decrease forecast average and/or peak demand by a small amount throughout the whole forecast period and recalculate the investments and opex needed to equate demand and supply; and

- Calculate the long run marginal cost (LRMC) as the difference of the present values of future estimated costs (Capex and Opex) before and after the shift in demand, divided by the difference of the present values of future estimated demand before and after the shift.

15. The perturbation approach involves greater complexity compared to the AIC method, as it requires re-optimization of existing investment plans (reassessment of the timing, size and cost of investments) in response to what-if questions concerning marginal shifts in future estimated demand.

16. An approach which is forward looking, yet simple and effective in capturing the cost effect of future annual changes in demand is the long run average cost estimation (LRAC). The Long Run Average Cost approach (LRAC) approach can be proxy to the average forward looking cost (operating and capital expenditure) required to meet future year-on-year demand. It can be summarized as follows:

    - Forecast average annual demand for each year of the future time horizon;

    - Develop an investment plan for capacity and infrastructure expansion that ensures that gas supply can satisfy demand in each year;

    - Calculate LRAC as the present values of the sum total of year-on-year investments and other costs, divided by the present values of the sum total demand satisfied year-on-year.

17. The drawback of LRAC is that is does not capture costs at the margin, i.e. the costs involved in providing an additional amount of output, but on the other hand it provides a ‘levelized’ average long term cost.

4. Comparison of economic cost methodologies

18. The advantages and disadvantages of alternative methodologies are contrasted in Figure 0.1 below.

	Cost plus	Average Incremental Costs (AIC)	Perturbation Approach to LRMC estimation	Long Run Average Costs (LRAC)
Description	Year-on-year pass through of all costs of operation plus a reasonable mark-up/profit margin	Approximates LRMC as the average change in forward looking operating and capital expenditure required to meet future demand. AIC is calculated as the sum total of the PVs of the year-on-year capex and the increments in other costs, divided by the sum total of the PVs of the incremental demand satisfied year-on-year;	Estimates how future costs can vary as a consequence of an increment or decrement of demand. LRMC is calculated as the difference of the PVs of future estimated costs (capex and opex) before and after the shift in demand, divided by the difference of the PVs of future estimated demand before and after the shift	It is a proxy to the average forward looking cost (operating and capital expenditure) required to meet future year-on-year demand LRAC is estimated as the PVs of the sum total of year-on-year investments and other costs, divided by the PVs of the sum total demand satisfied year-on-year
Advantages	▪ Simple ▪ Enables company to break-even financially ▪ Low risk to investors	▪ Forward looking ▪ Not overly complex to implement ▪ very good fit to LRMC	▪ Forward looking ▪ Closely approximates LRMC	▪ Forward looking ▪ Not overly complex to implement ▪ Good proxy for LRMC in cases there are no large swings in investments associated with changes in demand
Disadvantages	▪ not forward looking ▪ Year-on-year cost fluctuations ▪ Prices based on cost-plus do not take into account competition/prices of competing fuels ▪ No or limited incentives for efficiency		▪ Involves greater complexity to implement ▪ Requires least cost investment plans which are re-optimised in response to marginal shifts in demand	▪ Does not capture costs at the margin but instead provides a levelised average long term cost ▪ Requires a fair amount of quality data

Figure 0.1: Comparison of alternative approaches to cost estimation

19. Economic cost on the basis of LRMC approximation is a preferable method to cost-plus pricing given that it is a forward looking approach, which aims to capture the incremental cost effect of anticipated future changes in demand.On the other hand, the LRMC approximation methods are inherently complex as they involve measuring the incremental costs in response to demand changes; but most importantly, for the calculations under any LRMC approximation approach to yield meaningful results, one important precondition is the availability of appropriate information and data; in the case of LRMC estimation under the AIC approach, a key pre-requisite is the existence of comprehensive and optimal investment plans, whereas under the perturbation approach to LRMC estimation there is a need for continuous re-optimization of investment plans in response to marginal shifts in demand.

5. Criteria and selection of appropriate economic cost methodology

20. The suitability of the different economic cost approaches to calculation of economic cost of gas in Myanmar depends on a number of criteria:

- Forward and not backward looking methods
- Methods that are not overly complex to apply
- Availability of required data to properly apply the methods

21. Figure 0.2 below shows the extent to which the different approaches comply with the above criteria.

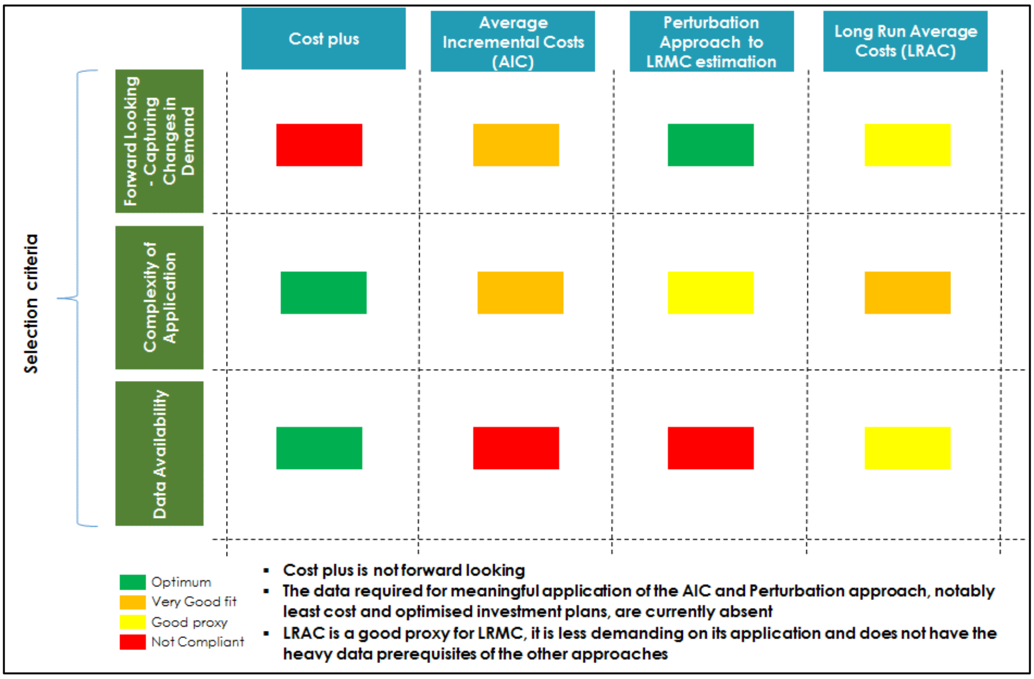

Figure 0.2: Selection of appropriate economic cost methodology for Myanmar

22. In terms of the extent to which alternative methods are forward-looking, the optimal approach is the Perturbation approach to LRMC estimation, while the AIC approach provides a very good fit. LRAC is a good proxy for LRMC in cases there are no large swings in investments associated with changes in demand.

23. In terms of the complexity of application, the Cost Plus approach is the simplest to apply but it lacks in sophistication and in capturing future cost fluctuations. On the other hand, the Perturbation approach is most complex to apply as it requires least cost investment plans which are re-optimised each time in response to marginal shifts in demand, with the use of sophisticated modelling and optimization tools. AIC is also complex to apply as it requires optimized least cost investment plans on a year-by-year basis according to anticipated demand. LRAC also requires an investment plan in place, but this is not necessarily optimized for year-on-year demand changes.

24. In terms of data, AIC and the Perturbation approach are most demanding, whereas LRAC requires a fair amount of quality data. Cost Plus requires limited data.

25. In Myanmar, the lack of data is a key factor driving the choice of the most appropriate approach, under current conditions. In this respect, there are no comprehensive gasdemand data. Available data is for annual ‘energy use allocation’ per customer, and there are no bottom up gas demand forecasts per customer. Demand for gas in the domestic market has so far been driven by the available gas to be provided rather than in response to actual needs of the consumers. Customer consumption profiles that would enable assessment of capacity adequacy and related investments, are absent.

26. In the face of these limitations, the adoption of complex and data intensive approaches such as AIC and Perturbation are not particularly suitable. On the other hand, the LRAC approach enables the approximation of LRMC, requires less data, and would be preferable to a backward looking Cost Plus approach to cost estimation.

6. Applying the selected economic cost methodology

27. The LRAC approach can be applied to all segments of the gas supply chain (gas wellhead costs, LNG import costs, LNG terminal and infrastructure costs, gas domestic transportation costs). The broad steps to LRAC estimation are the following:

- Forecast average annual volumes of gas corresponding to the gas supply chain segment being costede.g. volumes of gas supplied by a field when assessing the gas costs of that field, volumes of LNG demanded when assessing LNG import costs, volumes of gas transported through the domestic transport system when assessing the domestic gas transportation costs, etc.

- Develop an investment plan for capacity and infrastructure expansion that ensures that the gas volumes pertaining to the segment of the gas supply chain examined can be accommodated e.g. investment plan for a gas field when assessing the gas costs of that field, investment plan of LNG terminal and infrastructure when assessing LNG terminal and infrastructure costs, investment plan for rehabilitation or upgrade or expansion of the domestic transport system when assessing domestic gas transportation costs, etc.

- Estimate year-on-year economic costs pertaining to the segment of the gas supply chain examined over the examined horizon.

- Calculate LRAC as the present values of the sum total of year-on-year economic costs, divided by the present values of the sum total demand satisfied year-on-year.

28. In particular, the economic cost pertaining to a segment of the gas supply chain is approximated by estimating the required revenue for the development and operation of this gas supply chain segment; this includesprojections of the operation & maintenance expenses (OPEX) of the gas supply chain segment's infrastructure, estimation of the depreciation of the assets utilized (current stock of assets and new investments), as well as the assessment of the fair return that should be enjoyed on the assets of the particular the gas supply chain segment. An overview of the economic cost components is provided in Figure 0.3 below.

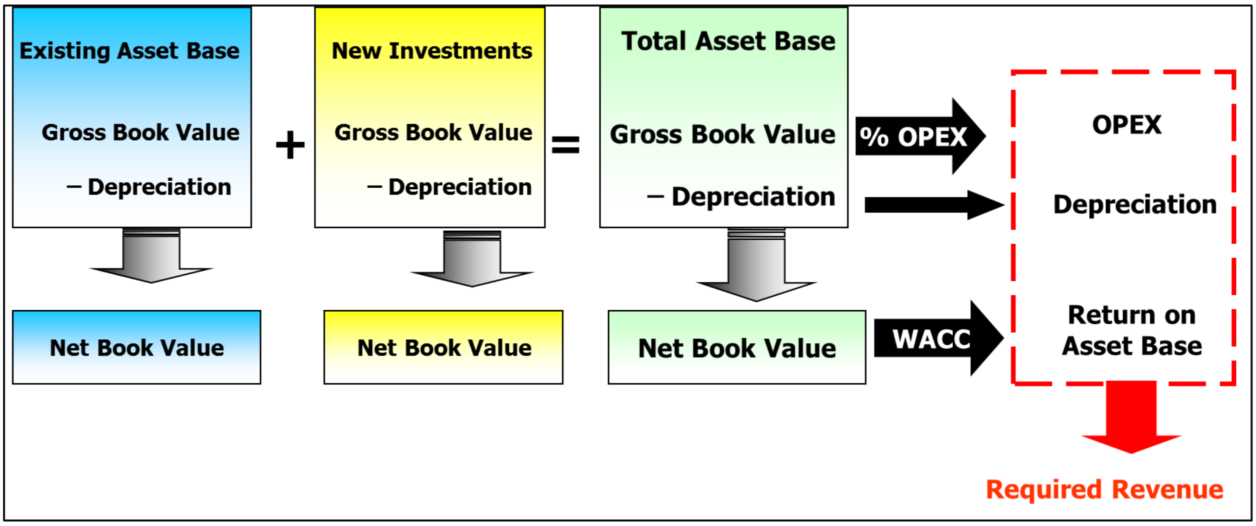

Figure 0.3: Economic cost components

Annex 7: Discount Rate Estimation

1. The real discount rate we have adopted in our modelling calculations is 6.5%. This is estimated on the basis of the minimum target 15% nominal IRR required from investments in gas infrastructure projects, according to MOE, adjusted for inflation of 8%. The assumed inflation rate is based on an average calculation of current inflation rates as reported by the Work Bank and Myanmar's Central Bank.[5,6]The real discount rate is estimated according to the following formula:

$$DRr = (1 + DRn) / (1 + \pi) - 1$$

where

DRr: real discount rate

DRn: nominal discount rate

π: inflation rate

2. By comparison, leading development banks, such as the World Bank and the Asian Development Bank, typically apply 10-12% as a notional range of the real discount rate for evaluating Bank–financed projects in developing countries.[7,8]However, this notional range is not necessarily the opportunity cost of capital in borrower countries, and Task managers are encouraged to use a different discount rate, as long as it is justified in the relevant Country Assistance Strategy.[9]

3. A recent note by the World Bank[10]stipulates that, on the basis of standard economic analysis, social discount rates should be linked to the long-term growth prospects of the country where the project takes place. Where no country-specific growth projections are available, the note suggests that if a 3% growth rate is adopted as a rough estimate for expected long-term growth rate in developing countries, given reasonable parameters for the other variables in the standard Ramsey formula linking discount rates to growth rates, a discount rate of 6% can be applied. Recognizing the difficulties in choosing an appropriate discount rate, the note recommends sensitivity analysis for a range of discount rates. This was performed by the Consultant and is presented in

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[5]http://data.worldbank.org/indicator/FP.CPI.TOTL.ZG/countries/MM?display=default

[6] http://www.cbm.gov.mm/

[7] Zhuang Juzhong, Zhihong Liang, Tun Lin, and Franklin De Guzman, 2007, Theory and practice in the choice of social discount rate for cost-benefit analysis: A survey, Asian Development Bank ERD Working Paper #94.

[8] Harrison, Mark, 2010, Valuing the future: The social discount rate in the cost-benefit analysis, Visiting Researcher Paper, Australian Government Productivity Commission.

[9] http://www.managingforimpact.org/sites/default/files/resource/world_bank_handbook_econ_analysis.pdf

[10] 'Discounting Costs and Benefits in Economic Analysis of World Bank Projects' by Marianne Fay, Stephane Hallegate, Aart Kraay and Adrien Vogt-Schilb, February 2016

Annex 2: Sensitivities. The sensitivity results showed that economic costs are not sensitive to variations in the discount rate.

4. We have also estimated, for comparison purposes, the nominal pre-tax discount rate on the basis of the Weighted Average Cost of Capital (WACC) approach.Our estimate gives a pre-tax WACC value of approx. 16.5%, which is very similar to the 15% nominal IRR required by the MOE.The pre-tax WACC, as opposed to the post-tax WACC is chosen as proxy for the opportunity cost of public/ government funds, that is the return that could have been generated by investing public/ government funds in the private sector, as such investment would not be subject to tax. The basis for our estimation of the pre-tax WACC for Myanmar is according to the following formula:

$$WACC = E/ (E + D) \times Re + D/ (E + D) \times De$$

where

E: value of firm's/ organization's equity

D: value of firm's/ organization's debt

Re: cost of equity

Rd: cost of debt

5. Re is estimated according to the following formula:

$$Re = Rf + \beta \times MRP + CRP$$

Where

Rf: risk-free rate

β: levered beta parameter of companies in similar industries

MRP: market risk premium for mature equity market

CRP: country-risk premium

6. For the risk-free rate (Rf) we take the current yield of U.S. Treasury bonds with 20-years to maturity which is 2.14%.[11] The levered beta parameter of companies in similar industries (β) is estimated according to the following formula:

$$\beta = \beta_{unlevered} \times (1 + (1 - \text{tax rate}) \times D/E)$$

[11] source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

7. The value of βunlevered is assumed to be 0.91 which is the value estimated by Damodaran[12]for 351 U.S. companies in the oil & gas sector. Assuming a zero tax-rate, since we are estimating pre-tax WACC and a debt to equity ratio of 100%, the value of β is estimated at 1.82.

8. We further assume a market risk premium (MRP) for mature equity markets at 6.25% and a country risk premium (CRP) of 6.46%, based on Damodaran estimates.[13] Thus the pre-tax cost of equity is estimated at 19.98%.

9. On the other hand, the cost of debt (Rd) is assumed at 13%, which is the cap applied by Myanmar's Central Bank to bank lending rates, according to latest reported figures[14.] On the basis of a debt to equity ratio of 0.5 (50% debt-50% equity), the nominal pre-tax WACC is estimated at 16.49%.

[12] source: http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/Betas.html
[13] http://www.stern.nyu.edu/~adamodar/pc/datasets/ctryprem.xls
[14] http://data.worldbank.org/indicator/FR.INR.LEND, http://www.cbm.gov.mm/