# DELIVERING AFFORDABLE, SUSTAINABLE, AND RELIABLE POWER TO PAPUA NEW GUINEANS

## Key Challenges and Opportunities in the Power and Domestic Gas Sectors

WORLD BANK GROUP

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## Disclaimer

## Executive Summary

### Introduction

1. **PNG is in a unique position in having a significant endowment in hydropower, natural gas and geothermal resources.** These resources are, however, underutilized; at present the country has one of the lowest per capita rates of consumption of electricity in the world, and it is estimated that only about 20 percent of the population has access to grid and off-grid electricity. Electricity services provided by the national electricity utility PNG Power Limited (hereinafter identified as PPL) to its customers are of poor quality and reliability, and average retail tariffs are very high ($0.30/kWh), reflecting the high costs of service delivery. Investment decisions have been ad hoc and not based on long-term, least-cost planning.

2. **Access to reliable and affordable electricity significantly improves people's lives and enables economic growth.**[1] The Government of PNG has set the ambitious goal of providing access to electricity to 70 percent of the population by 2030 and becoming fully carbon neutral by 2050.[2] A recent study concluded that delivering on the government's electrification goal will require an increase in generation capacity by about 300 megawatts (MW) by 2030.[3] Significant additional demand is expected from commercial, industrial and mining projects that will materialize in the next few years. Beyond electrification, the development of mining and other energy-intensive sectors, has been constrained by the lack of reliable power supply.

3. **Achieving the government's goal on access to electricity will require implementation of systematic least-cost planning to expand infrastructure in all segments of the electricity supply chain and strategically leveraging PNG's natural resources.** Identification and timely competitive implementation of optimum investments in new generation, transmission, and distribution facilities by PPL and other parties will address security of supply in the context of growing demand at the lowest cost available to the country, thereby bringing an affordable electricity service within reach for more and more consumers. At the same time, it will be necessary to ensure that PPL is able to efficiently provide good quality services to all its customers in a sustainable manner. Achieving the ambitious goal on access to electricity services will require the government to define and put in place a strategy addressing the institutional, technical and financial aspects needed to identify and build the optimum infrastructure (grid extension by PPL, mini-grids, individual systems) needed to connect new users across the country and permanently provide them with a good quality service.

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[1] The lack of access to affordable and reliable power supply limits economic growth in urban areas and smaller urban centers and contributes to poverty in rural areas. Low levels of access to an adequate supply of electricity limits the ability of children to study and to access school and health services and exacerbates already severe personal security problems. More generally, it also hinders economic activities and the potential for growth, for example, by refrigeration of fish, pumped irrigation, processing of produce, and development of tourism.

[2] Government of Papua New Guinea (2011); Department of National Planning and Monitoring (2010); National Strategic Plan Taskforce (2009).

[3] This would be an increase of almost 50 percent on the current installed capacity of 580 MW. With Bank support, the government has embarked on an exercise to prepare a National Electrification Rollout Plan (NEROP) for the country, and concluded the geospatial modelling, to understand how best to approach electrification in an efficient and cost-effective manner. The study is currently being finalized for adoption by government.

**4. Weak enforcement of sector planning over recent years and poor governance arrangements for the identification and implementation of new generation projects, combined with PPL's operational inefficiencies, have resulted in high current costs of service delivery.** PNG relies significantly on expensive thermal generation using imported oil products (an average of 37 percent of total generation by PPL was sourced from oil products in 2015-17), despite the country's enormous potential in lower-cost domestic energy resources, particularly hydropower and natural gas. Carrying out systematic planning to identify generation projects that represent the least cost options for the country will make it possible to move gradually away from expensive fossil fuel-based generation. Equally important is that identified projects are implemented at least cost for the country through competitive procurement processes, either directly by the utilities (PPL or others to be established), or by new entities such as Independent Power Producers (IPPs), Special-Purpose Companies (SPCs), or others.

**5. There is potential for gas to help to drive down power costs and expand the grid system in the decade ahead.** There is latent demand among a variety of power users that are grid-connected, off grid or currently not served. The development of such markets requires viable supply solutions all along the gas-value chain but is constrained by some of the same factors that have impeded development of the power system. These include a high-cost environment for connected infrastructure, low base of creditworthy offtakers and a weak planning framework. This note takes a close look at the market dynamics and policy setting driving the availability and cost of gas. This will critically affect the timing and scale of gas' contribution to PNG's power system development and achievement of the government's access goals. It screens potential gas supply solutions and suggests policy actions that could support the role of gas in the power system.

**6. Harnessing mining loads–which are primarily served by captive generation– offers a particular opportunity to underpin power sector development.** Their requirement for reliable long-term supply and ability to pay could help to underwrite new investment in generation, transmission and distribution assets in a variety of grid-based or off-grid solutions. Incorporating projections of mining loads from existing and planned mines is an important aspect of planning, while recognizing that some of these loads are uncertain. This note discusses possible scenarios and associated findings.

**7. Finally, to achieve the sustainable development of the power sector in PNG (including the government's goal on access), it is crucial to complement systematic least-cost planning and implementation of new investments to expand sector infrastructure with specific actions aimed at improving the operational and financial performance of PPL.** Given the geography and settlement patterns of PNG's population, it is estimated that grid electrification is the least-cost option for providing access to approximately 75 percent of the nation's future population; while off-grid systems are recommended for the other 25 percent.[4] The national utility is the natural provider of electricity service to all grid-connected users countrywide, however, PPL's current

[4] NEROP concluded that about 12-13 percent of households in PNG are currently connected to the grid. An additional 6 percent could be easily connected as they are within one kilometer of existing transformers. Others are more distant, but grid connection would still represent the best technical option for up to 75 percent of the country's population.

unsustainable operational and financial situation must be addressed to ensure provision of good quality services to existing customers and the connection of new users. PPL's operational and financial viability are also key to enabling private investments in new generation projects under the IPP scheme as the company will be the offtaker in power purchase agreements (PPA) with those investors. Even in cases where major clients (such as mines) can act as the main guarantor of the PPA, PPL will likely retain responsibility for transmission investments.

8. **The purpose of this note is not to present a comprehensive strategy to redress and develop the sector, but rather to focus on providing policy and technical advice on selected key building blocks indicated as priorities by the Government of PNG, which need to be addressed to unlock further sector development, particularly:**

- **identification of least-cost options for power generation and transmission**, especially the potential role of solar, wind and domestic gas-fired power vs. hydropower opportunities;
- **a high-level analysis of opportunities to develop the domestic gas value chain on the back of liquefied natural gas (LNG) growth**, especially in the power sector, and suggestions on how government action can enable this; and
- **recommended actions to strengthen PPL's financial and operational performance** by improving reliability of power supply, reducing system losses and increasing revenues.

## Lowering the Cost of Generation and Transmission: Least-cost Power Development Plan (LCPDP)

9. **A least-cost generation expansion study was conducted to analyze the optimal generation mix in PNG.** The study has been conducted at two levels: (a) a comparison of levelized cost of electricity (LCOE - in US cents/kWh) for different available generation options; and (b) a system analysis to optimize the generation mix to meet the projected demand by 2030, using a generation expansion study model. Optimized transmission systems have been developed to meet the requirement of delivering electricity from power plants to consumers in PNG.

10. **Given that they cover the majority of the population and targets in the NEROP plan, the study comprises both the POM (Port Moresby) and Ramu systems.**[5] Sectoral analysis has been adopted to conduct the demand forecast in both systems including electrification targets as defined in NEROP, as well as expected demand from the mining and other sectors. Only three small mines are currently supplied by PPL's grid (Hidden Valley, Eddie Creek, and Kainantu), and other existing mines are supplied by their own captive power plants due to their concerns about the current reliability of electricity supply from the grids.

[5] The Port Moresby (POM) generation and distribution system serves the National Capital District, the commercial, industrial and administrative center of Papua New Guinea. POM also serves surrounding areas in the Central Province. The Ramu system serves the load centers of Lae, Madang and Gusap in the Momase Region and the Highlands centers of Wabag, Mendi, Mt Hagen, Kundiawa, Goroka, Kainantu and Yonki.

11. **Three demand scenarios have been developed: (i) Business-as-usual (BAU); (ii) medium-growth in mining; and (iii) high-growth mining.** Under the BAU scenario, the system is planned to deliver on NEROP targets and considers the growth of industry but no new mining projects are considered to be connected into PPL grids. The medium-growth mining scenario considers the three additional mines that are most likely to be connected; while a high-growth mining scenario considers the connection of all mines that may possibly be developed by 2030, except those very remote from either the Ramu or POM grids. A number of generation options were considered as possible candidates based on available resources in both the POM and Ramu system, including hydropower (both through rehabilitation of existing and new facilities), gas power, wind power, solar PV, biomass (Ramu), geothermal (Ramu), coal-fired thermal (Ramu), diesel generation, and fuel oil-fired power plants.

12. **In addition, sensitivity analysis has been conducted to consider changes in a number of parameters.** These include: (i) a less aggressive NEROP target; (ii) higher investment costs for hydropower given the uncertainty of cost estimates; (ii) investment costs for both gas power and new renewal energy (wind power and solar PV) based on high costs of installation found in PNG compared to the international benchmark costs used in the base case; (iv) higher gas prices to illustrate the potential impact of indexation to international oil prices; (v) more available wind power and solar PV projects, with cost reduction; (vi) no consideration of carbon cost; and (vii) different discount rates (6 percent is used in base case, and 8 percent, 10 percent, and 12 percent are considered in sensitivity cases).

13. **The following findings can be observed in the POM system:**

- **Without connecting new mines in the planning period (2018-30), the peak load would grow from 137MW (2018) to 273MW (2030).** The demand growth would be met by an increase in capacity by rehabilitating the existing hydropower station (Rouna, 22MW), Niu Power gas plant (57MW), wind power (70MW), solar PV (80MW), Naoro Brown (80MW), Edevu hydro (51MW) and other new hydro (40MW). Diesel generation is also needed in the short term.
- **In the short term (2018-20), the POM system should increase its capacity immediately to keep enough system reserve.** Rehabilitation of the existing hydropower station (Rouna, 22MW) and commissioning the Niu Power gas plant (under construction, 57MW), together with peaking diesel engine (55MW), could keep the system operating at a safe margin. There would be additional opportunities to use gas to replace existing liquid fuels generation in the POM system on top of the planned 57MW Niu Power gas plant.
- **With the exception of the Edevu hydro station (51MW, under construction), Naoro Brown hydro (80MW), and both wind power (70MW) and solar PV (80MW) would be the least-cost choices in the medium term (2021-25).** Preparation of these generation options should, therefore, be initiated shortly considering the time required for project preparation.
- **In the long term (2026-30), new hydropower could be the major source of new capacity. If success can be demonstrated for both wind power and solar PV, these renewal energy sources should be considered as well.**

- **As the mining load is not as significant in the POM system, connection of the new mines in the planning period would not significantly affect the future generation mix.**

14. **The following findings can be observed in the Ramu system:**
    - **Connecting new mining load in the Ramu system would significantly affect the choice of generation options.** The peak load in 2030 is estimated at 312MW if no new mining is connected (NEROP would only meet residential consumers and other industries). It would grow to 659MW in the medium-growth mining scenario when three new mines could be connected, double the peak load in the BAU scenario; and grow further to 1,602MW (more than five times the peak load under the BAU scenario) in the high-growth mining scenario when more mines could be connected. This scenario would be subject to a high level of uncertainty whether and when mines would go ahead.
    - **Rehabilitation of existing hydropower stations (Ramu 1, Pauanda, and Yonki_Toe) is a no-regret solution to increase the availability of capacity in the Ramu system.** This should be the priority in the short term (2018-20). Diesel generation is also needed to fill the gap in electricity supply. Switching from imported fuel oil to LNG in Munum IPP in Lae would save fuel cost, provided that LNG is available.
    - **In the medium term (2021-25), piloting utility-scale wind power and solar PV should be considered.** There is also an opportunity to install gas engines in the Highlands, preferably close to existing infrastructure, for example in Hides or Kutubu, on a scale calibrated to demand growth on the Ramu grid and transmission connections. New hydropower (such as Ramu 2) would need to be commissioned in about 2025 to meet the demand due to its long construction period, so preparation of the identified hydropower projects should be initiated shortly. The uncertainty of connecting mining loads will affect the installation capacity of both gas power and hydropower substantially.
    - **In the long term (2026-30), new hydropower could be the major source of new capacity.** If success can be demonstrated for both wind power and solar PV, these renewables could be considered as well.

15. **The following findings can be derived for the gas generation option:**
    - **Gas-fired power generation has a potentially large role to play both to replace use of high-cost liquid fuels in the short term and to support power system expansion on a least-cost basis over the medium term.** The results of least-cost modeling highlight different opportunities in the Ramu and POM systems and high levels of sensitivity in demand for gas for power to cost factors, affecting the merit of gas power generation against alternative generation sources.
    - **In the Ramu system, proximity to gas production sources and lesser reliance on gas pipeline transportation, results in an LCOE of 9.1 US cents/kWh for gas engines and 10.8 US cents/kWh for gas turbines (at 60 percent capacity factor and including carbon cost).** This makes gas a lower cost generation option than existing liquid fuels and in the short to medium term provides an opportunity to expand grid capacity until lower cost hydro is available and wind and solar options are proven at scale.
    - **By comparison, in the POM system, reliance on gas piped over long distances results in a LCOE of 10.8 US cents/kWh for gas engines and 12.2 US cents/kWh for gas turbines**

**(at 60 percent capacity factor and including carbon cost).** This makes it harder to compete with hydropower, wind and solar over the medium term but in the short term there are still opportunities to use gas to replace existing liquid fuels generation on top of the planned 57MW Niu Power gas plant.

- **Sensitivity is highest to the selection of the discount rate, with gas becoming more competitive against hydropower as the rate used rises.** Although the LCOE for gas engines and turbines increases in both grids, they nevertheless rank ahead of hydropower in the Ramu grid, at a 12 percent discount rate.
- **Competitiveness is also quite sensitive to gas price, so that if rising oil prices were to be passed on in the gas price through indexation, gas competitiveness would suffer.**
- **When comparing gas turbine and gas engine technologies, gas turbines have a lower investment cost but are less efficient, while gas engines have higher investment costs with higher efficiency.** Under the current assumptions (including cost, gas price) the preferred choice is for gas engines in PNG, although gas turbines could serve as peaking capacity due to their relatively low investment cost ($US/kW). As a fossil fuel, gas competitiveness against non-fossil power sources also suffers with inclusion of a carbon cost.
- **The case for considering gas-to-power is based on the following factors:**
    - **gas generation can be installed more quickly than new hydropower;**
    - **in particular, gas engines, in a PNG context, can be deployed incrementally and flexibly;**
    - **wind and solar, while having lower LCOEs, are unproven at scale;**
    - **given the high cost of liquid fuels, some replacement (and therefore savings in operating costs for PPL and foreign exchange savings) is possible at modest cost in a short time frame, even if not least cost; and**
    - **it may be possible to negotiate lower and nonindexed gas prices than the prices used in the LCOE analysis.**

16. **The following findings can be derived for the hydropower (and rehabilitation) options:**

- **Rehabilitation of existing hydropower stations is a least-cost option in both the POM and Ramu systems and should be a priority.** Their LCOEs range from 1.4 to 1.8 US cents/kWh, which is much lower than the average cost of electricity in PNG.
- **Installation of new hydropower capacity in the Ramu system will be closely linked to the connection of new mining loads in that system.** In the BAU scenario, there is not much room for new hydropower capacity and new hydropower capacity becomes necessary and a least-cost option only when considering the connection of additional mining loads.
- **In addition to the Edevu hydro (which is under construction), the Naoro Brown hydropower project is a least-cost option in the POM system due to its low LCOE (4.3 US cents/kWh).** Additional new hydropower capacity (40-85MW) could be needed in the POM system after the projected commissioning of Naoro Brown.

17. **The following findings can be derived for new renewable (wind power, solar PV, and biomass power) options:**

- **With the anticipated resources and costs, wind power is a least-cost option in PNG.** It has a lower LCOE (6.2-6.9 US cents/kWh) than solar PV (8.1-8.6 US cents/kWh), as the capacity factor of wind power (35 percent) is much higher than solar PV (18.5 percent) even though wind power has a higher investment cost.
- **International experience in the past few years evidences the potential to reduce investment costs of both wind power and solar PV.** The potential cost reduction could make both wind power and solar PV more attractive.
- **Biomass power will be a least-cost option only when: (i) the oil price is high (for example, above $100.00/barrel for Brent); (ii) higher investment costs for gas power are considered; (iii) new mining load is connected to the Ramu grid; and (iv) a carbon cost is incorporated**.

**18. The following findings can be derived for the diesel and fuel oil-fired power options:**

- **Diesel and fuel oil-fired power plants are quite expensive as the fuel prices are high.** Neither of these options are least-cost options, but diesel generation could be installed in the short term to meet the growth in demand growth while developing other low-cost generation options (gas power, hydropower, wind power, and solar PV).
- **A fuel switch from fuel oil to gas (by re-gasifying LNG) could be considered for existing fuel oil-fired plants (Kanudi GT1 and GT2, and Munum IPP in Lae in the short term if there are no technical barriers and gas/LNG was available.** This benefit would decrease in the medium and long term, however, as fuel-oil fired plants would serve as reserve capacity due to their high fuel cost.

**19. The following finding has been determined for the geothermal option:**

- **PNG has geothermal resources in its northern coastal areas and islands, however, due to its anticipated high investment cost, it is not part of the least-cost solutions in the Ramu system.**

**20. The following finding can be derived for the coal-fired thermal option:**

- **Coal-fired thermal generation is not a least-cost option in the Ramu system, however, because the LCOE is as high as 20.7 US cents/kWh when carbon cost is included.**

**21. The study has considered the possible interconnection between the two systems, however, the cost savings that could be achieved do not outweigh the investment cost of this interconnection.** This option is, therefore, not recommended, at least when considering the evolution of the network during the planning period.

**22. The following recommendations for power generation are being proposed:**

- **Rehabilitation of existing hydropower is a quick and cost-effective measure to increase power supply in PNG.** PPL should start the technical diagnosis of the existing hydropower stations (Rouna, Ramu 1, Pauanda, and Yonki Toe) immediately to identify technical solutions for rehabilitation, including equipment replacement and civil works to improve dam safety. If needed, external partner support could be considered to accelerate the process.

- **Gas power is also a competitive generation option in the short and medium term, especially in the Highlands close to where gas is produced.** As with other generation technologies, the competitiveness of gas power from engines and turbines could be enhanced if investment costs were to fall to closer to international benchmarks. The basis on which gas is priced is also important, with oil indexation potentially undermining competitiveness in a higher oil price environment.
- **Wind power and solar PV would be attractive options to supply electricity–provided the anticipated renewable energy sources can be proven and their costs are kept in line with international trends.** Resource mapping for both wind and solar power will also provide additional confidence to the private sector. Piloting commercial-scale wind power and solar PV projects could be considered to get first-hand cost and development information in PNG, and implementation considered if wind power and solar PV can be developed at a larger scale.
- **The development of new hydropower links closely to demand growth.** In the POM system, Naoro Brown has quite a low LCOE (4.3 US cents/kWh) and should be developed as a priority, while Edevu and other hydropower with higher LCOEs would be developed later. Postponing the under-construction Edevu hydro by about five years could reduce the overall costs in the POM system. In the Ramu system, the development of new hydropower will be determined to a large extent by whether new mining loads could be connected. Negotiation with the developers of mining projects is encouraged, with intervention of the government, to sign long-term electricity sales agreements between PPL/generators and mine developers. This is critical for the investment by hydropower developers and PPL. Improving reliability of electricity supply by PPL is also critical to connect the mines (see Chapter Four).
- **Fuel switch for existing fuel oil-fired plants could be considered to replace costly fuel oil with gas (re-gasified from LNG) in the short term while a reliable small-scale domestic LNG supply chain is being developed.** As LNG-based generation would be quite costly, this cost saving benefit would decrease with the commissioning of both renewables (wind power and solar PV) and new hydropower in the Ramu system.
- **An important element will be to achieve further cost reductions in PNG.** We note that all costs (such as investment costs of generation and transmission, Operations and Maintenance (O&M) costs, and electricity retail prices) are much higher in PNG than other countries. A concerted effort should be made to identify the reasons for such differences to reduce the current costs, including introduction of competitive mechanisms for awarding projects–such as the development of an IPP framework, improvement of oversight and supervision of project construction and operation. Introduction of competitive procurement processes, development of local capacity to improve project management, and establishment of capable local bidders would be the key to optimizing investment costs. Reducing operational costs through replacement of diesel fuels and reduction of system losses is equally important.
- **Policies: Developing clear policies and establishing the right enabling environment for the development of the power sector will be important to realize the implementation of the least-cost plan in the most favorable conditions.** Issues such as financing and tariffs, policies and arrangements for connection of mining loads, rural electrification, and

domestic gas use are some of the areas to be considered. These topics need to be discussed and addressed in the context of overall power sector reform.

## Capitalizing on LNG Growth to meet Domestic Energy Needs

**23. In the near term, the government has opportunities to influence the way that gas development takes place as major new gas production and LNG projects are sanctioned.** Securing commitments to allocate some gas from LNG projects to meet domestic energy needs can be encouraged if the government enters negotiations with viable proposals and capitalizes on project developers' probable interest in obtaining political support and social license. To illustrate the type of gas-based options that the government could deploy in negotiations, we present a gas-to-power project concept located in the Highlands and connected to the Ramu grid. Other opportunities to utilize gas in the Port Moresby area–including fuel replacement and schemes to deliver LNG to other domestic markets–are also discussed.

**24. With a view to medium-term development of gas markets, but without holding up negotiations, the government should proceed with consultations on the draft Gas Policy White Paper and prepare a gas master plan and related studies.** The result would see the judicious use of policy measures by government to encourage domestic market development. A further essential outcome of this approach would be to assign responsibilities under clear mandates, preferably with an empowered government entity taking overall control and responsibility for the gas master plan's execution.

**25. The availability and cost of gas as a competitive fuel for power generation in the decade ahead will be shaped by:**

- **the availability of a large gas resource base and likely doubling or more of gas production in this period;**
- **the opportunity to work in tandem with existing and future investments in large integrated LNG export projects;**
- **obtaining gas prices that balance the interests of sellers and buyers; and**
- **near and medium-term government measures to secure gas for domestic use.** This is important as, without government establishing a conducive policy environment and deploying appropriate regulatory measures, gas could be less available and more costly than we think is achievable.

**26. PNG is now an established producer and exporter of gas but is only at the very early stages of domestic gas market development.** The country's 2P reserves[6] currently stand at 8 trillion cubic feet (tcf), whose ownership is almost entirely associated with the existing PNG LNG project. Additional discovered but undeveloped recoverable resources are estimated to be some 30 tcf, while more discoveries are possible with further exploration.

[6] The term 1P is often used to denote proven reserves, while 2P is the sum of proven and probable reserves and 3P the sum of proven, probable, and possible reserves. There is a further classification of contingent resources, divided into 1C, 2C and 3C.

**27. LNG exports under long-term sales contracts have proven to be a commercially viable solution to developing PNG's gas resources.** Such integrated projects have the scale to support large investments to accumulate gas from dispersed fields in remote areas, transport it by pipeline, and then liquefy and ship it to customers. Proven and probable gas resources (2P) are sufficient to support an increase in gas production from roughly 1 bcfd (billion cubic feet per day)[7] today to up to 2.3 bcfd by 2030 based mainly on brownfield and greenfield LNG projects.

**28. The domestic gas market currently absorbs under 4 percent of gas produced.** This scale has been insufficient to underpin the investment that would be needed in dedicated domestically orientated infrastructure. The availability of gas for domestic use will likely go hand-in-hand with LNG export projects. There is sufficient gas to both underpin investment in LNG export schemes and to supply the domestic market.

**29. The best opportunities are to work in complement with the gas fields and pipelines developed to serve LNG projects by:**

- **Relying on a portion of gas from the future development of the P'nyang gas field, which will be gathered and processed in the Highlands, to serve local uses.** The most probable local market for such gas would be a new gas-fired power plant in the region, possibly in Kutubu/Moro or Hides, with transmission lines to link to the Ramu grid. This could be competitive since diesel prices were $22.00/mmbtu in Mendi and Wabag and $26.00/mmbtu in Tari in 2017. Least-cost power generation analysis demonstrates gas to be among the least-cost options in the Ramu grid, especially in the short to medium term until hydropower is available and wind and solar are proven at scale. Gas is also more competitive than hydropower in the long term if the discount rate used is 10 percent rather than 6 percent, as used in the base case.
- **Using an allocation out of the additional gas piped to the coast near Port Moresby to feed the expanded PNG LNG project and the new Papua LNG project.** The market opportunities for gas in and around Port Moresby are likely to be more diverse in the next decade than in the gas-producing areas of the Highlands and Gulf lowlands. Opportunities to use domestically allocated gas in the Port Moresby area include: (i) possibly securing more attractively priced gas supply for the Niu Power plant that is under construction. This would support more affordable power supply to the grid; (ii) using containerized LNG delivered by truck to replace costlier liquid fuel use at the Kanudi power station, which may open up additional opportunities for containerized LNG delivery; (iii) developing latent power demand by offering more affordable gas-fired power supply to existing or potential captive generators; and (iv) for developing nonpower uses of gas, such as industrial parks.
- **Further exploring opportunities for a domestic sea-based LNG trade from Port Moresby to power generators in other coastal cities and islands, such as Lae and Lihir, utilizing containerized LNG or small-scale LNG concepts.** Delivery of LNG ISO containers[8] requires

[7] bcfd: Billion cubic feet per day.

[8] Standardized shipping containers, which follow International Organization for Standardization (ISO) standards and are often referred to as ISO containers, can be loaded on container ships, trucks and rail for transport. There are several

modest upfront modifications and investment and may be an economic solution for the scale and demand profile of the Munum power plant in Lae. To supply larger mining loads in Lihir, small-scale LNG vessels utilizing a conventional LNG supply chain may be needed. For this concept, the addition of liquefaction and regasification, plus unavoidable process losses and handling costs at each end and the transportation costs (mainly by ship), results in significantly higher costs to deliver gas. The high price of liquid fuels in more remote areas may, however, support the economics. For example, fuel oil and diesel prices in Lae averaged \$16.30/mmbtu and \$17.20/mmbtu, respectively in 2017. Replacing liquid fuel imports with domestically sourced LNG can improve the balance of payments and bring other benefits such as energy security.

- **Relying on continued liquefied petroleum gas (LPG) extraction from future gas projects, particularly for back-up in off-grid community-based power generation, for which establishment of a local distribution network for supply to this market would be needed.** Replacing LPG imports with domestically sourced LPG can improve the balance of payments and bring other benefits such as energy security, and cleaner fuel for cookstoves among rural communities.

**30. Current gas prices could be a challenge for PPL, especially in a high oil price environment.** The practice of pricing gas on a liquid fuels displacement basis that is oil indexed, may limit the range of viable gas-to-power options to a small set of opportunities for fuel switching at existing installed dual-use power plants or building relatively small gas-fired plants as an alternative to new liquid fuels-fired plants. The risk of higher oil prices could undermine the competitive position of gas-fired generation to serve Port Moresby and Ramu grid expansion.

**31. The challenge will be to develop a pricing scheme that does not dis-incentivize gas suppliers and that also ensures that any pricing concessions and benefits secured by the government are passed on to gas buyers (or indeed through the power tariff system to electricity consumers).** Export parity and sunk-cost approaches to pricing yield quite different price levels and, under each, domestic gas prices would fluctuate along with international market prices for oil and gas. This uncertainty and potential volatility makes domestic gas pricing based on international market prices not so suitable as a model for a strategic sector such as the power sector in a developing country such as PNG. Choosing a fixed, international benchmark oil price and setting a regulated domestic gas price based on that oil price can clarify and stabilize domestic gas prices. For example, at a benchmark price of \$70.00/barrel (bbl), the regulated domestic gas price in Port Moresby would be \$5.90/mmbtu.

**32. According to best practice in developing and mature gas markets, regulated prices are typically not linked to world market prices but are based on "cost plus".** Cost plus refers to recoverable costs of production, which are generally actual costs, but could also be costs that are deemed reasonable by the regulator based on certain performance criteria. For example, the regulator may limit costs only to those assets which are necessary to generate the product (the "regulated asset base"). The regulated asset base for domestic pipeline gas supply typically

established technologies and manufacturers that have developed ISO containers to hold LNG. These technologies can include vaporizers which regasify the containerized LNG for ready use in gas-fired power generators.

includes the wells, the flowlines, and the gas plant, and may include the export pipeline depending on where gas is transferred to the customer, but it typically does not include the liquefaction plant.

**33. High-level estimates of domestic gas prices using the cost-plus methodology in which domestic supplies are sourced from LNG project production and infrastructure facilities are:**

- **approximately \$3.30/mmbtu for new feedgas to the Papua LNG project delivered at Port Moresby;**
- **approximately \$4.00/mmbtu for new feedgas to serve PNG LNG Train 3 project delivered in the Highlands.** This cost is higher than for feedgas serving PNG LNG Trains 1 and 2, which is understood to benefit from shorter gathering distances and a higher liquids content in the gas.

**34. Aside from price, a significant constraint in developing viable domestic gas markets until now has been the weak position of the government to influence gas field development and the terms of gas supplied domestically which is linked to a broader challenge of limited capacity to plan and finance power system expansion.** It has been challenging to establish reliable offtake arrangements among potential buyers of gas since there is a limited pool of creditworthy buyers able to enter into long-term gas sales contracts. Limited progress has been made to date to develop commercial arrangements through which grid-based power is supplied to mining loads which constitute a significant potential source of power demand that is mainly self-supplied. Finally, there is the absence of a strong planning framework, since current institutional mandates for policy, regulation and planning are still being defined and capacity will need to be built up for a strong government-led planning process to occur.

**35. The government may need to distinguish between pragmatic measures to secure gas for domestic use in the next round of gas agreement negotiations, from a more comprehensive set of measures, based on stronger gas sector planning and new regulatory tools, which will take time to develop.** During state negotiations the government can utilize powers available under the Oil and Gas Act 1998 to secure a share of gas from proposed LNG export projects. In this regard, the formulation of a gas template agreement is an especially high priority.

**36. The government should identify objectives it wishes to achieve and its negotiating position.** Importantly, in PNG's current economic and political climate, LNG exports and the use of gas domestically depend on each other. The government needs support from strong project developers to help finance and build gas fields and infrastructure, and project developers may see modest domestic gas commitments as opportunities to strengthen their political support and "social license."

**37. The state will need to demonstrate that the likely incremental increase in domestic demand for gas presents no significant economic trade-off for them.** Gas output is set to more than double in the next decade. The least-cost generation analysis shows that, even in the most positive scenario for gas-to-power demand growth, domestic gas sales to the power sector would rise to little more than 6-7 percent of projected total output in 2030. There is sufficient gas to both underpin investment in LNG export schemes and to supply the domestic market.

**38. Investors will want to avoid a situation in which, at the time of obtaining LNG buyer commitments and financing for LNG project development, a proportion of the gas resources underpinning the project is reserved for domestic use, unless there is a viable proposal for offtake on the table.** The state's negotiating position can, therefore, be strengthened by proposing commercially viable plans to use gas in both the power and nonpower sectors. The most viable options rely on being able to piggy-back on the production facilities and infrastructure already built, or to be built, for LNG export.

**39. The concept of a modular gas power plant in the Highlands with phased development up to 110 MW has been selected to illustrate the parameters of a potentially competitive power generation option to support expansion of the Ramu grid.** PPL and the Wafi Golpu Joint Venture are currently exploring this idea which would see the mine as the anchor customer critical to underpinning the power investment. The government could play a role in securing attractively priced gas supply. For analysis, gas pricing is assumed to be at or near a cost-plus estimate of the delivered cost of gas to the plant but makes no assumptions about other commercial terms or plant ownership. A site selection of Kutubu/Moro or Hides would allow for synergies with energy infrastructure, skilled personnel and supply logistics–existing or planned.

**40. Several project concepts for gas use in the Port Moresby area would also help displace imported liquid fuel for generation and lower power supply costs overall, bringing broad-scale, long-term benefits such as increased electrification and a healthier industrial sector.** An immediate objective would be to secure gas supply for the Niu Power plant at a price that is lower than what is currently being discussed. Although small, there is also an immediate and relatively straightforward opportunity to use containerized LNG transported by truck to displace liquid fuel currently being burnt at the Kanudi power station. In addition, less defined but potentially substantial opportunities lie in developing latent captive generation and industrial demand in the Port Moresby area using lower-cost gas-fired power. Sea transport of LNG to displace liquid fuels in other less connected markets are also interesting opportunities. Further studies are needed to assess the technical and commercial viability of these schemes.

**41. The government's negotiating position will also be enhanced if it can demonstrate that effective measures are being taken to enhance the operational performance and financial sustainability of PPL so that it may enter discussions with gas suppliers, contractors and customers as a more credible counterpart.** This would include discussion of arrangements through which mining companies are able to sign long-term PPAs to obtain reliable grid-supplied electricity. Over the medium term, the government can build on progress made through negotiation to secure gas for domestic use through stronger gas-sector planning and supporting regulation. The World Bank will assist the consultations that have been launched following National Executive Council direction in March 2018 on the draft Gas Policy White Paper.

**42. International experience suggests that the optimal development of gas resources can benefit by undertaking gas master planning which will serve to inform policy, regulation, and**

**investment planning.** The objective of a gas master planning study is to create a credible, affordable, and competitive plan that can help overcome the chicken-and-egg problem between gas producers and gas consumers.

**43. While the draft Gas Policy White Paper highlights gas reservations and third-party access regulation to support domestic use of gas, these are only some among a variety of policy measures available.** It will be important for the government to consider a full range of options and decide where to place its emphasis.

**44. The government should, therefore:**

- **study further gas reservation policy options,** especially to link any reservation to viable gas offtake that meets power system development needs and optimal gas resource development, including that of "stranded gas";
- **set pricing policy that balances the interests of gas producers and consumers,** based on stable and predictable prices, especially for a strategic sector like power; and
- **determine the ideal structure and organization for any future in-country gas pipeline system**. Until the domestic gas market attains scale, any gas infrastructure dedicated to serving the domestic market will be very high cost.

**45. Overall, the government should prepare a road map to study and foster a domestic gas market that can maximize the benefit of domestic gas use for the country.** Such a road map would start with stakeholder consultations on the draft Gas Policy White Paper and launch development of a gas master plan. The result would see responsibilities assigned under clear mandates, preferably with an empowered government entity taking overall control and responsibility for the plan's execution.

## Improving PPL's Financial and Operational Performance

**46. An operationally and financially efficient and effective utility is a key enabler of provision of good quality electricity services to all the population of PNG.** This paper provides the scope and outcomes of a high-level assessment of current operational and financial performance of the national electricity utility PPL. The assessment highlights significant challenges currently faced by the company but also identifies main topics to be addressed and concrete actions under PPL's control to be implemented to improve its performance. Several proposed actions that can be implemented in the short to medium term (less than three years) are expected to have a significant positive impact on performance.

**47. Financial statements for FY2015, 2016 and 2017 show that PPL is in financial distress that threatens its sustainability and the stability of the electricity sector in the country.** Despite a high weighted average tariff for FY2017 of K 0.897/kWh (equivalent to $0.279/kWh), the EBITDA[9] margin for that period was just 7 percent due to excessive costs and expenses. The weighted average cost of generation was K 0.46/kWh in FY2017 which, added to transmission and

[9] Earnings Before Interest, Taxes, Depreciation, and Amortization.

distribution (T&D) costs of K 0.29/kWh, resulted in a total cost of supply of K 0.75/kWh (equivalent to $0.23kWh). Consequently, PPL had extremely limited funds to cover debt service and substantial investment needs in FY2017. Although investments were mostly funded with new debt, PPL was forced to exhaust its cash reserves to make payments as they fell. In the current circumstances, PPL is financially unable to carry out any of the investments required to improve the operating condition of the existing plants and networks and build new infrastructure to meet increasing demand, thereby compromising reliability of existing service and the ability to connect new consumers.

48. **Staff and Overheads/Fuel, which comprise 34 percent and 26 percent of total costs respectively, are the most significant cost categories.** PPL has 2,000 employees to service 111,927 registered customers (2017 figures) with a ratio of 56 customers per employee.[10] Staff costs also reflect the impact of an existing scheme that links total staff remuneration to revenues (that is, sales regardless of collection) without taking into consideration the company's operational performance and its cash needs to cover debt service and capital expenditure (capex). Turnaround of the financial situation of PPL has to start by improving the company's performance in revenues by optimizing sales and collection rates, but it is also recommended to adjust the scheme to calculate staff remuneration beyond the baseline on a cash basis (that is, collected invoices) and after payment of debt service and capex, and subject to PPL having achieved performance parameters, which shall include those required by the regulatory authority as a condition for tariff adjustment.

49. **In FY2017 PPL's own hydropower plants provided 39 percent of production while own thermal plants provided 24 percent and IPPs the remaining 37 percent.** PPL's own thermal production is significantly costlier than any other source of electricity (K 1.11/kWh vs. K 0.49/kWh of IPPs). Fuel consumption per kWh produced has increased in recent years due to plant degradation and insufficient maintenance. Procedures to monitor physical fuel consumption and procurement practices should be reviewed and improved to optimize fuel costs. Reducing the cost of service delivery requires diligent implementation of actions aimed at tackling its main cost drivers. An assessment of the technical and financial feasibility of rehabilitation and an upgrade of existing installed hydropower capacity is urgent as, if confirmed, it will be the least-cost option available to the country. Timely implementation through competitive processes of optimum investment projects identified in the LCPDP discussed in Chapter Two also has maximum priority.

50. **The financial sustainability of PPL crucially depends on the collection of permanent billings for energy consumed by users connected to its networks, however, less than 77 percent of the amount of energy injected into PPL's networks in FY2017 was sold (billed) by the utility, meaning total losses above 23 percent.** The amount of collected revenues are eroded by nontechnical losses (low billing rates) and issues related to collection of bills. In FY2016, up to 45 percent of invoices were not paid within 30 days and more than 39 percent were paid more than 90 days past their due date. In FY2017 these percentages further declined to 55 percent and 47 percent, respectively.

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[10] Comparable utilities in other emerging countries show ratios above 200 customers/employee.

51. **The effectiveness of billing and collection are issues under the company's control and must be addressed as a matter of urgency.** Sustainable reduction of nontechnical losses can be quickly addressed through the implementation of a Revenue Protection Program (RPP) to target its largest customers who constitute just 7 percent of total customer numbers but account for 77 percent of current physical sales. The establishment cost of an RPP is around $3 million which could be recovered in a few months, as each percentage point of current total losses that is converted to sales represents an annual additional revenue for PPL of $3.62 million.

52. **Permanent achievement of collection rates close to 100 percent for all regular customers should also have maximum priority for PPL.** Although uncollected bills are not a permanent financial loss, poor collection rates affect the financial condition of the utility. The current collection rate of bills issued by PPL to government agencies–that represent 14 percent of the company's sales–is very low. Amounts of unpaid receivables from those agencies, which are handled by PPL as non-disconnectable points of supply, reached K 61 million (equivalent to $18.7 million) in 2017. The increasing trend in this parameter started in 2016 and is growing at a rate above K 10 million per month (equivalent to $3.1million). This issue should be addressed at the broader government level as a matter of urgency.

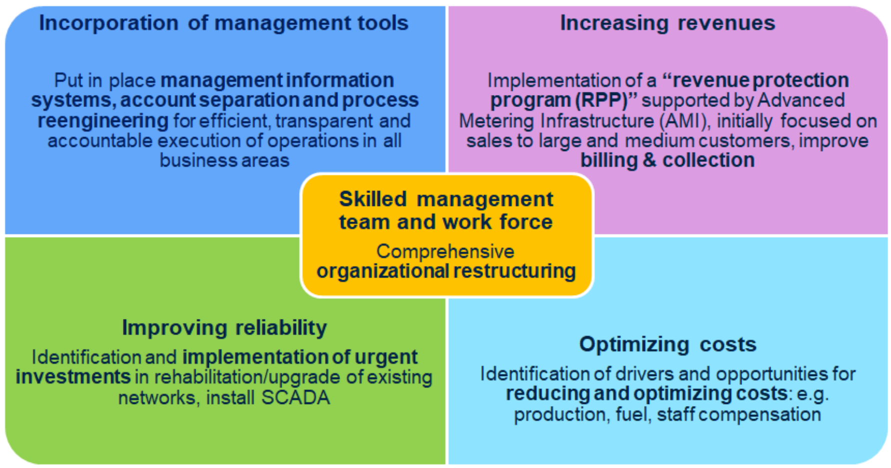
53. **Reliability of electricity supply is affected by several factors including poor planning and long-term underinvestment that have created several constraints.** Current available generation capacity is insufficient to supply demand with an adequate level of reliability. Overloaded network infrastructure in a poor operating condition results in high losses and bad quality of electricity supply to customers. The lack of a fully performing Supervisory Control and Data Acquisition system (SCADA) and Call Center further exacerbates the situation. Issues of reliability of supply in the Ramu grid are of particular concern given that several large customers (including mines) providing a significant share of PPL's revenues are connected to this system. Some critical investments that can significantly improve reliability of supply to key clients have been identified and should be implemented in the short term.

54. **Actions identified in the assessment to improve the financial and operational performance of PPL in all business areas have been grouped in a comprehensive two-phase Performance Improvement Plan (PIP) (Figure 1).** The timeline of actions in the proposed PIP aims to achieve maximum positive impacts on performance in the shortest possible period. Phase 1 of the PIP focuses on high-demand customers by improving quality of service and protecting revenues in sales to this segment. This is likely to produce quick positive financial impacts, create fiscal space and buy credibility to carry out actions in later phases of the plan. Implementation of the PIP will also pave the way to accelerate the electrification of the country and enable more private sector investments in generation to lower the cost of supply.[11] It is proposed that PPL

[11] The PIP would focus for an initial three-year period on the key aspects impacting the effectiveness of operations. While full execution of the PIP will require significant resources, immediate priority actions can be carried out with a relatively limited budget. Immediate implementation of the RPP and a Management Information System (MIS) is estimated at around US$10 million, while urgent investments in infrastructure rehabilitation and upgrades necessitate further assessment of their cost but could be in the order of US$30-50 million. For additional details see Chapter Four.

immediately carries out a detailed design of both phases of the PIP and submits it to Kumul Consolidated Holdings (KCH)[12] and the government for approval and arrangements for the immediate implementation of Phase 1.

**Figure 1: Main Building Blocks of the Performance Improvement Plan[13]**




**55. The assessment of the financial impact of the actions described in the PIP as well as the implementation of the LCPDP shows that:**

- **if the current situation remains unchanged, the expected result is a continued and accelerated deterioration of PPL's operational and financial performance**, as insufficient funds available for maintenance and investment will result in reduced sales and revenues and increased opex, further deteriorating the already unsustainable cash and liquidity position of the company. In the absence of continuous and substantial external financial support to cover operating expenses, PPL will fall into complete illiquidity, lacking the resources needed to meet payment obligations, including debt service. Under this scenario, the company will not be able to make any significant investments on its own and is unlikely to be a credible offtaker in PPAs for the implementation of new generation projects defined in the LCPDP.
- **if PPL succeeds in implementing a program to improve billing and collection rates by around 3 percent each, the result would be an important increase in operating revenue.** If the current method for calculating staff remuneration remains unchanged, however, improvements in PPL´s cash and liquidity position are insufficient to implement minimal

[12] Kumul Consolidated Holdings Limited (KCH) is the delegated owner of all State-Owned Entities/Enterprises (SOEs) for and on behalf of the state, including PPL.

[13] PPL has already been implementing some elements of the PIP on its own without Bank involvement (notably the component linked to organizational restructuring and establishment of skilled management team and workforce which was initiated in the first half of 2018) and various actions under the remaining PIP areas. At the date of printing of this report, PPL and the GoPNG requested Bank support for implementation of the remaining building blocks under the PIP through the proposed PNG Energy Utility Performance and Reliability Improvement Project (P167820), currently under preparation.

investments urgently needed to rehabilitate existing infrastructure. In the absence of substantial external financing, operations will continue to be financially unsustainable.

- **to sustain operations and enable implementation of the projects in the base case scenario of the LCPDP, PPL will need to carry out a comprehensive program of reforms including improvements in reduction of commercial and technical losses and collection rates, optimization of prices paid for fuel purchases, and changes in the method for calculating staff remuneration.** Under such a scenario, if the most concessional financing arrangements available to implement the investments in the base case of the LCPDP are used, a significant improvement in PPL´s financial position is possible, and the company can turn into a financially sustainable operation with a positive cash position generated through tariff revenues without the need for external funding. For this to happen, it is also crucial that PPL refrains from signing any PPA or other commitment not corresponding to a project in the LCPDP and/or not procured competitively.
- **in parallel with actions for cost reduction, efficiency improvement and revenue enhancement, PPL should start preparation and implementation in the short to medium term of a Financial Recovery Plan (FRP).** This will further improve the company's financial performance, including application of mechanisms for tariff setting and periodic adjustment to ensure permanent recovery of costs of efficient service delivery (as per the outcomes of the proposed cost of service study), debt restructuring, balance sheet clearing, debt equity restructuring, clearing account payables and receivables especially arrears from government agencies against debt write off and clearing bank account (deposited but not credited, if any). The Bank can assist with preparation and implementation of the FRP for PPL.

**56. A comprehensive approach comprising short and medium-term priority actions needs to be adopted to improve PPL's operational and financial performance in a sustainable manner with the following actions that need to be taken immediately:**

- **Increase the billing rate through the implementation of an RPP** for sustainable reduction of nontechnical losses in supply (unmetered consumption), initially focused on customers with recorded monthly consumption above 800kWh (7 percent of total number, representing 77 percent of current physical sales);
- **Increase the billing collection rate** by improving collection processes and prioritizing the management of customers with high overdue amounts and affordability;
- **Improve the reliability of electricity supply and reduce technical losses** by identifying and implementing urgent investments in rehabilitation/upgrade of existing infrastructure to address equipment in particularly poor condition and quality of service–notably to high-value customers in the Highland areas (details in Appendix 9) with a total estimated cost of $34.7 million;
- **Reduce staff costs/overhead costs and fuel cost** (currently 34 percent and 26 percent of total cost respectively): (i) staff costs can be reduced without reducing staff numbers by adjusting the procedure to calculate the "performance component" of staff remuneration over Cash Available after Debt Service and Capex; and (ii) by implementing improved procedures for metering electricity production and the fuel consumption of thermal plants (both owned by PPL and by IPPs);

- **Optimize production costs** through periodic update of the least-cost plan for generation and transmission and systematic competitive procurement of projects in the plan, disregarding any PPA not corresponding to a project in the LCPDP and/or not procured competitively. PPL could immediately initiate a feasibility study of repowering of existing own hydropower plants, and preparation of solar and wind farm projects identified in the LCPDP to be awarded through competitive bidding, and with priority for sites where these can replace expensive liquid fuel power generation; and
- **Improve efficiency, transparency and accountability in operations** by adopting new management models supported by state-of-the-art tools to "ringfence" the company's core businesses and leverage the private sector for investments in generation and provision of O&M services.

**57. Overall Conclusions**

1. **Electrification rates in the country are very low and mining projects are constrained by the availability of power.**
2. **There are opportunities for optimized (as opposed to ad hoc) planning, considering the government electrification goals, the mining growth opportunities as well as the opportunities and resources of the country.** These will not materialize on their own and will require a concerted effort from government.
3. **There is a need for the deliberate and careful implementation of the projects that are part of the least-cost plan and should avoid entering PPAs for any generation proposals that have not been the result of a competitive bidding process.** The least-cost plan indicates hydro in the POM grid and gas in the Ramu grid as the least-cost technologies of choice for these systems for the current demand outlook. Opportunities to meet the immediate need for additional generation capacity (namely through gas, wind and solar investments) have also been identified.
4. **In the near term, the government has opportunities to influence the way that gas development takes place as major new gas production projects are sanctioned.** Securing commitments to allocate some gas from LNG project developers can be encouraged if the government enters negotiations with viable proposals and capitalizes on project developers' probable interest in obtaining political support and social license.
5. **Improving PPL's financial and operational performance through the implementation of a PIP is essential to deliver on government goals of electrification and to enable private sector participation in generation projects.**

**58. The Bank is ready to support the Government of PNG in the implementation of these recommendations.**

## Abbreviations and Acronyms

| | |
|---|---|
| AMI | Advanced Metering Infrastructure |
| ASAI | Average System Availability Index |
| BAU | Business-as-usual |
| bbl | Barrel |
| bcfd | Billion cubic feet per day |
| Capex | Capital Expenditure |
| CMS | Commercial Management System |
| CNG | Compressed Natural Gas |
| CPI | Consumer Price Index |
| CRI | Cash Recovery Index |
| DMO | Domestic Market Obligation |
| EBITDA | Earnings Before Interest, Taxes, Depreciation and Amortization |
| EPM | Electricity Planning Model |
| ERP | Enterprise Resource Planning |
| FOB | Free-on-board |
| FRP | Financial Recovery Plan |
| GAMS | General Algebraic Modelling System |
| GTE | Gas-to-electricity |
| GTL | Gas-to-liquids |
| HFO | Heavy fuel oil |
| HPP | Hydro Power Plant |
| IEC | Israel Electric Corporation |
| IPP | Independent Power Producer |
| IRMS | Incidents Recording and Management System |
| KCH | Kumul Consolidated Holdings |

| | |
|---|---|
| LCOE | Levelized Cost of Electricity |
| LCPDP | Least-cost Power Development Plan |
| LNG | Liquefied Natural Gas |
| LPG | Liquefied Petroleum Gas |
| MIS | Management Information System |
| mmbtu | Millions of British Thermal Units |
| mmcfd | Millions of cubic feet per day |
| MW | Megawatt |
| NDRC | National Development and Reform Commission |
| NEROP | National Electrification Rollout Plan |
| NPV | Net Present Value |
| NWS | North-West Shelf |
| O&M | Operations and Maintenance |
| P&A | Processes and activities |
| PIP | Performance Improvement Plan |
| POM | Port Moresby |
| PPA | Power Purchase Agreement |
| PPL | PNG Power Ltd |
| PSC | Production Sharing Contract |
| RPP | Revenue Protection Program |
| SCADA | Supervisory Control and Data Acquisition |
| SPC | Special Purpose Company |
| tcf | Trillion cubic feet |
| T&D | Transmission and Distribution |
| WMS | Works Management System |

*Note:* Unless otherwise indicated, all dollar amounts quoted in this report are in U.S. dollars. The exchange rate used in the report is U$1.00 = K 3.26.

## Chapter One: Introduction and Context[14]

1. **PNG is in a unique position in having a significant endowment in hydropower, natural gas and geothermal resources.** These resources are, however, underutilized; at present the country has one of the lowest per capita rates of consumption of electricity in the world, and it is estimated that only about 20 percent of the population has access to grid and off-grid electricity. Electricity services provided by the national electricity utility PNG Power Limited (hereinafter identified as PPL) to its customers are of poor quality and reliability, and average retail tariffs are very high ($0.30/kWh), reflecting the high costs of service delivery. Investment decisions have been ad hoc and not based on long-term, least-cost planning.

2. **Access to reliable and affordable electricity significantly improves people's lives and enables economic growth.[15]** The Government of PNG has set the ambitious goal of providing access to electricity to 70 percent of the population by 2030 and becoming fully carbon neutral by 2050.[16] A recent study concluded that delivering on the government's electrification goal will require an increase in generation capacity by about 300MW by 2030.[17] Significant additional demand is expected from commercial, industrial and mining projects that will materialize in the next few years. Beyond electrification, the development of mining and other energy-intensive sectors has been constrained by the lack of reliable power supply.

3. **Achieving the government's goal on access to electricity will require implementation of systematic least-cost planning to expand infrastructure in all segments of the electricity supply chain and strategically leveraging PNG's natural resources.** Identification and timely competitive implementation of optimum investments in new generation, transmission, and distribution facilities by PPL and other economic agents will address security of supply in the context of growing demand at the lowest cost available to the country, thereby bringing an affordable electricity service within reach for more and more consumers. At the same time, it will be necessary to ensure that PPL is able to efficiently provide good quality services to all its customers in a sustainable manner. Achieving the ambitious goal on access to electricity services will require the government to define and put in place a strategy addressing the institutional, technical and financial aspects needed to identify and build the optimum infrastructure (grid extension by PPL,

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[14] *Data disclaimer:* The analysis and conclusions in this note are naturally dependent on data accuracy and availability. Data was obtained from various sources including PPL, other stakeholders, and international data. The Bank team used its best judgment and experience elsewhere to decide which data to use when sources were incompatible, or the data were found to be unrealistic.

[15] The lack of access to affordable and reliable power supply is limiting economic growth in urban areas and smaller urban centers and contributing to poverty in rural areas. Low levels of access to an adequate supply of electricity limits the ability of children to study and to access school and health services and exacerbates already severe personal security problems. More generally, it also hinders economic activities and the potential for growth, for example, by refrigeration of fish, pumped irrigation, processing of produce, and development of the tourism industry.

[16] Office of Climate Change & Development (2014); Independent State of Papua New Guinea (2011); Department of National Planning and Monitoring (2010); and National Strategic Plan Taskforce (2009).

[17] This would be an increase of almost 50 percent on the current installed capacity of 580MW. With Bank support, the government has embarked on an exercise to prepare a National Electrification Rollout Plan (NEROP) for the country, and concluded the geospatial modelling, to understand how best to approach electrification in an efficient and cost-effective manner. The study is currently being finalized for adoption by government.

mini-grids, individual systems) needed to connect new users across the country and permanently provide them with a good quality service.

4. **Weak enforcement of sector planning over recent years and poor governance arrangements for the identification and implementation of new generation projects, combined with PPL's operational inefficiencies, have resulted in high current costs of service delivery.** PNG relies significantly on expensive thermal generation using imported oil products (an average of 37 percent of total generation by PPL was sourced from oil products in 2015-17) despite the country's enormous potential in lower-cost domestic energy resources, particularly hydropower and natural gas. Carrying out systematic planning to identify generation projects that represent the least cost options for the country will make it possible to move gradually away from fossil fuel-based generation. Equally important is that identified projects are implemented at least cost for the country through competitive procurement processes, either directly by the utilities (PPL or others to be established), or by new agents such as Independent Power Producers (IPPs), Special-Purpose Companies (SPCs), or others.[18]

5. **There is potential for gas to help to drive down power costs and expand the grid system in the decade ahead.** There is latent demand among a variety of power users that are grid-connected, off grid or currently not served. The development of such markets requires viable supply solutions all along the gas-value chain but is constrained by some of the same factors that have impeded development of the power system. These include a high-cost environment for connected infrastructure, low base of creditworthy offtakers and a weak planning framework. This note takes a close look at the market dynamics and policy setting driving the availability and cost of gas. This will critically affect the timing and scale of gas' contribution to PNG's power system development and achievement of the government's access goals. It screens potential gas supply solutions and suggests policy actions that could support the role of gas in the power system.

6. **Harnessing mining loads–which are primarily served by captive generation–offers a particular opportunity to underpin power sector development.** Their requirement for reliable long-term supply and ability to pay could help to underwrite new investment in generation, transmission and distribution assets in a variety of grid-based or off-grid solutions. Incorporating projections of mining loads from existing and planned mines is an important aspect of least cost planning, while recognizing that some of these loads are uncertain. This note discusses possible scenarios and associated findings.

7. **Finally, to achieve the sustainable development of the power sector in PNG (including the government's goal on access), it is crucial to complement systematic least-cost planning and implementation of new investments to expand sector infrastructure with specific actions aimed**

[18] Typically, the plan is implemented directly by the service utilities mainly for network extension, rehabilitation and upgrade, by IPPs for new electricity generation projects, SPCs for construction and operation of new transmission systems and/or through the signature of long-term contracts (power purchase and transmission service agreements) signed with distribution and retail utilities.

**at improving the operational and financial performance of PPL.** Given the geography and settlement patterns of PNG's population, it is estimated that grid electrification is the least-cost option for providing access to approximately 75 percent of the nation's future population; while off-grid systems are recommended for the other 25 percent.[19] The national utility is the natural provider of electricity service to all grid-connected users countrywide, however, PPL's current unsustainable operational and financial situation must be addressed to ensure provision of good quality services to existing customers and the connection of new users. PPL's operational and financial viability are also key to enabling private investments in new generation projects under the IPP scheme as the company will be the offtaker in power purchase agreements with those investors.[20] Even in cases where major clients (such as mines) can act as the main guarantor of the PPA, PPL will likely retain responsibility for transmission investments.

**8. The purpose of this note is not to present a comprehensive strategy to redress and develop the sector, but rather to focus on providing policy and technical advice on selected key building blocks indicated as priorities by the Government of PNG, which need to be addressed to unlock further sector development, particularly:**

- **identification of least-cost options for power generation and transmission**, especially the potential role of domestic gas-fired power vs. hydropower opportunities;
- **a high-level analysis of opportunities to develop the domestic gas value chain on the back of liquefied natural gas (LNG) growth**, especially in the power sector, and suggestions on how government action can enable this; and
- **recommended actions to strengthen PPL's financial and operational performance** by improving reliability of power supply, reducing system losses and increasing revenues.

[19] NEROP concluded that about 12-13 percent of households in PNG are currently connected to the grid. An additional 6 percent could be easily connected as they are within one kilometer of existing transformers. Others are more distant, but grid connection would still represent the best technical option for up to 75 percent of the country's population.

[20] Other schemes can also be envisaged where PPL's role could be reduced to a transporter and distributor without having ownership of the power.

## Chapter Two: Lowering the Cost of Generation and Transmission: Least-cost Power Development Plan (LCPDP)

### *2.1 Opportunity*

**9. PPL operates two main systems–Port Moresby (POM) and Ramu–in the mainland and several small grids covering other islands.** The least-cost expansion of the two main systems is the key to developing the power sector of PNG and meeting the national electrification target. By the end of 2017, total installed capacity in POM and the Ramu grid amounted to 469MW, comprising hydropower (189MW), gas power (27MW), diesel generation (98MW), and fuel oil-fired capacity (155MW). The high share of thermal production based on expensive imported oil products results in an average consumer tariff of $0.30/kWh, much higher than in other countries with a similar generation mix. The current situation is incompatible with the provision of affordable electricity services to all people in the country as well as with the objective of achieving a carbon neutral power sector by 2050. It is also inconsistent with the existence of significant indigenous energy resources that could enable electricity generation at much lower costs.

**10. The sustainable development of the two main power systems requires the identification of generation and transmission projects that represent the least-cost options for the country to meet unserved energy needs, while optimizing costs of investments and operations consistent with the government's policies for the sector.** [21] Least-cost implementation of identified projects through competitive arrangements will result in lower costs of electricity supply, paving the way to increase access rates to electricity at affordable prices, and creating opportunities for energy-intensive businesses.

### *2.2 Approach Adopted for the Preparation of the LCPDP*

**11. The study has been conducted at two levels: (i) a comparison of the levelized cost of electricity (LCOE, US cents/kWh) for different available generation options; and (ii) system analysis to optimize the generation mix to meet the projected demand by 2030 using a generation expansion study model.** Optimized transmission systems have been developed to meet the requirement of delivering electricity from power plants to consumers in PNG. Interconnection of POM and Ramu systems is also analyzed.

**12. Given that they cover the majority of the population and targets in NEROP, the study comprises both the POM and Ramu systems.** Sectoral analysis has been adopted to conduct the demand forecast in both systems, including electrification targets as defined in NEROP, mining sector, and others. The areas that could be supplied by off-grid solutions (such as distributed solar PV, small and mini hydropower, diesel generation, and LNG) are not analyzed in the study and could be covered in follow-up studies.

[21] This study covers the POM and Ramu systems which are expected to cover about 90 percent of the total population in PNG. Extension of the LCPDP to the whole country will be supported as a complement to this study.

13. **The selected optimization model is Electricity Planning Model (EPM) a tool for undertaking least-cost planning developed by the World Bank team.** The EPM model is based on several GAMS models developed in-house to prepare the LCPDP for several countries.[22] Carbon emissions are quantified and integrated in the study following the World Bank valuation guidelines (World Bank 2014). The major assumptions considered for the development of the least-cost generation expansion study are included in Appendix One.

## *2.3 Levelized Cost of Electricity (LCOE)*

14. **As per discussions held with PPL, other agencies and local experts in PNG, the generation options that are considered feasible in both the POM and Ramu systems are presented in Table 2-1.**

**Table 2-1: Feasible Generation Options in the POM and Ramu Systems**

| *Generation Option* | *POM* | *Ramu* | *Notes* |
|---|---|---|---|
| *New hydropower* | √ | √ | Naoro Brown, Ramu 2, Baime, Mongi_bulum, Kaugel, Gembogl, Frieda River. |
| *Gas turbine/Gas engine* | √ | √ | Rich gas resource in PNG |
| *Solar PV* | √ | √ | Grid-connected concentrated solar projects, candidate is discussed in POM already. |
| *Wind farm* | √ | √ | Resource is available although there is not much discussion in Ramu. |
| *Biomass power* | - | √ | Proposal in Ramu, PPA signed. |
| *Geothermal* | - | √ | Northern PNG, possibly connected to Ramu system. |
| *Coal-fired power* | - | √ | Candidate to be considered in Lae (Ramu system). |
| *Diesel engine* | √ | √ | Existing, new capacity is feasible. |
| *Fuel oil-fired generation* | √ | √ | Existing, new capacity is feasible. |
| *Fuel switch from fuel oil to gas* | - | √ | Potential for Kanudi GT1 and GT2 (in POM) and Munum IPP in Lae (Ramu). |
| *Hydropower rehabilitation* | √ | √ | Only 35-65% of installed capacity is available from existing hydropower stations. |

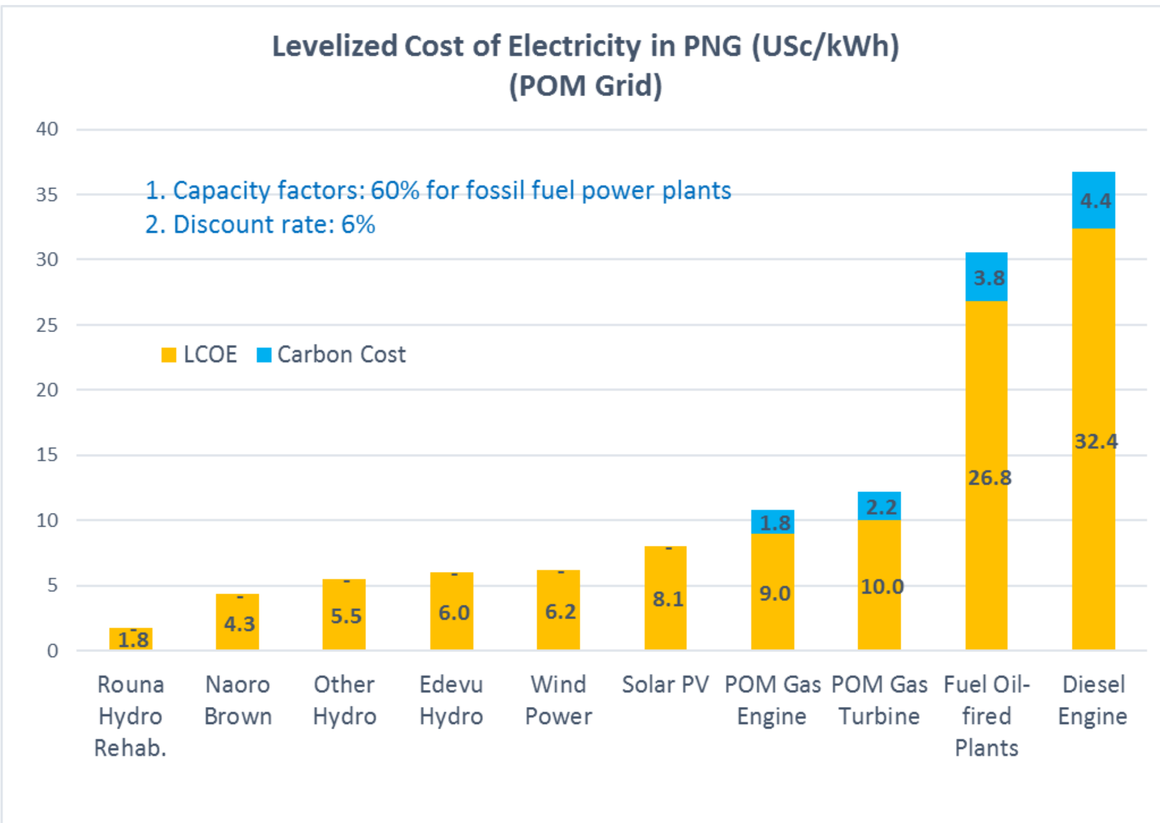
15. **A preliminary analysis of power plants under construction and in operation showed that the investment costs of power plants in PNG are much higher than other countries.** For example, the investment cost of a new gas power plant in Port Moresby based on Wartsila 34SG engines with an installed capacity of 57MW amounted to about $2,000.00/kW, while it could be about $750.00/kW in Australia. The high investment costs could be caused by the small market in PNG,

[22] General Algebraic Modelling System (GAMS) is a high-level modelling system for mathematical programming problems.

poor logistics, high land cost, lack of adequate competition, and poor project management including procurement. There is potential to reduce future costs by working on possible strategies to mitigate these constraints. In the study, the investment costs of most generation options are based on international prices, adjusted by local costs (such as land).

**16. LCOE is calculated based on the investment costs, annual opex, fuel costs, and costs of carbon emissions for each generation option.** Due to the difficulty of data collection, there are uncertainties on investment costs, capacity factors and fuel prices, and a range is, therefore, considered when estimating the LCOE for each option. Figures 2-1 and 2-2 present the results in both POM and Ramu grids, ranked by LCOE of each generation option.

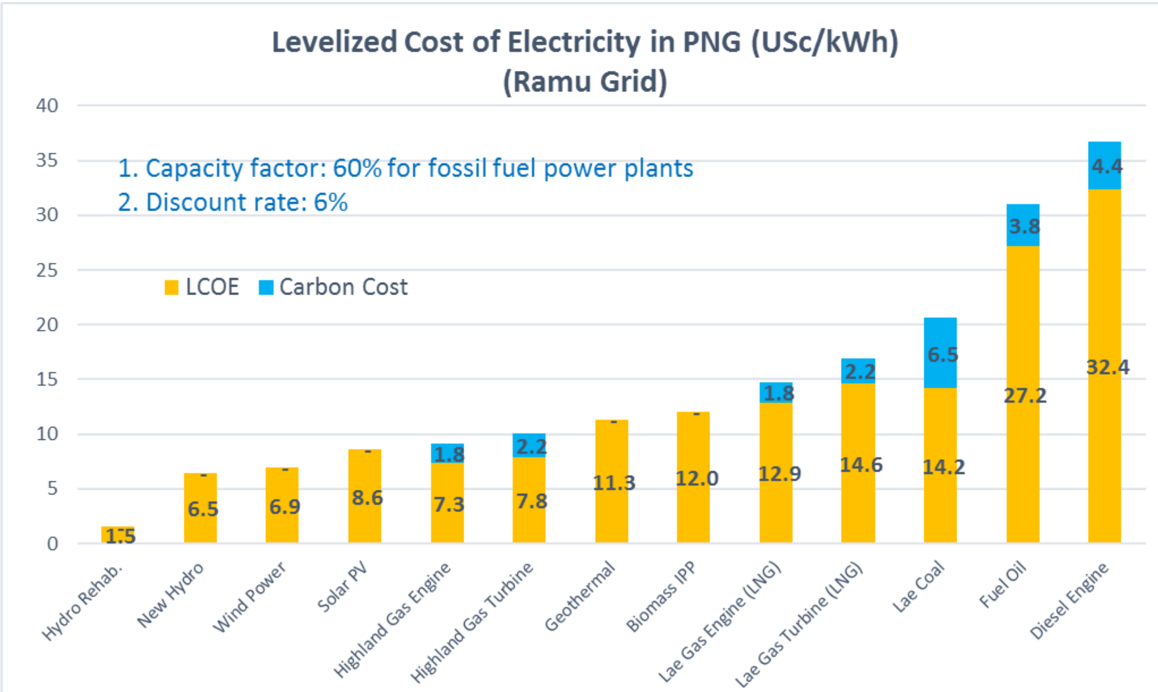
**Figure 2-1: Comparison of LCOEs in POM System**




*Source:* World Bank staff.

**17. In the POM system rehabilitation of the existing Rouna hydropower station has the lowest LCOE of 1.8 US cents/kWh.** Hydropower stations have quite low LCOEs, ranging from 4.3-6.0 US cents/kWh, of which Naoro Brown has the lowest cost of 4.3 US cents/kWh. Wind power and solar PV have more competitive LCOEs than fossil fuels, with values in the range of 6.2-8.1 US cents/kWh. Gas power's LCOEs are higher than renewables in the POM system due to its high fuel cost and carbon penalties, ranging from 10.8-12.2 US cents/kWh. Gas engines (with higher efficiency) have a lower cost than gas turbines. Diesel and fuel oil-fired generation are expensive options due to high costs of imported oil products. As can be seen from Figure 2-1, carbon considerations will add substantially to the cost of fossil fuels, mainly gas, diesel and fuel oil-fired plants.

**Figure 2-2: Comparison of LCOEs in Ramu System**




*Source:* World Bank staff.

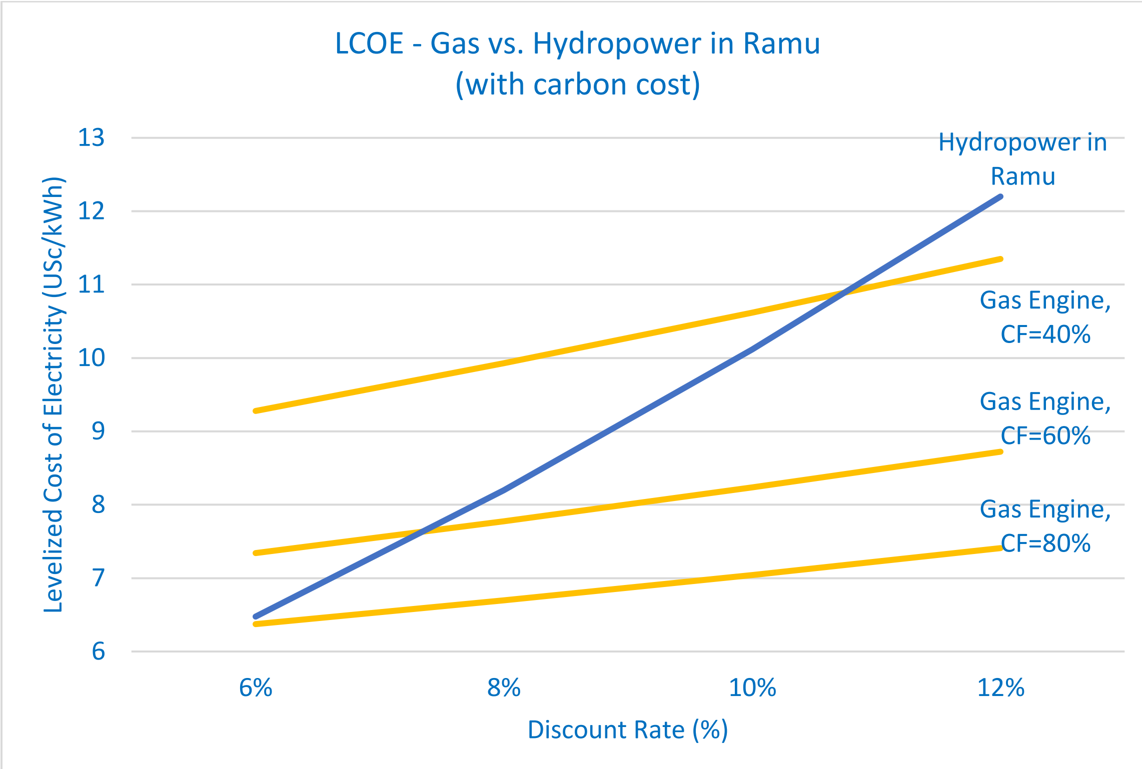
**18. In the Ramu system the rehabilitation of existing hydropower stations (Ramu 1, Pauanda, and Yonki Toe) has the lowest LCOE ranging from 1.4-1.7 US cents/kWh (an average of 1.5 US cents/kWh).** New hydropower also has a low LCOE of about 6.5 US cents/kWh while other generation options with a low LCOE (ranging from 6.9-10.0 US cents/kWh) include wind power, solar PV, gas engine and gas turbine in Highland area. All other generation options have high LCOEs, including geothermal and biomass (11.3-12.0 US cents/kWh); LNG-fired gas engine and gas turbine in Lae (14.7-16.8 US cents/kWh). Coal-fired thermal power in Lae (20.7 US cents/kWh); and fuel oil-fired and diesel generation are the most expensive options with LCOEs at more than 30 US cents/kWh.

**19. Uncertainties that exist for capacity factors, investment costs, and fuel prices as well as the selected social discount rate would affect the LCOEs of each generation option.**[23] Comparison of both gas engine in Hides and hydropower in the Ramu grid is illustrated in Figure 2-3. The LCOE for gas decreases with an increase in the capacity factor. A lower social discount rate would favor using more hydropower which has a higher investment cost but much lower operation cost (as is also the case with both wind power and solar PV). At a capacity factor of 60 percent and discount rate of 7 percent, the LCOEs of both gas engine in the Highlands and

[23] For an explanation of the meaning and calculation of discount rates see World Bank 2014.

hydropower in Ramu would be quite close. Hydropower will be more competitive at a lower discount rate than gas engine in Highland area.

**Figure 2-3: Comparison of LCOE for Gas Engines vs Hydropower Against Discount Rate**




*Source:* World Bank staff.
*Note:* CF: Capacity factor.

## *2.4 Demand Forecast*

**20. Sector analysis is used to project demand growth in the planning period in the following sectors: (i) implementation of NEROP (that is, electrification); (ii) mining; and (iii) other sectors.** Only three small mines are currently supplied by PPL's grid (Hidden Valley, Eddie Creek, and Kainantu with a total peak load of about 20MW). Other existing mines are supplied by their own captive power plants due to their concerns on the current reliability of electricity supply from the grids. Three demand scenarios have been developed: (i) a Business-as-usual (BAU) or base case scenario. Under BAU, the system is planned to deliver on NEROP targets and considers the growth of industry but no new mining projects are assumed to connect into PPL grids. This is consistent with the assumption in PPL's current 15-year plan; (ii) a medium-growth mining scenario considers the likely connection of three additional mines (Porgera, Ramu Nickel, and Wafi-Golpu with a total peak load of 310MW), all in the Ramu grid; and (iii) a high-growth mining scenario that considers the connection of all mines that may possibly be developed by 2030 in both the POM and Ramu grids, except those very remote (total peak load of 878.5MW). The details of the demand forecast are provided in Appendix One (major assumptions of least-cost study), and a summary of the three scenarios of demand forecast is presented in Table 2-2.

**Table 2-2: Summary of Demand Forecast by Scenarios**

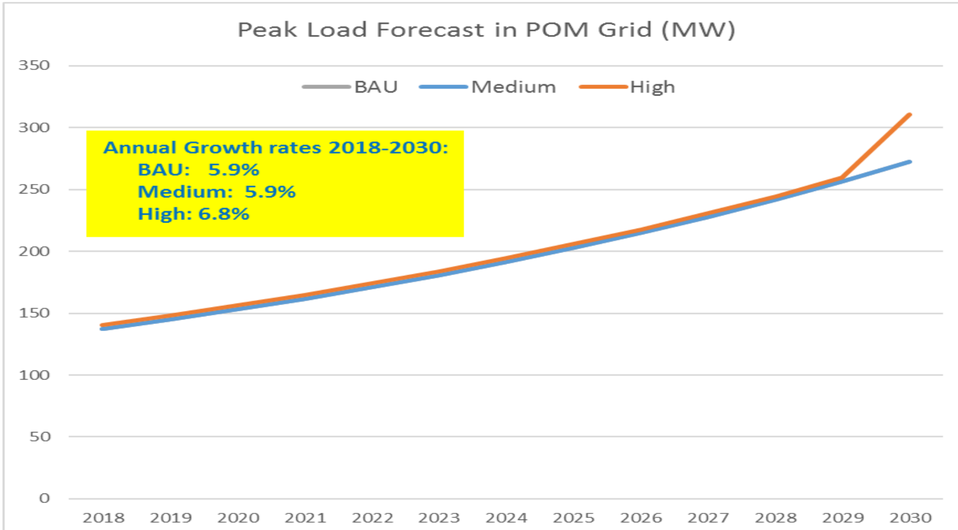
| Scenario | BAU | Medium-growth Mining | High-growth Mining |
|---|---|---|---|
| **Note** | No connection of new mines into the grids | Connection of 3 mines into the Ramu grid (Porgera, Ramu Nickel, Wafi-Golpu) | Connection of more mines in the POM grid (Tolukuma, Mayur) and in the Ramu grid (Crater Mountain, Frieda River, Yandera, Kili Teke, Mt Kare) |
| **Annual growth rate in POM System (2018-30)** | 5.9% | 5.9% | 6.8% |
| **Annual growth rate in Ramu System (2018-30)** | 9.4% | 8.2% | 14.0% |

*Source:* World Bank staff.

**21. Figures 2-4 and 2-5 present the aggregated demand forecast in both the POM and Ramu systems.**

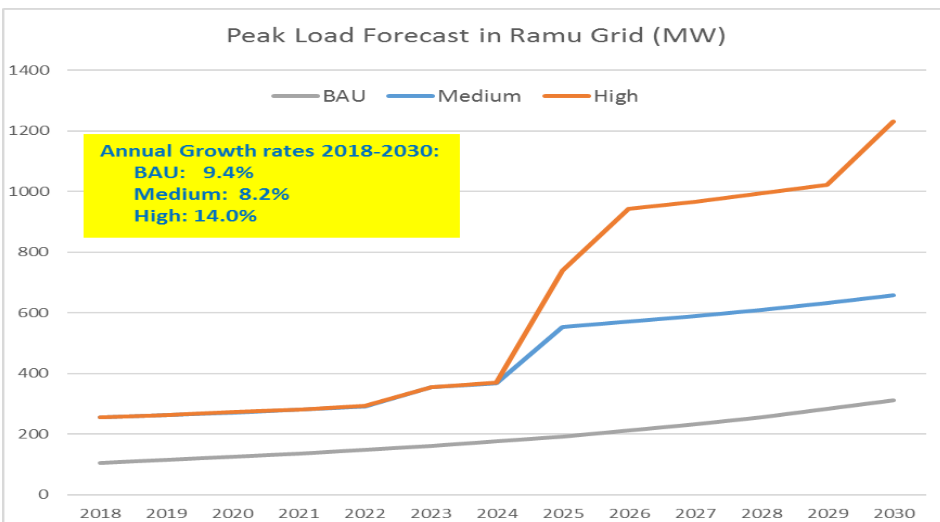
- **In the POM grid, the generation load would grow from 137MW (2018) to 273MW (2030) in both the BAU and medium-growth mining scenarios with no new mines connected to the grid (an average annual growth rate of 5.9 percent).** The peak load would increase from 141MW (2018) to 311MW (2030) when both the Tolukuma and Mayur mines would be connected (an average annual growth rate of 6.8 percent).
- **In the Ramu grid, the generation load would grow from 106MW (2018) to 312MW (2030) in the BAU scenario with no new connected mines (an average annual growth rate of 9.4 percent).** Under the medium-growth scenario, the peak load could increase from 255MW (2018) to 659MW (2030) (an average annual growth rate of 8.2 percent) while under the high-growth scenario, the peak load would increase from 256MW (2018) to 1,233MW (2030) (an average annual growth rate of 14.0 percent).
- **In the Ramu grid, the mining sector represents a significant share of the demand.** Under the medium-growth scenario, the share of mining load would be 53 percent of total peak load in 2030 and, in the high-growth scenario, the share of mining load would increase to 75 percent of total peak load in 2030.

**Figure 2-4: Aggregated Peak Load Forecast in the POM System**




*Source:* World Bank staff.

**Figure 2-5: Aggregated Demand Forecast in the Ramu System**




*Source:* World Bank staff.

## 2.5 Least-cost Generation Expansion Study

**22. Results for the least-cost study are presented for the three demand scenarios described above.** Several generation options were considered as possible candidates based on available resources in both POM and the Ramu system, including hydropower (through both rehabilitation of existing sites and new facilities), gas power, wind power, solar PV, biomass (Ramu), geothermal (Ramu), coal-fired thermal (Ramu), diesel generation, and fuel oil-fired power plants.

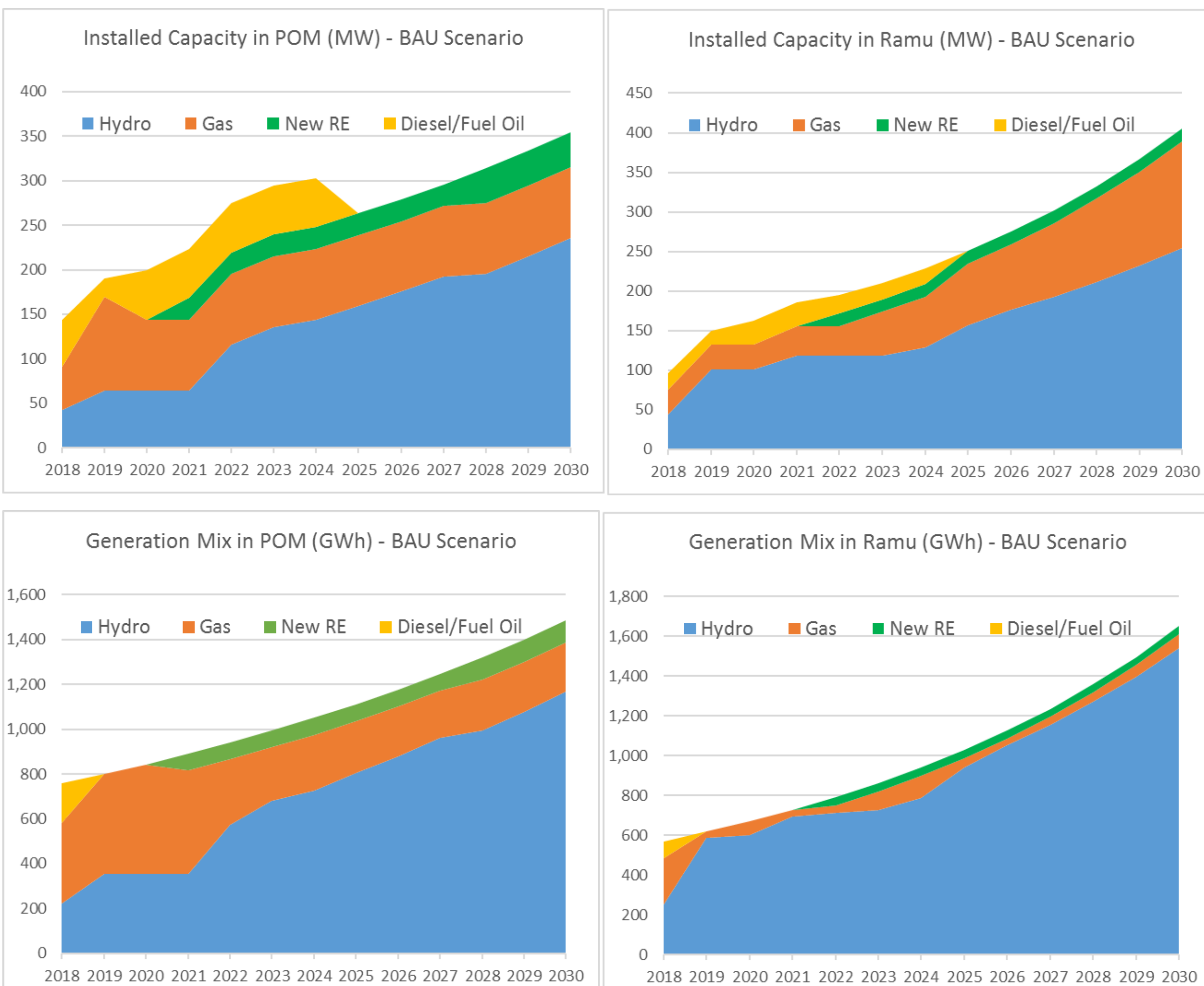
**23. In addition, sensitivity analysis has been conducted to consider changes in various parameters, as further detailed in the paper.** These include: (i) a less aggressive NEROP target; (ii) higher investment costs for hydropower due to the uncertainty of cost estimates; (iii) higher investment costs for both gas power and new renewables (wind power and solar PV) given the much higher actual costs in PNG; (iv) higher gas prices to illustrate the potential impact of indexation to international oil prices; (v) more available wind power and solar PV projects with cost reductions; (vi) no consideration of carbon cost; and (vii) different social discount rates (6 percent in base case, and 8 percent, 10 percent, and 12 percent in sensitivity cases).

24. **Additional analysis has also been undertaken to consider transmission expansion aspects and the possible interconnection between the POM and Ramu grids.** The analysis refers to all three scenarios (BAU, medium-growth mining, and high-growth mining) and includes three cases with different transmission capacities (100MW, 300MW and 500MW).

*Business as Usual (BAU) or Base Case*

25. **Figures 2-6 to 2-8 show the installed capacity and generation mix for all three scenarios in both the POM and Ramu systems.**

**Figure 2-6: Installed Capacity and Generation Mix for the BAU Scenario**



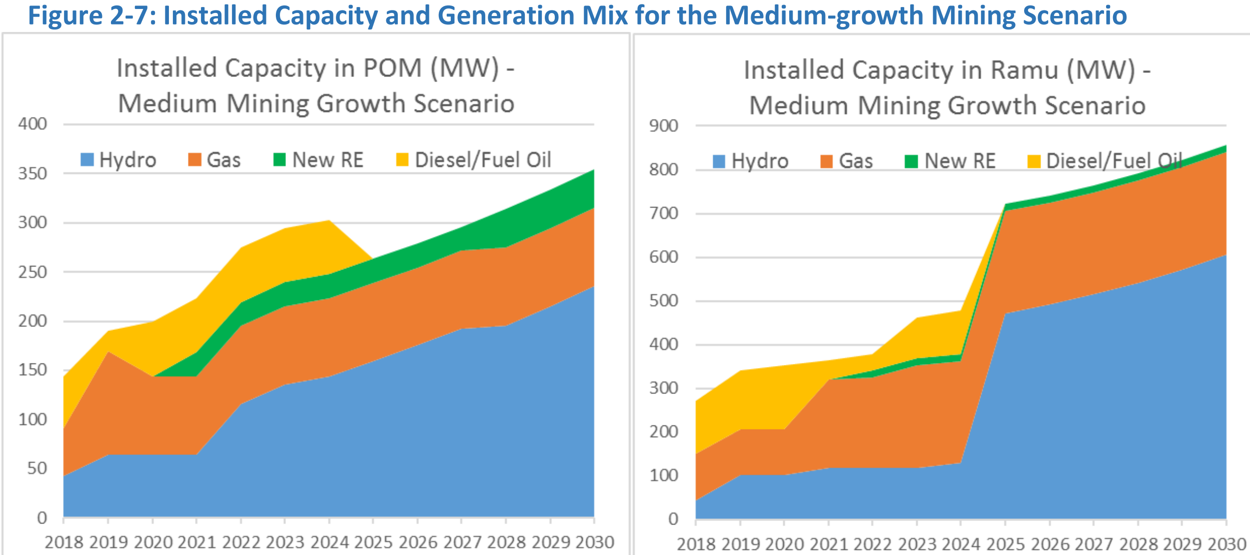

*Source:* World Bank staff.

26. **Under the BAU scenario, the peak load in the POM system would increase from 137MW (2018) to 273MW (2030) and from 106MW (2018) to 312MW (2030) in the Ramu system.** To meet the demand growth, the new added generation capacities of both systems are as follows:

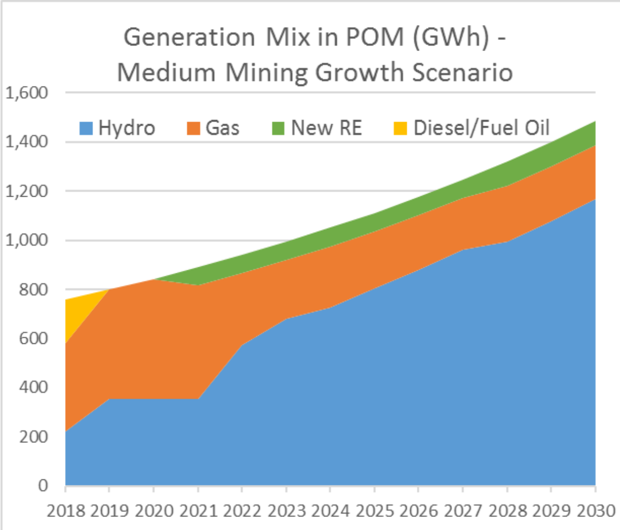
- **In the POM system, a total of 290MW of new available capacity is added in the planning period (2018-30),**[24] including fixed generation (POM gas 57MW, Edevu Hydro 51MW, both are under construction), rehabilitation of Rouna hydropower 22MW, wind power 25MW (actual installed capacity 70MW), solar PV 15MW (actual installed capacity 80MW), Naoro Brown hydropower 80MW, and other hydropower 40MW. A total of 55MW of diesel generation is added in 2020 to meet short-term demand, to serve as reserve in the medium term and retired in the long term.
- **In the Ramu system, a total of 330MW in new available capacity is added in the planning period (2018-30)**, including fixed generation (Baime hydro expansion 10MW, under construction), rehabilitation of existing hydropower 74MW (Ramu 1, Pauanda, and Yonki Toe), wind power 11MW (30MW installed), solar PV 6MW (30MW installed), hydropower 126MW, and gas power in the Highlands area 103MW.
- **A fuel switch from imported fuel oil to gas/LNG in two existing power plants (Kanudi GT1 and GT2, and Munum IPP in Lae) would save fuel cost, provided gas and LNG could be made available.**
- **The total investment costs for all new generation capacities amounted to $1,353 million over the planning period (2018-30), including $525 million in POM system and $828 million in Ramu system.**

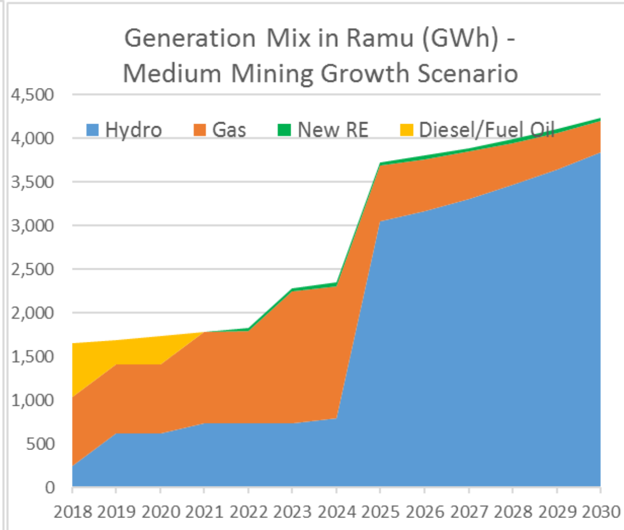
27. **Tables 2-3 and 2-4 present the yearly installed capacity by plants from 2018 to 2030 for the BAU scenario.** The infrastructure is also depicted in Figure 2-9.

**Figure 2-7: Installed Capacity and Generation Mix for the Medium-growth Mining Scenario**




[24] For clarity, at any given point the available capacity is the existing capacity in previous periods plus any new capacity that may have been added (constructed) and taking out any capacity that may have been retired during the period.




*Source:* World Bank staff.

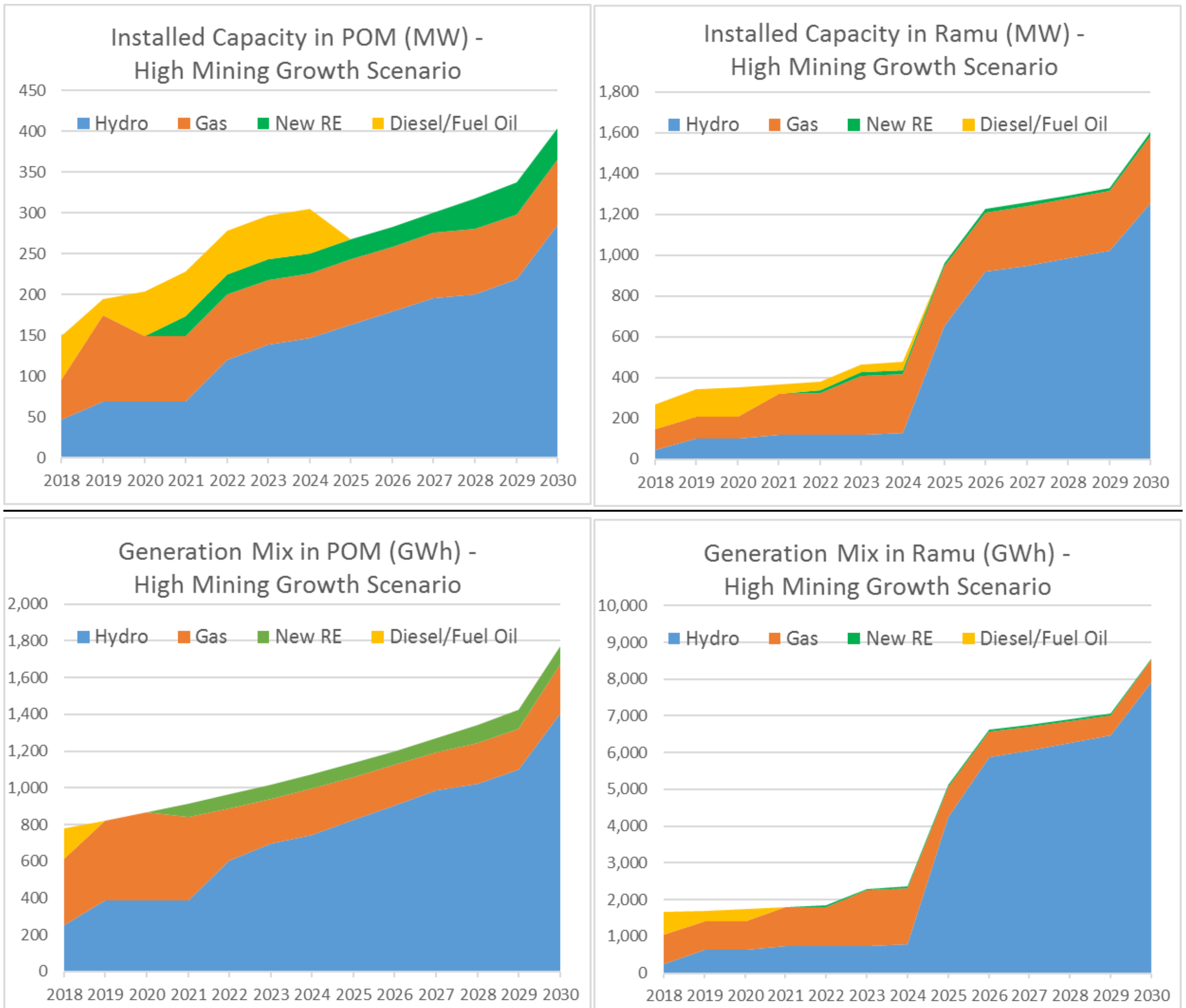
28. **Under the Medium-growth Mining scenario, three mines are expected to be connected into the Ramu system,[25] so the peak load would increase from 255MW (2018) to 659MW (2030).** As no new mines will be connected to the POM system under this scenario, the demand growth is the same for both the medium-growth and BAU scenarios in POM system (5.9 percent). To meet the demand growth, the new added generation capacities of both systems are as follows:

- **The new capacities in the POM system are the same as for the BAU scenario: total 290 MW new available capacity is added in the planning period (2018-30).** This includes fixed generation (POM gas 57MW, Edevu Hydro 51MW, both are under construction), rehabilitation of Rouna hydropower 22MW, wind power 25MW (actual installed capacity 70MW), solar PV 15MW (actual installed capacity 80MW), Naoro Brown hydropower 80MW, and other hydropower 40MW. A total of 55MW diesel generation is added in the short term, serves as a reserve in the medium term and is then retired in long term.
- **In the Ramu system, a total 706MW of new available capacity is added in the planning period (2018-30).** This includes fixed generation (Baime hydro expansion 10MW, under construction), rehabilitation of existing hydropower 74MW (Ramu 1, Pauanda, and Yonki Toe), wind power 11MW (30MW installed), solar PV 6MW (30MW installed), new hydropower 478MW, and gas engine in the Highlands area 128MW. Diesel generation 98MW is also needed in the short term and will serve as system reserve in the medium term, before being retired in the long term.
- **A fuel switch from imported fuel oil to gas/LNG in two existing power plants (Kanudi GT1 and GT2, and Munum IPP in Lae) would save fuel cost, provided gas and LNG could be available.**
- **The total investment costs for all new generation capacities amounts to $3,227 million over the planning period (2018-30), including $525 million in the POM system and $2,702 million in the Ramu system.**

[25] Porgera, Ramu Nickel, Wafi-Golpu, total peak load of 310MW.

29. **Tables 2-5 and 2-6 present the yearly installed capacity by plants from 2018 to 2030 for the medium-growth scenario.** The infrastructure is also depicted in Figure 2-9.

**Figure 2-8: Installed Capacity and Generation Mix for the High-growth Mining Scenario**




*Source:* World Bank staff.

30. **Under the High-growth Mining scenario, two additional mines are expected to be connected to the POM system and five additional mines connected to the Ramu system.**[26] The peak load would increase from 141MW (2018) to 311MW (2030) in the POM system while it would increase from 256MW (2018) to 1,233MW (2030) in the Ramu system. To meet the demand growth, the new added generation capacities of both systems are as follows:

- **In the POM system, a total of 334MW in new available capacity is added in the planning period (2018-30).** This includes fixed generation (POM gas 57MW, Edevu Hydro 51MW, both are under construction), rehabilitation of Rouna hydropower 22MW, wind power 25MW (actual installed capacity 70MW), solar PV 15MW (actual installed capacity 80MW),

[26] Tolukuma, Mayur, Crater Mountain, Frieda River, Yandera, Kili Teke, and Mt Kare.

Naoro Brown hydropower 80MW, and other hydropower 85MW. A total of 54MW of diesel generation is added in the short term to meet the demand, serve as a reserve in the medium term and be retired in the long term.

- **In the Ramu system, a total of 1,452MW of new available capacity is added in the planning period (2018-30).** This includes fixed generation (Baime hydro expansion 10MW, under construction), rehabilitation of existing hydropower 74MW (Ramu 1, Pauanda, and Yonki Toe), wind power 11MW (30MW installed), solar PV 6MW (30MW installed), new hydropower 1,128MW, and gas power in the Highlands area 224MW. A total of 35MW in diesel generation is added in the short term to meet demand, serve as a system reserve in the medium term before being retired in the long term.
- **A fuel switch from imported fuel oil to gas/LNG in two existing power plants (Kanudi GT1 and GT2, and Munum IPP in Lae) would save fuel cost, provided gas and LNG are available.**
- **The total investment costs for all new generation capacities amounted to $6,716 million over the planning period (2018-30), including $680 million in the POM system and $6,036 million in the Ramu system.**

31. **Tables 2-7 and 2-8 present the yearly installed capacity by plants from 2018 to 2030 for the High-growth Mining scenario.** The infrastructure is also depicted in Figure 2-9.

32. **The following findings can be observed in the POM system:**

- **Without connecting new mines in the planning period (2018-2030), the peak load would grow from 137MW (2018) to 273MW (2030).** The demand growth would be met by capacity increase of rehabilitation of existing hydropower station (Rouna, 22MW), gas power (57MW), wind power (25MW or 70MW installed capacity)[27], solar PV (15MW or 80MW installed capacity), Naoro Brown (80MW), Edevu hydro (51MW) and other new hydro (40MW). A total of 55MW of diesel generation is added in 2020 to meet short-term demand, to serve as reserve in the medium and retired in the long term.
- **In the short term (2018-20), the POM system should increase its capacity immediately to keep enough system reserve.** Rehabilitation of the existing hydropower station (Rouna, 22MW) and commissioning of the POM gas power plant (under construction, 57MW), together with a peaking diesel engine (55MW), could keep the system operating at a safe margin. A fuel switch from imported fuel oil to gas in Kanudi GT1 and GT2 should be considered provided that gas is available.
- **In the medium term (2021-25), except for the commissioning of Edevu hydro (51MW, under construction), Naoro Brown hydro (80MW), and both wind power (25MW or 70MW installed capacity) and solar PV (15MW or 80MW installed capacity) would be**

[27] The term installed capacity refers to the rated capacity of a generation unit (also referred to as the nameplate capacity). The term available capacity refers to the generation capacity that the system can effectively dispatch. While the installed capacity for thermal and hydropower is normally the same as, or close to, available capacity (although there may be differences caused by the use of each plant), for intermittent sources like wind or solar power there can be a large difference between installed and available capacity. This difference will be based on the capacity factor for each plant. For a summary of the assumptions used in the least-cost options analysis, including the assumptions on the capacity factors considered, refer to Appendix One.

**the least-cost choices.** Preparation of these generation options should, therefore, be initiated shortly considering the time required for project preparation.

- **In the long term (2026-30), new hydropower could be the major source of new capacity. If success can be demonstrated for both wind power and solar PV, these renewables should be considered as well.**
- **As the mining load is not significant in the POM system, connection of the new mines in the planning period would not significantly affect the future generation mix.**

**33. The following findings can be observed in the Ramu system:**

- **Connection of new mining load in the Ramu system would significantly affect the choice of generation options.** The peak load in 2030 is estimated at 312MW if no new mining is connected (only NEROP to meet residential consumers and other industries). It would grow to 659MW in the medium-growth scenario when three new mines could be connected, double the peak load in the BAU scenario; and grow further to 1,602MW (more than five times the peak load in the BAU scenario) in the high-growth scenario when more mines could be connected.
- **Rehabilitation of existing hydropower stations (Ramu 1, Pauanda, and Yonki_Toe) is a no-regret solution to increase the available capacity in the Ramu system.** This should be the priority in the short term (2018-20). Diesel generation is also needed to fill the gap of electricity supply. A fuel switch from imported fuel oil to LNG in Munum IPP in Lae would save fuel cost, providing that LNG was available.
- **In the medium term (2021-25), piloting utility-scale wind power and solar PV would be considered, as well as gas power in the Highlands area.** New hydropower would be required to be commissioned in about 2025 to meet the demand due to its long construction period, so preparation of the identified hydropower projects should be initiated shortly. The uncertainty of connecting mining loads will affect the installation capacity of both gas power and hydropower substantially.
- **In the long term (2026-30), new hydropower could be the major source of new capacity.** If success can be demonstrated for both wind power and solar PV, these renewables could be considered as well.

## Table 2-3: Least-cost Generation Expansion Plan in the POM System (BAU) (2018-30)

| POM Grid | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | |
| **Peak Load (MW)** | 137.4 | 145.0 | 153.1 | 161.8 | 171.1 | 180.9 | 191.5 | 202.7 | 214.8 | 227.7 | 241.6 | 256.6 | 272.7 |
| **Available Capacity (MW)** | 143.9 | 190.0 | 199.1 | 223.6 | 274.6 | 295.0 | 302.9 | 263.5 | 279.2 | 296.1 | 314.1 | 333.5 | 354.5 |
| **Reserve Margin (%)** | 5% | 31% | 30% | 38% | 61% | 63% | 58% | 30% | 30% | 30% | 30% | 30% | 30% |
| **1. Existing Capacity** | | | | | | | | | | | | | |
| Rouna_hydro | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| ExxonMobil_IPP | 26 | 26 | - | - | - | - | - | - | - | - | - | - | - |
| Moitaka_GT | 10 | - | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_LFO1 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_LFO2 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_GT3 | 23 | - | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_GT1 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Kanudi_GT2 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Sirinimu | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **2. Capacity Under Construction** | | | | | | | | | | | | | |
| POM_Power_Gas | - | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Edevu_Hydro_IPP | - | - | - | - | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| **3. New Capacity** | | | | | | | | | | | | | |
| Naoro_Brown | - | - | - | - | - | 20 | 28 | 44 | 60 | 77 | 80 | 80 | 80 |
| PV_POM_1 | - | - | - | - | - | - | - | - | - | - | 15 | 15 | 15 |
| Wind_POM_1 | - | - | - | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| POM_New_Diesel | - | - | 55 | 55 | 55 | 55 | 55 | - | - | - | - | - | - |
| POM_New_Hydro | - | - | - | - | - | - | - | - | - | - | - | 19 | 40 |
| Hydro_Rehab.(Rouna) | - | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| | | | | | | | | | | | | | |

*Source:* World Bank staff.
*Note*: (i) All capacities are available capacity for each power plant. (ii) The available capacity of wind power and solar PV are assumed to be their capacity factors multiplied by their installed capacity.

## Table 2-4: Least-cost Generation Expansion Plan in the Ramu System (BAU) (2018-30)

| Ramu Grid | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | |
| **Peak Load (MW)** | 106.2 | 115.0 | 124.8 | 135.6 | 147.7 | 161.1 | 176.1 | 192.8 | 211.5 | 232.4 | 255.8 | 282.1 | 311.7 |
| **Available Capacity (MW)** | 96.5 | 149.5 | 162.2 | 186.0 | 195.2 | 209.4 | 228.9 | 250.6 | 274.9 | 302.1 | 332.6 | 366.8 | 405.2 |
| **Reserve Margin (%)** | -9% | 30% | 30% | 37% | 32% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |
| **1. Existing Capacity** | | | | | | | | | | | | | |
| Ramu1 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 |
| Pauanda_hydro | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Baiune_hydro_IPP | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Taraka | 3 | - | - | - | - | - | - | - | - | - | - | - | - |
| Dobel_leased | 4 | 4 | - | - | - | - | - | - | - | - | - | - | - |
| Milford | 2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Madang | 7 | 7 | 7 | 7 | - | - | - | - | - | - | - | - | - |
| Wabag | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - |
| Kundiawa | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - | - | - |
| Goroka | 2 | 2 | 2 | 2 | 2 | - | - | - | - | - | - | - | - |
| Munum_IPP(Daewoo) | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| **2. Capacity Under Construction** | | | | | | | | | | | | | |
| Baime_hydro_IPP_Exp. | - | - | - | - | - | - | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **3. New Capacity** | | | | | | | | | | | | | |
| Ramu2_Hydro | - | - | - | - | - | - | - | 28 | 48 | 65 | 83 | 103 | 126 |
| Hydro_Rehab.(Ramu1) | - | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Hydro_Rehab.(Pauanda) | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Hydro_Rehab.(Yonki_Toe) | - | - | - | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| Ramu_Gas_Engine | - | - | - | 6 | 6 | 14 | 17 | 17 | 17 | 17 | 17 | 17 | 17 |
| Ramu_Gas_Turbine | - | - | - | - | - | 10 | 16 | 30 | 34 | 45 | 57 | 70 | 86 |
| Markham_Valley_PV | - | - | - | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Markham_Valley_Wind | - | - | - | - | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Ramu_New_Diesel | - | 2 | 19 | 19 | 19 | 19 | 19 | - | - | - | - | - | - |
| | | | | | | | | | | | | | |

*Source:* World Bank staff.

**Table 2-5: Least-cost Generation Expansion Plan in the POM System (Medium-growth Scenario) (2018-30)**

| POM Grid | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | |
| **Peak Load (MW)** | 137.4 | 145.0 | 153.1 | 161.8 | 171.1 | 180.9 | 191.5 | 202.7 | 214.8 | 227.7 | 241.6 | 256.6 | 272.7 |
| **Available Capacity (MW)** | 143.9 | 190.0 | 199.1 | 223.6 | 274.6 | 295.0 | 302.9 | 263.5 | 279.2 | 296.1 | 314.1 | 333.5 | 354.5 |
| **Reserve Margin (%)** | 5% | 31% | 30% | 38% | 61% | 63% | 58% | 30% | 30% | 30% | 30% | 30% | 30% |
| **1. Existing Capacity** | | | | | | | | | | | | | |
| Rouna_hydro | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| ExxonMobil_IPP | 26 | 26 | - | - | - | - | - | - | - | - | - | - | - |
| Moitaka_GT | 10 | - | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_LFO1 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_LFO2 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_GT3 | 23 | - | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_GT1 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Kanudi_GT2 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Sirinimu | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **2. Capacity Under Construction** | | | | | | | | | | | | | |
| POM_Power_Gas | - | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Edevu_Hydro_IPP | - | - | - | - | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| **3. New Capacity** | | | | | | | | | | | | | |
| Naoro_Brown | - | - | - | - | - | 20 | 28 | 44 | 60 | 77 | 80 | 80 | 80 |
| PV_POM_1 | - | - | - | - | - | - | - | - | - | - | 15 | 15 | 15 |
| Wind_POM_1 | - | - | - | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| POM_New_Diesel | - | - | 55 | 55 | 55 | 55 | 55 | - | - | - | - | - | - |
| POM_New_Hydro | - | - | - | - | - | - | - | - | - | - | - | 19 | 40 |
| Hydro_Rehab.(Rouna) | - | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| | | | | | | | | | | | | | |

*Source:* World Bank staff.

*Note*: (i) All capacities are available capacity for each power plant. (ii) The available capacity of wind power and solar PV are assumed to be their capacity factors multiplied by their installed capacity.

## Table 2-6: Least-cost Generation Expansion Plan in the Ramu System (Medium-growth Scenario) (2018-30)

| Ramu Grid | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Peak Load (MW)** | 254.9 | 262.4 | 270.8 | 280.3 | 291.1 | 354.6 | 367.8 | 554.8 | 570.3 | 588.2 | 608.6 | 631.9 | 658.5 |
| **Available Capacity (MW)** | 271.5 | 341.1 | 352.0 | 364.4 | 378.4 | 460.9 | 478.2 | 721.2 | 741.4 | 764.6 | 791.1 | 821.5 | 856.1 |
| **Reserve Margin (%)** | 6% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |
| **1. Existing Capacity** | | | | | | | | | | | | | |
| Ramu1 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 |
| Pauanda_hydro | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Baiune_hydro_IPP | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Taraka | 3 | - | - | - | - | - | - | - | - | - | - | - | - |
| Dobel_leased | 4 | 4 | - | - | - | - | - | - | - | - | - | - | - |
| Milford | 2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Madang | 7 | 7 | 7 | 7 | - | - | - | - | - | - | - | - | - |
| Wabag | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - |
| Kundiawa | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - | - | - |
| Goroka | 2 | 2 | 2 | 2 | 2 | - | - | - | - | - | - | - | - |
| Munum_IPP(Daewoo) | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| Porgera_Hides_gas_Captive | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| Ramu_Nickel_Diesel_Captive | 100 | 100 | 100 | - | - | - | - | - | - | - | - | - | - |
| **2. Capacity Under Construction** | | | | | | | | | | | | | |
| Baime_hydro_IPP_Exp. | - | - | - | - | - | - | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **3. New Capacity** | | | | | | | | | | | | | |
| Ramu2_Hydro | - | - | - | - | - | - | - | 180 | 180 | 180 | 180 | 180 | 180 |
| Mongi_Bulum_Hydro | - | - | - | - | - | - | - | - | - | - | - | 30 | 65 |
| Frieda_River_Hydro | - | - | - | - | - | - | - | 52 | 63 | 86 | 113 | 113 | 113 |
| ASAI Hydro | - | - | - | - | - | - | - | 111 | 120 | 120 | 120 | 120 | 120 |
| Hydro_Rehab.(Ramu1) | - | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Hydro_Rehab.(Pauanda) | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Hydro_Rehab.(Yonki_Toe) | - | - | - | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| Ramu_Gas_Engine | - | - | - | 94 | 99 | 128 | 128 | 128 | 128 | 128 | 128 | 128 | 128 |
| Markham_Valley_PV | - | - | - | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Markham_Valley_Wind | - | - | - | - | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Ramu_New_Diesel | - | 18 | 34 | 34 | 34 | 91 | 98 | - | - | - | - | - | - |

*Source:* World Bank staff.
*Note:* Some totals for available capacity may vary slightly due to the effects of rounding.

## Table 2-7: Least-cost Generation Expansion Plan in the POM System (High-growth Scenario) (2018-30)

| POM Grid | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | |
| **Peak Load (MW)** | 140.6 | 148.3 | 156.4 | 165.0 | 174.2 | 184.0 | 194.6 | 205.8 | 217.8 | 230.8 | 244.6 | 259.5 | 310.9 |
| **Available Capacity (MW)** | 148.9 | 195.0 | 203.3 | 227.8 | 278.8 | 297.0 | 304.9 | 267.5 | 283.2 | 300.0 | 318.0 | 337.4 | 404.2 |
| **Reserve Margin (%)** | 6% | 32% | 30% | 38% | 60% | 61% | 57% | 30% | 30% | 30% | 30% | 30% | 30% |
| **1. Existing Capacity** | | | | | | | | | | | | | |
| Rouna_hydro | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| ExxonMobil_IPP | 26 | 26 | - | - | - | - | - | - | - | - | - | - | - |
| Moitaka_GT | 10 | - | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_LFO1 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_LFO2 | 10 | 10 | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_GT3 | 23 | - | - | - | - | - | - | - | - | - | - | - | - |
| Kanudi_GT1 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Kanudi_GT2 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Sirinimu | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Tolukuma_Mine_Captive | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| **2. Capacity Under Construction** | | | | | | | | | | | | | |
| POM_Power_Gas | - | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| Edevu_Hydro_IPP | - | - | - | - | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| **3. New Capacity** | | | | | | | | | | | | | |
| Naoro_Brown | - | - | - | - | - | 18 | 26 | 43 | 59 | 75 | 80 | 80 | 80 |
| PV_POM_1 | - | - | - | - | - | - | - | - | - | - | 14 | 15 | 15 |
| Wind_POM_1 | - | - | - | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| POM_New_Diesel | - | - | 54 | 54 | 54 | 54 | 54 | - | - | - | - | - | - |
| POM_New_Hydro | - | - | - | - | - | - | - | - | - | - | - | 18 | 85 |
| Hydro_Rehab.(Rouna) | - | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| | | | | | | | | | | | | | |

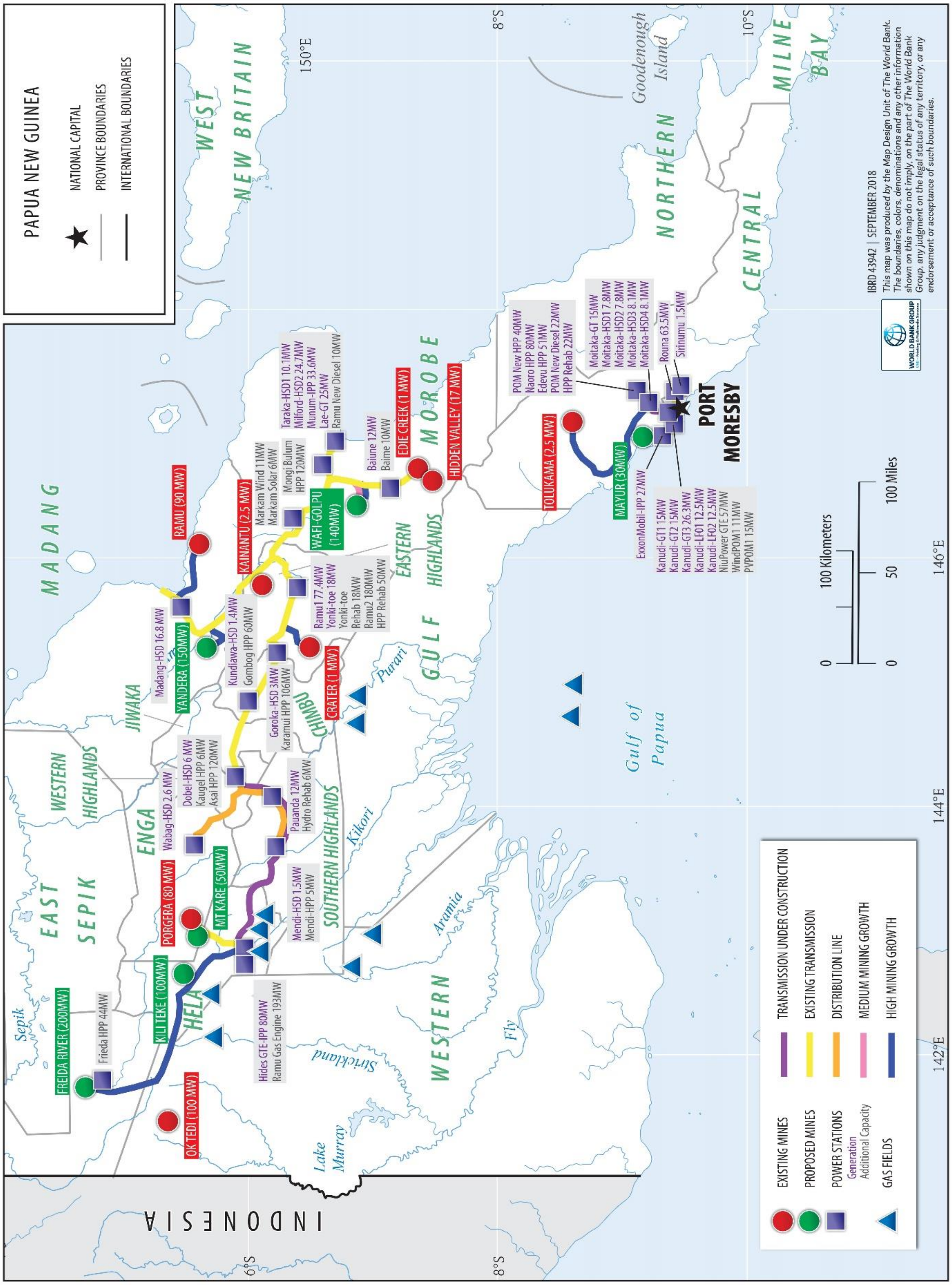
*Source:* World Bank staff.
*Note:* (i) All capacities are available capacity for each power plant. (ii) The available capacity of wind power and solar PV are assumed to be their capacity factors multiplied by their installed capacity.

## Table 2-8: Least-cost Generation Expansion Plan in the Ramu System (High-growth Scenario) (2018-30)

| Ramu Grid | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Peak Load (MW)** | 256.2 | 263.7 | 272.1 | 281.6 | 292.3 | 355.8 | 369.1 | 740.2 | 942.9 | 967.1 | 993.9 | 1,023.4 | 1,232.6 |
| **Available Capacity (MW)** | 271.5 | 342.8 | 353.7 | 366.1 | 380.0 | 462.6 | 479.8 | 962.3 | 1,225.7 | 1,257.3 | 1,292.0 | 1,330.4 | 1,602.4 |
| **Reserve Margin (%)** | 6% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |
| **1. Existing Capacity** | | | | | | | | | | | | | |
| Ramu1 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 | 27 |
| Pauanda_hydro | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Baiune_hydro_IPP | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Taraka | 3 | - | - | - | - | - | - | - | - | - | - | - | - |
| Dobel_leased | 4 | 4 | - | - | - | - | - | - | - | - | - | - | - |
| Milford | 2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Madang | 7 | 7 | 7 | 7 | - | - | - | - | - | - | - | - | - |
| Wabag | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - |
| Kundiawa | 1 | 1 | 1 | 1 | 1 | - | - | - | - | - | - | - | - |
| Goroka | 2 | 2 | 2 | 2 | 2 | - | - | - | - | - | - | - | - |
| Munum_IPP(Daewoo) | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| Porgera_Hides_gas_Captive | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| Ramu_Nickel_Diesel_Captive | 100 | 100 | 100 | - | - | - | - | - | - | - | - | - | - |
| **2. Capacity Under Construction or Approved** | | | | | | | | | | | | | |
| Baime_hydro_IPP_Exp. | - | - | - | - | - | - | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **3. New Capacity** | | | | | | | | | | | | | |
| Ramu2_Hydro | - | - | - | - | - | - | - | 180 | 180 | 180 | 180 | 180 | 180 |
| Mongi_Bulum_Hydro | - | - | - | - | - | - | - | - | 49 | 49 | 49 | 49 | 120 |
| Kaugel_Hydro | - | - | - | - | - | - | - | - | 79 | 79 | 79 | 79 | 80 |
| Gembogl_Hydro | - | - | - | - | - | - | - | 60 | 60 | 60 | 60 | 60 | 60 |
| Eddie_Creek_Hydro | - | - | - | - | - | - | - | 20 | 20 | 20 | 20 | 20 | 20 |
| Frieda_River_Hydro | - | - | - | - | - | - | - | 146 | 281 | 312 | 347 | 385 | 385 |
| ASAI Hydro | - | - | - | - | - | - | - | 120 | 120 | 120 | 120 | 120 | 120 |
| Karamui_Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 163 |
| Hydro_Rehab.(Ramu1) | - | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Hydro_Rehab.(Pauanda) | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Hydro_Rehab.(Yonki_Toe) | - | - | - | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| Ramu_Gas_Engine | - | - | - | 94 | 99 | 186 | 186 | 186 | 186 | 186 | 186 | 186 | 186 |
| Ramu_Gas_Turbine | - | - | - | - | - | - | - | - | - | - | - | - | 38 |
| Markham_Valley_PV | - | - | - | - | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Markham_Valley_Wind | - | - | - | - | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Ramu_New_Diesel | - | 20 | 35 | 35 | 35 | 35 | 42 | - | - | - | - | - | - |

*Source:* World Bank staff.
*Note:* Some totals for available capacity may vary slightly due to the effects of rounding.

## Figure 2-9: Existing Situation and Possible Growth Scenarios



*Sensitivity Analysis*

**33. As stated above, a sensitivity analysis has been conducted for several parameter changes to the three demand scenarios with the results presented below.**

***<u>Less Ambitious NEROP Target</u>***

**34. This parameter tested the implications of reducing the 2030 NEROP target from 70 percent to 50 percent of the population having access to electricity.**

- Peak loads would be reduced by 12MW in the POM system and 59MW in the Ramu system.
- BAU scenario:
  - In the POM system, installed capacity of new hydropower would be reduced by 15MW (2030); and
  - In the Ramu system, total new installed capacity by 2030 would be reduced by 76MW (hydropower by 45MW and gas power by 31MW).
- Medium-growth mining scenario:
  - Similar findings as BAU scenario.
- High-growth mining scenario:
  - Similar findings as BAU scenario.

***<u>Higher Investment Costs for Hydropower</u>***

**35. This parameter assumed a 20 percent increase in the investment costs for new hydropower and estimated the implications.**

- BAU scenario:
  - No major change to new capacity and generation mix by 2030 in both POM and Ramu system.
- Medium-growth mining scenario:
  - No major change to new capacity and generation mix by 2030 in the POM system; and
  - In the Ramu system, new installed capacity of hydropower would be reduced by 53MW and replaced by additional gas power of 53MW.
- High-growth mining scenario:
  - No major change to new capacity and generation mix by 2030 in the POM system.
  - In the Ramu system, new installed capacity of hydropower would be reduced by 76MW and replaced by additional gas power of 76MW.

***<u>Higher Investment Costs for Both Gas Power and New Renewable Energy</u>***

**36. Under this parameter the investment costs for gas power are assumed to be closer to the actual investments of existing plants, that is, $1,665.00/kW for gas turbines in POM, $1,914.00/kW for gas engines in POM; and 10 percent higher in Ramu.** The investment costs for both solar PV and wind power are also assumed to be higher than the international prices, that is, $1,300.00/kW for solar PV and $2,000.00/kW for wind power.

- BAU scenario:

    - No major change to new capacity and generation mix by 2030 in the POM system.
    - In the Ramu system, 14MW of new gas power would be replaced by an additional 14MW of new hydropower.
- Medium-growth mining scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - In the Ramu system, 30MW of new gas power would be replaced by 30MW of biomass power.
- High-growth mining scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - In the Ramu system, 57MW of new gas power would be replaced by an additional 57MW in new hydropower.

***Higher Gas Prices***

**37. This parameter assumes that gas prices are indexed to an oil price of $100.00/bbl (Brent).**

- BAU scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - In the Ramu system, 14MW of gas power would be replaced by 14MW of new hydropower.
- Medium-growth mining scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - In the Ramu system, 30MW of new gas power would be replaced by 30MW of biomass power.
- High-growth mining scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - In the Ramu system, 83MW of new gas power would be replaced by 30MW of biomass power and 53MW of new hydropower.

***More Resources for Wind Power and Solar PV With Cost Reduction to Follow Trends in Other Countries***

**38. This assumes that the available resources would be 500MW of solar PV and 500MW of wind power in each of the POM and Ramu systems.** The investment costs of solar PV and wind power would be reduced to $800.00/kW and $1,200.00/kW respectively.

- BAU scenario:
    - Wind power demonstrates its strong economic competitiveness and all assumed capacity would be installed in both POM and Ramu systems.
    - In both the POM and Ramu systems, all fossil fuel capacities are kept as reserve and it could achieve 100 percent generation from renewables (wind power and hydropower) after 2023.
    - In the Ramu system limited new capacity for hydropower is needed, no new gas capacity, and their generation would be replaced by wind power.
- Medium-growth mining scenario:
    - Similar findings as BAU scenario in the POM system.

    - New hydropower in the Ramu system would be reduced by 114MW while new gas capacity would be reduced by 64MW and replaced by wind power.
- High-growth mining scenario:
    - In the POM system, all available wind power is installed. Installed capacity of new hydropower would be reduced by 68MW.
    - In the Ramu system, all available wind power and solar PV would be installed. New gas power would be reduced by 130MW and new hydropower would also be reduced by 122MW.

***<u>Exclusion of Fixed Power Plants</u>***

**39. In this case, Edevu, POM Gas and Baime hydropower IPP were not considered as fixed plants but treated as candidates, so their selection will be based on their economic competitiveness vs. other generation options.**

- **Postponing the commissioning of Edevu (51MW) by about five years could bring down the system cost and Naoro Brown could be commissioned earlier than Edevu.** A comparison of Edevu with other new hydropower stations could be considered as the LCOE of Edevu seems high due to its lower capacity factor (Edevu 58 percent vs. Naoro Brown 80 percent).
- **No change with POM Gas (57MW) as it would still be required in 2019, as well as Baime hydro IPP (10MW).**

***<u>No Consideration of Carbon Cost</u>***

**40. This scenario does not account for the carbon cost.**

- BAU scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - An additional 56MW of gas power would be installed in the Ramu system to replace 56MW of new hydropower capacity.
- Medium-growth mining scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - An additional 92MW of gas power would be installed in the Ramu system to replace 92MW of new hydropower capacity.
- High-growth mining scenario:
    - No major change to new capacity and generation mix by 2030 in the POM system.
    - An additional 178MW of gas power would be installed in the Ramu system to replace 178MW of new hydropower capacity.

***<u>Impacts of Social Discount Rates (6 percent, 8 percent, 10 percent and 12 percent)</u>***

**41. In the base case, the social discount rate is selected as 6 percent calculated on the basis of the World Bank's technical note (World Bank 2016).** In developing countries, however, a higher rate could be selected. This sensitivity analysis is conducted to check the impact of changing the social discount rate parameter. It is noted that, in all three scenarios, applying different social discount rates would mainly change the generation mix of both gas power and hydropower in both the POM and Ramu system–for example, a higher discount rate would favor the investment of gas power vs. hydropower. The economic impacts of large-scale wind and solar PV generation would also be significant.

- BAU scenario:
    - The installed capacity of new hydropower in the POM system would decrease from 120MW to 89MW and an additional 32MW of gas power would be required when the social discount rate increases from 6 percent to 12 percent.
    - In the Ramu system, increasing the social discount rate from 6 percent to 12 percent would enable the installed capacity of new hydropower to decrease from 126MW to zero while gas power would increase from 103MW to 230MW.
- Medium-growth mining scenario:
    - Same findings as BAU scenario in the POM system.
    - Increasing the social discount rate from 6 percent to 12 percent in the Ramu system would enable the installed capacity of new hydropower to decrease from 478MW to zero while gas power would increase from 128MW to 605MW.
- High-growth mining scenario:
    - The installed capacity of new hydropower in the POM system would decrease from 165MW to 118MW and an additional 47MW of gas power would be required when the social discount rate increases from 6 percent to 12 percent.
    - In the Ramu system increasing the social discount rate from 6 percent to 12 percent would enable the installed capacity of new hydropower to decrease from 1,128MW to zero while gas power would increase from 224MW to 1,352MW.

*Optimization of Transmission Systems in POM and Ramu*

**42. An optimization of the transmission system was conducted–based on the least-cost plan detailed above–with the aim of meeting the requirement of delivering electricity from power plants to customers in the targeted PNG grids. The following are the summary findings (see Appendix Three):**

- **There is a need for immediate investment to improve the quality and reliability of the existing transmission and distribution network, especially in the Ramu system.** See Appendix Nine for more details.
- **In the POM system, a network of 66kV transmission lines is already well shaped.** Expansion of transformers at existing substations, a new substation, and line conductor replacement in particular sections will be needed at an appropriate time to meet the demand growth and generation development. Connection of new hydropower (Edevu, Naoro Brown and other new hydropower in Brown River Cascade) could require 132kV level transmission while connection of other new power plants close to load centers would consider 66kV lines.
- **Grid expansion in the Ramu system will be determined largely by the connection of mining loads.** With the connection of future generation and mining loads in both the Highlands area and Lae, the Ramu grid could form a large loop network in the center area and a higher-level voltage system (likely 230kV) would be introduced to accommodate the long transfer length and large capacity in the future. In the Lae area (east) and west Highlands area, a 132kV system will be established to connect into the proposed 230kV central loop network. Connection of new power plants would rely mainly on a 132kV/66kV system, or 230kV lines to connect remote hydropower under the high-growth mining scenario.

*Interconnection Between POM and Ramu Systems*

**43. The study also considered the possible transmission interconnection between the POM and Ramu systems.** Three schemes to interconnect the POM and Ramu systems have been analyzed with different transmission capacities: 100MW, 300MW and 500MW (see Table 2-9). It can be concluded that the savings in opex due to the interconnection of both systems are insufficient to compensate the investment costs of the interconnection, based on a Net Present Value (NPV) analysis from 2018-30. Additional information is provided in Appendix Three.

**Table 2-9: Transmission Interconnection Between the POM and Ramu Systems**

| ***Interconnection transmission capacity*** | ***100MW*** | ***300MW*** | ***500MW*** |
|---|---|---|---|
| Opex savings (millions of US$) (NPV, 2018-30) | | | |
| --- BAU | 9.6 | 9.6 | 9.6 |
| --- Medium-growth Mining | 33.2 | 33.3 | 33.3 |
| --- High-growth Mining | 35.0 | 35.0 | 35.0 |
| Interconnection investment costs (millions of $) | 125 (132kV) or 160 (230 kV) | 250 (132kV) or 260 (230kV) | 370 (132kV) or 280 (230kV) |

*Source:* World Bank staff.

*Major Findings and Recommendations*

**44. Based on the study of the three scenarios and complemented by the sensitivity analysis, the following findings can be derived for each type of generation option:**

***<u>Gas Power</u>***

- **Gas power generation is a least-cost option (the LCOE ranges from 9.1 to 10.0 US cents/kWh) in the Ramu system since the gas price in Hides which is close to gas production is quite competitive.** Both gas power in Lae (with higher gas price) and LNG-fired gas power are not, however, part of the least-cost expansion plan.
- **Higher gas prices, especially resulting from oil price indexation in a high oil price environment, could reduce the competitive position of gas power generation, with sensitivity especially high in the Ramu system.**
- **Competitiveness of gas power is affected substantially by the discount rate selected.** Increasing the discount rate (for example, from a base case of 6 percent to 12 percent) would imply a much bigger role for gas power.
- **When comparing gas turbine and gas engine technologies, gas turbines have a lower investment cost but are less efficient, while gas engines have higher investment costs with higher efficiency.** Under the current assumptions (such as cost and gas price) the preferred choice is for gas engines in PNG although gas turbines could serve as peaking capacity due to their relatively low investment cost ($/kW) (see specific proposal in Chapter Three).

***Hydropower (and Rehabilitation)***

- **Rehabilitation of existing hydropower stations is a least-cost option in both the POM and Ramu systems and should be a priority.** Their LCOEs range from 1.4 to 1.8 US cents/kWh which is much lower than the average cost of electricity in PNG.
- **Installation of new hydropower capacity in the Ramu system will be closely linked to the connection of new mining loads in that system.** In the BAU scenario, there is not much room for new hydropower capacity and new hydropower capacity only becomes necessary and a least-cost option when additional mining loads are connected.
- **In the POM system, besides the installation of Edevu hydro (which is under construction), the Naoro Brown hydropower project is a least-cost option due to its low LCOE (4.3 US cents/kWh).** Additional new hydropower capacity (40-85MW) could be needed in the POM system after the projected commissioning of Naoro Brown.

***New Renewables (Wind Power, Solar PV, and Biomass Power)***

- **With the anticipated resources and costs, wind power is a least-cost option in PNG.** It has a lower LCOE (6.2-6.9 US cents/kWh) than solar PV (8.1-8.6 US cents/kWh) as the capacity factor of wind power (35 percent) is much higher than solar PV (18.5 percent) even though wind power has a higher investment cost.
- **Potential to reduce investment costs of both wind power and solar PV could be anticipated as has been demonstrated internationally in past years.** The potential cost reduction could make both wind power and solar PV more attractive.

  **Biomass power will be a least-cost option only when: (i) the oil price is high (for example, \$100.00/bbl, Brent); (ii) higher investment costs for gas power are considered; (iii) new mining load is connected to the Ramu grid; and (iv) a carbon cost is incorporated.**

***Diesel and Fuel Oil-fired Power***

- **Diesel and fuel oil-fired power plants are quite expensive as fuel prices are high.** Neither of these options are least-cost options, but diesel generation could be installed in the short term to meet demand while other low-cost generation options (gas power, hydropower, wind power, and solar PV) are being commissioned.
- **Fuel switch from fuel oil to gas (by regasifying LNG) could be considered for existing fuel oil-fired plants (Kanudi GT1 and GT2, Munum IPP in Lae) in the short term if there are no technical barriers and gas/LNG is available.** This benefit would decrease in the medium and long term, however, as fuel-oil fired plants would serve as reserve capacity due to their high fuel cost.

***Geothermal***

- **PNG has geothermal resources in its northern coastal areas and islands.** Due to its anticipated high investment cost, it is not part of the least-cost solutions in the Ramu system.

***Coal-fired Thermal***

- **Coal-fired thermal generation is not a least-cost option in the Ramu system.** Its LCOE is as high as 20.7 US cents/kWh when carbon cost is included.

***Interconnection Between POM and Ramu Systems***

- **The study has considered possible interconnection between the two systems, however, the cost savings that could be achieved do not outweigh the investment cost.** It is, therefore, not recommended, at least when considering the evolution of the network during the planning period.

**45. The following recommendations are proposed:**

- **Rehabilitation of existing hydropower is a quick and cost-effective measure to increase the power supply in PNG.** PPL should start the technical diagnosis of the existing hydropower stations (Rouna, Ramu 1, Pauanda, and Yonki Toe) immediately to identify technical solutions for rehabilitation, including equipment replacement and civil works to improve dam safety. If needed, external partner support could be considered to accelerate the process.
- **Gas power is also a competitive generation option in the short to medium term, especially in the Highlands close to where gas is produced.** The competitiveness of gas power could be enhanced if investment costs for gas power were to fall to closer to international benchmarks. The basis on which gas is priced is important. Indexation of gas prices to the price of oil would potentially undermine the competitiveness of gas in a higher oil price environment.
- **Wind power and solar PV would be attractive options to supply electricity provided the anticipated renewable energy sources are proven and their costs could be kept in line with international prices.** Resource mapping for both wind and solar power will also provide additional confidence to the private sector. Piloting commercial-scale wind power and solar PV projects could be considered to get first-hand cost and development information in PNG, and further considered if wind power and solar PV can be developed at a larger scale.
- **The development of new hydropower links closely to demand growth.** In the POM system, Naoro Brown has quite a low LCOE (4.3 US cents/kWh) and should be developed as a priority while other hydropower options (Edevu and other hydro with higher LCOEs) are developed later. Postponing the under-construction Edevu hydro by about five years could reduce the overall costs in the POM system. The development of new hydropower in the Ramu system will be determined to a large extent by whether new mining loads are connected. Negotiation with the developers of mining projects is encouraged–with intervention of the government–to sign long-term electricity sales agreements between PPL/generators and mine developers. This is critical for investment by hydropower developers and PPL. Improving reliability of electricity supply by PPL is also critical to the viability of connecting the mines (see Chapter Four).
- **A fuel switch for existing fuel-oil fired plants could be considered to replace costly fuel oil with gas (regasified from LNG) in the short term when a reliable small-scale domestic LNG supply chain would have to be developed.** As LNG-fired generation would be quite costly, this cost saving benefit would decrease with the commissioning of wind power, solar PV and new hydropower in the Ramu system.
- **It will be important to achieve further cost reductions**. It is noted that all costs (investment costs, gas prices, O&M costs, and electricity retail prices) are much higher in PNG than other countries. A concerted effort should be made to identify the reasons for such differences to reduce the current costs, including introduction of competitive mechanisms for awarding projects–such as the development of an IPP framework, improvement of oversight and supervision of project construction and operation. Introduction of competitive procurement processes, development of

local capacity to improve project management, and establishment of capable local bidders will be a key to optimizing investment costs. Reducing operational costs through replacement of diesel fuels and reduction of system losses is equally important.

- **Developing clear policies and establishing the right enabling environment for development of the power sector will be important to realize implementation of the least-cost plan in the most favorable conditions.** Issues such as financing, tariffs, policies and arrangements for connection of mining loads, rural electrification, and domestic gas use are some of the areas to be considered. These topics need to be discussed and addressed in the context of overall power sector reform.

**Box 2-1: Implementation of the Outcomes of the LCPDP Through Competitive Procurement**

**Identifying the least-cost technologies to deliver the necessary power in PNG is not enough.** The investment needs of the power sector are large and of a long-term nature and will require mobilization of significant amounts of both public and private investments in the various stages of project development, and from a mix of domestic and foreign financing sources. To ensure the lowest cost of service for the country, the government needs to put in place the governance framework to guarantee that once the least-cost options have been identified, decisions regarding investments in additional generation and transmission capacity will be made on the basis of this plan, and selection of private partners done on the basis of competitive procedures.

**While competition is a key element, there are several possible implementation mechanisms:**

- **Directly by PPL** (mainly investments in network extension, rehabilitation and upgrades) using the most convenient financing arrangements available to the country (grants or loans from development partners); or
- **IPPs** for new electricity generation projects; or
- **SPCs** for construction and operation of new transmission systems.

**Given PPL's weak financial position certain mechanisms may need to be initiated:**

- **a framework that regulates government procurement of IPPs and strengthens institutional capacity to oversee/carry out a procurement process for IPPs;**
- **partnerships with the mining industry** where the mines make the project possible as the main offtaker to certain projects with PPL developing the transmission network and benefitting from excess power from such projects (if under the right conditions); and
- **the provision of sovereign guarantees for PPA payments and the provision of other essential government support for IPP projects.**

## Chapter Three: Capitalizing on LNG Growth to meet Domestic Energy Needs

### *3.1 Gas-to-Power Opportunity*

**46. Least-cost power generation analysis demonstrates that gas-fired generation using domestically produced gas can, under the right conditions, compete with other power sources and help to both drive down power costs and expand the grid system in the decade ahead.** This section of the report takes a close look at the market dynamics and policy setting driving the availability and cost of gas. This will critically affect the timing and scale of gas' contribution to PNG's power system development and achievement of the government's access goals.

**47. The availability and cost of gas as a competitive fuel for power generation in the decade ahead will be shaped by:**

i. **the availability of a large gas resource base** and likely doubling or more of gas production in this period (Section 3.2);
ii. **the opportunity to tag on to existing and future investments in large integrated LNG export projects to develop viable domestic uses of gas (Section 3.3);**
iii. **obtaining gas prices that balance the interests of sellers and buyers (Section 3.4)**; **and**
iv. **near and medium-term government measures to secure gas for domestic use (Section 3.5).**

The last of these is important. Unless government establishes a conducive policy environment and deploys appropriate regulatory measures, gas could be less available and more costly than we think is achievable.

**48. In the near term, the government has opportunities to influence the way that gas development takes place as major new gas production and LNG projects are sanctioned.** Securing commitments to allocate some gas from project developers can be encouraged if the government enters negotiations with viable proposals and capitalizes on project developers' probable interest in obtaining political support and social license. Based on analysis of the costs of gas supply, we present potentially viable gas-to-power project concepts located in the Highlands and connected to the Ramu grid and fuel replacement concepts at power plants serving the Port Moresby grid to illustrate the type of gas-based option that the government could deploy in negotiations.

**49. With a view to medium-term development of gas markets, but without holding up negotiations, the government should proceed with consultations on the draft Gas Policy White Paper and launch preparation of a gas master plan and related studies.** The result would see the judicious use of policy measures by government to encourage domestic market development. A further essential outcome of this approach would be to assign responsibilities under clear mandates–preferably with an empowered government entity taking overall control and responsibility for the gas master plan's execution.

### *3.2 Gas Resources and Supply Outlook*

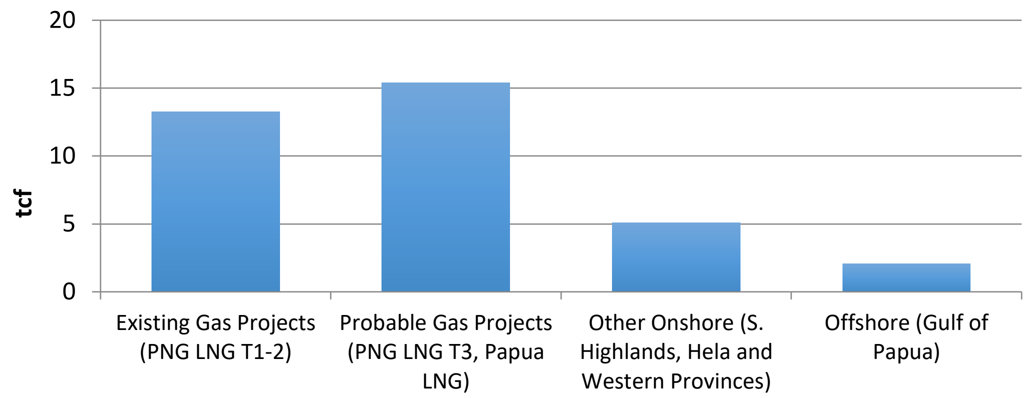
**50. PNG has a large discovered gas resource base located in the Papuan Basin across several provinces.** Ownership of the country's 2P reserves–that currently stand at 8 trillion cubic feet (tcf)–is almost entirely associated with the existing PNG LNG project. Additional discovered but undeveloped recoverable resources are estimated to be some 30 tcf. The government could benefit from further study of discovered and potential yet-to-find oil and gas resources. Recent drilling and resource assessment work will improve understanding of PNG's overall gas resource base. An enhanced resource assessment will provide a foundation for promoting further exploration and gas sector planning. The role of a gas supply study in gas sector planning as part of a gas master plan is discussed in Appendix Five.

**51. PNG's gas resource endowment does, however, lie far from the country's large population centers of Port Moresby and Lae with a large share located in the Southern Highlands, Hela, and Western Provinces.** This includes fields providing feedgas for PNG LNG's existing and expansion trains as well as other dispersed discoveries. There are also sizable discoveries in the Gulf Province (lowlands), including those that will provide feedgas for the proposed Papua LNG project. There are further gas fields offshore in the Gulf of Papua with no firm natural gas commercialization plan at this point.

**52. LNG export markets have presented the most viable commercialization options for a large proportion of the country's gas resources.** Figure 3-1 categorizes gas resources based on three stages of maturity: roughly 13 tcf of gas resources associated with existing gas projects (mainly PNG LNG Trains 1 and 2); a further 15 tcf associated with probable projects for LNG export (PNG LNG Train 3 and Papua LNG); and some 7 tcf without a firm development plan, onshore and offshore.

**53. Gas resources present a mixed set of upstream monetization opportunities and challenges.** With PNG's challenging terrain and undeveloped domestic gas market, all inland gas discoveries can be considered remote or stranded without significant investment in infrastructure. Very large (multi-tcf) discoveries and the liquids-rich (that is, high-value) gas composition of some fields has helped to drive commercial development of existing and probable LNG export schemes. Remaining gas resources which are dispersed and, in some cases, quite small, face challenges to be monetized. Such resources are referred to as "stranded". It is important to note that the term "stranded" is contextual and fluid and reflects a mix of factors, including: (i) upstream ownership (which may impact the likelihood for inclusion in planned LNG export schemes); (ii) proximity to existing infrastructure; and (iii) nearby market opportunities. A change in upstream ownership, infrastructure, market opportunity or other incentives could unlock the monetization of these resources.

**Figure 3-1: PNG Recoverable Gas Resources (by Maturity Level)**[28]




Source: Company announcements, Department of Petroleum

**54. Gas production growth has been, and will continue to be, driven mainly by LNG exports.** Commercial development of the large-scale integrated PNG LNG project depends on commitments of substantial volumes of gas on the supply side and long-term LNG offtake agreements on the buyer side to underwrite the high costs of gas infrastructure. With new gas resources having been discovered, this model for gas development is being used as a basis for the PNG LNG expansion and Papua LNG projects. Moreover, proposals to develop "stranded" gas discoveries have, in most cases, also relied on aggregating sufficient gas to underwrite the cost of a pipeline to the coast for LNG export.

**55. A new wave of gas projects that developers hope to sanction in the next two to three years are the basis for projecting rapid growth in firm, probable and possible production out to 2040 (Figure 3-2):**

i. **<u>Firm Production</u> represents gas production associated with existing projects which includes PNG LNG Trains 1 and 2 and the Hides Gas-to-Electricity (GTE) project.** This production includes existing domestic gas supply of some 14 million cubic feet per day (mmcfd) in Hides GTE sales and the 20 mmcfd of PNG LNG Joint Venture gas committed to the domestic market.

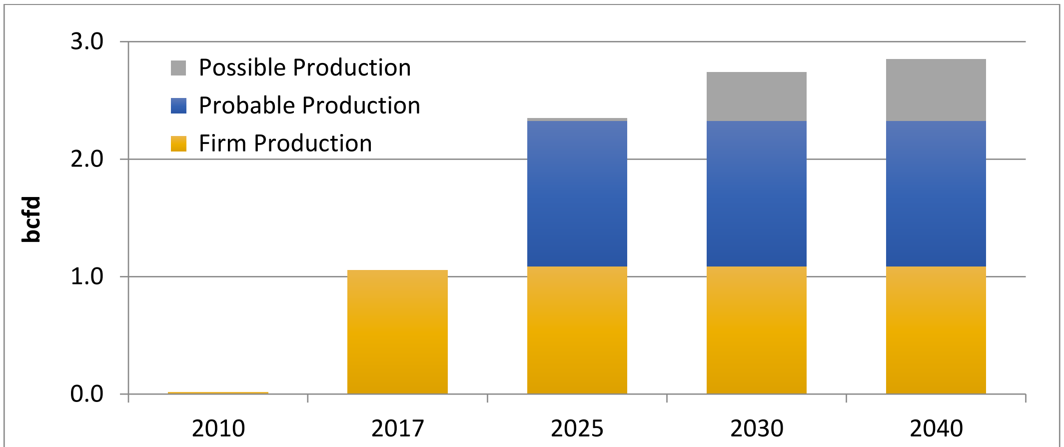
ii. **<u>Probable Production</u> represents gas production associated with probable investments in PNG LNG Train 3 (P'nyang gas field) and Papua LNG (Elk and Antelope gas fields) which are in the planning stages and have yet to be sanctioned.**[29]

iii. **<u>Possible Production</u> represents hypothetical commercialization of gas resources** under assumptions of offshore and onshore gas infrastructure solutions, previously or currently being studied by operators (includes the Stanley and Ketu/Elevala onshore fields and the Pasca offshore field). Such developments are assumed to take place over a longer time horizon.

[28] Estimates shown for existing projects include 3P reserves and 3C resources associated with PNG LNG Trains 1 and 2 and very small reserves associated with the operational Hides GTE. All other estimates are for 3C contingent resources.

[29] The Stanley gas project, for which a State Gas Agreement was signed in 2014, has been put on hold indefinitely and is not included in this category. The Pasca gas field partners are preparing to enter negotiations with the government for development of the field–which includes LPGs and condensate (with gas reinjected) in an initial phase. Gas sales is a second phase, however, partners are not expected to reach a final investment decision on a gas sales phase within the next two to three years.

**Figure 3-2: PNG Gas Production Outlook**



Source: Company announcements, Internal analysis

**56. A very large proportion of onshore gas resources will need to be committed to LNG export for the projects categorized as "probable" to be sanctioned.** As with the existing PNG LNG Trains 1 and 2, they depend on captive arrangements in which the reserves of designated gas fields are committed through to depletion to provide feedgas for liquefaction so that the project can meet its long-term LNG sales commitments. It is only on this basis that large pipeline investments to get gas from inland gas fields to liquefaction plant on the coast are possible.

### *3.3 Domestic Gas Market*

**57. PNG's domestic gas market has just begun to develop and current consumption is very limited.** About 35 mmcfd out of a total of some 1,000 mmcfd of gas output is presently committed for domestic use, all of it for power generation. Since 1991, some 14 mmcfd of gas has been sold to the Hides GTE project to supply the 80MW plant that serves the Porgera gold mine 75km away via a transmission line. Furthermore, after completion of PNG LNG, project partners committed 20 mmcfd of gas for domestic sale. This forms the basis of gas deliveries to: (i) the PNG LNG plant site power station where 25MW of capacity has been allocated for power sales to PPL under a five-year PPA, which can presumably be extended until the LNG plant expands and requires more power for its own use; and (ii) the under-construction 57MW Niu Power plant, where negotiations are underway with PPL for a long-term PPA.

**58. The domestic gas market has remained undeveloped due, in part, to high costs of building gas infrastructure to get gas to market and low levels of demand (lack of scale).** PNG is a high-cost environment for any connected infrastructure and gas infrastructure is no exception. Construction of large-diameter pipelines to bring gas from remote inland areas where it is produced to the coast or other potential demand centers face high capital costs. This is due to long distances travelled and challenging operating environments which are especially costly onshore. Thus far, only export LNG markets have been able to provide the scale and sales prices needed to justify such investments. At one time or another, the option to separately pipe nonPNG LNG Joint Venture gas from noncaptive gas discoveries in the Highlands has been examined. Project sponsors have, however, always looked at LNG export, not the domestic market, to underwrite the construction costs of a dedicated pipeline.

**59. To demonstrate the high cost of large-diameter, long-haul pipelines, analysis of the costs of pipelines needed for LNG export projects was carried out.** This analysis drew on publicly available information and internal pipeline cost data, including international experiences and previous pipeline studies completed for PNG. Based on the initial cost analysis, which includes a commercial return for investors, the cost to deliver gas from the Highlands to PNG LNG facilities near Port Moresby via a 1.65 billion cubic feet per day (bcfd) pipeline is of the order of $2.50/mmbtu. For gas delivered via a 1.2 bcfd pipeline from the lowlands of the Gulf Province to LNG facilities on the southern coast–a possible development scheme for Papua LNG–costs could be around $1.00/mmbtu. This lower cost is attributed to shorter distances travelled over generally easier terrain.

**60. An important opportunity to use gas domestically is to tag on to the gas fields developed to serve LNG projects.** Power is already generated for captive use at Hides in the Highlands, where feedgas for PNG LNG is processed. There may be an opportunity to rely on a proportion of gas from the future development of the P'nyang field to serve markets in the Highlands. The most probable market for such gas would be a new power plant with transmission lines to link to the Ramu grid. Least-cost power generation analysis confirms demand for such a project, particularly with attractive gas prices and if new mining loads in the region can be secured to underpin new plant investment. This opportunity is currently being studied by PPL and the Wafi Golpu Joint Venture and would need the mine as the anchor customer critical to underpinning the investment. This concept is discussed further in Box 3-1.

**61. Another important opportunity to use gas domestically is to tag on to the pipelines developed to bring gas to the coast where it is liquefied and exported.** There should be an opportunity to use an allocation of future gas piped to the coast near Port Moresby to feed PNG LNG Train 3 and the new Papua LNG project. Papua LNG feedgas from the Elk and Antelope fields–which should enjoy lower transport costs compared to PNG LNG expansion feedgas piped from the Highlands–can be prioritized for allocation to expand domestic gas use in the Port Moresby area. Moreover, the market opportunities for gas in and around Port Moresby are likely to be more diverse in the next decade than in the gas-producing areas of the Highlands or the Gulf and Western Provinces, possibly presenting additional opportunities for domestic gas use for both power generation and nonpower uses of gas.

**62. An immediate opportunity to use an allocation of gas from Papua LNG may be to secure long-term gas supply for the Niu Power plant at a price lower than what is currently being discussed.** This 57MW gas-fired plant is under construction 3 kms away from the PNG LNG liquefaction plant site and will make a sizable contribution to the grid when it comes onstream as early as 2019. Niu Power and PPL are currently negotiating a PPA that includes long-term, oil-indexed gas supply from the PNG LNG Joint Venture delivered via a domestic gas plant and pipeline under construction adjacent to the LNG plant.

**63. The gas price under discussion will make gas more attractive than costlier liquid fuels but it is still higher than the price that can be achieved through state negotiations.** The government should explore any opportunity to secure more attractively priced domestic gas to supply the Niu Power plant long term as this would enhance the already positive impact of adding gas-fired power to the Port Moresby grid. Pending negotiations, Papua LNG's liquefaction plant may be sited at the PNG LNG site which would make supply logistics relatively straightforward. On timing, it may be possible to arrange for

PNG LNG Joint Venture feedgas to supply Niu Power early on, until Papua LNG feedgas is available in 2024 or later.

**64. Another opportunity for Papua LNG gas to support more affordable grid-based power in the Port Moresby area is through fuel switching at those remaining power plants that are burning high-cost liquid fuels.** After the Niu Power plant is commissioned, several units supplying the Port Moresby system that are currently burning liquid fuels are due for decommissioning.[30] PPL plans to keep two gas turbines at the Kanudi power station[31] to serve as backup and to meet peak demand. With modest modifications, LNG can be loaded into 20 to 40 foot LNG ISO containers at the PNG LNG plant and trucked approximately 24 kms to Kanudi where, again, only modest modifications would be needed to accept these containers. LNG ISO containers can hold LNG for 45 to 75 days and include vaporization units that eliminate the need to invest in regasification or storage. Trucked, containerized LNG is a proven concept utilized around the world with various equipment suppliers, including in the US and Japan.

**65. Based on the use of standard 40 foot LNG ISO containers, and assuming that Kanudi runs on a peak-shaving basis with a 10 percent capacity factor, the plant would require four to five container deliveries per week (0.5 mmcfd).** With a 30 percent capacity factor, 14 deliveries per week, or two per day (1.7 mmcfd) would be needed. In addition to site modifications, modest investment would be needed in containers and flatbed trucks. The volume of gas needed to replace imported liquid fuels at Kanudi may be small but can, nonetheless, contribute to lowering PPL's fuel bill, improve the country's balance of payments, lower carbon and sulfur emissions, and possibly improve the reliability of the Kanudi facilities where low diesel fuel quality has been associated with unscheduled downtime and unplanned maintenance costs. Further studies should be undertaken to assess the commercial and technical feasibility of this concept.

**66. An important, longer-term opportunity to increase domestic gas use in the Port Moresby area could be for pipeline gas to be developed to serve new industrial parks to boost the development of an industrial manufacturing sector in the Port Moresby area.** Current and prospective investors in industry face high fuel costs for imported liquid fuels. Making pipeline gas available to new industrial parks where gas demand can be aggregated to make infrastructure development more economical could boost development of an industrial manufacturing sector and bring large-scale job creation.

**67. Development of industrial parks still faces hurdles, such as challenging supply chains for manufactured goods and limited interest in the manufacturing industry to make long-term fuel purchase commitments.** The government would need to play a role in supporting such a development, including ensuring that affordable energy is prioritized for those industries that maximize social and economic benefits for PNG. Furthermore, any future scheme for such industrial use of gas that is dependent on a reservation of gas otherwise destined for LNG export could deprive the power sector of access to gas. As long as the decision to allocate gas to such use is based on value optimization, there should be no reason, in principle, to prevent such allocation from taking place.

[30] It is understood that in the near term, following the startup of the Niu Power plant, PPL will decommission older units at Moitaka and Kanudi IPP (LF1 and LF2) with a total capacity of approximately 60MW. Only the PPL-owned Kanudi power station will remain in operation to meet peak demand loads.

[31] GT1 and GT2 have 30MW of installed capacity, of which 22.5MW is available.

**68. There is also latent demand among a variety of power users that are grid-connected, off grid, or currently not served that could be another opportunity for affordable, gas-fired power to support the development of such markets.** If power loads from captive generators currently burning liquid fuels are connected to the grid, there could be a need to install more gas-fired generation capacity in the Port Moresby area. Without capturing latent demand, power modeling completed in Chapter Two indicates that no further newbuild gas-fired power is needed in the foreseeable future for the Port Moresby grid after Niu Power comes onstream. PPL is currently conducting an on-the-ground study to measure latent demand from captive generation.

**69. In addition to the above, once a scheme to containerize LNG at the PNG LNG plant is established, incremental demand may develop from existing or planned captive generators keen to replace liquid fuels.** Markets for containerized LNG could be developed in the Port Moresby area or in more remote coastal areas and outer islands which would see LNG trucked to the Port Moresby container port for further delivery by sea on container ships. One interesting opportunity would be to ship LNG containers to the Munum IPP power plant[32] in Lae to displace the burning of liquid fuel. In Lae, fuel oil and diesel prices averaged \$16.30/mmbtu and \$17.20/mmbtu, respectively in 2017. As is the case with Kanudi, operating hours at Munum are expected to decrease at the start of the next decade after new generation capacity in the Ramu system comes onstream. Based on a 10 percent factor for peak-shaving purposes, Munum would require two to three 40 ft containers per day.

**70. Another opportunity to use gas locally would be to establish a small-scale, sea-based LNG trade from Port Moresby to power generation capacity in coastal areas and islands where pipeline connectivity is not economic and demand is larger than can feasibly be met with containerized LNG.** Unlike containerized LNG loaded on ships or flatbed trucks, special-purpose small-scale LNG vessels range in size from about 1,000 cubic meters (820 dead weight tonnes) to 30,000 cubic meters (17,600 dead weight tonnes) in LNG storage capacity and utilize a range of tank designs and technology.

**71. To load the ships, modifications will be required at PNG LNG plant's loading facilities and jetty and, to be ready for use, the LNG must be regasified at or near the point of use, thereby imposing additional costs.** The addition of liquefaction and regasification, plus unavoidable process losses and handling costs along the supply chain, results in significantly higher costs to deliver gas to a user. These opportunities may still be viable, however, in an environment where the delivered cost of liquid fuels is, in any case, very high. Replacing liquid fuel imports with domestically sourced LNG can improve the balance of payments and bring other benefits such as energy security.

**72. Under a possible small-scale LNG supply scenario that would see LNG secured from existing LNG facilities, ex-plant, on a cost-plus basis, costs for regasified LNG in a coastal market such as Lae could be in the range of \$8.50–\$12.00/mmbtu.** This is based on integrated LNG export project costs versus incremental cost of supply and includes costs for loading, shipping, unloading, regasification and a commercial return. Costs would increase if the final consumer is not sited at the regasification facility and additional gas transport is required. These results were crosschecked with netbacks[33] from LNG

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[32] The Munum IPP has 33.6MW of installed capacity, of which 31.2MW is available.
[33] Netback is a summary of all the costs associated with bringing one unit of oil to the marketplace and all of the revenues from the sale of all the products generated from that same unit, expressed as gross profit per barrel.

destinations in Northeast Asia and with other supply chain scenarios that would see LNG purchased from the existing LNG plant based on a contract formula of 11-15 percent indexation to oil ($70/bbl oil). This range represents, at the low end, an opportunity to secure "domestic LNG" in a similar way to contracts secured in Indonesia as part of domestic market obligations (DMO), and, at the high end, a price closer to the regional average for new long-term contracts.

**73. Internationally, the added costs of small-scale LNG schemes often render similar projects uneconomic as the delivered product is not much cheaper than liquid fuels but the high costs of liquid fuels in PNG may be enough to justify a small-scale LNG scheme.** Indeed, this is evident from the interest being shown by industry players in schemes under which LNG would be transported to hubs or anchor offtakers (like island mines) for regasification and use or further distribution. Interest may also reflect the fact that, under the PNG Price Regulation Act (2008), LNG is not, and cannot be, declared as regulated goods. Newcrest has also expressed interest in utilizing gas to power its mining operations in Lihir where the company has three power plants with 22 Wartsila engines totaling 170MW of installed capacity. Displacing liquid fuels for that volume of capacity could require up to 500 tonnes of LNG per day, or 200,000 tonnes per annum (approximately 27 mmcfd).

**74. Another opportunity is to rely on further liquefied petroleum gas (LPG) extraction from future gas projects, particularly for back-up in off-grid community-based power generation for which establishment of a local distribution network to supply this market would be needed.** Replacing LPG imports with domestically sourced LPG can improve the balance of payments and bring other benefits such as energy security and cleaner fuel for cookstoves among rural communities.

**75. To benefit from the opportunities outlined above to piggy back on captive gas production and infrastructure, it will be important to increase the pool of creditworthy buyers able to enter into long-term gas sales agreements.** In this regard, PPL's inability to qualify as a purchaser under Section 67 of the Oil and Gas Act is a significant constraint. For example, this has prevented it from using domestic source gas in its 95MW dual-use generators. Restoration of its ability to make long-term purchase commitments and other arrangements, which would enable a creditworthy counter-party to engage in power generation (for example, IPPs) will be needed.

**76. A related challenge is the limited progress to date to develop commercial arrangements through which grid-based power is supplied to mining loads which constitute a significant potential source of power demand that is mainly self-supplied.** The mining sector's requirement for reliable long-term supply and its ability to pay could serve to underwrite new investment in generation, transmission and distribution assets in a variety of grid-based solutions. Among the challenges to overcome is reliability in the performance of grid supply, and a way to allocate risks associated with uncertain mining startup, ramp up and potential price-induced suspensions.

**77. Finally, a strong planning framework is needed to identify, prioritize and structure viable domestic uses of gas.** Because gas supply chains are complex and rely on infrastructure to connect gas buyers with gas suppliers, there is an onus to coordinate investments. This can be supported by having a strong government-led planning process. In the 2000s, the then Department of Petroleum and Energy–in collaboration with international organizations including the World Bank and the private sector–developed and released the preliminary phase of a gas master plan for PNG. Further studies and efforts to develop a more defined set of gas sector development priorities based on a comparative analysis of options never materialized into an official gas master plan. Changes in departmental employees over time and the need to dedicate resources to the large-scale PNG LNG project during its development naturally led to a loss of institutional knowledge related to this effort.

**78. The government has demonstrated interest in renewing efforts to develop a gas master plan with the goal of ensuring that any gas secured for the domestic market is used most efficiently and for the maximum benefit of Papua New Guineans.** Current institutional mandates for policy, regulation and planning are still being defined in PNG and capacity will need to be built up for a strong government-led planning process to occur. A full discussion on the objectives and elements of gas master planning are in Appendix Five.

### *3.4 Gas Pricing*

**79. Current gas contracts in PNG are negotiated between buyer and seller and prices paid for domestic gas are indexed at a discount to oil, reflecting gas' role as an alternative to liquid fuel.** The current gas price paid by PPL (passed through to PPL in PPAs with the power producer who procures gas) are understood to be in the range of 9 percent x Japan Crude Cocktail with no price ceiling. This makes gas more attractive than oil (oil parity is ~17 percent) but continues to expose PPL to international oil price levels and volatility. The price of gas sold by PNG LNG upstream partners to Oil Search who, in turn, sells gas to Hides GTE for power generation and onward transmission to the Porgera gold mine, is not known but company-reported data suggests that the gas sales price is also linked to the price of liquid fuel alternatives. Following expiry of the original 20-year Hides GTE gas contract, the price for Hides gas is understood to have increased in 2012 under renegotiated terms which run until 2021 or earlier delivery of a defined cumulative gas volume.

**80. Current gas prices could be a challenge for PPL, especially in a high oil price environment.** The practice of pricing gas on a liquid fuels displacement basis that is oil indexed may limit the range of viable gas-to-power options to a small set of opportunities for fuel switching at existing installed dual-use power plant or building relatively small gas-fired plant as an alternative to new liquid fuel-fired plant. The risk of higher oil prices could undermine the competitive position of gas-fired generation to serve Port Moresby and the Ramu grid expansion.

**81. Upcoming gas negotiations provide an opportunity to secure more acceptable commercial terms for domestic buyers, particularly for PPL.** The challenge will be to develop a pricing scheme that does not dis-incentivize gas suppliers and that also ensures that any pricing concessions and benefits secured by the government are passed on to gas buyers (or indeed through the power tariff system to electricity consumers). The following paragraphs explore pricing parameters to be considered from a sellers' and buyers' perspective.

**82. The price which a seller could seek for gas that would otherwise be processed into and marketed as LNG would be at par with the opportunity cost of free-on-board (FOB) LNG supply minus the savings in variable cost from not running the LNG plant–essentially the fuel cost of the plant.** According to this argument, domestic gas tagging on to the PNG LNG project would be worth the current spot gas import price in Japan (average price in June 2018 of $9.30/mmbtu) minus a shipping cost ($1.00/mmbtu) and fuel cost (9 percent or $0.75/mmbtu) which gives $7.55/mmbtu. Note that Brent crude traded at $74.40/bbl in June 2018 so domestic gas would be worth 58 percent of Brent.

**83. In PNG's present circumstances in which the amount of gas likely to be diverted away from LNG use is small, it is arguable that incremental costs of domestic gas are in fact quite low.** Equipment for producing, processing and transporting natural gas is generally overdesigned, so there is likely to be space in the system to deliver, for example, 5 percent additional gas to meet domestic contracts. The opportunity cost of producing gas now rather than keeping it in the ground is the present value of gas that would otherwise be exported sometime in the future. If one assumes that gas would have been produced in 20 years with a 10 percent discount rate, 5 percent own use upstream, and a long-term oil price of $70.00/bbl, then the opportunity cost of domestic gas in this example would be $0.80/mmbtu. This approach to pricing essentially treats the costs of building gas production and pipeline for LNG as a sunk cost so that domestic gas sales do not need to cover a pro-rataed share of costs.

**84. The export parity and sunk-cost approaches to pricing illustrated above yield quite different results and, under each, domestic gas prices would fluctuate along with international market prices for oil and gas.** This uncertainty and potential volatility makes domestic gas pricing based on international market prices not so suitable as a model for a strategic sector such as the power sector in a developing country such as PNG. To mitigate the uncertainty and volatility, governments adopt a variety of approaches. One approach to help clarify and stabilize domestic gas prices is to choose a fixed international benchmark oil price and to set a regulated domestic gas price based on that oil price. For example, at an international benchmark price of $70.00/bbl, the regulated domestic gas price in Port Moresby would be $5.90/mmbtu.

**85. According to best practice in developing and mature gas markets, for example in the United States and Europe, regulated prices for goods and services are typically not linked to world market prices but are based on "cost-plus".** Cost plus refers to recoverable costs of production which are generally actual costs but could also be costs that are deemed reasonable by the regulator based on certain performance criteria. Recoverable costs typically include running costs but also investment cost as well as an acceptable return on investment.

**86. As a rule, recoverable costs for an asset must be spread out over the total production from that asset.** As an example, if 20 mmcfd of gas were to be produced for domestic use in addition to 1,000 mmcfd produced for export, the recoverable capital and opex of the gas field would have to be spread out over 1,020 mmcfd. Alternatively, only the costs for those assets which are necessary to generate the product or service may be included in what is known as the "regulated asset base". The regulated asset base for domestic pipeline gas supply typically includes the wells, the flowlines, and the gas plant and may include the export pipeline depending on where gas is transferred to the customer but it typically does not include the liquefaction plant.

**87. A high-level estimate of domestic gas prices using the cost-plus methodology described above, in which domestic supplies piggy-back on LNG project production and infrastructure facilities, is shown**

**in Table 3-1.** It is estimated that, based on public domain data available on the development concept for the Elk and Antelope gas fields, the Papua LNG project would be able to deliver new domestic gas to Port Moresby at a cost-plus price of approximately $3.30/mmbtu. Similarly, it is estimated that the PNG LNG Train 3 project would be able to deliver new domestic gas to Hides or Kutubu at a cost-plus price of approximately $4.00/mmbtu. This cost is higher than for feedgas supplied to PNG LNG Trains 1 and 2 which is understood to benefit from shorter gathering distances and a higher liquids content in the gas.

**88. The high-level cost-plus estimates imply scope to obtain competitive gas prices which would be able to support opportunities for gas-to-power and other uses of gas.** The price at which a buyer will be willing to buy gas is linked to the costs of the buyer's alternative energy options. For some buyers, the ceiling is the cost of hydropower, for others the ceiling is just below parity to liquid fuel prices. Price indexation, such as to oil, oil products or coal, values gas as a substitute to other fuel options. Liquid fuels are the prevalent fuel source for power generation in the current power system. The price of diesel in the Highlands in 2017 averaged $22.00/mmbtu in Mendi and Wabag and $26.00/mmbtu in Tari while, in the Port Moresby area, prices paid for liquid fuels at Kanudi in 2017 were around $15.00/mmbtu. With oil price escalation having taken place in 2018, liquid fuel prices are going up, not down.

**Table 3-1: Preliminary Estimate of Domestic Gas Prices using the Cost-Plus Methodology**

| Concept | Regulated Asset Base | Cost-Plus Gas Price |
|---|---|---|
| Supply of sales gas from the existing gas plant in Hides | PNG LNG gas fields; Hides Gas Conditioning Plant | $2.20/mmbtu |
| Supply of sales gas from the existing pipeline in Port Moresby | PNG LNG gas fields; Hides Gas Conditioning Plant; Onshore pipeline; Offshore pipeline | $4.40/mmbtu |
| Supply of sales gas from a new Papua LNG plant in Port Moresby | Elk/Antelope gas fields; Upstream gas processing plant; Onshore pipeline; Offshore pipeline; Gas processing part of the liquefaction plant | $3.30/mmbtu |
| Supply of sales gas from a new PNG LNG Train 3 processing plant in the Highlands | P'nyang gas field; Onshore wet gas pipeline; Gas processing plant | $4.00/mmbtu |

**89. Further study is needed to understand sensitivities around the impact of prices on power and nonpower consumers as this can help inform an understanding of what prices are acceptable to consumers.** An initial assessment is that PPL could benefit from gas prices that are more stable and predictable than at present (that is, limited/no volatility, limited or no indexation to oil). In the case of sellers, it is worth noting that, even if a price is offered for domestic gas that covers costs and delivers a reasonable return, suppliers may opt not to sell gas to a prospective buyer for other noncommercial reasons, such as management priorities.[34]

[34] This is one justification for Western Australia's continued domestic gas reservation policy, despite inquiries and requests from industry to remove the policy. The Western Australian Government has argued that, without contractual requirements to make gas available domestically, some developers would not be interested in pursuing domestic opportunities, even if commercially attractive.

### *3.5 Recommended Way Forward*

**90. The government may need to distinguish between pragmatic measures to secure gas for domestic use in the next round of gas agreement negotiations–from a more comprehensive set of measures, based on stronger gas sector planning and new regulatory tools which will take time to develop.**

***Near-Term Measures***

**91. During state negotiations the government can utilize powers available under the Oil and Gas Act 1998 to secure a share of gas from proposed LNG export projects.** This includes powers to attach conditions to petroleum development licenses when approving new projects and negotiating specific terms into gas agreements with the licensees. In this regard, the formulation of a gas template agreement is an especially high priority. The government should identify objectives it wishes to achieve and positions to negotiate from. Importantly, in PNG's current economic and political climate, LNG exports and the use of gas domestically depend on each other. The government needs support from strong project developers to help finance and build gas fields and infrastructure, and project developers may see modest domestic gas commitments as opportunities to strengthen their political support and "social license".

**92. Investors that have risked large sums of money in finding gas and can monetize it profitably by liquefying and exporting it will claim that the incremental costs and efforts of serving a domestic market instead must be adequately compensated.** The state will need to demonstrate that the likely incremental need for gas in the domestic market presents no significant economic trade-off for them. Gas output is set to more than double in the next decade and current domestic use of gas is less than 4 percent of current output. The least-cost generation analysis shows that even in the most positive scenario for gas-to-power demand growth (with grid-connected mining loads), domestic gas sales to the power sector would rise to little more than 6-7 percent of projected total output in 2030. There is sufficient gas to both underpin investment in LNG export schemes and to supply the domestic market. The availability of gas for domestic use will, therefore, go hand-in-hand with LNG export projects.

**93. Investors will also want to avoid a situation in which, at the time of obtaining LNG buyer commitments and financing for LNG project development, a proportion of the gas resources underpinning the project is reserved for domestic use, unless there is a viable proposal for offtake on the table.** The state's negotiating position can, therefore, be strengthened by proposing commercially viable plans to use gas in both the power and nonpower sectors. The most viable options rely on being able to piggy-back on the production facilities and infrastructure already built, or to be built, for LNG export. The government's negotiating position will also be enhanced if it can demonstrate that effective measures are being taken to enhance the operational performance and financial sustainability of PPL, so that PPL may enter discussions with gas suppliers, contractors and customers as a more credible counter-party. This would include discussion of arrangements through which mining companies are able to sign long-term PPAs to obtain reliable grid-supplied electricity.

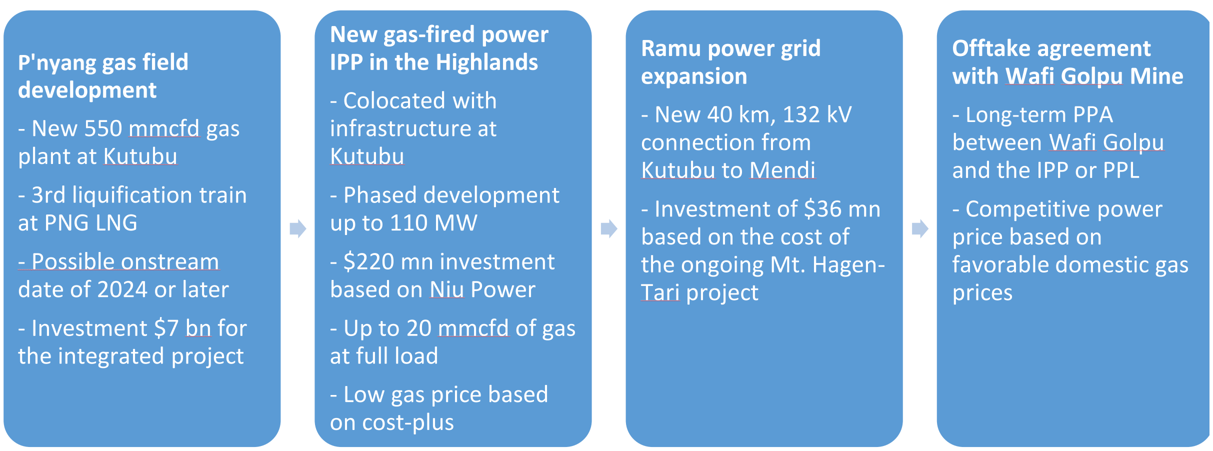
## Box 3-1: Business Case for a New Gas-fired Power Plant in the Highlands

**The least-cost power generation analysis suggests that there is a business case for new, gas-fired power in the Highlands fueled by gas resources in the nearby P'nyang gas field.**

**Based on operator cost estimates and actual capital and operational costs incurred in the recent and nearby PNG LNG project, we believe that P'nyang gas could be developed at a unit cost-plus price of approximately $4.00/mmbtu.** This is based on developing the field through a new wet gas-gathering pipeline to a new 550 mmcfd gas conditioning plant located in Kutubu. From there, most of the new gas would flow to a new, third liquefaction train at the PNG LNG plant in Port Moresby, while a small proportion of the new gas would be used to fuel a new, gas-fired power plant in the Highlands.

**Logical sites for a new gas-fired power plant in the Highlands would be Kutubu/Moro or Hides, because of synergies with existing infrastructure and supply logistics, and the availability of skilled personnel in the area.** While Hides benefits from existing gas treatment and captive power facilities, Kutubu is a long-established oil-producing center. New gas transmission line extensions and gas processing is also planned for Kutubu, including the proposed inlet for P'nyang gas.

**Projected demand from the Ramu grid under a variety of scenarios–which depend critically on supplying grid electricity to mines–could justify installed generation capacity in quite a wide range.** This suggests a modular approach which would enable capacity to be calibrated to increments in demand growth. Given that the new Niu Power gas-fired power station in Port Moresby which is currently under construction will be equipped with ~10MW Wartsila SG34 gas engines, we suggest installing similar machines in the Highlands with the number of machines and the project phasing subject to further study. We envisage that the new power plant will be connected to the Ramu grid at Mendi. The 132 kV connection between Mt. Hagen and Tari, that is currently under construction, as well as the rest of the Ramu grid, will have to be upgraded to bring the new gas-fired power to customers across the area.




**Based on a cost-plus power price of $4.00/mmbtu and an assumed investment cost into new gas engines of $1,984.00/kW installed, the new gas-fired power plant would be able to generate power at an LCOE of $105.00/MWh at a load factor of 50 percent.** This is 26 percent lower than the current average cost of thermal power generation in the Ramu grid of $141.00/MWh. Taking account of the estimated investments into the Ramu power grid of US$144 million, the end-user power price would be $243.00/MWh which would be 13 percent lower than the current price in the Ramu grid of $279.00/MWh.

**The P'nyang field could come onstream in 2024, that is, three years after new gas would be needed to fuel the new power plant in 2021.** One possible solution to this problem could be to temporarily swap up to 10 mmcfd of gas from P'nyang with PNG LNG gas or to simply buy gas from the PNG LNG project from 2021 until 2024. This should be commercially feasible given that the proposed domestic gas price of $4.00/mmbtu is well above the estimated cost-plus upstream gas transfer price of around $2.50/mmbtu in the PNG LNG project.

***Medium-term Measures***

**94. Over the medium term, the government can build on progress made through negotiation to secure gas for domestic use via stronger gas sector planning and supporting regulation.** The government has launched consultation on appropriate gas policies, including suggestions on how to strengthen the gas provisions of the Oil and Gas Act 1998. A draft White Paper on Gas Policy was endorsed by National Executive Council for further consultation in March 2018.

**95. International experience suggests that the optimal development of gas resources can benefit by undertaking gas master planning that will serve to inform policy, regulation, and investment planning.** A gas master plan typically draws on studies of gas resources, gas markets, and the value of gas in different end-uses to develop a plan covering gas supply, infrastructure, and demand. The objective of a gas master planning study is to create a credible, affordable, and competitive plan that may be used to align all stakeholders both on the government side and in the private sector. Gas master planning can play a particularly important role in countries with a developing energy sector–such as PNG–which tend to suffer from a chicken-and-egg problem between gas producers and gas consumers. A master plan may help to provide clarity and, therefore, reduce risk for investors along the value chain. A full discussion of gas master plans may be found in Appendix Five.

**96. A growing body of experience among governments in gas-rich countries shows that it can be challenging to find the right set of policy measures and regulatory instruments to secure gas for domestic use.** Drawing on this experience, Table 3-2 summarizes the range of available approaches, noting their advantages and disadvantages in the context of PNG. The full review of options can also be found in Appendix Five.

**Table 3-2: Summary of Policy Approaches to Support Domestic Use of Gas**

| Government Action | Description & Considerations |
|---|---|
| **(a) Gas reservations** | • The goal is to ensure that PNG's gas resources more directly result in development of the energy sector, mainly by improving access to reliable, affordable energy. Possible methods to achieve this include:<br>(a) A volumetric reservation, which requires a percentage of gas production to be offered to the domestic market;<br>(b) A tax (royalty, export tax, levy, tax allowances) that incentivizes domestic gas market development and, while gas exports predominate, secures funds (instead of gas molecules) earmarked for investment in improving domestic energy accessibility and affordability; and/or<br>(c) Requiring domestic gas project proposals as a condition of approval. This would require developers to show that domestic needs have been sufficiently studied and prioritized and viable options pursued.<br>• The above options have opportunities and challenges for PNG and require strong government planning to ensure their success.<br>• A single undifferentiated volumetric reservation could impact LNG export and smaller "stranded" field developments in different ways.<br>• Any of these methods can be developed into national policy or be deployed contractually on a project-by-project basis. |

| | |
|---|---|
| **(b) Gas price regulation** | • The government's approach to pricing should balance interests of the operators and consumers.<br>• Governments around the world vary greatly in their level of regulatory control over prices. This ranges from firmly set prices to providing a price formula or guidance on pricing and terms to leave pricing and negotiation.<br>• Whether set or left to negotiation, gas prices can reflect one or more of these principles:<br>(a) Controlled prices set at or below cost;<br>(b) Cost-plus or cost of service, calculated as wellhead, processing, and transport costs plus a commercial return;<br>(c) Netback pricing which values gas based on a price further downstream (either FOB or at destination); and/or<br>(d) Commodity indexation, such as indexation to coal or liquid fuels.<br>• Gas prices can also vary greatly by sector (power, nonpower), reflecting each sector's fuel alternatives, ability to pay, and price sensitivity. |
| **(c) Gas transport organization & regulation** | • In the PNG context, a primary objective of regulating how gas is transported for domestic use is to suppress the monopolistic behavior of incumbents and promote gas supply development and competition.<br>• Upstream owners of "stranded gas" see third-party access as an opportunity to monetize gas resources as export projects.<br>• Another option that has been explored (as a substitute for, or in addition to, third-party access) is to promote state-sponsored pipeline(s) with the goal of unlocking stranded gas fields.<br>• Governments may also support development of the domestic gas supply chain by assigning certain functions to a designated operator(s). An example is a single buyer, such as a state-owned gas aggregator, whose role is to aggregate domestic supplies and organize its efficient distribution to domestic users. |

**97. While the White Paper on Gas Policy highlights gas reservations and third-party access regulation to support domestic use of gas, these are only some among a variety of policy measures available.** It will be important for the government to consider a full range of options and decide where to place its emphasis. The government should study further gas reservation policy options, especially to link any reservation to viable gas offtake that meets power system development needs and optimal gas resource development, including that of "stranded gas". Domestic gas commitments secured through upcoming negotiations can pave the way for better-planned gas market development. Any policy selected should be pragmatic in addressing PNG-specific gas needs and industry targets.

**98. The government's approach to gas pricing should balance the interests of gas producers and consumers.** High-level estimates of the costs of supply to derive a cost-plus basis for domestic gas pricing suggest gas could be available at competitive prices both in the Highlands close to gas production, and in or near Port Moresby where feedgas is delivered for LNG processing, when compared to prevailing prices of alternatives, especially liquid fuels.

**99. Similarly, before determining the best form of regulation for an in-country gas pipeline system, the government should undertake a study to determine the ideal structure and organization for such a system.** This is especially so, given that until the domestic gas market attains scale any gas infrastructure dedicated to serving the domestic market will be very high cost. Such a study would develop a design for domestic gas transport and investigate options to promote its development whether through private investment alone or with support of a state-sponsored aggregator.

**100. Overall, the government should prepare a road map to study and foster a domestic gas market that can maximize the benefit of domestic gas use for the country.** Such a road map would start with stakeholder consultations on the White Paper and launch development of a gas master plan. The result would see responsibilities assigned under clear mandates, preferably with an empowered government entity taking overall control and responsibility for the plan's execution.

## Chapter Four: Improving PPL's Financial and Operational Performance

### *4.1 Opportunity*

**101. Delivering on electrification targets, and more generally on expansion of a reliable electricity service throughout PNG, requires an operational and financially sustainable utility.** Whatever the institutional structure and ownership of PPL, a necessary condition for the sustainable development of the power sector is the operational and financial viability of the companies in charge of providing generation, distribution and retail services to final consumers (usually identified as "utilities"). This derives simply from the fact that the power sector exists because there are electricity consumers. Activities of all agents in the sector should aim at ensuring that electricity consumers receive a consistent, good quality service and pay tariffs to their provider that reflect the costs incurred for efficient operations in all segments of the electricity supply chain (a social safety net could be needed to protect low-income consumers unable to pay cost-reflective tariff rates). If this condition is achieved, service utilities should be able to recover their own costs and pay for costs of energy purchases to companies operating in the upstream generation and transmission businesses.

**102. If, however, utilities fail to apply good management practices, provide good services to their customers and/or have poor performance in billing and collection, it is unlikely that they can achieve financial viability and become attractive offtakers for new investments in the upstream segments.** Operational and financial viability of utilities is, therefore, a necessary and in general sufficient condition to enable the sustainable development of the whole power sector. Taking into consideration the current institutional structure of the power sector in PNG, this means that achieving operational and financial viability of PPL is absolutely key to ensure the sector's development. Implementation of the LCPDP also hinges on PPL performance. Even if increased private sector participation can be leveraged for some of the investments, these still require a healthier utility.[35]

**103. The section below provides a high-level assessment of PPL's current operational and financial performance.** As can be observed from the assessment, the company is facing a challenging situation, however, the drivers are easily identifiable and solutions are under PPL's realm of control. Several effective actions can be implemented in the short to medium term (less than three years), with expected significant positive impact on the performance of the company. Implementation of those actions constitutes the first step in a trajectory towards a "steady state" condition characterized by efficiency in operations in all business areas and financial sustainability of PPL. A detailed description of each proposed action is presented in the following sections of this chapter.

[35] Additional private sector investment could be leveraged to implement the least-cost options and increase generation capacity, however, private sector participation in the electricity sector requires a healthier utility to provide sufficient comfort to IPPs as to PPL's ability to pay for supply contracts.

## *4.2 Diagnostic of PPL's Current Situation*

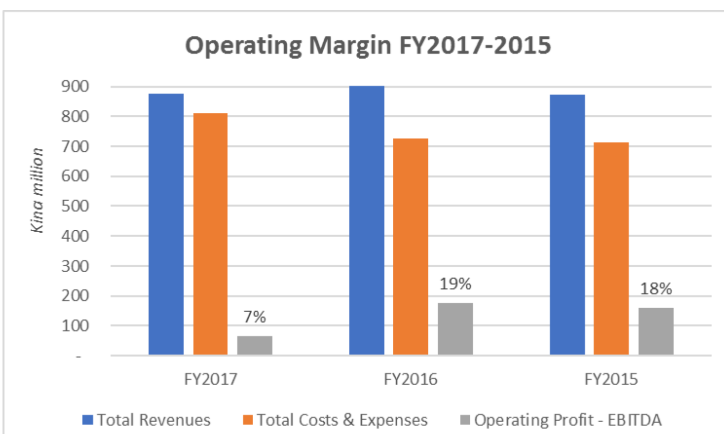
***<u>Low Operating Profit, Cash and Illiquidity</u>***

**104. The review of PPL's financial statements for FY2015, 2016 and 2017 shows that the company is facing a situation of financial distress that threatens its sustainability and the stability of the electricity sector in the country.** Under the current circumstances, PPL is financially unable to carry out any of the investments required to increase the installed capacity of the country, to improve the operating condition of the existing plants and networks and, therefore, the reliability of the service. In the absence of urgent and deep changes in the way PPL runs its operation, the company is soon to face a situation of illiquidity, further erosion of assets and production, and financial default. The government will have to manage the consequences and be forced to provide funding to the utility or to restructure the sector.

**105. PPL's weighted average tariff for FY2017 was approximately K 0.897/kWh (equivalent to $0.279/kWh).** This is significantly higher than the weighted average tariffs of $0.17/kWh for 27 similar power sectors in Sub-Saharan Africa with installed capacity below 1 GW and including a mix of hydro and thermal generation (Trimble et al. 2016; pp 26,31).

**106. Despite what should be a sufficient tariff, the substantial level of costs and expenses left the company with an EBITDA[36] margin of just 7 percent (Figure 4-1).** PPL was, therefore, far from meeting the fundamental principle in finances establishing that companies with significant investment needs must have a healthy EBITDA margin of at least 20 percent to be able to cover all their financing needs. Consequently, PPL had extremely limited funds to cover debt service and substantial capital expenditure (capex) needs in FY2017 and, although capex was mostly funded with new debt, PPL was forced to exhaust its cash reserves to make payments as due. As a result, in FY2018, PPL is fully dependent on commercial loans to fund its permanent working capital needs which in FY2017 amounted to approximately $20 million.

**Figure 4-1: PPL's Operating Margin**



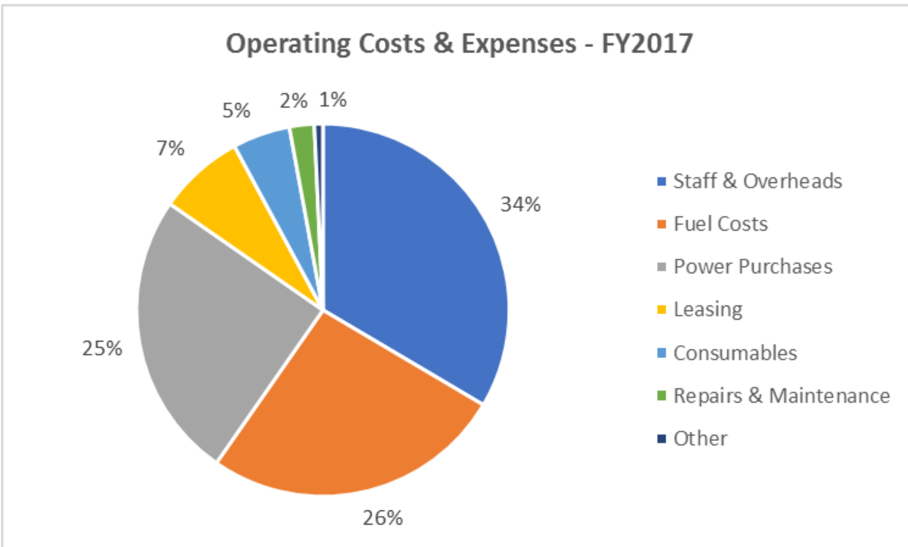

*Source:* World Bank staff (with PPL data).

[36] Earnings Before Interest, Taxes, Depreciation and Amortization.

***Costs and Expenses***

**107. Current costs and expenses are high–resulting in an extremely narrow Operating Margin of 7 percent as mentioned above.** Operating costs and expenses of $250 million are oversized for a company with 100,000 customers and $270 million of revenues. Despite the tariff freeze of 2013, costs and expenses were not controlled and, instead, increased steadily from one year to another. Staff & overheads and fuel costs–which comprise approximately 34 percent and 26 percent of total revenues respectively–are the most significant cost categories.

**Figure 4-2: PPL's Distribution of Operating Costs and Expenses**




*Source:* World Bank staff (with PPL data).

**108. Large impact of staff costs on financial performance of PPL needs to be addressed, and this can still be done without reducing staff numbers.** Staff: PPL has 2,000 employees to service 111,927 registered customers (2017 figures), a ratio of 56 customers per employee which is several times lower than the average of 278 customers per employee for the sample of Sub-Saharan utilities mentioned earlier (Trimble et al. 2016; p46). According to PPL's financials, in FY2017 the company made K 217.5 million ($67.8 million) of cash payments to its employees–equivalent to K 108,742 (or $33,876.00) per employee–a figure that is substantially higher than the average of $13,000.00 (in 2014 $) for a group of 38 comparable power utilities in Sub-Saharan Africa (Trimble et al. 2016; p45). Total staff remuneration included K 58 million (over $18 million) in call-outs, higher duties, stand-by and other allowances, as well as K 16 million ($5 million) in incidental & meal allowances. Despite the high staff numbers, the company also incurred K 12 million ($3.7 million) of overtime expenses.

**109. Total staff remuneration is believed to be calculated as a function (that is, a percentage) of Revenues (sales regardless of collection) and before any consideration of cash needs to cover debt service and capex.** To allow the company to have sufficient funds to pay its financial obligations and to pursue much needed investments (maintenance and growth), it would be advisable to calculate staff remuneration beyond the baseline on a cash basis (that is, collected invoices) and after payment of debt service and capex, and subject to PPL having achieved performance parameters which should include those required by the regulatory authority as a condition for tariff adjustment.

**110. Fuel: Liquid fuel consumption (lt/kWh) varies significantly across regions and there is a trend to higher consumption per kWh generated due to plant degradation and insufficient maintenance.** Furthermore, there are significant differences in fuel price/lt amongst plants located within the same region and a significant difference between the K 2.655/lt average price paid by PPL vs. the K 1.58/lt paid by IPPs which is partially attributable to fuel type but otherwise not fully explained. Fuel procurement practices must be reviewed to improve purchasing terms and internal processes must follow individual plant costs to optimize overall costs.

**111. Production Costs**: **In FY2017 PPL's hydro plants provided 39 percent of production while PPL's thermal plants provided 24 percent and IPP's 38 percent (Table 4-1).** PPL's own thermal production is significantly costlier than any other source of electricity (K 1.11/kWh vs. K 0.49/kWh of IPPs), mainly because it is based on diesel which is the most expensive primary resource used in the power sector of PNG. Thermal IPPs also have high production costs as they use expensive imported heavy fuel-oil (HFO).

**112. The weighted average cost of generation was K 0.46/kWh in FY2017 which, when added to the cost of transmission and distribution (T&D) of K 0.29/kWh, results in K 0.75/kWh, equivalent to $0.23kWh.** This production cost does not compare well with the weighted average of $0.14/kWh for a group of 39 power sectors in Sub-Saharan Africa (Trimble et al. 2016; p28) and is a direct reflection of the high costs and expenses referred to above. Total production costs should improve once the main drivers of costs and expenses are examined and rationalized. Rehabilitation of hydropower capacity, where possible, and optimization of production costs, notably through implementation of the LCPDP (as discussed in Chapter Two), is urgent.

**Table 4-1: PPL Fuel Mix and Production Costs**

**PPL - Fuel Mix & Production Costs**

| | 2017 | | | 2016 | | | 2015 | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Generation - MWh** | **%** | **Avge. Cost** | **Generation - MWh** | **%** | **Avge. Cost** | **Generation - MWh** | **%** | **Avge. Cost** |
| **PPL Hydro** | 504,954 | 39% | 0.04 | 541,983 | 41% | 0.06 | 617,806 | 50% | 0.06 |
| **PPL Thermal** | 308,854 | 24% | 1.11 | 344,494 | 26% | 2.82 | 330,047 | 27% | 0.45 |
| **Power Purchases** | 494,475 | 38% | 0.49 | 432,132 | 33% | 0.31 | 277,817 | 23% | 0.45 |
| **Sub-total** | 1,308,283 | 100% | **WAvg. 0.46** | 1,318,609 | 100% | **WAvg. 0.86** | 1,225,670 | 100% | **WAvg. 0.25** |
| **T&D Cost** | | | 0.29 | | | 0.20 | | | 0.21 |
| **Total Cost** | | | **0.75** | | | **1.06** | | | **0.46** |

*Source:* World Bank staff (with PPL data).
*Note:* Totals may not necessarily add to 100% due to the effect of rounding.

***<u>Revenues: Electricity Generation and Sales</u>***

**113. Table 4-2 below includes data on generation, sales and collection for each system in the 2015-17 period provided by PPL.**[37] Energy sales have been relatively stable in the last three years (2015-17). The amount of energy injected into the networks in 2017 was 1,327 GWh, and only 74 to 77 percent of

[37] The data provided by different PPL departments is slightly different, so where relevant a range is provided.

that amount was sold (billed) to the company's 111,927 formal customers. Collected revenues are eroded by nontechnical losses (low billing rates) and issues related to collection. PPL's system losses (technical and nontechnical) have increased steadily over the years and stood at a level between 23 and 26 percent by the end of FY2017.[38] In FY2016, up to 45 percent of invoices were not paid within 30 days and more than 39 percent were paid more than 90 days past their due date. In FY2017 these percentages deteriorated to 55 percent and 47 percent, respectively.

**114. Financial sustainability of PPL crucially depends on permanent billing (sales) of amounts of energy produced and consumed by users connected to its networks and collection of billed amounts.** Effectiveness in billing and collection are issues under the company's control and must be addressed as a matter of urgency.

**Table 4-2: Generation, Sales and Losses (2015-17)**[39]

| System | Year | Gen. MW | Gen. GWh | Billed Dist. GWh | Billed Dist. M$-Kina | Dist. # Custom | Losses - |
|---|---|---|---|---|---|---|---|
| Port Moresby | 2015 | 114 | 591 | 448 | 406 | 44,327 | 24% |
| | 2016 | 123 | 645 | 498 | 449 | 41,259 | 23% |
| | 2017 | 125 | 682 | 492 | 448 | 46,178 | 28% |
| Ramu | 2015 | 80 | 550 | 372 | 292 | 50,690 | 32% |
| | 2016 | 79 | 506 | 372 | 300 | 42,025 | 26% |
| | 2017 | 84 | 474 | 385 | 282 | 40,410 | 19% |
| Gazelle | 2015 | 10 | 54 | 42 | 38 | 10,540 | 23% |
| | 2016 | 10 | 57 | 45 | 41 | 9,764 | 21% |
| | 2017 | 10 | 54 | 42 | 38 | 10,952 | 22% |
| Others | 2015 | 21 | 107 | 81 | 75 | 14,375 | 24% |
| | 2016 | 22 | 110 | 94 | 86 | 13,074 | 15% |
| | 2017 | 22 | 118 | 105 | 96 | 14,387 | 10% |
| Total | 2015 | 225 | 1,301 | 942 | 811 | 119,932 | 28% |
| | 2016 | 234 | 1,319 | 1,009 | 876 | 106,122 | 23% |
| | 2017 | 240 | 1,327 | 1,025 | 864 | 111,927 | 23% |

M$-Kina: Million of Kina
Sold = Billed
Source: PPL

*Note:* Minor variations in calculations are due to the effects of rounding.

***Addressing Losses in Supply and Collection***

**115. Total losses currently incurred by PPL in supply are very high compared to any well-performing company providing service in comparable conditions and have two causes.** First, there are technical losses in supply which correspond to amounts of energy dissipated in the network infrastructure (power lines, transformers, and other equipment) and not consumed by electricity users. The quantum of technical losses depends on the condition of the network infrastructure and can be optimized (clearly below 10 percent, probably around 7-8 percent for networks like those operated by PPL) through investments in rehabilitation and upgrade of those assets. Second, commercial or nontechnical losses are

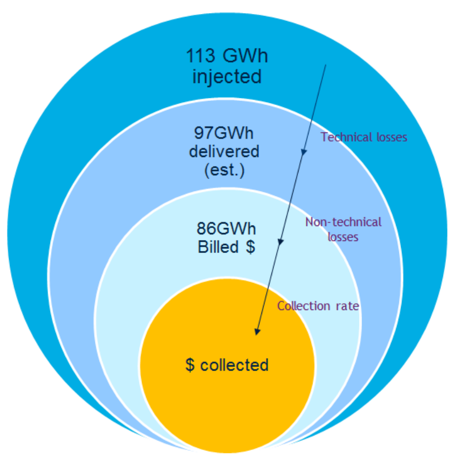
[38] Information provided by other units within PPL shows some slight differences in annual amounts of production and sales and related total losses: 21.2 percent in 2015; 24.0 percent in 2016 and 25.9 percent in 2017. This is understandable as current tools available for operations do not allow accurate recording of generation injected into the networks and amounts of energy sold.
[39] Losses values as percentage of generation.

the amounts of energy consumed by electricity users connected to the networks but not metered and billed by PPL. Nontechnical losses of a well-performing utility in supply to regular areas (where day-to-day operations can be carried out without constraints) are close to zero as the company can implement operational procedures supported by state-of-the-art tools to permanently meter and bill amounts of energy consumed by all users connected to the networks who are regular customers of the company.

116. **The breakdown of total losses in supply between technical and nontechnical factors is never known.** Technical losses can be estimated using engineering modelling and estimated nontechnical losses are simply the arithmetic difference between total recorded losses and estimated technical losses. In any case, the 23-26 percent total losses currently incurred by PPL in supply clearly show that both technical and nontechnical components are abnormally high. Rather than trying to estimate current values, what really matters is to identify and implement the actions needed to optimize technical losses and reduce nontechnical losses close to zero (at least in supply to regular areas) in a permanent manner.

117. **Optimization of technical losses requires an assessment of the current condition of network infrastructure at all voltage levels.** This would define the investments and other actions needed to rehabilitate and upgrade network assets and improve their operating conditions by eliminating abnormal overloads and voltage drops and incorporating new equipment to better use network infrastructure. As investments in rehabilitation and upgrade of network infrastructure are significant in the current condition of assets operated by PPL, they need to be prioritized according to expected impacts on quality of supply and reduction of technical losses. It is important to highlight that the cost to the utility of each kWh of technical losses is the generation cost.

**Figure 4-3: Energy Injected vs. Sales Collected (per month, first half of 2017)[40]**




*Source:* World Bank staff (with PPL data).

118. **Each percentage point of current total losses (exceeding 23 percent of generation) that becomes increased sales represents an annual additional revenue for PPL of $3.62 million, exceeding the total estimated investment amount of the Revenue Protection Program (RPP).** As it is reasonable to assume that current commercial losses are above 10 percent and the RPP targets 77 percent of total physical sales, the expected payback period of investments in the project will be extremely short (less than six months if

[40] The values shown assume 23 percent of energy losses, 14 percent of which are technical losses.

just 2 percent in commercial losses become increased sales). As already stated, however, the most important feature of the project is the permanent protection of almost four-fifths of PPL's current revenues.

119. **In addition to high losses in supply which represent a permanent financial loss (a kWh that was generated but not sold will never be recovered), PPL also faces significant problems in collecting on bills issued to its customers.** Well-performing utilities collect almost 100 percent of bills issued to regular customers not later than two to three months after the date of issuance. Accumulated arrears are, in general, very low. In the case of PPL, the company does not have in place the arrangements and supporting tools needed to accurately measure collection rates ($ collected/$ billed) for a certain period (typically three to six months).

120. **The amounts of uncollected bills corresponding to different periods (in some cases several years) are extremely high–evidencing the very poor performance of the company in managing receivables.** Although uncollected bills are not a permanent financial loss, poor collection rates are affecting the financial condition of the utility. Past due receivables have a significant and negative impact on the company's working capital. In addition, comprehensive experience in developing countries worldwide shows that the probability of collecting unpaid bills decreases over time, particularly for small customers accumulating significant arrears.[41]

121. **The current collection rate of bills issued by PPL to government agencies representing 14 percent of the company's sales is very low.** Amounts of unpaid receivables from those agencies which are handled by PPL as nondisconnectable points of supply reached K 61 million (equivalent to $18.7 million) in 2017. The increasing trend of this parameter started in 2016 and is growing at a rate above K 10 million per month (equivalent to $3.1 million). This issue should be addressed at the broader government level as a matter of urgency.

122. **Permanent achievement of collection rates close to 100 percent for all regular customers should have maximum priority for PPL.** As billing and collection are two key components of the revenue cycle, achieving and sustaining optimum collection rates over time also requires: (i) the adoption of adequate organizational arrangements; (ii) the reengineering of commercial processes and activities with the support of state-of-the-art tools to enable efficient, transparent and accountable execution; and (iii) the training of staff with the right technical qualifications and ethics in the use of those tools. Several short-term actions proposed by the Bank team aim explicitly to achieve permanent optimization of collection rates of bills issued by PPL to manageable (nongovernment) customers, as well as to address payment of bills by government agencies.

[41] The combined performance of an electricity utility in billing and collection is usually measured through the Cash Recovery Index (CRI) that is defined as the product of billing and collection rates in a certain period (typically six months). The billing rate is calculated as kWh billed/kWh injected in the networks while collection rate is computed as $ collected/$ billed. To assess the evolution of performance of the company in billing and collection, the CRI should be computed every month for the six-month period ending in that month. Sustained improvement in billing and collection will be reflected in increasing values of the CRI. In "steady state", PPL should be able to achieve and sustain values of CRI well above 90 percent for supply to regular customers.

***Reliability of Electricity Supply***

**123. Reliability of electricity supply is affected by various planning, operational and financial factors.** Poor planning and long-term underinvestment has created several bottlenecks: insufficient power availability, generation units not operating at full capacity, spinning reserves not meeting the minimum requirements, the poor operating condition of T&D infrastructure (overloaded main power transformers without backup, equipment failing, feeders suffering from large voltage drops and technical losses).

**124. Severe financing constraints limit maintenance activities to corrective actions.** In the distribution network, very limited switchgear equipment (such as reclosers and disconnectors) has been installed which results in very low operational flexibility. A permanent fault in the very last segment of a feeder typically causes an outage in the whole line until completion of repair if a switchgear to isolate the affected segment is not installed. Intermittent faults due to lightning and other weather events result in permanent disconnection because reclosers are not available in most of the feeders.[42] Overall, the Average System Availability Index (ASAI) computed for the three main systems was 97 percent just for feeder outages (high and medium voltage) in 2017 as PPL does not accurately record interruptions and other incidents at low voltage level due to a lack of specific tools for that purpose (Outage Management System). This figure evidences low quality in electricity supply to customers.[43]

**125. Most of the medium to high voltage distribution substations of the POM network are managed through a Supervisory Control and Data Acquisition system (SCADA).** In other networks, operations are managed manually through operations centers located in main cities and villages via radio, voice or telephone communication. The information and control function on generation plants and substations available in SCADA is basic and not complete. The dispatch of power plants is not handled in real time by the operational control room and it only follows the daily dispatching program prepared by PPL's generation team. Any difference between the planned dispatch and real-time dispatch beyond a certain level causes system instabilities (voltage and frequency issues) and system separation and thereby affecting the reliability and quality of supply. The generation operating reserve,[44] is not enough to maintain system stability during an accidental disconnection of generation units.

**126. A call center located in POM centralizes reception of complaints from customers companywide that are related to both commercial and electricity supply issues.** In cases of events creating major outages, the call center may receive about 9,000 calls in a day. Although the situation has improved recently, further improvements are needed. Communication between the call center and regional distribution operations centers and dispatch control room is via telephone and there is no tool (information system) in place to monitor performance of the field crews in charge of service restoration. The operations centers located in main cities and villages dispatch field crews following instructions of the dispatch/operations control room (only in POM) and complaints communicated by the call center.

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[42] While the causes or the fault are normally cleared after a short period, a long outage occurs since, in the absence of a recloser, the switch needs to be closed manually.

[43] Once PPL operates with the support of an Outage Management System the company will be able to get real information on reliability indices.

[44] Generating capacity available to the system operator within a short interval of time to meet demand in case a generator goes down or there is another disruption to the supply.

**127. Issues of reliability of supply in the Ramu grid are of particular concern given that several mines are connected to this system.** While ensuring reliability of supply to all of PPL's customers is important, ensuring reliability to the mines is key because large customers provide the bulk of PPL's revenues and, therefore, enable the rest of PPLs operations. In addition, PPL incurs penalties when it is not able to provide supply to certain mines–for example, to the Hidden Valley Gold Mine. There are already some planned investments that will improve the current weaknesses[45] and others are proposed as part of the least-cost plan discussed in Chapter Two. In the interim, there are some quick and immediate critical investments that can be undertaken to significantly improve reliability of supply to key clients in the short term, particularly on the transmission network of the Ramu system (see Appendix Nine for additional details).

## 4.3 Proposed Approach for Recovery: Preparation and Implementation of a Performance Improvement Plan (PIP)

**128. The assessment of the current situation evidences the urgent need to improve financial and operational performance of PPL in all areas so that it can deliver on electrification targets and, more generally, play its role in the expansion of a reliable electricity service.** To improve the financial and operational performance, a special emphasis is needed on distribution operations and commercial functions to permanently provide good quality services to its customers and sell and collect all amounts of electricity consumed.

**129. To improve its performance, PPL needs to strengthen both its human resources and supporting tools for operations, reengineer processes and activities in all business areas to maximize efficiency, transparency and accountability in operations, and optimize revenues and costs.** The company also must invest in infrastructure rehabilitation and upgrade to improve quality and reliability of electricity supply. For that purpose, it is proposed to prepare and adopt a comprehensive two-phase PIP aimed at ring-fencing PPL's core business and achieve and sustain over time significant improvements in operational performance, as well as reach financial sustainability of the utility and PNG's power sector. In that "steady state", tariff revenues allow the utilities to recover both efficient operating expenditures and costs of investments used to replace assets that are needed for service provision at the end of their lifetimes, including an adequate remuneration on equity.

**130. The scope of the proposed PIP for PPL (both phases) is presented in Table 4-3 below–which also summarizes the recommendations made for the main business areas, together with an indication of the priority/timeline for their implementation (for additional detail see Appendix Six).** Actions in the scope of the proposed PIP need to be implemented in a manner that maximizes effectiveness, starting with some quick wins. It is recommended to focus initially on high-demand customers by improving reliability in supply and protecting sales revenues to this segment. This is likely to produce quick results, create fiscal space, and buy credibility to carry out following actions in the scope of the PIP.

[45] For example, a transmission reinforcement project to be financed by the Japan International Cooperation Agency and an additional 34MW fuel oil IPP plant by a Korean investor.

Table 4-3: Main Building Blocks of the PIP

| Area | Recommendations | |
|---|---|---|
| | Phase I: High-priority Actions (Short Term) | Phase II: Medium-priority Actions (Medium Term) |
| **Skilled management team and workforce** | • Comprehensive organizational restructuring and competitive selection and appointment of a local skilled management team. Organizational restructuring is about developing staff capacities and skills through training in new approaches for efficient operations and supporting tools | • Staff upskilling/reallocation/implementation of special program for young talent, to make the best use of the existing human capital inside PPL |
| **Incorporation of management tools** | • Commercial Management System (CMS) to support all commercial processes<br>• Enterprise Resource Planning (ERP) system to support management of corporate resources<br>• Incidents Recording and Management System (IRMS) for attending to, and resolving, interruptions in electricity supply to customers<br>• Account separation of the three major business activities | • Map customers and network infrastructure using a Geographic Information System (GIS):<br>• Install a Works Management System (WMS) |
| **Increasing revenues** | • Reduction of nontechnical losses through implementation of an RPP targeting 7,800 of the largest customers representing 77% of current physical sales<br>• Implementation of improvements in customer service and efficiency in revenue cycle operations: elimination of manual processes, incorporation of e-bills and mobile phone payments<br>• Implementation of improved procedures for collection of old and future debts | • Assess consumption in areas with constraints to carry out field operations<br>• Secure payment for consumption by government consumers<br>• Launch a cost of service study |
| **Improving reliability** *(and reduce technical losses)* | • Implementation of urgent investments in network rehabilitation/upgrade to address situations of unacceptable quality of service (see Appendix Nine).<br>• Studies to identify improvements in T&D networks stability, protection systems and quality of supply to large consumers; tests to assess condition of existing equipment (see Appendix Nine)<br>• Upgrading existing SCADA System to operate and control from generation to Medium Voltage (MV) distribution. | • Mid-term investments for reliability<br>• Upgrade the Operations Control Center |
| **Optimizing costs** | • Adjusting procedure to calculate "performance component" of staff remuneration over Cash Available after Debt Service and Capex<br>• Implementation of improved procedures for metering electricity production and fuel consumption of thermal plants (both owned by PPL and by IPPs)<br>• Implementation of actions for optimization of production costs: feasibility study of repowering of existing own hydropower plants; assessment of replacement of diesel gensets of isolated systems by renewable (solar + storage) plants; review existing thermal generators; introduce renewable energy in isolated centers<br>• Systematic implementation of least-cost plan for generation and transmission<br>• Identification and implementation of new management models to "ring-fence" PPL's core businesses and leverage private sector for investments in generation and provision of O&M services | • Staff compensation: Incorporate performance criteria<br>• Fuel: Review arrangements for fuel procurement<br>• Production Costs: Continue to implement least-cost plan of generation and transmission: invest in rehabilitating hydro, launch competitive bidding for new generation projects |

*Source:* World Bank staff.

**131. A brief description of each of the five building blocks of the PIP and of the two-phase program of proposed actions is presented in the following paragraphs[46].**

[46] PPL has already been implementing some elements of the PIP on its own without Bank involvement (notably the component linked to organizational restructuring and establishment of skilled management team and workforce which was initiated in the first half of 2018) and various actions under the remaining PIP areas. At the date of printing of this report, PPL and the GoPNG requested Bank support for implementation of the remaining building block under the PIP through the proposed PNG Energy Utility Performance and Reliability Improvement Project (P167820), currently under preparation.

**132. One: Skilled Management Team and Workforce: A necessary precondition to achieving good performance of a utility is to have a management team with appropriate technical competencies and ethics.** PPL's reorganization is not about reducing staff numbers, but about finding the right people to do the right jobs.

- **In the short term (Phase I), the company should continue and expand the scope of this task by including a comprehensive restructuring aimed at defining and putting in place an optimum organizational structure.** Each position in the structure should be occupied by local managers and supervisors with adequate academic skills and ethics and selected through competitive transparent processes. Short-term external support for management in some positions could be brought in as needed but should be coupled with local resources to ensure knowledge transfer. All staff should be trained in a new way of doing business that is driven by optimizing customer service in all dimensions ("PPL exists because it has customers to serve") and maximizing efficiency, transparency and accountability in operations.
- **In the medium term (Phase II), the company should work on staff training and skills development** as well as eventual reallocation among departments aimed at having in place capable teams to run processes and activities in all business areas, including planning and implementation of investment projects to build new network infrastructure. By upskilling staff, PPL can make the best use of the existing human capital in the company.

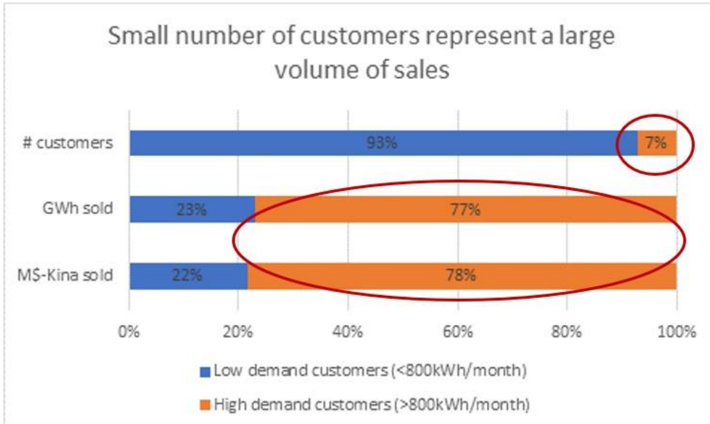
**133. Two: Incorporation of Management Tools**: **To enable the new way of doing business, PPL needs to incorporate state-of-the-art tools to support execution of operations in all business areas and provide timely reliable corporate information to management.** Having the right management tools will allow management to have access to data to identify specific issues that need to be addressed and develop targeted solutions to improve the company's operational and financial performance.

- **In the short term (Phase I), it is recommended that process reengineering in all business areas takes place, driven by efficiency, transparency, and accountability, and enabled by optimum use of functionalities of an initial set of management information systems (MIS) to be incorporated by the company:**
  - i. **a CMS that enables efficient execution of all commercial functions;**
  - ii. **Corporate Resources Management System (aka the ERP) to support management of shared services:** accounting, finances, human resources, procurement, logistics, corporate planning, and information technology (IT); and
  - iii. **an IRMS to receive customers' complaints for outages, identify the location and analyze the extent of an interruption in electricity supply, and enable fast resolution and service restoration.** For the area of finance, in particular, it is also recommended that PPL separates the accounts of the key business activities (electricity generation, T&D, and retail) to manage them as separate business units, as this will enable the company to understand each business in detail.[47]

[47] PPL is an integrated utility with three major business activities: electricity generation, T&D, and retail, each of which has a different profile in terms of cost structure, investment needs, and human resources. The company does not, however, have separate accounts for each business activity, and instead produces fully consolidated financial information. It is highly advisable that PPL manages its three business activities as separate business units with equally separate accounts. This is common practice for integrated utilities and for any company with more than one business activity.

- **In the medium term (Phase II), additional systems could be added–such as a GIS to build and keep permanently updated reliable customer and asset databases and a WMS.**

**Figure 4-4: PPL's Distribution of Customers vs Energy Sold**




*Source:* World Bank staff.

**134. Three: Increasing Revenues (Billing and Collection):**[48] **PPL should immediately put a strong focus on reducing losses and improving billing and collection which are issues under the company's control and have maximum priority.**

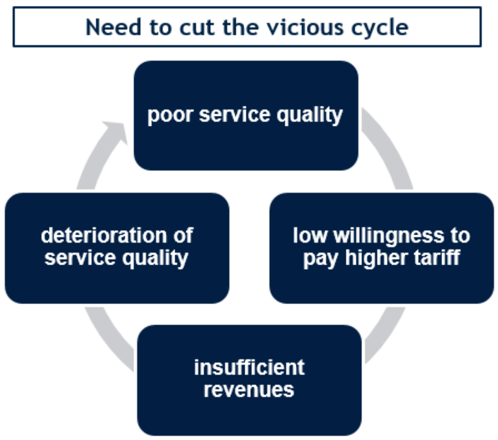
- **In the short term (Phase I), it is proposed that:**
  i. **PPL urgently implement an RPP for sustainable reduction of nontechnical losses in supply** (unmetered consumption) that is initially focused on those customers with recorded monthly consumption above 800 kWh (7 percent of total number, but representing 77 percent of current physical sales) (Figure 4-4).
  ii. **PPL systematically use the CMS to support efficient and accountable execution of commercial processes and activities (P&A) that the company must carry out to serve all its customers.** This includes: (i) monthly revenue cycle (metering, billing, collection, disconnection/reconnection) for credit (postpayment) consumers; (ii) management of purchases and consumption of prepayment customers; and (iii) registration of new customers. All existing manual processes (meter reading and billing) should be eliminated.
  iii. **PPL implement new approaches widely adopted in developing countries for distribution of bills ("e-billing" to mobile phones via email or SMS) and collection/purchases (mobile phone payments).**
- **In the medium term (Phase II):**
  i. **PPL should quantify losses in supply to areas where the company's staff face security issues due to aggressive behavior of their inhabitants (not necessarily regular customers).** Regularization of supply to those areas requires large investments in construction of new infrastructure (distribution networks and metering systems). As an initial step, PPL should implement wholesale metering in the feeders supplying those areas to compute amounts of energy injected and losses and assess the financial viability of the investments needed to regularize supply.

[48] See Appendix Four for additional details on selected aspects.

ii. **PPL should define and put in place "ad hoc" procedures to maximize collection of old debts, as well as to ensure regular payment of bills by government agencies.**

iii. **The sector regulator (or eventually the utility) should launch a cost of service study,** including a review of the current tariff structure that is aimed at identifying actions on the revenue side to improve financial performance.

**Figure 4-5: Service Quality vs Ability to Collect Revenues**




*Source:* World Bank staff.

135. **Four: Improving Reliability: PPL should focus on identifying and implementing urgent investments in rehabilitation/upgrade of existing infrastructure to address the poor condition of equipment and quality of service.** Immediate priority should be given to actions that will solve urgent cases and achieve a fast and positive impact on service quality. Experience shows that an initial improvement in service quality is a prerequisite to enable tariff increases to wealthy consumers able to pay cost-reflective rates (Figure 4-5). The overall rehabilitation/upgrade of network infrastructure must be considered as a phased process that will take several years and require substantial financial resources.

- **In the short term (Phase I), PPL should address physical investments that can no longer be postponed and prioritize them according to their impact on network reliability and quality of service,** including: (i) installation of new switchgear equipment (such as reclosers, disconnectors); (ii) installation of capacitors in MV lines and substations; (iii) improvement of the protection system in MV/HV substations; (iv) reinforcements/replacements needed to solve major overloads/voltage drops. PPL must also incorporate as soon as possible a SCADA system to efficiently and remotely operate, supervise, and control their MV/HV infrastructure.[49]
- **In the medium term (Phase II), PPL must prepare an investment plan aimed at removing: (i) any constraint to supply deriving from insufficient capacity; (ii) configurations not meeting applicable criteria on stability and reliability; and (iii) other situations involving basic (medium and high voltage) network infrastructure.** PPL should also adopt actions needed to operate with the support of a single fully performing control center to properly manage system operation, fault restoration, and attention to customers' complaints. Considering the small size of the PNG electricity system, it is recommended that the company initially puts in place a "Single Control

[49] SCADA is complemented by IRMS to manage and resolve incidents at low-voltage level.

Center" to deal with the generation and T&D systems. The IRMS will assist PPL in addressing outages and other incidents effectively.

136. **Five: Optimizing Costs: PPL needs to identify and implement actions aimed at reducing and optimizing costs.** In order of quantitative impact, staff & overheads, fuel, and production costs are the most significant cost categories.

- **In the short term (Phase 1), PPL should address:**
  - **<u>Staff & Overheads</u>: Urgent changes are needed to staff compensation, which can be implemented without reducing staff numbers.** Total staff remuneration is calculated as a percentage of revenues (sales regardless of collection rate) and, therefore, does not take into consideration various critical issues such as actual payments received by the company, cash needed to service debt, and investments required to maintain the existing assets and to build new ones. An urgent measure is to change the calculation method for the "performance component" of staff remuneration so that it is calculated over Cash Available after Debt Service and Capex.
  - **<u>Fuel:</u> Improve metering of fuel consumption of all thermal plants.** Ensure accurate metering of parameters in commercial transactions with IPPs and amounts of energy injected to T&D networks by installing metering systems to record all electrical parameters involved in commercial transactions with IPPs.
  - **<u>Production Costs:</u> For existing assets, PPL should launch a feasibility study for repowering of existing own hydropower plants, review all existing thermal generators to decide the ones that should be discontinued, and promote replacement of diesel-fired generation facilities of existing isolated systems** (around 12) by others based on renewable resources (solar + storage batteries) through competitive bidding. For new assets, PPL needs to systematically adopt least-cost planning (preparation and periodic update of the LCPDP) and least-cost (competitive) implementation of projects in the plan.
  - **<u>Management Models</u>: Leverage the private sector to manage infrastructure which will limit risks and, if appropriately managed, help to contain costs.** It is recommended to "ring-fence" PPL's core businesses (network T&D and retail) by: (i) procuring all new amounts of power and energy needed to supply demand by existing and future customers through PPAs to be signed with private investors;[50] and (ii) outsourcing O&M of existing *(thermal)* generation facilities in main and isolated systems.
- **In the medium term (Phase II):**
  - **<u>Staff & Overheads</u>: PPL can incorporate performance criteria such as loss reduction, billing, collection, quality of service and other parameters demanded from PPL by the regulator as a condition to approve tariff adjustments which impact PPL's revenues.**
  - **<u>Fuel:</u> PPL should review arrangements for fuel procurement.**
  - **<u>Production Costs</u>: PPL should implement the outcomes of the study developed in Phase 1.**

[50] Competitive bidding of solicited investment.

## 4.4 Financial Implications of the LCPDP and PIP

**137. Chapter Two of this paper addressed the LCPDP while this section describes the scope of the proposed PIP to improve PPL's operational and financial performance.** The scenarios considered in assessing financial impacts are summarized in Table 4-4, while the expected financial impact of implementing actions in the PIP and projects forming part of the LCPDP are described below. These figures are the result of high-level financial projections prepared for illustrative purposes. As such, they are not intended to replace the results of comprehensive corporate financial projections which must be prepared as an indispensable tool for assessment of PPL's financial sustainability under different future scenarios.

**Table 4-4: Scenarios Considered for Financial Impact Analysis**

| Scenario | Description[51] |
|---|---|
| Baseline (B) | PPL current financial outlook, no changes implemented. |
| Baseline plus Loss Reduction & improvement on collections (B+LR) | Loss reduction of 3% plus 3% increase in collections. |
| Business-as-usual (BAU): Changes needed to implement the BAU scenario of the LCPDP (see Chapter Two) | Loss reduction of 3% plus 3% collection increase similarly to B+LR above, plus: (i) 10% reduction in fuel costs; (ii) the investments required under the base case of the LCPDP which are financed with deeply concessional loans; (iii) a staff remuneration scheme with a fixed component (salaries and wages, other allowances, and superannuation) and a variable component that is calculated on the basis of collected revenues and payable with cash available after debt service, capex, and a minimum treasury balance equivalent to one month of opex. The sum of the fixed and variable components shall not exceed 24% of operating revenue, as is currently the case; and (iv) a 5% reduction in staff numbers to reflect natural attrition. |

*Source:* World Bank staff.

**138. Baseline (B): This corresponds to financial projections to illustrate PPL´s current financial outlook.** If the current situation remains unchanged, the expected result is a continued and accelerated deterioration of PPL's operational and financial performance. Insufficient funds available for maintenance and investments will result in reduced sales and revenues and increased operating costs,[52] further deteriorating the company's already unsustainable cash and liquidity position. In the absence of continuous and substantial external financial support to cover opex, PPL will fall into complete illiquidity, lacking the resources needed to meet payment obligations, including debt service. Under this scenario, the company will not be able to make any significant investments on its own and is unlikely to be a credible offtaker in PPAs for the implementation of new generation projects defined in the LCPDP.

**139. Baseline plus Loss Reduction & Improvement on Collections (B+LR): This scenario reflects the positive impact that a 3 percent reduction in losses and a 3 percent increase in collections would have on PPL´s financial performance.** The result would be an important increase in operating revenue. If the

[51] For an additional description of the key features of the scenarios, see Appendix Seven.
[52] With the only exception being the termination of the leasing contract assumed to take place by the end of FY2019.

current method for calculating staff remuneration remains unchanged, however, improvements in PPL´s cash and liquidity position will be insufficient to implement minimal investments that are urgently needed to rehabilitate existing infrastructure. In the absence of substantial external financing, therefore, operations would continue to be financially unsustainable.

**140. BAU: To sustain operations and enable implementation of the projects in the base case scenario of the LCPDP, PPL will need to carry out a comprehensive program of reforms,** including: (i) reducing commercial and technical losses; (ii) improving collection rates; (iii) optimizing prices paid for fuel purchases; and (iv) changes in the method for calculating staff remuneration. This scenario incorporates a combination of several performance improvement measures as described in Table 4-4. Under such a scenario, if the most concessional financing arrangements available to implement the investments in the base case of the LCPDP are used, a significant improvement in PPL´s financial position is possible and the company can become a financially sustainable operation with a positive cash position generated through tariff revenues without the need for external funding.

**141. Table 4-5 summarizes the outcome of the scenarios described above.**

**Table 4-5: Outcome of Financial Analysis for Various Scenarios**

| | 2017 | 2018 | | | 2019 | | | 2020 | | | 2021 | | | 2022 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *K'000* | Actual | B | BL + LR | BAU | B | BL + LR | BAU | B | BL + LR | BAU | B | BL + LR | BAU | B | BL + LR | BAU |
| **Total Revenue** | 875,077 | 891,756 | 926,743 | 970,446 | 886,763 | 921,533 | 1,032,644 | 881,818 | 916,373 | 1,100,155 | 876,936 | 911,279 | 1,173,579 | 872,117 | 906,250 | 1,253,569 |
| **Total Opex** | (809,472) | (815,477) | (823,873) | (747,892) | (823,039) | (831,384) | (810,572) | (768,502) | (776,795) | (786,719) | (774,590) | (782,832) | (834,409) | (780,696) | (788,887) | (893,057) |
| **EBITDA** | 65,605 | 76,280 | 102,870 | 222,553 | 63,724 | 90,149 | 222,072 | 113,316 | 139,578 | 313,437 | 102,346 | 128,446 | 339,170 | 91,422 | 117,363 | 360,511 |
| **EBITDA Margin** | 7.6% | 8.7% | 11.3% | 24.0% | 7.3% | 10.0% | 22.4% | 13.1% | 15.5% | 29.6% | 11.9% | 14.4% | 30.0% | 10.7% | 13.2% | 29.8% |
| **Net Profit/Loss** | (15,432) | (23,234) | 3,356 | 124,727 | (36,045) | (9,619) | 124,939 | 13,506 | 39,769 | 217,054 | 2,533 | 28,633 | 243,733 | (8,408) | 17,533 | 265,954 |
| **Profit Margin** | -1.8% | -2.6% | 0.4% | 12.9% | -4.1% | -1.0% | 12.1% | 1.5% | 4.3% | 19.7% | 0.3% | 3.1% | 20.8% | -1.0% | 1.9% | 21.2% |
| **Operating Cash** | 96,404 | (12,896) | 28,730 | 144,918 | (24,952) | 16,427 | 139,460 | 25,134 | 66,268 | 225,424 | 14,652 | 55,544 | 245,283 | 4,210 | 44,863 | 260,226 |
| **Increase / (Decrease) in Cash** | (6,041) | (138,835) | (97,209) | 20,665 | (151,147) | (109,768) | 15,902 | (101,101) | (59,967) | 102,616 | (111,587) | (70,695) | 123,420 | (122,046) | (81,393) | 139,243 |

*Source:* World Bank staff calculations.
*Note:* Some calculations may vary slightly due to the effect of rounding.

**142. No simulation results are shown for the LCPDP scenarios that consider the mining loads (medium or high).** Any analysis of those scenarios would require incorporating "ad hoc" supply agreements to be signed between PPL and the involved mines whose scope, technical and financial conditions, and obligations of the parties cannot be established with reasonable certainty at this time. A more detailed analysis of PPL's future financial performance under different assumptions on sector development and roles allocated to the company will require the preparation of an elaborated corporate financial modelling tool, as well as assessment of costs of service delivery (current situation and efficient performance) and allocation among consumers categories (tariff structure and rates).

### *4.5 Recommended Way Forward*

**143. Preparation and adoption of detailed PIP: The proposed PIP sets out a two-phase program that could be presented to other technical partners, financiers, and investors.** It is proposed that PPL immediately carries out a detailed design of both phases of the PIP and submits it to Kumul Consolidated

Holdings (KCH)[53] and the government for approval and definition of arrangements for immediate implementation of Phase 1. Effective adoption of high-priority actions in this phase will strengthen the physical and institutional infrastructure, improve the operational and financial performance of PPL, pave the way to accelerate the electrification of the country and enable more private sector investments in generation to lower the cost of supply.[54]

**144. Budget for implementation: While full execution of the PIP will require significant resources, immediate priority actions can be carried out with a relatively limited budget.** The cost of immediate implementation of the RPP and MIS is estimated at around $10 million while urgent investments in infrastructure rehabilitation and upgrades necessitate further assessment but could be in the order of $30-40 million.[55]

**145. Implementation of the PIP is a precursor/precondition for electrification: The PIP focuses mostly on improving the utility's performance and does not address other subjects like electrification.** Having said this, an efficient utility company is better placed to perform effectively the execution of investments in grid extension and provision of electricity services to new users. This is of particular relevance for Papua New Guinea where electrification rates are very low and affordability for vast segments of the population is a significant constraint requiring pragmatism in the definition of tariff regimes. Government agencies (sector ministries) are typically responsible for the design of those electrification programs in all aspects (allocation of roles among agents, definition of optimum technical options, sources of funds for investments, and operating costs).

[53] Kumul Consolidated Holdings Limited (KCH) is the delegated owner of all State-Owned Entities/Enterprises (SOEs) for and on behalf of the state, including PPL.

[54] The PIP would focus for an initial three-year period on the key aspects impacting the effectiveness of operations.

[55] See Appendix Nine for an indicative list.

## Chapter Five: Overall Conclusions

**146. This report has covered policy and technical advice to:**

- **(i)** **identify least-cost options for power generation and transmission**, in particular the potential role and opportunities of domestic gas-fired power, hydropower, and other renewable energy;
- **(ii)** **provide a high-level analysis of the opportunities and challenges of developing a domestic gas value chain in PNG,** especially in the power sector, and the role that policy may play in overcoming barriers; and
- **(iii)** **provide recommendations on actions to strengthen PPL's financial and operational performance.**

**147. Detailed findings and recommendations are presented in each section of the report, but a summary of findings can be summarized as follows:**

**148. LCPDP:** The results of the least-cost options analysis show that, while in the long-term hydro and other renewables generation will be key to meeting the government's access goals and future demand, gas generation can play an important role as a transition in replacing liquid fuels, lowering power costs and supporting grid expansion. Systematic and coordinated oversight of project selection and adherence to well-prepared competitive bidding processes will be the essential requirement to lower supply costs and consumer tariffs to drive sustained economic growth in industrial, commercial and residential sectors. In the short term, rehabilitation of existing hydropower to restore generation capacity is a key priority.

**149. Capitalizing on LNG growth to meet domestic energy needs:** There is an immediate window of opportunity through gas project negotiations to secure gas needed for domestic power. Negotiations will be strengthened by identifying viable off take. The pre-feasibility of options–in the Highlands where gas is processed before being piped to the coast and in Port Moresby where liquids fuel replacement is achievable using future feed gas piped from the Highlands–should be examined urgently. The amount of gas involved (<5 percent of projected gas output) would not impact LNG economic fundamentals. It is important to negotiate gas prices that limit exposure to global oil price volatility and achieve a level closer to delivered costs, plus a reasonable return ("cost-plus"). LNG project developers are likely to be interested in obtaining political support and social license to get their agreement. This approach secures access to gas in advance of settling the full policy and regulatory framework to support longer term domestic gas market development and allows time to prepare a gas master plan and complete consultation on the Gas Policy White Paper.

**150. Improving PPL's financial and operational performance:** Building PPL into an efficient utility and a creditworthy offtaker will accelerate the implementation capacity needed nationally to achieve electrification goals and enable efficient private investments in the sector. An operationally and financially performant utility is a key enabler of provision of good quality electricity services to all the population of PNG. The high-level assessment of current operational and financial performance of the national electricity utility PPL highlights significant challenges currently faced by the company, but also identifies main topics to be addressed and concrete actions under PPL's control to be implemented to improve its performance. Several proposed actions can be implemented in the short to medium term (less than three years), which are expected to have significant positive impact on the company's performance. For the short term, it is important to focus on improving PPL financial and operational performance, specifically through areas such as the implementation of an RPP and implementation of priority investments to improve reliability of the existing T&D network.

**151. Furthermore, a few reflections are presented for consideration by PNG authorities:**

- **Electrification rates in the country are very low and mining projects are constrained by availability of power.**
- **There are opportunities for optimized (as opposed to ad hoc) planning,** considering the government electrification goals, the mining growth opportunities as well as the opportunities and resources of the country. These will not materialize on their own and will require a concerted effort from government.
- **There is a need for the deliberate and careful implementation of the projects that are part of the least-cost plan** and a need to avoid entering into PPAs for any generation proposals that have not been the result of a competitive bidding process. The least-cost plan indicates hydro in the POM grid and gas in the Ramu grid as the least-cost technologies of choice for these systems for the current demand outlook. Opportunities for meeting the immediate need for additional generation capacity (namely through gas, wind, and solar investments) have also been identified.
- **In the near term, the government has opportunities to influence the way that gas development takes place as major new gas production projects are sanctioned.** Securing commitments to allocate some gas from LNG project developers can be encouraged if the government enters negotiations with viable proposals and capitalizes on project developers' probable interest in obtaining political support and social license.
- **Improving PPL's financial and operational performance through the implementation of a PIP is essential to deliver on government goals of electrification and to enable private sector participation in generation projects.**

**152. The Bank is ready to support the Government of PNG in the implementation of the various recommendations included in this report.**

## Appendix One: Major Assumptions for Least-cost Study in PNG[56]

**1. General**

- Planning Period: 2018–30
- Target Power Systems:
  - POM power system and Ramu system given that these two systems cover about 90 percent of the total population of PNG.
  - The least-cost planning study is carried out for each system, then interconnection of both the POM and Ramu systems is analyzed.
  - Social Discount Rate: an estimate of 6 percent based on annual growth of GDP per capita in PNG following the World Bank's guideline.
- Reserve Margin: Standard
  - 30 percent for each grid per discussion with PPL colleagues.
  - Limited by functions of the selected model (GAMS) and available time to finish the task. A reliability analysis is not conducted to verify whether the reserve margin is appropriate–this would be completed in a follow-up study.
- Carbon value is considered in the study. The value is taken from the World Bank's guidance note: \$35.00/tonne $CO^2$ in 2020, and \$50.00/ton $CO^2$ in 2030; linear growth is assumed for each year in the planning period.
- Optimization Model: GAMS–developed by the World Bank team.

**2. Demand Forecast**

**Sector analysis is used to project the demand growth in the planning period for the following sectors: (i) mining; (ii) implementation of NEROP; and (iii) other sectors.** The Bank team reviewed the demand forecast conducted by PPL and realized that PPL does not consider either the mining sector or the NEROP target in their plan. Three scenarios have, therefore, been developed: (i) BAU–with an assumption that no new mining projects are connected into PPL grids; (ii) a medium-growth mining scenario with connection of three mines to the Ramu grid based on assessment of their possible connection; and (iii) a high-growth mining scenario with the three mines in the medium-growth scenario and the connection of a further seven mines in both the POM and Ramu grids.

**2.1 Mining Sector**

**The mining and processing of metallic mineral ores to produce copper, nickel, gold and minor metal by-products is energy intensive.** Availability of reliable grid-based supplies can limit energy costs borne by the mine only to the costs of connection and regular consumption tariffs. If, on the other hand, a mine provides its own back-up generation due to grid-reliability issues or opts for self-generation due to remoteness from the grid, this adds significantly to capital costs and operating costs. Those additional costs could render a mine nonviable or require the mine to be designed to selectively mine smaller quantities of higher quality mineral ores needing less energy consumption per unit of output.

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[56] Revised on June 16, 2018.

**The Bank team consulted with the mining industry to obtain information on the anticipated new mining projects in PNG.** The list of mining projects located in the areas covered by both grids is provided in Table 1A.1.

**Table 1A.1: Existing and Planned Mining Projects in POM and Ramu Grid Areas**

| Mining Projects | Peak Load (MW) | Possible System Connection | Note |
|---|---|---|---|
| Tolukuma | 2.5 | POM | Existing |
| Mayur Resources Limestone | 30 | POM | Planned in 2030 |
| Hidden Valley | 17 | Ramu | Existing, PPL supplies |
| Porgera (Hides_gas) | 80 | Ramu | Existing |
| OK Tedi | 100 | Private | Existing, about 350km from the grid, self-supplied |
| Ramu Nickel and expansion | 90 | Ramu | Existing |
| Eddie Creek | 1 | Ramu | Existing, PPL supplies |
| Kainantu | 2 | Ramu | Existing, PPL supplies |
| Crater Mountain | 1 | Ramu | Existing |
| Frieda River | 235 | Ramu | Planned in 2026, peak load is planned at 155MW in 2026, growing gradually to 235MW by 2036 |
| Wafi-Golpu | 140 | Ramu | Planned in 2025 |
| Yandera | 150 | Ramu | Planned in 2025 |
| Kili Teke | 100 | Ramu | Planned in 2030 |
| Mt Kare | 50 | Ramu | Planned in 2030 |

*Source:* World Bank staff.

**There is only a small number of mines that are connected to the grid but they account for a very small proportion of the electricity used by the mining sector in PNG.** Out of a total of 14 mining projects, three have been supplied by PPL (Hidden Valley, Eddie Creek, and Kainantu–all small to medium-scale gold mines with a total peak load of 20MW); five are existing mines and supplied by their own captive power plants (Tolukuma, Porgera, OK Tedi, Ramu Nickel, and Crater Mountain); and six mines are expected to be commissioned during 2025-30.

**A significant subset of mines are simply too remote for grid-based solutions to be available and a very high proportion of the energy consumed by mines in PNG is self-generated.** This includes existing island mines–such as Lihir gold mine–and those in remote mountainous terrain–like Ok Tedi which is some 350 kms from the Ramu grid. Some future mines–such as a reopened Panguna mine on Bougainville–also belong to this subset. For purposes of the least-cost generation modeling, these mining loads have not been considered.

**A second subset of mines could conceptually be served by the grid but have faced barriers in doing so.** Among existing mines, the Ramu nickel mine and Porgera gold mine fall into this category. They both rely on off-grid solutions; Ramu on self-generation both at the inland mine site and at the coastal nickel processing plant; Porgera on power purchases from a gas-fired generation plant at Hides gas field built expressly to serve this off-grid solution. Among probable new mines, the developers of Wafi-Golpu copper mine have examined several options including grid-supply provided by a new transmission line.

**These represent mining loads that exceed the present capacity of the Ramu grid to serve the mines in terms of both amounts of electricity and reliability.** For purposes of least-cost generation modeling, these mining loads have been included in a scenario that considers only the most "probable" grid-supplied mines. Although categorized as "probable", actual grid supply would have to take place under PPAs in which the power supplier would secure long-term offtake necessary to underwrite the incremental costs of supply and the power purchaser would secure reliable supply to avoid the costs of self-generated power supply. Reaching commercial agreement with an appropriate allocation of risk may be challenging.

**A third subset of mines consists of those at various stages of planning which could, in favorable circumstances (positive outcomes of feasibility work and/or approval of permits) and with investment in extending the grid to those mines in the period up to 2030, be served by the Ramu or Port Moresby grids.** This group ranges from the Frieda River mine, which is subject to approval of permits but is quite distant from the Ramu grid and favors a hydro-generated solution, to several mining projects that can only be considered possible at this stage. For purposes of the least-cost generation modeling, these mining loads have only been included in a scenario that illustrates the potential outer boundary of mining loads on the 2030 power system planning horizon and has a low likelihood of eventuating.

**An assessment of the grid connection possibility for these existing and new mines is analyzed below:**

***Existing Mines***

- **Tolukuma: It cannot be connected at present as the grid infrastructure has not been extended to the mine gate.** Investment in a grid connection from Port Moresby to the mine would be costly due to difficult terrain and should be conditional (cannot be justified on its existing demand) on discovery of additional newer and larger ore deposits close to it.
- **Porgera: It cannot be connected at present as the grid infrastructure has not been extended to the mine gate and the grid does not have adequate transmission capacity (80 MW) to supply the mine.** Cheaper grid power would enable mining at low cut-off grade to extend the life of the mine. New exploration resource and cheaper grid power can assist in extending the life of the mine beyond 2021 to 2030 but it is also expected to lodge a lease renewal application to extend its life.
- **OK Tedi: The mine is about 350km from the main grid and supplied by its own captive plants.** Extending the grid could not be justified given the high cost of transmission.
- **Ramu Nickel: it can be connected at present but extension of the transmission line to the mine gate is needed.** Mine life to 2045.
- **Crater Mountain Mine: It cannot be connected at present as the grid infrastructure has not been extended to the mine gate.** The peak load of the mine is small (1MW), however, and the cost of grid infrastructure could not be justified until a larger resource is explored.

***New Mines***

- **Wafi-Golpu: It cannot be connected now as there is no grid infrastructure at the proposed mine gate and the current grid has insufficient capacity.** With grid infrastructure and cheaper (less than HFO) and reliable electricity supply, grid supply could be possible. A mining lease application has been submitted and the mine is planned from 2025 to 2050.
- **Frieda River: It cannot be connected now as there is no grid infrastructure at the proposed mine gate and the current grid has insufficient capacity.** With grid infrastructure and reliable electricity

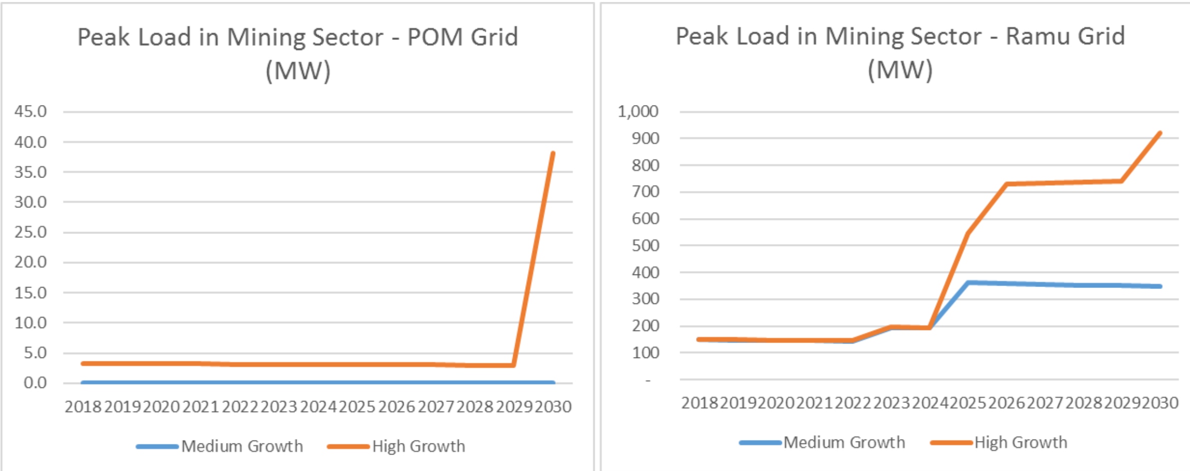
supply from the grid, grid supply could be possible. A mining lease application has been submitted but the project is isolated in a remote location. Mining planned from 2026 to 2050.

- **Yandera: It cannot be connected now as there is no grid infrastructure at the proposed mine gate and the current grid has insufficient capacity.** With grid infrastructure and reliable electricity supply, grid connection is possible. A feasibility study has not been completed and a mining lease application has not been submitted yet. Mining planned from 2024 to 2050 and beyond.
- **Kili Teke: It cannot be connected now as there is no grid infrastructure at the proposed mine gate and the current grid has insufficient capacity.** Grid connection is possible if grid infrastructure and reliable electricity supply are anticipated. The mine has a good porphyry deposit closer to potentially cheaper Highlands gas power. A feasibility study has not been completed and a mining lease application has not been submitted yet. Expected to commission in about 2030 or beyond for at least 25 years.
- **Mt. Kare: It cannot be connected now as there is no grid infrastructure at the proposed mine gate and the current grid has no capacity.** Grid connection is possible if grid infrastructure and reliable supply can be secured. The mine has a good high-grade gold deposit, prefeasibility has been completed and it is closer to the Hides-Porgera transmission line and potentially cheaper Highlands gas power but a mining lease application has not yet been submitted. Difficult to manage landowners' issues. Expected to commission in about 2030 or beyond for at least 25 years.
- **Mayur: It cannot be connected now as there is no grid infrastructure at the proposed mine gate and the current grid has no capacity.** Grid connection is possible if grid infrastructure and reliable supply can be secured. A feasibility study has not been completed and the mine is close to POM grid. A mining lease application has not yet been submitted. Expected to commission in about 2030 or beyond for 25 years.

**Based on the assessment of each mining project, two more scenarios were developed: (i) medium-growth mining; and (ii) high-growth mining.** In the medium-growth scenario, three mines are proposed to be connected–Porgera, Ramu Nickel and expansion, and Wafi-Golpu. In the high-growth scenario, seven additional mines are proposed to be connected–Tolukuma, Mayur, Crater Mountain, Frieda River, Yandera, Kili Teke, and Mt. Kare.

**Figure 1A.1 presents the peak load in the mining sector in both grids.** In the POM grid, no new mines are expected to be connected under the medium-growth scenario, while two mines are expected to be connected in the high-growth scenario, with their total peak load of 38 MW by 2030. In the Ramu grid, the peak load of connected mining projects would increase from 150MW in 2018 to 347MW in 2030 in the medium-growth scenario and to 921MW in 2030 in the high-growth scenario.

**Figure 1A.1: Peak Load in the Mining Sector**



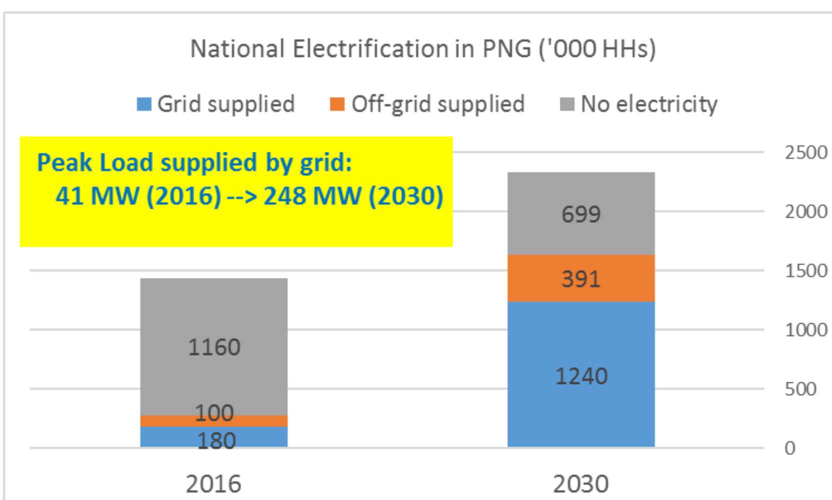

*Source:* World Bank staff.

## 2.2 NEROP

**The demand forecast for implementation of NEROP is based on a previous study (Earth Institute and Economic Consulting Associates 2017) that was financed by the World Bank.** Based on the NEROP study, the Government of PNG is considering achieving an electrification ratio of 70 percent by 2030, of which about 75 percent would be supplied by grid and the remaining households would be supplied by off-grid and mini-grid solutions.

**Under the NEROP study, the total number of households with access to electricity is expected to increase from 1,440,000 in 2016 (from a population of 7.63 million) to 2,330,000 in 2030 (of a population of 12.33 million).** According to the government plan, the peak load that could be supplied by the grid would increase from 41MW (2016) to 248MW by 2030–with an average annual growth rate of 13.8 percent (Figure 1A.2).

**Figure 1A.2: Evolution of HH Access to Electricity**



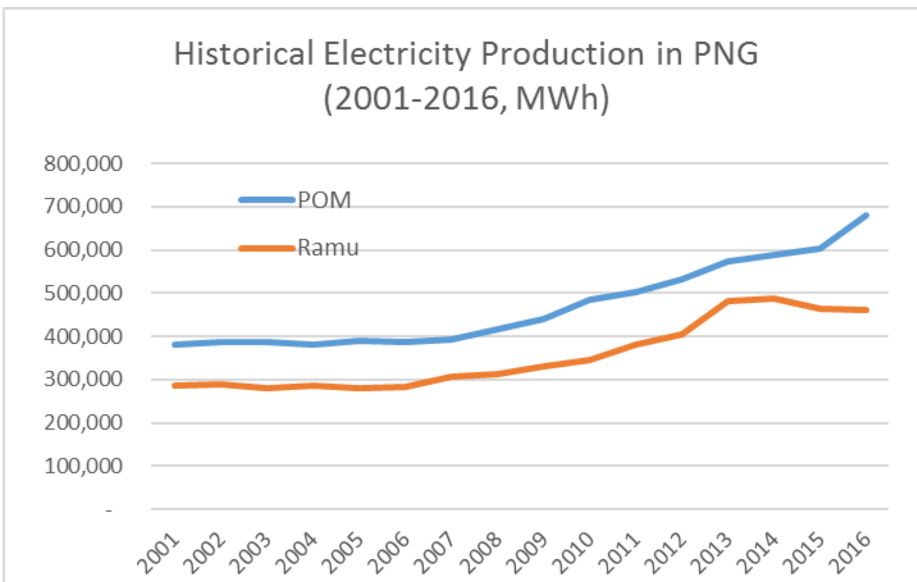

*Source:* World Bank staff.

**A less aggressive NEROP target was assumed with an electricity ratio reduced from 70 percent to 50 percent by 2030.** With the same share of grid-supplied electricity, the peak load of NEROP implementation to be supplied by the grid would increase from 41MW (2016) to 177MW by 2030, a reduction of 71MW in comparison to 248MW (2030) in BAU scenario. This less aggressive target is analyzed in sensitivity analysis.

## 2.3 Other Sectors

**Demand in other sectors is based on a review of PPL's forecast using a simple linear regression method based on historical electricity supply by PPL in both grids.** Figure 1A.3 presents the historical electricity consumption in both the POM and Ramu grids during 2001-16. There was limited demand growth during 2001-06–total production in both grids increased by 0.2 percent annually on average. Growth in demand was constant during 2006-16 with average annual growth rates of total production of 5.8 percent in the POM grid and 5.0 percent in the Ramu grid. This natural growth rate is expected to continue in coming years. The average annual growth rates of electricity consumption in the POM and Ramu grids for other sectors were assumed to be 5.0 percent and 4.5 percent respectively during 2016-30 with the peak load increasing from 123MW (2016) to 244MW (2030) in the POM grid and from 91MW (2016) to 169MW (2030) in the Ramu grid.

**Figure 1A.3: Historical Electricity Production in PNG**



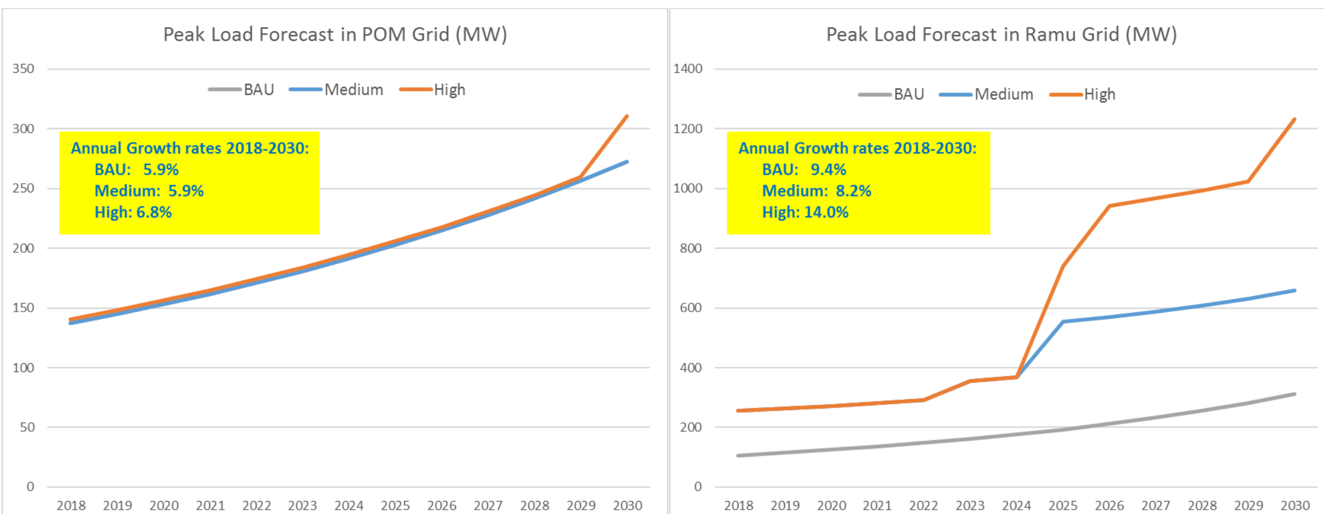

*Source:* World Bank staff.

## 2.4 Demand Forecast in POM and Ramu Grids

**Considering the demand forecast of the NEROP plan, expected projects in the mining sector, and demand growth for other sectors, plus the estimated line losses in both grids (currently about 25 percent and projected to decline to 15 percent by 2030), the resulting generation load and electricity supply in both systems are illustrated in Figure 1A.4.**

- **In the POM grid, the generation load would grow from 137MW (2018) to 273MW (2030) in both BAU and the medium-growth scenarios when no new mines would be connected into the grid**, with an average annual growth rate of 5.9 percent. The peak load would increase from 141MW (2018) to 311MW (2030) when both the Tolukuma and Mayur mines could be connected (an average annual growth rate of 6.8 percent).
- **In the Ramu grid, the generation load would grow from 106MW (2018) to 312MW (2030) in the BAU scenario when no new mines could be connected with an average annual growth rate of 9.4 percent.** Under the medium-growth scenario, the peak load could increase from 255MW (2018) to 659MW (2030) (an average annual growth rate of 8.2 percent) while under the high-growth scenario, the peak load would increase from 256MW (2018) to 1,233MW (2030) (an average annual growth rate of 14.0 percent).
- **In the Ramu grid, the mining sector will comprise a majority of the demand when mining projects are connected into the grid.** In the medium-growth scenario, the share of mining load would be 53 percent of total peak load in 2030 and, in the high-growth scenario, the share of mining load would increase to 75 percent of total peak load in 2030.

**Figure 1A.4: Aggregated Peak Load Forecast in PNG**




*Source:* World Bank staff.

**3. Existing Installed Capacity**

**By the end of 2017, the existing installed capacity amounted to 225MW in the POM grid (Table 1A.2) and 244MW in the Ramu grid (Table 1A.3).** Hydropower, gas (in POM only), diesel and fuel oil are the main type of power plants in both grids, of which both diesel and fuel oil-fired plants occupy a substantial share of the generation mix–57 percent in the POM grid and 51 percent in the Ramu grid.

**Table 1A.2: Installed Capacity in POM Grid**

| No. | Fuel | Plant Name | Installed Capacity | Available Capacity |
|---|---|---|---|---|
| | | | MW | MW |
| 1 | Hydro | Rouna_hydro | 63.5 | 41.4 |
| 2 | Hydro | Sirinimu | 1.5 | 1.0 |
| 3 | Hydro | Tolukuma_Mine_Captive | 5.0 | 5.0 |
| 4 | Gas | ExxonMobil_IPP | 27.0 | 26.0 |
| 5 | Fuel Oil | Moitaka_GT | 15.0 | 10.0 |
| 6 | Fuel Oil | Kanudi_GT1 | 15.0 | 11.0 |
| 7 | Fuel Oil | Kanudi_GT2 | 15.0 | 11.5 |
| 8 | Fuel Oil | Kanudi_GT3 | 26.3 | 23.0 |
| 9 | Diesel | Moitaka_HSD1 | 7.8 | 0.0 |
| 10 | Diesel | Moitaka_HSD2 | 7.8 | 0.0 |
| 11 | Diesel | Moitaka_HSD3 | 8.1 | 0.0 |
| 12 | Diesel | Moitaka_HSD4 | 8.1 | 0.0 |
| 13 | Fuel Oil | Kanudi_LFO1 | 12.5 | 10.0 |
| 14 | Fuel Oil | Kanudi_LFO2 | 12.5 | 10.0 |
| | | Total | 225.1 | 148.9 |

*Source:* World Bank staff.

**Table 1A.3: Installed Capacity in Ramu Grid**

| No. | Fuel | Plant Name | Installed Capacity | Available Capacity |
|---|---|---|---|---|
| | | | MW | MW |
| 1 | Hydro | Ramu1 | 77.4 | 27.0 |
| 2 | Hydro | Pauanda_hydro | 12.0 | 5.0 |
| 3 | Hydro | Baiune_hydro_IPP | 12.0 | 12.0 |
| 4 | Hydro | Yonki_Toe | 18.0 | 0.0 |
| 5 | Diesel | Taraka | 10.1 | 2.8 |
| 6 | Diesel | Dobel_leased | 6.0 | 4.3 |
| 7 | Diesel | Milford | 24.7 | 2.3 |
| 8 | Diesel | Madang | 16.8 | 6.9 |
| 9 | Diesel | Mendi | 1.5 | 0.0 |
| 10 | Diesel | Wabag | 2.6 | 1.2 |
| 11 | Diesel | Kundiawa | 1.4 | 1.4 |
| 12 | Diesel | Goroka | 3.0 | 2.4 |
| 13 | Fuel Oil | Lae_Gas_Turbine | 25.0 | 0.0 |
| 14 | Fuel Oil | Munum_IPP(Daewoo) | 33.6 | 31.2 |
| | | Total | 244.1 | 96.5 |

*Source:* World Bank staff.

**It should be noted that available capacity is quite low in PNG–the available capacity was only 66 percent of total installed capacity in the POM system and as low as 40 percent in the Ramu system.** Retirement of existing capacities are also considered based on consultation with PPL and economic life for different types of power plants (Exxon Mobil IPP, 2020; Moitaka GT, 2019; Kanudi LFO1 and LFO 2, 2020; Kanudi GT3, 2019; Lae GT, 2019; and diesel plants with five years economic life).

**4. Fixed Plants (Under Construction)**

**In the study, those power plants under construction are considered as fixed.** The plants include Edevu hydro 51MW (commissioned in 2022) and POM gas 57MW (commissioned in 2019). These two plants will be connected into the POM grid; and (ii) Baime hydropower expansion 10MW (to be commissioned in 2024) that will be connected into the Ramu grid.

**Other power plants–that have either been approved by the government or have signed a PPA with PPL–are considered as candidates but not fixed in the study.** These plants include: (i) Naoro Brown 80 MW (approved and connected to the POM grid); and (ii) Markham Valley Biomass (IPP) 30 MW (PPA signed) in the Ramu grid. These plants are considered as available generation options in the study.

**5. Generation Options**

**Based on discussions with PPL and other agencies and local experts in PNG, the following generation options are considered as feasible in both the POM and Ramu systems (Table 1A.4).**

**Table 1A.4: Feasible Generation Options in the POM and Ramu Systems**

| *Generation Option* | *POM System* | *Ramu System* | *Note* |
|---|---|---|---|
| New Hydropower | √ | √ | Naoro Brown, Ramu 2, Baime, Mongi_bulum, Kaugel, Gembogl, Frieda River. |
| Gas Turbine/Gas Engine | √ | √ | Rich gas resource in PNG. |
| Solar PV | √ | √ | Grid-connected concentrated solar projects, candidate is discussed in POM already. |
| Wind Farm | √ | √ | Resource is available although there is not much discussion in Ramu. |
| Biomass Power | - | √ | Proposal in Ramu, PPA signed. |
| Geothermal | - | √ | Northern PNG, possibly connected to Ramu system. |
| Coal-fired Power | - | √ | Candidate to be considered in Lae (Ramu system). |
| Diesel Engine | √ | √ | Existing, new capacity is feasible with imported diesel. |
| Fuel Oil-fired Generation | √ | √ | Existing, new capacity is feasible with imported fuel oil. |
| Fuel switch from oil fuel to gas | - | √ | Potential for Kanudi GT1 and GT2 (in POM) and Munum IPP in Lae (Ramu). |
| Hydropower Rehabilitation | √ | √ | The available capacities are only about 35-65% of installed capacities from existing hydropower stations. |

*Source:* World Bank staff.

**Preliminary analysis of power plants under construction and operation showed that the investment costs of power plants in PNG are much higher than other countries.** For example, the investment cost of a new gas power plant in Port Moresby based on Wartsila 34SG engines with an installed capacity of 57MW amounted to about $2,000.00/kW while it could be about $750.00/kW in Australia.

**The high investment costs could be caused by the small market in PNG, poor logistics, high land cost, lack of adequate competition, and poor project management (including procurement), so there is potential for cost reductions in PNG.** In the study, the investment costs of most generation options are based on international prices and adjusted by local costs (such as land). Sensitivity analyses are conducted to show the impacts of local high investment costs on the least-cost generation expansion plan.

## 5.1 New Hydropower and Rehabilitation

### *5.11 New Hydropower*

**PNG is a country with rich hydro resources so hydropower generation is a viable option for future planning and, based on consultation with PPL and information collected by the Bank team, the following new hydropower stations could be developed:**

- POM System:
    - Edevu Hydro 51MW, under construction (fixed);
    - Naoro Brown 80MW, approved already; and
    - Other hydropower projects–a maximum capacity of 1,000MW is assumed.

- Ramu System:
    - Baime Hydro expansion, 10MW, PPA signed with PPL and under construction (fixed);
    - Ramu 2 Hydro, 180MW, under discussion with KCH/PPL;
    - Mongi Bulum Hydro, 120MW;
    - Kaugel Hydro, 80MW;
    - Gembogl Hydro, 60MW;
    - Eddie Creek Hydro, 20MW;
    - Frieda River Hydro, 600MW;
    - Purari Hydro, 2,000MW;
    - Karamui Hydro, 1,800MW; and
    - ASAI, Hydro, 120MW (in Madang).

**Information was collected from PPL, feasibility study reports, and presentations of different stakeholders on the technical indexes that are considered for the new hydropower plants (Table 1A.5).**

**Table 1A.5: New Hydropower Generation Options**

| *Generation Option* | *Investment Cost ($/kW)* | *Capacity Factor (%)* | *Earliest Commissioning Year* |
|---|---|---|---|
| *Edevu Hydro* | *3,420* | *58* | *2022* |
| Naoro Brown * | 3,340 | 80 | 2023 |
| Ramu 2 | 4,933 | 75 | 2025 |
| Other new hydropower in POM ** | 3,500 | 65 | 2025 |
| Other new hydropower in Ramu ** | 5,000 | 75 | 2025-30 |

*Source:* World Bank staff.
*Note:* * Costs of both access road and grid connection are included. ** Investment costs of other new hydropower in both POM and Ramu grids were estimated by the task team based on limited available information of other hydropower projects (Edevu, Naoro Brown, Ramu 2).

*5.12 Rehabilitation of Existing Hydropower*

**A site visit to an existing hydropower station (Ramu 1) showed that potential exists to rehabilitate the existing hydropower stations.** This potential could be applied to Rouna, Ramu 1, Pauanda, and Yonki Toe hydropower stations. Based on discussions with PPL colleagues, the assumptions made for rehabilitation of existing hydropower stations are presented in Table 1A.6.

**Table 1A.6: Options for the Rehabilitation of Existing Hydropower Generating Stations**

| *Generation Option* | *Investment Cost ($/kW)* | *Increase of Available Capacity (MW)* | *Earliest Commissioning Year* |
|---|---|---|---|
| *Rouna Hydro Rehab.* | *530* | *22* | *2018* |
| Ramu 1 Hydro Rehab. | 291 | 50 | 2018 |
| Pauanda Hydro Rehab. | 556 | 6 | 2018 |
| Yonki Toe Hydro Rehab. | 370 | 18 | 2020 |

*Source:* World Bank staff.

## 5.2 Gas Power

*5.21 Gas Technologies*

**In PNG, two types of gas generation technologies have been applied–gas engine and gas turbine–with both gas technologies considered as candidates in the study.** Combined cycle is not considered as the growth of the power market in PNG will not be big enough (at least in the medium-growth scenario) to justify a combined cycle. The Bank team also collected information on the actual investment costs of gas-fired power plants in PNG. The major assumptions for both gas technologies and prevailing actual investment costs are considered in the sensitivity analysis (Table 1A.7).

**Table 1A.7: Options for Gas Engine and Turbine Generators**

| *Generation Option* | *Investment Cost ($/kW)* | *Average Gross Efficiency (%)* | *Reference Investment Cost in Australia and US ($/kW)* | *Local High Investment Costs ($/kW) for Sensitivity Analysis* |
|---|---|---|---|---|
| *Gas Engine in POM* | *1,321* | *47* | *1,300* | *1,914* |
| Gas Turbine in POM | 1,205 | 39 | 750-1,100 | 1,665 |
| *Gas Engine in Ramu* | *1,448* | *47* | – | *2,105* |
| *Gas Turbine in Ramu* | *1,321* | *39* | – | *1,832* |

*Source:* World Bank staff.
*Note:* * The investment costs of both gas turbine and gas engine in both US (published by EIA) and Australia (used in their planning) have been reviewed and used as reference to estimate the costs of gas power plants in PNG.

*5.22 Gas Prices*

**Gas prices derived from the international market are used in the study:**

- **POM: the gas price is assumed to be $6.75/mmbtu**, this is equivalent to an oil price of about $75.00/bbl
- **Ramu: the gas price is assumed to be $4.25/mmbtu in the Highlands area (Hides) where gas is produced and $11.50/mmbtu for LNG in the coastal area (Lae).**

Regarding uncertainty in the gas price, a sensitivity analysis was conducted to assume an oil price of $100.00/bbl–equivalent to a gas price of $9.00/mmbtu in POM, $6.50/mmbtu in the Highlands area (Hides), and $15.00/mmbtu for LNG in Lae.

*5.23 Gas Availability*

**Gas availability was based on a probable LNG project development outlook and the government's preliminary proposal in the draft Gas Policy White Paper for a 15 percent domestic reservation of export gas (see Appendix Five).** This limitation was considered in the model.

## 5.3 Wind Power

**The size of the grids and road conditions would not allow PNG to have large projects (50MW+) with very big turbines (blades larger than 90m and turbines higher than 120m).** From discussions with PPL colleagues, one wind farm site (20MW) has been identified in POM and there is also a potential area to install a wind farm in the Ramu grid. In the BAU case, the 20MW and an additional 50MW are considered as candidates in POM and 30MW is considered in Ramu. In the sensitivity case, total possible installed capacity for wind power is assumed as 500MW in each of POM and Ramu.

**No wind farm has yet been installed in PNG, although a wind resource mapping study that is financed by the World Bank is being conducted.** An international comparison has, therefore, been conducted to estimate the investment cost of wind farms in PNG. Engineering, Procurement and Construction (EPC) prices in other countries (Indonesia and the Philippines) for similar size wind power projects are used as reference prices in PNG, adjusted by local costs.

**The following assumptions are used for wind power in both the POM and Ramu grids:**

- **Investment Cost: $1,616.00/kW in POM and $1,776.00 in Ramu.**
- **Capacity Factor: 35 percent.**
- **Firm Capacity: The capacity factor (35 percent) has been applied to assume 35 percent of installed capacity is firm capacity.**

Like gas power, potential actual higher investment costs can be foreseen. There has been an international trend towards reduced costs in the past few years. Both low- and high-cost scenarios are, therefore, considered in the sensitivity analysis–$1,200.00/kW and $2,000.00/kW respectively.

### 5.4 Solar PV

**In PNG, distributed solar PV has been installed as an off-grid solution to supply electricity in rural areas.** There are, however, no grid-connected concentrated solar PV farms, although solar resource mapping work is being conducted and financed by the World Bank.

**Based on preliminary results and comparison to similar small-scale solar PV projects in other countries, the following assumptions are used for solar PV in both the POM and Ramu grids:**

- **Investment Cost: $977.00/kW in POM and $1,072.00 in Ramu.**
- **Capacity Factor: 18.5 percent.**
- **Firm Capacity:** The capacity factor (18.5 percent) has been applied to assume 18.5 percent of installed capacity is firm capacity.

Like wind power, potential actual higher investment costs can be foreseen. There has been an international trend towards reduced costs in the few past years. Both low- and high-cost scenarios are, therefore, considered in the sensitivity analysis–$800.00/kW and $1,300.00/kW respectively.

**As a result of discussions with PPL colleagues, one site of solar PV (30MW) has been identified near Port Moresby airport in POM and sites are also available in the Ramu grid.** In the BAU case, 30MW and an additional 50MW are considered as candidates in the POM grid while 30MW is considered in the Ramu grid. In the sensitivity case, total possible installed capacity for solar PV is assumed as 500MW in each of the two grids.

### 5.5 Biomass Power

**A proposal was received by PPL and a PPA has been signed to develop a biomass power plant (30MW) in Ramu, so this candidate is considered in the study.**

**The following assumptions are made based on information collected and a comparison to biomass power projects in Australia:**

- **Investment Cost: $5,143.00/kW, including plantation, a high cost of $6,140.00/kW is considered in the sensitivity analysis.**
- **Gross Efficiency: 25 percent or 13.5 mmbtu/MWh.**
- **Variable Cost Related to Fuel Supply: $0.01/kWh.**

### 5.6 Coal-fired Generation

**A proposal is under discussion to develop a coal-fired power plant (50MW) in Lae.** The Bank team does not have detailed information on the project.

**Based on a comparison of coal-fired power projects in Australia and the USA, the following assumptions were used:**

- **Investment Cost: $3,049.00/kW.**
- **Gross Efficiency: 25 percent or 13.5 mmbtu/MWh**, considering its small size.
- **Coal Price: $4.74/mmbtu, equivalent to a coal price of $100.00/tonne in Australia.**

### 5.7 Geothermal

**In Ramu, geothermal resources could be developed for power generation.** As there is no available information in PNG, however, the Bank team used data from Indonesia where actual geothermal power plants have been built, made minor adjustments and has assumed an investment cost for geothermal of $6,100.00/kW.

### 5.8 Diesel Generators

**The Bank team reviewed the actual operational costs of existing diesel generators, and used the following assumptions:**

- **Investment Cost: $929.00/kW.**
- **Gross Efficiency: 26 percent or 13.1 mmbtu/MWh.**
- **Diesel Price: $21.00/mmbtu, equivalent to about K 2.30/liter (the average price in PNG in 2017).**

### 5.9 Fuel Oil-fired Plants

**The following assumptions were used for new fuel oil-fired power plants:**

- **Investment Cost: $2,349.00/kW in POM, $2,579.00 in Ramu.**
- **Gross Efficiency: 32 percent or 10.5 mmbtu/MWh.**
- **Price of Fuel Oil: $18.90/mmbtu.**

**Given that LNG is available in Lae, it is possible to switch the fuel of two existing fuel-oil fired plants (Lae Gas Turbine 25MW, Munum IPP 33.6MW) in Lae from fuel oil to LNG as the price of LNG is lower.** A fuel switch for existing fuel oil-fired plants is also considered as an option.

## 6. Carbon Emission Factors

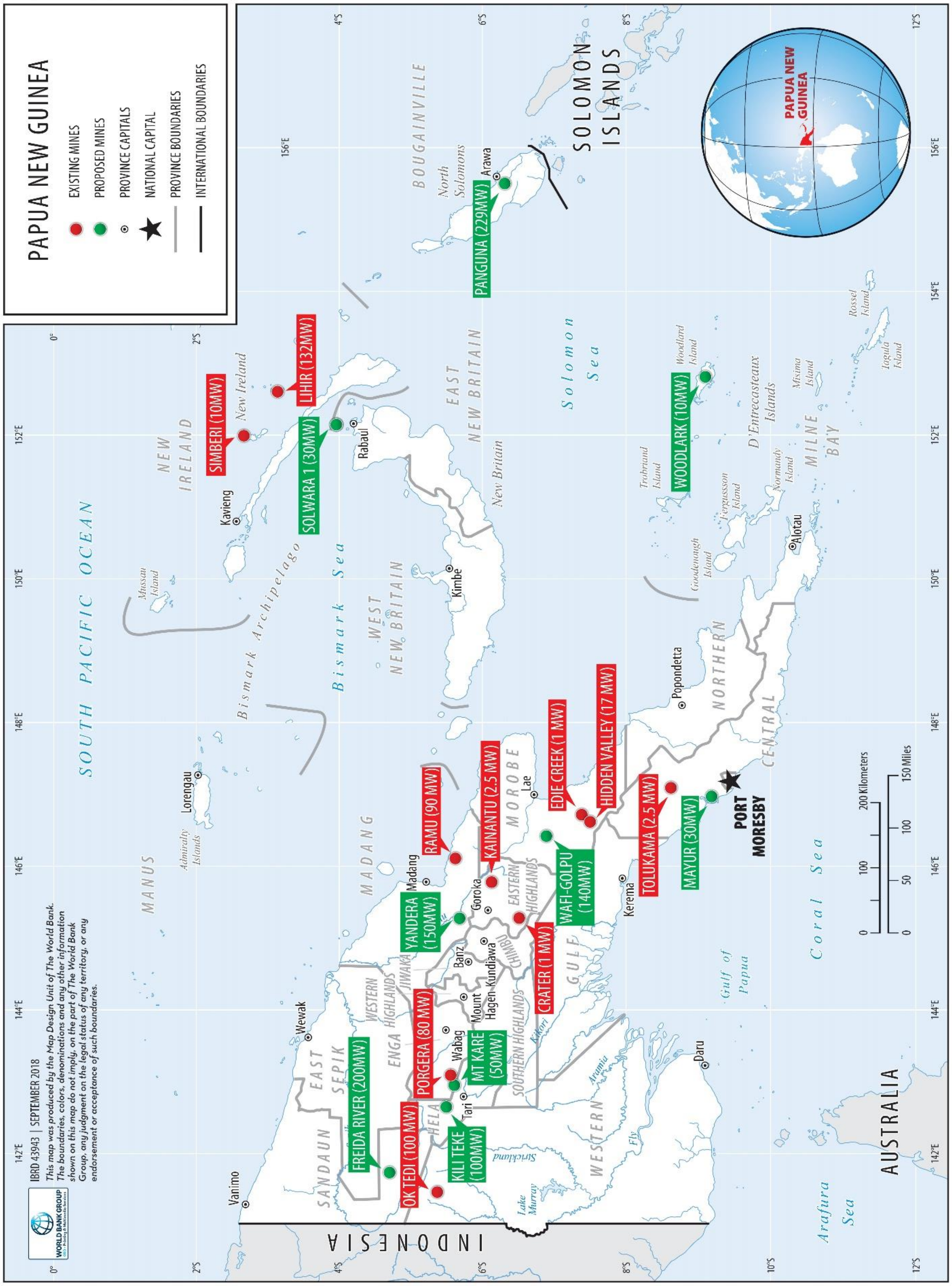
**The following carbon emission factors are applied for fossil fuel-fired generation options:**

**Table 1A.8: Emission Factors for Fuel (Kg/mmbtu)**

| Fuel Type | $CO^2$ |
|---|---|
| Gas/LNG | 53.1 |
| Fuel Oil | 75.1 |
| Coal | 95.6 |
| Diesel | 73.3 |

*Source:* US Environmental Protection Agency.

## Appendix Two: Location of Mining Sites



## Appendix Three: Information on Optimization of Transmission Systems

**Transmission system optimization aims to meet the requirement of delivering electricity from power plants to customers in targeted PNG grids by considering the generation mix to meet projected demand and geographical location by 2030.** This section focuses on only two major grids–namely POM and Ramu–which represent about 90 percent of PNG's peak demand and 95 percent of its sold electricity by volume. Each grid is connected by a transmission system as an independent grid.

**The POM system covers mainly Port Moresby's City Center, the Bay Area, LNG plant area, and hydro power area along the Rouna River basin.** The 66kV line is a main transmission system, and major load centers (City Center area and Bay Area) are well connected because each major substation is fed by at least a double-circuit (DC) line and these form a loop network. Most major thermal plants are, and will be, located in the Bay Area where it is easy to access this loop. Hydropower plants and gas generators at LNG plant are connected through a transmission line to transfer generated power to load centers through radial connection.

**The Ramu system covers the Lae area (Lae Port and Lae City Center and Suburbs), Madang area (Northeast Coastal area), and Highlands area (Middle to Northwest mountain area).** The transmission system in the Ramu Grid consists of 132kV and 66kV and network configurations are the main South–North (that is, Lae to Madang) network whose voltage level is 132kV and 66kV, and Middle–Northwest (that is, from the middle point of the South–North network to Highlands network) network whose voltage level is 66kV, likely to a 90-degree right rotated "T" shape. There is a radial network only and most of the transmission route consists of a single-circuit (SC) line.

**As the transmission system is much longer than that of the POM grid, the Ramu grid has already introduced a 132kV system but the Highlands area suffers from voltage quality because this area is mainly supplied by a long 66kV SC line.** The major load center is the Lae area and potential huge load centers are mining fields in the Highlands area. Most thermal power plants are in Lae and others are in Madang but the major power sources are the Ramu 1 hydropower plant (HPP) and Yonki Toe of Dam (Yonki TOD) HPP which are closely located at the branch point of the South–North network and Middle–Northwest network.

*Highlights of the Study: POM System*

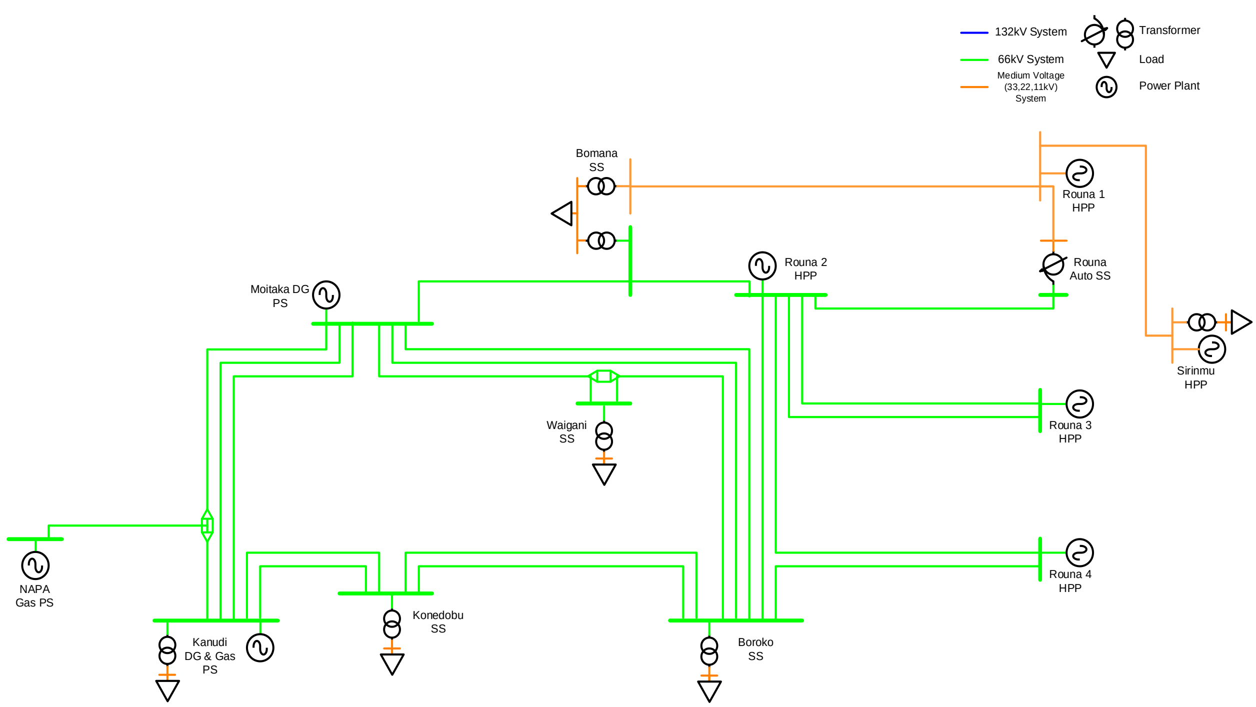
**The POM grid expects a continuous increase in demand in the City Center and Bay area.** A 66kV transmission line is already well shaped but expansion of transformers at existing substations, a new substation, and line conductor replacement in particular sections will be needed at an appropriate time. The transmission system plan is, therefore, relatively straightforward as it captures demand growth and generation development and this study considers various development options for the POM grid.

**In regard to generation development, there are some large power plants committed and expected.** For the gas power plant in the Bay area, a well-configured 66kV network already exists nearby–only a short connection to the existing substation is required. For utility-scale PV plants around the airport, 66kV lines to the nearby substation are appropriate. As the potential location for a wind farm is the north area of the LNG processing plant field, a 66kV line to the wind farm's concentration substations is necessary. For hydropower, relatively large-scale HPPs are envisaged in the Brown River basin–namely the Edevu HPP and Naoro Brown HPP, while further potential HPP is also expected in the Brown River Cascade.

**Based on the technical limitations of plant location, load center location, and amount of transferred power, a 132kV-level transmission system must–like the Ramu grid–be introduced in the POM grid.** The largest possible mining load is Mayur Limestone which is located northwest of the LNG processing plant in the high-growth scenario. The 66kV extension from the LNG plant substation to this mining site is, therefore, the shortest and least-cost option to transfer power to the grid.

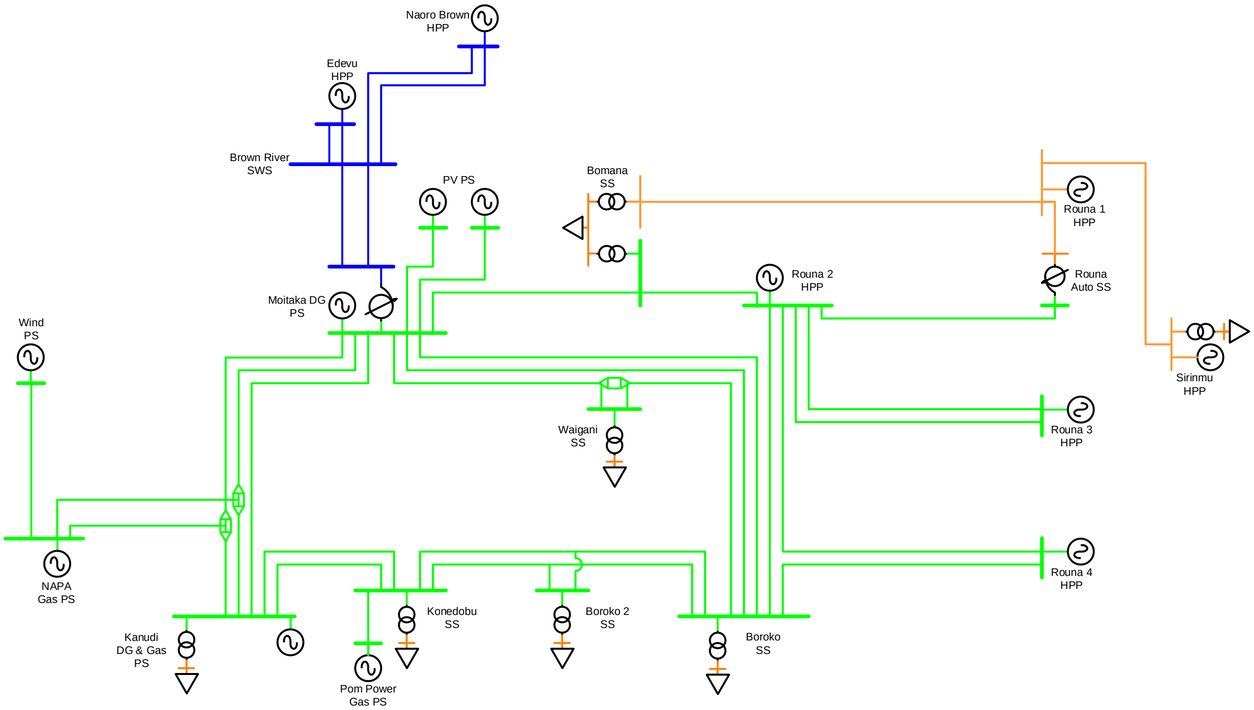
**On the other hand, while residential, commercial, and industrial demand will grow and require an expansion in the transmission network, the mining load will not exist nor be connected to the grid in either the BAU or medium-growth scenarios.** Figure 3A.1 presents the current POM transmission system, Figure 3A.2 presents the anticipated one for the BAU and medium-growth scenarios by the early 2030s and Figure 3A.3 for the high-growth scenario.

### Figure 3A.1: Current POM Grid



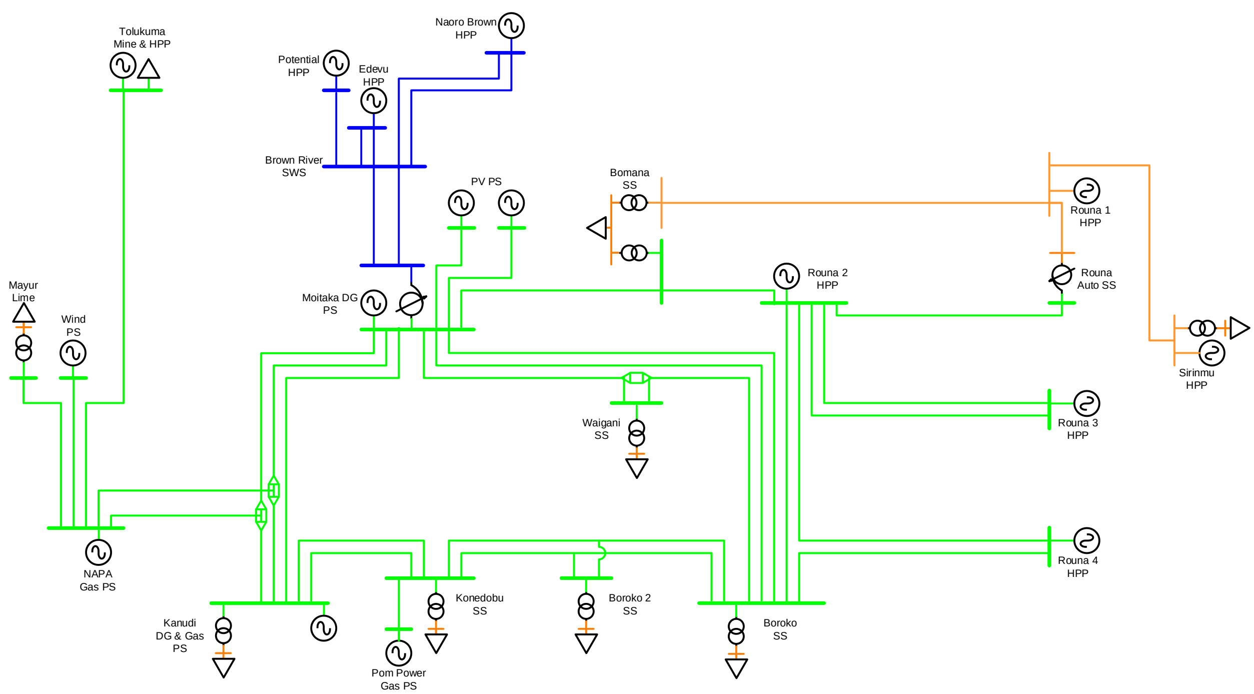

*Source:* World Bank staff.

## Figure 3A.2: POM Grid by Early 2030s (BAU and Medium-growth Scenario)




*Source:* World Bank staff.

## Figure 3A.3: POM Grid by Early 2030s (High-growth Scenario)




*Source:* World Bank staff.

**Table 3A.1 shows the estimated investment cost for the POM transmission system in the BAU and medium-growth scenarios and Table 3A.2 for the high-growth scenario for three timelines.**

**Table 3A.1: Estimated Investment Cost for the POM Transmission System (BAU and Medium-growth Scenario)**

| Project | Early 2020s | Mid 2020s | Early 2030s | Total |
|---|---|---|---|---|
| **Projects for** 66kV Substation[57] | **7.1** | **7.5** | **7.5** | **22.1** |
| **Projects for** 132kV Substation | n.a. | 21.2 | n.a. | 21.2 |
| **Projects for** 66kV Transmission Line | 0.1 (SC:1km) | 3.5(SC:46km,DC:5km) | n.a. | 3.6(SC:37km, DC:5km) |
| **Projects for** 132kV Transmission Line | n.a. | 35.1 (DC:95km) | n.a. | 35.1 (DC:95km) |
| **Total** | **7.2** | **67.3** | **7.5** | **82.0** |

*Source:* World Bank staff.
*Note:* (i) Unit: Millions of $; SC: Single Circuit; DC: Double Circuit. (ii) n.a. means there are no projects planned for the relevant period.

**Table 3A.2: Estimated Investment Cost for the POM Transmission System (High-growth Scenario)**

| Project | Early 2020s | Mid 2020s | Early 2030s | Total |
|---|---|---|---|---|
| **Projects for** 66kV Substation[58] | **7.1** | **7.5** | **7.6** | **22.2** |
| **Projects for** 132kV Substation | n.a. | 21.2 | 0.1 | 21.3 |
| **Projects for** 66kV Transmission Line | 16.7 (SC:121km) | 6.9 (SC:46km, DC:5km) | 1.4 (SC:10km) | 25.0 (SC:177km, DC:5km) |
| **Projects for** 132kV Transmission Line | n.a. | 35.1 (DC:95km) | 14.8 (SC:60km) | 49.9 (SC:60km, DC:95km) |
| **Total** | **23.8** | **70.7** | **23.9** | **118.4** |

*Source:* World Bank staff.
*Note:* (i) Unit: Millions of $; SC: Single Circuit; DC: Double Circuit. (ii) n.a. means there are no projects planned for the relevant period.

*Highlights of the Study: Ramu System*

**The Ramu grid expects a continuous increase in demand in the commercial, industrial (except mining), and residential sectors along with nationwide electrification.** To improve reliability and quality of power transfer from major HPPs to the Lae area, the 132kV transmission system expansion will be completed soon and, for the purpose of system strengthening to accommodate mining sector development, the first phase of installation of a 132kV system in the West Highland area is underway and will soon be completed.

**The Lae area is one of the main load centers in the Ramu grid and, while a 132kV transmission system is already operating, expansion to two main substations, namely Taraka and Milford which house diesel generator sets (to be decommissioned) will be necessary in line with demand growth.** One option is the simple expansion in existing two substations because there will be enough space after diesel generators

[57]This includes MV feeder expansion to connect feeders from substations to redistribute the MV network to balance two substations' load.
[58]This includes MV feeder expansion to connect feeders from substations to redistribute the MV network to balance two substations' load.

decommissioning. The other option is to construct a new 132kV substation near Taraka. For the Madang area, growth is moderate and expected peak demand can be covered by using the existing 66kV transmission system, while expansion is considered for the substation that is capable of coping with demand growth in this area.

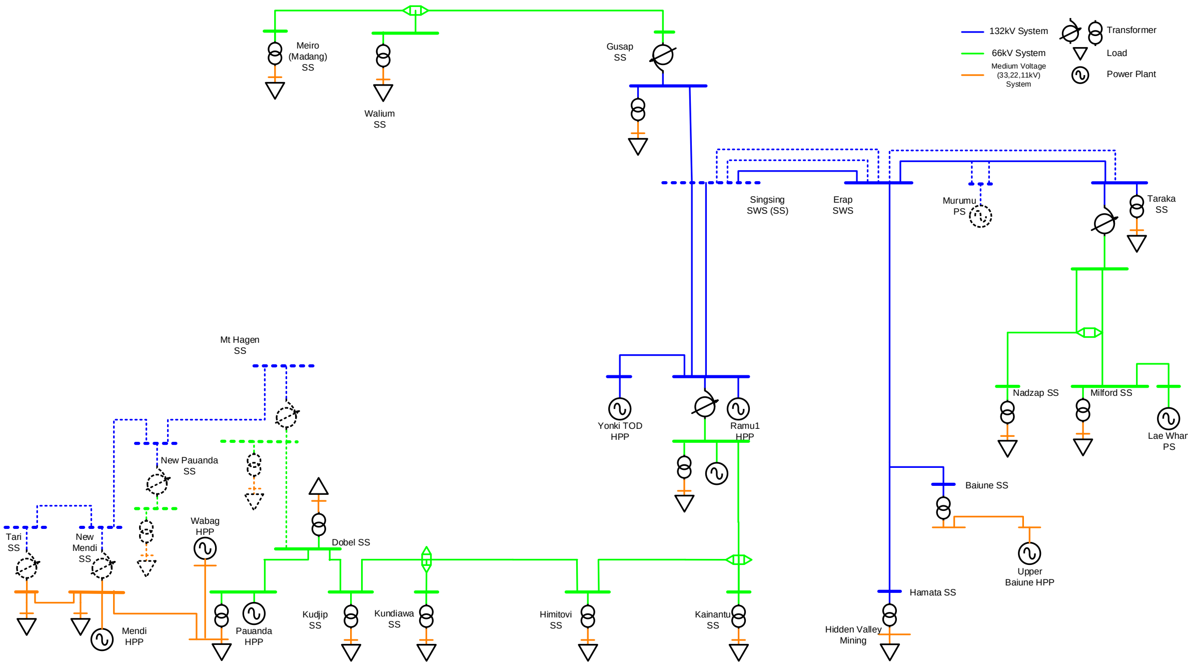
**For household and normal industrial load in the Highlands area, the existing 66kV system–which will be reinforced by the committed 132kV system expansion from the western side–will be able to handle future demand but an additional new 66kV substation on the eastern side of the existing grid will be required.** By considering: (i) the future demand of the mining and gas processing sectors in the Highlands area; (ii) the necessity for better reliability and quality of supply; and (iii) the potentially large hydropower and gas generation capacity, the Northern Arc Corridor should be considered to connect the Highlands area and the northern end of the existing 132kV South–North route directly. As a result, the Ramu grid will form a large loop network in the center area.

**Technically speaking, one higher-level voltage system will be needed in some cases in the future–a long transmission line with larger capacity–especially to accommodate the Western Highlands area's development of mining, gas-fired, and hydro generation.** This study, therefore, sets 230kV as the next system voltage level because it is common internationally. For this transmission system in the Western Highlands, two options are examined in the high-growth scenario. One is an early introduction of a 230kV line, whereas the other is a late introduction of the same line.

**Regarding generation development, there are some large power plants committed and expected, however, the locations are scattered in and beyond the Ramu grid.** Furthermore, expected installed capacities are relatively large. It is assumed that most HPPs and thermal power plants will be connected by extending the existing 132kV system. For the Frieda River HPP–which will be developed with Frieda River mining–the expected distance to the existing MV grid is, however, about 350km and expected installed capacity is 400MW, some of which will be consumed by the onsite mining plant. For the Karamu HPP–which is the first phase of the Wabo HPP (2,000MW class)–the expected distance to the existing key 132kV station is about 180km. Due to technical limitations of the 132kV system, a 230kV system has to connect both HPPs to the transmission grid if they are developed in the high-growth scenario.

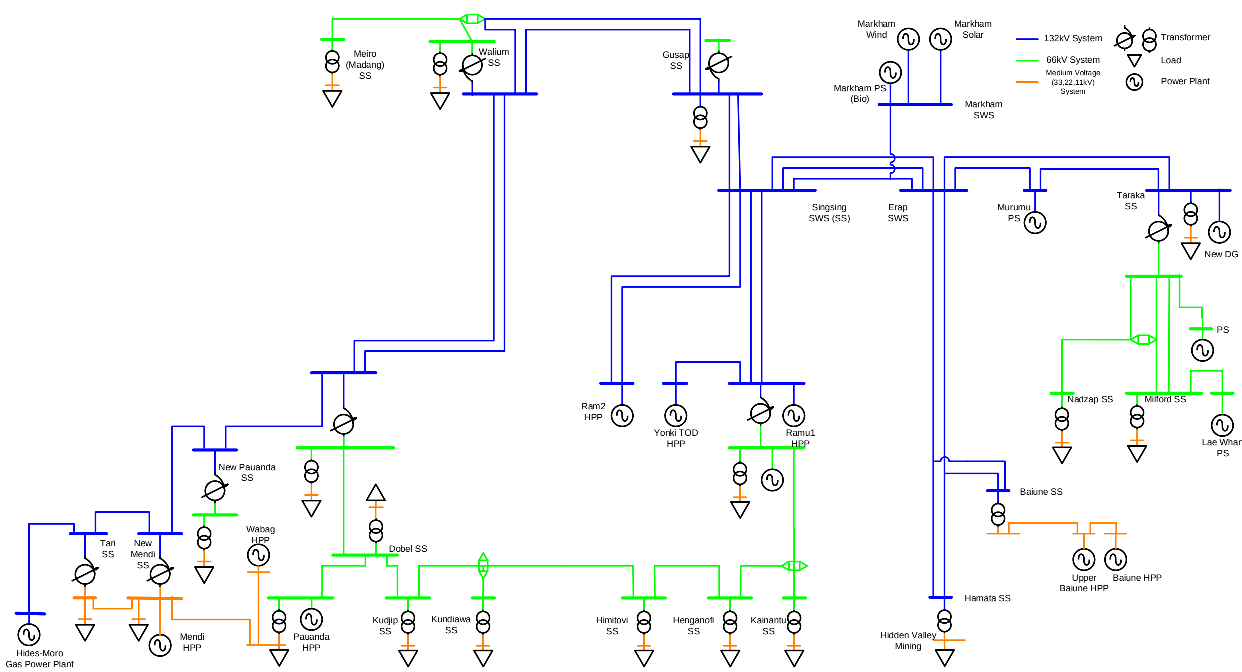
**The medium-growth scenario expects the connection of the Porgera, Ramu Nickel and Cobalt (at its mining site and associated refinery facility in the coastal area), and Wafi-Golpu mines.** Scenario-oriented Ramu grid expansion plans have, therefore, been developed. Many mining sites will be supplied by extension of the existing 132kV or 66kV transmission system–except Yandera Gold in the high-growth scenario because the site location is close to the envisaged Northern Arc Corridor and its load can be supplied by either a 132kV or 230kV system. Figure 3A.4 presents the current Ramu transmission system, while Figures 3A.5, 3A.6, 3A.7.1 and 3A.7.2 present the BAU, medium-growth, and high-growth scenarios respectively by the early 2030s.

## Figure 3A.4: Current Ramu Grid



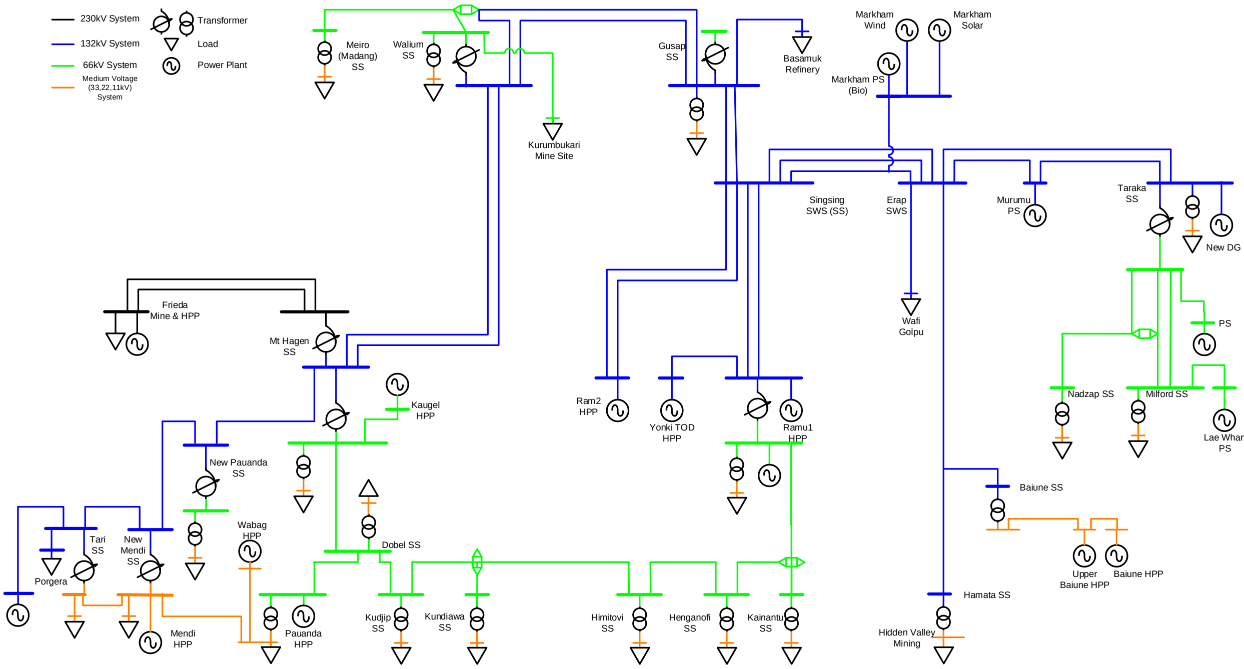

*Source:* World Bank staff.

## Figure 3A.5: Ramu Grid in Early 2030s in BAU Scenario



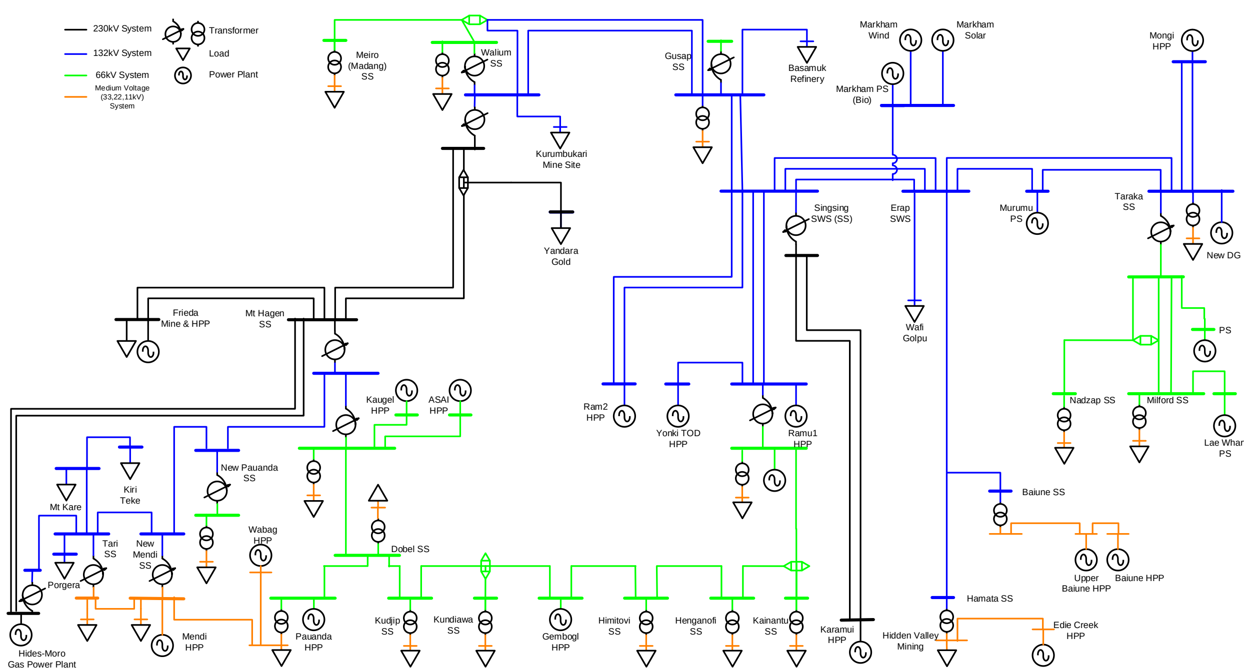

*Source:* World Bank staff.

## Figure 3A.6: Ramu Grid in Early 2030s in Medium-growth Scenario



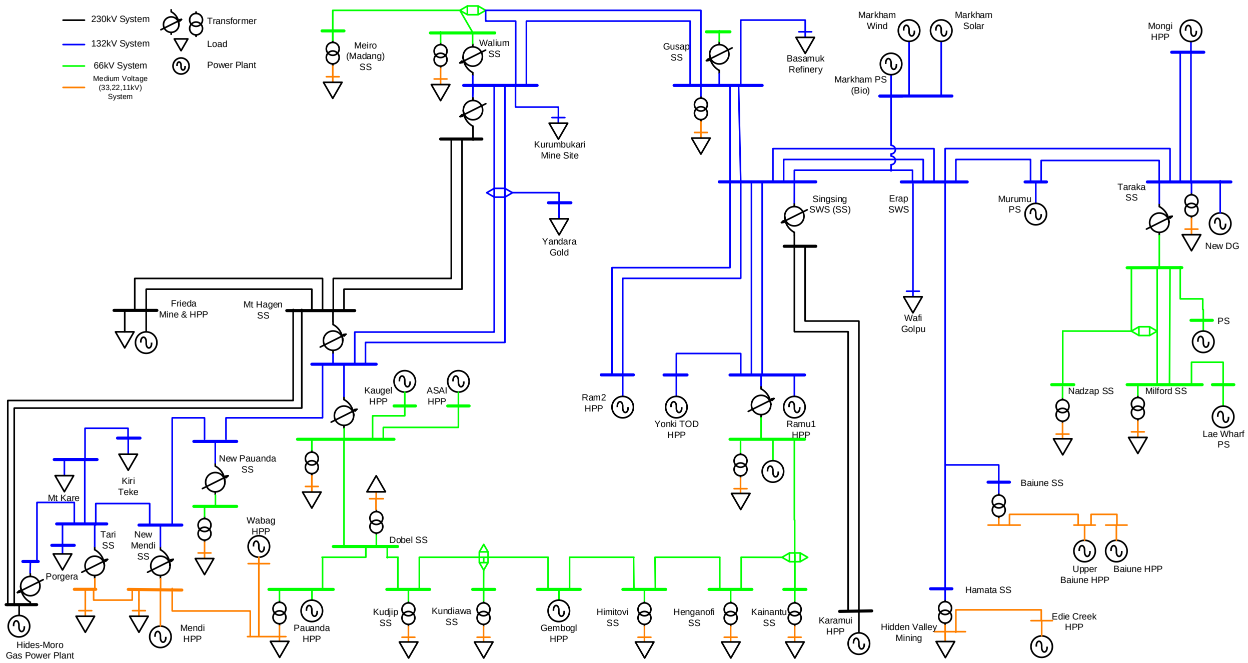
*Source:* World Bank staff.

## Figure 3A.7.1: Ramu Grid in Early 2030s in High-growth Scenario (Early 230kV Introduction Case)



*Source:* World Bank staff.

## Figure 3A.7.2: Ramu Grid in Early 2030s in High-growth Scenario (Late 230kV Introduction Case)




*Source:* World Bank staff.

**Tables 3A.3-3A.6 show the estimated investment costs of the Ramu grid in each scenario for three timelines.**

### Table 3A.3: Estimated Investment Cost for the Ramu System in BAU Scenario

| Project | Early 2020s | Mid 2020s | Early 2030s | Total |
|---|---|---|---|---|
| **Projects for 66kV Substation** | **4.9** | **9.5** | **4.1** | **18.5** |
| **Project for 132kV Substation** | 18.9 | 11.3 | 23.3 | 53.5 |
| **Project for 66kV Transmission Line** | 8.9 (SC:40km) | 1.6 (DC:8km) | n.a. | 10.5 (SC:40km, DC:8km) |
| **Project for 132kV Transmission Line** | 152.1 (SC:206km, DC:190km) | 24.5 (SC:90km) | 7.3 (DC:18km) | 183.9 (SC:296km, DC:208km) |
| **Total** | **184.8** | **46.9** | **34.7** | **266.4** |

*Source:* World Bank staff.
*Note:* (i) Unit: Millions of $; SC: Single Circuit; DC: Double Circuit. (ii) n.a. means there are no projects planned for the relevant period.

**Table 3A.4: Estimated Investment Cost for the Ramu System in Medium-growth Scenario**

| Project | Early 2020s | Mid 2020s | Early 2030s | Total |
|---|---|---|---|---|
| **Projects for 66kV Substation** | 4.9 | 9.5 | 4.3 | 18.7 |
| **Project for 132kV Substation** | 18.5 | 11.3 | 25.6 | 55.4 |
| **Project for 230kV Substation** | n.a. | 16.9 | n.a. | 16.9 |
| **Project for 66kV Transmission Line** | 8.9 (SC:40km) | 1.6 (DC:8km) | 3.7 (DC:20km) | 14.2 (SC:40km, DC:28km) |
| **Project for 132kV Transmission Line** | 122.2 (SC:95km, DC:190km) | 65.0 (SC:212km, DC:18km) | n.a. | 187.2 (SC:418km, DC:208km) |
| **Project for 230kV Transmission Line** | n.a. | 261.0 (DC:350km) | n.a. | 261.0 (DC:350km) |
| **Total** | **154.5** | **365.3** | **33.6** | **553.4** |

*Source:* World Bank staff.
*Note:* (i) Unit: Millions of $; SC: Single Circuit; DC: Double Circuit. (ii) n.a. means there are no projects planned for the relevant period.

**Table 3A.5: Estimated Investment Cost for the Ramu System in High-growth Scenario (Early 230kV Installation)**

| Project | Early 2020s | Mid 2020s | Early 2030s | Total |
|---|---|---|---|---|
| **Projects for 66kV Substation** | 4.9 | 9.7 | 4.2 | 18.8 |
| **Project for 132kV Substation** | 9.9 | 11.3 | 25.9 | 47.1 |
| **Project for 230kV Substation** | 33.9 | 42.0 | 16.9 | 92.8 |
| **Project for 66kV Transmission Line** | 8.9 (SC:40km) | 5.4 (SC:28km, DC:4km) | 3.0 (DC:20km) | 17.3 (SC:68km, DC:24km) |
| **Project for 132kV Transmission Line** | 29.8 (SC:95km) | 65.0 (SC:212km, DC:18km) | 60.2 (SC:85km, DC:80km) | 155.0 (SC:392km, DC:98km) |
| **Project for 230kV Transmission Line** | 79.2 (SC:190km) | 533.0 (SC:225km, DC:590km) | 134.0 (DC:180km) | 746.2 (SC:415km, DC:780km) |
| **Total** | **166.6** | **666.4** | **244.2** | **1,077.2** |

*Source:* World Bank staff.
*Note:* Unit: Millions of $; SC: Single Circuit; DC: Double Circuit.

**Table 3A.6: Estimated Investment Cost for the Ramu System in High-growth Scenario (Late 230kV Installation)**

| Project | Early 2020s | Mid 2020s | Early 2030s | Total |
|---|---|---|---|---|
| **Projects for 66kV Substation** | 4.9 | 9.7 | 4.3 | 18.9 |
| **Project for 132kV Substation** | 18.9 | 11.3 | 25.9 | 56.1 |
| **Project for 230kV Substation** | n.a. | 64.4 | 16.9 | 81.3 |
| **Project for 66kV Transmission Line** | 8.9 (SC:40km) | 2.4 (SC:8km, DC:4km) | 3.7 (DC:20km) | 15.0 (SC:48km, DC:24km) |
| **Project for 132kV Transmission Line** | 152.3 (SC:206km, DC:190km) | 74.5 (SC:247km, DC:18km) | 60.2 (SC:85km, DC:80km) | 287.0 (SC:538km, DC:288km) |
| **Project for 230kV Transmission Line** | n.a. | 652.0 (SC:170km, DC:780km) | 134.0 (DC:180km) | 786.0 (SC:170km, DC:960km) |
| **Total** | **185.0** | **814.3** | **245.0** | **1,244.3** |

*Source:* World Bank staff.
*Note:* (i) Unit: Millions of $; SC: Single Circuit; DC: Double Circuit. (ii) n.a. means there are no projects planned for the relevant period.

## Appendix Four: Preliminary Assessment of Uses of Gas

**There are numerous potential uses of gas for which there can be substantial economic and social benefits, including in meeting national climate obligations.** A gas resource base of the size found in PNG could allow for a variety of uses of gas aside from gas-to-power.

**This appendix contains an initial screening of all possible gas monetization options and is organized to address the three main categories of gas use:**

- **Extraction of premium products:** Apart from methane, raw wellhead gas contains components such as ethane, propane, butane, and pentane which may be worth more when they are extracted from the gas and sold separately than when they are left inside the gas and sold against their heating value. When maximizing the value of natural gas for the country, the first question to ask is whether to invest in extraction and processing facilities to monetize such premium products.
- **Domestic use of gas for generating affordable heat and power:** In many cases natural gas may serve as a cheap fuel that may be used to generate cheap power and heat for local industry and for the local population, thereby providing the basis for economic growth through competitiveness and greater prosperity. Before considering the export of gas and gas-based products, a government should ask how a natural gas endowment may be deployed to boost growth of the local economy.
- **Gas-based export to bring in foreign currency:** Export of gas and gas-based products has the potential to generate a lot of revenues and bring in significant foreign currency which, in its turn, may be used to invest in infrastructure and education and to sponsor the development of economic activity outside of the mining sector.

***Category One: Extraction of premium products to maximize value at the source***

Condensate: **Natural gas is a mix of gas and condensate which may be separated from the gas at the source and sold as a premium product–typically priced at par with gasoline.** For operational reasons, natural gas must be "dry", that is, condensate must be taken out for long-distance pipeline transport (more than 100 km).

☑ **Separation of condensate from wellhead gas is best practice in PNG today.** For example, PNG LNG separates condensate from gas in the Hides Gas Conditioning Plant for export through a dedicated liquid pipeline.

**Liquefied Petroleum Gas (LPG) Extraction: Natural gas contains propane and butane–collectively known as LPG–which may be extracted from the gas and sold as a premium product.** LPG is mainly used for cooking and as motor fuel but it may also be used as fuel for decentralized power generation, particularly in remote areas. LPG has a much higher value as a separate product than when combined with gas and is typically priced at par with kerosene. Extraction of LPG, or "deep extraction" involves cooling down the gas which is more expensive than condensate separation that is based on gravity.

*LPG extraction lowers the heating value of gas, therefore, enough LPG must stay behind in the gas so that it can be used for LNG production.*

☑ **PNG currently uses approximately 11,000 tonnes per year of imported LPG, particularly for cooking.** LPG can be an attractive fuel for decentralized, captive power generation and may be used as a transition fuel in the power sector for natural gas. Furthermore, using domestically sourced LPG would provide an opportunity to reduce the price of LPG and improve the balance of payments for the country.

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| **Case Study:** Origin, the largest LPG distributor in PNG, plans to supply LPG to Tier 2 IPP projects–that is, IPP projects outside the POM and Ramu grid areas. They also have plans to use existing supply chains to supply LPG to decentralized community grids to help electrify rural areas. |

<u>Ethane Cracking:</u> **Natural gas contains ethane which is an important feedstock for production of plastics (ethylene, propylene, and derivatives).** Development of a gas-based petrochemical sector holds the potential for significant job creation, particularly the further downstream processing goes. On the other hand, a world-scale ethane cracker would require a minimum of approximately 150 mmcfd of ethane for a minimum of 25 years. This means that one would need to produce and source 3 bcfd of raw gas on the assumption that the ethane content is 5 percent.

*Ethane extraction lowers the heating value of gas, therefore, enough ethane must stay behind in the gas so that it can be used for LNG production.*

☒ **Based on a high-level review of gas resources in PNG, gas production may reach a plateau of 2 bcfd for at least 25 years, which means that there would not be enough ethane available in the right place, at the right time to feed a world-class ethane cracker.**

***Category Two: Domestic use of gas to fuel local economic development***

<u>Gas-to-power:</u> **The most widespread use of gas in the world is in the form of fuel for power generation.** Gas is a very flexible fuel that may be used across the full range of power generation technologies, that is, engines, turbines, and steam boilers. Furthermore, gas is the cleanest fossil fuel, both in terms of air quality and greenhouse gas emissions. Gas is typically cheaper than liquid fuel per unit of energy–particularly when it is sourced domestically. This also helps to improve the country's balance of payments.

☑ **Gas is the fuel of choice for grid-based power generation in PNG in the Highlands and in Port Moresby where plenty of domestic gas could be available.** This would drive down the cost of power generation compared to more expensive liquid fuel and more capital-intensive hydropower and geothermal.

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| **Case Study:** Kumul Petroleum and Oil Search, through their joint venture Niu Power, are constructing a 59MW gas-fired power plant in Port Moresby which is expected to lower the cost of power generation in the capital compared to the current, liquid fuel-fired generator fleet. |

☑ **Gas may also be the fuel of choice for captive power generation by large industrial customers, particularly mines, if they are located in the vicinity of an existing gas field or at a short distance from a gas pipeline.**

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| **Case Study:** There have been several feasibility studies of gas and LNG supply to mines for captive power generation–for example, a proposal by DSME ENR and Petromin to build a gas-fired power facility in Madang for the Ramu Nickel and Cobalt project and the Yandera copper project. |

☒ **Given the challenges and very high cost of laying a pipeline through PNG, gas may not be able to compete with liquid fuel–notably heavy fuel oil–and coal in more remote areas, notably when gas demand is small relative to the length of the pipeline which would make the unit transport cost of gas supply prohibitively high.**

**Industrial gas utilization: In many countries around the world gas is a popular fuel for generating process heat in industrial boilers and burners.** Domestic gas typically competes on price with more expensive liquid fuel and on air quality and greenhouse gas emissions with more polluting coal for steam generation. Gas is the fuel of choice for industrial furnaces as it has a minimal impact on product quality and, therefore, helps manufacturers to minimize product rejection rates–particularly in the glass and ceramics industries.

☑ **Industrial utilization of gas may offer a large, untapped potential for economic development in PNG, particularly in the industrial sector, with a high number of jobs per unit of product and gas, such as food processing and manufacturing.**

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| **Case Study:** There have been several ideas in PNG to use natural gas in the downstream mining and metals sectors and for the production of building materials, such as cement, ceramics, and glass. |

**Gas for heating: In cold countries, gas is a popular fuel for space and water heating in the residential and commercial sectors.**

☒ **Given the meteorological conditions in PNG, heat demand in homes and offices is limited to hot water.** This does not justify investment into a city gas distribution network.

**Gas for cooking: Gas as fuel for cookstoves is considered an important solution to improve indoor air quality and, therefore, improve the living conditions and the health of people who depend on less sophisticated forms of fuel today.**

☒ **The widely dispersed population of PNG does not justify investment into a city gas network.** Gas could, theoretically, be distributed to households in the form of compressed natural gas (CNG) cylinders if PNG did not have an existing supply chain in place for the distribution of LPG.

**Gas as motor fuel: CNG is used as a motor fuel in public transport, passenger vehicles, rickshaws, and mopeds and notably in urban areas where it helps to improve air quality compared to diesel.**
☒ **Given the large distances and the limited road network in PNG, investment into a CNG distribution network is probably not economical.**

***Category Three: Export of gas and gas-based products to generate additional fiscal revenue***

__Pipeline export:__ **The simplest form of gas-based export is the construction of a gas pipeline to a neighboring gas market.** The advantage of pipeline transport is the low cost compared to other gas-based export options (such as LNG) over shorter distances up to 1,000 km as well as the scalability and reliability of pipeline infrastructure. On the other hand, a gas pipeline connects only to one specific market and needs a long-term commitment to amortize the investment. Gas export is known for generating significant income for the country and contributes to the balance of payments, but the challenge is to determine whether such income would have a bigger overall impact on the local economy than the alternative of using the same gas domestically.

☒ **PNG is close enough to Australia to construct a gas pipeline project but the gas price in Queensland is too low to make such a project economical and PNG is too far away from other centers of demand to consider the export of gas by pipeline.**

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| **Case Study:** PNG was at one time considering the export of gas to Australia by pipeline, but the project was abandoned because of the low gas price in Queensland once coal-bed methane resources were commercialized. |

__LNG:__ **The best-known way to export gas is in the form of LNG which is cheaper than pipeline transport over longer distances exceeding 1,000 km even though 10 percent or more of the gas is consumed as fuel for the liquefaction process.** A world-scale liquefaction train produces about 3.5 million tonnes of LNG per year and needs about 500 million standard cubic feet of feedgas per day to operate, including the fuel. As with pipeline export, LNG is known for generating significant income for the country and contributes to the balance of payments, but the challenge is to determine whether such income would have a bigger overall impact on the local economy than the alternative of using the same gas domestically.

**An LNG project creates significant employment in the construction phase and a few hundred skilled jobs during the operational phase.** This is significantly fewer than the number of jobs that would be created when gas is used to build up a domestic manufacturing industry. On the other hand, the significant income from LNG exports may be used by the government to develop other sectors of the economy with the potential to create even more employment opportunities.

☑ **PNG is close to the premium gas markets of Japan, the Republic of Korea, and China and has successfully exported LNG ever since PNG LNG came onstream in 2014.** PNG LNG serves as an example for monetization of large gas resources in the Elk/Antelope and P'nyang fields which are expected to form the basis for investment into two additional liquefaction trains and which could generate significant additional income for PNG. Other smaller gas resources could perhaps be used to backfill existing and planned liquefaction plants. On the other hand, depending on the size and the location of the prospect, such smaller resources could be of better use domestically.

__Fertilizer__: **Methane may be used as feedstock to produce ammonia which is an intermediary product that may be converted into urea.** Urea (N) is the main component in the PNS mix of phosphate, nitrate, and sulphate that make up industrial fertilizer. A world-scale ammonia/urea plant produces about 1.2 million tonnes of urea per year and needs about 80 mmcfd of feedgas to operate.

**A fertilizer project creates a similar number of jobs per unit of investment in the construction phase and a similar number of jobs per unit of gas in the operational phase as an LNG project.** The export of fertilizer may generate significant revenues for the country, although typically less income per unit of gas than LNG. On the other hand, the production of fertilizer may be a good gas monetization route for resources that are too small to justify investment in a world-scale LNG plant or too far away to backfill an existing plant. Depending on the needs of the agricultural sector, some or all of the fertilizer produced may be used domestically. This would open additional job opportunities as well as contribute to the balance of payments as domestically produced fertilizer displaces imports.

☒ **PNG currently imports less than 20,000 tonnes of urea per year which means that a fertilizer project would be built for export.** It will be more economical to use gas resources to underpin and backfill existing and new LNG projects in the country.

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| **Case Study:** Oswal Projects of India and Oil Search looked at the feasibility of urea production in PNG in 2006 and Duncan Goenka Group of India and Petromin PNG Holdings studied the feasibility of urea in 2011. Neither of these initiatives has resulted in an investment proposal. |

<u>Methanol</u>: **Methane serves as feedstock to produce methanol which is an important intermediary product for the chemical sector.** A world-scale methanol plant produces about 1.7 million tonnes of methanol per year and requires about 160 mmcfd of feedgas to operate.

**A methanol project creates a similar number of jobs per unit of investment in the construction phase and a similar number of jobs per unit of gas in the operational phase as an LNG project.** The export of methanol may generate significant revenues for the country although typically less income per unit of gas than LNG. On the other hand, methanol may be a good gas monetization route for resources that are too small to justify investment in a world-scale LNG plant or too far away to backfill an existing plant.

**Methanol could be used domestically provided that the country has a well-developed chemical sector.** In this case, the use of domestically produced methanol would displace methanol imports and, therefore, improve the balance of payments.

☒ **Given that PNG does not have a large chemical sector, there does not seem to be a good reason to pursue a methanol project in PNG compared to using gas resources to underpin and/or backfill existing and new LNG plants in the country.**

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|---|
| **Case Study:** Sojitz Corporation of Japan and Kumul Petroleum are currently assessing the business case for methanol production in PNG. Earlier in 2008, the Government of PNG, Itochu Corporation, and Mitsubishi Gas Chemical Company looked at opportunities to produce methanol and dimethyl ether. This did not lead to an investment proposal. |

<u>Gas-to-liquids (GTL)</u>: **Through a chemical process known as Fisher-Tropsch, natural gas may be converted into liquid fuels which may be easier to store and take on board airplanes and motor vehicles than natural gas.** GTL is highly energy intensive as the process consumes around 40 percent of feedgas as fuel for the conversion. Consequently, GTL can only compete with oil production if feedgas can be

obtained at very low cost, typically $2.00/mmbtu or less. This means that GTL is a niche application that is typically used by countries either for strategic reasons or to improve the balance of payments.

☒ **Given that PNG produces enough oil and has its own refinery, the country does not need GTL either for reasons of security-of-supply or to improve its balance of payments.**

## Appendix Five: Assessment of Policy Tools to Encourage Domestic Use of Gas

### Gas Master Plans

**Gas master planning is a structured process for a gas resource holder to systematically consider and assess the many different options to create value from gas and to maximize value for the country–not only monetary value such as fiscal revenues but also social benefits such as employment.** The objective of a gas master planning study is to create a credible, affordable, and competitive plan that may be used to align all stakeholders–both on the government side and in the private sector. Gas master planning can play a particularly important role in countries with a developing energy sector such as PNG which tend to suffer from a chicken-and-egg problem between gas producers and gas consumers and where a master plan may help to provide clarity and, therefore, reduce risk for investors along the value chain.

**The principal components of a comprehensive Gas Master Plan are:**

a) **Gas supply study:** An overview of gas resources in close collaboration with upstream operators, classified by level of certainty and maturity along with cost-plus estimates of gas and natural gas liquid prices at the wellhead and at strategic hubs in the country. It should be noted that the classification of resources by different levels of certainty and maturity typically leads to multiple supply scenarios.
b) **Market study for gas and gas-based products**: An analysis of the market over time, both in terms of volumes and prices for gas and gas-based products–most notably power and heat but also condensate, LPG, ethane, LPG, fertilizer, and methanol–in close collaboration with local power companies and local and regional industrial players. It considers the local market vs. the international (regional) market (a generic overview of possible gas monetization routes may be found in Appendix Four).
c) **Gas-to-power**: Establishing the role that gas could play in the local power system vs. other fuels and renewable generation technologies. The outcome of a gas-to-power study is typically a least-cost power master plan that considers social constraints such as climate goals.
d) **Value of gas study**: A high screening-level business case for all possible gas monetization options, analyzing not just the monetary value (the net present value) but the wider economic and social benefits of each option for the country, including multiplier effects of supply chains and fiscal revenues of the different options. This includes both domestic gas options and export options to regional and international markets. A value of gas study is typically executed in close collaboration between upstream operators, downstream power and industrial players, and the ministry of economic affairs and/or finance of the country.
e) **National gas strategy:** Formulation of a national gas strategy aimed at maximizing the value of the country's gas resources.
f) **Infrastructure master plan:** Development of a gas and power infrastructure blueprint for the country to provide clarity and to derisk investments by independent parties along the gas and energy value chain. It should design the role of the government and governmental entities in operating and regulating different parts of the value chain.
g) **Energy roadmap:** Creation of a roadmap (or "master plan") showing the timeline, the cash flow, and the impact on the overall gas balance of each individual energy project. This includes

upstream, midstream, and downstream projects. Notably, and most importantly, such a roadmap shows the dependencies between the different projects.

h) **Stakeholder management:** Organization of engagements such as meetings, interviews, and workshops to ensure that all relevant stakeholders–both on the public and private sides–continue to be committed throughout the entire process.

## Gas Reservations

**Gas reservations are one tool employed to ensure that gas supply development more directly leads to domestic gas market development.** These cover volumetric reservations of gas, taxes that incentivize domestic marketing of gas, and case-by-case conditions of project development. The advantages and disadvantages of each approach are set out in Table 5A.1.

**Table 5A.1: Possible Tools for Securing Domestic Gas Supply Through Reservation**

| Description | Pros/Opportunities | Cons/Risks |
|---|---|---|
| **Volumetric Reservation**<br>Percentage of gas production that must be offered to the domestic gas market. May include a single buyer such as the state. | • Clear, measurable signal to developers and to potential buyers.<br>• The reservation may be for a proportion that is still consistent with viability of a multi-train LNG expansion.<br>• Reasonable pricing. | • Value erosion which may require concessions upstream.<br>• Even a low percentage DMO may impact feasibility of marginal or less economic discoveries.<br>• 'One-size-fits-all' approach may not apply given the limited mix of upstream opportunities. |
| **Taxes**<br>The objective is to use taxes (royalty, export tax, levy, tax allowances) to provide an economic incentive for domestic supply.<br><br>Taxes may be earmarked for a specific purpose related to gas market development. | • Clear, measurable signal to developers and industry.<br>• Can ensure the most efficient development of infrastructure and energy supply which may or may not include gas. | • Any new tax must be weighed against the total burden and incidence of tax in the gas fiscal regime.<br>• Domestic benefit conditional on taxes being employed as earmarked.<br>• Benefits also conditional on quality of plans to which funds are allocated and fund management.<br>• Added administrative burden. |
| **Domestic Priority as a Condition of Approval**<br>Developers must show domestic opportunities were sufficiently studied and viable opportunities are included in the project development proposals as a condition of approval. | • Chance for more flexibility which may be more effective in a challenging environment with mixed opportunities.<br>• Employs experienced, commercially minded parties (developers) to solve market problems–which may lead to more effective outcomes. | • Difficult to measure and requires clear guidance to developers.<br>• Being discretionary may cause uncertainty and add to risk.<br>• Conditions of approval are subjective and may be weakly enforced with a weak enforcement body. |

**If the government opts to pursue a volumetric reservation, further study into PNG's potential markets for gas is recommended to determine the most appropriate reservation share.** For example, Western Australia's Domestic Gas Reservation Policy (Box 5A.1) is based on forecasts for domestic demand out to

2050 and for ultimately recoverable reserves. These forecasts were completed in conjunction with policy drafting in 2006; 15 percent represents gas demand's share of ultimately recoverable reserves in 2050. Studies undertaken for gas master planning can play a critical role in supporting the government's understanding of domestic gas needs.

### Box 5A.1: International Examples of Domestic Gas Reservations

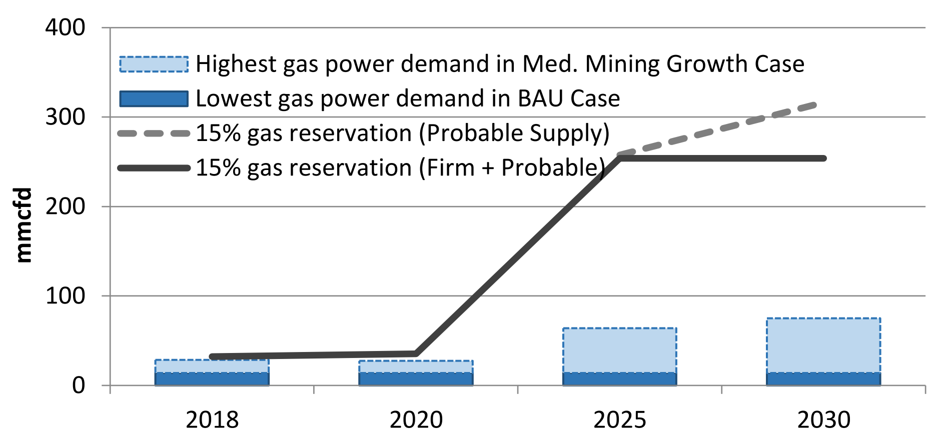
**Western Australia:** Western Australia initiated a Domestic Gas Reservation Policy in 2006–with further clarification in the Strategic Energy Initiative in 2012. As a condition of approval, LNG producers must show they have made necessary plans to make 15 percent of the gas equivalent of LNG production available to the domestic market. This includes showing plans to access the market via new or existing infrastructure. Gas can be sold to any domestic user at the market price. There is also a provision for domestic gas offsets or "swapping" gas reservation requirements with other energy supply efforts. This was included in part due to developer concerns about the remoteness of LNG projects but a gas offset or 'swap' has yet to take place. This policy has been largely successful in ensuring supply of gas to the domestic market at acceptable prices.

**Indonesia:** In 2004, Indonesia amended its Oil and Gas Law to add a gas DMO to its Production Sharing Contract (PSC) which already included an oil DMO. The gas DMO stipulated that PSC partners would provide up to 25 percent of their entitlement gas volumes to meet domestic needs. Offtakers of DMO gas have included the state-owned power and gas transmission companies. The state compensates PSC partners for DMO volumes based on a price approved by the minister (no formula or policy guidance). In practice, domestic gas sales are negotiated on a project-by-project basis under the supervision of the regulator–SKK Migas (formerly BP Migas)–who can influence prices during the negotiations and approval process. Indonesia's domestic gas market has been starved for new supply in recent years and the DMO has been instrumental in securing supply, including LNG cargos from remote LNG export projects at oil-indexed contract prices. Significant fiscal and regulatory risk in Indonesia associated with increased resource nationalism has, however, reduced upstream investment and supply availability–emphasizing the importance of balancing national goals with the need to offer an attractive investment environment.

**A 15 percent domestic gas reservation–which is among the measures that the government is considering in the White Paper–would reserve sufficient supply to meet gas demand forecast for on-grid power (Chapter Two).** Figure 5A.1 illustrates what amount of gas this would imply, given the gas production outlook presented in Figure 3.2. Based on a 15 percent reservation, there could be upwards of 250 mmcfd of domestic gas supply available by 2030 associated with probable projects PNG LNG Train 3 and Papua LNG.

**To merely secure supply via domestic gas reservation is not enough to ensure development of a market.** Based on the current supply and demand view, significant alternative power or nonpower demand must be developed to absorb full domestic supply volumes. This emphasizes the need to undertake further gas market studies and planning to fully understand power and nonpower gas use opportunities to maximize absorption of gas into the market with the best outcome for the country.

**Figure 5A.1: Preliminary Assessment of a 15% DMO**




Source: Internal analysis (range for gas power demand based on least-cost generation analysis

**The legislation necessary to impose a volumetric domestic gas reservation on a case-by-case basis is already in place.** If the government were to opt for a mandatory statutory reservation, however, the Oil and Gas Law would have to be amended. In principle, discretionary imposition of a reservation could be implemented through the approval process by attaching conditions to each Petroleum Development License. Another avenue would be through the negotiated gas agreement for each project.

**Maintaining flexibility to impose a volumetric reservation on a case-by-case basis may be advantageous if the government is presented with very different gas project proposals.** As discussed previously, PNG has a mixed number of upstream opportunities–ranging from multi-tcf, liquids-rich fields to marginal, stranded fields. For smaller resources, in particular, developers may be motivated to supply all or a significant share of gas to the domestic market if presented with a viable opportunity. In this case, the government may want to consider encouraging domestically focused developments. In any case, the government should ensure the domestic gas policy recognizes these different opportunities and sends the appropriate signals to all developers.

**A volumetric gas reservation can be effective in making gas available for domestic use but government intervention may be necessary to ensure it is consumed.** A volumetric reservation, in principle, puts responsibility on developers to make gas available. On the other hand, the government assumes responsibility to ensure viable buyers and supply opportunities. If the local market or government falls short of putting forth such opportunities, reserved supply may go unutilized.

**A domestic gas policy of case-by-case conditions of development could support more downstream investment.** Upstream developers in PNG are experienced and successful international gas players. A policy that would require developers to determine and present a proposal for domestic gas use could lead to beneficial results for the country. This policy is less defined than a volumetric reservation, however, and would require careful management to ensure fair and beneficial application.

## Gas Price Regulation

**Aside from, or in combination with gas reservations, governments sometimes opt to regulate gas prices on a prescriptive basis.** Several gas pricing mechanisms are employed around the world; those most applicable to the PNG-context are described in Table 5A.2. Along with an assessment of domestic gas uses, it is recommended that the government devote time and resources to assess the most appropriate pricing approach in the context of the economy overall and the specific opportunities and goals in each sector (gas-to-power, industrial use).

**Table 5A.2: Wholesale Gas Pricing Mechanisms**

| Description | Pros/Opportunities | Cons/Risks |
|---|---|---|
| **Domestic Price Setting**<br>Government sets the domestic gas price to be attractive enough to ensure use in certain sectors. | • No need to pay for a direct subsidy on domestic gas out of public funds as it is paid for by gas producers. | • De facto additional tax on revenues may make it difficult for gas producers to take investment decision.<br>• Indirect subsidy and the value of gas may not be related to cost. |
| **Cost-plus or Cost of Service**<br>Wellhead and transport costs are calculated based on costs and a commercial return. | • Gas producers guaranteed a return.<br>• Domestic buyers protected from oil market price volatility and escalation.<br>• Costs are project and location specific.<br>• Value of gas is linked to PNG context. | • Gas producers forgo upside on profits in high oil price environment.<br>• Must ensure 'benefit' of cost-plus gas prices is passed on to the end-user rather than captured by an intermediary.<br>• Needs to be underpinned by strong cost control/audit. |
| **Netback Pricing**<br>In the PNG context, piped gas at the LNG plant gate would be the LNG FOB price less a liquefaction tariff. | • Gas producers largely left whole with opportunity to capture price upside from higher oil prices.<br>• Opportunity to mitigate volatility and uncertainty (smoothing mechanism, ceiling and floor, S-curve). | • Value of domestic gas is determined by the value of gas in developed LNG-consuming gas markets.<br>• Buyers exposed to oil price volatility and escalation. |
| **Commodity Indexation** to oil or a derivative of oil (commodity chosen often reflective of alternative fuel options). | • Gas is often sold at a discount to oil parity (16-17% indexation) which can encourage fuel switching.<br>• Opportunity to mitigate volatility and uncertainty (smoothing mechanism, ceiling and floor, S-curve). | • Buyers exposed to oil price volatility and escalation.<br>• Chance of no benefit of domestic gas resource for local market.<br>• Value of gas determined externally.<br>• Without oversight, gas producers may earn more on domestic sales. |

**An initial assessment suggests a cost-plus approach could be the most beneficial pricing mechanism for domestic delivery of piped gas that would otherwise feed large-scale LNG export projects.** This preliminary conclusion recognizes that gas price determination based on premium LNG export markets may not be appropriate given PNG's stage of development. A cost-plus approach to pricing for the power sector would introduce gas price predictability and stability to the country's generation fuel mix while also ensuring a commercial return for developers. This would reduce PPL's exposure to international crude price fluctuations and could promote more gas-fired power generation. For the nonpower market, gas prices that range from cost-plus, to cost-plus with elements of competing fuel indexation, to indexation to oil, could be considered. Studies undertaken for gas master planning can play a critical role in identifying priority markets and the ability of customers in those markets to pay.

**Regulated pricing can secure low-priced gas for high-priority markets (this would be the power sector in PNG) but this benefit should be weighed against the costs of any potential implied subsidy or disincentive to industry.** Regulated pricing can, in principle, reflect any one or a mix of the other pricing mechanisms. The regulated price can be set at below-cost, at cost-plus, indexed to other commodities, or based on other factors such as the retail price of electricity. If regulated prices are set below cost-plus, developers will likely expect concessions elsewhere in the fiscal terms to account for the value erosion. The cost-benefit analysis of the different pricing scenarios will vary based on the source of the gas (scale, project costs) and the intended market (ability to pay, proportion of fuel costs to total costs).

**The more favorable the gas pricing mechanism for the domestic market–such as a cost-plus model–the bigger the mandate placed on the government to use policy, regulation, and enforcement to ensure that the savings and 'benefit' associated with favorable domestic gas prices are passed on.** Revenues forgone by the government to secure favorably priced domestic gas could end up having little impact if captured by companies (and not passed on as energy price savings) or used as a feedstock for other products for export (such as methanol). This risk emphasizes the importance of gas master planning.

### Box 5A.2: International Examples of Domestic Gas Pricing

**Western Australia:** Gas prices are determined between buyers and sellers and have historically been relatively low and stable owing to long-term legacy contracts from the North-West Shelf (NWS) project. The foundational contract between NWS partners–whose 1977 ratified State Agreement includes domestic supply conditions–and the then State Electricity Commission was priced to compete with gas' main substitute–domestic coal. Woodside, one of the region's major suppliers, reported average NWS sales prices of US$3.50-US$3.60/mmbtu in 2016 and 2017–a price that has been relatively stable in recent years. Western Australia's market has grown since the 1980s with more buyers and sellers today. In recent years, various reports put new contract prices in the range of US$5.50-US$10.00/mmbtu with linkages to inflation (Consumer Price Index or CPI), and, in some contracts, oil.

Gas plays an important role in the economy–supplying power, industry, commercial and residential sectors–and gas prices have an impact on household spending and income (jobs). The government has conducted several inquiries into gas pricing in recent years and has stated its view that the economy should benefit from being "energy-rich" and should not pay for gas under the same principles as "energy-poor" importers. Although it does not set prices, it has made other efforts to promote supply availability, competition and investment with the goal of maintaining prices that reflect the scale of energy resources available to Western Australians.

**Israel:** Gas prices are determined between buyers and sellers. The gas market is defined by point-to-point sales to a handful of power generators (state and IPP) and industrial buyers. Israel's Antitrust Authority early on rejected the idea of regulated, low gas prices for the power sector, particularly for state producer Israel Electric Corporation (IEC). IEC purchases gas from Tamar gas field partners at a long-term contracted price of US$5.042.00/mmbtu (starting in 2012) x (US CPI + 1 percent) with renegotiation allowed in 2021 after 10 years. This puts the current price close to US$6.00/mmbtu. Following complaints from IEC regarding the high linkage to inflation, Israel's Electricity Authority issued several decisions on what it considers fair pricing terms for gas to power. Its recommendations for contract terms include interruptible supply priced 10 percent below firm volumes, take-or-pay to meet 65-80 percent of total annual quality and only a 30 percent linkage to CPI. While the government does not control gas prices, it has made other efforts to promote a healthy, competitive gas market, including efforts by the Antitrust Authority to prevent a supply monopoly or duopoly.

**China:** The central government's National Development and Reform Commission (NDRC) historically kept tight controls over gas prices up to the city gate. The NDRC would set different ex-factory prices for onshore fields that were calculated as the wellhead cost + a gas processing fee + a margin for the national oil company producer. The ex-factory price would vary by field and by end-user allowing for the protection of specific sectors and higher prices for those with the ability to pay. This ex-factory price was a guidance against which producers and buyers could negotiate a final price within a +/-10 percent band. Once prices were set, the NDRC would adjust prices infrequently and without predictability. The NDRC would also set pipeline tariffs based on distance to market, capex, and a margin for the operator. These pipeline tariffs were also subject to NDRC adjustment which were made even less frequently.

Regulated prices supported development of China's gas market but the start of pipeline gas imports in 2010 and growing maturity of the local market put pressure on the NDRC to reform the gas pricing mechanism. The complicated system of cost-plus pricing which functioned well with few buyers and few, lower-cost, domestic supply sources was now unsustainable. Reforms rolled out in 2011 and in subsequent years replaced cost-plus with a gas pricing formula linking gas, at a discount, to a basket of imported LPG and fuel oil prices.

## Appendix Six: Detailed Recommendations per PIP Area

| Area | Recommendations | |
|---|---|---|
| | **Phase I: High Priority Actions (Short Term)** | **Phase II: Medium Priority Actions (Medium Term)** |
| **Skilled Management Team and Workforce** | Comprehensive organizational restructuring and competitive selection and appointment of a local skilled management team. Organizational restructuring is about developing staff capacities and skills through training in new approaches for efficient operations and supporting tools | Staff upskilling/reallocation/implementation of special program for young talent, to make the best use of the existing human capital inside PPL |
| **Incorporation of Management Tools** | **CMS** to manage all commercial processes such as revenue cycle and customer service.<br><br>**ERP** information system to support management of shared services: accounting, finances, human resources, procurement, logistics, corporate planning, Information Technology (IT).<br><br>**IRMS**[59] to identify location and analyze extent of an interruption in electricity supply and enable fast resolution and service restoration.<br><br>**Account separation of the three major business activities**: electricity generation, transmission, and distribution. | **Map customers and network infrastructure using GIS**: Mapping of customers (points of electricity supply) and network infrastructure on a GIS, including customers' connections and links with network assets.<br><br>**Install a WMS:** Incorporate a WMS to manage all construction/installation works of network infrastructure. |
| **Increasing Revenues** | **Reduction of nontechnical losses through implementation of an RPP** supported by Advanced Metering Infrastructure (AMI) to systematically record and monitor consumption of around 7,800 of PPL's largest customers (monthly consumption above 800kWh) representing 77 percent of current physical sales.<br><br>**Implementation of improvements in customer service and efficiency in revenue cycle operations.** Complete installation of prepayment meters for customers not included in the scope of the RPP, elimination of manual processes (meter reading and billing), incorporation of improved new approaches for distribution of bills ("e-billing") to mobile telephones via email or SMS, and collection/purchases (mobile phone payments). Implementation of full-scope attention of customers via Contact Center, Internet and social networks.<br><br>**Implementation of improved procedures for collection:** Assure all customers pay their old debt and future bills.<br><br>*(Improvement of technical losses covered under reliability)* | **Assess consumption in areas with constraints to carry out field operations:** Identify areas where field operations cannot be carried out in a regular manner due to security constraints. Assess consumption in areas in list validated by implementing wholesale metering in the feeders supplying those areas (by installing AMI in MV feeders and distribution transformers) to compute amounts of energy injected and losses and assess the financial viability of the investments needed to regularize supply.<br><br>**Secure payment of consumption of government consumers:** Create and keep updated a list of "nondisconnectable" and "disconnectable" agencies of central and local governments validated by the Independent Consumer & Competition Commission; switch "disconnectable" agencies to prepayment.<br><br>**Launch a cost of service study**, including review of the current tariff structure aimed at identifying actions on the revenue side to improve financial performance. |
| **Improving Reliability** *(and reduce technical losses)* | **Implementation of urgent investments in network rehabilitation/upgrade needed to address unacceptable quality of service:** Prepare a detailed technical loss reduction plan to confirm and implement urgent investments in rehabilitation/upgrade of existing infrastructure to improve the condition of network assets and improve the service quality in the short term. Immediate priority should be allocated to address "burning" cases that can be implemented at a relatively low cost and eventual fast actions with a big impact on service quality. Examples are installation of new switchgear equipment (reclosers and disconnectors); the installation of capacitors in MV lines and substations; improvement of the protection system in HV/MV | **Mid-term investments for reliability:** In the medium term, PPL must prepare an investment plan aimed at removing any constraint to supply deriving from insufficient capacity, configurations not meeting applicable criteria on stability and reliability and other situations involving backbone (MV/HV) network infrastructure.<br><br>**Upgrade the Operations Control Center**: Single full performing Control Center (generation and T&D) to properly manage system operation, fault restoration, and attention to customers' complaints. Considering the small size of the PNG electricity system, for first implementation stages, it is recommended that a "Single Control Center" |

[59] Also identified as Outage Management System.

| Area | Recommendations | |
|---|---|---|
| | Phase I: High Priority Actions (Short Term) | Phase II: Medium Priority Actions (Medium Term) |
| | substations; reinforcements/replacements of transformers and conductors as needed to solve big overloads/voltage drops. Studies to identify improvements in transmission and distribution networks stability; protection systems and quality of supply to large consumers; tests to assess condition of existing equipment (see Appendix Nine).<br><br>**Upgrading existing SCADA** System to operate and control from generation to MV distribution. | deal with generation, transmission and distribution systems. The IRMS will assist PPL in addressing outages and other incidents effectively. |
| **Optimizing costs** | **Adjusting procedure to calculate "performance component" of staff remuneration:** The "performance component" of PPL's staff remuneration to be calculated over Cash Available after Debt Service and Capex.<br><br>**Implementation of improved procedures for metering electricity production and fuel consumption of thermal plants (both owned by PPL and by IPPs):** Installation of metering systems to record all electrical parameters involved in commercial transactions with IPPs and of amounts of energy injected into T&D networks.<br><br>**Implementation of actions for optimization of production costs:** (i) launch a feasibility study for repowering of existing own HPPs; (ii) assessment of replacement of diesel gensets of isolated systems by renewable (solar + storage) plants through competitive bidding; (iii) review existing thermal generators to decide the ones that should be discontinued; and (iv) introduce renewable energy in isolated centers.<br><br>**Systematic implementation of least-cost plan for generation and transmission.**<br><br>**Identification and implementation of new management models** to "ringfence" PPL's core businesses and leverage the private sector for investments in generation and provision of O&M services by, for example: (i) procuring all new amounts of power and energy needed to supply demand of existing and future customers through PPAs to be signed with private investors; and (ii) outsourcing O&M of existing generation facilities in main and isolated systems. | **Further changes to staff compensation**: Incorporate performance criteria such as loss reduction, billing, collection, quality of service and other parameters demanded from PPL by the regulator as a condition for approving tariff adjustments which impact PPL's revenues.<br><br>**Fuel:** Review arrangements for fuel procurement.<br><br>**Production costs:** Continue to implement least-cost plan of generation and transmission: perform investments on rehabilitating hydro, launch competitive bidding for new generation projects (such as hydro, gas, and solar + storage batteries). |

## Appendix Seven: Key Financial and Operational Performance Data for PPL

| PPL - Income Statement | | | |
|---|---|---|---|
| *K'000* | **FY2017** | **FY2016** | **FY2015** |
| Operating Revenues | 858,426 | 881,188 | 843,729 |
| Non-Operating Revenues | 16,651 | 19,486 | 29,338 |
| **Total Revenues** | **875,077** | **900,674** | **873,067** |
| **Total Costs & Expenses** | **809,472** | **725,707** | **714,420** |
| **Operating Profit - EBITDA** | **65,605** | **174,967** | **158,647** |
| **Operating Margin** | **7%** | **19%** | **18%** |
| Depreciation | -77,574 | -75,985 | -66,615 |
| Financing Cost | (10,221) | (16,210) | (23,818) |
| Income Tax Expense | 6,758 | -17,997 | -4,834 |
| **Net Profit** | **-15,432** | **64,775** | **63,380** |
| **Profit Margin** | **-2%** | **7%** | **7%** |

| *K'000* | **FY2017** | **FY2016** | **FY2015** |
|---|---|---|---|
| **Operating Costs & Expenses** | | | |
| Fuel Costs | 212,010 | 186,782 | 207,004 |
| Power Purchases | 202,182 | 176,817 | 146,181 |
| Leasing | 60,409 | 3,277 | 3,335 |
| Repairs & Maintenance | 17,420 | 23,461 | 30,800 |
| Consumables | 40,336 | 34,300 | 33,389 |
| Other | 5,986 | 15,381 | 13,031 |
| *Sub-total* | *538,343* | *440,018* | *433,740* |
| Direct Salaries & Wages | 49,231 | 45,149 | 55,301 |
| Indirect Salaries & Wages | 44,270 | 52,986 | 34,292 |
| Direct Personnel Costs | 15,293 | 7,171 | 75,247 |
| Indirect Personnel Costs | 0 | 93,224 | 25,082 |
| Overheads Direct & Indirect | 162,335 | 87,159 | 90,758 |
| *Sub-total* | *271,129* | *285,689* | *280,680* |
| **Total Costs & Expenses** | **809,472** | **725,707** | **714,420** |

| PPL - SOURCES & USES (K'000) | | | |
|---|---|---|---|
| **Sources** | **2017** | **2016** | **2015** |
| Cash from Operations | 96,404 | 53,958 | 117,529 |
| Cash from Financing Activities | 80,070 | - | - |
| Cash from Asset Disposals | - | 77,549 | 35,226 |
| **Total Sources** | **176,474** | **131,507** | **152,755** |
| **Uses** | | | |
| Investments (Capex)-net | (92,851) | (35,256) | (45,625) |
| Debt Service | (89,664) | (84,631) | (95,438) |
| Rural electrification | - | (8,140) | (18,788) |
| **Total Uses** | **(182,515)** | **(128,027)** | **(159,851)** |
| **Gap between Sources & Uses** | **(6,041)** | **3,480** | **(7,096)** |
| Cash at the beginning of the year | 7,142 | 3,662 | 10,758 |
| Cash at Year end | 1,101 | 7,142 | 3,662 |

**PPL's Capex 2017-2015**

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| **Capex Forecast** | 348,010 | 361,845 | 283,861 |
| **Capex - Actual** | 92,851 | 35,256 | 45,625 |
| **Deficit** | **255,159** | **326,589** | **238,236** |

**PPL - Working Capital**

| *K'000* | 2017 | 2016 | 2015 |
|---|---|---|---|
| Fuel Inventory | 18,753 | 12,098 | 6,358 |
| Trade Receivables* | 78,513 | 17,489 | 43,602 |
| Trade Payables | 161,497 | 141,356 | 142,442 |
| **Operating Working Capital** | **(64,231)** | **(111,769)** | **(92,482)** |

*Net of provisions , excl. +90 days

**PPL - Liquidity Ratios**

| *K'000* | 2017 | 2016 | 2015 |
|---|---|---|---|
| EBITDA/Interest (x) | 6.42 | 10.79 | 6.66 |
| Quick Ratio (x) | 0.79 | 0.60 | 0.55 |
| Net Debt to EBITDA (x) | 2.7 | 0.75 | 1.3 |
| FCFO/Debt | 2% | 14% | 35% |

**PPL- Electricity Generation**

| Source - MWh | 2017 | *% Total* | 2016 | *% Total* | 2015 | *% Total* |
|---|---|---|---|---|---|---|
| Hydro | 504,954 | *39%* | 541,983 | *41%* | 617,806 | *50%* |
| Thermal | 308,854 | *24%* | 344,494 | *26%* | 330,047 | *27%* |
| Purchased | 494,475 | *38%* | 432,132 | *33%* | 277,817 | *23%* |
| **Total** | **1,308,283** | *100%* | **1,318,609** | *100%* | **1,225,670** | *100%* |

*Note:* Some totals may vary slightly from 100% due to the effect of rounding.

**PPL - Fuel Costs and Consumption**

| | NGI | Ramu | Momase | Southern |
|---|---|---|---|---|
| Fuel Consumption (lts.) | 15,483,494 | 1,284,355 | 9,671,131 | 41,096,356 |
| Fuel Cost * ('000) | 40,832 | 68,412 | 24,910 | 82,120 |
| Avg. Cost/kWh** | 0.832 | 0.845 | 0.719 | 0.622 |
| Lts/kWh** | 0.319 | 0.366 | 0.279 | 0.315 |
| PPL Avge. Price/lt*** | 2.675 | 2.603 | 2.800 | 2.541 |
| IPP Avge. Price/lt**** | | 1.58 | | |

* FY2017 ** Jan-Oct 2017 *** Jan-17 to Apr-18

**** Jan-17 to Apr-18 all thermal IPPs

| *K'000* | Revenues FY2017 | % | Tariff*** K/kWh | |
|---|---|---|---|---|
| **General** | 481,003 | 56% | 0.987 | |
| **Domestic** | 15,971 | 2% | 0.785 | |
| **Industrial*** | 158,652 | 19% | 0.850 | |
| **Easipay** | 169,780 | 20% | 0.761 | |
| **Mining** | 26,668 | 3% | 0.478 | |
| **Total **** | 852,074 | 100% | **0.897** | ***WAvge.*** |

* Mining customers are segregated for Tariff purposes

** Approx. figure

*** Actual Revenue/kWh

**PPL Scenarios: Description of Key Features**

**Baseline:**

a) Generation: Same as in 2017.
b) Losses: 25 percent.
c) Collection Factor: 90 percent (this is the current rate per financials). Improvement in collection was reduced slightly so as not to reach 100 percent–which would be unrealistic.
d) Fuel: Adjusted by local and international inflation rates.
e) PPA Prices: Only adjusted for inflation.
f) Opex (ex-staff): Adjusted by inflation (2 percent).
g) Staff Costs: 24 percent of Sales (Operating Revenue).
h) Debt & Debt Service: Same as in 2017. For Multilateral Development Bank debt only interest of 0.50 percent (principal. paid by government)
i) Capex: Kept at bare minimum for basic T&D.
j) Debt Funding: Only for funds available under ADB´s loan. No working capital funding.

**Other Features for Scenarios Beyond Baseline:**

a) Capex: LCPDP plus T&D of LCPD (ex-hydro) @ $2.2 million per plant ($150,000.00 per km x avge. 5 kms per plant + $24,000.00/MW of substation cost x avge. 60MW/plant - ANZ Report) plus electrification @ $105 million/year for 75,380 connections/year (NEROP).
b) Connection Charge: $100.00/connection.
c) PPA Prices: As per PPL info plus $13.00cts/kWh for gas.
d) Opex Related to New Connections: 30 percent increase over maintenance and consumables of previous year starting in 2018.
e) Financing: All investments are financed with concessional loans under the same terms as the existing ADB loans–that is, PPL pays interest at 0.5 percent and the government pays the principal.

## Appendix Eight: High-priority Actions to Optimize Billing and Collection Rates

**PPL classifies its customers into the following tariff categories (Table 8A.1):**

(i) Domestic (credit);
(ii) General Supply (postpaid, consisting of medium business customers and government agencies);
(iii) Ramu Sugar and Mining (largest industrial customers in Lae System);
(iv) Industrial;
(v) Public Street Lighting;
(vi) Easypay Domestic (prepaid); and
(vii) Easypay General (prepaid).

### Table 8A.1: Physical Sales and Revenues per Tariff Category in First Eight Months of 2017

| | DOMESTIC | | | | | GENERAL SUPPLY | | | | | RAMU SUGAR | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 Months Jan-Aug 17 **System** | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. |
| P. Moresby | 3.5 | 2.8 | 0.80 | 864 | 505 | 171.8 | 169.8 | 0.99 | 12,529 | 1,714 | | | | | 0 |
| Ramu | 6.0 | 4.6 | 0.77 | 190 | 3,941 | 93.3 | 92.4 | 0.99 | 3,784 | 3,082 | 3.4 | 1.8 | 0.53 | 60,714 | 7 |
| Gazelle | 0.2 | 0.2 | 0.75 | 1,316 | 19 | 16.4 | 16.2 | 0.99 | 3,667 | 559 | | | | | 0 |
| Others | 4.4 | 3.5 | 0.80 | 283 | 1,944 | 37.8 | 37.6 | 0.99 | 2,521 | 1,874 | | | | | 0 |
| **Total** | **14.1** | **11.05** | **0.78** | **275** | **6,409** | **319.3** | **316** | **0.99** | **5,521** | **7,229** | **3.4** | **1.8** | **0.53** | **60,714** | **7** |
| % of Total* | 2.0% | 2.0% | | | 5.9% | 46.4% | 55.9% | | | 6.6% | 0.5% | 0.3% | | | 0.0% |

| | MINING | | | | | INDUSTRIAL | | | | | PUBLIC STREET LIGHTING | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 Months Jan-Aug 17 **System** | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month MWh/ Client | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. |
| P. Moresby | | | | | | 69.5 | 59.3 | | 184,840 | 47 | 0.0 | 0.9 | | | 0 |
| Ramu | 86.4 | 19.2 | 0.22 | 10,800 | 1 | 43.7 | 41 | 0.94 | 182,083 | 30 | 0.0 | 0.1 | | | 0 |
| Gazelle | | | | | | 1.6 | 1.6 | | 200,000 | 1 | 0.0 | 0.0 | | | 0 |
| Others | | | | | | 1.6 | 1.4 | | | 0 | 0.0 | 0.1 | | | 0 |
| **Total** | **86.4** | **19.2** | **0.22** | **10,800** | **1** | **116.4** | **103.3** | **0.89** | **186,538** | **78** | **0.0** | **1.1** | | | **0** |
| % of Total* | 12.5% | 3.4% | | | 0.0% | 16.9% | 18.3% | | | 0.1% | 0.0% | 0.2% | | | 0.0% |

| | EASYPAY - DOMESTIC | | | | | EASYPAY - GENERAL | | | | | TOTAL | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 Months Jan-Aug 17 **System** | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | Month kWh/ Client | Dist. #Custom. |
| P. Moresby | 59.2 | 41.3 | 0.70 | 193 | 38,382 | 18.1 | 17.4 | 0.96 | 812 | 2,787 | 322.1 | 291.5 | 0.91 | 927 | 43,435 |
| Ramu | 30.4 | 21.2 | 0.70 | 128 | 29,683 | 9.7 | 9.4 | 0.97 | 258 | 4,705 | 272.9 | 189.7 | 0.70 | 823 | 41,449 |
| Gazelle | 6.5 | 4.5 | 0.69 | 100 | 8,099 | 2.0 | 1.9 | 0.93 | 137 | 1,858 | 26.7 | 24.35 | 0.91 | 317 | 10,536 |
| Others | 17.4 | 12.1 | 0.70 | 277 | 7,860 | 5.7 | 5.5 | 0.96 | 410 | 1,738 | 66.9 | 60.2 | 0.90 | 623 | 13,416 |
| **Total** | **113.5** | **79.1** | **0.70** | **169** | **84,024** | **35.5** | **34.2** | **0.96** | **401** | **11,088** | **688.6** | **565.75** | **0.82** | **791** | **108,836** |
| % of Total* | 16.5% | 14.0% | | | 77.2% | 5.2% | 6.0% | | | 10.2% | 100.0% | 100.0% | | | 100.0% |

M$-Kina: Millions of Kina
Sold = Billed
* % of Total for all tariff categories

*Source:* World Bank staff.
*Note:* Some totals may vary slightly due to the effect f rounding.

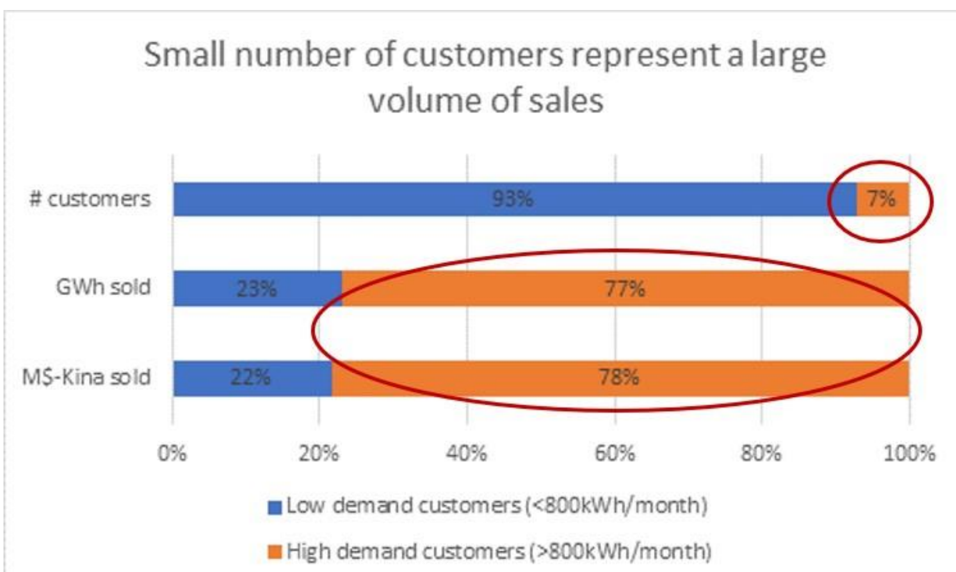
**Sustainable optimization of billing and collection rates starts from an assessment of the composition of the market served by PPL.** PPL's current sales are largely concentrated in a relatively small number of customers. A "high consumption" group formed by only 7,839 customers (domestic users with monthly consumption above 800kWh; customers in the General Supply category; Ramu Sugar; and all mining and industrial consumers) represent 77 percent of physical sales. Sales to the remaining 93 percent of customers (domestic users consuming less than 800kWh/month; Public Street Lighting; Easypay Domestic; and Easypay General customers) are just 23 percent of the total. Table 8A.2 and Figure 8A.1 show the composition of each of the "high" and "low" consumption segments.

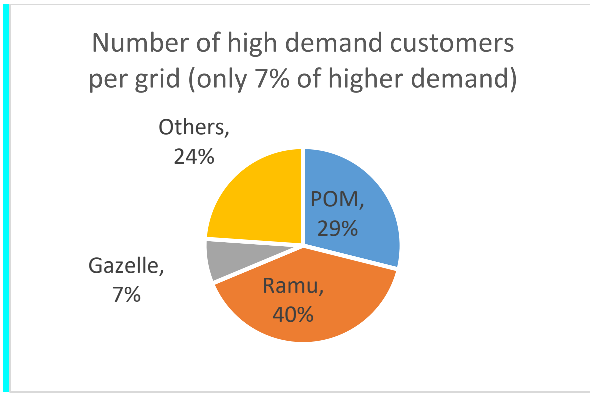
### Table 8A.2: High and Low Consumption Segments (Typical 2017 Month)

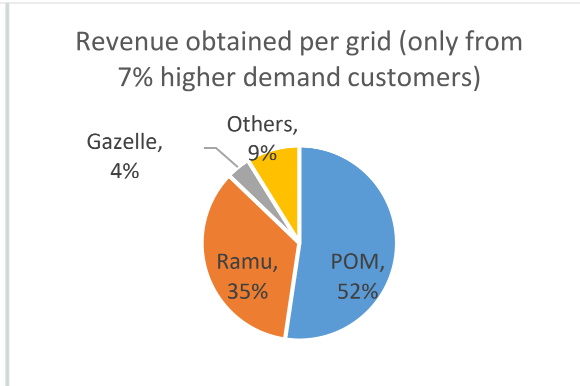
| PPL retail business | Total | | | | Low demand customers<br>DOMESTIC<br>PUBLIC STREET LIGHTING<br>EASYPAY - DOMESTIC<br>EASYPAY - GENERAL | | | | | High demand customers - RPP<br>DOMESTIC<br>GENERAL SUPPLY<br>RAMU SUGAR<br>MINING INDUSTRIAL | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly (Jan-Aug 17) System | Sold Dist. GWh | Sold Dist. M$-Kina | kWh/ Customer | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | kWh/ Customer | Dist. #Custom. | Sold Dist. GWh | Sold Dist. M$-Kina | Dist. $/kWh | kWh/ Customer | Dist. #Custom. |
| P. Moresby | 40.3 | 36.4 | 927 | 43,435 | 9.7 | 7.5 | 0.77 | 235 | 41,169 | 30.6 | 29.0 | 0.95 | 13,503 | 2,266 |
| Ramu | 34.1 | 23.7 | 823 | 41,449 | 5.8 | 4.4 | 0.77 | 150 | 38,329 | 28.4 | 19.3 | 0.68 | 9,087 | 3,120 |
| Gazelle | 3.3 | 3.0 | 317 | 10,536 | 1.1 | 0.8 | 0.75 | 107 | 9,957 | 2.3 | 2.2 | 0.99 | 3,929 | 579 |
| Others | 8.4 | 7.5 | 623 | 13,416 | 3.4 | 2.7 | 0.77 | 298 | 11,542 | 4.9 | 4.9 | 0.99 | 2,628 | 1,874 |
| **Total** | **86.1** | **70.7** | **791** | **108,836** | **19.9** | **15.3** | **0.77** | **197** | **100,997** | **66.1** | **55.4** | **0.84** | **8,438** | **7,839** |
| % of Total | 100% | 100% | | 100% | 23% | 22% | | | 93% | 77% | 78% | | | 7% |

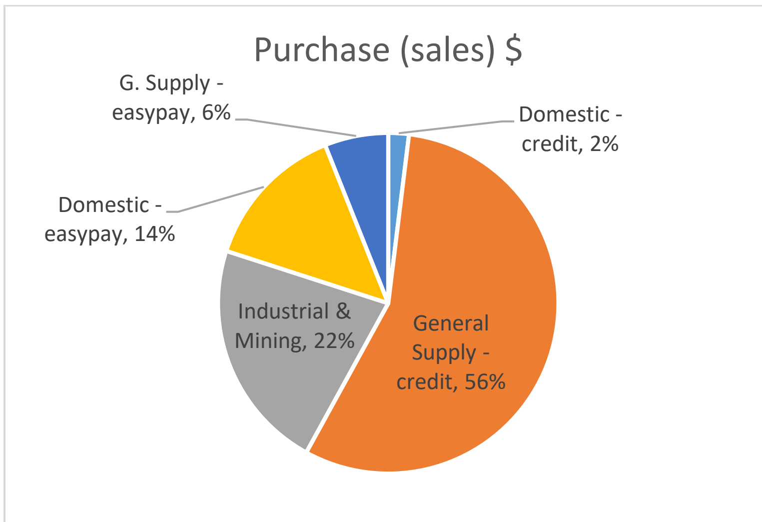
*Source:* World Bank staff.
*Note:* Some totals may vary slightly due to the effect of rounding.

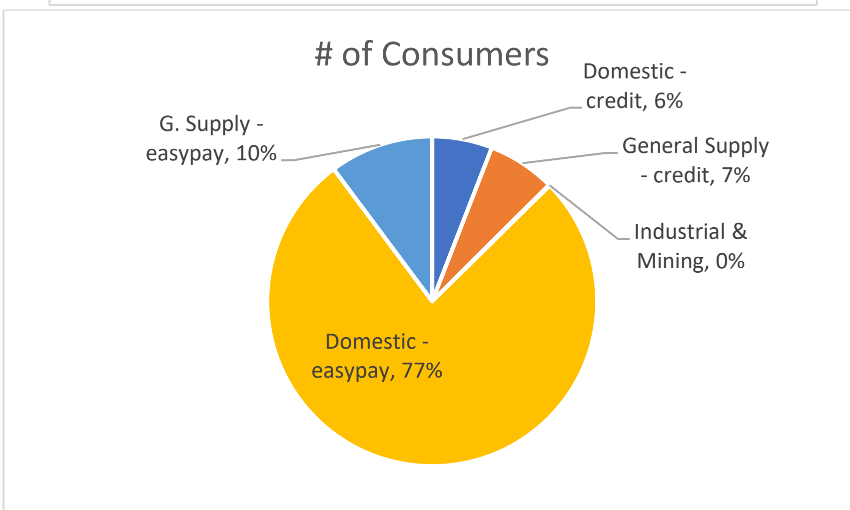
### Figure 8A.1: PPL's Distribution of Customers vs Energy Sold






*Source:* World Bank staff.

**Taking into consideration the large concentration of PPL's sales in the high-consumption segment formed by its customers with monthly recorded consumption above 800 kWh (less than 7 percent of the total), any strategy aimed at reducing nontechnical losses should focus initially on ensuring "0 unmetered consumption" in supply to customers in that segment.** This means that every unit (kWh of electricity) consumed in the segment is metered and billed on a permanent basis. This can be achieved through the implementation of an RPP that incorporates an AMI for systematic recording of consumption of all customers in the segment, together with the adoption of organizational arrangements (creation of a special-purpose Metering Control Center) for permanent monitoring and immediate correction of any abnormal situation detected with the support of the AMI tool.

**Implementation of the RPP implies a relatively small investment (less than $3 million for the "high-consumption" segment of the market served by PPL) to protect 78 percent of the company's revenues in a permanent manner.** The amortization period through reduced nontechnical losses should be very short (less than one year). The most important feature of the implementation of an RPP, however, is the sustainability over time of loss reduction achieved. Almost all well-performing utilities having very low nontechnical losses have implemented RPPs as it is the most effective way to sustain this good condition. The RPP for PPL can be fully implemented in around one year from decision to implementation.

**In addition to the RPP, PPL must incorporate a state-of-the-art CMS (also known as a Customer Information System) to support efficient, transparent, and accountable execution of commercial P&A that PPL has to carry out to serve all its customers.** Those P&A include the monthly revenue cycle (metering, billing, collection, disconnection/reconnection) for credit (postpayment) consumers; management of purchases and consumption of prepayment customers; and registration of new customers. The scope of the contract for implementation of the CMS comprises the reengineering of all commercial P&A; eliminating all existing manual processes (meter reading and billing); incorporating new approaches widely adopted in developing countries for distribution of bills ("e-billing" to mobile phones via email or SMS); and collection/purchases (mobile phone payments). Implementation of CMS will, therefore, make it possible to eliminate the current manual process for meter reading and billing of postpayment customers and reduce long periods from issuance of bill to collection. Equally important, it will improve customer service through convenient options for purchases and payments and, in the future, full commercial management via the Call Center (no need for the customer to move to an agency).

**RPP and CMS are the main tools for commercial management of all PPL's customers located in areas where the company can carry out its regular operations without constraints.** The Bank team was informed there are some areas where PPL staff face security issues due to aggressive behavior of their inhabitants (not necessarily regular customers). Regularization of supply to those areas requires large investments in construction of new infrastructure (distribution networks and metering systems). As an initial step, PPL should implement wholesale metering in the feeders supplying those areas to compute amounts of energy injected and losses and assess the financial viability of the investments needed to regularize supply.

**PPL must define and put in place "ad hoc" procedures to maximize collection of old debts and to ensure regular payment of bills by government agencies (representing around 14 percent of current sales in kWh).** While recovering uncollected amounts of old bills helps to improve the financial condition of the utility, maximum priority should be allocated to achieve and sustain on time collection rates close to 100 percent. Management of old debts of nongovernment consumers should focus on medium and large customers using the average amount of unpaid bills as the driving criterion. All small customers should be converted to prepayment (the process is well advanced but must be completed). PPL could allocate a certain amount of monthly energy purchases to payment of old debts. This approach only makes sense provided it does not put at risk their ability to regularly pay for future consumption, so creating incentives for theft. The utility should proceed with extreme care in the matter to avoid creating a problem rather than implementing a solution.

## Appendix Nine: Proposed Immediate Investments, Assessments and Studies to Improve Quality and Reliability of Electricity Supply

| ACTIVITY | Budget ($) |
|---|---|
| Installation of one 30 megavolt ampere power transformer in each of Taraka (132/66 kV) and Milford (66/11 kV) transmission substations. | 2,000,000 |
| Assessment of stability of POM and Ramu systems and identification of options for improvement: static and dynamic (transient) performance, rotor angle stability, voltage stability and voltage collapse. | 100,000 |
| Assessment of existing protection system of transmission and distribution networks of POM and Ramu systems and identification of options for improvement. | 150,000 |
| Assessment of options to improve reliability of supply to large mines and industrial customers in Ramu system. | 200,000 |
| Assessment of condition of existing transmission power transformers: oil testing, electric parameters, thermographic inspection. | 250,000 |
| Installation of new switchgear equipment (reclosers, disconnectors) in MV distribution networks to optimize network configurations and enhance flexibility in operations. | 4,500,000 |
| Installation of fault indicators in the most important MV circuit branches. | 500,000 |
| Installation of capacitors in MV distribution lines and substations to optimize power factor during peak hours. | 2,000,000 |
| Replacement of network assets in poor condition in HV/MV distribution substations. | 10,000,000 |
| Reinforcements/replacements needed to solve big overloads/voltage drops in backbone MV/HV distribution networks. | 10,000,000 |
| Construction of MV distribution backup facilities to improve quality of service in commercial and industrial areas. | 5,000,000 |
| **TOTAL** | **34,700,000** |

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