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Energizing Economic Growth in Ghana:

Making the Power and Petroleum Sectors Rise to the Challenge

June 2013

Energy Group
Africa Region
World Bank

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FOREWORD

We have prepared this report in the belief that it will help bring about policies and decisions that will ensure that Ghana's emergence as a middle-income economy is not held back by the energy sector, as at present. We recommend that the Government make a concerted effort to "think big" and provide more direct and proactive leadership to the energy sector, given its centrality to boosting economic growth.

This report was prepared during a period of electricity shortages and rolling power blackouts. The current power shortfall is particularly serious for two reasons: the frequency of these episodes is increasing—the previous blackout was just 5 years ago—and the economic damage inflicted is greater, because Ghana's economy has evolved to become ever more dependent on reliable electricity supply.

Our review identifies four themes that are common to the power and petroleum sectors:

- First, Government policies and decisions have delayed investments in the sector, resulting in energy shortages.
- Second, the performance of several of the state-owned energy enterprises and oversight agencies needs to be greatly improved.
- Third, the investment requirements of the sectors far exceed what can be financed publicly, and the Government must take steps to attract private-sector investment on a large scale.
- Finally, the current pricing/tariff policies for energy are not financially sustainable, and must be reformed.

Solutions to these problems are well known; the challenge is to carry them out. Proactive leadership of the energy sector, with a focus on efficiency and timely delivery, is crucial to Ghana's ambitions for economic growth. We look forward to assisting the Government of Ghana with implementing these solutions.

Yusupha Crookes

Country Director for Ghana

ABBREVIATIONS

AOE	additional oil entitlements
Bbl	barrels
Bbl/d	barrel per day
Bcf	billion cubic feet
BOST	Bulk Oil Supply and Transport Company
BST	Bulk Supply Tariff
CDB	China Development Bank
CFLs	compact fluorescent lamps
EC	Energy Commission
ECG	Electricity Company of Ghana
ELPS	Escravos to Lagos Pipeline System
FiT	feed-in tariff
FPSO	floating production storage and offloading
GHC	Ghana cedi
GIPC	Ghana Investment Promotion Centre
GNGC	Ghana National Gas Company
GNPC	Ghana National Petroleum Company
GRA	Ghana Revenue Authority
GRIDCo	Ghana Grid Company Limited
GWh	gigawatt-hours
HFO	heavy fuel oil
IPP	independent power producer
LCO	light crude oil
kW	kilowatt
kWh	kilowatt-hour
LCs	letters of credits
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	meter
m/s	meters per second
MBbl/d	thousand barrels per day
MMBtu	million British thermal units
Mcfd	thousand cubic feet per day
MMcfd	million cubic feet per day
MoE	Ministry of Energy
MoFEP	Ministry of Finance and Economic Planning
MW	megawatt

MWp	megawatt-peak
MIS	management information systems
NED	Northern Electricity Distribution
NEDCo	Northern Electricity Distribution Company
NITS	National Interconnected Transmission System
NOC	national oil company
NPA	National Petroleum Authority
O&M	operations and maintenance
PC	Petroleum Commission
PNs	promissory notes
PPAs	power purchase agreements
PRMA	Petroleum Revenue Management Act
PURC	Public Utilities Regulatory Commission
PV	photovoltaic
SAPP	Sunon-Asogli Power Plant
SBU	Strategic Business Unit
SOE	state-owned enterprise
TEN	Tweneboa, Enyenra, and Ntomme
TOR	Tema Oil Refinery
TSC	Transmission Service Charge
TT2PP	Tema Thermal 2 Power Station
Valco	Volta Aluminum Company
VRA	Volta River Authority
WAGP	West Africa Gas Pipeline

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EXECUTIVE SUMMARY

Overview

The main objective of this report is to provide the new Government of Ghana with recommendations on the actions needed to improve the performance of Ghana's energy sector. The report focuses on the power and petroleum sectors, taking account of the interdependence between the sectors, and providing recommendations for how they can, together, drive future economic growth.

This report aims to highlight the centrality of fixing the problems in the power sector as a path to ensuring that Ghana's economic growth ambitions are not stymied by a lack of electricity. The problems and their solutions are well known; what has been lacking is decisive and timely decision making to break the tendency to adopt *reactive measures* that often come too late when *proactive measures* would have led to better outcomes.

Natural gas will play a vital role in Ghana's future energy picture. Demand for gas in the power sector is set to expand rapidly, as new thermal generation capacity is built to meet rapidly growing power demand. However, to ensure successful development of its gas sector, Ghana will need to address a number of important challenges.

The newly established oil and gas sectors have already produced impressive results, and their revenue contributions to Ghana are expected to peak at above US$3 billion per year billion in 2018–22. Nevertheless, there are reasons to be cautious. In the next decade, oil and gas production and revenues will come from only three big fields—Jubilee, TEN (Tweneboa, Enyenra, and Ntomme), and Sankofa—of which only Jubilee is in production, and its results to date have not met expectations. The output and revenues from all three fields are subject to production and timing uncertainties.

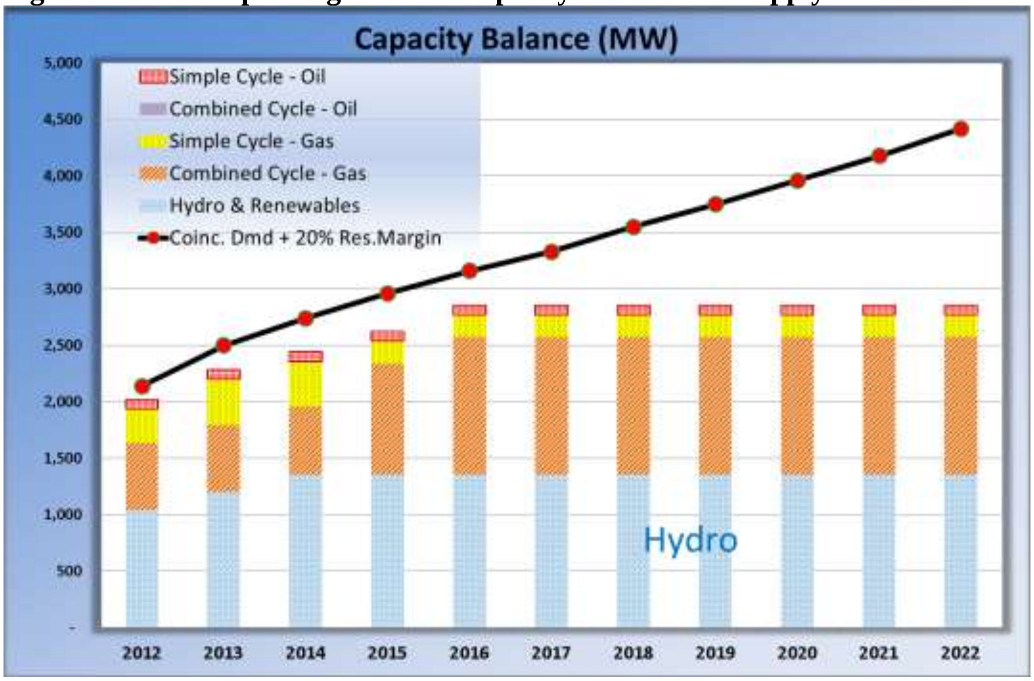
Power sector

At a time when the Ghanaian economy is achieving sustained growth in excess of 6% annually, with ambitions to raise this further, there is a risk that misguided and inappropriate policies will lead to the power sector becoming a drag on the economy. A major, avoidable power crisis in 2006–7 is estimated to have cost the country nearly 1% in lost growth of gross domestic product during those years. Five years later, Ghana once again was plunged into power shortages, which also could have been avoided if lessons from the past had been learned and decisions taken to ensure that adequate dual-fuel generation capacity was built. The present recent power shortages, arising from a cut-off of imported gas from Nigeria, could have been mitigated if Ghana's own gas from the Jubilee field had been developed in a timely manner in parallel with oil production that began in 2010.

The power sector faces two challenges arising from forces external to the sector: the lack of adequate and secure quantities of reasonably priced fuel for power generation, and the lack of adequate public funds to finance the sector's investment requirements. These challenges are exacerbated by the poor technical and financial performance of the Electricity Company of Ghana (ECG) and Volta River Authority (VRA), and policies and practices that seriously damage the financial health of ECG, VRA and the Ghana Grid Company Limited (GRIDCo).

Generation capacity shortages are expected. In the past 15 years, Ghana has added about 1,000 megawatts (MW) of thermal generation capacity. As a result, Ghana's current generation capacity of 2,125 MW is made up of about 50% hydro and 50% thermal plants. Nevertheless, inadequate and unreliable power supply remains a major constraint to future economic growth.

Figure 1: Forecast power generation capacity demand and supply



Source: World Bank staff calculations.

Large investments are needed to meet expanding demand. Ghana needs to invest over US$4 billion in the next 10 years to make up for the past investment deficit and upgrade its power sector infrastructure. Generation, transmission, and distribution all need substantial upgrading, and the necessary investments must take place in a synchronized manner.

Barriers to attracting IPPs need to be removed. Public funds of this magnitude are not available, which means that it is critical to attract private investors, particularly for generation. While Ghana already has some independent power producers (IPPs), the system for attracting new IPPs is not working well. At present, concerns about the assured availability of gas for power plants are a major barrier for potential IPPs. Ghana may not have access to adequate supplies of gas for power generation until 2015, or possibly even 2018.

Further, the governance and regulatory framework does not attract IPPs. To begin with, potential IPPs lack a credible buyer because ECG, the usual offtaker, is in poor financial health, and there are legitimate concerns about its ability to pay power producers. Further, there is uncertainty about procedures and regulations. What a potential IPP developer has to go through in practice is often significantly different from the official framework, which creates uncertainty for the private investor. Finally, the IPP development process is cumbersome and time consuming because Ghana does not have a single-window system for IPPs.

It is essential that the Government take steps to remove these barriers to IPPs in power generation. The Ministry of Energy should lead the process by appointing a full-time, high-level IPP coordinator tasked to do so, in conjunction with the Ministry of Finance and Economic Planning's (MoFEP's) Public Private Partnership unit.

ECG's commercial performance needs improvement. Tariff policies that provide subsidies to consumers have harmed the financial health of ECG and Northern Electricity Distribution Company (NEDCo). Because of low residential tariffs, the bulk of ECG revenues come from non-residential consumers, who account for 56% of sales revenue, even though they account for only 12% of ECG's unit sales. This implicit cross-subsidy imposes a significant burden on commercial customers. Further, since the Public Utilities Regulatory Commission **(**PURC) has failed to increase retail tariffs, ECG is expected to incur losses of US$44 million in 2012, and US$60 million in 2013. ECG's losses are worsened by high technical losses; poor revenue collection, from both Government entities as well as private consumers and rising dollar-denominated payment obligations.

ECG's distribution losses are very high; they were 27% in the second quarter of 2012. ECG has to pay for "lost" energy it buys from VRA, but does not earn any revenue on it. Reducing these losses by 10% would save ECG US$85 million per year. Other middle-income countries have successfully cut their distribution losses. The actions needed to reduce ECG's losses have already been specified in technical studies; ECG must now implement them.

ECG's poor financial condition means that it is in no position to finance its investment program, or even properly maintain its existing system, much of which is old. Further, faced with financial difficulties, ECG fails to pay fully for the power it buys from VRA and IPPs, thus harming their financial health.

ECG is a large, top-heavy, over-centralized organization, with significant weaknesses in its management, corporate governance, and institutional culture that call for a profound change. A company the size and importance of ECG should be led by a first-rate Board of Directors and staffed with high-caliber managers. A profound long-term change in ECG corporate governance and institutional culture is called for, with improved commercial performance and better customer service (both in electricity supply and in commercial matters) as the centerpiece of a new approach.

In addition, several short-term actions are needed to restore ECG's financial health. The simplest of these is that ECG collects its past dues from Government as well as private customers; the Government's cooperation is essential for recovering the dues from official entities. Next, ECG has been financing its losses with expensive short-term suppliers' credits, which only worsen its financial situation. Hence, ECG should refinance these credits into cheaper longer-term finance from conventional commercial sources. Further, ECG should reduce its operating expenses, (which have have been rising considerably in excess of inflation in recent years), as well as the costs of its inputs by competitive procurements and better inventory management.

Further, PURC should resume implementing the quarterly automatic retail tariff mechanism, and also prepare for the next major tariff revision in mid-2013; together, these actions will give ECG much needed additional revenue.

VRA is facing financial collapse, due in large part to external shocks. The cut-off of West Africa Gas Pipeline (WAGP) gas has forced VRA to buy light crude oil (LCO) to operate its thermal power plants. Since LCO generation is nearly three times as expensive as gas-fired generation, this has shifted VRA's financial status from a small profit in 2011 to large losses in 2012, which continue into 2013. These losses mean that VRA is in no position to finance its investment program. Further, VRA's financial situation is worsened by the low rate at which it sells power to the Volta Aluminum Company (Valco). The Government should either to cease providing subsidized electricity to Valco, or to finance these subsidies from the general budget.

Given the prospect of continued negative cash flow in 2013, VRA will find it difficult to service the short-term debt overhang (over US$350 million) accumulated in 2012, irrespective of any efforts to reduce further capital expenditures. The only available option for VRA is to refinance this costly short-term debt, which is degrading its balance sheet and its investment capacity.

The Government should resolve VRA's debt overhang as soon as possible, because the cost of this bailout will increase over time. The Government will need to assume responsibility for most of the debt incurred (via commercial letters of credit) to buy crude oil in 2012 and the first half of 2013. Once cost-reflective bulk electricity pricing mechanisms, with provision for timely indexation, are put in place, VRA will be able to finance its new-generation investments independently.

VRA's hydro and thermal operations should be separated. While the technical performance of VRA's hydro plants is good, the performance of its thermal power plants is below accepted norms. VRA's thermal power stations are underperforming, with high numbers of forced outages and unsatisfactory plant availability. This underperformance has aggravated the load shedding since September 2012, because VRA units were unable to operate at full capacity on a sustained basis to mitigate the loss of output from the Sunon Asogli plant. It is essential that thermal power stations perform better in the future. In 2003, the Cabinet had approved a decision to separate the management of VRA's hydro and thermal plants, but it was never implemented. Given the increasing importance of thermal power plants, and the need to make the best use of the available gas supplies, it is time to implement this separation.

When gas is in short supply, in principle it would be cheaper to use a combination of LCO and heavy fuel oil (HFO) to generate power, instead of only LCO. Since this approach has not yet been tested in Ghana, VRA should study the technical and financial merits of this fuel blend.

Energy efficiency should be implemented aggressively. Even with quick remedial actions, Ghana may face difficulties in generating adequate power. Further, additional power generated from new thermal plants will be more expensive than hydro power, with final retail costs of US¢12–15/kilowatt-hour. Given these high costs, it is likely that there are significant opportunities for reducing energy use through demand-side management, where the cost of reduction will be much less than the cost of power. Ghana has already instituted several energy efficiency measures, such as promotion of compact fluorescent lamps and establishment of standards for air-conditioners and other appliances.

However, Ghana has only begun to scratch the surface of energy efficiency in the electricity sector. Energy efficiency efforts need to be expanded significantly to cover not only the major electricity-using appliances and machinery to be installed in the industrial, commercial, and residential sectors but also the design of new buildings to be constructed. The Government should task the Energy Commission (EC) with preparing a plan to vigorously implement energy efficiency in the electricity sector.

Renewable energy is expected to play a small but growing future role. The Government has established a target of 10% of power generation coming from renewable sources (which includes under-100 MW hydro plants) by 2020. So far, Ghana only has a 2MW grid-connected renewable energy plant in operation. Both solar and wind are at early stages of development, and the wind resource in Ghana is limited. Further, both solar and wind power are expected to require significant tariff premiums over conventional generation to be financially viable. Thus, the target of 10% for 2020 is unlikely to be achieved.

Nonetheless, global trends in the solar photovoltaic (PV) manufacturing industry, with sharply declining investment costs per kilowatt installed, suggest that medium- to large-scale grid-connected solar plants (without storage) have a role to play in Ghana. VRA could consider solar projects close to its reservoirs so that solar and hydropower could complement each other, and there would no additional costs of connecting the solar power to the grid. PURC's announcement of the feed-in tariff for solar power has removed an element of uncertainty for potential private project developers.

Further, it is also likely that stand-alone solar systems in the remotest rural areas are likely to be much cheaper than conventional rural electrification, whose subsidy requirements are a major burden for NEDCo, and also for ECG, though to a lesser extent.

GRIDCo should be assigned overall responsibility for sector planning. GRIDCo is a well-run transmission company, and is the only power utility that is currently financially viable. It is well suited for preparing the indicative medium- and long-term plans for power generation capacity requirements. The EC would still remain responsible for indicative planning for the energy sector as a whole**.**

PURC performance. Though PURC has been in existence for nearly 15 years and has made significant progress on advancing customer rights, its performance is not good enough, as indicated above by PURC's failure to apply the automatic indexation scheme to tariff setting, except during two very brief periods. The main challenges faced by PURC are: (1) capacity constraints, as PURC is unable to retain trained staff and there is very little practical experience of the power utility industry amongst the staff; (2) insufficient transparency because PURC has adopted a closed approach to decision making; and (3) unbalanced membership of the Commission, because stakeholder representation, rather than professional qualifications, is the basis for selecting several PURC Commissioners. The Government should take steps to mitigate these problems.

Natural gas sector

Ensuring an adequate and secure supply of natural gas is fundamental to improving the availability and cost of power in Ghana. Ghana is fortunate that that it has domestic gas resources and it can import gas from Nigeria. However, delays in the implementation of the Jubilee associated gas infrastructure and supply interruptions on WAGP have combined to produce an acute gas shortage. Increasing gas availability will require accelerating new local gas projects and improving execution on the part of state-owned enterprises and regulatory agencies.

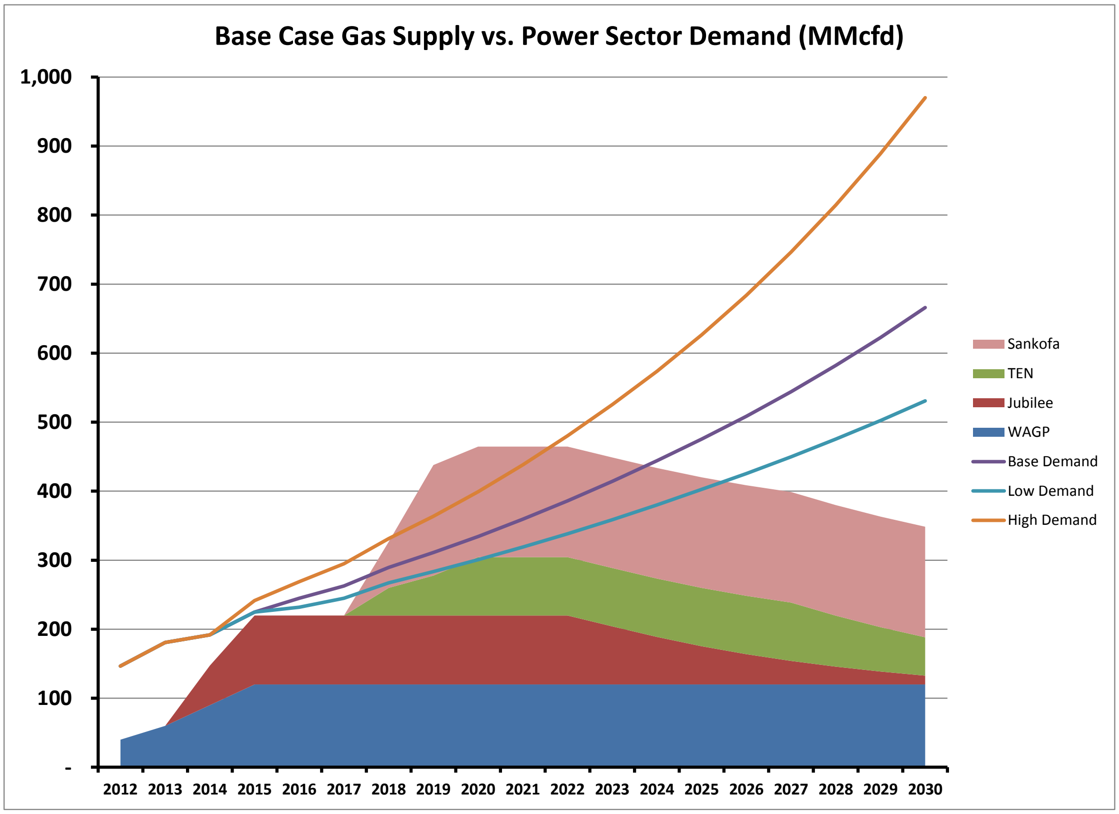
Gas demand and supply sources are vulnerable. Gas supply and demand in the power sector could come into tenuous balance as early as 2015, once the Jubilee gas infrastructure is complete, and Nigerian deliveries reach full foundation volumes (Figure 2). However, these supply sources are vulnerable to delays and delivery shortfalls, which could lead to continued gas deficits until 2017–18, when the TEN and Sankofa fields are assumed to begin production.

Gas is cheaper than other fuels for power generation. The weighted average cost of local (Jubilee, TEN, Sankofa) and imported (Nigeria) gas delivered to Takoradi is estimated at US$6.13 per million British thermal units (MMBtu) over the 10-year period 2014–23. When compared to the cost of light crude oil—over US$17/MMBtu based on an oil price of US$100 per barrel—gas supply provides enormous economic benefits to the power sector.

Power generation is the best use of gas in Ghana. The Government should place a clear priority on satisfying power sector demand for gas before considering expanding supply to petrochemical projects. At a minimum, the Government should wait two to four years before committing gas to petrochemicals to allow time for the major near-term gas supply uncertainties to be resolved.

Delays in local gas supply result in high costs. The estimated ***additional*** cost of buying liquid fuels for power generation when adequate gas is not available is currently $1 million per day. Hence, the Government must ensure that commercial and technical planning for Sankofa and TEN is completed in 2013.

Figure 2: Base case gas supply and power demand for gas



Source: World Bank staff calculations.

If reduced hydro output or higher economic growth were to increase the power sector's demand for gas, and gas supplies do not develop as envisaged, then gas supply would be inadequate over the entire planning horizon. In such a scenario, securing additional Nigerian supply would become an urgent priority. However, Nigeria is not in a position to offer more gas to Ghana, particularly on a firm basis in the next 2–3 years. The best that Ghana could hope for is a small volume of interruptible gas, and even this would likely be at a price higher than existing Nigerian supply.

An alternative to additional Nigerian gas is imported liquefied natural gas (LNG); however, this option is complex. While a floating LNG receiving and regasification terminal could be completed in 2–3 years, this timeframe would be too late to help with the worst of the short-term gas supply crisis. Further, the cost of LNG will be higher than other gas sources available to Ghana. Nevertheless, it is prudent to continue feasibility work on an LNG import project, taking account of the costs, risks, and benefits.

GNGC's and BOST's operational capacities are questionable. Ghana National Gas Company (GNGC) was established in 2011 and vested with the responsibility for commercializing, transporting, and processing natural gas. However, the EC has recently awarded the exclusive license for gas transportation to the Bulk Oil Supply and Transport Company (BOST), the state-owned fuel wholesaler. As the exclusive gas transmission utility, BOST would assume responsibility for operating and maintaining the pipeline and for dispatching gas receipts and deliveries. It is understood that BOST would not own the pipeline and would not buy or sell gas, except for operational purposes, such as line pack. This would leave GNGC in the position of owning a pipeline it did not operate or control.

At this early stage in the development of Ghana's gas sector, introduction of another gas enterprise creates unneeded confusion in the midstream institutional structure, and BOST has no relevant experience in operating a gas transmission system. Hence, the Government should reconsider the decision to award this license to BOST.

There are serious questions about the capacity of GNGC or BOST to operate the processing plant and pipeline efficiently and safely. Experience in this arena is generally lacking in Ghana and building capacity will take time. Hence, the Government should hire a contract operator for the processing plant and pipeline, to be in place when commissioning takes place.

GNGC profitability has yet to be proven. If GNGC buys gas for more or less the weighted average cost of US$6.13/MMBtu and sells gas at Takoradi on a competitive basis with WAGP gas, it could generate substantial profit. It is assumed that the intention is to distribute that profit to government. However, the Petroleum Revenue Management Act (PRMA) is ambiguous as to whether gas revenue is to be deposited in the Petroleum Holding Fund or included in the calculation of Benchmark Revenue. Amendment to the PRMA may be needed and GNGC's dividend policy would need to be established accordingly.

On the other hand, there is a risk that GNGC could become another financially crippled state enterprise, since it will buy gas from producers in dollars and sell gas to VRA in Cedis, thus being exposed to both currency and credit risk. The proposed transfer of the pipeline operating responsibility to BOST coupled with the retention of debt service obligations on the China Development Bank (CDB) credit further increase the risk level of GNGC's business.

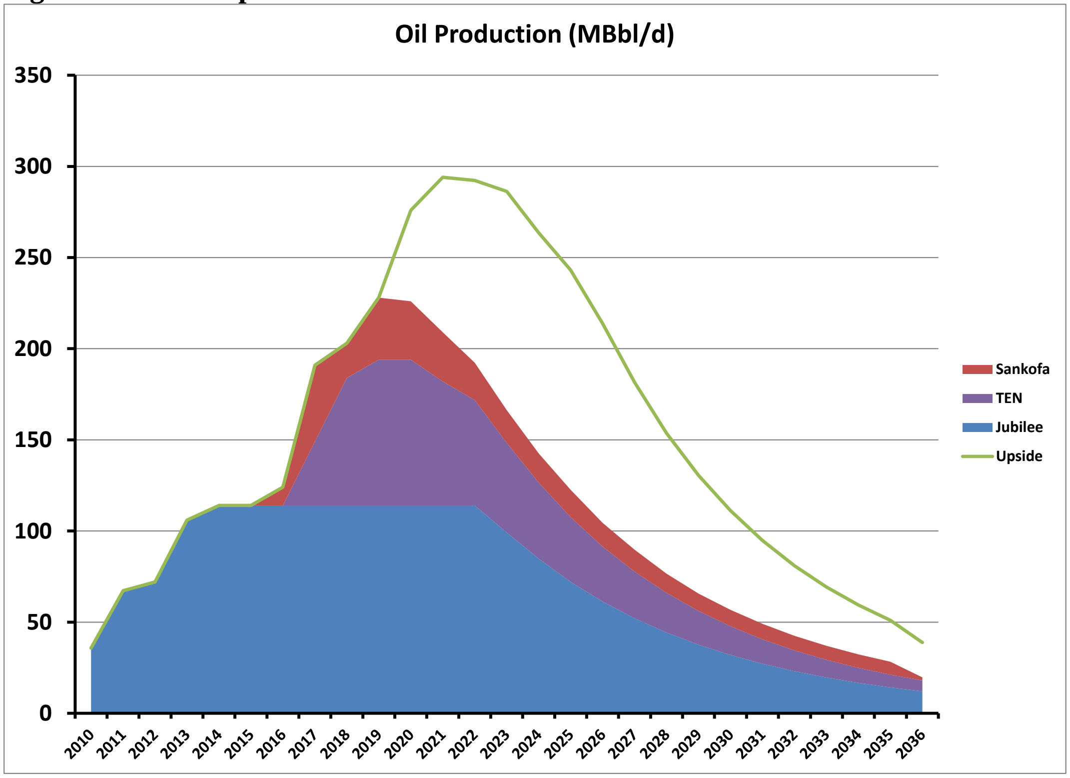
An officially announced Gas Pricing Policy is needed. Proper pricing is central to the development of the natural gas sector. The Government has not yet published its Gas Pricing Policy, though the underlying principles were endorsed by the Cabinet in mid-2012, based on a detailed study carried out by international consultants. The Government should publish this policy without delay.

Commercial issues in the gas market need to be addressed. Negotiating gas volume guarantee arrangements between producers of non-associated gas and power generators (VRA, IPPs) will not be easy. For example, producers of non-associated gas are likely to require take-or-pay guarantees that buyers, such as VRA, may find difficult to accept. Further, credit issues represent a potential major challenge, particularly for non-associated gas projects, such as Sankofa, where the project economics rely entirely on gas sales to the local market. Given its financial condition, VRA will find it impossible to provide guarantees acceptable to gas producers without supporting guarantees from the Government. Moreover, gas suppliers and lenders are likely to seek mitigation against ECG's risk of non-payment to VRA. The Government must quickly develop its approach to providing credit support for gas developments.

Upstream oil and gas

The emerging upstream oil and gas sector has already produced impressive results. Production is expected to peak at around 230,000 barrels per day in 2019–20 (Figure 3).

Figure 3: Total oil production



Source: World Bank staff calculations

Nevertheless, there are reasons to be cautious. First, in the next decade, oil and gas production and revenues will only come from Jubilee, TEN and Sankofa. So far, only Jubilee is in production, and its results to date have not met expectations, necessitating a costly remediation program. Since TEN and Sankofa are still in the development stage, the output and revenues from all three fields are subject to production and timing uncertainties. Further, the results from exploration have not been as prolific as the number of discovery announcements would suggest, and future exploration activity could begin to decline.

Future exploration and appraisal are risky and unknown. The first phase of deepwater exploration and appraisal is ending. By July 2013, the exploration periods for all five of the Tano Basin blocks will have expired, and the acreage held by licensees will be reduced to only those areas with active appraisal, development, or production programs. In 2013, there could be as few as four exploration wells drilled.

Re-starting exploration will require issuance of new licenses, in effect re-starting the clock on the typical 7-year exploration period built into Ghana's petroleum agreements. In the case of the Tano Basin relinquishments, license terms will have to reflect the likelihood that discovered fields will be small. In the Accra/Keta Basin, terms will have to reflect the high risk and the unknown range of potential field sizes. Licenses in the ultra-deepwater will have to account for extremely high costs and longer exploration and appraisal periods needed to mobilize rigs. Initial licenses in the Volta Basin will likely be structured as seismic options, whereby the licensee acquires and interprets seismic over the block before committing to an exploration well.

Gas production will peak in 2020–22. Gas production in this analysis peaks in 2020–22 at roughly 340 million cubic feet per day (net of adjustments for oil industry usage offshore, reinjection, and processing shrinkage. Estimated total gas production over the period 2010–-2036 is 1.9 Tcf (trillion cubic feet).

Government oil and gas revenues will peak in 2020. Assuming an oil price of US$100/barrel (Bbl), and gas prices of US$1.25/MMBtu for Jubilee, US$6.00/MMBtu for TEN, and US$8.00 for Sankofa, Government oil and gas revenue will increase steadily from US$542 million in 2012 to US$1.4 billion by 2016. Beginning in 2017, revenues surge to a peak of almost US$4 billion in 2020 as a result of new fields coming on line and the exhaustion of cost recovery at Jubilee. Jubilee remains the backbone of the Government revenue stream throughout the planning horizon. Sankofa, by contrast, is a relatively minor contributor to Government revenues.

Revenue for 2013 could reach $800 million. For 2013, the Government is budgeting US$582 million in oil revenue based on production of 90,000 Bbl/d and an oil price of US$90/Bbl. These assumptions are quite conservative. At expected levels of production (105,000 Bbl/d) and a price of US$100/Bbl, government revenues for 2013 would reach roughly US$800 million.

Weaknesses in the income tax regime hamper revenue generation from oil and gas. Income taxes and participating interests represent the biggest components of Government revenue. However, income tax realizations continue to be suppressed by accelerated capital allowances and intercompany interest deductions. The absence of ring-fencing and thin capitalization rules within the Petroleum Income Tax Law is largely to blame. Ghana should re-examine the provisions of the tax code dealing with these deductions. Further, the Government should establish workable regulations and procedures implementing the PRMA, and should address calculation inconsistencies either in regulation or by amendment of the law. The audit function of the Ghana Revenue Authority should be greatly strengthened. However, the overall structure of Ghana's petroleum taxation regime remains progressive, competitive, and flexible and does not require a major overhaul.

Ghana's budget framework should take account of the allocation of petroleum revenue to GNPC. The PRMA allocates a portion of the revenue coming from participating interests to the national oil company, GNPC. This allocation consists of GNPC's participating equity share of capital and operating costs, plus a portion of the net revenue after deducting such costs. Ghana's practice has been to allocate 40% of such revenue to GNPC. Our analysis shows that allocations to GNPC would exceed deposits in the Ghana Stabilisation Fund and the Ghana Heritage Fund over the next 4 years. Further, while gross 2014 petroleum revenues are expected to be roughly $1 billion, the amount available for the current budget is likely to be around US$500 million. The effect of reduced remittances to the Petroleum Holding Fund resulting from surplus retention by GNPC should be considered within Ghana's budget framework.

GNPC's strategic role needs careful examination. GNPC's primary responsibility is managing Ghana's commercial interests in upstream petroleum operations. Today, this role consists of marketing royalty oil and managing Ghana's 15–20% carried participating interests in petroleum developments. However, GNPC's ambition is to evolve into a commercially independent oil company, acting as an operator at times and taking larger, fully paid equity stakes, including investment in exploration.

In deciding whether such an expansion of GNPC's role is advisable, Ghana should consider several factors. First, investments in activities outside of upstream petroleum should generally be avoided, except where they are needed to catalyze upstream projects.

Second, the timeline for development of GNPC's capacity (both human and financial) should be compared against the total investment needs of the sector to determine if there is sufficient space for GNPC's investments at the point GPNC is ready to make them.

Third, the returns from GNPC's equity investments—including the social returns coming from GNPC acting as a catalyst for expansion of Ghana's industrial base—should be compared against the total financial and social returns of alternative investments Ghana could make, and the risks of new ventures should be carefully assessed. In the case of deepwater exploration, GNPC's exposure to dry-hole exploration risk could be US$20–50 million per project. The depth and diversification of GNPC's portfolio should be assessed to ensure that losses of this order of magnitude can be absorbed.

In addition to these investment criteria, worldwide experience that indicates that national oil companies that operate as fully independent commercial entities come from countries that have far greater resource endowments than Ghana, higher levels of economic development, and a greater degree of macroeconomic and fiscal stability. In any event, GNPC's commercial ambitions should be matched with improved governance and transparency arrangements.

Key Conclusions and Recommended Actions

The main objective of this report is to provide the new Government of Ghana with recommendations on the actions needed to improve the performance of the energy sector in Ghana. The report's summary findings and recommendations are presented here in a succinct, tabular format, so that they are readily available at a glance, with details provided in the report.

No.	Recommendations/Findings	Comments/Timing
Ministry of Energy/Ministry of Finance		
Power sector		
1.	Recognize that: ▪ Large-scale private-sector investment is essential to generation. ▪ Power sector subsidies have reached unsustainable levels. ▪ Performance of ECG, VRA, PURC, and EC needs improvement. ▪ Natural gas is essential for current and future power generation. ▪ Gas-based power generation will be much more expensive than hydro generation, and oil-based generation will be much more expensive than gas-based generation. ▪ Energy efficiency and demand-side management can be much cheaper than thermal generation, while renewable energy will not be able to meet its target of 10% by 2020.	All future power sector plans should be based on this understanding.
2.	Pay ECG amounts owed by public bodies.	Within 3 months
3.	Take over VRA's short-term debt incurred for LCO purchases.	Within 3 months
4.	To enhance power generation capacity and output:	
	▪ Appoint top-notch technical adviser on IPPs in MoE. ▪ Designate full-time high-level IPP facilitator to lead open, competitive solicitation and contracting process that is based on standardized terms, including payment risk mitigation.	Within 6 months
	▪ Formalize GRIDCo's responsibility for preparing the indicative medium- and long-terms plan for power generation requirements.	Within 6 months
	▪ Merge Bui Power Authority with VRA.	Begin planning immediately, implement within 18 months
5.	Shut down Valco until generation using LCO ceases, or else the subsidy should be borne directly by the national budget, not the power sector.	Immediately
6.	Reassess the clearinghouse payments mechanism to institute direct payment of electricity bills by as many state bodies as possible	Within 3 months
7.	Task the Energy Commission to draw up aggressive energy efficiency and demand-side management plans in all end-user sectors.	Within 3 months
8.	Set professional eligibility criteria for Board membership of energy sector SOEs.	Within 6 months

<table>
<tr><td colspan="3">Natural gas sector</td></tr>
<tr><td>1.</td><td>Recognize that:
▪ Power generation is the highest-value use of gas.
▪ Delays in the flow of local gas amount to an additional cost of US$ 1 million a day for buying light crude oil.</td><td>All future gas sector plans should be based on this understanding.</td></tr>
<tr><td>2.</td><td>Ensure that commercial and technical planning for Sankofa and TEN is completed in 2013.</td><td>Within 6 months</td></tr>
<tr><td>3.</td><td>Reconsider award of the Transmission Utility license to BOST in light of unnecessary complications and potential for delays.</td><td>Within 3 months</td></tr>
<tr><td>4.</td><td>Amend PRMA to resolve ambiguities and establish GNGC's dividend policy accordingly.</td><td>Within 12 months</td></tr>
<tr><td>5.</td><td>Publish the Gas Pricing Policy.</td><td>Immediately</td></tr>
<tr><td>6.</td><td>Hire a contract operator for the processing plant and pipeline to be in place when commissioning begins.</td><td>Within 3 months</td></tr>
<tr><td rowspan="3">7.</td><td colspan="2">Study additional gas options:</td></tr>
<tr><td>▪ Maintain frequent dialogue with Nigeria regarding additional gas supplies.</td><td>Ongoing</td></tr>
<tr><td>▪ Undertake feasibility studies for an LNG terminal and retain a commercial adviser to open dialogue with LNG suppliers.</td><td>Within 6 months</td></tr>
<tr><td>8.</td><td>Develop an approach to provide credit support for gas development.</td><td>Within 12 months</td></tr>
<tr><td colspan="3">Oil sector</td></tr>
<tr><td>1.</td><td>Recognize that:
▪ Future oil production and revenue rest on just three big fields, which are subject to production and timing uncertainties.
▪ It is not prudent to plan on the assumption of additional large discoveries.
▪ A new licensing strategy that takes account of the potential and risks in the areas to be licensed is needed to re-start exploration.
▪ Oil revenues available to the current national budget in the near term will be much less than expected, due to GNPC financing requirements, lags in income tax realizations, and allocations to the Ghana Heritage Fund.</td><td>All future oil sector plans should be based on this understanding.</td></tr>
<tr><td rowspan="3">2.</td><td colspan="2">For GNPC:</td></tr>
<tr><td>▪ Tightly define GNPC's long-term strategic role, and develop and publish a long-term business plan for GNPC.
▪ Ensure that the scope and magnitude of GNPC's investment program are appropriate, and consider reducing the percentage of net revenue from participating interests allocated to GNPC.</td><td>Within 6 months</td></tr>
<tr><td>▪ Institute improvements in GNPC's transparency and governance practices, consistent with its commercial ambitions.</td><td>Within 12 months</td></tr>
<tr><td>3.</td><td>Re-examine the petroleum income tax system, particularly those provisions dealing with capital allowances, thin capitalization rules, ring-fencing, and intercompany charges.</td><td>Within 12 months</td></tr>
<tr><td>4.</td><td>In implementing PRMA:
▪ Establish workable regulations and procedures.
▪ Address calculation inconsistencies either in regulation or by amendment of the law.</td><td>Within 12 months</td></tr>
</table>

Other official entities		
PURC – Power sector		
1.	Resume the automatic quarterly retail tariff adjustment mechanism, and explain its rationale to the public.	Within 3 months
2.	Prepare the next major tariff revision.	Implement by mid-2013
3.	Make the regulatory processes more systematic and transparent.	Within 6 months
4.	Hire and retain skilled professionals with industry experience.	Within 6 months
ECG		
1.	▪ Collect owed dues from ECG customers, particularly private. ▪ Put in place an efficient/effective mechanism to collect revenue.	Within 3 months
2.	▪ Refinance short-term suppliers' credits into longer-term financing. ▪ Cease taking on costly, non-transparent financial commitments to suppliers.	Within 3 months
3.	▪ Reduce distribution losses, particularly non-technical losses.	Begin planning immediately, implement within 12 months
4.	▪ Reduce operating expenses. ▪ Conduct competitive procurements. ▪ Reduce inventory costs by synchronizing procurement with utilization plans.	Begin planning immediately, implement within 6 months
VRA		
1.	Study utilization of LCO/HFO blend to reduce generation costs.	Within 6 months
2.	Implement full operational and financial separation of thermal from hydro generation.	Begin planning immediately, implement within 18 months

I. INTRODUCTION

1. The main objective of this report is to provide the new Government of Ghana with recommendations on the actions needed to improve the performance of Ghana's energy sector. The report focuses on the power and petroleum sectors, taking account of the interdependence between the power and natural gas sectors, and providing recommendations for how they sectors can, together, drive future economic growth.

Power sector

2. Worldwide experience shows that a well-functioning power sector is essential for rapid economic growth and improvements in the quality of life of the people of any country. This report aims to highlight the centrality of fixing the problems with Ghana's power sector as a path to ensuring that a lack of electricity does not stymie Ghana's ambitions for economic growth. The problems and their solutions have been extensively studied (see Box 1). What has been lacking in recent years[1] is decisive and timely decision making to break the cycle of *reactive measures* that often come too late, when *proactive measures* would have led to better outcomes.

3. A major power crisis in 2006–7 is estimated to have cost the country nearly 1% in lost gross domestic product (GDP) growth in those years. The immediate cause of the crisis was a shortfall in hydropower production due to lower water levels in Lake Volta. This shock could not be cushioned by thermal power generation because the Government of Ghana had not invested in additional thermal generation after 2000. Nor had the Government facilitated independent power producers' (IPPs') ability to do so. The situation was aggravated by the resumption of the Valco smelter, which needed large amounts of power, at a time when the level of Lake Volta did not provide an adequate reserve cushion in a dry year.

4. Five years later, Ghana once again experienced power shortages that also could have been avoided if lessons from the past had been learned. The much-delayed development of associated gas from the Jubilee field, available but unexploited since December 2010, and the inordinate time required to reach financial closure on new generation by IPPs illustrate this failure to learn.

5. **Power sector shortages threaten future economic growth.** Now, when the Ghanaian economy is achieving sustained growth in excess of 6% annually, with ambitions for higher growth, there is a risk that the power sector will become a drag on the economy. As the country consolidates its middle-income status, it needs (and should insist upon) better service delivery and performance by its state-owned energy enterprises.

6. A study[2] undertaken jointly by the Governments of Ghana and the United States concluded that "inadequate and unreliable" power supply is one of the three major constraints to future economic growth.[3] The rapid pace of urbanization and the changing composition of GDP as the service sector grows in prominence render even more urgent the need to ensure adequate and reliable power supply.

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[1] Ghana's power sector has performed relatively well in the past. As a result, Ghana is a regional leader in terms of two key indicators: the amount of electricity consumed per capita, and the share of the population with access to electricity.

[2] U.S. Department of State and Government of Ghana, *Partnership for Growth: Constraints Analysis*, June 2011

[3] The other two major constraints are lack of access to credit and lack of access to secure land rights.

7. **Inadequate reasonably priced fuel and public funding pose major future challenges.** The power sector faces two challenges arising from forces external to the sector: the lack of adequate, ensured quantities of reasonably priced fuel for power generation, and the lack of adequate public funds to finance the sector's investment requirements. These challenges are exacerbated by poor performance by some of the sector's entities, and policies and practices that seriously damage the financial health of the utilities.

Box 1: Findings of previous World Bank power sector reports

The World Bank prepared a brief for the incoming Government of Ghana in 2009, and a detailed analytical report in 2005. Their main findings are presented below. Much of what was stated then is still pertinent.

Key Issues in 2009 Brief prepared by the World Bank

- Valco is negatively impacting the financial viability of the sector. The future of Valco as a viable long-term proposition without heavy dependence on recurrent subsidies needs to be evaluated and delinked from the power sector.
- Much of the country's high-voltage transmission system is aging badly and increasingly unreliable. The risk of outages remains significant as electricity demand continues to rise faster than the rate of economic growth
- The electricity distribution subsector (Electricity Company of Ghana [ECG] and Northern Electricity Distribution Company [NEDCo]) suffers from poor commercial and operational performance. There are high losses due to old and overloaded networks in many areas, combined with problems of metering, billing, electricity theft, and inadequate revenue collection.
- Weak management and regulation of the electricity sector by the Government remains a key issue. There is no clearly defined policy toward private investment in power. The Ministry of Energy (MoE) has no power sector investment plan based on least-cost principles that could provide the basis for mobilizing both public and private resources in a systematic manner.

Findings of 2005 World Bank report

- Enhancing efficiency in all aspects of the sector is the key challenge before Ghana's policy makers. Realizing higher efficiencies in both operations and investment is critical to providing a better deal to existing electricity consumers and to promoting access to potential consumers.
- The sector institutions are caught in a downward spiral of below-potential performance, low resource mobilization and underinvestment, and mounting arrears of payments between sector entities and by external clients, mostly Government entities.
- Timely implementation of power sector reforms is critical. There is a need to enhance the commercial operation of the sector, such as the introduction of contracts for bulk power generation and supply.
- Measures to promote efficient use of current assets are vital. Determining the best institutional and management arrangements for Volta River Authority (VRA)-owned thermal assets is important. The Government has decided to contract out the operations and management of the Aboadze Thermal complex (to be established by unbundling VRA's thermal assets) to the private sector.
- Valco subsidies. Any explicit or implicit subsidies to Valco, including through the power tariff, should be transparent and be borne by the Government, rather than by consumers.
- Efficiency issues are most pressing in the distribution sector. A big part of the distribution sector's financial woes stems from the poor payment culture of Government or public-sector power institutions.

Source: Ghana Energy Policy Economic & Sector Work papers, World Bank, June 2005

8. At present, Ghana is unable to meet current demand for electricity. One of the major reasons for the shortages is the August 2012 cut-off of supply of gas from the West Africa Gas Pipeline (WAGP), (the only source of gas supply in Ghana), because of pipeline damage. Also, Ghana's power system has historically faced systemic risks from erratic water availability, and that is expected to continue because hydro still accounts for more than half of Ghana's generation capacity. In principle, the diversification to

gas has improved Ghana's capacity to absorb the risks of fluctuations in hydropower output. However, the uncertainties of imported gas supplies have added to the unreliability of total power generation.

9. The impact of the gas cut-off would have been mitigated if Government had taken steps to ensure that Ghana's own gas from the Jubilee field had been developed in a timely manner, in parallel with oil production that began more than two years ago. Further, 200 megawatts (MW) of Ghana's generation capacity can run only on gas, and it has been idled by the interruption in gas supply.[4]

10. Fortunately, nearly 80% of Ghana's thermal generation capacity, consisting of combined-cycle and simple-cycle gas turbines, can operate on both gas and light crude oil (LCO). However, LCO-based power is nearly three times more expensive than gas-based power.[5]

11. The increase in power generation costs has not been matched by an increase in the Bulk Supply Tariff. The gas cut-off has imposed an additional cost of US$27 million per month on the power sector, as dual-fuel generators have used LCO instead of gas. As a result, VRA's financial health has been seriously damaged, which, in turn, makes it impossible for VRA to finance its required investments in additional generation capacity.

12. Thus, the impact of the external shock on the economy has been felt with greater force because of non-supportive energy sector policies and practices, and will continue to be felt even after WAGP gas supply is resumed.

13. **A gas shortage is expected to continue for the next 2–5 years.** In the next 10 years, the bulk of Ghana's additional power generation capacity will rely on natural gas—a significant change from the past, when hydropower was dominant. This means that the ensured availability of adequate gas for power generation is a binding prerequisite for reliable and adequate power supply. As discussed later in this report, Ghana will not have access to adequate supplies of gas for power generation until 2015, or possibly even 2018.

14. **Power sector performance and policy problems deter needed investments.** MoE has estimated that Ghana needs to invest over US$4 billion[6] in the next 10 years to make up for the past investment deficit and upgrade its power sector infrastructure. The three major electricity subsectors—generation, transmission, and distribution—all need substantial upgrading, and the necessary investments must take place in a synchronized manner. As discussed below, the distribution and generation subsectors also need quick and decisive policy changes.

15. One of the problems identified by a recent diagnostic study[7] is that Ghana's governance and regulatory framework does not attract private-sector investment in generation, and harms the financial health of power utilities, particularly ECG and VRA. Thus, at present, without significant policy changes and improvements in the performance of power sector entities, there is no clear way forward to produce the investments required to generate and deliver the needed additional electricity supply.

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[4] The gas-only 200 MW Sunon Asogli plant was unable to operate, resulting in load-shedding.

[5] The estimated fuel costs for combined-cycle generation are US¢6.5/kilowatt-hour (kWh) for gas and US¢17/kWh for LCO. For simple-cycle generation, the estimated costs are US¢9.5/kWh for gas and US¢26/kWh for LCO. While LCO-based generation is expensive, it is still cheaper than generation from small, stand-alone diesel generators, where the fuel costs can reach US¢40/kWh.

[6] Ghana Ministry of Energy, *Investment Opportunities in the Power Sector*, January 2012.

[7] *Ghana Power Sector Problem Tree*, Annex B: MCC Compact II, March 2012.

Natural gas sector

16. As discussed above, demand for gas in the power sector will expand rapidly as new thermal generation capacity is built to meet rapidly growing electricity demand. Further, there will also be emerging demand for gas as a petrochemical feedstock and as a source of heat in industrial processes. It is important to ensure that the power sector has the top priority in using the available gas supply, as this is the highest-value use of gas in Ghana.

17. Ghana will need to address a number of important challenges to ensure the successful development of its gas sector. The most important challenge is to ensure that the commercial and technical planning for the development of the Sankofa and TEN (Tweneboa, Enyenra, and Ntomme) fields is completed in 2013, so that they can begin to produce gas expeditiously. However, all indications are that gas from these fields will not be available for consumption before 2017–18, and Ghana is very likely to rely on substantial quantities of liquid fuel for power generation until then.

18. Gas prices and transportation tariffs must be set in a manner that maintains economic incentives for investment in production and pipeline facilities, while ensuring that delivered prices to end users are competitive with alternative fuels. The Government approved a Gas Pricing Policy in 2012, but its publication is still pending. Pricing of non-associated gas will be largely based on investment costs and will not yield significant rents to the Government.

19. An integrated set of commercial, policy, and regulatory arrangements must be put in place to align and coordinate the interests of stakeholders along the value chain, from upstream production to end use. The Energy Commission has recently awarded Bulk Oil Supply and Transport Company (BOST) a license to be the Gas Transmission Utility in Ghana. This award is likely to create confusion about the division of labor and responsibilities between BOST and Ghana National Gas Company (GNGC).

Upstream oil and gas

20. The newly established oil and gas sectors have already produced impressive results, and their revenue contributions to Ghana are expected to be more than the initial estimate of US$1.0 billion per year. Nevertheless, there are reasons to be cautious. First, in the next decade, oil and gas production and revenues will come from only three big fields: Jubilee, TEN, and Sankofa. So far, only Jubilee is in production, and its results to date have not met expectations, necessitating a costly remediation program. Since TEN and Sankofa are still in the development stage, the output and revenues from all three fields are subject to production and timing uncertainties.

21. Further, the results from exploration have not been as prolific as the number of discovery announcements would suggest, and future exploration activity could begin to decline. In any case, by July 2013, the exploration periods for all five of the Tano Basin blocks will have expired, and the acreage held by licensees will be reduced to only those areas with active appraisal, development, or production programs. In 2013, there could be as few as three exploration wells drilled.

22. Exploration has just begun in the Accra/Keta basin, which is a high-risk area. In the Volta Basin, exploration has not even begun, and this is also a high-risk area. A new licensing strategy that takes account of the potential and risks in the areas to be licensed is needed to stimulate exploration.

23. GNPC is Ghana’s principal entity in the upstream oil sector. GNPC’s ambition is to evolve into a commercially independent oil company, acting as operator at times and taking larger, fully-paid equity stakes, including investment in exploration. It is important to ensure that GNPC has a carefully defined long-term strategic mission and role, and that it has the governance structure needed to achieve its goals.

24. The Petroleum Revenue Management Act (PRMA) is Ghana’s principal law governing the use of petroleum revenues. Some practical issues have emerged in the implementation of PRMA. Further, oil

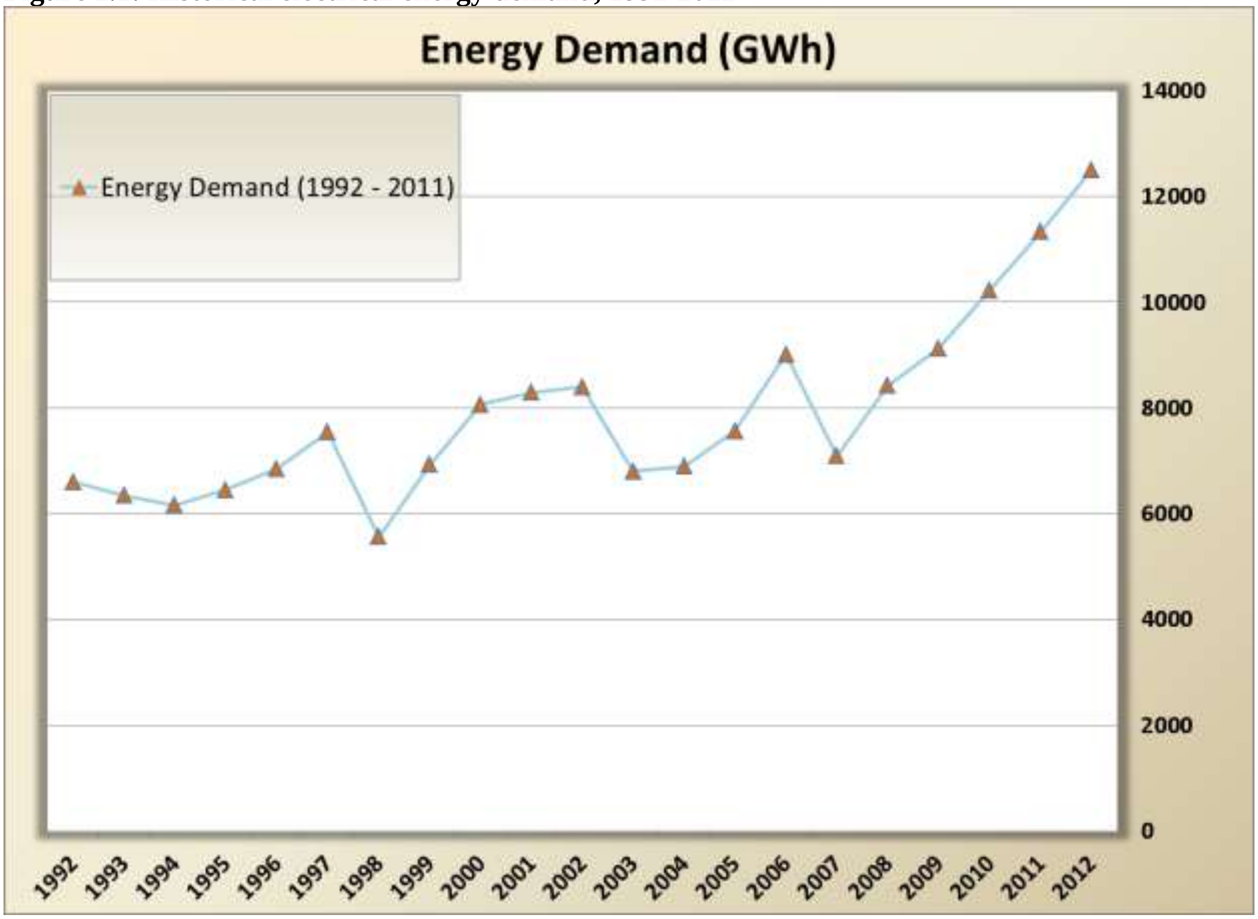
revenues have been below expectations, in part because taxpayers have claimed large deductions for loss carry-forwards, capital allowances, and intercompany interest and overheads. These issues need to be addressed. The effect of reduced remittances to the Petroleum Holding Fund resulting from surplus retention by GNPC should be considered within Ghana's budget framework.

II. ELECTRICITY DEMAND AND SUPPLY

Electricity demand

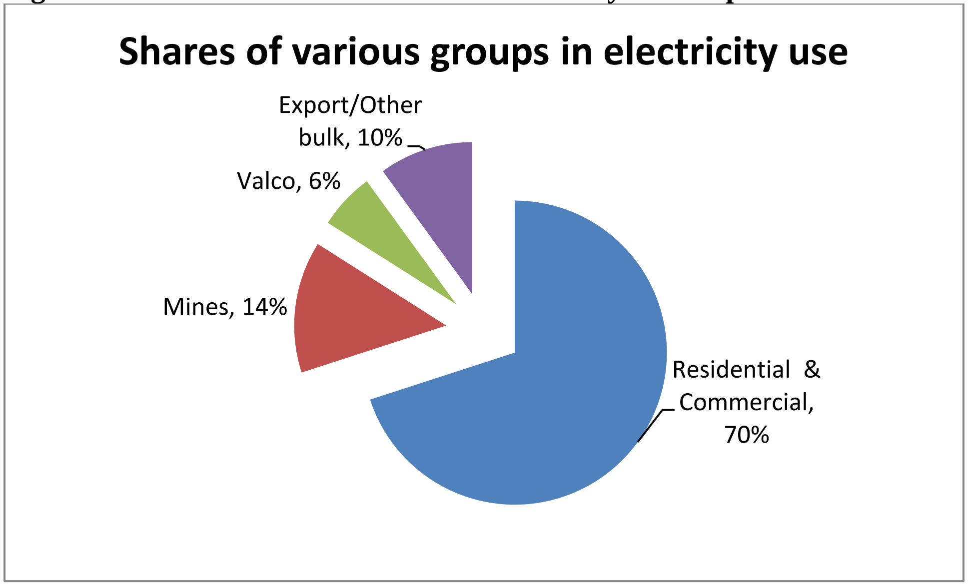
25. **Past trends.** In the past, the consumption of electricity was occasionally constrained by the shortage of power from hydro plants, which were the main source of power in Ghana until 1998. More recently, with additional power available from thermal plants, the consumption of electricity has been increasing rapidly, with total sales increasing by over 10% per year over 2009–12 (Figure 2.1).

Figure 2.1: Historical electrical energy demand, 1992-2012



26. **Source of demand.** Since the 1990s, residential and commercial demand for electricity has increased rapidly, and is the dominant component of electricity use in Ghana. The other significant consumers of electricity are Volta Aluminum Company (Valco) and the mining companies. Figure 2.2 shows the current shares of the various groups of consumers.

Figure 2.2: Shares of various sectors in electricity consumption



Source: World Bank staff calculations.

27. **Consumption forecast.** The Ghana Grid Company Limited (GRIDCo), the Energy Commission (EC), and the Volta River Authority (VRA) have produced electricity demand forecasts. All of them forecast growth rates of demand of in the range 6–7%. While this is a reasonable base case for investment planning purposes, the actual growth rate could be much higher if growth rates in GDP exceed 7% annually on a sustained basis.

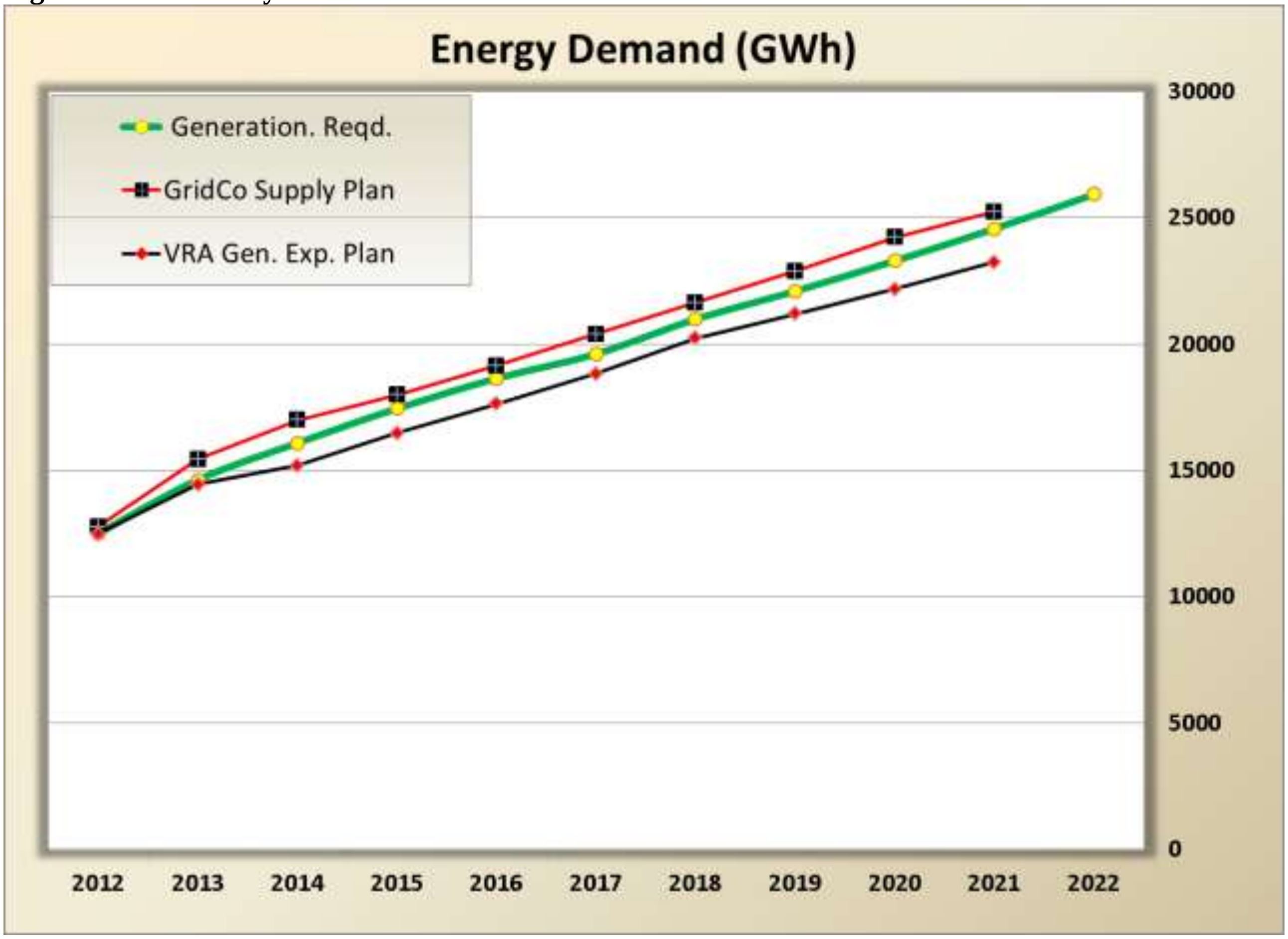
28. The most recent demand forecasts were carried out in 2011 by GRIDCo[8] and VRA. GRIDCo's forecast for residential and commercial growth is 6.5% per year, while VRA's projected annual growth rate is 6.9%. The main difference between GRIDCo's and VRA's forecasts relates to mines, Valco, and other new consumers.

29. There is considerable uncertainty about the future demand from Valco. Even though Valco has the capacity to consume about 310 megawatts (MW) of electricity, representing five potlines of operation, it is unable to pay the full price of electricity. Consequently, the supply to Valco is determined periodically by the availability of cheap hydropower, or by the Government's willingness to supplement the price paid by Valco in order to meet the full cost of supplying electricity.

30. An updated, consolidated forecast, prepared for this review, along with the VRA and GRIDCo forecasts, is shown in Figure 2.3.

[8] Ghana Grid Company Limited, "2012 Electricity Supply Plan."

Figure 2.3: Electricity demand forecast

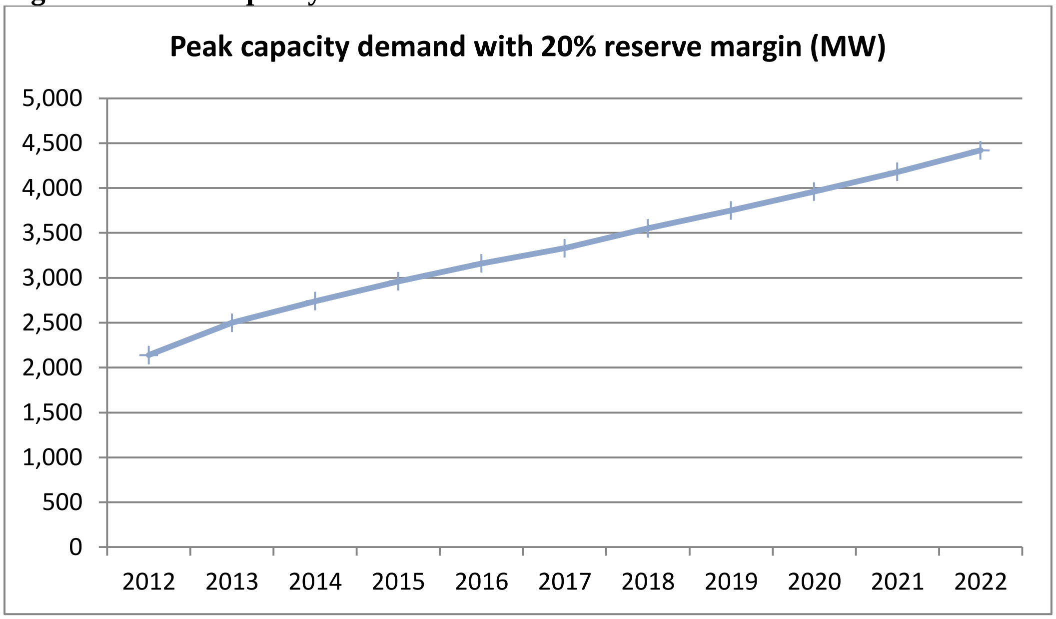


Source: World Bank staff calculations.

31. **Capacity requirement forecast.** A reasonable level of reserve margin is an essential component of peak demand**.** Both the VRA and the GRIDCo demand forecasts utilized an 18% reserve margin. The VRA forecast counted its solar and wind generation projects toward its reserve margin, which fails to recognize that they are not sources of reliable base load generation. Additionally, during peak hours (05:00–06:30 hrs. and 18:00–20:30 hrs.), solar generation is not available.

32. This report uses a 20% reserve margin. It should be noted that even this level of reserves may be insufficient to cope with the hydrological risk of dry years. The peak demand, including a 20% reserve capacity margin, is shown in Figure 2.4; the details of the peak demand forecast are available in Annex 2.1. The demand growth on the base case will require the addition of about 2,400 MW of generation capacity until 2022, which would more than double Ghana's total generation capacity.

Figure 2.4: Peak capacity demand forecast



Source: World Bank staff calculations.

Electricity supply sources

33. Until 1998, the supply of electricity in Ghana was exclusively from hydroelectric sources. Since then about 1,000 MW of thermal generation capacity has been added. Currently, the installed nameplate generation capacity is 2,412 MW. The current dependable generation capacity of 2,125 MW in Ghana is made up of about 50% hydro and 50% thermal.

34. **Hydropower.** The Akosombo generating station (1,020 MW) and the Kpong Plant (160 MW) are the only hydro stations in operation. The 400 MW Bui Hydroelectric Project is almost complete and is expected to be fully commissioned in late-2013.

35. Several other hydro sites have been identified as having generation potential, including Pwalugu (48 MW), Kulpawn (80 MW), Juale (87 MW), Daboya (44 MW), and Hemang (75 MW). However, none of these sites has a full feasibility available yet, and given the long lead time in constructing such plants, it is not expected any of them could produce power before 2020. In any case, together they amount to only 334 MW, which means that these projects would only make a modest contribution to power generation in Ghana.

36. **Natural gas.** The first 110-MW unit of VRA's Takoradi Thermal Power Station, commissioned in 1998, was the first significant thermal-based supply source in Ghana. By the end of 2000, the station was expanded to 550 MW, and has just been further expanded by the addition of a third tranche of 132 MW of combined-cycle generation capacity. All but 220 MW of this capacity is fully owned and operated by VRA.[9]

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[9] TAQA, the sovereign wealth fund of Abu Dhabi owns 90% of this.

37. Another 500 MW of thermal power plants has been installed and commissioned at Tema at various dates. Some of them are public projects, but most of the capacity is private (Sunon Asogli, 200 MW), or semi-private (CENIT, 126 MW).

38. Several thermal generation projects totaling over 1,000 MW are currently at various stages of development by both public and private operators. These projects include Kpone (Alstom), Sunon Asogli Expansion, Takoradi 2 combined-cycle expansion, CENIT/TT1PP expansion, and Takoradi 3 expansion.

39. **Renewable energy targets.** The Government has stated that it wants to achieve 10% renewable energy in the generation mix by 2020. It is presumed that the target is 10% of total generation, not generation capacity, although the precise target is not clear from the Renewable Energy Act.

40. The Renewable Energy Act defines hydro not exceeding 100 MW as renewable energy. Pwalugu, Kulpawn, Juale, Daboya, and Hemang would, in principle, help in meeting the 10% renewable energy objective, but none of these is expected to produce power before 2020. The feed-in tariff (FiT) for small hydro projects has been announced to be US¢11.18/kilowatt-hour (kWh), which has introduced an element of certainty for potential developers of these hydro projects.

41. **Solar.** The solar resource is abundant in Ghana. The monthly average solar irradiation is between 4.4 and 5.6 kWh/m^2/day, with sunshine duration of between 1,800 and 3,000 hours per annum. However, till recently, little was done to exploit this resource for grid-connected power generation.

42. VRA has just completed a small 2-megawatt-peak (MWp) solar photovoltaic (PV) grid-connected plant as a pilot project in Navrongo in the Northern Electricity Distribution Company (NEDCo) areas of operation, which should be commissioned later this year. Four sites in the environs of Kaleo (near Wa), Lawra, Jirapa, and Navrongo have been identified and acquired for a total of 10-MWp PV plants. VRA is seeking concessionary funding to develop the remaining 8 MWp.

43. Canada's Siginik Energy Ltd. has signed a 25-year Memorandum of Understanding with the Electricity Company of Ghana (ECG) for a 50-MW ground-mounted PV project in the northern region, near the Ivorian border. However, the proposed project's development timeline is not clear at this stage.

44. The prospects for grid-connected power generation have improved because of the recent decline in the price of solar panels.[10] The FiT for solar projects has been announced to be US¢20.14/kWh, which would provide a reasonable incentive to the developers of solar projects. In light of these developments, Ghana should consider larger grid-connected solar power plants. One emerging possibility is solar plants located at hydropower plants. These solar plants would save some costs by feeding power into the same lines as the hydropower plant. Further, the solar panels could cover the reservoir, thus avoiding the need for additional land. Finally, the solar power would be available as a complement to hydropower when water levels are low.

45. **Rural solar power.** Solar power has considerable potential to serve households in unelectrified villages. At present, households anticipate getting power from grid power. Therefore, there is a reluctance to invest in PV systems. Further, solar PV's potential as an interim electrification solution in remote, rural communities is stymied by a policy that focuses heavily on grid connections, even though this means that the Government is paying high subsidies for grid electricity connections in remote areas. This is particularly ineffective in times of power shortages, because the rural areas generally get very little power when supplies are short.

[10] http://www.economist.com/news/21566414-alternative-energy-will-no-longer-be-alternative-sunny-uplands.

46. A more cost-effective subsidy policy for rural electrification would include stand-alone mini-grids and stand-alone household systems for customers who are not within economic reach of the grid in a timely manner. This would reduce the strain on the power utilities' finances,[11] and also provide service quicker to those who will not have grid service in a reasonable time period.

47. **Wind power.** Ghana's best wind resources are found primarily along narrow stretches of its eastern coastline. Along the coastline, the speeds (mostly 6–7 meters per second [m/s] at 50 m) are classified as "marginal"[12] for wind generation. Nevertheless, grid-connected wind power is likely to be cheaper than grid-connected solar power.

48. At present, there are three projects in the planning phase. VRA intends to build a wind power plant as a joint venture with a foreign partner with wind farm experience. Currently two reputable companies have been identified who are working with VRA to undertake the wind measurement, after which the project could be developed. Wind measurements will be undertaken at four coastal sites and four inland sites. It is anticipated that two of these sites would be developed,[13] provided that the wind speed proves to be adequate.

49. NEK, a Swiss company, has partnered with Accra-based Atlantic International Holding Co. Ltd. to develop a 50 MW project.[14] China Wind Power is considering up to a 2x 50 MW project, but has not yet made any concrete plans. The FiT for wind plants has been announced to be US¢12.55/kWh, which would provide some incentive to the developers of wind projects.

50. Clearly, it will be several years before the full extent to which Ghana's wind resource is technically and financially viable for development on a large scale becomes clear. Yet, it is already evident that wind power is not likely to prove to be a substantial contributor to the power supply in the next decade.

51. **Biomass and mini-hydro**. These resources have not yet been developed for generating electricity in Ghana, and there are no projects in an advanced planning stage. Some developers are undertaking feasibility studies for biomass projects.

52. **Infeasibility of renewable energy target.** There still remains a need to assess all of Ghana's renewable energy resources to determine their cost-effective contribution to grid-based power supply and electricity access in remote areas. Given the lead times and challenges in developing renewable energy, it is apparent that the Government target of 10% renewables in the generation mix will prove to be unattainable by 2020.[15]

53. **Coal.** Coal is a well-established, relatively inexpensive fuel for generating power, and is widely used around the world. However, Ghana does not have coal deposits, nor any infrastructure for large-scale imports of coal. The option of using coal for power generation in Ghana has not yet been studied to any significant degree. Further, coal-based generation, which has high levels of associated carbon dioxide

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[11] The current tariff structure does not compensate the distribution companies for the higher costs associated with rural electrification.

[12] 2004 U.S. Department of Energy, National Renewable Energy Laboratory, Wind Resource Map for Ghana – 50 m. Available at: http://www.nrel.gov/wind/pdfs/ghana.pdf.

[13] Volta River Authority, VRA Projects; On-going Generation Projects. Available at: http://vraghana.com/projects/index.php.

[14] NEK, Kpone/Pram Pram, Ghana. Available at: http://www.nek.ch/windenergie-geothermie-e/referenzen-umwelttechnik/windenergie-kpone-prampram/referenz-windenergie-kpone-prampram.php?navanchor=2110021.

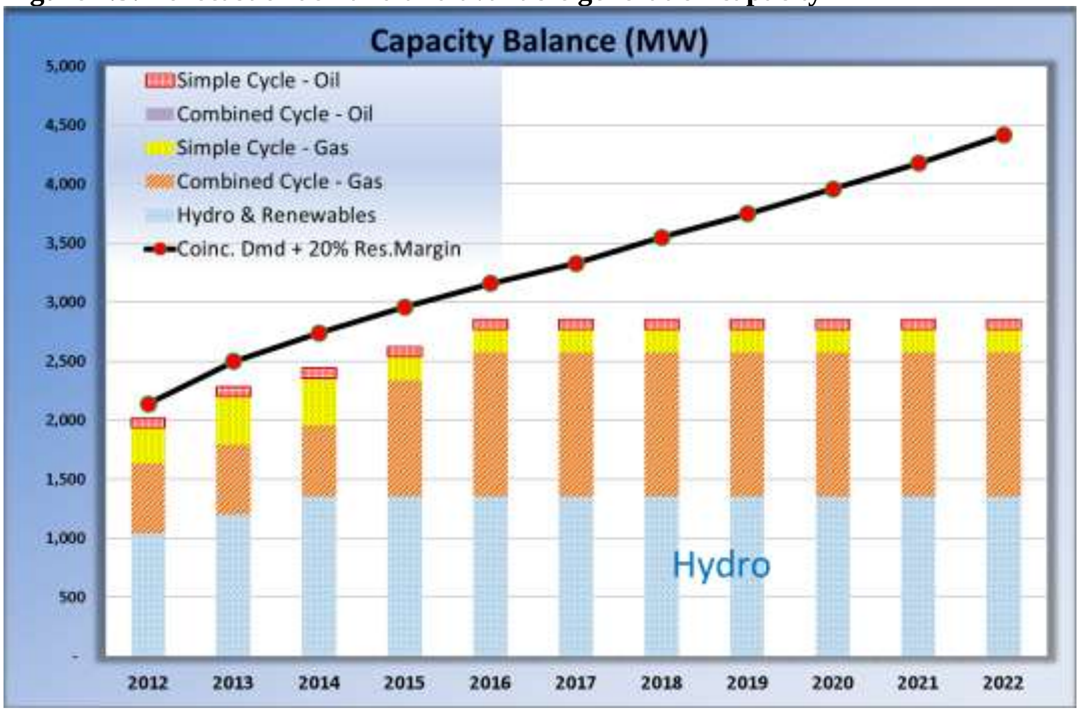
[15] Without further detailed analysis, it is difficult to estimate what can be achieved by 2020.

emissions, is seen as contributing to global climate change. Nevertheless, the option of coal-based generation should not be ruled out without further analysis. The Energy Commission should be tasked to examine the relevance and merits of coal as primary fuel for Ghana.

Forecast of available generation capacity

54. Based on assumptions related to existing and committed generation plants, the available generation capacity and the demand are shown in Figure 2.5 (see Annex 2.1 for details).

Figure 2.5: Forecast of demand and available generation capacity



Source: World Bank staff calculations.

55. Table 2.1 presents the key assumptions used for this forecast, with comparable assumptions from the VRA and GRIDCo forecasts.

Table 2.1: Plant availability assumptions underlying generation capacity forecast

Plant	This Report	VRA	GRIDCo
Takoradi Thermal Power Station (TTPS) (T1) [16]	80%	70%	70%
Takoradi International Company (TICo) (T2)	85%	85%	80%
Mines Reserve Plant (MRP)	75%	75%	75%
Sunon Asogli Power Plant (SAPP)	75%	75%	68%
Other Thermal Plants	85%	85%	85%

Source: World Bank staff calculations.

Forecast of generation capacity shortages

56. Our analysis (Figure 2.5) indicates that the installed generation capacity in the next decade, based on existing and committed plants, will fall short of the peak demand every year. This generation capacity shortage will exist unless plants other than the existing and committed projects are commissioned. The generation shortages will become particularly acute after 2016.

57. To keep pace with the growing demand for electricity, Ghana needs to add—beyond those already planned and committed—an additional 1,560 MW of dependable generation capacity from new projects in the next decade. Given the minimum 2–3-year lead time before financing can be finalized, time is short for Ghana to take action to avoid a new recurrence of load shedding post-2017.

[16] Until 2010, the availability of the TTPS had been significantly lower than would normally have been expected. The supply projections of VRA and GRIDCo, which were conducted based on 2010 performance factors, assumed that the availability of TTPS would remain at about 70%. The remedial actions taken by VRA have resulted in an improved availability. Accordingly, the assumed availability for this study has adopted the improved availability of 80%.

III. RESOLVING GENERATION AND TRANSMISSION BOTTLENECKS

Primacy of natural gas in generation

58. Until 1998, the generation of electricity in Ghana was exclusively from relatively cheap hydroelectric sources. This legacy still influences public opinion, because the public has not been clearly told about the increasing role and higher costs of thermal plants in the supply of power, both today and in the future. In the past 15 years, about 1,000 MW of thermal generation capacity has been added, and much of the future capacity addition is based on natural gas, yet the notion of plentiful cheap hydro still lingers in public opinion.

59. Current investment plans from VRA and IPPs add up to about 740 MW of additional generation capacity. Only about 360 MW of this additional capacity will come from hydro, and about 380 MW will be in the form of combined-cycle gas power stations.

60. For the additional 1,560 MW that is needed to meet demand, there are only limited generation options. Ghana's hydro potential has been largely exploited, and there may be only an additional 100–300 MW of hydropower, beyond what is already planned.

61. As discussed in Chapter 2, renewable energy will make only a small contribution, and coal has not yet been even studied in Ghana. In contrast, Ghana already has experience with gas-based power generation, and has discovered its own source of indigenous gas.

62. Under this set of circumstances, natural gas will assume a dominant role in future large-scale power generation in Ghana. Natural gas is both cleaner and cheaper than oil,[17] the only credible alternative fuel available to Ghana's power sector for the medium term.

63. Gas is already being produced from the Jubilee field but is being re-injected. Gas sales will begin in 2014 once pipeline infrastructure is in place. However, this gas supply is already "spoken for," as it will be fully absorbed by existing power plants. Greater volumes of Ghanaian gas are not expected to be available before 2017. Additional volumes of gas *may* also become available from Nigeria via the West Africa Gas Pipeline (WAGP), although this is highly uncertain.

64. Nevertheless, the available supply of gas, both local and via pipeline, will not be enough to meet the needs of the power sector for the period through 2015 (Chapter 6). Thus, Ghana will have to rely significantly on liquid fuels for power generation until then, or possibly even later, if there are some delays in indigenous gas becoming available.

65. Regardless of the source, the cost of the gas[18] will be such that gas-based power generation will be at least US¢9–10/kWh at the generation level. This is more expensive than prevailing thinking in Ghana has suggested. Current power tariffs in Ghana do not reflect such supply costs, due in part to cheap legacy hydropower. Furthermore, government policy and public perception have failed to take account of the shrinking share that hydro represents in the current and future generation mix.

66. **Recommendations.** The Government should:

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[17] Oil is crucial for revenue mobilization and transportation, but is not cheap for power generation or major industrial use. Light crude oil (LCO) costs range from US¢17/kWh (combined-cycle) to US¢26/kWh (simple-cycle).

[18] In the planning scenario (Chapter 5), Sankofa is the marginal gas source throughout the majority of the planning horizon. From the point of view of economic efficiency, this implies that the Sankofa price (roughly $10/million British thermal units delivered to Takoradi) is the market-clearing price of gas in Ghana.

- Recognize that adequate supplies of natural gas are essential for power generation, and take steps, as described later in this report, to facilitate the availability of gas.
- Recognize and publicize that gas-based power generation will be more expensive than legacy hydro generation, though cheaper than other readily implementable alternatives, such as LCO.

Barriers to attracting IPPs

67. There are three IPPs in operation in Ghana—Takoradi International Company (TICo), Sunon Asogli Power Plant (SAPP), and CENIT. The Government Consent and Support Agreement for a fourth IPP, Cenpower, received Parliamentary approval in October 2012.

68. The importance of IPPs to ensuring the reliability of supply within the energy sector cannot be overstated. The energy demand in Ghana has exceeded the firm generation capacity of Ghana's primary generator, VRA. The Government has expressed its desire to increase generation capacity to 5000 MW by 2015. VRA's recent financial struggles do not suggest that it can be counted on to provide the required increment in energy supply.

69. Under these circumstances, IPPs and IPP facilitation are essential to ensuring reliable energy supply for the attainment of Ghana's growth objectives. Attaining the expected increment in generation capacity will depend upon proactive and accelerated private-sector initiatives. Apart from concerns about the availability of adequate amounts of gas as a fuel, there are several other barriers to attracting IPPs to invest in power generation in Ghana.

70. **Lack of a credible offtaker.** In Ghana's first IPP project, VRA had the dual role of both owner and offtaker. This was rationalized on the basis that the purpose of the project was to complement hydro generation from Akosombo and Kpong, and enable the optimization of the yield from these sources. Since then, VRA has been unwilling to sign power purchase agreements (PPAs) with IPPs since it regards IPPs as competing generation entities.

71. The current structure of the power sector includes the definition and licensing of "bulk customers," who are free to procure their power needs directly from wholesale suppliers via transmission services provided by an Independent System Operator. In accordance with EI 1937, the potential offtakers of power are ECG, NEDCo, the mining companies, and other licensed bulk customers.

72. The reality is that only ECG, and no other potential buyer, has signed a PPA to offtake power from any of the IPPs. Three out of the four PPAs underpinning IPP development in Ghana have ECG as the offtaker, and one has VRA as the concurrent co-owner and offtaker. The IPPs that have attempted to enter the Ghanaian market have reported difficulties in securing PPAs with other organizations.

73. The mines and bulk customers lack financial motivation to sign binding PPAs. At present, bulk customers enjoy access to low-priced hydro or hydro-blended supply from VRA. Moreover the terms of these agreements are short, are typically renewed annually, and have flexible terms. Furthermore, the arrangements with VRA do not necessitate capacity payments, take-or-pay clauses, or any other clauses that are usually included in PPAs with IPPs. The generous terms of VRA supply make these potential offtakers reluctant to execute a PPA with an IPP.

74. As discussed in Chapter 4, many potential participants do not consider ECG as a credible, bankable offtaker. As a result, IPPs are likely to require a sovereign guarantee for their PPA with ECG. Government's reluctance to issue such sovereign guarantees has proven to be a major stumbling block for new IPPs over the past 5+ years.

75. **Uncertainty of procedures and regulations.** A framework for promotion, selection and regulation of IPPs exists, but what an investor goes through in practice often varies significantly from the formal framework. This leads to uncertainty for private investors. Project developers have indicated that during each step of developing their IPPs, they encountered new and unknown requirements for

advancing their developments to the next step. For example, IPPs register with the Ghana Investment Promotion Centre (GIPC) to access fiscal incentives, such as duty exemptions for capital equipment. The process of obtaining actual exemptions ends up being cumbersome, costly, and time consuming due to necessary approvals required from several Government agencies (Ministry of Energy [MoE], GIPC, Ghana Revenue Authority [GRA], Ministry of Finance and Economic Planning [MoFEP]).

76. **Cumbersome and time-consuming development process.** Ghana does not have a single-window system for IPPs. Private-sector developers have to deal with multiple regulatory authorities, and spend significant time in negotiations with them, which makes the project development process time consuming and costly.

77. **Recommendations.** The Government should take steps to create a more attractive environment for IPPs by mitigating the barriers listed above. One of these steps would be to appoint a top-notch technical adviser on IPPs in MoE. Further, the Government should designate a full-time, high-level IPP facilitator to lead an open, competitive solicitation and contracting process that is based on standardized terms, including payment mitigation risk.

VRA—the dominant power generator

78. VRA's core mandate has undergone significant changes in recent years. Ghana Grid Company Limited (GRIDCo) was formed in December 2006 to be the Independent Transmission System Operator, and accordingly took over VRA's transmission functions and assets in 2008. The establishment of the Bui Power Authority (BPA), with the responsibility of developing a hydroelectric plant at Bui, has reduced VRA's functions relating to the Black Volta Basin, contrary to its founding legislation mandating it to be responsible for all hydro resources within the Volta Basin. Northern Electricity Department, the distribution department of VRA from the late 1980s until 2011, has also been restructured into a wholly owned VRA subsidiary company, known as NEDCo.

79. VRA has nevertheless remained the dominant player in power generation in the country. VRA owns and operates the 1020-MW Akosombo hydroelectric plant, the 160-MW Kpong hydroelectric plant, the 330-MW TAPCo and 130-MW Takoradi thermal 3 (T3) plants at Aboadze, and the 126-MW Tema T1 plant. VRA also operates the 80-MW Mines Reserve Plant and the 50-MW Siemens plant, both at Tema. Finally, VRA has a 10% shareholding in the 220-MW TICO plant with TAQA New World, Inc., now undergoing expansion, and has been assigned the responsibility of installing and operating the 200-MW Alstom generation units purchased by the Government in 2007.[19]

80. At energy production costs of about US¢5/kWh, hydro costs are far lower than thermal generation costs, which range between US¢9/kWh (gas-fired combined-cycle gas turbine) and US¢27/kWh (LCO-fired, open-cycle gas turbines). VRA is therefore able to offer energy to bulk consumers at blended costs of hydro and thermal, which are lower than the pure thermal costs of IPPs. The Government has also often provided VRA with funding for fuel purchases during periods when tariffs have fallen below the full cost recovery levels, thus enabling VRA to sustain some level of stability in generation and minimize the extent of load shedding.

[19] The only other generating plants in the country are the 200-MW Sunon Asogli plant at Tema, an IPP established by the Shenzen Group from China, and the newly commissioned 126-MW CENIT plant, also at Tema.

Underperformance of VRA's thermal plants

81. A recent audit[20] concluded that VRA's Akosombo and Kpong hydro plants are performing well. Nevertheless, the audit recommended that, given the high capacity factor of the plants, attention should be given to sufficient maintenance to prevent forced outages and possible future degradation in performance.

82. The audit also found that VRA's thermal power stations at Takoradi and Tema are not performing well. These weaknesses have aggravated the recent period of load shedding since September 2012, because VRA units were unable to operate at full capacity on a sustained basis to mitigate the loss of output from Sunon Asogli resulting from the gas supply cut-off.

83. The audit found that the performance of the VRA plants at Takoradi improved during the last 2 years of the period (2009-10), although not to the level that would be expected internationally. The simple-cycle performance of the two VRA Takoradi gas turbines is much lower than the international targets, having a very high number of outages. Similarly, the combined-cycle performance of Takoradi is very low and well below international benchmarks. Both the gas and steam sections show very high level of outages, with the steam section being the worse of the two[21].

84. Initially, the performance of the more recent Tema plant (TT1PP) was low. However, lately it seems to be improving toward internationally acceptable levels, but this goal has not yet been achieved. The maintenance in Tema seems to be carried out generally in line with original equipment manufacturer specifications, but is constrained by availability of spare parts, resulting in longer than strictly necessary outage times.

85. **Recommendations.**. Given the difference between the good performance of VRA's hydro plants and the poor performance of its thermal plants, the Government should once again consider separating the thermal plants from VRA's hydro operations. The mid-2003 Cabinet-approved Power Sector Reform Strategy envisaged such a separation, but it was never implemented.

86. The thermal plants should either be put under a separate, new entity, which could be a subsidiary of VRA provided it was run as an entirely separate business, or ultimately be entirely separated from VRA. Since the vast majority of the future generation capacity additions will be thermal power, it is essential that thermal power stations perform well, and the current dispersion of skills within VRA across very different technical areas has not proven satisfactory. A purely thermal generation company would be unable to cover inefficiencies and poor performance in thermal generation through hidden cross-subsidies from hydro generation, and would thus be more easily made accountable for better technical performance.

87. The study of the merits of such a separation could also be expanded to examine the case for merging BPA with an all-hydro VRA, since both operate plants on the same river basin.

VRA's financial vulnerability

88. VRA's performance has been dependent on the proportion and cost of thermal and hydro generation in the supply mix, the level of tariffs approved by the Public Utilities Regulatory Commission (PURC), and the amount of energy allocated and price paid by Volta Aluminum Company (Valco). VRA incurred net losses for five successive years from 2003 to 2007 and also in 2009. These

[20] KEMA, *Technical and Operational Audit of Volta River Authority (VRA)*, Submitted to: Public Utilities Regulatory Commission of Ghana, November 2012. The analysis was based on plant data for 2005-10.

[21] VRA has made efforts to raise performance of the Takoradi plant since 2010, but data on 2011-12 plant availability and outages was not available for analysis at the time this review was undertaken.

were periods of relatively low hydro generation, high fuel prices, and less than full cost recovery from tariffs. In 2008, 2010, and 2011, however, a combination of high hydro generation, tariff increases, and availability of gas for power generation, as well as Government assistance in the form of crude oil purchases in lieu of implementation of full cost recovery tariffs enabled VRA to make net profits.

89. The net losses coupled with mounting trade and other receivables, including inter-utility debts, which increased from about Ghana cedi (GHC) 185 million in 2007 to GHC 636 million by 2011, have created serious cash deficits for VRA. This situation has prevented VRA from contributing to the investment required to maintain and expand the power system in an orderly manner and compelled VRA to rely on Government support and commercial borrowings for crude oil purchases.

90. **Losses due to LCO purchase.** VRA is facing a very difficult financial situation, due in large part to its vulnerability to external shocks over which it has little control. While VRA made a profit in 2011 (about US$55 million), its financial situation deteriorated sharply in 2012. First, there was no increase in the Bulk Supply Tariff (BST), even though VRA's costs had increased. More important, the shutdown of gas supply obliged VRA to buy much more LCO. VRA's loss for 2012 was GHC 438 million (US$ 230 million), prior to receiving a Government subsidy of GHC 361 million.

91. VRA's short-term crude oil purchase obligations, as of the end of 2012, amounted to GHC 1,151 million (US$604 million). This includes the Government support of US$53 million provided in December 2012 for a cargo of LCO delivered in January 2013.

92. VRA's LCO requirements for 2012 were financed using a combination of letters of credits (LCs) established on VRA's behalf by financial institutions, Government promissory notes (PNs), and supplier credit arrangements. The LCs, supported by PNs issued by MoFEP, amounted to a face value of US$306 million during 2012 (Table 3.1). During the first quarter of 2013, VRA estimates that about GHC 602 million (US$317 million) is required to purchase LCO, because gas supplies will not be available.

Table 3.1: VRA's commitments for LCO purchases

Outstanding/Overdue LCO Commitments as of December 31, 2012	**GHC Million**	**US$ Million**
Letter of Credit Commitments (payable by VRA)	396.5	207.9
Letter of Credit Commitments (payable with MoFEP PNs)	564.1	295.8
Medium-Term Loan (Used to pay-off VRA Short-term LCO obligations)*	190.7	100.0
TOTAL	**1,151.3**	**603.6**

Source: VRA.

93. VRA is expected to realize a considerable operating loss in the range US$400–500 million in 2013 in the absence of an increase in the BST.[22] If there are further delays in the resumption of gas

[22] Under the assumption that Nigerian gas supply will resume at 90 million standard cubic feet per day on May 1, 2013.

supply, the losses will be larger. Apart from its vulnerability to gas supply interruptions, VRA is faced with risks resulting from unfavorable oil price and exchange rate movements. All of these factors can easily jeopardize its financial performance if there is no rapid mechanism, such as a quarterly tariff adjustment to mitigate these exogenous shocks.

94. **Clearinghouse mechanism.** A cross-debt clearinghouse arrangement has been established to manage the inter-utility and Government debts comprises VRA, ECG, NEDCo, Ghana Water Company Ltd., and the Government of Ghana represented by MoFEP. The clearinghouse is expected to meet quarterly to reconcile the cross-indebtedness of the participants and net off such debts where appropriate. The outstanding amount owed by each agency after the netting off is expected to be paid to the creditor utility. This arrangement has not been effective, primarily because there are no means of enforcing payment expected from the net debtors. Therefore VRA, which has over 80% of its revenues accruing from these other members of the clearinghouse, is constantly owed, leading to the build-up of receivables.

95. In 2012, MoFEP suspended the clearinghouse mechanism, but no alternative payment arrangements have been put in place. Reviving and restructuring the clearinghouse is urgent, since monies owed to the power utilities by Government bodies have reached unsustainable levels, with negative consequences for the utilities' operations. However, MoFEP's dissatisfaction that it is carrying an unreasonable burden of paying for the electricity consumption of revenue-earning entities, such as universities, is warranted. While necessary, clearance of state arrears by the Government is not sufficient in the absence of better arrangements to prevent recurrence of the arrears. A task force on this matter should be set up immediately and asked to propose alternative payment arrangements within a two-month period.

96. **Implications of poor financial status.** Given the huge need for investment in additional generation capacity to meet the growth in demand, a generator with most of its output based on hydro should generate significant cash flow from current operations, and should be able to self-finance part of its investment program and to borrow based on the strength of its balance sheet. Instead, VRA will be in a situation where, even with a fairly optimistic scenario for gas availability, current operations will result in net cash outflows. In addition, VRA will have to deal with the large stock of short-term debt accumulated in 2012.

97. VRA's capital expenditure program is no longer achievable. In 2011, VRA invested only about US$67 million in capital expenditures, instead of the US$123 million originally planned. Prior to the cut-off of gas supply, VRA was projecting large investments in generation, with total capital expenditures of US$860 and US$595 million, respectively, in 2013 and 2014.

98. In the absence of any buffer or contingency funds, it is not clear how a loss-making VRA would finance even moderate levels of capital expenditure in 2013. Going forward, quarterly financial reviews of both capital and operational expenditures by VRA are essential, and less expensive credit lines need to be put in place to help tide over unanticipated calls on cash.

99. Given the prospect of continued negative cash flow in 2013, VRA will find it difficult to service the short-term debt overhang accumulated in 2012, irrespective of any efforts to reduce further capital expenditures. The only available option for VRA is to refinance this short-term debt, at relatively high interest rates, which would further deteriorate its balance sheet. The current situation is highly anomalous. VRA's absolute level of debt is not especially high for a generation utility of this size, but too much of the debt consists of expensive short-term loans that were used to finance current expenses rather than investments.

100. **Recommendation.** Government financial support to resolve VRA's finances is unavoidable. The sooner this bailout occurs the better, because its cost will increase over time. The Government will need to assume responsibility for most of the debt incurred (via commercial letters of credit) to buy crude oil in

2012. Once a credible (cost-reflective with timely indexing mechanisms) bulk electricity pricing mechanism is put in place, VRA would be able to generate a significant and predictable level of cash flow, and therefore take on long-term debt in its own name to finance new generation investments.

Bui Power Authority (BPA)

101. Established in 2007, BPA is charged with developing and managing a hydroelectric plant at Bui on the Black Volta.

102. BPA has mobilized concessionary loans from the Government of the People's Republic of China (US$263.5 million) and export buyer's credit from the Export-Import Bank of China (US$298.5 million), in addition to a contribution by the Government of Ghana of US$60 million to finance the hydroelectric dam at Bui. Parliamentary approval has recently been obtained for the project lenders to provide the additional funding of US$168 million required to complete the project. This brings the total cost to date of the 400-MW project to about US$790 million.

103. As part of the financing arrangements for the project, the Government of Ghana and BPA have entered into several covenants with the project lenders that include the mortgage and escrow of the assets, land, and revenues associated with BPA and the project. In support of this, BPA has secured a PPA with ECG at a tariff that will generate sufficient revenues to cover its costs, currently estimated about US¢10/kWh, and will be finalized once the project is completed and the final cost established. This tariff, which has been negotiated with the PURC kept informed, is substantially above the current PURC-approved BST that ECG pays VRA.

104. BPA is apparently required by these various loan and other agreements to maintain its status as an independent entity from VRA, at least until the loan repayment and all other obligations relating to the mortgage and land have been satisfactorily discharged. The main motivation for a possible merger of BPA with VRA is the operational efficiency that can be achieved through the sharing of maintenance skills and operational experiences. So far, BPA and VRA have been collaborating effectively toward the replication of operating systems, standards, and practices, as well as in the field of personnel training and skills development. Therefore, the indications are that the benefits of joint operation are being largely obtained without the merging of the two entities, although this implies the unnecessary duplication of corporate functions, such as administrative and other overheads that could otherwise be avoided.

105. **Recommendations**. The Government is advised to undertake an independent analysis of the merits of a merger between BPA and VRA sooner rather than later, given that inertia and staff resistance will build up if this is inordinately postponed. The question of a merger could be addressed at the same time as a review of the merits of unbundling thermal generation from VRA to set up a purely thermal power company, which would have greater inherent logic than the existence of two different hydro entities operating on the same river.

Aggressive promotion of energy efficiency and demand-side management

106. Even with rapid remedial action, Ghana is likely to face difficulties in generating adequate power to meet the increasing demand driven by a rapidly expanding economy. In any case, even if adequate amounts of power can be generated, the costs will be much higher than in the past.

107. In the coming era of high-cost power and possible persisting shortages, it is imperative that Ghana ensure that consumers utilize available power is efficiently. Given that the economic cost of thermal power delivered to end users will be more than US¢12–15/kWh, it is likely that there are

significant financially viable opportunities for reducing energy use through energy efficiency, and shifting electricity use to off-peak periods via demand-side management. In other words, in many cases, it will be cheaper to reduce demand than to generate and deliver electricity to be used wastefully.

108. Ghana has already instituted several energy efficiency measures, such as promotion of compact fluorescent lamps (CFLs)[23] and establishment of standards for air-conditioners and other appliances. However, Ghana has only begun to scratch the surface of energy efficiency in the electricity sector. These efforts need to be expanded significantly to identify large segments of demand where there are significant opportunities for energy efficiency in the appliances and machinery to be installed in the future.

109. **Focus on industrial and commercial sectors**. In emerging economies, large industries and commercial organizations are a potential source of energy savings, and this is likely to be the case in Ghana. A recent study[24] concluded that “energy is poorly managed in the Tema industrial area and there is an energy efficiency gap resulting from the low implementation [of] energy efficiency measures.” Industrial users could be induced to undertake cost-effective energy efficiency investments, but these opportunities have not been systematically exploited or identified as a means of improving their profitability.

110. **Power factor corrections.** Many large industrial customers have unsatisfactory power factors,[25] a technical problem that requires unnecessary investments in distribution and generation. Since it is very cost-effective for these customers to invest in increasing their power factors, efforts must be made to ensure that all large customers have acceptable power factors.

111. **Recommendations.** The Government should give high priority to energy efficiency and demand-side management, and consider them on an equal basis with generation expansion. It is important to focus on those opportunities where the costs of energy efficiency and demand-side management programs are financially attractive to the implementers, so that the plans are implemented without delays. The Energy Commission should be tasked to undertake an analysis of energy consumption in the industrial sector to develop energy efficiency initiatives.

Upgrading transmission

112. **GRIDCo.** The Ghana Grid Company was set up to be the Independent Transmission System Operator and took over VRA’s transmission assets in 2008. GRIDCo’s financial performance has consistently improved since its establishment in 2008. From net losses of GHC 15.5 and GHC 6.9 million, respectively, in 2008 and 2009, the company recorded net profits in 2011 (GHC 84 million), and GHC 65 million in 2012.

113. **Aged infrastructure**. Transmission losses on Ghana’s National Interconnected Transmission System (NITS) between January 2011 and June 2012 have varied between 3.1% and 6.1%. More significantly, in 2012, Ghana had a number of total system collapses, in part attributable to transmission system failures.

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[23] During the power crisis of 2007, MoE instituted such an energy efficiency program, which encouraged consumers to replace high-energy-intensity incandescent lamps with energy-efficient CFLs.

[24] Raphael Wentemi Apeaning, *Energy Efficiency and Management in Industries—A Case Study of Ghana’s Largest Industrial Area.* Master’s thesis, Linköping University, Sweden, May 2012.

[25] Power factor is a number between 0 and 1, with lower values implying less effective use of electrical power. The customers had a power factor of less than 0.8.

114. A recent report[26] concluded that Ghana's transmission system, concentrated in the southern part of the country, is relatively old. It was constructed mainly in the 1970s, with very little subsequent investment. Substantial investments are needed to maintain and upgrade the existing system, and expand into other parts of the country.

115. About half of Ghana's 161-kilovolt (kV) transmission infrastructure, which has been operating since the 1960s, is long past its recommended retirement age. Ghana's transmission system needs a significant amount of investment to offset the underinvestment of the past decade, when transmission was still part of VRA's responsibilities.

116. Ghana's NITS has several critical lines on which events requiring contingency pose problems, resulting in load shedding, low voltage, overloading of adjacent lines, and, in the worst cases, voltage collapse.[27] Additionally, 20% of the 3,138-MVA transformer capacity of the NITS has been cited as being overloaded.

117. In recent years, GRIDCo has taken steps, guided by its Transmission Master Plan, to undertake a variety of projects to increase power transfer capability and operational reliability on these and other potentially problematic lines.

118. **Transmission investment requirements.** The required transmission system upgrades have been quantified and are currently being executed by GRIDCo. The majority of the planned investments in transmission are expected to be made through 2015. These projects are needed to strengthen critical lines throughout the NITS and to create the 330-kV backbone, which will serve as the basis for future development of Ghana's power system. The total transmission investment costs over 2010–20 are estimated to be about US$1.0 billion (Annex 3.1)

119. **GRIDCo's healthy financial condition.** GRIDCo is now the only creditworthy utility in the country, with a profit of about US$24 million for 2012 and a projected US$33 million profit in 2013. However, GRIDCo's profits were higher in 2011, at US$56 million. The reason for the lower profits is that the transmission service charge (TSC) has not been increased. If the TSC is not adjusted upward, GRIDCo's profitability and capacity to invest for the long term will decrease.

120. Another problem is that ECG owes GRIDCo about US$43 million. While ECG agreed, in principle, to repay all arrears by March 2013, it will find it difficult to make this payment without a substantial reduction in Government payment arrears to ECG. Further, Valco owes GRIDCo about US$8 million, equivalent to about one year of consumption. In turn, GRIDCo owes US$8 million to VRA.

121. This financial interrelationship makes it clear that the Government must ensure that ECG and Valco are able to make their payments in a timely manner. It has already been shown that ECG's actual or perceived inability to pay what it owes makes it difficult to attract IPPs in generation; the failure of Valco and ECG to pay GRIDCo on time will eventually jeopardize investment in transmission also.

122. At present, GRIDCo is mobilizing financing for its investment program from a number of sources, including private commercial banks without a Government guarantee. Thus, GRIDCo is now a credible operator able to raise long-term financing on the strength of its balance sheet and prospects for future cash flow generation. It is important to secure this success by ensuring regular adjustments to the TSC, currently eroded by inflation, and other components of the tariff. It is also critical to ensure that

[26] KEMA, *Technical and Operational Audit of Ghana Grid Company Limited (GRIDCo)*, Submitted to Public Utilities Regulatory Commission of Ghana, November 2012.
[27] GRIDCo, Transmission System Master Plan for Ghana, 2011.

GRIDCo can comply with the commitments made to lenders (loan covenants, such as debt service coverage ratio), in order to preserve its track record and build credibility with the financial markets.

123. **Sustaining GRIDCo's financial viability**. The financial viability of GRIDCo will be sustainable only if:

- Tariffs are periodically adjusted using the Automatic Tariff Adjustment Formula to account for increases in costs due especially to inflationary increases in local costs and currency depreciation and associated higher cedi costs for imports.
- The Government and ECG can meet their debt obligations under the clearing house arrangement on a timely basis to enable GRIDCo to reduce its trade and other receivables, which increased from about GHC 6.9 million in 2009 to GHC 142 million by 2011.
- GRIDCo implements measures to reduce its losses to levels within the limits prescribed by PURC to avoid the additional cash burden created by the higher losses.

124. **Managing long-term demand-supply balance.** Several power sector entities have prepared estimates of Ghana's long-term demand-supply balance. However, no stakeholder is explicitly responsible for this function and, as a result, no stakeholder feels responsible for planning or acting to provide the needed generation additions for the system.

125. GRIDCo is well positioned to take up this planning role and this was the Government's intention in its 2003 Power Sector Reform Strategy. The nature of GRIDCo's functions requires every generator to provide GRIDCo with updated data on its capacity to meet current and future energy demand. Furthermore, GRIDCo has the responsibility of balancing daily power supply and demand.

126. **Recommendations.** PURC should take actions to raise the TSC and adjust it periodically to maintain its value in real terms. Further, the Government should designate GRIDCo as the entity responsible for preparing the indicative plans for the power sector requirements into the medium and long terms.

IV. REFORMS URGENTLY NEEDED IN POWER DISTRIBUTION

The Electricity Company of Ghana (ECG), is the dominant distribution utility in Ghana, while NEDCo handles about 10% of the public distribution load. ECG's operations cover 36% of Ghana's area, but ECG distributes about 90% of the public distribution load. In contrast, NEDCo's operations cover 64% of Ghana's land area, but it has no large industrial customers, as all large customers are directly connected to GRIDCo. In addition, the Enclave Power Company is a privately owned Ghanaian company licensed to operate in the Free Zones enclave at Tema (considered as export).

127. A key pillar for the sustainability of the power sector is provision of service of acceptable quality at rates that allow recovery of total efficient costs. At present, neither ECG nor NEDCo has good technical, commercial, and financial performance.

Electricity Company of Ghana

128. ECG is one of Ghana's largest and most important state-owned enterprises, as well as one of the largest power utilities in sub-Saharan Africa. It has over 1.8 million customers, 5,600 staff members, and annual sales of about US$800 million.

129. ECG is responsible for the purchase of electrical energy in bulk from VRA (or any other supplier of electricity) for distribution to consumers located in the lower third of Ghana's territory. About 51% of the company's customers are lifeline consumers who account for 6% of energy consumed and 1% of sales revenue. The bulk of its revenues come from non-residential consumers, who account for 12% of energy consumption and 56% of sales revenue, followed by residential consumers who account for 34% of energy consumption and 36% of sales revenue. The Special Load Tariff and high-voltage mines account for the balance of both energy consumption and sales revenue.

130. Faced with rapidly rising demand on top of a generally overstretched distribution network in need of upgrading, ECG has to invest at least $100 million annually to meet its service obligations to customers. This is a considerable challenge, in terms of both fund-raising and implementation capability.

131. **ECG's poor financial situation.** ECG does not have the ability to finance these investments. ECG is in a difficult financial situation today, as it often has been in the past. After making a small profit in 2010 (about US$4 million), for the first time in several years, ECG realized a small loss in 2011 (about US$16 million). The unaudited 2012 loss for ECG in 2012 is GHC 50 million, (US$26 million) and this is projected to rise in 2013 to US$60 million (Table 4.1). ECG's cash flow difficulties are even worse than the profit and loss accounts would indicate because of poor revenue collection and rising dollar-denominated payment obligations.

Table 4.1: ECG financial situation (millions)

Financial Indicators	2011		2012		2013	
	US$ M	**GHC M**	**US$ M**	**GHC M**	**US$ M**	**GHC M**
Total operating revenue	806	1,209	795	1,391	746	1,495
Total operating costs	833	1,249	827	1,447	789	1,582
Operating result	(27)	(41)	(32)	(56)	(43)	(87)
Operating margin	-3%	-3%	-4%	-4%	-6%	-6%
Financial and others	11	17	(12)	(21)	(16)	(33)
Net result	**(16)**	**(24)**	**(44)**	**(77)**	**(60)**	**(120)**
Net cashflow	4	7	(15)	(27)	(97)	(195)

Source: World Bank staff calculations. 2012 & 2013 figures are projections made in Oct.2012.

132. As of mid-year 2012, ECG owed 60% more to its main suppliers (VRA, GRIDCo, and Sunon Asogli Power Plant [SAPP])—a total of GHC 402 million, compared to GHC 250 million at the beginning of 2012 (see Table 4.2).[28]

Table 4.2: ECG payables to main suppliers as of end June 2012 (in GHC millions)

Main ECG Suppliers	Opening Balance 2012	Bills in 2012	Payments in 2012	Balance—End of June 2012	Variation in 2012
VRA	211	285	154	342	+62%
GRIDCo	19	90	101	9	–54%
SAPP independent power producer	20	136	105	51	+149%
Total	**250**	**510**	**359**	**402**	**+60%**

Source: World Bank staff calculations.

133. **Factors within ECG's control.** Several of the factors responsible for ECG's poor financial condition are within ECG's control. To begin with, ECG's distribution losses (technical and non-technical) remain very high (27% in the second quarter of 2012, of which 16% were non-technical). ECG does not earn any revenue for this "lost" energy, but has to pay to buy it.

[28] ECG confirmed that the difference in the amounts invoiced by SAPP and the amounts considered due and paid by ECG is still not solved.

134. The System Reliability Report 2012 mentioned unacceptably high inventory levels as one of the factors leading to ECG's poor financial performance. Inventory levels are high because of unplanned procurement decisions.

135. ECG has been using costly short-term suppliers' credits to finance purchase of equipment without competitive tendering and adequate regard to value for money. ECG contracted numerous suppliers' credits in 2010–12 to finance such capital projects. This is a costly way to buy equipment, as interest rates are embedded in the price of the goods, and has worsened ECG's financial situation. In the second half of 2012 alone, ECG will have to pay GHC 61.3 million for these contracts and GHC 76.4 million in 2013.

136. Note that these liabilities are foreign exchange based (as is the PPA with SAPP) and from 2013 with the Bui Power Authority and ECG uses its revenues from mining companies in forex to pay for these contracts. ECG's US$60 million supply-and-install meter purchasing scheme for the Ashanti West Region is not included in the above and will further aggravate ECG's cash flow in the coming years.

137. If ECG could reschedule these liabilities over, for example, 5 years, it would improve its cash flow by about GHC 49 million and GHC 48 million, respectively, in 2012 and 2013 (this is significant, as current projections for net cash flow show deficits of GHC 27 million and GHC 195 million).

138. Local costs for staff, administrative and, operations and maintenance (O&M) expenses are rising in excess of local inflation rates. Finally, ECG is unable to collect dues and from private customers, who owed ECG about GHC 205.4 million, as of 30 June 2012.

Factors outside ECG's control. Several factors are outside ECG's control. First, ECG's revenue per unit is frozen in the absence of tariff adjustments. The PURC had established an automatic quarterly tariff adjustment mechanism in early 2011, but suspended it a year later. This mechanism for timely and automatic indexing of tariff levels had helped briefly to make ECG financially viable in 2010–11.

139. The depreciation of the cedi has increased the costs of debt repayment, equipment imports, and power purchases from SAPP, as these costs are all denominated in US dollars.

140. Finally, ECG is unable to collect dues from the Government and other public-sector bodies, which owed ECG about GHC 428.2 million.

141. **Implications of ECG's financial problems.** Despite predicted losses and shortfall in cash, ECG has an ambitious capital expenditure plan of US$190 million on average per year for 2012–15. Absent an improvement in its financial results, ECG will find it impossible to finance this ambitious investment plan.

142. As is often the case in distribution utilities in other similarly situated countries, ECG will be tempted to defer scheduled maintenance expenditures in order to reduce the negative cash flow. This will only further reduce the reliability of service, because of deterioration in the quality of the infrastructure.[29]

143. ECG's network is already unreliable, with unacceptably high outages and poor voltage in many areas.[30] Voltage fluctuations, frequent failures, and long outage periods impose cost burdens on the economy and reduce Ghana's attractiveness as a destination for foreign investment. ECG's existing consumers complain forcefully about unsatisfactory customer service in areas such as fault resolution, payment disputes, or requests for new connections.

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[29]The average annual investment in the ECG network has been roughly US$100 million over the last 4 years. ECG estimates that about US$200 million per year was to meet investment requirements.
[30] KEMA, *ECG Final Report: Technical and Operation Audits of ECG*, November 2012.

144. ECG's poor financial condition has implications not only for ECG, but also for other entities in the power sector because of the interlinked chain of payments stretching from the end users to the suppliers of fuel to the power producers. This creates liquidity problems and financing costs in the transmission and generation sectors, making it difficult to undertake the necessary investments in transmission and generation.

145. When ECG is faced with liquidity constraints arising from its poor revenue collection, it reduces its payments to other utilities from which it buys power. In mid-2012, ECG owed 60% more to its main suppliers (VRA, GRIDCo, and SAPP)—a total of GHC 402 million, compared to GHC 250 million at the beginning of 2012. Finally, most important from the long-term perspective, a financially weak distribution utility is a major barrier for private investments by independent power producers (IPPs). Even if the IPPs do not sign PPAs directly with ECG, there are serious concerns about the bankability of a PPA with other parties in which the revenues ultimately originate from a financially weak ECG. The IPPs are concerned that ECG may not pay the bulk purchaser fully, in which case the risk of the bulk purchaser not being able to honor its financial commitments to the IPP rises.

146. In short, a financially weak ECG has made it difficult to finance the necessary investments not only in distribution but also in new generation. Hence, it is essential for the development of the entire sector that actions be taken to ensure that ECG is financially sound.[31]

147. **Ashanti Region SBU pilot.** In line with the Power Sector Reform agenda, the Board of ECG in December 2009 resolved to operate the Ashanti Region as a pilot Strategic Business Unit (SBU) for 2 years. The ECG management was also to enter into a Management Support Services Agreement with a reputable utility for the pilot project. The business model was subsequently to be extended to all ECG operational areas after assessing the experience of the pilot SBU project for 2 years.

148. Inordinate delays have occurred in proceeding with the SBU. However, the former government indicated to ECG and its lenders in November 2012 its commitment to see the SBU pilot implemented in the Ashanti Region, despite lack of support from ECG top management.

149. The rationale for testing the SBU model was mainly to devolve the decision-making power away from the Head Office to improve efficiency at the operational level and to achieve financial autonomy for the operational areas of ECG. Previous institutional studies have concluded that the current ECG organizational structure is over-centralized for such a large company and ill-suited to provide good service to consumers. Further initiatives to involve private parties in segments of the power distribution business may also be worth exploring, as a means of improving customer service and achieving better commercial performance through network upgrades and rigorous billing, metering, and revenue collection.

150. **ECG's overall operational performance.** ECG's historical performance, both technical and commercial, has been mediocre for most of the past 30+ years,[32] despite many changes of top management and periodic reform efforts involving external support.

[31] The Kenyan power sector is considered a success in terms of the considerable level of investments from private investors and donors. Kenya's market structure is similar to that of Ghana. The key difference is that Kenya has ensured that adequate tariff regulation is implemented to keep the buyers of electricity from generators financially viable.

[32] Weak ECG performance was one of the main factors that led to the decision to transfer responsibility for power distribution in northern Ghana to VRA via the creation of Northern Electricity Distribution (NED) in 1986.

151. As borne out by institutional studies,[33] ECG is a large, top-heavy, over-centralized organization, with significant weaknesses in its management and corporate governance that is ill-suited to providing a service orientation to its clients. Without a change of corporate culture and approaches for management, ECG will remain the Achilles heel of the entire power sector.

152. A profound change in corporate governance and institutional culture is called for, with improved commercial performance and better customer service (in both electricity supply and commercial matters) as the centerpiece of a new approach. ECG should be led by a first-rate Board of Directors and staffed with high-caliber managers running the company, with the support of modern management tools (management information systems and other information technology applications) that enhance transparency in operations and corporate governance, if it is to deliver better service to Ghana, and cease to be a brake on development of the power sector as a whole.

153. **Recommendations.** It is essential that the Government pay the amounts it and public-sector entities owe to ECG as soon as possible. Further, the Government should reassess the clearinghouse payments mechanism to institute direct payment of electricity bills by as many state bodies as possible, particularly those that are revenue-earning entities, such as universities.

154. Further, PURC should resume, without delay, the automatic quarterly tariff adjustment mechanism, which is essential for sustainably restoring the power sector's financial viability. It is also essential for PURC to explain clearly to the public how and why this quarterly adjustment takes place. PURC should continue to prepare the next major tariff revision, so that it can be implemented no later than mid-2013.

155. Financial recovery alone, while crucial, will not lead to sustained better commercial and operational performance by ECG. To achieve this, the Government is advised to raise the caliber of the ECG Board by appointing highly experienced and respected managerial and professional members to it, with a clear mandate to implement a change in corporate culture to put better service delivery and operational efficiency at the center of management attention.

156. ECG itself needs to take a number of actions. First, it should undertake some finance-related actions. The most important of these is to refinance its suppliers' credits into longer-term financing from sources other than the suppliers. ECG should also cease to take on new non-transparent financial commitments to suppliers, particularly those that require it to escrow part of its revenues to meet such obligations. And, ECG must make fresh efforts to collect the owed dues from its private-sector customers.

157. Further, ECG must make all efforts to reduce distribution losses. A technical audit identified losses "as the single largest issue that is effectively reducing available financial resources for investment." ECG must tackle the issue of energy losses immediately, because inaction going forward will make the situation even worse. It is particularly important to reduce non-technical losses, which result from poor metering, inadequate revenue management, and theft. It is estimated that every percentage reduction in system losses is worth about an additional US$8.5 million per year in cash flow.

158. ECG should also undertake some operations-related actions. These include reducing inventory costs by making sure that the signing of contracts for goods and equipment is synchronized with concrete plans to utilize them. They also include efforts to reduce its operating expenses, and to conduct its procurement in a competitive manner that leads to lower equipment prices.

[33] Consultancy services for a review of Ghana's electricity distribution subsector, (May 2008) and "On the Path to Improved Profitability: Launch of Pilot SBUs in Ashanti Region" (Oct. 2012), both by Pricewaterhouse Coopers.

159. Finally, ECG must implement a management improvement program to improve operational performance in a sustainable manner. Key components of such a program would include: (1) “revenue protection” of sales to large and medium customers (less than 3% in number but representing more than 50% of sales) using advanced metering technologies to permanently eliminate losses in this “high-value” segment; and (2) incorporation of MIS to support all commercial operations and management of corporate resources to enable a more efficient, transparent, and accountable management.

Northern Electricity Distribution Company

160. In line with the objective of the power sector reform to unbundle the sector into separate generation, transmission, and distribution utilities, VRA restructured its distribution department, NED, into a semi-independent, wholly owned subsidiary company of VRA, known as NEDCo in May 2012. NEDCo is currently responsible for the distribution of power in the northern two-thirds of Ghana, but accounts for only 10% of the national total sales of electricity.

161. While 72% of Ghana’s population has access to electricity, the northern, upper east, and upper west regions have access rates of 44%, 30%, and 32%, respectively. These regions with low access rates are part of NEDCo’s distribution area.

162. Less than 1% of NEDCo’s customers consume more than 600 kWh/month and pay tariffs above the cost of operation. The great majority of NEDCo customers are in the residential (lifeline/subsidized) category, paying tariffs below NEDCo’s average operating cost per unit. Further, NEDCo has difficulty in collecting its dues from Government ministries, departments, and agencies.

163. NEDCo had 20% distribution loss and aggregate, technical, commercial, and collection losses of nearly 39% at the end of 2011.

164. **NEDCo finances.** NEDCo is not financially viable now, and is not expected to be financially viable in the next 5 years, despite the elaboration of a business plan by the new NEDCo management team that is centered on large expansion of sales to higher-value consumers. The financial situation of NEDCo will continue to be poor, because the Government’s aggressive rural electrification program will lead to the connection of more lifeline customers, who pay rates lower than the average operating costs in the NEDCo area.

165. **Financial burden on VRA. The** Government’s policy toward power distribution in the NEDCo area is to leave VRA with the cost burden of the operational deficit and to invest massively in increasing access through capital subsidies for rural electrification, without regard to the subsequent O&M implications. This statement is equally valid for the Government’s approach to rural electrification in ECG’s operating area, but ECG is better able to deal with the losses through cross-subsidies from higher-value consumers. VRA is unable to recover these costs through the Bulk Supply Tariff (BST), and there is no funding mechanism in place via the overall retail tariff structure set by PURC to compensate VRA for the subsidy to NEDCo.

166. The policy needs to be revised and agreement reached on how to cover NEDCo’s structural deficit, through either a national levy on all users and/or a lower BST to NEDCo, the cost of which would in turn have to be recovered from some other segment of the electricity market.

167. **NEDCo’s challenges.** NEDCo’s network has not seen the level of investment required to match the increase in customer base. This has led to increase in losses, poor customer supply voltages, frequent outages due to line breakdowns, and overloaded distribution transformers resulting in NEDCo’s inability to connect new customers and poor voltages.

168. NEDCo is facing significant technical challenges, including:

- High technical losses—10.62%

    - Long distribution networks with overloaded transformers
    - Inadequate mapping of network and customers
- Aged equipment and poor power system reliability
- Suppressed demand
- Lack of spares for effective O&M
- Low voltages (outside acceptable limits set by LI 1816)

169. **Capacity building in NEDCo.** NEDCo, like other Ghanaian utilities, needs to upgrade its professional capacities. NEDCo is a victim of a one-way brain drain that deprives it of the best minds. NEDCo struggles to recruit and keep top-class employees because they get poached by other organizations in more developed parts of the country relative to northern Ghana. The allure of living in more developed parts of the country and its accompanying advantages—weather, education, utilities, etc.—also means that talented workers are reluctant to leave their current postings to pursue careers with NEDCo.

170. **Funding for NEDCo's investment program.** Previous improvement projects in NEDCo-controlled areas have been carried out using concessional funding. Given Ghana's current middle-income status, concessional funding is not readily available to support NEDCo's investment program on the scale envisaged in its business plan. Some form of annual Government financial support for NEDCo's capital expenditure program will need to be incorporated in the national budget. To assist NEDCo's investment plans in the short term, the Government should divert some of its rural electrification funds for use in improving NEDCo's network.

Valco subsidies are hurting the power sector

171. Valco, Ghana's state-owned aluminum smelter, has remained in operation despite its high economic cost for Ghana. At Ghana's cost of electricity, Valco cannot be viable if it pays the full cost of electricity supply.[34] At present, the Government has chosen to prop up Valco by providing it electricity at a subsidized rate, at a time when the country is undergoing power cuts. The total subsidy from the low power tariff is estimated to be around US$150 million per year.[35] In the current context of load shedding, it would be far more economic for the Government to shut down Valco and provide the power to other consumer segments that pay tariffs closer to the true cost of supply. This would still be true if all the Valco staff remained on full salary during the shutdown.

172. At present, as in the past, Valco has been operating with heavy power subsidies. While there does not appear to be a strong economic justification for these subsidies, this report has not assessed the desirability of the Government continuing to provide support to Valco. For the power sector, what matters is that this type of hidden subsidy to Valco harms the viability of power sector utilities. Not only does Valco pay an extremely low tariff, but even so, Valco has failed to pay VRA and GRIDCo in full, and has significant payment arrears with them.

[34] The fuel cost alone of the electricity required for Valco to produce one ton of aluminum is presently above $3,900/ton, which is much higher than current international aluminum prices of about US$2,100/ton.
[35] Based on light crude oil (LCO) single-cycle generation costs.

173. The Government has also not honored its commitment to VRA to make up the revenue shortfall between the BST and the Valco tariff, with the result that the onerous burden of the Valco subsidy has to be borne by VRA, and thereafter the other power consumers in Ghana.

174. **Recommendations.** Given the almost inevitable rise in the real cost of power in Ghana in the coming years due to the increasing share of expensive thermal power, electricity consumers should not be expected to bear the additional cost burden of the Valco subsidy. These subsidies should be transferred to the national budget, if the Government decides to keep Valco in operation. Valco should pay the same tariff for electricity as other large users, as this will preserve the financial health of GRIDCo and VRA and mitigate the extent of tariff increases to other consumers.

Regulatory agencies

175. **Public Utilities Regulatory Commission**. Though PURC has been in existence for nearly 15 years and has made significant progress on advancing customer rights protection, it has not performed satisfactorily on its primary mandate of power tariff regulation. A needs assessment study[36] conducted in May 2009 observed that "…PURC has broadly speaking been pursuing its mandate, but not to the degree that good international experience would indicate appropriate…." This is still the situation today, as indicated above by PURC's failure to apply the automatic indexation scheme to tariff setting, except during two very brief periods.

176. PURC now has additional responsibilities, as it is also the designated body for regulating gas prices.

177. The main challenges faced by PURC are:

- Capacity constraints. PURC is unable to retain the staff it trains at considerable expense. In addition, there is very little practical experience among the staff within the regulatory body of the operations of the regulated industry. As a result, the regulatory process has lacked the requisite industry knowledge, direct operational experience, confidence, and assertiveness required to meet the expectations of the public utilities as well as the private sector and boost investor confidence.
- Insufficient regulatory transparency. The regulatory process is undermined by a lack of openness and transparency in regulatory decision making. PURC has adopted a closed approach to decision making. For example, the application of the rate-setting guidelines in deriving tariffs is not demonstrated to stakeholders when tariffs are announced.
- Unbalanced PURC membership. The stakeholder representation basis for certain members of the Commission, rather than the qualifications and experience of the individual members, has raised concerns that the members tend to look after the interests of their constituents instead of the financial viability of power sector utilities, which is in the national interest. The Commission's decisions are often perceived as being skewed in favor of the consumers, rather than being balanced and principled.

178. **Recommendations.** The Government should undertake the following actions:

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[36] Whitaker Consulting, *Needs Assessment for PURC*, report prepared for SECO, World Bank, and PURC, May 2009.

- Make the regulatory processes more systematic and transparent. More systematic and transparent mechanisms for tariff approvals are necessary. Timelines and targets must be established and followed. Regulatory performance must be evaluated periodically and improvements promptly made. State interventions should be rare; if and when they occur, the impacts and costs incurred by the industry and national economy should be critically assessed and properly accounted for.
- Improve regulatory capacity. A strategy for hiring and retaining skilled professionals with industry experience is needed. PURC needs independent and reliable information to assess the extent to which the utilities' expenditures should be allowed in the tariff. In addition, the outsourcing of some of the regulatory functions may be considered and adopted for those technical assessments and matters where the PURC staff does not have the requisite and practical industry knowledge and experience.
- Review the composition of PURC. Government should empanel experts as Commissioners with no stakeholder affiliations to manage the regulatory process. This will help to ensure that PURC is able to support national goals, instead of the narrower agendas of particular political or other social groups.

179. **Energy Commission**. The EC is responsible, *inter alia,* for the entry of the private sector into the industry, and to prepare, review, and update periodically indicative national plans to ensure that reasonable demands for energy are met. So far, the current approach has not successfully delivered results in these two crucial areas of the power sector. Integrated power sector investment planning has been neglected and carried out in a piecemeal manner by different stakeholders apart from the EC, which has not assumed the leadership expected of it.

180. The EC's Framework for the Procurement of Electric Power Generation, along with other policies, has not been successful in attracting the required investments into the power sector. This framework needs a re-assessment toward identifying the improvements required to guarantee that it meets the expectations of the investors while protecting the interest of the public.

181. There is a gap in the power sector with respect to sector planning and development, primarily because of lack of sharp delineation of the roles of EC, GRIDCo and the Ministry of Energy (MoE). There is a need to define clearly the relationship between EC and MoE, given that a key function of the EC is to advise and help MoE in the formulation of national energy policies. However, in recent years, both parties have been dissatisfied with their interactions—MoE has felt that EC has not delivered timely and useful advice, while EC feels its services are insufficiently called upon.

182. The EC, given its current functions, would be best suited to carry out indicative planning related to the national energy needs as whole, because this has to take into consideration the possible effects of the interplay of demand or substitution between various energy sources, such as electricity, natural gas, LPG, diesel, biomass, solar, etc., in order to derive a truly strategic national energy planning perspective.

183. **Recommendation**. The Government should reaffirm that EC is the entity responsible for carrying out indicative sector planning related to the national energy needs as whole, while transferring responsibility for power sector investment planning to GRIDCo.

V. NATURAL GAS SECTOR

184. Ensuring an adequate and secure supply of natural gas is fundamental to improving the availability and cost of power in Ghana. Ghana is fortunate that, due to discovery of domestic gas resources and proximity to Nigeria, it has a number of different gas sources to which it can turn. However, delays in the implementation of the Jubilee-associated gas infrastructure and supply interruptions on the West Africa Gas Pipeline (WAGP) have combined to produce an acute near-term gas shortage necessitating the purchase of some $50 million per month in light crude oil. Alleviation of this gas shortage will require acceleration of new gas projects and improved execution on the part of state-owned enterprises.

Natural gas demand and supply

185. In Ghana, as in many other countries, gas demand is driven by power generation and, more specifically, by the competing fuel economics of gas versus oil and other liquid fuels. Crude oil and its derivatives are readily available in world markets, and are easy to transport and store. For this reason, security of supply of oil products is usually not a concern. However, at current price levels, oil is often a very expensive option. Oil at $100 per barrel is equal to roughly $17 per million British thermal units (MMBtu) on a gas equivalency basis.

186. When pipeline gas is available, it can usually be delivered at significantly lower prices, thereby saving money in power generation. Under favorable conditions, liquefied natural gas (LNG) can also be competitive, since prices are traditionally indexed to oil prices at less than full price parity. In addition, combustion of natural gas in power plants emits roughly half the carbon dioxide of liquid fuels, although the degree to which this benefit is factored into fuel-sourcing decisions varies greatly from country to country.

187. **Gas demand estimation.** To estimate gas demand in Ghana, this report has constructed three electricity demand scenarios corresponding to GDP growth rates of 6.8% (base case), 5.5% (low case), and 9.0% (high case). From each demand scenario, the energy output of hydro and renewables was subtracted to arrive at a call on thermal energy production. Then, the production of each existing and planned thermal power plant was converted to a corresponding gas consumption figure, using assumptions regarding availability, load factor, and thermal efficiency. Because the demand estimates are derived on a plant-by-plant basis, they do not capture unsatisfied demand during the 2013–14 period, when installed generation capacity is expected to be insufficient to serve electricity demand.

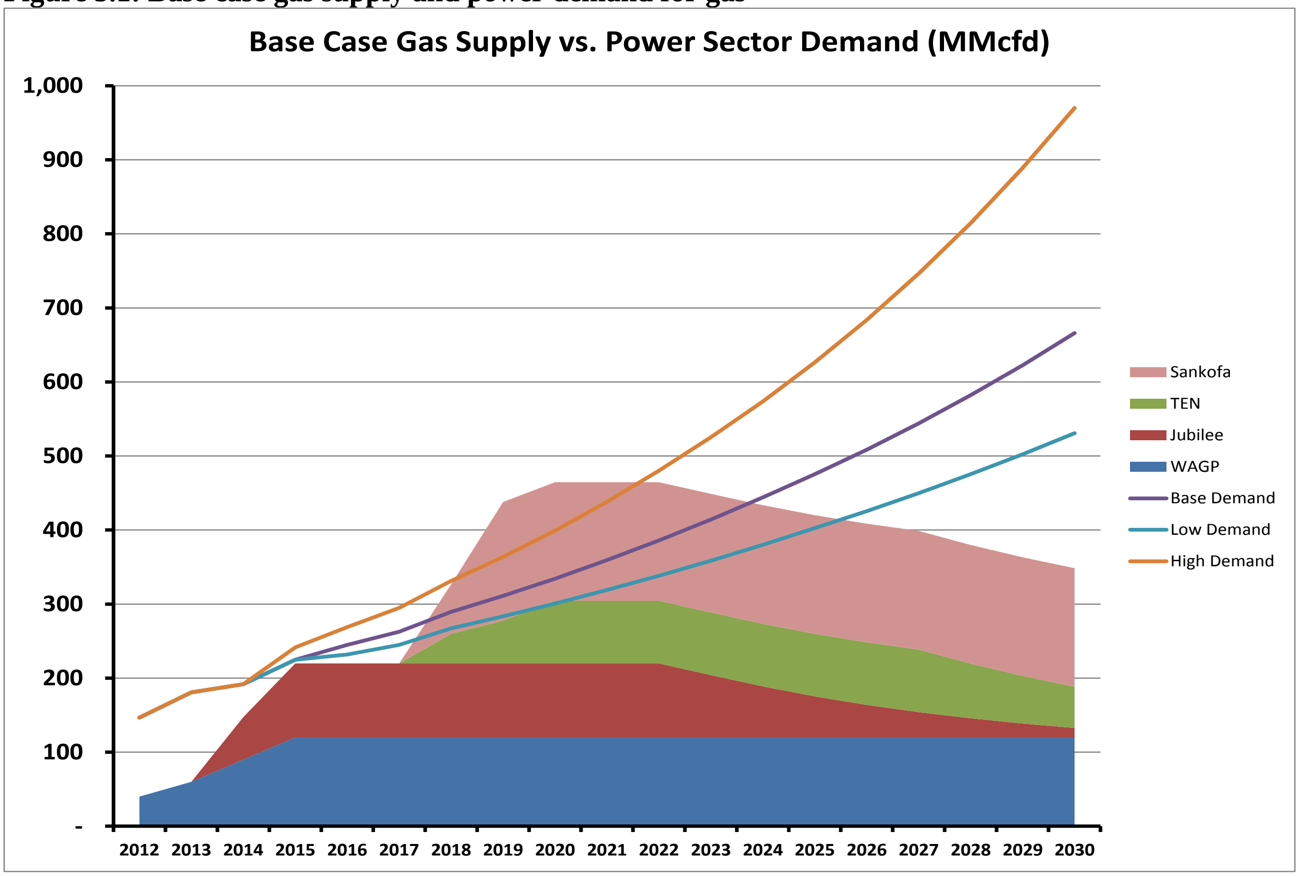
188. **Gas supply.** Ghana has a number of gas supply options, each with its own volume and timing characteristics. The following assumptions are used to estimate gas supply:

- Nigerian gas via WAGP. Although deliveries from WAGP have been erratic and prone to interruption, this report assumes that WAGP volumes will ramp up by the year 2015 to 120 million cubic feet per day (MMcfd), the foundation volumes under the gas sales agreements. However, no additional Nigerian gas is assumed to be available in the short to medium term.
- Jubilee-associated gas. Gas from the Jubilee field is assumed to become available in mid-2014, when the Western Corridor Gas Infrastructure project is assumed to be in service. Sales gas volumes delivered to Takoradi are assumed to be 100 MMcfd, declining post-2022 when Jubilee oil production starts to decline.
- TEN-associated and non-associated gas. Gas deliveries from the TEN (Tweneboa, Enyenra, and Ntomme) development are assumed to begin in 2018, ramping up to 85 MMcfd by 2020.
- Sankofa non-associated gas. Production from the Sankofa field is assumed to begin in mid-2018 at a rate of 160 MMcfd, a production rate that is sustained for 18 years.

- LNG. LNG is assumed to be available as a long-term supply option, but is not explicitly included in the supply scenario.

189. Under this set of assumptions, gas supply and demand in the power sector could come into tenuous balance as early as 2015 (see Figure 5.1), once the Jubilee gas infrastructure is complete and Nigerian deliveries reach full foundation volumes. However, these supply sources are vulnerable to delays and delivery shortfalls, which could lead to continued gas deficits until 2017–18, when the TEN and Sankofa fields are assumed to begin production. Thereafter, Ghana can be reasonably assured of adequate gas supply until 2024 or so, depending on the rate of demand growth. Ghana has multiple alternatives for securing supply for the years after 2024 and ample time to evaluate these alternatives.

Figure 5.1: Base case gas supply and power demand for gas



Source: World Bank staff calculations.

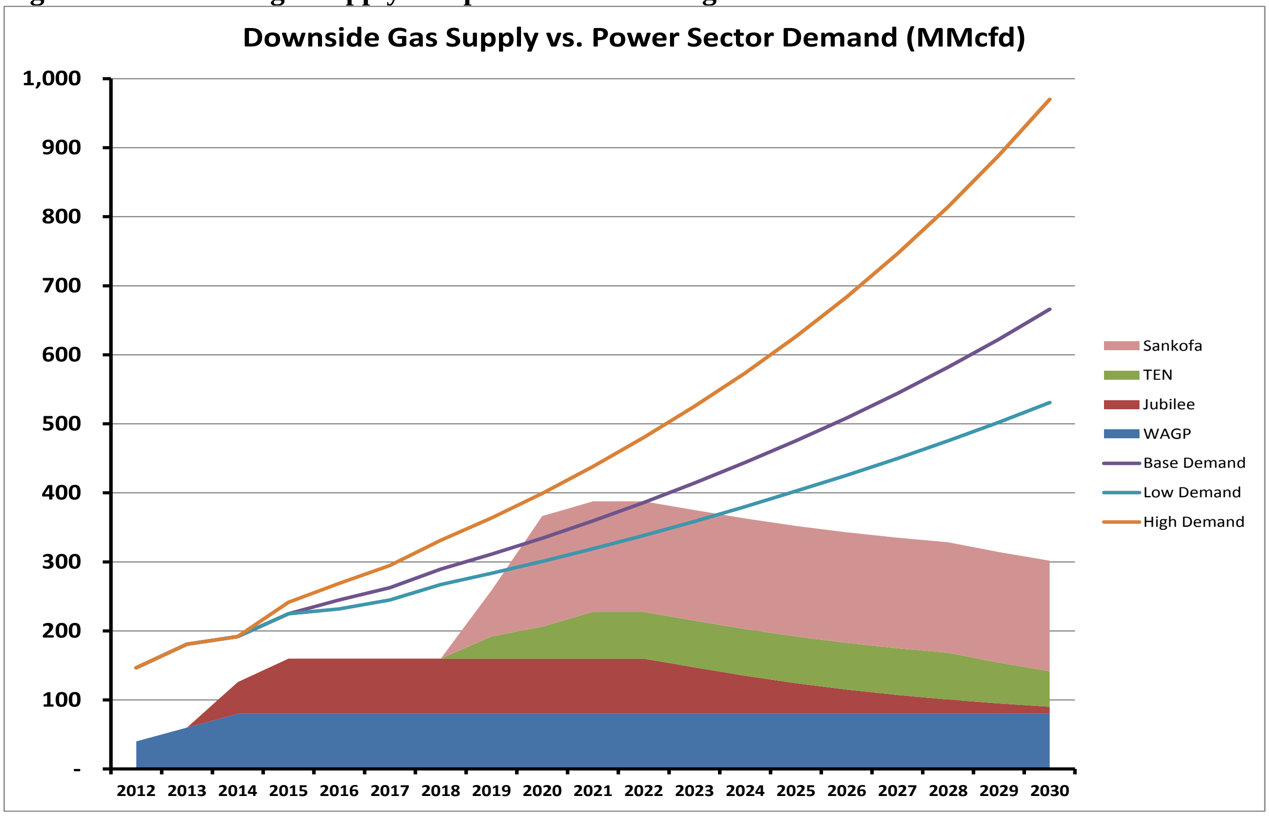
Downside supply scenario. Security of gas supply will remain a persistent risk. Jubilee gas production could fall short of expectations, and additional delays could occur in the gas infrastructure project. The volume and timing of sales gas from TEN will not be known until development and production get underway. Sankofa commercial arrangements could take longer than expected to finalize. And WAGP deliveries are likely to continue being prone to interruptions and curtailments. Moreover, a shortfall in hydropower generation could increase the call on thermal power output.

190. A downside supply scenario (Figure 5.2) has been created by capping both WAGP and Jubilee deliveries at 80 MMcfd, delaying the start-up of both Sankofa and TEN by one year, and reducing sales

volumes available from TEN. Under this set of assumptions, the short-term gas deficit extends to 2019, and new long-term supplies are needed much sooner.

191. If reduced hydro output or higher economic growth were to push the call on thermal power generation toward the high-side demand case for electricity, then gas supply would be inadequate throughout the entire planning horizon. In such a scenario, securing additional Nigerian supply would become an urgent priority, and an LNG import project would become very attractive.

Figure 5.2: Low case gas supply and power demand for gas



Source: World Bank staff calculations.

Role of Sankofa supply. Given these supply risks, development of the Sankofa/Gye Nyame non-associated gas project becomes a top priority. The availability of 160 MMcfd of baseload supply for 18–20 years would act as the backbone for Ghana's gas supply portfolio. Moreover, as the only domestic gas source not linked to oil production, Sankofa could compensate for delays or production shortfalls in associated gas projects. On the other hand, if supply from other projects meets expectations, Sankofa gas could be used as reserve capacity or as an anchor for development of non-power markets, so long as flexible supply arrangements are negotiated.

192. **Potential LNG role.** LNG could also play a role in ensuring security of supply, but the economic justification for an LNG import project is complex. Due to recent advances in technology, a floating LNG receiving and regasification terminal could be completed in 2–3 years, but this would be too late to help with the worst of the short-term gas supply crisis. On the other hand, from 2017 onward, LNG supply may not be needed if other supply sources start up as planned. But even in this case, security of supply and risk mitigation factors could argue in favor of an LNG import project.

193. However, the cost of LNG will be high. If global supply and demand stay roughly in balance, LNG commodity prices could be 70–90% of oil prices on a heat-equivalent basis. Unit regasification costs would vary enormously with utilization, due to the high fixed cost of the import terminal infrastructure. Even in a favorable commodity price setting and with reasonable levels of utilization, the final delivered price of LNG will be higher than other gas sources available to Ghana. Under adverse conditions, the cost could even exceed oil parity.

194. Because of these risks and because an LNG import project would entail substantial long-term contractual and capital commitments, Ghana should approach the LNG option with caution. Nevertheless, it is prudent to continue feasibility work on an LNG import project, taking account of the costs, risks, and benefits. Given the preparatory and conceptual work already done by the Volta River Authority (VRA), the Government should designate it as the lead agency for LNG and ensure it hires world-class advisors on the commercial and financial structure of the project.

195. **Additional Nigerian gas.** Additional Nigerian gas would be the best solution to the short-term supply solution, but is unlikely to be available. Gas demand in Nigeria is growing rapidly, and the Escravos to Lagos Pipeline System (ELPS) pipeline system, from which WAGP gas is sourced, is unstable. Nigeria is carrying out major projects to debottleneck and stabilize the ELPS system, but these projects will not be in place for 2–3 years. Until then, Nigeria will not be in a position to offer more gas to Ghana, particularly on a firm basis. The best that Ghana could hope for is a small volume of interruptible gas, and even this would likely be at a price higher than existing Nigerian supply. Nevertheless, Ghana should pursue this option, even if the chance of success is small.

196. **Realistic power sector tariffs needed.** None of Ghana's long-term supply options will be financially workable, unless the additional power generated from the more expensive fuel can be sold at higher prices than those prevailing today. Without a rigorously enforced full-cost pricing policy in the power sector, higher-cost gas supplies will just perpetuate the current financial problems of the power sector.

197. **Recommendations**. The Government should ensure that commercial and technical planning for Sankofa and TEN is completed in 2013, leading to the earliest possible project sanction. Further, the Government should move ahead with feasibility studies for an LNG terminal and retain a commercial adviser to advance dialogue with LNG suppliers. It is also recommended to maintain continuing dialogue with Nigeria regarding additional gas supplies.

Cost of gas supplied to the power sector

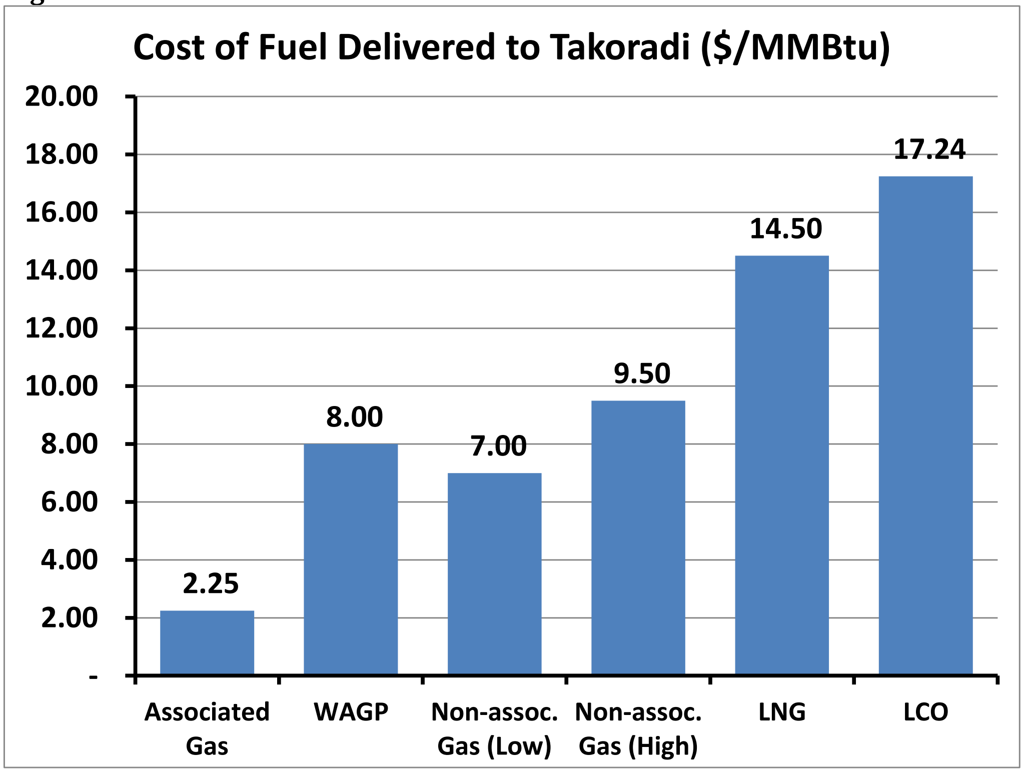
198. The cost of gas supplied to the power sector will depend on the supply mix. At Jubilee, the marginal cost of producing associated gas will be low—effectively just the cost of integrating delivery of associated gas with the operating conditions of the pipeline. In negotiations for gas purchase from upstream producers, Ghana National Gas Company (GNGC) is believed to be seeking pricing terms that reflect this low cost. For this report, a wellhead price of $1.25/MMBtu is assumed, a figure that would cover the cost of delivering associated gas and would give upstream investors economic incentive not to re-inject gas.

199. Non-associated gas, on the other hand, must receive a price high enough to support the capital and operating costs of stand-alone gas production facilities. Based on an economic analysis of the Sankofa field, the wellhead price of non-associated gas is assumed to be $8.50/MMBtu for a completely stand-alone gas development. However, when non-associated gas reservoirs are developed as part of an integrated oil and gas development project—for example in the case of TEN—the minimum gas price could be reduced. On this basis, the wellhead price for TEN gas is assumed to be $6.00/MMBtu. To these wellhead prices, an assumed transportation cost of $1.00/MMBtu is added to estimate the cost of gas delivered to Takoradi.

200. With respect to gas imports, a price of \$8.00/MMBtu is assumed for WAGP gas delivered to Takoradi, based on the commodity and transportation arrangements currently in effect. LNG is assumed to cost \$14.50/MMBtu based on indicative prices received in VRA's commercial studies.

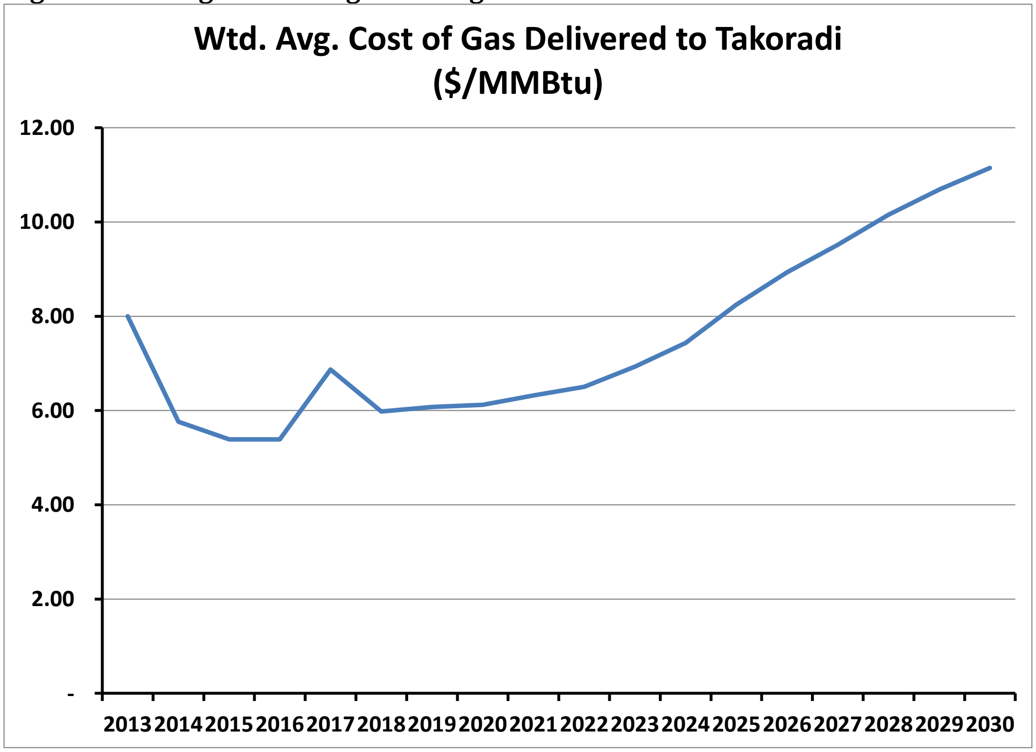
201. **Weighted average cost.** Using the above costs, the weighted average gas cost delivered to Takoradi is estimated at \$6.13/MMBtu over the 10-year period 2014–23. When compared to the cost of light crude oil—\$17.24/MMBtu based on an oil price of \$100 per barrel—gas supply provides enormous economic benefits to the power sector. A comparison of the delivered cost of alternative fuels is shown in Figure 5.3, and the evolution of weighted average gas prices over time is shown in Figure 5.4.

Figure 5.3: Cost of various fuels delivered to Takoradi



Source: World Bank staff calculations.

Figure 5.4: Weighted average cost of gas delivered to Takoradi



Source: World Bank staff calculations.

Institutional structure: GNGC and BOST

202. GNGC was established in 2010 and vested with the responsibility for commercializing, transporting, and processing natural gas.[37] Shortly thereafter, GNGC launched the Western Corridor Gas Infrastructure project to transport associated gas from the Jubilee field to VRA plants in Aboadze. The cost of the project, estimated at US$750 million, is being financed from the US$3 billion infrastructure loan from the China Development Bank (CDB).

203. The Energy Commission recently awarded the exclusive license for gas transportation to Bulk Oil Supply and Transport Company (BOST), the state-owned fuel wholesaler. As the exclusive transmission utility, BOST would assume responsibility for operating and maintaining the pipeline and for dispatching gas receipts and deliveries. It is understood that BOST would not own the pipeline and would not buy or sell gas, except for operational purposes, such as line pack. This would leave GNGC in the position of owning a pipeline it did not operate or control.

204. At this early stage in the development of Ghana's gas sector, introduction of another midstream gas enterprise creates unneeded confusion in the institutional structure. A complex commercial arrangement will now be needed between BOST and GNGC to compensate GNGC for its investment in the pipeline. Fees charged by BOST would need to be set up. Transfer or secondment of GNGC staff may

[37] PNDC Law 64 assigns responsibility for natural gas commercialization to GNPC. No amendment to GNPC's mandate has been made to reflect the creation of GNGC.

be required. BOST will now have to negotiate transportation agreements paralleling the gas purchase and sales agreements concluded by GNGC.

205. Furthermore, BOST appears to bring no relevant experience in operating a gas transmission system. Unbundling of the transportation and merchant functions originally assigned to GNGC could have been achieved on an accounting basis or by establishing separate subsidiaries of GNGC.

206. Last, there are serious questions about the capacity of GNGC or BOST to operate the processing plant and pipeline efficiently and safely. Experience in this arena is generally lacking in Ghana, and building capacity will take time. A number of options exist for addressing this challenge, including hiring a contract operator. A solution needs to be finalized immediately, so that the team responsible for operating the pipeline can be mobilized to work with the construction contractor during the commissioning phase.

207. **GNGC profit**. In carrying out its gas merchant function, GNGC could generate substantial profit. For example, if GNGC sells gas to VRA and other customers at Takoradi for US$8.00/MMBtu (i.e., parity with WAGP deliveries), it would generate a margin of US$1.87/MMBtu based on the weighted average cost of gas presented earlier. Sales of LPG produced at the processing plant would generate an additional margin.

208. On the other hand, there is a substantial risk that GNGC could become yet another financially crippled state enterprise. In performing its merchant function, GNGC will purchase gas in dollars from producers and sell gas to VRA in Cedis, thereby becoming exposed to foreign exchange and credit risks. Additional sources of risk to GNGC come from the proposed relationship with BOST and from the retention of debt service obligations on the CDB loan

209. It is assumed that the intention is to distribute any profit generated within GNGC to the Government. However, the Petroleum Revenue Management Act (PRMA) is ambiguous as to whether gas revenue is to be deposited in the Petroleum Holding Fund or included in the calculation of Benchmark Revenue. Amendment to the PRMA may be needed and GNGC's dividend policy would need to be established accordingly.

210. **Recommendations**. The Government should revisit the decision to award the Transmission Utility license to BOST in light of unnecessary complications and potential for delays. Further, the Government should ensure that a qualified, insurable contract operator for the processing plant and pipeline is in place when commissioning begins. Finally, the Government should amend PRMA to resolve ambiguities, and establish GNGC's dividend policy accordingly.

Gas sector commercial framework

211. Commercializing natural gas requires knitting together a complex set of contracts governing the purchase, sale, transportation, and processing of gas. These must align the interests of differing interest holders in the various links of the value chain. Negotiating these contracts will take time, and Ghana's general unfamiliarity with the gas sector risks extending this time beyond what is acceptable given the high cost of oil-fired power.

212. **Gas pricing.** The issue of gas pricing is central. Government has not yet published its Gas Pricing Policy, though the underlying principles were endorsed by the Cabinet in mid-2012, based on a detailed study carried out by international consultants. The study advised that gas pricing should reflect gas supply allocation priorities between different market segments, such as power generation, petrochemicals, industrial, and commercial users. It also established benchmarks for maximum supply costs in the various market segments and minimum gas prices for associated and non-associated gas.

213. **Volume commitments.** Negotiating gas volume arrangements is likely to be challenging. Producers of non-associated gas will be reluctant to assume any guaranteed delivery obligations, whereas IPPs may consider such provisions critical. Conversely, producers of non-associated gas are likely to

require take-or-pay guarantees that buyers such as VRA may find difficult to accept. In addition, Ghana will need to establish a robust commercial framework to define the delivery point for gas, the responsibility for gathering and connecting new supply sources, and the custody of gas in the transportation system.

214. **Credit arrangements**. Credit issues represent a potential major challenge for development of gas supply, particularly for non-associated gas projects, such as Sankofa, where the project economics rely entirely on gas sales to the local market. Given its financial condition, VRA will find it impossible to provide guarantees acceptable to gas producers without supporting guarantees from Government. Moreover, since VRA's main customer is ECG, with a poor track record of timely payment to VRA, gas suppliers and lenders are likely to seek mitigation against ECG risk as well. The Government must quickly develop its approach to providing credit support for gas developments.

215. **Recommendations**. The Government should finalize and publish the Gas Pricing Policy expeditiously. Further, the Government should plan its approach to credit support.

Petrochemicals and other non-power uses of gas

216. **Gas as a petrochemical feedstock.** Beyond its role as a fuel for power generation, natural gas can also serve as a feedstock in the production of petrochemicals, such as urea, ammonia, ethylene, and methanol. Ghana has received a number of proposals and inquiries from investor groups in this area, particularly with respect to urea-based fertilizer projects.

217. A urea plant with production capacity of 800,000 tons per annum—considered the minimum efficient scale—would consume roughly 50 MMcfd of dry gas for 20–30 years. Ethylene and methanol plans at minimum economic scale would consume similar volumes of gas. The supply/demand balances presented earlier show that this quantity of gas will not be available until 2017–18 at the earliest. In the long term, additional demand from petrochemicals would accelerate the time frame when new gas supplies would be needed. Put differently, entering into firm commitments with petrochemical investors to supply 20–30 years of baseload gas supply would push more of the long-term gas supply risk—both volume and price—onto the power sector.[38]

218. Gas supply cost represents another major challenge to petrochemical production, since the price of feedstock is constrained by the price of the final commodity being produced. Normally, this constraint results in low price requirements for gas supply. Using prevailing commodity prices and capital costs, the maximum sustainable feedstock gas price is estimated at US$4.00–7.00/MMBtu, prices that in many cases will be lower than Ghana's weighted average cost of gas. Looked at on a marginal cost basis, supplying gas to petrochemical projects is even less appealing, since it would require incremental supplies of non-associated gas and/or imports at prices on the order of US$10–15/MMBtu.

[38] Supplying 50 MMcfd to the petrochemical sector is estimated to raise gas prices to the power sector by $0.40 per MMBtu.

Table 5.1: Maximum gas price payable as a feedstock

Product	Plant Capacity (kiloton/yr)	Capital Cost (US$ million)	Commodity Price (US$/ton)	Gas Supply Volume (MMcfd)	Maximum (US MMBtu)
Urea	800	$858	$400	47	$7.04
Ethylene	270	$784	$1300	64	$3.95
Methanol	800	$637	$350	69	$4.12

Source: World Bank staff calculations.

219. **Industrial use of gas.** Gas can also be used as a heat input in a wide range of industrial processes, but its value in these applications can vary widely. As a replacement for liquids as a boiler fuel, the value of gas can be high, with alternative fuel netbacks approaching or even exceeding those of power generation.

220. However, as a heat input to smelting and other metallurgical applications, gas is often severely price-constrained by the final commodity price in a similar manner to petrochemicals. In particular, supplying gas to Valco is seen as a very low-value use of scarce gas.

221. Industrial users tend to adopt gas quickly once it is available, and making distributed gas available in industrial areas, such as Takoradi, would likely spur substantial demand. Such latent industrial demand is roughly estimated at 100 MMcfd.

222. **Recommendation. The** Government should place a clear priority on satisfying power sector demand for gas before considering supply to petrochemical projects. At a minimum, the Government should wait 2–4 years before committing gas to petrochemicals to allow time for the major near-term gas supply uncertainties to be resolved.

VI. UPSTREAM OIL AND GAS SECTOR

223. Ghana's emerging upstream petroleum sector has registered a series of impressive results over the last six years. However, limits to the success of the upstream sector are coming into view. Production from Jubilee to-date has not met expectations, necessitating a costly remediation program. Results from exploration have not been as prolific as the number of discovery announcements would suggest, and future exploration activity could begin to decline.

Exploration and appraisal

224. **Tano Basin exploration results**. Although oil shows were observed in exploration wells drilled more than 100 years ago, systematic exploration of Ghana's onshore and shallow offshore acreage did not begin until the 1970s. Between 1970 and 2002, more than 80 wells were drilled, resulting in six discoveries. The Salt Pond field, discovered in 1970, was the only commercial development coming out of the early exploration efforts and is still producing roughly 200 barrels of oil per day.

225. In 2004, the focus of exploration shifted toward deepwater Cretaceous stratigraphic traps.[39] Between 2004 and 2008, Ghana National Petroleum Company (GNPC), on behalf of the Government of Ghana, entered into petroleum agreements covering 12 offshore blocks, including the five key exploration blocks in the deepwater Tano Basin,[40] where the majority of the recent drilling has taken place.

226. Since 2007, 32 exploration wells[41] have been drilled, of which 21 have been successful. In addition, 22 appraisal wells have been drilled, of which 19 have been successful. The resulting success rates —66% for exploration and 73% for exploration and appraisal combined —are considered remarkable for a frontier exploration play.

227. The discoveries to date have been stratigraphic traps comprising Turonian and Campanian age turbidite fans drilled in water depths of 500–2,500 meters. The cost of an exploration well is estimated at US$80–100 million.

228. **Appraisal activity**. Of the 21 discoveries made to date, 11 have been appraised. Six appraisal wells were drilled at Jubilee, even though the results of the discovery well and the first confirmation well had already confirmed the field would be economic to develop. Seven appraisal wells were required in the Tweneboa, Enyenra,[42]Ntomme (TEN) complex of fields before enough resources could be confirmed to support commercial development; these fields have now been consolidated into a single development project designated TEN.

229. Three appraisal wells were drilled in the Sankofa, Sankofa East, Gye Nyame complex, and these confirmed the commercial viability of both oil and gas/condensate. Three appraisal wells were drilled on the Teak discovery, but a dry hole on the third appraisal well raises doubts about the viability of Teak as a stand-alone development.

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[39] GNPC had noted the deepwater Cretaceous potential during the earlier exploration phases before deepwater drilling technology had advanced sufficiently to make exploration feasible.
[40] Sometimes also referred to as the Western Basin.
[41] Includes two appraisal wells that were deepened to test exploration objectives.
[42] Originally designated as Owo.

230. Single appraisal wells have been drilled on Odum, Mahogany Deep,[43] and Dzata, none of which appears to be moving toward commerciality. None of the other pre-2012 discoveries has been appraised, and the prospects of commercial development are remote.

231. Since 2011, Hess has made seven discoveries on the Deepwater Tano/Cape Three Points block, including the very promising Pecan discovery announced in December 2012. Appraisal and pre-development activities are now being planned.

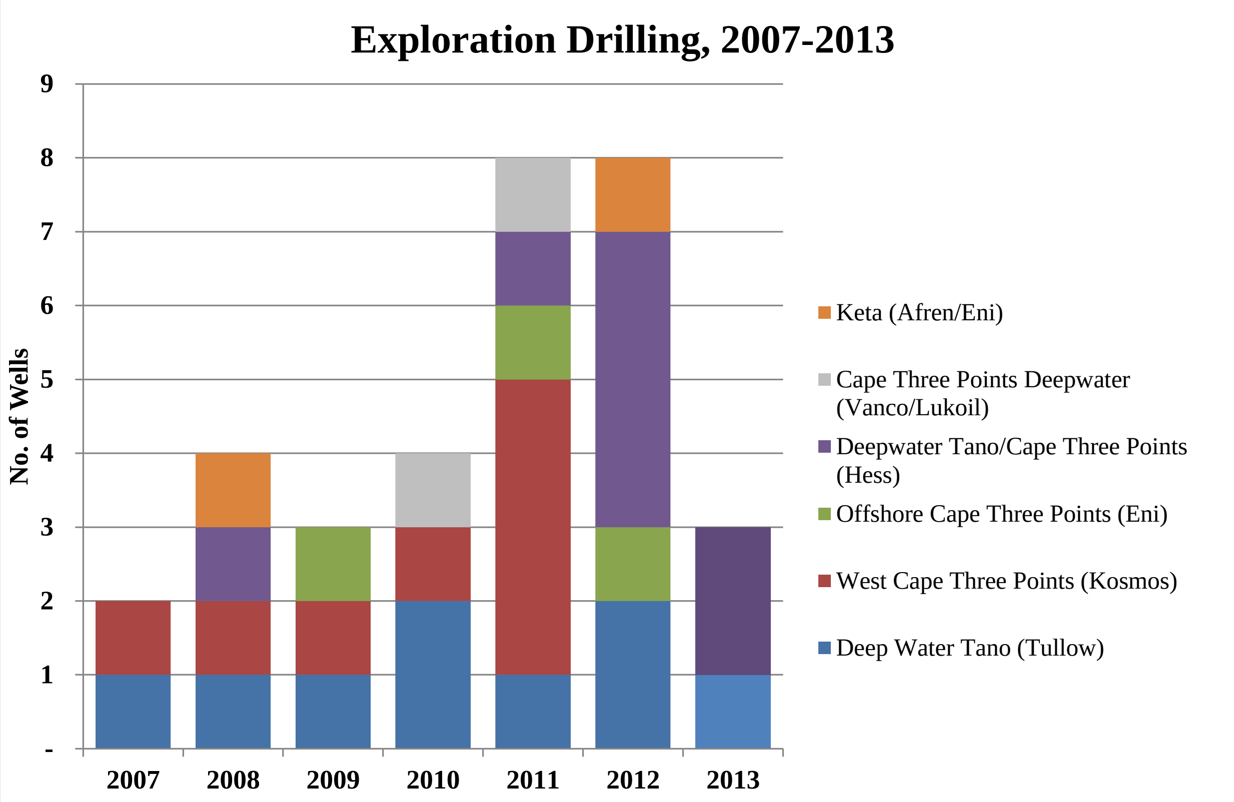
Table 6.1: Tano Basin Exploration Blocks

Block Designation	Operator	Contract Ratified	Exploration Period Ends	Exploration & Appraisal Wells 2007–13	Discoveries
Deepwater Tano	Tullow	July 2006	February 2013	17	Jubilee, Tweneboa, Enyenra, Ntomme, Wawa
West Cape Three Points	Kosmos	May 20014	May 2011	16	Jubilee, Teak, Mahogany Deep, Akasa, Bada, Odum,
Offshore Cape Three Points	Eni	March 2006	March 2013	6	Sankofa, Gye Nyame, Sankofa East
Deepwater Tano/ Cape Three Points	Hess	July 2006	July 2013	8	Paradise, Pecan, Beech, Hickory North, Almond, Cob, Pecan North
Cape Three Points Deepwater	Vanco/ Lukoil	August 2002	June 2013	3	Dzata

Source: Company press releases and GNPC website.

[43] Sometimes designated Mahogany East, SE Mahogany, and SE Jubilee.

Figure 6.1: Exploration drilling 2007–2013



Source: World Bank staff calculations.

Table 6.2: Field appraisal activity, 2007–2012

Field Area	Appraisal Wells Drilled	Status
Jubilee	6	Field development plan approved July 2009. In production since December 2010.
TEN (Tweneboa-Enyenra-Ntomme)	7	Development plan pending approval.
Teak	3	Uncertain. Possible future Jubilee satellite.
Sankofa, Sankofa East, Gye Nyame	3	Development plan under preparation.
Mahogany Deep	1	Uncertain. Possible future Jubilee satellite.
Odum	1	Uncertain. Thin pay zone.
Dzata	1	No data released. Presumed unsuccessful.

Source: Company press releases and World Bank staff calculations.

232. **Outlook for future exploration and appraisal.** The first phase of deepwater exploration and appraisal is nearing an end. By July 2013, the exploration periods for all five of the Tano Basin blocks will have expired, and the acreage held by licensees will be reduced to only those areas with active appraisal, development, or production programs. In 2013, there could be as few as four exploration wells drilled.

233. Future exploration in Ghana will follow four avenues:

- **Tano Basin relinquishments.** The areas relinquished from the original exploration blocks can be relicensed. Although the petroleum system in this basin has been abundantly proven, the challenge here will be field size. The original operators explored these areas thoroughly and any prospect that appeared likely to hold a commercial sized discovery was already drilled.

- **Accra/Keta Basin.** Exploration in the eastern offshore areas is only just starting. Two blocks have been licensed (TAP/Ophir and Vanco/Eni), and at least two others are under negotiation. Exploration in the Accra/Keta Basin will focus on proving up the same Cretaceous turbidite play that was successful in the Tano Basin. However, the presence of a petroleum system in the eastern offshore has not been proven, and the risks are very high. Two wells have been drilled to date one well drilled in 2008 was abandoned before reaching the target zone, and another well drilled in 2012 was unsuccessful. The TAP/Ophir consortium is expected to drill the Starfish prospect in 2013. The success or failure of this well will have a strong bearing on the pace of further exploration.

- **Ultra-deepwater.** The Cretaceous fan systems identified in the Tano Basin extend into the ultra-deepwater areas seaward of the existing blocks. This potential could also exist in the Accra/Keta Basin. However, well costs in waters greater than 3,000 meters will be at least $150 million, and only a handful of rigs in the world have the capability to drill in these depths. Development will also be very costly and will challenge the limits of existing technology.

- **Voltaian Basin.** Exploration has not yet begun on a large but very high-risk onshore frontier basin. No licenses have been issued and no seismic has been shot. Although some oil seeps were observed in the past, the basin is extremely old, and the chances of a working petroleum system are considered remote.

234. Re-starting exploration will require issuance of new licenses, in effect re-starting the clock on the typical 7-year exploration period built into Ghana's petroleum agreements. In the case of the Tano Basin relinquishments, license terms will have to reflect the likelihood that discovered fields will be small.

235. In the Accra/Keta Basin, terms will have to reflect the high risk and the unknown range of potential field sizes. Licenses in the ultra-deepwater will have to account for extremely high costs and longer exploration and appraisal periods needed to mobilize rigs. Initial licenses in the Volta Basin will need to be structured as seismic options, whereby the licensee acquires and interprets seismic over the block before committing to an exploration well.

Development and production outlook

236. Ghana's exploration and appraisal experience over the last six years provides the basis for a reasonable planning scenario regarding development and production. Of the 21 discoveries made to date, only Jubilee, TEN, and Sankofa[44] are confirmed developments. Mahogany Deep, Teak, and other minor discoveries in the West Cape Three Points license are unlikely to support a stand-alone development, but

[44] Including Sankofa East and Gye Nyame.

could be developed as Jubilee satellites in the future.[45] None of the other pre-2012 discoveries is likely to mature into development projects.

237. Based on this general development scenario, the future oil and gas production has been estimated to the year 2036, the year in which the Jubilee production license expires.

238. The assumptions for the base case projections are:

- **Jubilee.** The ongoing well remediation program at Jubilee is successful, and production reaches the 120,000 Bbl/d design capacity of the floating production storage and offloading (FPSO) in 2013. A full field in-fill drilling program begins in 2014, extending the production plateau until 2022. Sales of associated gas begin in mid-2014 with an initial production rate of roughly 100 MMcfd (net of FPSO consumption, re-injection needs, and processing shrinkage).
- **TEN.** The field development plan is sanctioned in 2013, leading to first oil in mid-2017. Peak production is 80,000 Bbl/d before oil production decline begins in 2021. Gas production begins in 2018 ramping up to 85 MMcfd before declining post-2027.
- **Sankofa.** The Sankofa/Sankofa East/Gye Nyame complex of fields is sanctioned as an integrated oil/gas/condensate development in 2014. First oil production from an accelerated oil development starts in 2016, and the second phase gas/condensate development starts production in 2018. In this second phase development, gas sales of 160 MMcfd are sustained for 18 years.

239. A summary of the production and resource estimates and the resulting oil and gas production forecasts is shown in Table 6.3.

Table 6.3: Production and resource estimates from confirmed developments

Field Development	**Start Production Year**	**Peak Oil Production (Bbl/d)**	**Peak Gas Sales (Mcfd)**	**Total Oil (MMBbl)**	**Total Gas[46] (Bcf)**
Jubilee	2010	114,000	100,000	683	442
TEN	2017	80,000	85,000	250	424
Sankofa	2017	40,000	160,000	120	1,077
TOTAL	**--**	**--**	**--**	**1,053**	**1,943**

Source: World Bank staff calculations.

240. **Oil projections.** The projections (Figure 6.2) show total oil production peaking in 2019–20 at around 230,000 Bbl/d. Total production over the period 2010–36 is 1.1 billion barrels.

241. Upside potential vis-à-vis the base case is extremely limited over the next decade. Production from the established fields will be limited by the design capacity of the production facilities, and timelines

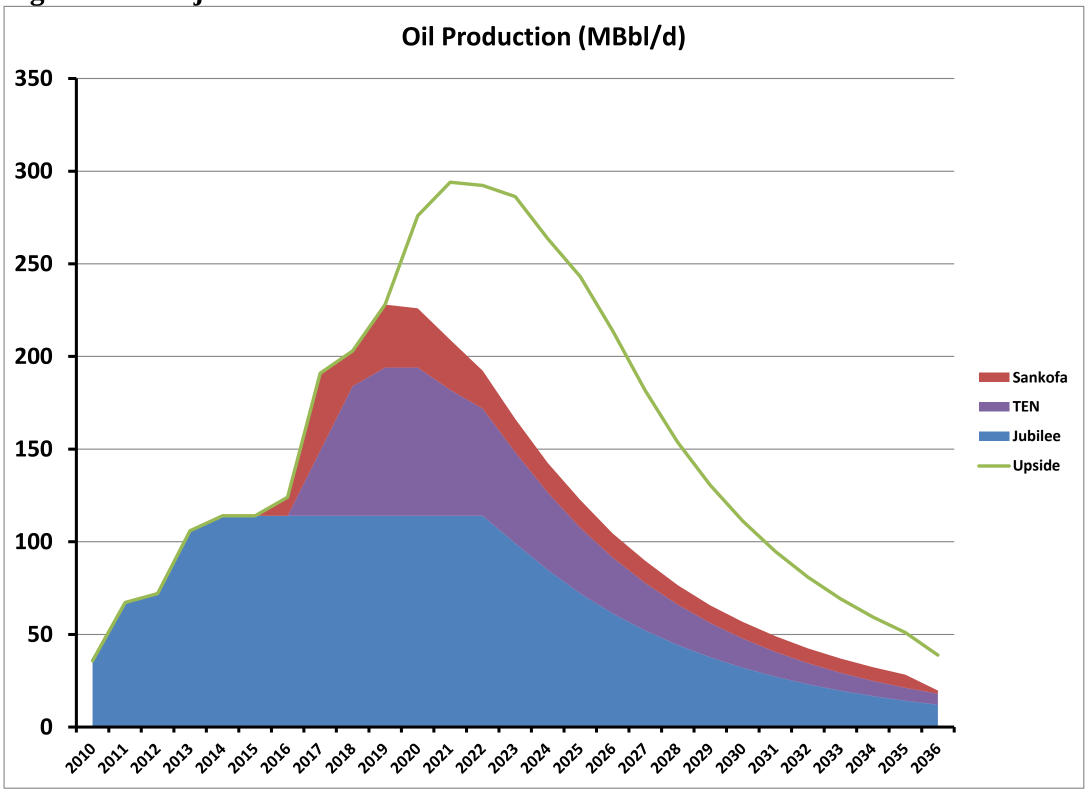
[45] Development of Mahogany, Teak, Akasa, and Bada has been designated variously in the past as META or MTAB.

[46] Net sales gas production after FPSO usage, re-injection needs, and processing shrinkage.

associated with exploration, appraisal, and development mean that the production effect of any new discoveries will be many years hence.

242. Long-term upside oil potential is estimated by assuming future development of Pecan (assumed 300 MMBbl field starting production in 2020) and MTAB (assumed 140 MMBbl starting production in 2022). These upside developments could take total production to around 300,000 Bbl/d in the 2020–24 timeframe.

Figure 6.2: Projected Oil Production Profile

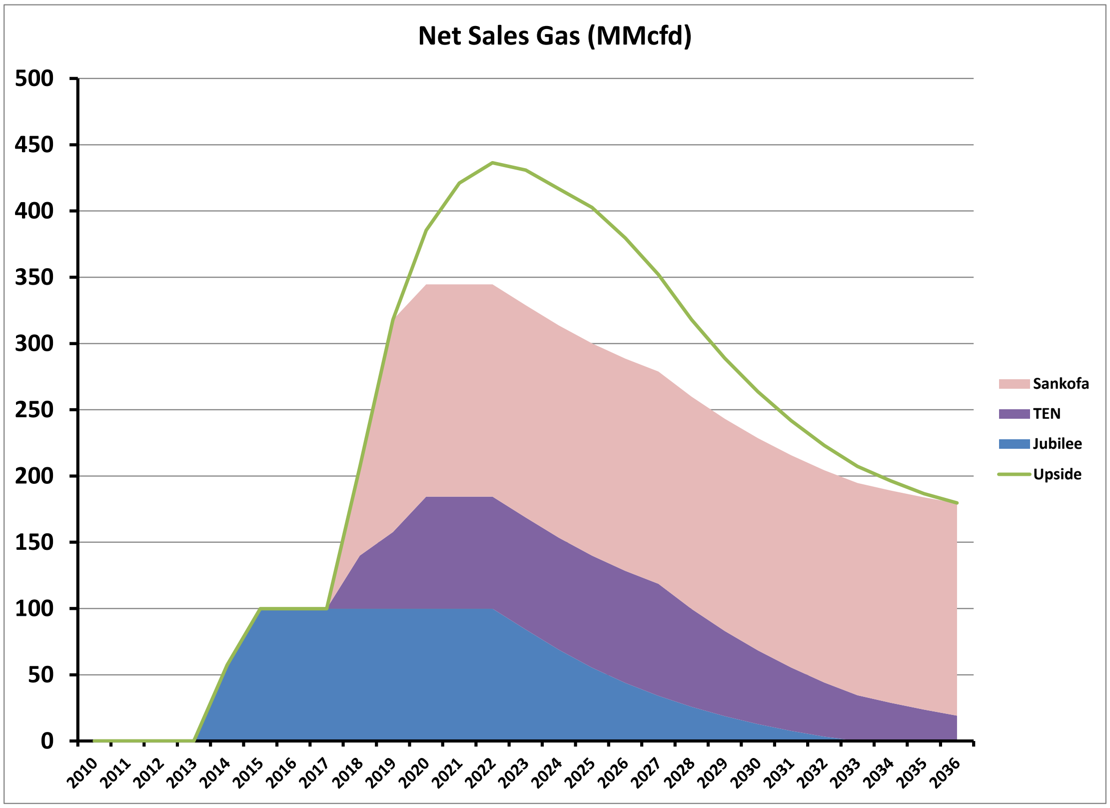


Source: World Bank staff calculations.

243. **Gas projections.** Gas production in this analysis peaks in 2020–22 at roughly 345 MMcfd net of adjustments for FPSO usage, reinjection, and processing shrinkage (Figure 6.3). Estimated total gas sales over the period 2010–36 are 1.9 trillion cubic feet.

244. Gas production upside is limited to the additional associated gas from the potential oil developments at Pecan and MTAB. The appraisal results at Sankofa and Gye Nyame suggest that a second phase expansion of non-associated gas is unlikely. As discussed in Chapter 5 of this report, downside gas production risk is substantial, coming primarily from potential delays in TEN and Sankofa.

Figure 6.3: Projected Gas Supply Profile



Source: World Bank staff calculations

Projections of Government revenues

245. Future Government petroleum revenues consist primarily of royalties, participating interests, income tax, and additional oil entitlements (AOE). Using the foregoing production profiles together with estimates of capital costs and operating costs, this report has projected future Government revenue under the prevailing fiscal terms (Figures 6.4 and 6.5). The projections are based on an oil price of US$100/Bbl, and gas prices of US$1.25/MMBtu for Jubilee, US$6.00/MMBtu for TEN, and US$8.00/MMBtu for for Sankofa.

Figure 6.4: Projected Total Government Revenue from Oil and Gas

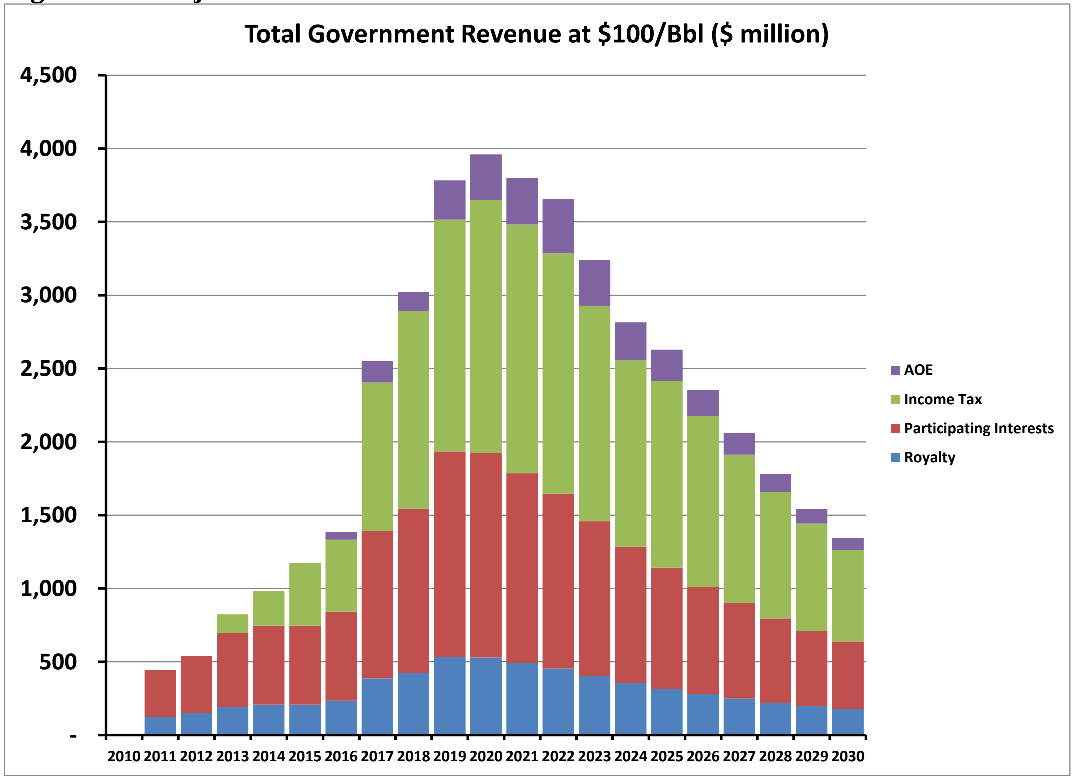
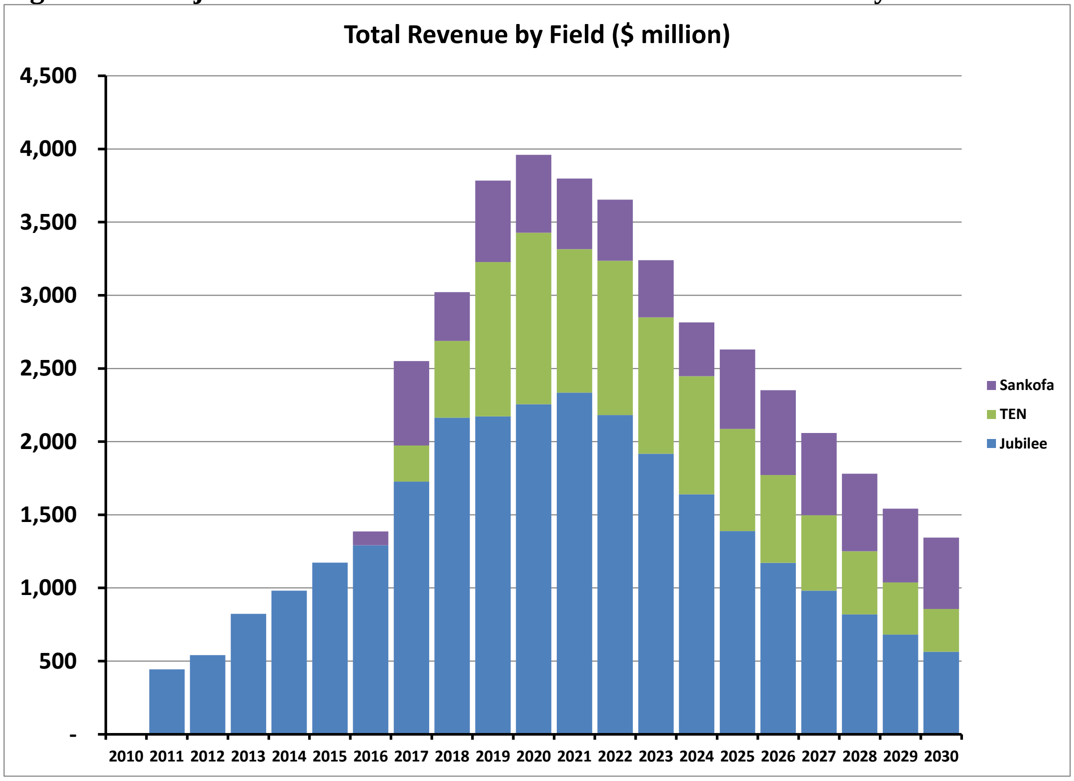


Figure 6.5: Projected Total Government Revenue from Oil and Gas by field



Source: World Bank staff calculations.

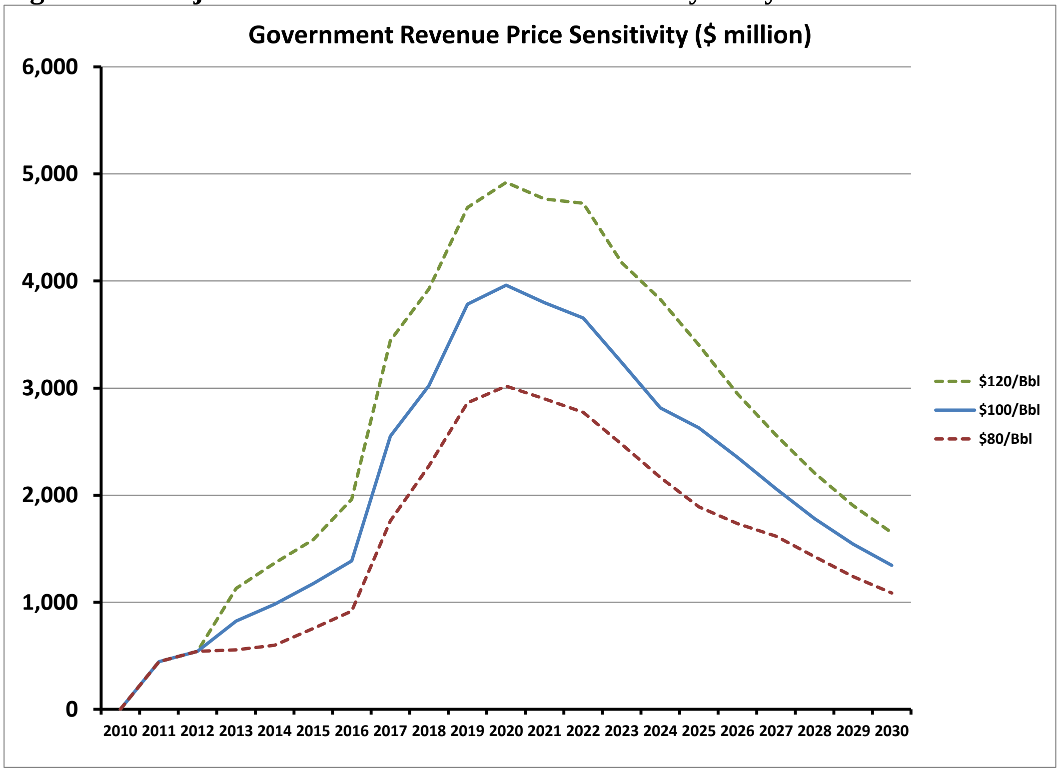
246. The projections show Government oil and gas revenue increasing steadily from US$542 million in 2012 to US$1.6 billion by 2016. Beginning in 2017, revenues surge to a peak of almost US$4 billion in 2019–22 as a result of new fields coming on line and the exhaustion of cost recovery at Jubilee.

247. Income taxes and participating interests represent the biggest components of government revenue. However, experience in Ghana and elsewhere shows that the timing of income tax collections on petroleum production can be hard to predict, since the tax positions of individual companies are strongly influenced by loss carry-forwards, inter-company interest, and other tax planning mechanisms. The projections also show that AOE —the resource rent tax—is a comparatively minor component of Government revenue. This reflects the finding that investor rates of return on Jubilee and TEN are attractive but not exceptional at US$100 per barrel.

248. The projections also show (Figure 6.5) that Jubilee remains the backbone of the Government revenue stream throughout the planning horizon. Sankofa, by contrast, is a relatively minor contributor to Government revenues. This reflects a common challenge with non-associated gas projects, namely, the difficulty in setting prices in such a way that production projects are profitable while ensuring that gas is delivered to end users at competitive prices. Under these circumstances, it is rare to see a domestic non-associated gas project generating high levels of tax revenue. On the contrary, it is quite common to see fiscal incentives being granted to non-associated gas projects in order to make them economically viable.

249. As is always the case, revenue projections are highly sensitive to oil prices. A comparison of government revenues under various oil prices is provided in Figure 6.6.

Figure 6.6: Projected Government Revenue - Sensitivity analysis



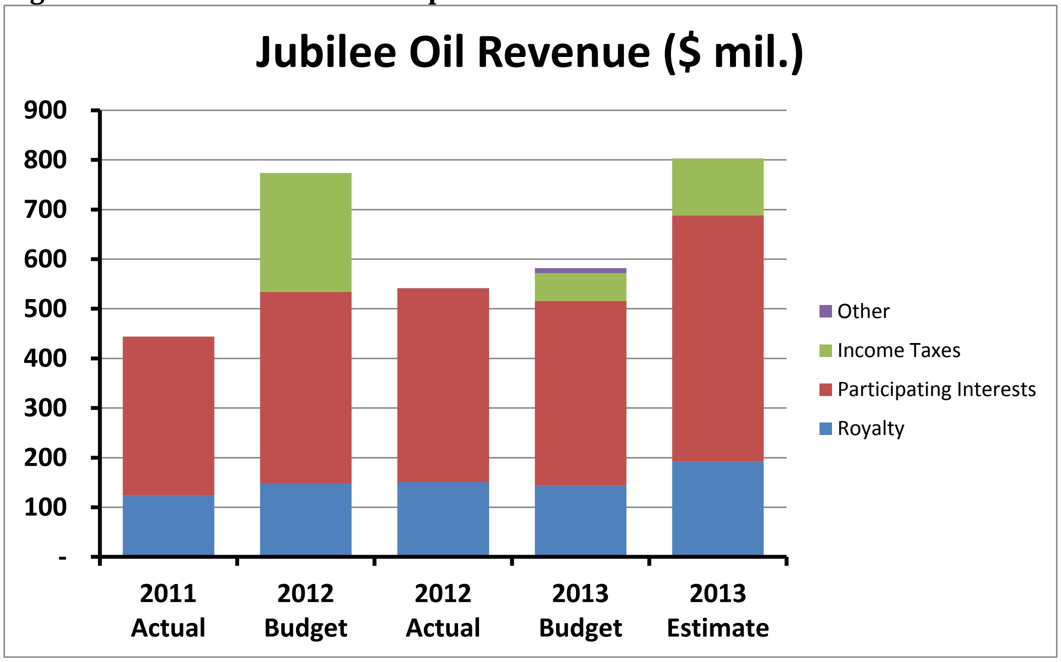
Source: World Bank staff calculations.

Petroleum revenue management

250. **Receipts from Jubilee.** Government revenues from Jubilee to date have fallen far below expectations. For 2012, a 20% oil production shortfall was almost exactly offset by higher oil prices, with the result that revenues from royalties and participating interests were almost exactly at budgeted levels (see Figure 6.7). However, income tax receipts for 2012—forecasted at US$240 million in the budget—were zero due to sizable but foreseeable capital allowances and loss carry-forwards claimed by oil company taxpayers.

251. For 2013, the Government is budgeting US$582 million in oil revenue based on production of 90,000 Bbl/d and an oil price of US$90/Bbl. These assumptions are quite conservative. At expected levels of production (105,000 Bbl/d) and a price of US$100/Bbl, government revenues for 2013 would reach roughly US$800 million.

Figure 6.7: Government Oil Receipts



Sources: Ministry of Finance and Economic Planning (MoFEP) and World Bank staff calculations.

252. Income tax realizations continue to be suppressed by accelerated capital allowances and intercompany interest deductions. The absence of ring-fencing and thin capitalization rules within the Petroleum Income Tax Law is largely to blame. Ghana should re-examine the provisions of the tax code dealing with these deductions. The audit function of the Ghana Revenue Authority should be greatly strengthened. However, the overall structure of Ghana's petroleum taxation regime remains progressive, competitive, and flexible and does not require a major overhaul.

253. **Revenue allocation.** The Petroleum Revenue Management Act (PRMA) was enacted in April 2011, five months after production began from the Jubilee field. In the two years since the PRMA went into effect, the Government has experienced start-up problems in implementing some of the provisions of the law, and some technical shortcomings in the drafting of the law have become apparent. Nevertheless, the core oversight and public disclosure functions appear to be solidly on track.

254. Under the terms of the PRMA, petroleum revenue from all sources is deposited into a consolidated Petroleum Holding Fund. Petroleum revenue is defined broadly to include royalties, participating interests, income and capital gains taxes, surface rentals, dividends and taxes from the national oil company, and any other government income derived from upstream and midstream petroleum operations.

255. A key feature of the PRMA is the calculation of Benchmark Revenues, an annual estimate of petroleum revenue for the following year. The calculation method for Benchmark Revenue is defined in detail in the PRMA and is based on moving averages of historical and expected values of both price and production. Allocation of petroleum revenue to the current year budget, the so-called Annual Budget Funding Amount, is limited to 70% of Benchmark Revenues.

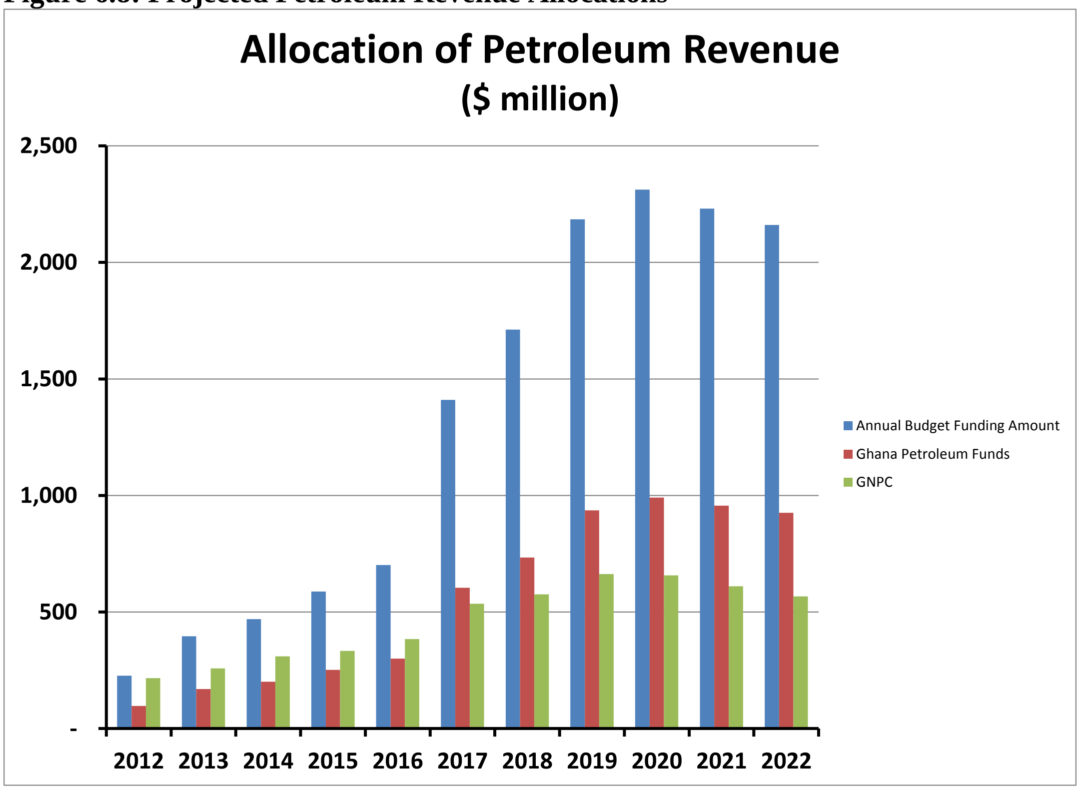
256. In addition, the PRMA allocates a portion of the revenue coming from participating interests to the national oil company, GNPC. This allocation consists of GNPC's participating equity share of capital and operating costs, plus a portion of the net revenue after deducting such costs. The law sets the

maximum share of net revenue from participating interests that GNPC can receive at 55%, but Government practice has been to allocate 40% of such revenue to GNPC.

257. The PRMA establishes two petroleum funds, the Ghana Stabilisation Fund and the Ghana Heritage Fund. When actual petroleum revenues exceed Benchmark Revenues, the excess revenue is directed to the Stabilisation and Heritage funds in proportions established by Parliament. When actual revenue falls short of Benchmark Revenue, withdrawals are to be made from the Stabilisation Fund in order to cushion the budgetary effect of lower oil prices or production.

258. These allocation rules and the revenue forecasts presented earlier have been used to develop estimates of how oil revenue would be allocated under current policy and practice (Figure 6.8). The analysis shows that, while gross 2014 petroleum revenues are expected to be roughly US$1 billion, the amount available for the current budget is likely to be around US$500 million. The analysis also shows that allocations to GNPC would exceed deposits in the Ghana Petroleum Funds over the next four years.

Figure 6.8: Projected Petroleum Revenue Allocations



Source: World Bank staff calculations.

259. **Implementation and oversight.** As called for in the PRMA, MoFEP now issues quarterly and annual petroleum revenue reports. These reports show the volume, price, and sales proceeds corresponding to each cargo of crude oil sold. The reports also show how revenue was allocated in accordance with the PRMA. MoFEP is also responsible for producing the annual Benchmark Revenue estimate.

260. Calculation of Benchmark Revenue has been shown to be challenging, in part because of production uncertainties and in part because of weaknesses in the calculation method prescribed in the PRMA. Over-estimation of Benchmark Revenues, in turn, results in over-allocation of oil revenues to the current budget and under-funding of the Stabilisation and Heritage Funds. Technical shortcomings in the

determination of Benchmark Revenue should be corrected through either regulation or amendment of the PRMA.

261. The PRMA establishes two committees to oversee aspects of the petroleum revenue management system. The Investment Advisory Committee is responsible for monitoring the management and performance of the petroleum funds, including establishing investment guidelines. The Public Interest and Accountability Committee (PIAC) is responsible for monitoring and evaluating compliance with the PRMA. PIAC has issued two high-quality reports analyzing the revenue disclosures from MoFEP and pointing out technical shortcomings in the drafting and implementation of the law. Most of PIAC's recommendations have been incorporated by MoFEP. Although the PRMA requires the Government to fund PIAC's budget, PIAC remains dependent on donor support for its operating expenses.

262. **Recommendations**. The Government should re-examine the petroleum income tax system, particularly those provisions dealing with capital allowances and intercompany charges. Further, the Government should establish workable regulations and procedures implementing the PRMA, and should address calculation inconsistencies either in regulation or by amendment of the law. The Government should re-assess the provisions of the PRMA giving priority allocation of participating interests to GNPC. Finally, the Government should fulfill its obligation under the PRMA to fund PIAC's operating budget.

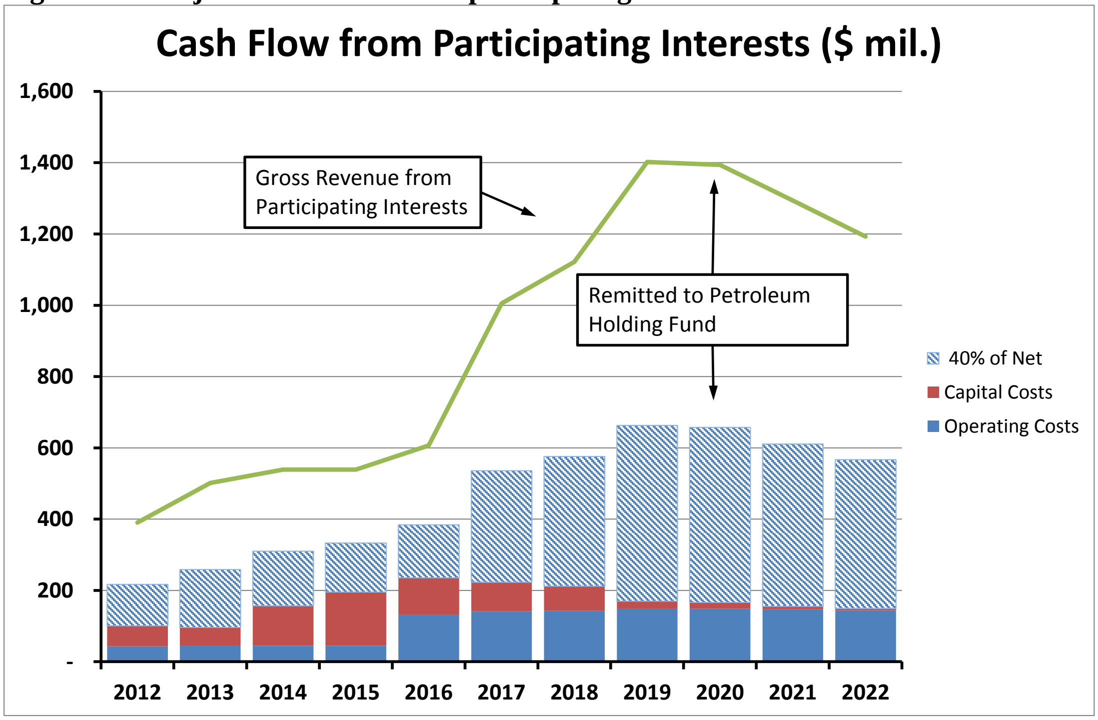
GNPC: Current and future roles

263. **GNPC investment requirements.** By virtue of its equity share in each field development, GNPC will have future investment requirements estimated at over US$600 million over the next 10 years. During the peak years of 2014–17, GNPC's investment requirements will average over US$100 million per year by virtue of the simultaneous development of TEN and Sankofa. In most cases, the petroleum agreements allow GNPC to finance its capital requirements with the oil company partners in exchange for a reduced share of future petroleum production. However, this should be viewed as a financing decision only, delaying rather than eliminating GNPC's capital obligations.

264. GNPC also pays a share of operating costs corresponding to its carried and additional participating interests in each field. For Jubilee alone, GNPC's share of operating costs is estimated at US$45 million per year. However, once the new fields are producing, this figure will grow to roughly US$150 million per year or more. Operating costs plus capital costs average roughly US$180 million per year over the next 10 years.

265. **Funds allocated to GNPC.** As described above, the PRMA allocates GNPC a portion of the revenue from participating interests equal to its share of capital and operating costs *plus* a portion of the net revenue after deducting such costs. Over the next four years, this would provide GNPC with an average of US$150 million per year above and beyond its capital and operating costs, a figure that would grow to over US$400 million per year when new fields come into production (Figure 6.9). It is understood that the intended use for this additional cash allocation is to capitalize GNPC with sufficient resources to invest on a fully paid basis in new exploration and production ventures.

Figure 6.9: Projected cash flow from participating interests



Source: World Bank staff calculations.

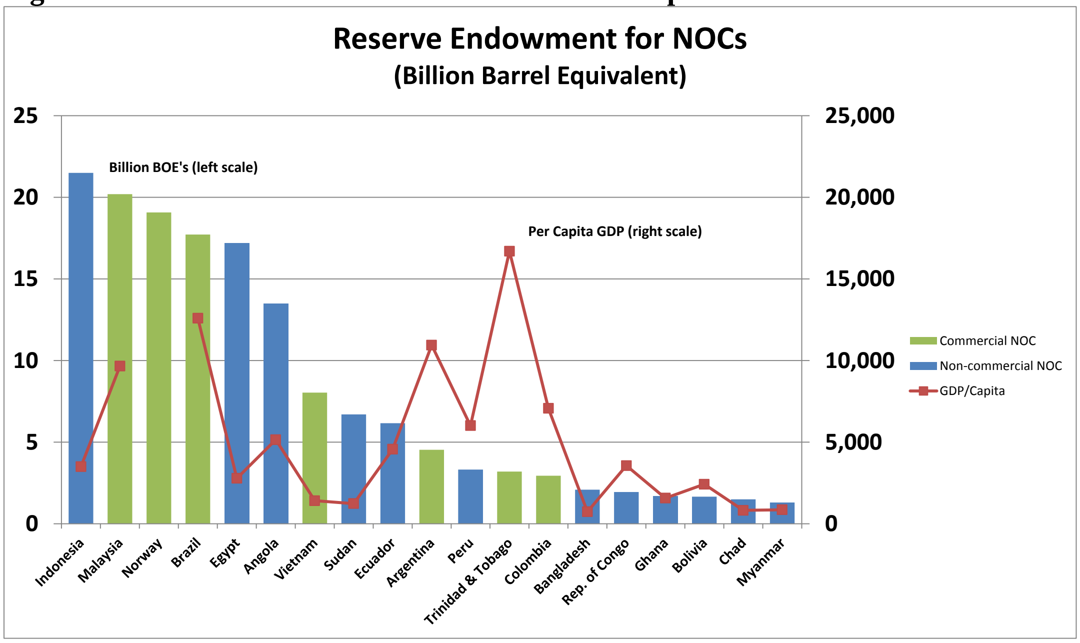
266. **GNPC strategic role.** GNPC's primary responsibility is managing Ghana's commercial interests in upstream petroleum operations. Today, a large part of this role consists of marketing Ghana's royalty oil and managing the Government's 15–20% carried participating interests in petroleum developments. However, GNPC's ambition is to evolve into a commercially independent oil company, acting as operator at times and taking larger fully-paid equity stakes, including investment in exploration. In the long run, this could result in share flotation, participation in projects outside Ghana, and other hallmarks of a fully-commercialized national oil company (NOC).

267. In deciding whether such an expansion of GNPC's role is advisable, Ghana should consider the following:

- The returns from GNPC's equity investments—including the social returns coming from GNPC acting as a catalyst for expansion of Ghana's industrial base—should be compared against the total financial and social returns of alternative investments Ghana could make.
- The risks of new ventures should be soberly assessed. In the case of deepwater exploration, GNPC's exposure to dry-hole exploration risk could be US$20–50 million per project. The depth and diversification of GNPC's portfolio should be assessed to ensure that losses of this order of magnitude can be absorbed.
- The timeline for development of GNPC's capacity (both human and financial) should be compared against the total investment needs of the sector to determine if sufficient space will exist for GNPC's investments at the point they are ready to make them.
- Investments in activities outside of upstream petroleum should generally be avoided, except where they are needed to catalyze upstream projects.
- The effect of reduced remittances to the Petroleum Holding Fund resulting from surplus retention by GNPC should be considered within Ghana's budget framework.

268. In addition to these investment criteria, the experience of NOCs from similarly situated countries should be examined. Generally, countries with NOCs operating as fully independent commercial entities have far greater resource endowments, higher levels of economic development, and a greater degree of macroeconomic and fiscal stability (see Figure 6.10).

Figure 6.10: Reserve endowment for national oil companies



Source: World Bank staff calculations.

269. GNPC's commercial ambitions should be matched with improved governance and transparency arrangements. GNPC should publicly disclose the results of its operations, including audited financial statements. Sales of royalty oil, results from participating interests, and new venture activities should be separately reported. GNPC should be required to present its investment budget publicly as part of the Government's consolidated annual budget or in the same manner as other state-owned enterprises. Corporate governance improvements, including an independent Board of Directors, should be established.

Recommendations. The Government should tightly define GNPC's long-term strategic role and develop and publish a long-term business plan for GNPC. Further, the expansion of the scope and magnitude of GNPC's investment program should be made subject to the criteria outlined above. Based on the agreed long-term strategy and investment needs, the percentage of net revenue from participating interests allocated to GNPC may need to be adjusted. Finally, governance arrangements at GNPC should be improved to reflect its commercial ambitions.

Annexes

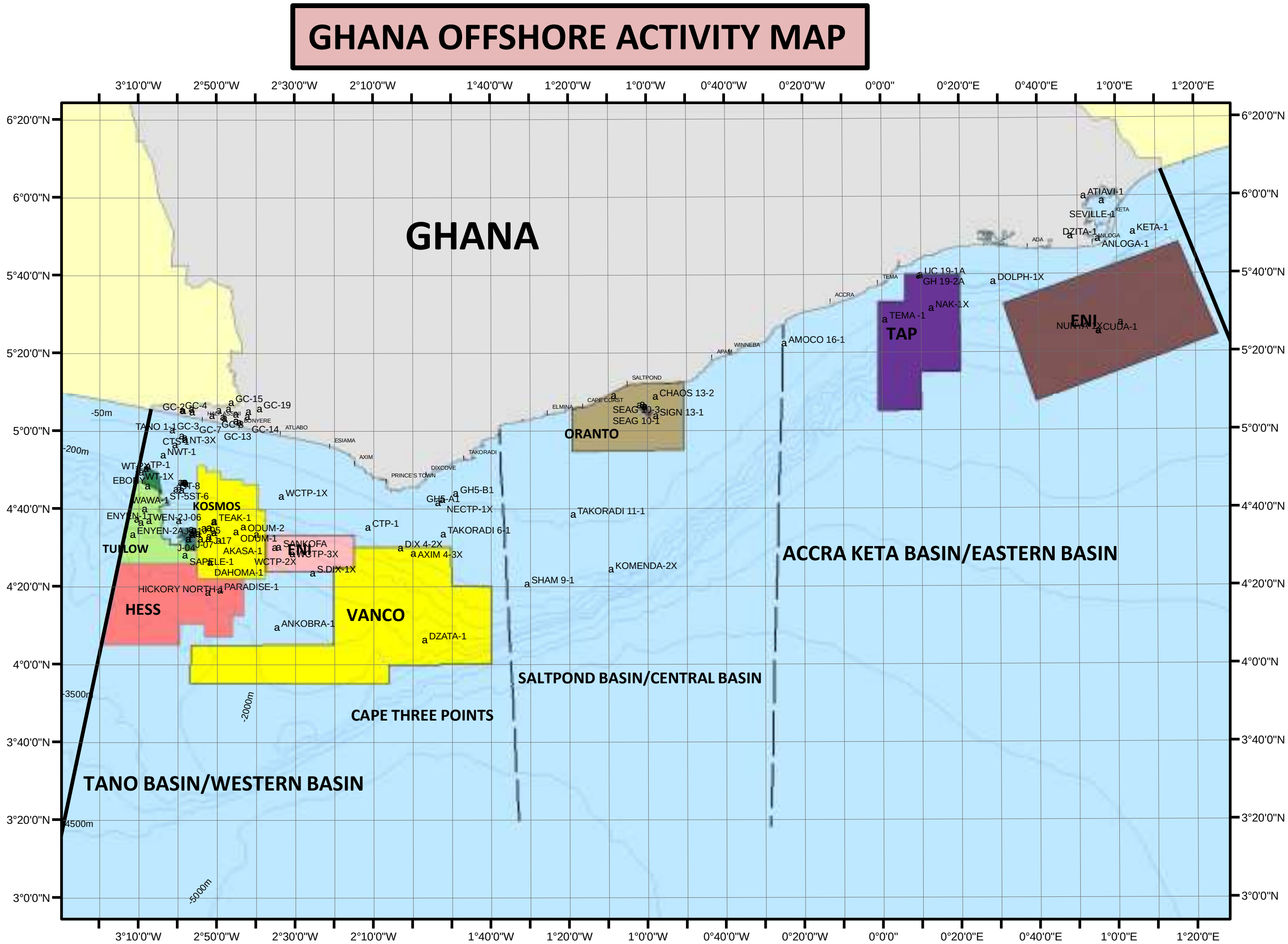
ANNEX 2.1: PEAK DEMAND AND GENERATION CAPACITY FORECAST DETAILS

Projected Capacity & Energy Balance												
Capacity Balance (MW)		*Expected*	*Projected*									
Capacity Demand		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
	Local Demand w/o Valco	*1,609*	*1,736*	1,854	1,980	2,115	2,259	2,412	2,576	2,751	2,938	3,138
	Valco	77	154	154	154	154	154	154	154	154	154	154
	Exports (CEB & SONABEL)	100	136	141	197	227	227	257	257	257	257	257
	New Loads (Mines)	-	55	137	137	137	137	137	137	137	137	137
	Growth post-2012 (@ 6.8% Base)	-	127	245	371	506	650	803	967	1,142	1,329	1,529
	Total Max Demand	1,786	2,081	2,286	2,468	2,633	2,777	2,960	3,124	3,299	3,486	3,686
	Max Coincident Demand	1,786	2,081	2,286	2,468	2,633	2,777	2,960	3,124	3,299	3,486	3,686
	Coinc. Dmd + 20% Res.Margin	**2,140**	**2,500**	**2,740**	**2,960**	**3,160**	**3,330**	**3,550**	**3,750**	**3,960**	**4,180**	**4,420**
Installed Supply Capacity												
	Renewables - Wind & Solar	0	0	0	0	0	0	0	0	0	0	0
Hydros	Akosombo HEP	900	900	900	900	900	900	900	900	900	900	900
	Kpong HEP	140	140	140	140	140	140	140	140	140	140	140
	Bui HEP	-	160	320	320	320	320	320	320	320	320	320
	Other Hydros	-	-	-	-	-	-	-	-	-	-	-
	Hydro & Renewables	1,040	1,200	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360	1,360
CC-Gas	TTPS (T1)	300	300	300	300	300	300	300	300	300	300	300
	TICO (T2) + Expansion	-	-	-	300	300	300	300	300	300	300	300
	Sunon Asogli Power	180	180	180	180	180	180	180	180	180	180	180
	Takoradi (T3)	30	120	120	120	120	120	120	120	120	120	120
	Takoradi T3X - Expansion	-	-	-	-	-	-	-	-	-	-	-
	TT1PP + CENIT + Expansion	-	-	-	-	-	-	-	-	-	-	-
	CENPOWER Kpone IPP	-	-	-	80	315	315	315	315	315	315	315
	KTPP (Alstom) Expansion	-	-	-	-	-	-	-	-	-	-	-
	Domunli	-	-	-	-	-	-	-	-	-	-	-
	CC-Gas	510	600	600	980	1,215	1,215	1,215	1,215	1,215	1,215	1,215
SC-Gas	TICO (T2)	200	200	200	-	-	-	-	-	-	-	-
	Tema (TT1PP)	100	100	100	100	100	100	100	100	100	100	100
	CENIT	20	100	100	100	100	100	100	100	100	100	100
	Future	-	-	-	-	-	-	-	-	-	-	-
	Osaegyefo (Effasu) Barge	-	-	-	-	-	-	-	-	-	-	-
	KTPP/Bonyere (Alstom) Plant	-	-	-	-	-	-	-	-	-	-	-
	SC-Gas	320	400	400	200	200	200	200	200	200	200	200
SC-Oil	Imports (CIE)	-	-	-	-	-	-	-	-	-	-	-
	Tema (TT2PP) Siemens Plant	45	45	45	45	45	45	45	45	45	45	45
	Emerg. (MRP) Reserve Plants	40	40	40	40	40	40	40	40	40	40	40
	SC-Oil	85	85	85	85	85	85	85	85	85	85	85
	Total Installed Supply Capacity	**1,955**	**2,285**	**2,445**	**2,625**	**2,860**	**2,860**	**2,860**	**2,860**	**2,860**	**2,860**	**2,860**
	Net Capacity balance	**169**	**204**	**159**	**157**	**227**	**83**	**-100**	**-264**	**-439**	**-626**	**-826**
Resultant Reserve Margin (%)		***9%***	***10%***	***7%***	***6%***	***9%***	***3%***	***-3%***	***-8%***	***-13%***	***-18%***	***-22%***
	Additional Capacity Required	***185***	***215***	***295***	***335***	***300***	***470***	***690***	***890***	***1100***	***1320***	***1560***

ANNEX 3.1: TRANSMISSION MASTER PLAN COST

Annual Distribution of Master Plan Cost			
Year	**Line [US$ M]**	**Substation [US$ M]**	**Total [US$ M]**
2010	0	27.7	27.7
2011	51.4	37.9	89.3
2012	48.6	59.4	108
2013	187.4	101.4	288.7
2014	27.1	31.6	58.7
2015	132.1	62.2	194.3
2016	56.7	19.6	76.3
2017	27.6	32.2	59.8
2018	4	16.4	20.3
2019	15.8	19.7	35.5
2020	41.7	34.5	76.2
TOTAL	**592.3**	**442.6**	**1034.8**

Source: GRIDCo: 2012 Transmission Master Plan.



Annex 6.1: Ghana Offshore Petroleum Activities

ANNEX 6.2: EXPLORATION AND APPRAISAL WELLS, 2007-2013

Exploration and Appraisal Wells, 2007-2013

Date	Well	Block	Operator	Net Pay (meters)	Objective	Result
18-Jun-07	Mahogany-1 (Jubilee)	WCTP	Kosmos	95	Exploration	Successful
22-Aug-07	Hyedua-1 (Jubilee)	DWT	Tullow	41	Appraisal	Successful
9-Oct-07	IN-3X	SWT	Tullow		Exploration	Oil encountered, non-productive
25-Feb-08	Odum-1	WCTP	Kosmos	22	Exploration	Successful
6-May-08	Mahogany-2	WCTP	Kosmos	50	Appraisal	Successful
20-Nov-08	Ebony-1	SWT	Tullow	4	Exploration	Oil encountered, non-productive
11-Dec-08	Hyedua-2	DWT	Tullow	55	Appraisal	Successful
17-Dec-08	Ankobra-1	DWT/CTP	Hess		Exploration	Unsuccessful
29-Dec-08	Cuda-1X	Keta	Afren/Eni		Exploration	Unsuccessful
8-Jan-09	Mahogany-3/Mahogany Deep	WCTP	Kosmos	33	Appraisal w/ Deep Expl	Successful
9-Mar-09	Tweneboa-1	DWT	Tullow	21	Exploration	Successful
16-Sep-09	Sankofa-1A	OCTP	Eni	36	Exploration	Successful
15-Oct-09	Mahogany-4	WCTP	Kosmos	43	Appraisal	Successful
8-Dec-09	Odum-2	WCTP	Kosmos	20	Appraisal	Successful
23-Dec-09	Mahogany Deep-2	WCTP	Kosmos	14	Appraisal	Successful
21-Jan-10	Tweneboa-2	DWT	Tullow	32	Appraisal	Successful
26-Feb-10	Dzata-1	CTPDW	Vanco/Lukoil	25	Exploration	Successful
20-Apr-10	Dahoma-1	WCTP	Kosmos		Exploration	Unsuccessful
9-Jun-10	Mahogany-5	WCTP	Kosmos	23	Appraisal	Successful
26-Jul-10	Owo-1	DWT	Tullow	53	Exploration	Successful
13-Sep-10	Owo-1ST	DWT	Tullow	35	Appraisal	Successful
21-Oct-10	Onyuna-1	DWT	Tullow		Exploration	Unsuccessful
10-Jan-11	Tweneboa-3/Ntomme-1	DWT	Tullow	44	Appraisal w/ Deep Expl	Successful
10-Feb-11	Teak-1	WCTP	Kosmos	73	Exploration	Successful
3-Mar-11	Enyenra-2A	DWT	Tullow	32	Appraisal	Successful
28-Mar-11	Teak-2	WCTP	Kosmos	27	Appraisal	Successful
12-Apr-11	Sankofa-2	OCTP	Eni	41	Appraisal	Successful
6-Jun-11	Bada-1	WCTP	Kosmos	3	Exploration	Successful
7-Jun-11	Paradise-1	DWT/CTP	Hess	149	Exploration	Successful
15-Jun-11	Makore-1	WCTP	Kosmos		Exploration	Unsuccessful
28-Jul-11	Gye Nyame-1	OCTP	Eni	30	Exploration	Successful
23-Aug-11	Akasa-1	WCTP	Kosmos	33	Exploration	Successful
28-Sep-11	Enyenra-3A	DWT	Tullow	17	Appraisal	Successful
18-Nov-11	Teak-3A	WCTP	Kosmos	35	Appraisal	Successful
NA	Dzata-2	CTPDW	Vanco/Lukoil		Appraisal	Unsuccessful
NA	Chita	CTPDW	Vanco/Lukoil		Exploration	Unsuccessful
18-Jan-12	Ntomme-2A	DWT	Tullow	39	Appraisal	Successful
16-Mar-12	Enyenra-4A	DWT	Tullow	32	Appraisal	Successful
25-Apr-12	Nunya-1X	Keta	Afren/Eni		Exploration	Unsuccessful
4-May-12	Teak-4A	WCTP	Kosmos		Appraisal	Oil encountered, non-productive
25-Jun-12	Gye Nyame-2A	OCTP	Eni		Appraisal	Unsuccessful
30-Jun-12	Hickory North	DWT/CTP	Hess	30	Exploration	Successful
18-Jul-12	Wawa-1	DWT	Tullow	33	Exploration	Successful
31-Jul-12	Beech	DWT/CTP	Hess	45	Exploration	Successful
20-Sep-12	Sankofa East-1X	OCTP	Eni	104	Exploration	Successful
30-Sep-12	Almond	DWT/CTP	Hess	16	Exploration	Successful
11-Dec-12	Okure-1	DWT	Tullow		Exploration	Oil encountered, non-productive
13-Dec-12	Pecan-1	DWT/CTP	Hess	75	Exploration	Successful
17-Jan-13	Sankofa East-2A	OCTP	Eni	49	Appraisal	Successful
Ongoing	Sapele	DWT	Tullow		Exploration	
Planned	Cob	DWT/CTP	Hess		Exploration	
Planned	Sankofa East 3A	OCTP	Eni		Appraisal	
Planned	Starfish	Accra	Ophir		Exploration	

ANNEX 6.3: OIL AND GAS PRODUCTION FORECAST—BASE CASE

Base Case Production Forecast

	Oil Production (MBbl/d)				Sales Gas Supply (MMcfd)				
	Jubilee	TEN	Sankofa	Total	WAGP	Jubilee	TEN	Sankofa	Total
2010	36	-	-	36	-	-	-	-	-
2011	67	-	-	67	-	-	-	-	-
2012	72	-	-	72	40	-	-	-	40
2013	106	-	-	106	60	-	-	-	60
2014	114	-	-	114	90	57	-	-	147
2015	114	-	-	114	120	100	-	-	220
2016	114	-	10	124	120	100	-	-	220
2017	114	35	42	191	120	100	-	-	220
2018	114	70	19	203	120	100	40	67	327
2019	114	80	34	228	120	100	58	160	438
2020	114	80	32	226	120	100	85	160	465
2021	114	68	27	209	120	100	85	160	465
2022	114	58	21	192	120	100	85	160	465
2023	99	49	18	166	120	84	85	160	449
2024	85	42	16	143	120	69	85	160	434
2025	72	35	15	123	120	55	85	160	420
2026	61	30	13	104	120	44	85	160	409
2027	52	26	12	90	120	34	85	160	399
2028	44	22	11	77	120	26	74	160	380
2029	38	19	10	66	120	19	64	160	363
2030	32	16	9	57	120	13	56	160	349
2031	27	13	9	49	120	8	48	160	336
2032	23	11	8	42	120	3	41	160	324
2033	20	10	8	37	120	-	35	160	315
2034	17	8	7	32	120	-	29	160	309
2035	14	7	7	28	120	-	24	160	304
2036	12	6	2	20	120	-	19	160	299