



Power Systems Energy
Consulting (PSEC)



Ghana Wholesale Power Reliability Assessment 2010

Final Report
March 2010

This report was produced by Power Systems Energy Consulting (PSEC) in collaboration with Ghana Grid Company Limited (GRIDCo).

PSEC is responsible for the final content of this report, unless otherwise cited.

© 2010 Power Systems Energy Consulting (PSEC)

Do not reproduce or distribute without the prior written permission of Power Systems Energy Consulting.

Table of Contents

Executive Summary	vii
1 Introduction	1
1.1 HOW POWER SYSTEMS WORK	2
1.2 FACTORS THAT AFFECT RELIABILITY	3
1.3 THE COST TO SOCIETY OF RELIABILITY FAILURES	7
2 System Overview	9
2.1 MARKET STRUCTURE	9
2.2 ELECTRICITY DEMAND	11
2.3 GENERATION RESOURCES IN GHANA	14
2.4 THE TRANSMISSION SYSTEM	16
2.5 THE DISTRIBUTION SYSTEM	16
3 Electricity Demand in Ghana	19
3.1 HISTORICAL DEMAND	19
3.2 DEMAND FORECAST: 2010	26
3.3 DEMAND FORECAST: 2010 TO 2018	28
3.4 DEMAND-SIDE MANAGEMENT	30
3.5 IMPORTS AND EXPORTS	32
3.6 CONCLUSION	33
4 Generation Reliability Assessment	35
4.1 EXISTING INFRASTRUCTURE	35
4.2 RESERVE MARGIN AND UNFORCED GENERATION CAPACITY	37
4.3 PLANNED GENERATION CAPACITY ADDITIONS	43
4.4 GENERATION RESOURCE ADEQUACY: 2010	47
4.5 GENERATION RESOURCE ADEQUACY: 2010 TO 2018	48
4.6 FIRM HYDRO CAPACITY	51
4.7 CONCLUSION	52
5 Transmission Reliability Assessment	55
5.1 EXISTING TRANSMISSION SYSTEM	55
5.2 THE CONCEPT OF TRANSFER CAPABILITY	55
5.3 EXISTING TRANSMISSION OVERLOADS AND CONSTRAINTS	57
5.4 EXISTING VOLTAGE VIOLATIONS	59
5.5 LOSSES	60
5.6 AVAILABLE TRANSFER CAPABILITY BETWEEN AREAS	61
5.7 PLANNED TRANSMISSION UPGRADES	66
5.8 CONCLUSION	68
6 Economic Cost of Reliability Failures	69
6.1 VALUE OF LOST LOAD	69
6.2 IMPACT OF RELIABILITY ON ECONOMIC DEVELOPMENT	72
7 Economic Incentives for Investment	75
7.1 GHANA'S TARIFF STRUCTURE	75
7.2 ECONOMICS OF GENERATION	77
7.3 ECONOMICS OF TRANSMISSION	81
7.4 SOCIAL IMPACT OF TARIFFS	83

8 Conclusion	85
8.1 OVERVIEW	85
8.2 NEXT STEPS	86
8.3 AN EVOLVING SYSTEM	87
Appendix A Transmission System Transfer Capabilities	89

Table of Figures

Figure 1.1 – Ghana’s Power Sector.....	2
Figure 2.1 - Basic Power Network.....	9
Figure 2.2 - Electricity distribution zones for ECG (yellow) and NED (red).....	10
Figure 2.3 - Peak Demand of Major Load Centres By Service Provider	12
Figure 2.4 – A Typical 24-Hour Demand Profile (January 2010).....	14
Figure 2.5 - Generation Resources in Ghana	15
Figure 2.6 - Ghana's Power Transmission Network	17
Figure 3.1 - Actual Peak Demand: 2000 to 2009	20
Figure 3.2 - Actual Energy Demand: 2000 to 2009	20
Figure 3.3 - Cumulative Peak Demand and Energy Demand Growth: 2000-2009.....	21
Figure 3.4 - Peak Demand by Service Provider: 2000 and 2009	21
Figure 3.5 - Normalized GDP, Peak Demand, and Energy: 2000-2008	22
Figure 3.6 - Peak Demand and Energy Growth for Urban Areas: 2000 to 2009	23
Figure 3.7 - Demand and Energy Consumption By Sector: 2001	24
Figure 3.8 - VALCO Demand and Energy Consumption: 2000 - 2009.....	25
Figure 3.9 - Peak Demand and Energy Consumption Growth By Sector: 2010	27
Figure 3.10 - Effect of VALCO Operations on 2010 Peak Demand and Energy Demand.....	27
Figure 3.11 - Forecasted Peak Demand: 2009 to 2018	29
Figure 3.12 - Forecasted Energy Demand: 2009 to 2018	29
Figure 3.13 - Forecasted Cumulative Growth Rates By Sector: 2009-2018.....	30
Figure 3.14 - Effect of Demand Side Management Programs	31
Figure 4.1 – An Example of Generation Facility Operating Modes.....	36
Figure 4.2 - Akosombo Water Level (2000 to 2009).....	40
Figure 4.3 - Reserve Margin Based on Unforced Capacity: 2000 to 2009.....	41
Figure 4.4 - Unforced Capacity and Demand: 2000-2009	42
Figure 4.5 - Determining an Adequate Reserve Margin	43
Figure 4.6 – Reserve Margin Outlook With New Generation Capacity Additions: 2010 to 2018	48
Figure 4.7 - Projected Reserve Margin, Nominal Case: 2010-2018.....	49
Figure 4.8 - Reserve Margin Fuel Risk Contingency Scenarios: 2010 to 2018	50
Figure 4.9 - Reserve Margin Supply and Demand Contingency Scenarios: 2010 to 2018.....	51
Figure 5.1 - Losses in Transmission and Distribution	61
Figure 5.2 - Non-Simultaneous Firm (Non-Firm) Transfer Capabilities	63
Figure 5.3 - Simultaneous Firm (Non-Firm) Transfer Capabilities	65
Figure 7.1 - Bulk Power Tariffs, 2001-2008.....	76
Figure 7.2 – Estimated Levelized Cost of Generation in 2008.....	77
Figure 7.3 - PJM Cost of New Entry for Combined Cycle Plant (2012 Estimate).....	79
Figure 7.4 - PJM Average CONE for Different Technologies (2012 Estimate)	80

Table of Tables

Table 2.1 - Ghana's Ten Largest Load Centres, 2009	13
Table 3.1 - Impact of VALCO Demand on National Peak and Energy Demand Growth	25
Table 3.2 - 2010 Demand Scenarios	26
Table 4.1 - Commercial Generation Facilities	35
Table 4.2 - Plant Dependable Capacity and Forced Outage Rates	37
Table 4.3 - Plant Generation and Capacity Factors	38
Table 4.4 - Comparison of Reserve Margins	39
Table 4.5 - Ghana Historical Reserve Margins	41
Table 4.6 - Generation Capacity Additions: 2010-2018	44
Table 4.7 - Projected 2010 Reserve Margin with and without Sunon-Asogli operational in 2010	47
Table 5.1 - Fact Sheet on Ghana's Transmission Network	55
Table 5.2 - Key Transformers and Loadings	59
Table 5.3 - Substation Voltages	60
Table 5.4 - Zone Aggregation for Total Transfer Capability Calculations	62
Table 5.5 - Simultaneous Firm Transfer Capabilities: Importing Areas	64
Table 5.6 - Simultaneous Firm Transfer Capabilities: Exporting Areas	65
Table 5.7 - New Transmission Projects	66
Table 6.1 - Impact of Outages	70
Table 6.2 - Value per Unit of Electricity	71
Table 6.3 - Value of Lost Load	71
Table 6.4 - Comparison of Electrification in Africa	72
Table 7.1 - Estimated Levelized Cost of New Generation Resources	81
Table 7.2 - Estimated ERV of Transmission Infrastructure	82
Table A.1 - Non-Simultaneous Firm Transfer Capabilities	89
Table A.2 - Non-Simultaneous Non-Firm Transfer Capabilities	90
Table A.3 - Simultaneous Firm Transfer Capabilities	91
Table A.4 - Simultaneous Non-Firm Transfer Capabilities	91

Executive Summary

This report is intended to present the outlook for Ghana's bulk power supply system for stakeholders and the general public. It presents an overview of the operating status of the bulk power system and assesses whether it meets minimum reliability standards, a reflection of its ability to reliably supply the anticipated demand in the 2010 operating year. In addition, the report addresses historical and long-term physical or structural limitations that could impair the reliability of the power system going forward and it also estimates the cost to society and the Ghanaian economy of potential reliability failures.

PSEC uses industry-standard measures of system reliability – reserve margin for generation capacity, and transfer capability for transmission capacity – to assess the overall reliability of Ghana's power system. The assessment shows that Ghana's wholesale electricity supply system is not expected to meet minimum reliability standards for the 2010 year. The reserve margin, a widely used measure of generation adequacy, currently stands at 10.1%. While this number represents a modest improvement over reserve margins in the past, it is well below the PSEC-estimated minimum reserve margin for reliable operation of 20%, and the West African Power Pool (WAPP) recommended minimum of 25%. Likewise, firm transfer capability, a measure of how well the electricity system can move power around to locations that need it, will remain inadequate in many key areas including Accra and Kumasi.

A handful of generation and transmission projects scheduled for completion in 2010 will improve reliability *if completed and made operational as expected*. A new generation project, Sunon Asogli (SAPP) in Kpone, will potentially increase the reserve margin to 14.9%; while this remains short of the minimum target it should improve system-wide reliability. Three transmission projects will potentially improve transfer capability and decrease congestion, consequently improving reliability in the major metropolitan areas of Accra and Kumasi. However, failure to complete these projects on time will worsen an already precarious situation. Reserve margin will drop to 4.9%, transfer capability will reduce, and system reliability will decline. Even if these projects are executed perfectly, Ghana's bulk power system will still not attain the minimum reliability standard. Further, their benefits are not eternal. Demand growth will return the system to an unreliable state unless investment is persistent. Since electricity infrastructure can take 3 to 6 years to plan and complete, new projects must be initiated today in anticipation of future needs.

The above shows that Ghana's electricity system remains in the balance. On paper, the three to five year generation expansion plan in place will improve the reliability of generation supply to the required levels by 2014, even if demand growth remains robust. However, many of these projects face several hurdles and potential delays in becoming operational ranging from securing reliable access to natural gas to project financing to legal disputes. Any delays or cancellations of any of these projects are likely to leave the electricity system back into an unreliable state. Moreover, Ghana depends almost solely on hydroelectric and thermal technologies for commercial generation and will continue to do so at least for the short to medium term, meaning that water risk and fuel risks are inherent. We believe the projects in the transmission expansion plan alone will not result in adequate firm transfer capability for all load centres. Future reports should include an assessment of the improvements from these projects, and additional projects considered as appropriate.

Adding to the risk of reliability failure is the fact that the projections for future demand do not include power demand from the operation of VALCO. That is, the current assessments assume that VALCO will remain offline for the foreseeable future. The system as planned

simply cannot support the startup of VALCO without the addition of new generation capacity above and beyond what is in the current plan, or some form of demand curtailment such as rolling blackouts. It is important to note that VALCO is representative of several possible types of energy intensive customers, and therefore this assessment shows that the bulk power system is severely limited in its ability to support additional heavy industries.

The current predicament is a result of a decade of chronic underinvestment in generation and transmission infrastructure despite robust growth in demand and energy consumption. From 2000 to 2009, the natural (i.e. uncurtailed) peak demand and energy grew growth rates were 44% and 100%, respectively, driven in large by three major factors: economic growth, urbanization, and industrial activity. In the same period, installed generation capacity grew only 7% while very few new transmission projects were completed compared to the capacity needed. Certainly, the growing pains inherent with the nascent power sector reform effort may have been a factor in this lack of investment. However, the most significant factor was a tariff structure that was insufficient to meet the true long run marginal cost of generation and transmission¹, especially considering the rampant currency devaluation and escalating cost of infrastructure of the period. For example, the bulk generation tariff in 2008 was not even sufficient to cover the cost of fuel for thermal plants, let alone cover fixed operating costs, maintenance, and depreciation. The result of this was that the existing utilities were unable to sufficiently invest in improving the performance of existing capacity or in adding new capacity; at the same time the low tariffs made entry by private parties unattractive. Simply put, consumers of electricity were not being charged the true cost of reliably generating and delivering power; eventually consumers got what they paid for – an unreliable system.

Rectifying the underinvestment of the last decade while supporting the expected new growth in demand will require very significant, sustained levels of investment in generation and transmission infrastructure. Specifically, much of this investment will have to be private since a) the public sector does not have the necessary capital to fund everything on its own, especially given competition from other, equally critical needs; and b) Ghana's deregulated market will require a thriving, competitive private sector to function well. Above all, attracting this private capital is dependent on having the right market structure and sufficient tariffs to attract new entry and provide adequate returns that enable existing participants to invest and earn a reasonable profit. At the same time, it is important that the market structure and tariffs ensure that electricity is properly valued on both the supply side and the demand side, incentivize reliability and an appropriate mix of generation and transmission resources, and ensure that electricity is as affordable as possible within the context of reliability. Ghana's market structure and tariffs must be reviewed, recognizing that in the medium to long term, flawed economics creates an unhealthy industry that is not sustainable. The right changes can transform the power sector into a success story like the telecom industry in Ghana – into a vibrant and competitive industry with many private participants and improved availability and reliability of services, as well as fair prices to consumers.

To reiterate, the most important part of attaining reliability in the future is an appropriate market structure. However, in the short term a focus on operational improvements in transmission and generation and demand side management programs (DSM)² can play a significant role in helping increase the reliability of the electricity system. PSEC recommends that a number of studies be conducted in order to provide a better understanding of the system that can be used to develop more targeted and precise operational procedures and context-appropriate DSM programs. These include:

¹ This was the legacy of a fully-regulated, hydro-dominated electricity sector.

² DSM reduces the demand for new generation and transmission capacity.

1. An explicit loss-of-load expectation study that will be used to establish an official generation reserve margin for the Ghana wholesale power supply system. This study must consider factors such as the loss of load probability and quantify the systemic risks identified. The outcome of this study will be used to determine adequate levels of generation capacity needed to meet acceptable reliability levels going forward.
2. A continuous assessment of the available transfer capability of the transmission system under varying system conditions. This continuous assessment will be used to identify new projects to add transmission capacity to the network.
3. Develop remedial action schemes for system operators to enforce transmission limits in accordance with good utility practice.
4. Strategies for the design and implementation of demand side management programs, which can help shape demand patterns to improve reliability.
5. An analysis of the impact of the oil find on power requirements, including both the direct impact on demand from commercial and industrial activity, and the possible indirect impact on demand from economic growth and GDP per capita

Such studies and subsequent actions can help Ghana get the most out of its electricity sector whilst necessary new infrastructure is put into place, and beyond.

The challenges ahead may sound daunting, and indeed expensive. However, it is important to realize that as a society, we incur the full cost of electricity whether we choose to pay a low tariff and endure the cost of reliability failures, or we choose to pay fair power prices to assure availability and reliability. For Ghanaians, the cost to society of insufficient wholesale power supply adequacy and security is massive. PSEC estimates this cost to be between US\$320 million to \$924 million annually, or 2% to 6% of GDP, not including a number of indirect costs. For reference Ghana's GDP growth averaged 5.5% over the last 10 years, a rate that is considered quite robust. In comparison, US\$320 million is enough to fund all of GRIDCo's identified reliability projects from 2010 to 2016 or to add 500-700MW of combined-cycle thermal generation capacity each year (that is the equivalent of adding a new Akosombo facility every 2 years). These figures indicate that the total cost to society of reliable power is truly in excess of the investment needed to attain reliability and avoid or at least dramatically reduce reliability failures.

Finally, it is important that all stakeholders in Ghana's power sector (consumers, regulators and politicians) recognize that the sector is in a new era. Gone are the days of monolithic power facilities like Akosombo that can meet the entire country's needs for decades; and gone are the days of low cost, seemingly limitless hydroelectric power and untenably low tariffs. The new era will require an emphasis on operational efficiency and excellence in reflection of the increasing presence of thermal generation, which requires nothing less. It will require properly structured power markets and sustainable tariffs that are constantly monitored and frequently updated to reflect the actual, not theoretical, state of the system. It will require a continued emphasis on managing supply and demand to ensure system reliability. And it will require that all parties value power properly, and make efforts to utilize it efficiently. Electricity is a key infrastructural element for economic growth. It is a versatile "energy currency" that underpins a wide range of products and services that improve quality of life, increase worker productivity, and encourage entrepreneurial activity. As such, it must be at the forefront of the national dialogue.

1 Introduction

This report focuses on the reliability of the Ghana wholesale power supply market for the 2010 operating year. It is intended to present the operating status of the power system to stakeholders and the general public, and to discuss whether the existing power supply infrastructure is adequate and secure enough to support commercial energy transactions between wholesale power buyers and sellers for the 2010 operating year.³ In very simple terms, it projects demand for 2010 and assesses whether there will be sufficient unforced generation⁴ and transmission capacity to reliably supply the anticipated demand. It examines risk factors associated with the demand forecasts as well as those associated with generation and transmission and draws the necessary conclusions as to whether the existing wholesale power supply resources will be adequate and secure for the 2010 operating year. This report also addresses historical and long-term physical or structural limitations that could impair the reliability of the power system going forward and the cost to society and the Ghanaian economy of potential reliability failures.

This is the first in a series of annual assessments of the reliability of the Ghana wholesale power supply system specifically designed for stakeholders and the general public. Going forward, the Ghana Grid Company (GRIDCo) intends to publish the Annual Reliability Assessment Report before the start of each operating year. This report is not intended to be a technical or engineering report targeted at practitioners with technical knowledge in power systems engineering or wholesale power systems. It is intended for both technical and non-technical audiences, with an emphasis on helping economists, regulatory policy makers, investors, developers, bankers, non-engineering planners and the general public to understand the condition of the wholesale power supply infrastructure and the critical physical and structural factors necessary to assure reliable supply.

There were two key drivers that caused the initiation of power sector reform in 1994. First, low tariffs resulted in chronic lack of investment and poor quality of service. The low tariffs also resulted in substantial deficits; in 2002 deficits of the three electricity utility companies – the Volta River Authority (VRA), the Electricity Company of Ghana (ECG), and the Northern Electricity Department (NED) – approached US\$204 million, or 11% of Government spending, and 4% of Ghana's gross domestic product (GDP)⁵. Second, there was a need to invest in additional generation and transmission infrastructure to support rapidly growing demand by encouraging private sector investment and introducing competition in the wholesale power supply market. As part of this process, GRIDCo was formed in 2006 as an electric transmission utility with the responsibility of dispatch and transmission operations to provide fair and open access to the interconnected power system to all market participants. GRIDCo is therefore responsible for wholesale power supply reliability from generation and transmission to delivery at the bulk power distribution centres. Accordingly this report deals with the assessment of the reliability of the wholesale or bulk power transmission system. It does not address retail power or power distribution reliability, which is the function of ECG for southern Ghana and NED for northern Ghana.

³ Adequacy and security are the two main aspects of reliability. Adequacy means having sufficient resources to provide a continuous supply of electricity in spite of scheduled or unscheduled outages. Security is the ability of the power system to withstand sudden, unexpected disturbances.

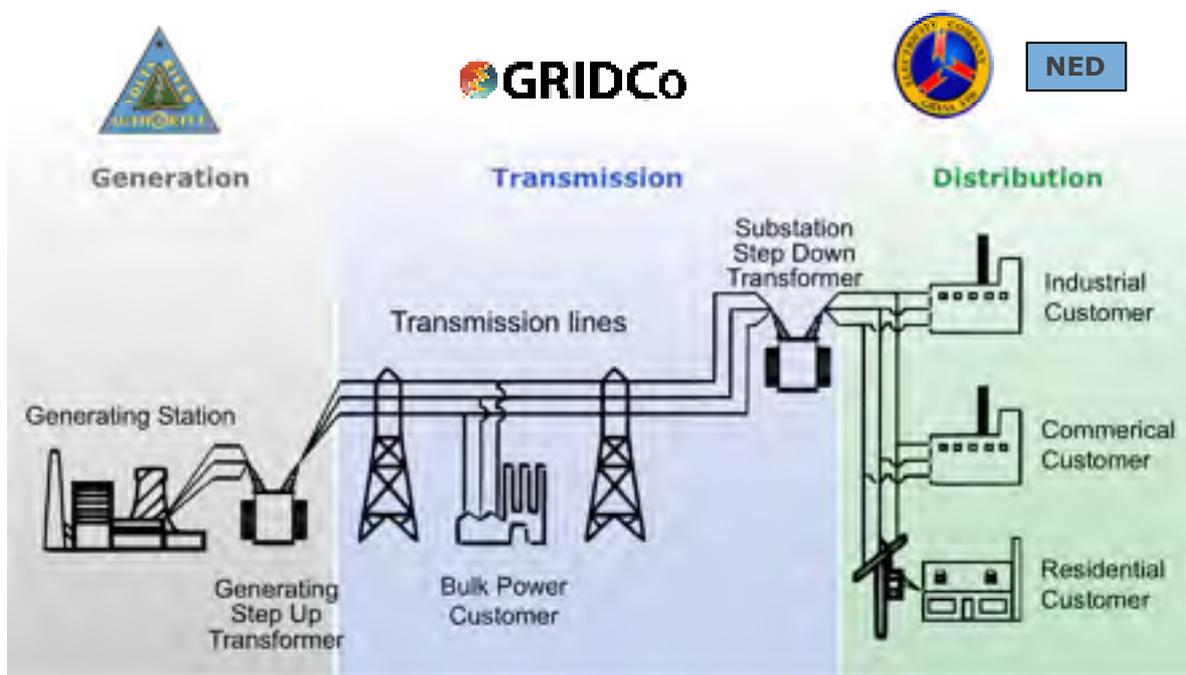
⁴ Unforced capacity is a measure of available generation capacity. It refers to total generation capacity less the amount that is expected to be out of service. See Chapter 1 for more detail.

⁵ Sarah Keener and Sudeshna G. Banerjee, *Ghana: Poverty and Social Impact Analysis of Electricity Tariffs*, ESMAP Technical Paper 088, December 2005.

1.1 How Power Systems Work

Bulk power systems comprise three main sub-systems – generation, transmission and bulk distribution centres. Bulk power is typically generated at very low voltages such as 13 kV to 24 kV at power stations. For example, the bulk power station at Akosombo generates power at 14.4 kV⁶. This bulk power must be transmitted over long distances to bulk load centres such as Accra, Kumasi and Tamale. To minimize transmission losses, the power must be transmitted at very high voltages. Therefore the output from bulk power generators is passed through step-up transformers located at the power station switchyard onto the transmission system. The primary bulk power transmission voltage in Ghana is 161 kV. At the bulk power distribution centre, the power is stepped down through step-down transformers for wholesale power buyers such as ECG and NED for further distribution through their respective distribution networks to their customers (see Figure 1.1).

Figure 1.1 – Ghana’s Power Sector



Thus, the transmission of power from bulk power generators to bulk power distribution centres is very similar to the haulage of farm produce from commercial farms to bulk market centres. In this case the farmer who cultivates and harvests the farm produce is analogous to a generation owner such as VRA who generates the power. The trucker who carts the farm produce in a truck from the farm across trunk roads to the bulk market centre is analogous to a transmission company such as GRIDCo. The marketer who receives the farm produce at the bulk market centre is analogous to a bulk power distribution company such as ECG or NED.

Each of the three sub-systems of a wholesale power system comprises many interconnected elements. When each one of these elements functions as expected, we get a functioning sub-system, and combined with other functioning sub-systems, a reliable wholesale power system. Any elemental failure can compromise the reliability of the entire system; therefore

⁶ "Akosombo Brochure", Volta River Authority, 2010. <<http://www.vra.com/Publications/akobrochure.pdf>>

planners and operators allow necessary redundancies for critical elements to ensure reliable supply. There are many analogous systems that incorporate similar redundancies to assure reliability. For example the automobile industry rightfully allows for a spare tire (a redundancy) in the design of an automobile to avoid mission failure in case of a flat tire. Commercial aircraft systems have at least two engines to ensure they will remain aloft in the event of a single engine failure. Human systems also allow for some redundancies such as two eyes or kidneys to avoid total vision or renal failure. Similarly, wholesale power systems need redundancies in the generation and transmission subsystems to assure reliability. A well-designed and reliable power system must have adequate redundancies so that an unplanned elemental failure such as the outage of a single transmission line, transformer or generator will not cause a partial or total power outage.

Having explored the need for redundancies in power systems, it is worth noting that not only is it expensive to provide 100% redundancy of every element of a power supply system but it is also impractical. For example, in automobile systems, the industry provides a spare tire but not a spare steering wheel column. Although it is conceivable for an automobile to experience mission failure because of a steering wheel column failure, the likelihood of a failure of the steering wheel column is very low. Similarly, the power industry has developed approaches for determining redundancies that are necessary to meet the acceptable reliability standards defined by the industry. Is it conceivable that a well-designed power system with adequate redundancies could experience an outage? Yes, but the likelihood is very low. The industry plans and designs the system to a reliability standard of one outage in ten years.⁷ Thus outages are expected to be rare, but not impossible events.

Although the redundancies needed in the power system, such as power lines and power transformers are generally of a physical nature, there are often structural issues that inherently prevent the timely deployment of these physical resources. We cannot address power system reliability without examining the structural issues that potentially affect the deployment of these physical resources. Therefore, it is important for us to broadly examine all the direct and indirect factors that affect reliability.

1.2 Factors That Affect Reliability

In the Introduction, we mentioned that a well designed and reliable power system has sufficient redundancies to accommodate unplanned elemental outages without causing a total or partial failure of the system. We also mentioned that while redundancies are of a physical nature there could be structural issues that impair the deployment of these physical resources. In this section, we examine the structure of the power industry in Ghana and identify any potential structural impediments that negatively affect reliability. We also examine industry best practices from other developing and developed countries and discuss how these alternative structures have improved reliability.

Historically, economists believed that utility operations were “natural monopolies” because of significant economies of scale that existed in the industry. Larger power producers enjoyed considerable production and distribution efficiencies⁸. Therefore most power companies around the world were structured as public monopolies with extensive integration of

⁷ The industry standard is to plan the system such that the risk of shedding load due to shortage of resources will be, on average, not more than one day in ten years.

⁸ In economic theory a natural monopoly occurs in an industry where the capital cost is so high that it creates a barrier to other entrants, making it unprofitable for a second company to compete. The high cost creates economies of scale that make it more efficient to have one producer or supplier rather than several.

generation, transmission, and/or distribution services and centralized planning of supply resources to meet demand growth⁹. This integral structure was believed to maximize coordination and efficiency in the design, development, and financing of wholesale power supply resources. To prevent utilities from abusing their monopoly power, they were regulated by government and were allowed a fixed rate of return above their cost.

Over time it became self evident that the state-owned, vertically integrated monopoly structure was plagued by poor performance and limited capital for operations and investment. For example, many state-run power entities had high costs and untenable tariffs that under recovered the long-run marginal cost of their operations. As a result, their weak balance sheets could not attract capital to extend the reach of power to new consumers. The lack of capital also led to underinvestment in utility infrastructure, which subsequently led to higher operating costs due to expensive emergency maintenance and frequent and/or prolonged outages.

Second, the lack of competition inherent in a monopoly structure accounted in large part for poor performance and poor managerial decisions. For example, one of the reasons that led Colombia to begin power sector reform in 1993 was the high amount of non-technical losses (e.g. theft, unaccounted consumption, etc) in the system. These losses had historically proven difficult to eradicate because it was feared that cracking down on those practices would also be politically treacherous.

Third, it was often the case that managerial decisions at state-owned public utilities were heavily influenced by government objectives that were not necessarily consistent with the utilities' business objectives. It was always a challenge for government to adjust tariffs to ensure full cost recovery given the impact on the consumers (i.e. voters). As a result, tariffs lagged the full cost of power production and delivery, and in many cases could not cover even variable operating costs. These factors, borne out of the fully regulated state-owned monopoly structure, severely compromised power supply reliability, and in many countries it hindered economic development.

If the essential characteristics of a properly structured power market are reliable supply, continued investment in infrastructure and fair prices to consumers, then the vertically integrated state-owned natural monopoly structure provided neither, as the evidence demonstrated. While many of the state-owned monopoly entities continued to provide power to consumers, it was anything but reliable and/or fairly priced. Indeed the state-owned entities that continued to operate under those conditions only tried to delay the inevitable – bankruptcy! The expectation of reliable power supply from bankrupt institutions is a mirage because an industry with bankrupt institutions is itself bankrupt and cannot meet its obligation to consumers. Additionally if regulation was intended to use administrative means to achieve the competitive market outcome of reliable and fairly priced power, then the tariff offered to the monopolies rendered them ineffective in assuring reliability because they could not attract capital for timely investments. Such regulatory regimes were also anything but effective because they failed to effectively use administrative means to achieve supply availability and reliability. Thus, a structural shift from a fully regulated monopoly was necessary to increase competition by allowing private participation and for consumers to pay fair rates.

⁹ Some developing countries – particularly those in Asia, the Middle East, and Africa – featured state-owned, vertically integrated legal monopolies, while others – notably in South America – featured separate distribution and customer services from bulk power generation and transmission.

Technological advances in combined cycle technology challenged the long held economies of scale view and fuelled the migration to a new structure. Relatively new and small-sized combined cycles were more efficient than large-scale coal and oil/gas steam plants. Therefore it was possible for investors to enter the utility business and invest in small and efficient combined cycle units to supply wholesale power. Thus the long-held economies of scale monopoly structure view began to unravel.

Many countries, including Ghana, embarked on power sector reforms to migrate from the regulated monopoly structure towards a deregulated competitive market structure. In order to make competitive markets possible, it was necessary to open access to transmission lines to permit new market entrants to buy and sell power. Therefore it was necessary to functionally “unbundle” generation, transmission, and distribution.

Ghana’s government began its market-based power sector reforms in the mid nineties to open up the industry to new market participants and simultaneously began to unbundle wholesale power generation and transmission.¹⁰ Historically, Ghana’s power industry had featured semi-vertically integrated state-owned monopolies. The Volta River Authority (VRA) was responsible for wholesale power generation and transmission, while the Electricity Corporation of Ghana was responsible for distribution¹¹. As part of the reform process, VRA was functionally unbundled into two institutions; GRIDCo was created out of VRA in 2006 and was tasked with wholesale power transmission, and legacy VRA continued operation as a generation-only company.

Since the mid-nineties, several pieces of legislation have been passed to facilitate the creation of a competitive wholesale power market. Two regulatory institutions, the Energy Commission (EC) and the Public Utilities Regulatory Commission (PURC), were formed, with the responsibility of helping to create and maintain a healthy and competitive power sector. The PURC sets rates and tariffs, monitors performance, promotes fair competition, and works to balance the interests of utility providers and consumers. The EC issues licenses and establishes performance standards for utilities. Ghana’s Grid Code has been finalized, published and launched. The Market Rules are still in the initial stages of development. Private investors have responded to efforts by the government to create a viable power market. Since Ghana enacted the Energy Commission Act, 1997, Act 541, five private entities have announced or are at various stages of construction of a total of 960 MW of new generation facilities. The influx of new generation facilities could provide the redundancies needed in generation, which should significantly improve generation reliability or at least get the industry a lot closer to where it needs to be. Thus, a structural shift from a monopoly to a competitive market structure with private participants has in part enabled the availability of physical redundancies in generation - one of the key components of wholesale power supply reliability.

Similar structural shifts have occurred in other local industries in Ghana. For example, the structural changes in the telecom industry over a decade ago has created a vibrant and competitive industry with many private participants, and it has significantly improved availability and reliability of telecom services at fair prices to consumers. The explosive growth in telecom has created enormous opportunity for government, market participants and consumers. For the government, an increase in tax revenue and the creation of well-paying jobs that otherwise would be unavailable – these benefits even ignore secondary

¹⁰ Distribution had historically been functionally unbundled in Ghana.

¹¹ ECG was responsible for power distribution in all of Ghana until 1987 when NED was established as a division of VRA with the responsibility for wholesale power distribution in the northern section of Ghana.

benefits from reduction in vehicular traffic and the savings from demand reduction in road infrastructure. For the general public, reliable and available telecom services at fair prices. Lastly, for market participants, a fair return on investment for their shareholders.

In spite of the recent achievement in creating generation redundancies, additional challenges remain. Although a change in market structure encouraged private participants to invest in generation, government had to provide additional economic incentives not available to existing agencies. The current generation tariff is unlikely to incentivize construction in new generation facilities because it falls short of the long-run marginal cost, especially if the marginal generation is expected to be gas-fired. We show in Chapter 7 of this report that the tariff may not be enough to cover even the variable costs of operation for a typical combined cycle unit before accounting for fixed costs and debt service payments. Hence there is an urgent need for tariff reform if the industry wants to achieve reliable power supply through investment in physical generation and transmission resources.

Under the power sector reforms, dispatch and transmission operations remain regulated mainly because they are monopoly functions. This is analogous to air traffic control where one can have only one air traffic control for a defined geographic region. When the market becomes operational, dispatching and transmission operations is expected to be the responsibility of the Electricity Transmission Utility (ETU). Currently the ETU is integral to GRIDCo, but it will be carved out as an independent entity. The ETU will not own transmission infrastructure but will have operational control. Legacy GRIDCo will own the transmission infrastructure.

Since generation reliability must be combined with transmission reliability to ensure wholesale power supply reliability to meet growing demand, effective strategies must be adopted to ensure timely investment in transmission. Ghana has seen private sector response to generation investment, but transmission investments appear to be lagging because there is currently no mechanism for private participation in transmission investment. It is PSEC's opinion that investment in transmission need not remain a monopoly of legacy GRIDCo. Indeed investment in transmission facilities can and should be opened to private participants. The same market competition that is needed on the generation side to provide the necessary redundancy in generation is also needed on the transmission side. Just as a change in market structure and a need for tariff revision is expected to encourage private investment in generation, a similar change in market structure to permit private investors in transmission plus a fair transmission tariff will provide the necessary physical redundancies needed in the transmission network to assure transmission reliability. It is important to get the market structure right to assure timely investments by market participants. Policy makers and the state-owned entities should not be lured into thinking that securing a government loan to provide the physical generation and transmission resources needed is fait accompli and will fix the reliability problem for good. First, such an action only provides temporary relief and simply postpones the problem. Second, government response to the physical resources needed in generation and transmission is unlikely to be timely, as we have often seen in the past. Government often intervenes when the problem has become critical, and it can be slow to rectify the problem due to the time delay associated with securing concessionary loans, navigating the tender and contractor selection processes and initiating construction and start-up. Untimely investments in the power sector can cause enormous harm to the country's economy and it can quickly destroy value – it is a costly proposition and a situation the country cannot afford. Addressing the market structure properly is one of the key components of ensuring timely investments.

A transmission tariff that addresses dispatch and transmission service cost and important ancillary services such as reactive power and voltage support, regulation, and operating reserves is also needed to encourage investment to permit the efficient flow of power between buyers and sellers. These structural changes are imperative to guarantee reliable power supply. The progress that has been made to foster competition in generation should be pursued to its logical conclusion to permit competition in transmission infrastructure investment.

Since this report focuses on only wholesale power reliability we will not discuss retail power reliability (i.e. the reliability of the distribution system). Retail power distribution must be addressed by the retail power entities to the extent there are reliability problems that impair power delivery from the bulk distribution centres to their end-use customers. It is in the interest of the industry as a whole for the distribution agencies to provide similar annual reliability assessments of the distribution infrastructure.

1.3 The Cost to Society of Reliability Failures

The cost to society of wholesale power reliability failures is enormous and can have a deleterious effect on Ghana's economy. Chapter 6 quantifies this cost using existing industry accepted approaches, and finds a cost range of US\$320 million to \$974 million in 2009. Additionally, reliability outages negatively affect the economy either directly or indirectly from business/investment growth that otherwise would not occur and the effect on annual GDP could be as high as 6% as discussed in Chapter 6.

These figures indicate that the total cost to society of reliable power is truly in excess of the existing revenue from tariff collections by the power entities. Instead, it is the sum of the tariff collections plus the cost of reliability failures. The economic cost could even be far larger if secondary factors such as damage to appliances, consumer costs from alternative supply efforts and lost foreign direct investment are considered. Therefore, as a society we incur the full cost anyway, whether we choose to pay a low tariff and endure the cost of reliability failures and the negative impact it has on the economy, or we choose to pay fair power prices to assure availability and reliability.

Significant progress has been made since the commencement of power sector reforms in mid-nineties. Yet additional changes in the market structure for Ghana's electricity sector are needed to create a competitive market that provides reliability assurance to stakeholders and the general public. If we make the structural changes, similar to the changes that were made in the telecom industry, then the wholesale power industry will attract new entrants and timely investment in the physical generation and transmission redundancies to assure power supply availability and reliability. Reliable and fairly priced power is essential to economic development and in attracting foreign direct investment. Additionally, low tariffs that stifle industry growth do not serve society well because it denies society of growth opportunities and eventually leaves it worse off.

The growth and opportunity for all stakeholders that has resulted from structural changes in the telecom industry is also realizable for the wholesale power industry. The potential for power could be even greater if we follow through with the structural reforms already began. However, the benefits are realizable only if services are provided at fair prices that recover long-run marginal cost plus a fair rate of return. Today's telecom consumer is far better off under the competitive market structure than the telecom consumer under the old regulated telecom monopoly of years past. It is the turn of power.

In the remaining chapters we discuss reliability for the 2010 operating year and beyond.

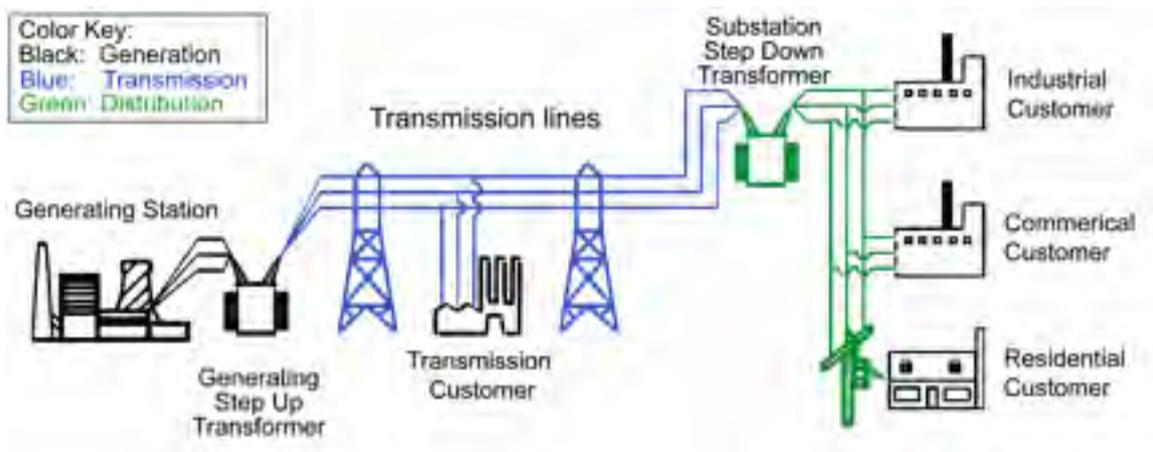
Chapter 2 provides an overview of Ghana's electricity system, including its market structure, demand characteristics, existing infrastructure, and reliability goals. Chapter 3 presents demand in more detail, including historical demand, current demand drivers, and projected demand for the 2010 operating year and beyond. Chapters 4 and 5 discuss generation and transmission reliability. The cost of reliability failures are examined in Chapter 6, and the economic incentives that will drive investments needed for system reliability are described in Chapter 7. We provide a conclusion in Chapter 8.

2 System Overview

In many ways, electricity forms the backbone of modern life and modern economies. It is a versatile “energy currency” that can be used to provide a variety of services from lighting to heating and cooling to computing. End users often take it for granted that power will be available when they turn on lights or appliances. However, delivering that capability requires a complex network of infrastructure that must be perpetually managed and coordinated.

Generally, electricity goes through a three-step process before arriving at the end user for consumption. First, power is produced from generators that are usually located far from the load centres. The power is then transported over the transmission grid, which is composed of transmission lines, transformers, and other components, to the bulk load distribution substations. From bulk load distribution substations, power is delivered to the individual customer sites using distribution lines. Since electric power currently cannot be stored easily in large quantities, this process must occur instantaneously in response to demand – for example, to the flick of a light switch.

Figure 2.1 - Basic Power Network



The challenge for power system operators is to maintain the balance between supply and ever-changing demand, given a complex system with millions of customers and tens, hundreds, or even thousands of generators – a system in which demand can change at the flick of a light switch. The ability of the power system to maintain this balance under varying system conditions is the ultimate measure of its reliability.

2.1 Market Structure

Before power sector reform, Ghana’s market was highly regulated, with generation and transmission vertically integrated in VRA and distribution handled by ECG¹², a fully state-owned enterprise, and NED, a subsidiary of VRA. ECG delivered power to customers in the southern half of the country while NED delivered power to customers in the northern half (Figure 2.2).

¹² Then referred to as the Electricity Corporation of Ghana.

Figure 2.2 - Electricity distribution zones for ECG (yellow) and NED (red)



Like many developing nations, Ghana needed outside capital to help develop its power sector. As part of the power sector reforms, Ghana commenced the process of unbundling generation, transmission, and distribution functions into separate markets, with immediate competition in generation and eventually distribution.

As a result of reform, utilities have become specialized entities focusing on one of three areas. VRA maintained its generation assets including Akosombo, Kpong, and Aboadze, and now focuses almost exclusively on generation. ECG and NED continued to focus exclusively on distribution. As a new public utility, GRIDCo was essentially spun out of VRA and has the sole responsibility for operating transmission in an open and non-discriminatory manner. The PURC and EC were purposefully formed to jointly oversee the electricity sector. The PURC sets rates and tariffs, monitors performance, promotes fair competition, and works to balance the interests of utility providers and consumers. The EC issues licenses and establishes performance standards for utilities.

The new structure enables and encourages the free entry of independent power producers (IPPs) into the generation market, creating a competitive generation market which, when combined with open access to transmission, also facilitates a bulk power trading market. The structure also emphasizes decentralization at the distribution level, with plans for eventually adding more distributors, each operating in a defined geographic service area.

While the reform process has formally been completed, the power sector is still undergoing transition in terms of achieving the designed structure. At present VRA accounts for 88% of

all grid-connected generation, with only the remaining 12% of generation coming from IPPs. As previously mentioned, competition is a key tenet of the successful operation of unbundled power sectors, particularly in generation. Without it, many of the limitations from the pre-reform structure exist, with the added influence of market power. For example, the Bulk Supply Tariff (BST) is still highly susceptible to government influence since the vast majority of generating capacity is government-owned.

2.2 Electricity Demand

At present, Ghana's electricity sector has a customer base of more than 2 million residential and commercial customers and 1,150 industrial customers¹³. In 2009 these customers contributed to a peak power demand of 1,423 MW and a cumulative energy demand of 10,116 GWh. Peak demand is the maximum amount of electricity that customers consume instantaneously, while energy demand is the amount of electricity they use over time (i.e. the sum of instantaneous demand over time).

2.2.1 Load Centres

Electricity demand in Ghana is divided across 40 load centres, which include cities, clusters of smaller towns and villages, and large industrial sites such as mines. In Ghana, a relatively small number of load centres account for a large fraction of total demand (see Figure 2.3). In fact Ghana's ten largest load centres together accounted for nearly 68% of peak demand and 72% of energy consumption in 2009 (see Table 2.1). Most of these load centres coincide with urban centres – Accra, Tema and Kumasi alone account for approximately 49% of total national peak demand.

The remaining major load centres are associated with heavy industrial activity. Industrial customers are characterized by very high, consistent power demands. The four largest mines alone accounted for 12.5% of national peak demand, and each mine consumed a significant amount of energy relative to their peak demand. For example, the load centres at Takoradi and New Obuasi had similar peak demands (44.7 MW and 53.0 MW, respectively), but New Obuasi as a mining site had over 50% more annual energy demand than Takoradi. Large industrial customers like mines often buy power on the wholesale market, and hence have direct relationships with transmission and generation entities. This is partially because the size of their demand requires special reliability requirements, and also because of the traditionally strong link between the development of electricity infrastructure to support specific industrial activity. For example, the need to supply electricity to VALCO was a major driver in the construction and financing of the Akosombo hydroelectric facility.

Because the majority of the major load centres are located in the southern part of the country, ECG handles a very high fraction of customers and serves a very high fraction of demand and energy consumption compared to NED.

¹³ Ghana Energy Statistics, Ghana Energy Commission, 2009.

Figure 2.3 - Peak Demand of Major Load Centres By Service Provider

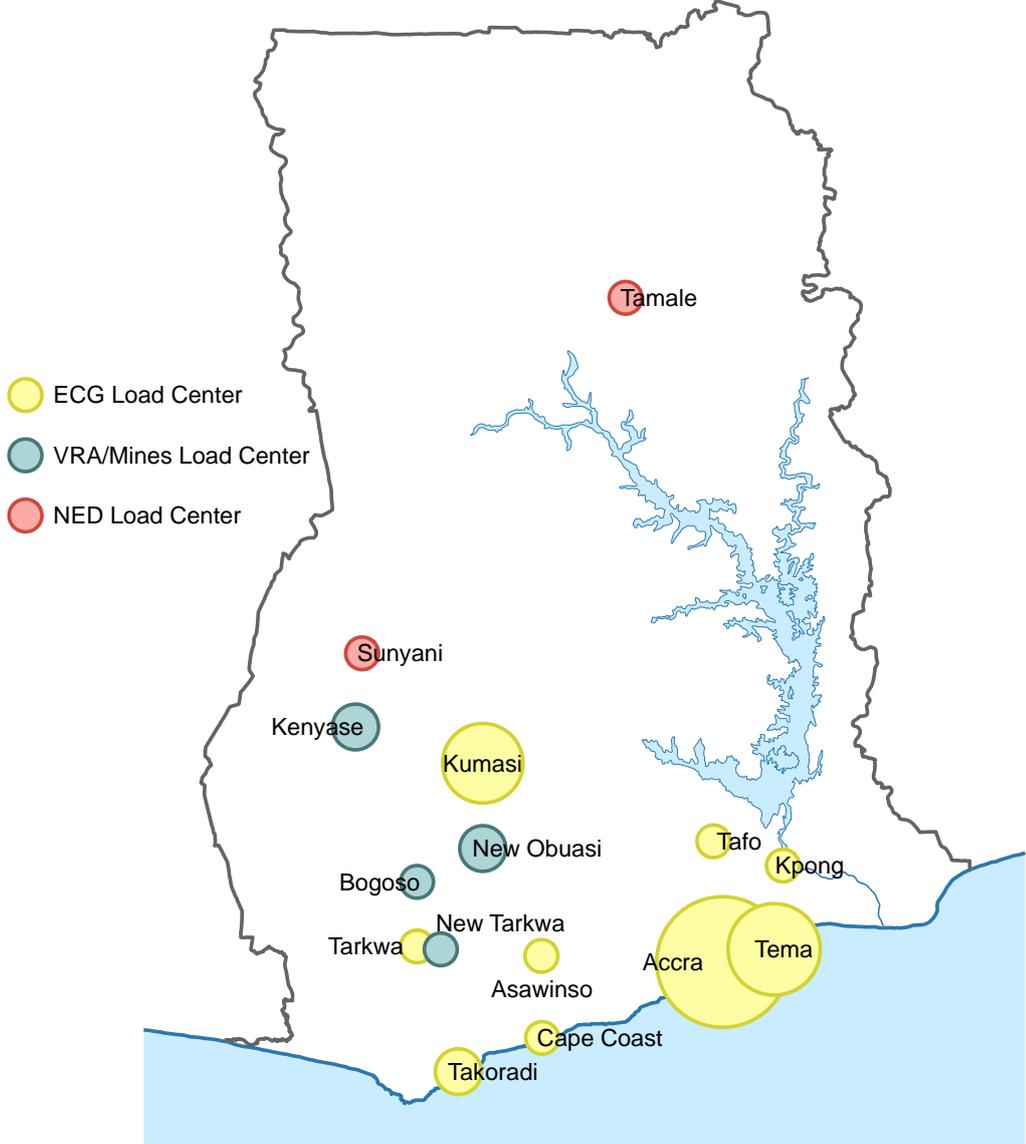


Table 2.1 - Ghana's Ten Largest Load Centres, 2009

Rank	Load Centre	Bulk Power Service Provider	Peak Load (MW)	Energy (GWh)
1	Accra (Achimota + Mallam)	ECG	380.2	2,896.0
2	Tema	ECG	183.0	1,215.9
3	Kumasi	ECG	154.4	1,051.4
4	New Tarkwa (G.G.L.)	VRA/MINES	56.8	308.3
5	New Obuasi (A.G.C.)	VRA/MINES	53.0	458.0
6	Takoradi	ECG	44.7	343.9
7	Tarkwa	ECG	37.7	350.3
8	Sunyani	NED	30.5	226.3
9	Kenyase (Newmont)	VRA/MINES	30.2	251.9
10	Asawinso	ECG	29.8	171.7
Total			1,000.3	7,273.5
% Of 2009 System Peak Load or Energy			70.3%*	71.9%

* Note that the peak loads across the load centres are not exactly coincident, and hence the number above is approximate.

2.2.2 Demand Variations

Demand for electricity is not constant, but rather varies both throughout the day and throughout the year. Intra-day demand variations are driven by the underlying consumption patterns of residential, commercial, and industrial customers. Residential customers are characterized by small, highly variable demands, commercial customers are characterized by mid-sized, moderately variable demands, and industrial customers are characterized by large, consistent demands. For almost all systems, the assorted mix of customers and demand profiles results in one or more significant system peaks during each 24-hour period. In Ghana, there is a single peak over the four-hour period starting from 6pm to about 10pm (see Figure 2.4), and over 24 hours, the load averages about 80% of the system peak. Ghana's daily load shape is not as volatile as the load shape of countries in the temperate and polar regions. For example the PJM market in the United States, which covers much of the eastern mid-Atlantic part of the country, had a 24-hour load average of 58.9% of the system peak in 2006¹⁴.

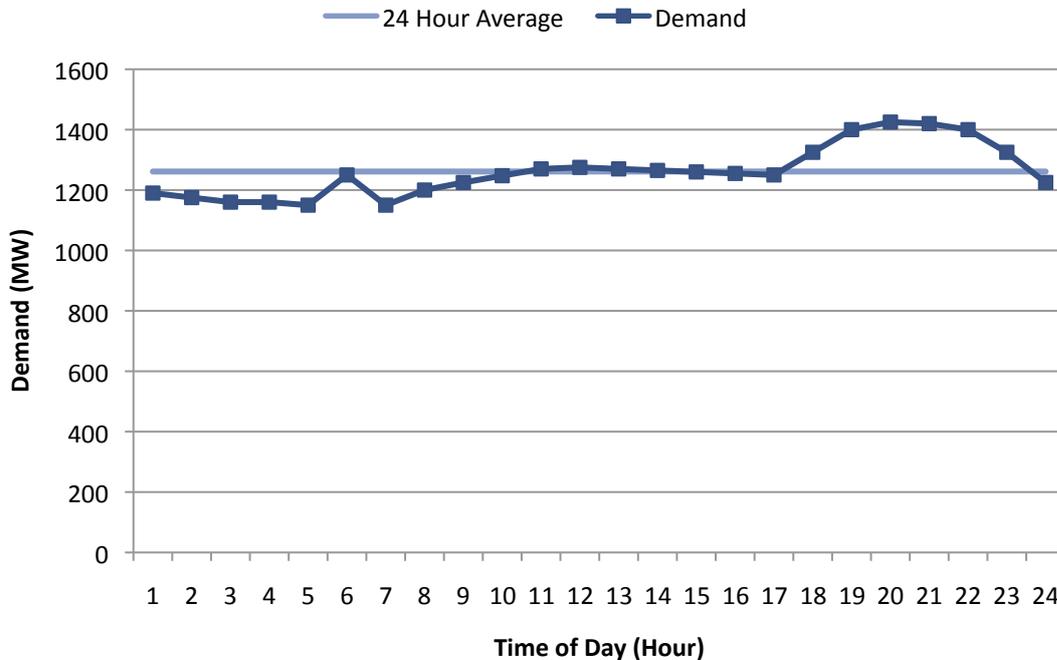
Demand variations throughout the year are driven mostly by weather and the availability of sunlight, which affect demand for three of electricity's key services – lighting, heating, and cooling. Ghana's equatorial location and tropical climate results in minimal seasonal variance in daylight and temperature relative to more polar locations such as Norway or South Africa. Hence there is minimal seasonality in electricity demand.

Ghana's less pronounced peak demand is an advantage, and it allows for more efficient use of generation resources. Installed generation capacity must be sufficient to meet peak demand requirements plus an operating reserve margin. If the load shape is relatively flat, it

¹⁴ F. A. Felder and A. Hajos, *Using Restructured Electricity Markets in the Hydrogen Transition: The PJM Case*, In Proc. of the IEEE: Special Issue on the Hydrogen Economy, Vol. 94, No. 10, pp. 1864-1879, October 2006.

increases the capacity utilization of generation assets. On the other hand, if the load shape is peaky, capacity utilization is relatively low because a larger fraction of generation capacity will operate only during the peak period.

Figure 2.4 – A Typical 24-Hour Demand Profile (January 2010)



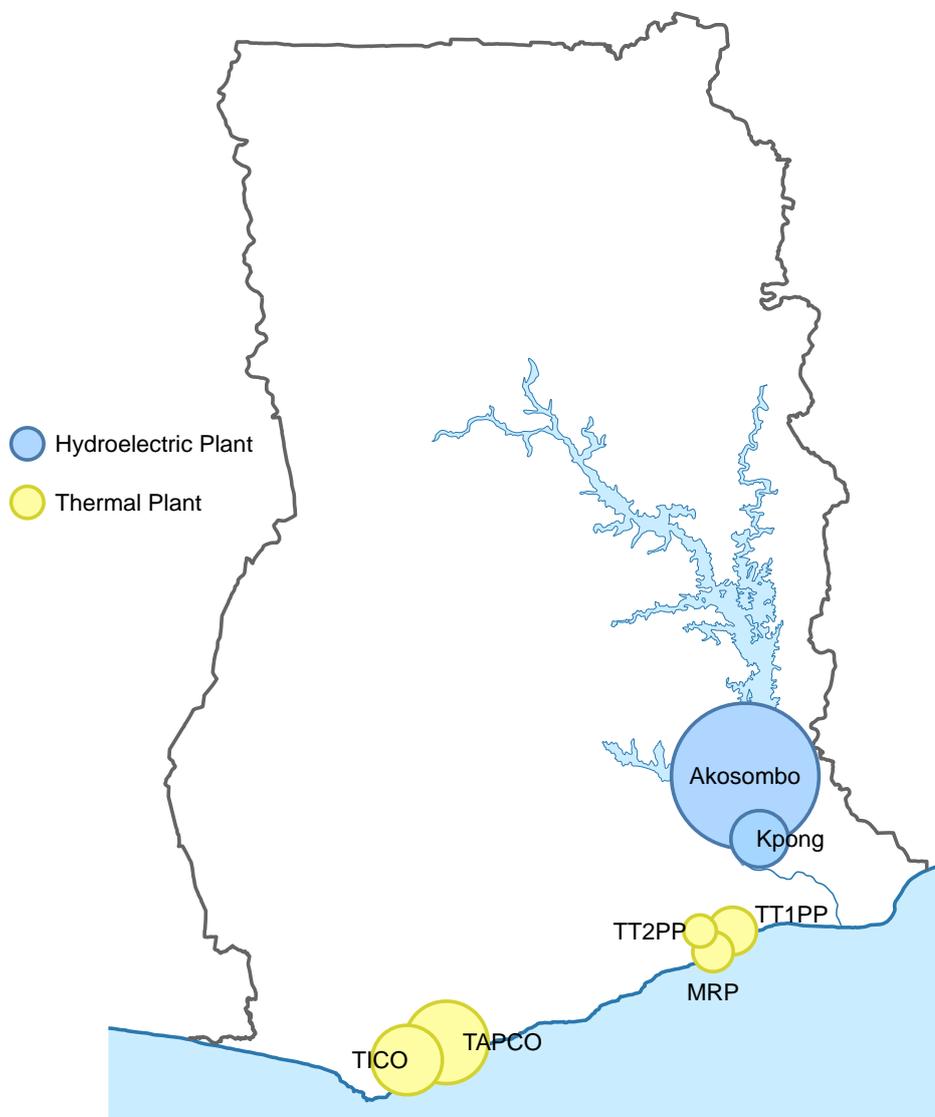
2.3 Generation Resources in Ghana

Ghana relies on two primary types of generation facilities: hydroelectric plants and thermal plants. Hydroelectric plants convert potential energy from running or falling water into electrical energy. Typically, a series of dams and reservoirs on river basins collect water, which is then directed through large pipes to turbines that spin generators – machines that convert mechanical energy into electrical energy – to create electricity. The dams and reservoirs act like a battery, and allow operators to have some control of power production levels over time. In contrast, thermal plants convert chemical energy from fossil fuels such as coal, oil, and natural gas into mechanical energy using turbines, the mechanical energy is subsequently converted into electricity using a generator.

There are seven major generation facilities in Ghana, two hydroelectric and five thermal (see Figure 2.5). Historically, Ghana has been largely dependent on hydroelectric power. Two hydroelectric plants, located at Akosombo and Kpong on the Volta River, represent the core of Ghana’s generation system, accounting for 1,180 MW of generation capacity or 60% of the national total. Akosombo, Ghana’s first large-scale power generation facility, became operational in 1966. It remains the largest single generation facility in the country with an installed capacity of 1,020 MW, more than 50% of total national installed capacity. Kpong, whose role is to optimize the extraction of energy from the Volta Lake, operates directly downstream of Akosombo and has an installed capacity of 160 MW.

Ghana's five thermal plants, two located at Aboadze near Takoradi and three located in Tema, represent the remaining 40% of generation capacity. The Aboadze plants, one simple cycle combustion turbine plant and one more efficient combined cycle plant, provide a total maximum capacity rating of 550 MW. These plants can be operated on light crude oil (LCO) or natural gas (NG); at present they are run mostly on LCO due to challenges vis-à-vis natural gas availability. The remaining three plants are one LCO/NG dual-fired plant and two diesel generators located in Tema, which together provide an additional 213 MW of capacity. In Ghana, thermal plants are typically located on or near the coast, closer to fuel supply sources. LCO and diesel are delivered via tanker, and natural gas is delivered via the West African Gas Pipeline (WAGP), which runs off the coast of Ghana.

Figure 2.5 - Generation Resources in Ghana



2.4 The Transmission System

The transmission system is an interconnected network that supports the bulk transfer of electricity over long distances from generation facilities to distribution centres called bulk power distribution substations. While, generation's role is to make sure that electricity is available *when* customers demand it, transmission's role is to make sure electricity is available *where* customers need it.

Ghana's high voltage transmission network connects generation sites in Akosombo, Aboadze, Kpong, and Tema to the various load centres around the country. The network features more than 4,000 kilometres of high voltage electric transmission lines that connect more than 40 substations (see Figure 2.6).

The primary backbone of Ghana's transmission system is a network of 161 kV lines and substations. This primary network is supplemented with a sub-transmission system of 34.5 kV lines and a single 69 kV line in the lower Volta region – the 34.5 kV network is sometimes classified as distribution. Ghana's high voltage transmission system interconnects with Togo and Benin via a 161 kV transmission line¹⁵, and with Cote d'Ivoire via a 225 kV transmission line¹⁶. A small network of low-voltage lines connects Ghana to the border towns of Po and Leo in Burkina Faso and Dapaong in Togo. These cross border interconnects allow Ghana to traded power with its neighbouring countries. Regional efforts have been underway to integrate the transmission networks of ECOWAS member states to facilitate power trading among the regional entities. In this regard, the West African Power Pool (WAPP) has begun efforts to build regional transmission lines to interconnect major load centres. One such regional transmission line is the 330 kV Aboadze-Volta (Tema)-Lome-Sekete (Benin)-Ikeja West (Nigeria) transmission line. The segment from Aboadze to Tema is in an advanced state of completion. There are also plans to build additional regional lines such as the 330 kV Takoradi-Kumasi-Han line. Upon completion, Ghana's primary transmission backbone will be 330 kV, which should provide significant reinforcement and increased power transfer capability from generators to loads.

GRIDCo manages the Ghana transmission network. Because transmission interconnects both the supply side (generation) and demand side (distribution), the transmission authority is a natural candidate to coordinate the electricity system. Hence GRIDCo functions as an independent system operator (ISO) for Ghana's electricity system, and consequently has the dispatch responsibility. With this comes the responsibility to maintain reliability at the wholesale supply level.

2.5 The Distribution System

The distribution system is a network of low voltage distribution lines that deliver electricity directly to customers. The distribution system is generally considered to begin at the bulk power distribution substation where GRIDCo delivers power to the wholesale power buyers such as ECG and NED, and end at the retail consumer's meter. Beyond the meter lies the customer's electric system, which consists of wires, equipment, and appliances.

In the next chapter, we review Ghana's demand over the last decade and examine the forecast for 2010 as well as the projection for the next decade.

¹⁵ In partnership with Communaute' Electrique du Benin (CEB)

¹⁶ In partnership with Compagnie Ivoirienne d' Electricité (CIE)

Figure 2.6 - Ghana's Power Transmission Network



Source: "The National Grid", Ghana Grid Company Limited (GRIDCo). Jan 2010.
<http://www.gridcogh.com/site/ng.php>

3 Electricity Demand in Ghana

Demand for electricity in Ghana has been robust over the past decade due to economic growth, urbanization, and rural electrification. This trend is expected to continue into the next decade. The trends in demand growth and the expectations for the next decade are discussed in detail in this chapter.

3.1 Historical Demand

Over the last decade, Ghana experienced compound annual growth in peak power demand of about 1.4% annually, from a base of 1,258 MW in 2000 to 1,423 MW in 2009, and growth in cumulative energy demand of 3.3% annually from 7,539 GWh in 2000 to 10,116 GWh in 2009 (see Figure 3.1 and Figure 3.2). At first glance, this growth may seem unexceptional or even minimal, however a closer look at the figures shows that growth over the last 10 years has been anything but a slow steady progression. Rather, there have been several cycles of ebb and flow in demand and energy consumption, and a rich composite of high growth in some sectors and sharp curtailment in other sectors. The growth rates have been driven largely by three trends:

1. **Robust economic growth:** Ghana's GDP grew at an average of 5.5% per annum between 2000 and 2009.
2. **Rapid urbanization:** Ghana's urban population share went from 44% to 52% between 2000 and 2010.¹⁷
3. **VALCO's demand curtailment:** VALCO operations have been interrupted several times over the last 10 years due to power unavailability issues.

Sections 3.1.1 to 3.1.3 take a closer look at each of these phenomena, their impacts on electricity demand, and potential implications for the future.

Figure 3.3 shows the cumulative growth for peak demand and energy demand by service provider for the period 2000 to 2009. Internal demand grew robustly across all service providers (except VALCO), while exports remained essentially flat. The compound annual growth rate for industrial sector demand was amongst the highest at 5.7%, resulting in a cumulative growth over the last decade of 64%. As shown in Figure 3.4, this sector, served by VRA, represented approximately 14% of the total demand in Ghana in 2009.

If the segment of large load customers served by VRA continues to increase at the historical growth rate it would significantly increase total demand. Starting in 2010, however, the VALCO load is excluded from the forecast. This reduces the contribution of the industrial sector to total demand, resulting in a conservative estimate of overall demand.

¹⁷ Deputy Minister, Ghana Ministry of Local Government, Rural Development and Environment. Forty-first session of the United Nations Commission on Population and Development.

Figure 3.1 - Actual Peak Demand: 2000 to 2009

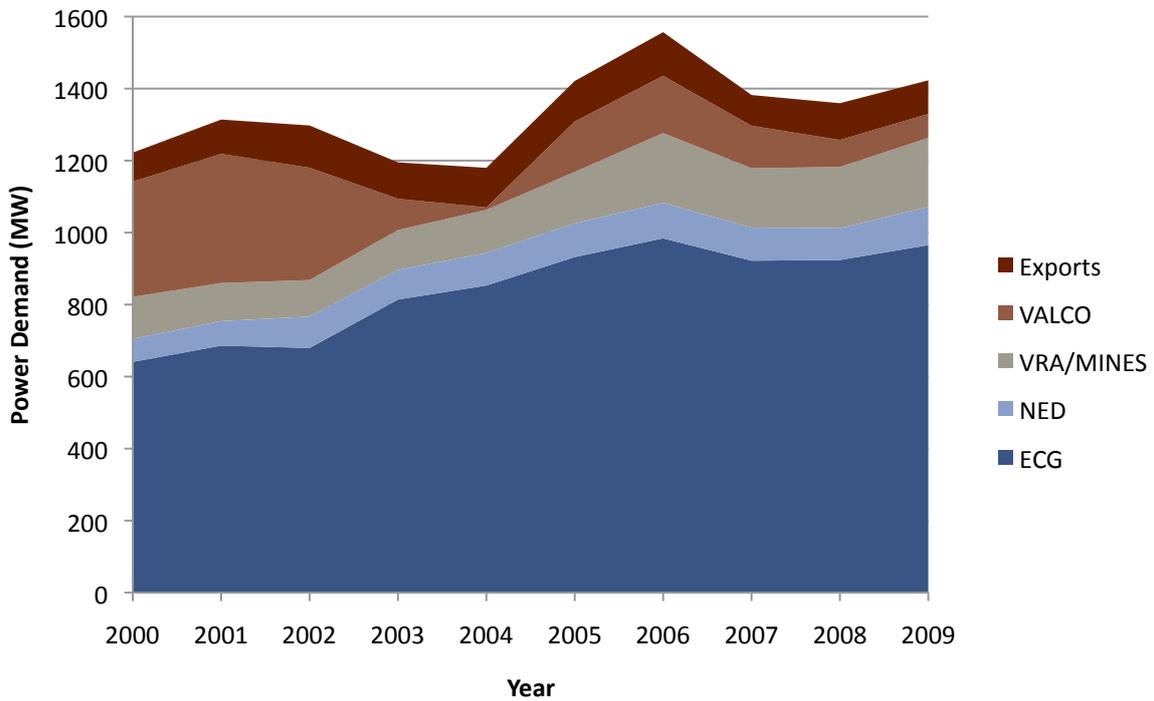


Figure 3.2 - Actual Energy Demand: 2000 to 2009

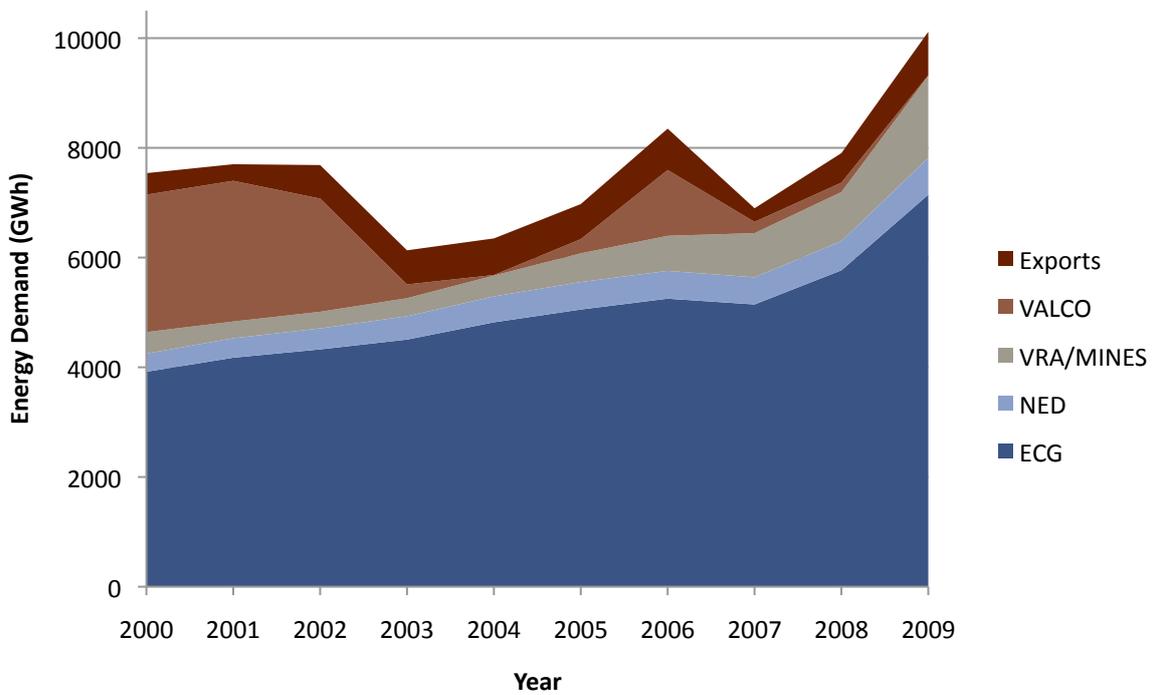


Figure 3.3 - Cumulative Peak Demand and Energy Demand Growth: 2000-2009

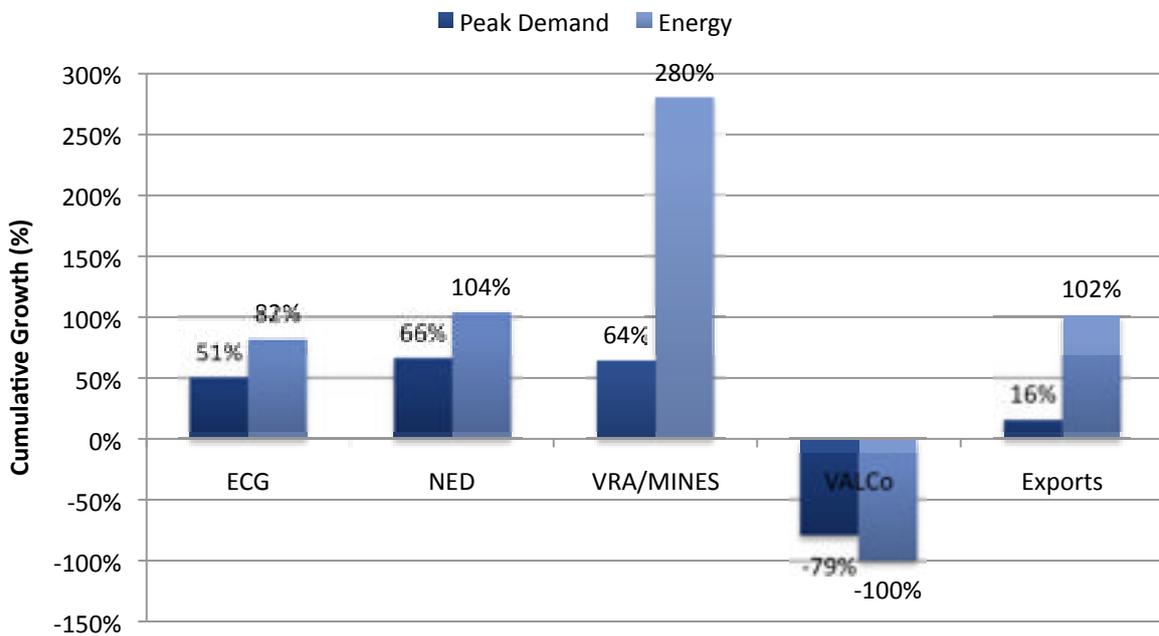
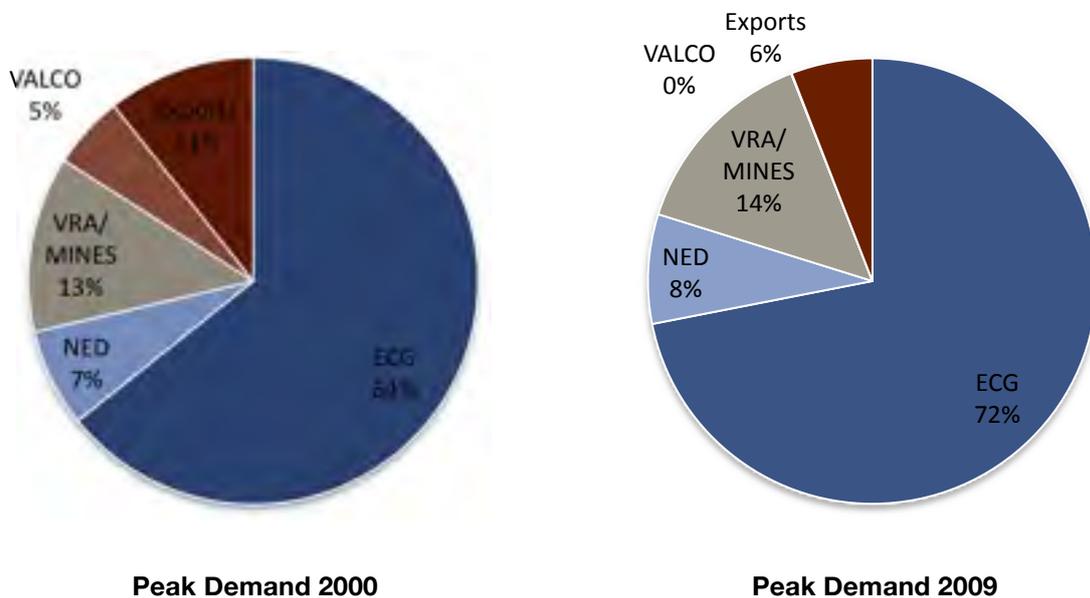


Figure 3.4 - Peak Demand by Service Provider: 2000 and 2009



3.1.1 Impact of Economic Activity

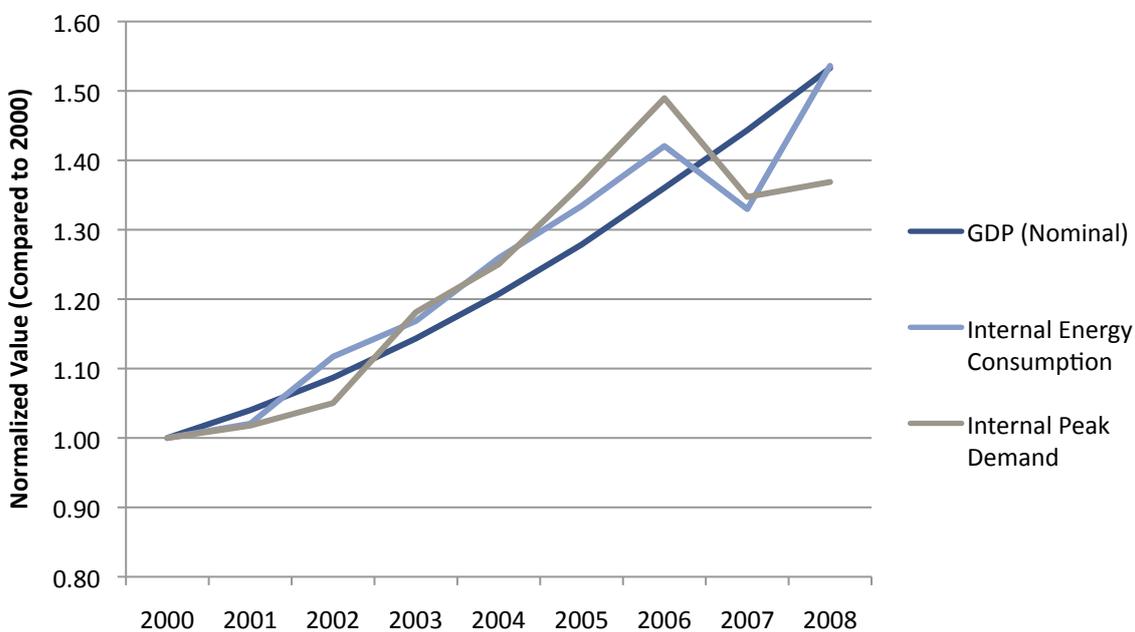
Electricity is a key input into most activities in modern economies, and as such demand and consumption are highly correlated to GDP growth, a widely used indicator of economic activity. Ghana's real GDP growth averaged 5.5% per annum between 2000 and 2008, for a

total of 53% over the eight-year period (see Figure 3.5)¹⁸. This suggests that economic growth was a key driver in the growth of electricity demand.

Examples of electricity’s role as a key input into economic activity are myriad. The primary sector of the economy, which includes activities related to extraction of resources from the earth (for example mining and farming), uses electricity to operate heavy machinery that can make processes faster and more efficient. The secondary sector, which includes activities related to manufacturing and production, uses electricity to power factories, warehouses, and the equipment inside of them. The tertiary sector, which includes service business and retail operations, uses electricity for lighting, heating and cooling, and the operation of productivity tools like computers and printers. Economic growth indicates, for example, that mines are using more heavy machines to extract more materials, factories are producing more products, and offices are expanding operations.

Economic growth also typically translates to higher wages and incomes for workers, more employment opportunities (i.e. more workers), or both. This in turn translates to higher household incomes. Electricity becomes the energy form of choice for use in the home as incomes rise because it is cleaner, more versatile, and easier to use than competing forms of energy like firewood and kerosene. Additionally, wealthier households tend to purchase and use more electricity-consuming appliances like air conditioners, washing machines, and water heaters. Hence GDP growth drives electricity consumption both in the workplace and at home, and GDP is frequently used as a key parameter when modelling future demand.

Figure 3.5 - Normalized GDP, Peak Demand, and Energy: 2000-2008



* Note the sharp effect of VALCO curtailment in 2007 on internal peak demand and energy consumption.

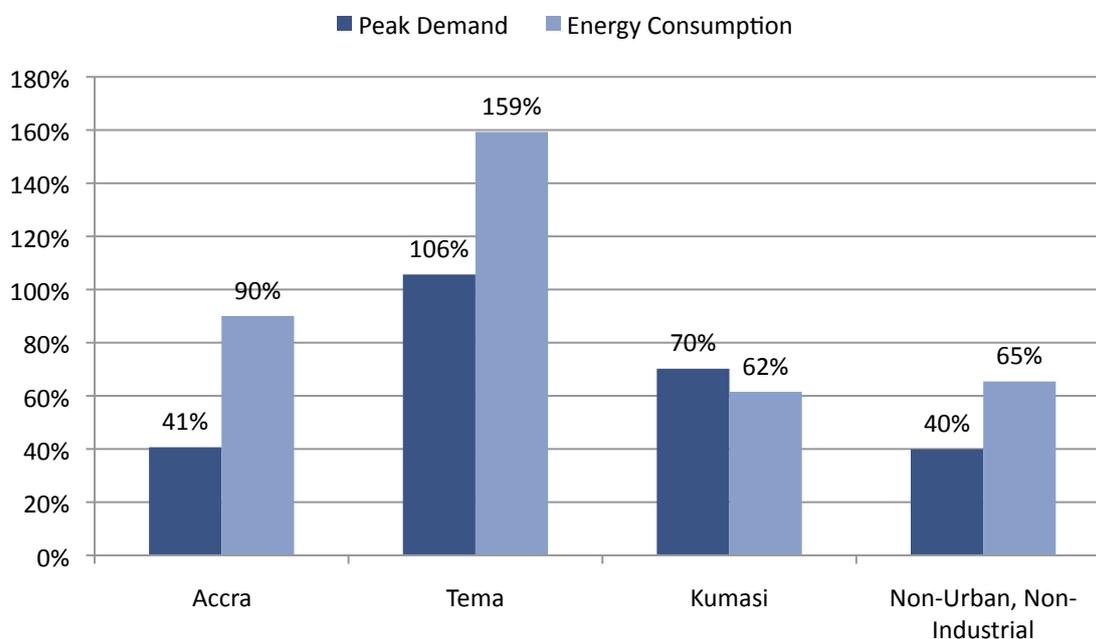
¹⁸ “World Development Indicators”. World Bank. <<http://devdata.worldbank.org/>>

3.1.2 Impact of Urbanization

Urbanization has been a constant theme in Ghana over the last half-century. The proportion of the population living in urban areas rose from 23 percent in 1960 to 44 percent in 2000, and is expected to rise to 52 percent by the end of 2010¹⁹. Urbanization is a key driver of increased electricity consumption for several reasons. First, the urbanized population in Ghana generally has significantly better access and connectivity to electricity; as of 2008, 85% of urban areas were connected, compared to only 23% of rural areas²⁰. Second, low-cost substitutes for electricity such as firewood (biomass) and kerosene are harder to access and more expensive for the urban dweller compared to the rural dweller. Third, urban areas have been the focal point of economic growth and tend to have higher incomes per capita, which drive increased electricity use. For example, higher incomes typically lead to greater ownership of electricity-consuming household appliances.

Accra, Tema, and Kumasi (ATK), Ghana's three largest cities, have been at the centre of the urbanization movement over the last decade, and subsequently have been key drivers in increased urban electricity usage. ATK's share of total national peak electricity demand rose from 48% in 2000 to 52% in 2009, and its share of energy consumption has held steady at just over 50%. This is despite significant investments in rural electrification and sharp increases in rural demand, and booming growth in the industrial sector (e.g. mines). The most aggressive growth was in Tema, where peak demand grew more than 106% over the 10-year period and energy consumption grew more than 159% (see Figure 3.6).

Figure 3.6 - Peak Demand and Energy Growth for Urban Areas: 2000 to 2009



¹⁹ Deputy Minister, Ghana Ministry of Local Government, Rural Development and Environment. Forty-first session of the United Nations Commission on Population and Development.

²⁰ Electricity Access in 2008: Africa, International Energy Agency, February 2010. <http://www.iea.org/weo/database_electricity/electricity_access_database.htm>

Urbanization has significant implications for power sector reliability. Neither Accra nor Kumasi has sufficient local generation within their transmission zones to meet internal demand, and both face difficulties in cost-effectively siting generation facilities (see Section 5.6). This means that they are and will continue to be heavily reliant on the transmission network to import power from adjacent transmission zones. Tema, in contrast, does have significant generation within its transmission zone and has planned capacity additions over the next five years (see Section 4.3). However, robust growth within its transmission zone may affect its ability to export power to other zones, and consequently place additional strain on other parts of the transmission network.

3.1.3 Impact of VALCO Demand

Historically, VALCO has been the largest individual contributor to both national peak demand and energy use, and in fact the origins of Ghana’s bulk power system can be traced back to VALCO’s voracious need for reliable power. As such it is important to understand how the variation in VALCO demand over the last decade has affected overall demand growth.

At a normal operating level of 4 to 5 active potlines, VALCO’s demand represents a significant portion of Ghana’s demand. In 2001, for example, VALCO’s peak demand was 27% of total peak demand in Ghana, and its energy demand was 33% of the total (see Figure 3.7). However, since 2003 peak demand and energy consumption have varied significantly, with a sharp trend towards reduced demand (see Figure 3.8). VALCO’s demand pattern reflects a series of shut downs and production scale backs due to electricity supply difficulties that resulted from low water levels at Akosombo. Plant activity was sharply curtailed in 2003 to ensure that Ghana’s populace would have access to electricity as Akosombo and Kpong’s production levels dropped. In 2005 operations were restarted at about 50% capacity, but were quickly reduced again in response to power shortages. The plant was again shut down in January 2009 and it only contributed relatively low values of 68 MW to peak demand and 10 GWh to energy demand in that year. As of March 2010, VALCO is offline.

Figure 3.7 - Demand and Energy Consumption By Sector: 2001

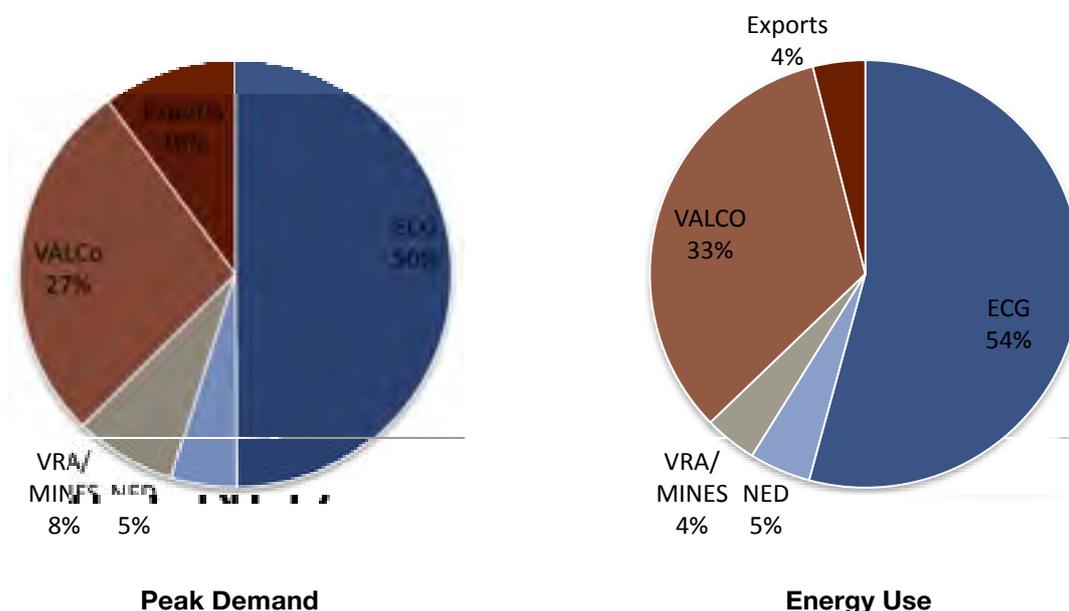
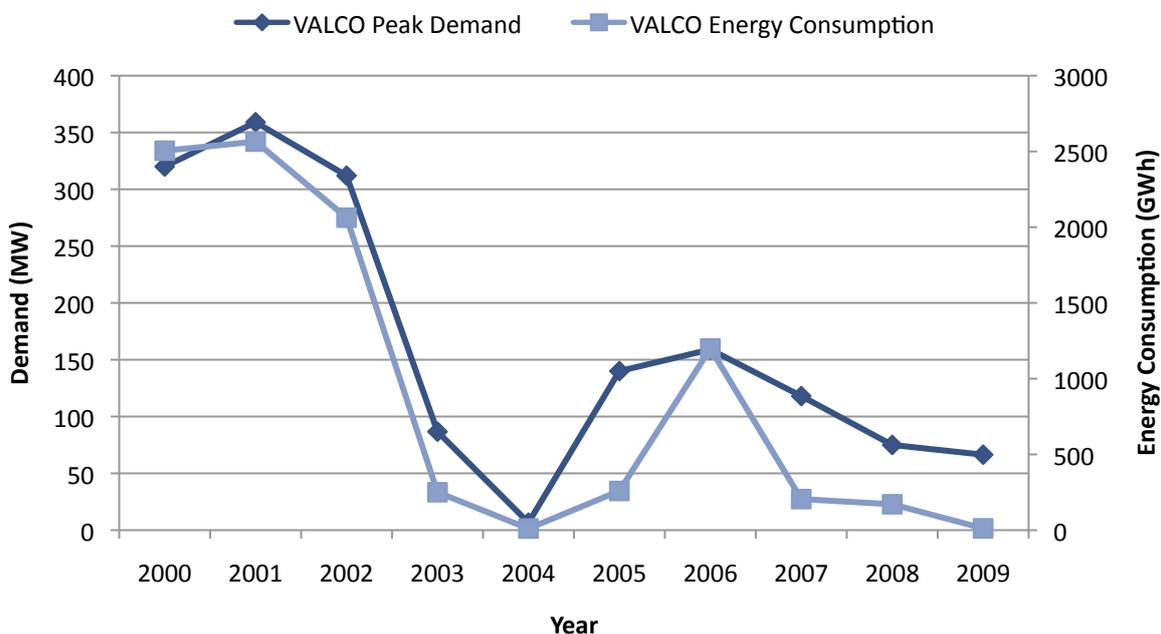


Figure 3.8 - VALCO Demand and Energy Consumption: 2000 - 2009



Curtailment of VALCO demand has played a key factor in allowing the electricity system to better absorb the growth in demand from other sectors, particularly given that no new generation facilities were added between 2000 and 2008 (see Chapter 1). While VALCO's peak demand and energy shrunk 80% and 99%, respectively between 2000 and 2009, the rest of Ghana's peak demand and energy demand grew more than 44% and 100%, respectively during that period. This translates to compound annual growth rates of 4.2% and 8.0%, respectively (see Table 3.1). The net effect was that Ghana's peak demand and energy demand grew 13% and 34% over the ten-year period, which translates to compound annual growth rates of 1.4% and 3.3%, respectively (see Table 3.1). Peak demand and energy demand are projected to remain very robust for the foreseeable future; however future growth must be matched with new generation capacity because there are no more loads such as VALCO to offset the effects of growth in the residential, commercial and other industrial sectors.

Table 3.1 - Impact of VALCO Demand on National Peak and Energy Demand Growth

	Compound Annual Growth Rate (%) 2000 to 2009		Cumulative Growth (%) 2000 to 2009	
	Peak Demand	Energy	Peak Demand	Energy
Including VALCO	1.4	3.3	13.1	34.2
Excluding VALCO	4.2	8.0	44.6	100.7

In projecting future demand, it is critical to carefully consider the state of VALCO's operations. If VALCO returns to a normal production level of at least 4 pot lines, demand

growth will be further accelerated and the demand forecast will require a significant upward adjustment. In subsequent sections of this chapter, we review the demand forecasts for 2010 through 2018 and compare the projected growth trends to the historical trends. VALCO is generally assumed to be offline after 2010, so the demand forecast does not include any contribution from VALCO. For a fair comparison of the forecast to historical growth rates, we use the historical values excluding VALCO demand.

3.2 Demand Forecast: 2010

Peak demand in 2010 is projected to be 1,547 MW, an increase of approximately 8.0% over the 2009 peak demand²¹. The forecast growth rate of 8.0% is significantly higher than the historical annual peak demand growth rate of 4.2% (excluding the demand at VALCO).

GRIDCo elevated its demand forecast for 2010 after a new system peak of 1,489 MW was recorded for January 2010. Although the International Monetary Fund (IMF) projects that Ghana's GDP will grow between 5% and 6% in 2010, matching the annual rate of growth from 2007-2009²², if the robust demand realized in January continues, the projected GDP growth may have to be revised upwards because power demand is highly correlated with GDP. The projected peak demand growth is also reasonable because industrial and commercial growth is projected to be particularly robust, at 15%. Additionally, some demand growth is a result of higher system losses at peak due to congestion in the transmission system.

VALCO remains a latent factor that could significantly increase demand growth. Based on its historical operation, VALCO's demand could be as high as 360 MW²³, which would raise the forecast peak demand as high as 1,907 MW, compared to the current estimate of 1,547 MW. Third, it is not clear to what extent the expected increase in industrial activity later in the year related to the discovery of oil off the coast of Ghana, has been factored into the forecast. Based on these factors, the 2010 peak demand can range from the forecast value of 1,547 MW to a high of 1,907 MW if VALCO operates at its normal output of 4 or more pot lines.

Table 3.2 - 2010 Demand Scenarios

	2009 Actual	2010 Projected	2010 Projected with VALCO Operation
Peak Demand	1,423 MW	1,547 MW	1,907 MW
Energy Demand	10,116 GWh	10,305 GWh	11,160 GWh

The corresponding energy demand is projected to be 10,305 GWh in 2010, an increase of approximately 2% over that of 2009. This is significantly lower than the historical compound annual energy demand growth rate of 8.0% (excluding the demand at VALCO). The projections suggest that robust growth in the NED, VRA, and Export sectors will be offset by reduced demand in the ECG and VALCO sectors (see Figure 3.9). If, however, energy demand growth rate turns out to be closer to the historical compound annual growth rate of

²¹ Note that both the 2009 value and 2010 forecast exclude VALCO activity. VALCO is expected to remain offline in 2010,

²² "World Development Indicators". World Bank. <<http://devdata.worldbank.org/>>

²³ VALCO's peak demand was 359 MW in 2001

8.0%, the projected energy demand for 2010 will be approximately 10,925 GWh, compared to the forecast of 10,305 GWh. Again, the energy demand forecast could also be conservative because it assumes VALCO remains offline during the entire year. If VALCO restarts operations for just a third of the year, for example, this could add as much as 855 GWh²⁴ in energy demand, raising it to a high of 11,160 GWh. A combination of historical growth levels and VALCO operations could result in energy demand as high as 11,780 GWh. This would translate to peak demand and energy growth rates of 31.2% and 10.2%, respectively (see Figure 3.10).

Figure 3.9 - Peak Demand and Energy Consumption Growth By Sector: 2010

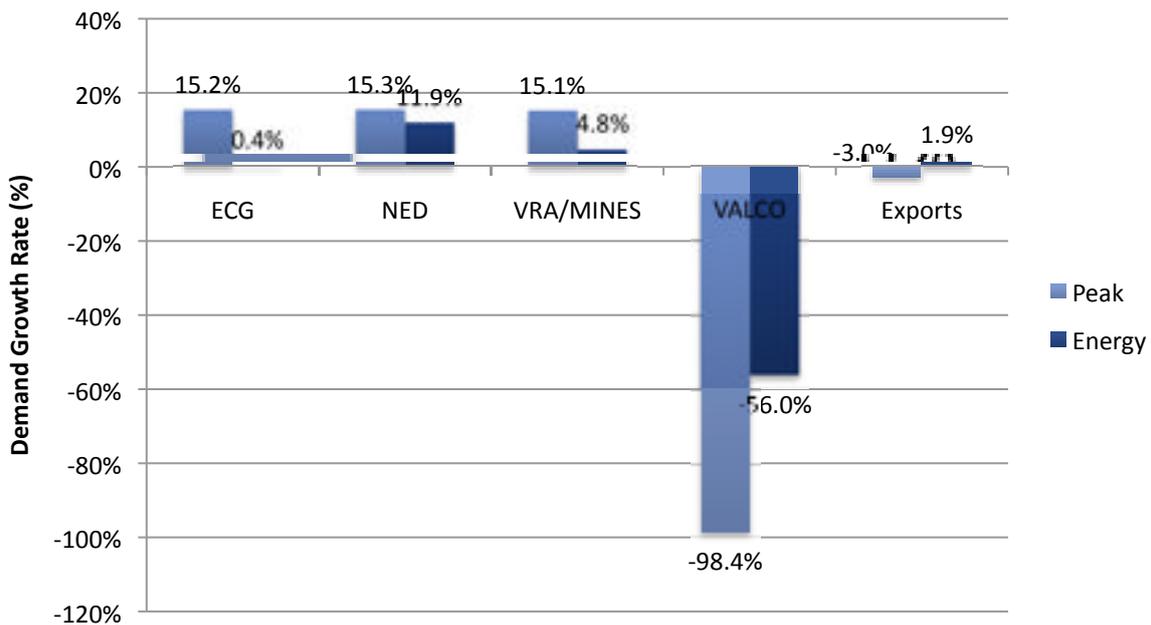
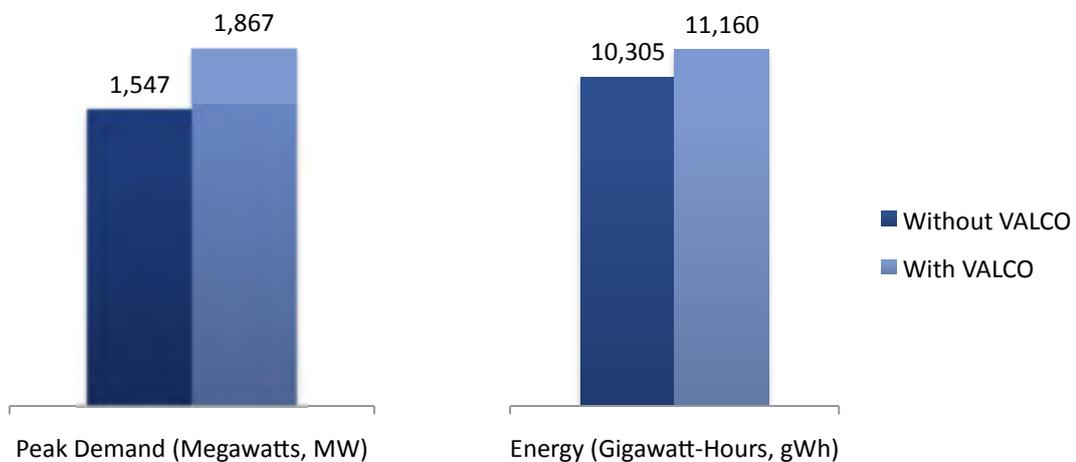


Figure 3.10 - Effect of VALCO Operations on 2010 Peak Demand and Energy Demand



²⁴ Estimate based on prorating VALCO's 2001 total energy consumption of 2,565 GWh for 4 months of operation. $2,565 \text{ GWh} \times 0.333 = 855 \text{ GWh}$.

3.3 Demand Forecast: 2010 to 2018

GRIDCo projects that the next decade will bring cumulative growth of 101% and 93% in peak and energy demand, respectively, driven in large part by the same key factors that drove growth in the last decade: population growth, economic development, and urbanization. This translates to annualized growth rates of 8.6% and 7.6% for peak and energy demand, respectively. At the projected rate, peak demand will double between 2009 and 2018, growing from 1,423 MW to 2,856 MW. Energy demand will almost double, growing from 10,116 GWh in 2009 to 19,469 GWh by 2018. The peak and energy demand in Ghana from 2009 to 2018 are shown in Figure 3.11 and Figure 3.12, respectively.

The forecasted peak demand growth rate is higher than the historical growth rate of 4.2%, while the energy demand forecast is roughly in line with the historical growth rate of 8.0%²⁵. A key factor in the forecasted growth rate is the expected increase in industrial activity related to the discovery of oil off the coast of Ghana. The extraction and processing of oil is likely to drive further economic development and consequently electricity consumption, depending on the extent to which Ghana develops a downstream oil industry. However, the forecasted growth rates could still be conservative since VALCO is assumed to remain offline for the entire forecast period. Depending on its operational state, VALCO could also generate significant additional demand. In 2000, VALCO's aluminium smelters required approximately 350 MW of peak power and consumed 2,500 GWh of energy, representing 26% and 33% of the respective national demands. However, production activity has been limited since 2003. The reduced operational state of VALCO for most of the decade played a significant role in offsetting the huge growth in demand for power from other customers, enabling the electricity system to absorb the high growth rate. However, the new decade may bring the opposite effect.

The component of peak demand for the segment of large load customers served by VRA will more than double, from 18% of peak demand in 2009 to 38% in 2018. Similarly, the respective component of energy demand increases from 14% in 2009 to 38% in 2018. The segment served by VRA comprises mainly industrial load, which has a higher load factor – that is, load tends to remain almost constant throughout the year – than the residential and commercial sectors. This means that there may be a need for more baseload generation in the overall national generation mix as demand in this sector increases.

The forecasted cumulative demand growth rates by service provider from 2009 to 2018 are shown in Figure 3.13. These rates are generally slightly lower than historical rates, except for the segment of large load customers served directly by VRA that has a cumulative energy demand growth rate of 384% (i.e. a 19.4% annualized rate), which is somewhat higher than the historical growth rate of 280% over a similar period (i.e. a 16.0% annualized rate). Again, the burgeoning oil and gas sector is expected to drive much of this growth.

²⁵ Historical rates exclude VALCO demand.

Figure 3.11 - Forecasted Peak Demand: 2009 to 2018

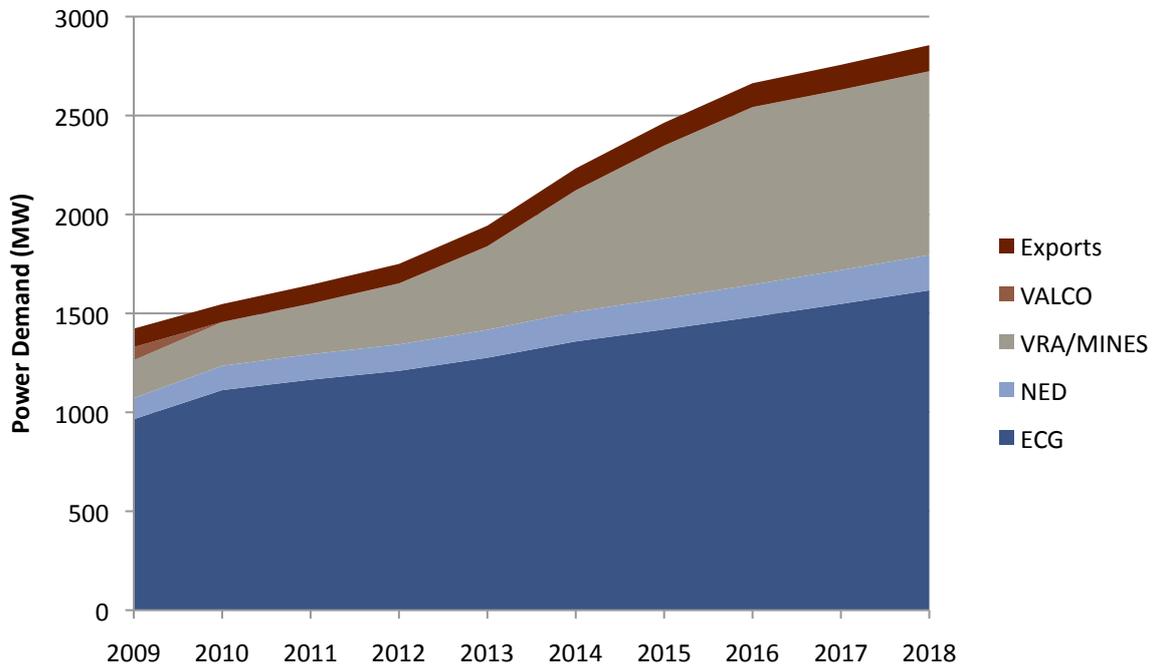


Figure 3.12 - Forecasted Energy Demand: 2009 to 2018

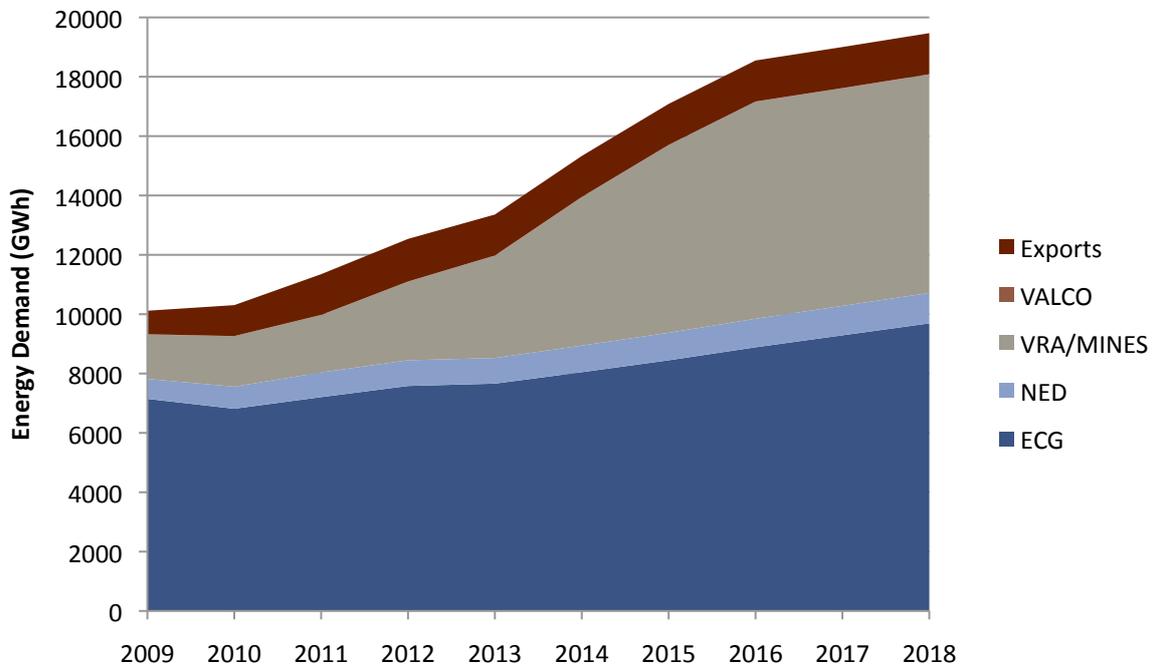
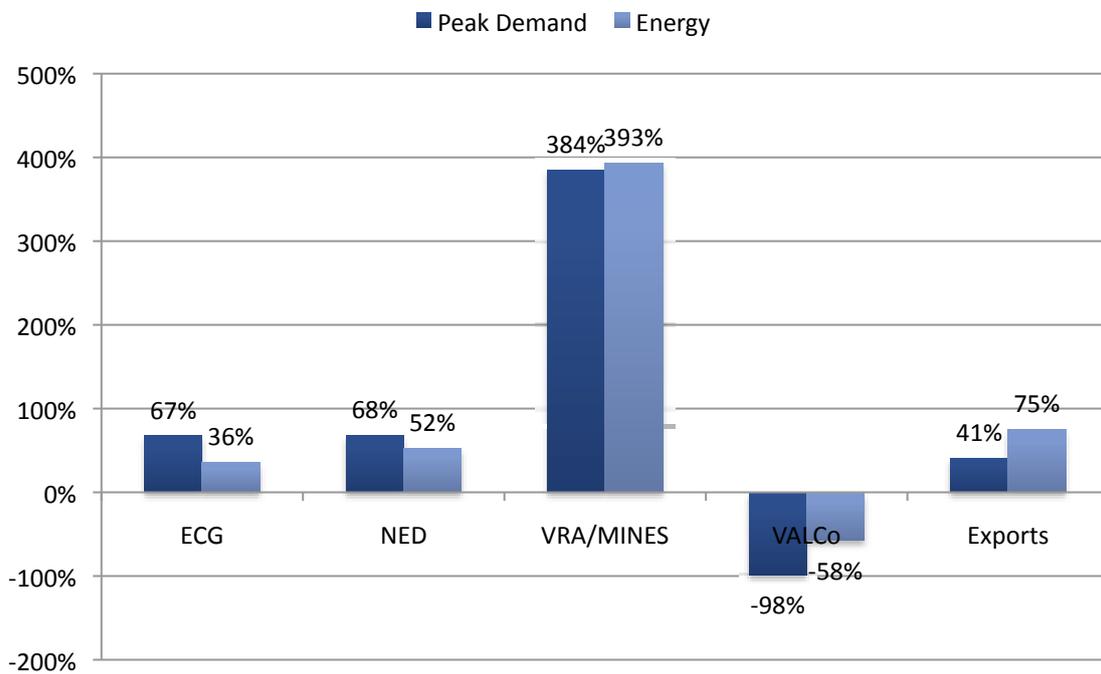


Figure 3.13 - Forecasted Cumulative Growth Rates By Sector: 2009-2018



3.4 Demand-Side Management

Demand-side management (DSM) can play an important role in the efficient and reliable operation of the power system. DSM reduces the demand for new generation and transmission capacity. DSM is achieved either by a reduction in demand or the addition of distributed generation. Distributed generation facilities, which are sometimes called distributed energy resources, refer to small-scale power generation sources that produce power on-site or close to the load, and are connected at the distribution end of the power system. An example of distributed energy is an array of solar photovoltaic panels installed on a residential roof. Distributed energy resources reduce the amount of centralized generation capacity required from large-scale hydro and thermal plants, and consequently the amount of energy that must be transmitted and distributed across transmission and distribution facilities as well.

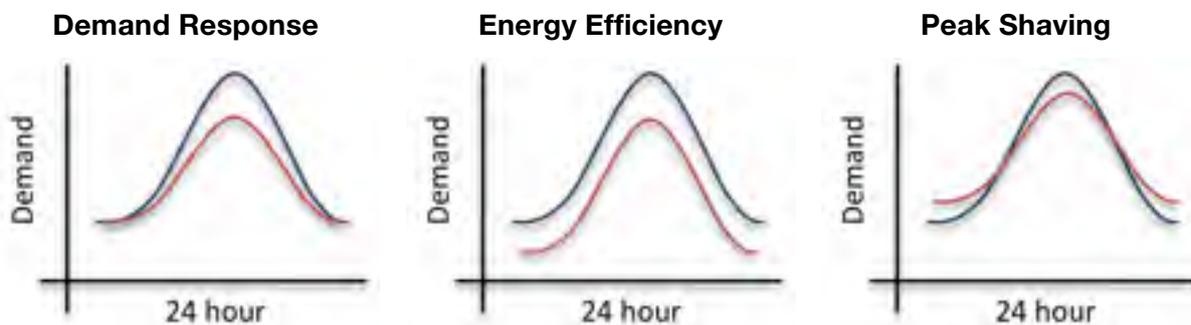
Demand reduction can be passive or active. Passive demand reduction includes energy efficiency programs that use efficient loads with relatively low energy consumption. Energy efficiency programs focus on technology and operational procedures that provide the same level of service but use less energy. For example, an energy efficiency program might emphasize the installation of fluorescent lighting and/or skylights instead of higher energy intensity incandescent lighting to attain the same level of illumination. Another program might advocate the use of computer sleep and hibernation functions to reduce demand from offices and homes. Energy efficiency typically reduces demand in a fairly uniform manner, with the greatest benefits coming from reduced peak demand.

Active demand reduction includes demand response and peak-shaving programs. These programs work with customers, such as factories or commercial offices, to reduce their energy usage during periods of peak demand, which prevents the need to utilize costly and

sometimes emissions-heavy generation from peaking plants. The cost of producing power at peak demand periods is usually much higher than average, and can be more than ten times the average cost per megawatt. Figure 3.14 schematically compares energy efficiency, demand response, and peak shaving.

Peak-shaving programs encourage customers to conduct energy intensive activities at off peak periods when demand on the power system is low. For example, a program might encourage residential customers to do laundry or iron their clothes in the morning when possible, rather than in the late afternoon or evening. This reduces peak demand, but increases off-peak demand. Although total energy consumption is essentially unchanged, the system realizes a load shift from the peak period to the off-peak period. This load shift provides a significant saving to the utility in avoided capacity costs.

Figure 3.14 - Effect of Demand Side Management Programs



Customers who participate in DSM programs are usually incentivized through capacity payments from their local utilities or load aggregators to reduce their non-essential electricity usage during the peak periods. Typically payments consist of a capacity charge that customers receive periodically for being enrolled in the program (subject to meeting certain participation criteria), and a curtailment charge that customers receive when they participate in an actual demand response event.

Demand response schemes are most easily implemented with large customers, however they can be implemented with smaller commercial and residential customers as well. This often involves the installation of automated control and monitoring systems to shed loads in response to a request by a utility. Services (lights, machines, air conditioning) are reduced according to a pre-planned load prioritization scheme during the critical timeframes.

The use of DSM can reduce cost by displacing or deferring the need for capital investment in generation and transmission, and it can enhance reliability by providing the operator with more flexibility to respond to system disturbances. DSM can also play a major role in keeping generation costs and prices low. For example, it is estimated that just a 5% lowering of demand would have resulted in a 50% price reduction during the peak hours of the California electricity crisis in 2000 and 2001²⁶. This is also true in Ghana because the demand curve, although relatively flat when compared to countries in the temperate and polar regions, is sufficiently peaky to realize gains from DSM. A measure of the peakiness of

²⁶ The Power to Choose - Enhancing Demand Response in Liberalised Electricity Markets, International Energy Agency, 2003.

the daily demand curve is the ratio of average demand to peak demand. In Ghana this ratio is 80%, meaning that Ghana has the capacity to benefit from DSM programs.

Implementing effective demand side management programs in Ghana can be challenging. Recall from Section 2.2.2 that Ghana experiences peak electricity demand between 6pm and 10pm. This suggests that peak demand is driven in large part by lighting loads, which are relatively difficult to curtail because a) substitute options like kerosene lamps are inconvenient and can cause health problems over time, and b) lighting often forms the basis of rural electrification programs. In spite of the general difficulty in curtailing lighting loads we believe government tariff subsidies and other pricing distortions especially for residential consumers in higher consumption brackets can sometimes serve as a disincentive to conserve power. In Ghana, it is quite common for consumers to leave lights on in rooms that are not in use while the opposite is true for most middle class families in developed countries.

Ghana's situation lends itself to effective energy efficiency programs that substitute high energy intensity appliances with lower energy intensity units. During the power crisis of 2007, the Ministry of Energy instituted such an energy efficiency program that encouraged consumers to replace their high-energy intensity incandescent lamps with energy efficient ones. This is an example of an energy efficiency program at the retail level.

Although this energy efficiency program was successful, there is no available information on continuously on-going efforts or programs to make energy efficiency or other demand-side management programs an integral part of the wholesale power integrated resource planning mix. We recommend the PURC to mandate the load serving utilities such as ECG and NED to make energy efficiency and demand-side management an ongoing program in their energy delivery obligation. Specifically, the PURC could ask the load serving entities to present DSM programs each year that are designed to meet a fixed percentage of their peak load obligation. Further, the load serving entities should collect and gather data that can be used to measure the economic and reliability benefits of DSM programs and their general effectiveness.

3.5 Imports and Exports

Ghana's imports and exports of electricity are driven primarily by two factors: the need to meet growing peak demand and the variability of the Volta River flow rates. The primary electricity trading partners are Côte d'Ivoire and Togo, with whom electricity is traded via the existing transmission interconnections. For example, Ghana has an exchange agreement with Côte d'Ivoire for up to 200-250 MW of power import/export as need arises on either side²⁷.

In December 2003, Ghana signed the ECOWAS Energy Protocol, which calls for the elimination of cross-border barriers to trade in energy, and encourages investment in the energy sector. This agreement, along with the WAPP agreement, is expected to lead to a more active regional import and export power market. These agreements have potentially significant benefits for Ghana. Demand for electricity is growing rapidly throughout the region, which simultaneously creates a larger market for Ghana to trade power with in the larger ECOWAS region.

²⁷ Strategic National Energy Plan 2006-2020, Ghana Energy Commission, July 2006.

3.6 Conclusion

In this chapter we have examined historical peak demand and energy growth rates and discussed reasons why we believe the 2010 estimate for peak and energy are reasonable, albeit conservative because of the uncertainty around VALCO's operation and the potential for load growth as oil production picks up later this year. In spite of these uncertainties we are confident that the 1,547 MW peak load estimate and the 10,305 GWh energy demand estimate for 2010 are reasonable. The robust peak demand and energy growth rates projected for 2010 are higher than the historical growth rates because the system recorded a new peak of 1489 MW in January, 2010 reflective of increasing economic activity and GRIDCo expects this trend to continue.

We have assumed that VALCO will be offline in 2010 and we believe this assumption is reasonable. We observed that peak and energy demand growth in the other sectors in the last decade have been offset by the decline in VALCO consumption because no new generation was added between 2000 and 2008.

Our high side estimate of 1,907 MW for peak demand and 11,780 GWh for energy assumes VALCO is operational. Obviously VALCO's operation would mean a 31.2% increase in peak demand and 10.2% increase in energy over the expected values. This scenario would require sufficient new generation resources to be online to meet the incremental VALCO load and without which VALCO must remain offline.

We also recommend the PURC to mandate the load serving utilities to present annual demand-side management programs designed to meet a fixed percentage of their peak load obligation. This recommendation is designed as a means to encourage inclusion of DSM as a viable option in the wholesale power integrated resource planning mix.

The next chapter describes existing and planned generation capacity in Ghana's electricity sector and it assesses the adequacy of generation capacity to serve the projected 2010 peak demand and energy reliably.

4 Generation Reliability Assessment

As we mentioned in the Introduction, there are two main aspects to reliability in power systems: adequacy and security. Adequacy means having sufficient resources to provide a continuous supply of electricity in spite of scheduled or unscheduled outages. Security is the ability of the power system to withstand sudden, unexpected disturbances. In this chapter we focus on generation adequacy as an indicator of generation reliability in Ghana's bulk power system. Generation adequacy, or the sufficiency of generation supply to meet expected demand, is one of the fundamental components of wholesale power supply adequacy assessment. A high level of generation adequacy provides assurance of sufficient redundancy in the wholesale generation supply system and minimizes the risk of generation deficiency in the event of an unplanned outage. We use an industry standard measure of adequacy, the generation reserve margin, to assess the adequacy of Ghana's operable generation capacity for the 2010 operating year and to make projections for the future. Among the factors included in the analysis are demand uncertainties and the effect of systemic risks such as fuel supply for thermal generation resources and water availability for hydro generation resources.

4.1 Existing Infrastructure

As of 2009, Ghana had 7 commercial power plants with a combined nameplate capacity of 2,031 MW (See Table 4.1). Hydroelectric facilities located at Akosombo and Kpong represented 60 percent of generation capacity, while an array of thermal plants including combined-cycle gas turbine plants, simple-cycle gas turbine plants, and diesel generators represented the remaining 40% of generation capacity. Currently, the Volta River Authority operates all plants, with the exception of the privately owned Takoradi Thermal Power Plant-T2 (TICO). Hence the generation sector is only 12% private and 88% state-owned by capacity.

Table 4.1 - Commercial Generation Facilities

Plant	Owner/ Operator	Installed Capacity* (MW)	Maximum Capacity (MW)	% Of Existing Capacity
Akosombo Hydroelectric Plant	VRA	1,023	1,020	52.7%
Kpong Hydroelectric Plant	VRA	160	152	7.9%
Takoradi Thermal Power Plant-T1 (TAPCO)	VRA	364	330	17.0%
Takoradi Thermal Power Plant-T2 (TICO)	TICO	241	220	11.4%
Tema Thermal Power Plant-T1 (TT1PP)**	VRA	113	113	5.8%
Mines Reserve Plant (MRP)	VRA	80	50	2.6%
Tema Thermal Power Plant-T2 (TT2PP)	VRA	50	50	2.6%
TOTAL		2,031	1,935	100.0%

* Nameplate capacity

** Maximum capacity assumed to be equal to nameplate capacity

Generation facilities in Ghana are operated using the concept of *economic dispatch*, meaning that their production levels are coordinated in order to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and

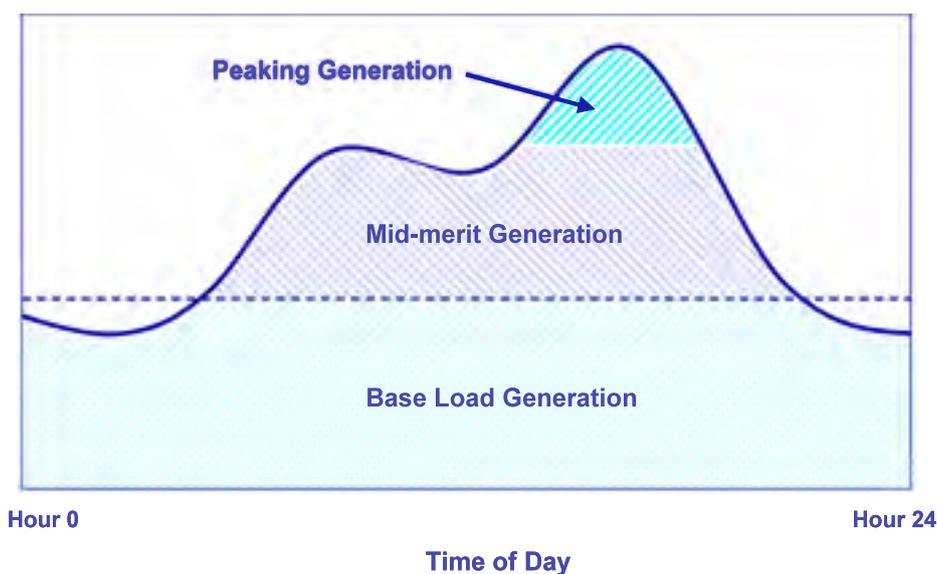
transmission facilities. Consequently, generation facilities are each assigned to one of three operating modes – baseload, peaking, and mid-merit – as shown in Figure 4.1.

Baseload plants are those with the lowest generation costs, highest reliability, and greatest safety. They form the backbone of the generation system and produce power at a relatively consistent level throughout the day and night, and over the course of the year. Hence, they tend to have a high capacity factor, or ratio of actual energy output to maximum sustainable energy output.

Mid-merit plants typically have intermediate generation costs while maintaining high levels of reliability and safety. They adjust their output as demand for electricity fluctuates throughout the day and over the course of the year, and consequently have moderate capacity factors.

Peaking plants are the most expensive units to operate and generally operate only when there is very high demand. Their value is in their ability to be dispatched (i.e. come online) quickly when needed.

Figure 4.1 – An Example of Generation Facility Operating Modes



The role each plant plays is a function of the plant's technology and fuel supply, which are the two key drivers of dispatchability and cost. At present, Ghana's two large-scale hydroelectric facilities at Akosombo and Kpong play predominantly baseload generation roles although they also play the other two roles occasionally when necessary. In 2010, the two plants are expected to operate at a combined capacity factor of 68%.²⁸ Like most facilities of their type, Akosombo and Kpong produce large amounts of power at low marginal cost. Akosombo, with its reservoir, has the ability to store water and dispatch it as necessary to generate power to match demand and consequently has operated in mid-merit mode in the past when Ghana's peak demand was well below its maximum operable capacity. Thermal generation, depending on fuel and prime-mover type, operates in all three

²⁸ The expected capacity factor of 68% is low for base load generation. The minimum capacity factor for baseload generation facilities in the industry is approximately 75%. Akosombo and Kpong are limited by their firm energy capability, and consequently have a long-term average combined production of 6100 GWh and a combined maximum production of 6900 GWh. The projection for 2010 is therefore 104% of the long-term average.

modes. Coal plants often operate as baseload units because of their lower fuel costs compared to oil and gas, combined-cycle units operate in mid-merit mode and simple cycle units operate in peaking mode. VRA's Aboadze Thermal Power Plant facility generally operates in mid-merit mode, while the remaining thermal facilities generally operate in peaking modes.

4.2 Reserve Margin and Unforced Generation Capacity

The level of redundancy in generation supply is expressed as a reserve margin. The reserve margin is the amount by which generation capacity exceeds the projected peak demand, expressed as a percentage of peak demand.²⁹ A high reserve margin means that the power system will be better able to withstand the unexpected loss of one or more generation plants or unexpected increases in load growth.

A simple approach to determining the reserve margin is to compare the peak demand to the unforced generation capacity. The unforced generation capacity is the capacity expected to be available during the peak demand period and it is used in the industry because it is a risk-adjusted measure of available generation capacity. Unforced capacity adjusts the total capacity to account for the likelihood that some plants may be out of service during the peak period due to maintenance or unplanned outage. It provides an estimate of the net dependable generation capacity that is expected to be available during the peak.

Table 4.2 shows the forced outage rate for each of the generation plants. The forced outage rate (FOR) is the probability that the unit will not be available for service when required due to an unanticipated system failure. The capacity-weighted average forced outage rate is 8.0%. The total dependable capacity at peak of 1,703 MW is discounted by the weighted average forced outage rate to get an unforced capacity of 1,566 MW³⁰. This unforced capacity is used in subsequent analyses.

Table 4.2 - Plant Dependable Capacity and Forced Outage Rates

Plant	Dependable Capacity at Peak* (MW)	Forced Outage Rate (%)
Akosombo	900	0.14
Kpong Hydroelectric	140	0.13
Takoradi T1 (TAPCO)	300	24.42
Takoradi T2 (TICO)**	200	24.42
Tema T1 (TT1PP)	113	N/A
Mines Reserve Plant (MRP)	50	N/A
Tema T2 (TT2PP)	-	N/A
CAPACITY WEIGHTED AVERAGE		8.0

* Based on GRIDCo operational estimates

** Due to unavailability of data, TICO's forced outage rate was set equal to TAPCO's

²⁹ Reserve Margin = (Generation Capacity – Demand)/Demand

³⁰ Unforced Capacity = Dependable Capacity at Peak * (1 – Forced Outage Rate). For a Dependable Capacity of 1,703 MW and Forced Outage Rate of 8.0% in 2009, Unforced Capacity = 1,703 MW * (1 – 0.08) = 1,566 MW. This assumes the Tema Thermal Plant 2 was offline.

Table 4.3 is a summary of projected generation plant performance in 2010, and the contribution of each plant to the total generation capacity and energy produced. Hydro generation (Akosombo and Kpong plants) is expected to provide 60% of Ghana's total capacity, and produce more than 62% of the energy required in 2010. Thermal generation (all other plants) is expected to provide the remaining 40% and 38% of capacity and energy production, respectively.

Table 4.3 - Plant Generation and Capacity Factors

Plant	Maximum Capacity (MW)	Dependable Capacity at Peak* (MW)	Availability (%)	Expected 2010 Generation (GWh)	Capacity Factor
Akosombo	1,020	900	96%	5,298	64.9%
Kpong Hydroelectric	152	140	96%	1,059	87.1%
Takoradi T1 (TAPCO)	330	300	70%	1,920	72.7%
Takoradi T2 (TICO)	220	200	80%	1,250	71.0%
Tema T1 (TT1PP)	113	113	85%	779	86.2%
Mines Reserve Plant (MRP)	50	50	75%	-	-
Tema T2 (TT2PP)	50	50	85%	-	-
TOTAL	1,935	1,753	-	10,306	66.6%

* This assumes the Tema Thermal Plant 2 (TT2PP) is operational; it also assumes the dependable capacity at peak of the Mines Reserve Plant and Tema Thermal Plants 1 and 2 are equal to their maximum capacities.

** Capacity Factor based on 8,000 hour operational year

4.2.1 Current Reserve Margin

To determine Ghana's actual reserve margin in 2009 we compared the peak demand to the unforced generation capacity. As described above, in 2009 Ghana had unforced generation capacity of 1,566 MW compared to peak demand of 1,423 MW. In essence Ghana had only 140 MW of dependable surplus generation capacity to meet any load or generation contingency, which translates to a reserve margin of 10.1%. By any measure, this is a very low reserve margin. In fact, each of the individual units at Akosombo and Aboadze is more than 100 MW in capacity; therefore the loss of any one of these units would almost erase the reserve margin completely and will necessitate immediate load shedding.

For comparison, Table 4.4 shows the reserve margins for selected markets around the world. The average reserve margin in the United States, for example, is approximately 25%³¹. Many markets in the US have a minimum reserve margin requirement of 15%, but it is clear from the average value that practically all the markets exceed the minimum requirement; PJM, the largest power market in the US by demand, has a reserve margin of 26.0%. In Mexico the reserve margin rose to 40.9% in 2008 following an aggressive multi-year expansion program

³¹ Estimate based on data found in: "Electric Power Markets: National Overview", United States Federal Energy Regulatory Commission. February 2010.
<<http://www.ferc.gov/market-oversight/mkt-electric/overview.asp>>

in response to high demand and growth in 2000 and 2001; however there are plans to allow the reserve margin to adjust to approximately 25% over the next 5 years³². As of 2009, South Africa had a reserve margin of 10.9%, but its major power utility Eskom is undergoing an aggressive capital expansion plan with the goal of increasing the reserve margin to beyond 15%³³.

Table 4.4 - Comparison of Reserve Margins

Country	Peak Demand (MW)	Estimated Unforced Capacity (MW)	Reserve Margin (%)
Ghana	1,423	1,566	10.1%
South Africa (Eskom)*	36,513	40,503	10.9%
Malaysia**	14,007	19,723	40.8%
United States (PJM)***	130,100	164,179	26.0%
Mexico****	-	51,091	40.9%

* Annual Report 2008, Eskom. 2009.

** Electricity Supply Industry In Malaysia Performance And Statistical Information 2008, Electricity Supply Regulatory Department, Energy Commission of Malaysia

*** Electric Power Markets: PJM”, United States Federal Energy Regulatory Commission. February 2010. <http://www.ferc.gov/market-oversight/mkt-electric/pjm.asp>

**** Energy Sector Outlook 2007-2016, Secetaria de Energia de Mexico, 2006.

Most large wholesale power systems maintain a minimum reserve margin of 15% for reliable operations, hence South Africa’s stated target. However, that is only a heuristic; in practice reserve margins are heavily influenced by the amount of surplus capacity needed to cover unexpected losses in generation or the loss of a major import. Specifically, there are two issues that affect the required level of reserve margin in a system: (a) the size of the system, and (b) the composition of units in the system. For example, for a small system with peak load of 1,000 MW a 15% reserve margin would be 150 MW, which may or may not be sufficient to cover the single largest system contingency. In contrast a 15% reserve margin for a system with a peak of 10,000 MW is 1,500 MW, which is probably sufficient to cover the single largest system contingency³⁴. Thus it is often the case for small systems to carry larger percent reserve margins that exceed the 15% threshold.

Similarly, the composition of the generation units in the wholesale power system affects the choice of the percent reserve margin. Unless the amount of surplus generation is sufficient to cover the loss of the single largest unit, the loss of some generation units will result in load shedding regardless of the percent reserve margin level. For example, in a 1,000 MW peak load system served by ten 100 MW generators, a 100 MW spare (10% reserve margin) would be sufficient to cover the loss of a single unit. If the same system has just two 500 MW generators, the spare will have to be at least 500 MW (50% reserve margin) to cover the loss of a single unit.

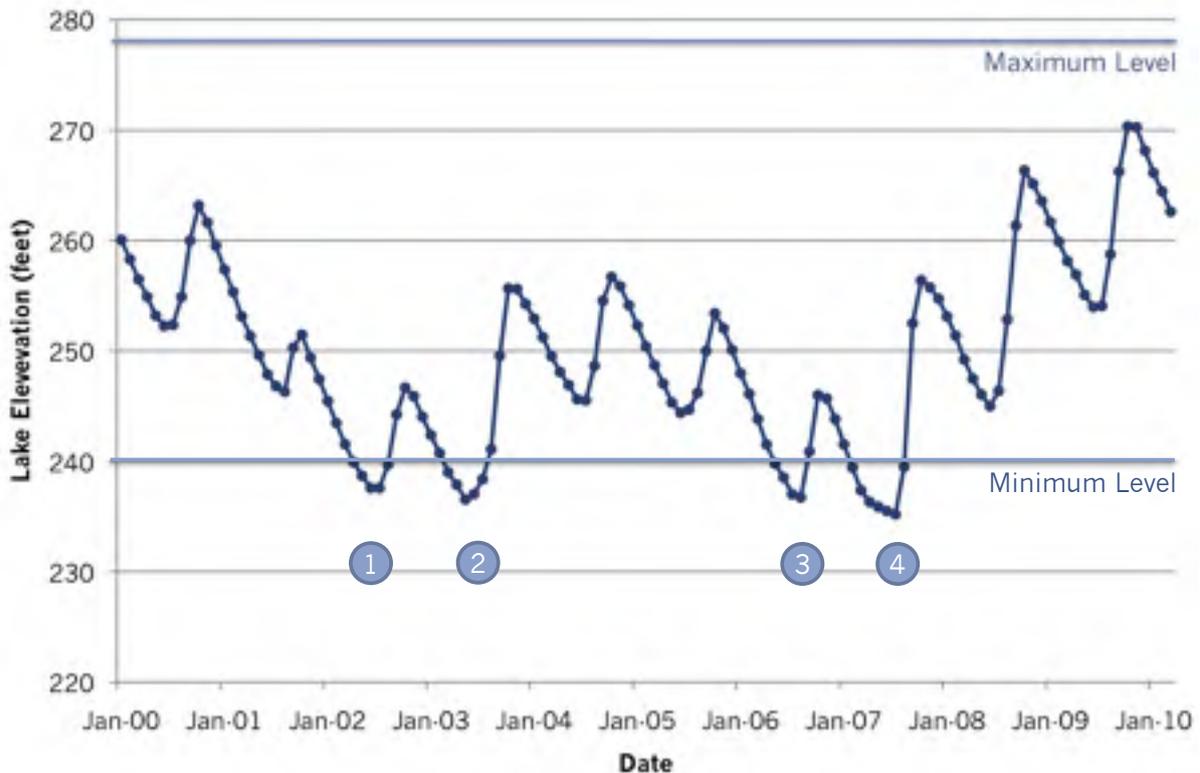
³² *Energy Sector Outlook 2007-2016*, Secetaria de Energia de Mexico, 2006.

³³ Annual Report 2008, Eskom.

³⁴ Two of the biggest types of generation plants are nuclear plants and hydroelectric plants. The world’s largest nuclear facility, Kashiwazaki-Kariwa in Japan, has 1210 MW generator units and the world’s largest hydro facility, the Three Gorges Dam in China, has 700MW generator units.

The above illustration means that in reality Ghana probably needs a reserve margin greater than 15% because a) it is a relatively small system, and b) there are relatively few generators in the system. Ghana's risk of generation shortage is exacerbated by the country's high dependence on hydroelectric generation and seasonal rainfall patterns in the main catchment areas of the Volta Lake. In the last 10 years alone, the lake has been drawn down below its minimum level at least four times (see Figure 4.2).

Figure 4.2 - Akosombo Water Level (2000 to 2009)



* Based on monthly data
 ** Source: Volta River Authority (VRA)

4.2.2 Target Reserve Margin for Generation Adequacy

Table 4.5 and Figure 4.3 show Ghana's annual historical reserve margin over the last decade, and Figure 4.4 shows Ghana's historical demand compared to the unforced capacity over the last decade. Although the reserve margins in 2003 and 2004 appear to be higher than 15%, in reality those numbers were artificially high because VALCO was compelled to shut down to reduce system demand because of poor electricity production at Akosombo and Kpong due to water shortages.³⁵ Thus, Ghana's bulk power system did not meet the large system's industry minimum reserve margin of 15% in any single year in the last decade.

³⁵ If VALCO had continued to operate at the 2002 level in 2003 and 2004, the reserve margins for 2003 and 2004 would have been -7.1% and -6.2%, respectively. A negative reserve margin indicates that the electricity system is unable to meet demand.

Ghana’s reserve margin was already critically low in 2000 (9.7%), and the situation was exacerbated by a combination of the robust demand growth discussed in Chapter 1 and minimal capacity additions between 2000 and 2008. Over that period, Ghana added only 100 MW, or an additional 7%, of unforced capacity (Table 4.5) while demand grew almost 12% including VALCO curtailment. Demand and supply imbalances of this kind, if not addressed in a timely manner, always get manifested in shortages or poor quality service.

Given the 2009 reserve margin of 10.1% and the forecasted growth, the wholesale power generation resources will be inadequate and will fail to meet the minimum generation reliability standard without new generation additions and/or increased net imports in 2010.

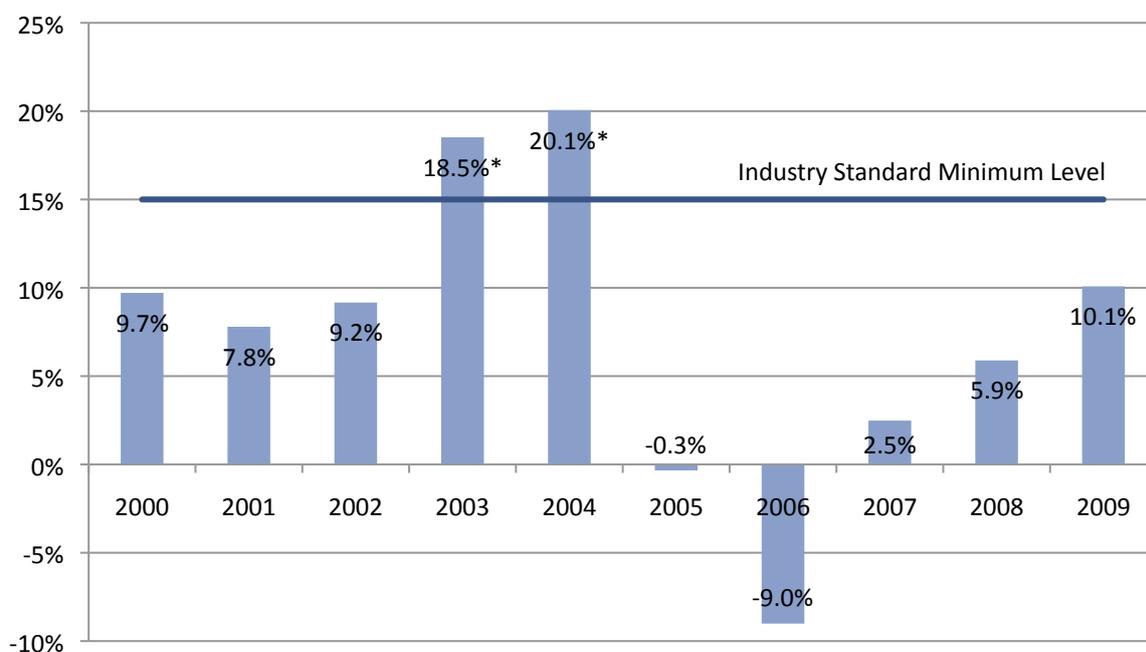
Table 4.5 - Ghana Historical Reserve Margins

Parameter	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Peak Dependable Capacity (MW)	1440	1540	1540	1540	1540	1540	1540	1540	1565	1672
Forced Outage (MW)	99	124	124	124	124	124	124	124	126	134
Unforced Capacity (MW)	1341	1416	1416	1416	1416	1416	1416	1416	1439	1566
Peak Demand (MW)*	1222	1314	1298	1195	1180	1421	1557	1382	1359	1423
Reserve Margin (%)**	9.7%	7.8%	9.2%	18.5%	20.1%	-0.3%	-9.0%	2.5%	5.9%	10.1%

* Includes Exports

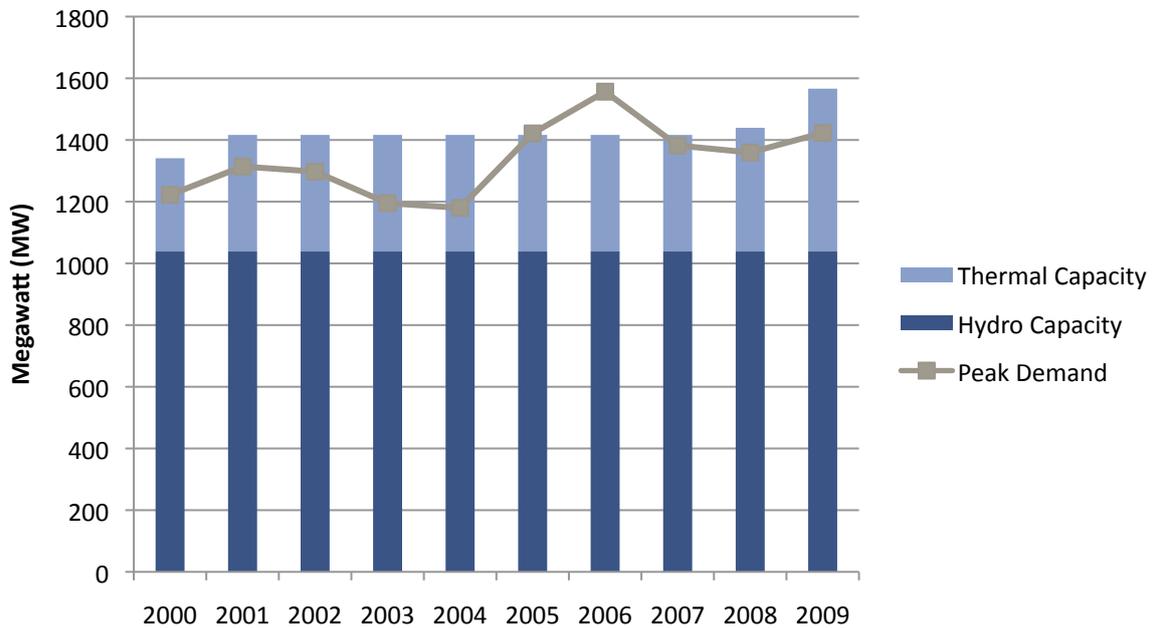
** Reserve margins for 2003 and 2004 do not include VALCO demand since VALCO was shut down due to water shortage. With VALCO demand included, the reserve margins would have been -7.1% and -6.2%, respectively.

Figure 4.3 - Reserve Margin Based on Unforced Capacity: 2000 to 2009



* Again reserve margins for 2003 and 2004 do not include VALCO demand since VALCO was shut down due to water shortage. With VALCO demand included, the reserve margins would have been -7.1% and -6.2%, respectively

Figure 4.4 - Unforced Capacity and Demand: 2000-2009



As described above, the target reserve margin for a power system must be at least equal to its single largest contingency. Considering generation facilities only, the single largest contingency will be the dependable capacity at peak of one of the generation units at Akosombo, which is 150 MW. However, other factors introduce the risk that a single event could cause Ghana’s wholesale power system to lose capacity larger than 150 MW. Specifically, Ghana’s system is highly dependent on hydro, and it is also vulnerable to fuel supply risks.

A total of 1,040 MW, or about 60 to 65% of Ghana’s dependable capacity at peak is derived from hydro resources at Akosombo and Kpong, both of which are dependent on seasonal rainfall in the main catchment area of the Volta Lake. The available capacity from both generation resources will be severely reduced in the event of low rainfall or drought conditions in any single year. Recall from Figure 4.2 that the Volta Lake has been drawn below its minimum level at Akosombo in 4 of the last 10 years, making this scenario a realistic probability. In the past, some turbines at Akosombo have been taken offline in periods of severe water shortage since they cannot operate at low water levels. For example, in 2007, the water level fell below 235 feet, and Akosombo operated with only 2 turbines for part of the year (normal operation is 6 turbines). If we assume conservatively that 1 or 2 turbines would be completely unavailable in periods of severe water shortage, this single event could result in the loss of 150 MW to 300 MW of peak dependable capacity. This would increase the single largest generation contingency from 150 MW to a range of 300 MW and 450 MW.

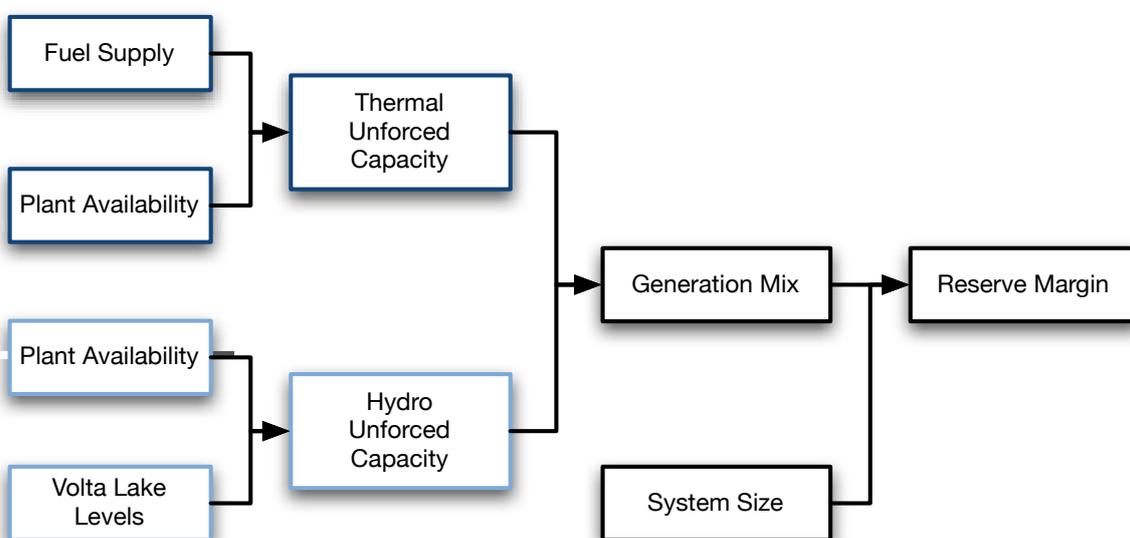
Another source of risk is fuel supply. The addition of the Aboadze plants helped to increase the fuel diversity of Ghana’s generation resources. In 2009 these plants contributed 500 MW to Ghana’s dependable net capacity at peak. Combined with the 113 MW of peak dependable from the Tema Thermal Plant 2, the dependable net thermal capacity is 613 MW. This means that 663 MW of thermal generation capacity is dependent on light crude oil or natural gas fuel. As of now Ghana still imports all of its fossil fuels, therefore any disruption in the import of these products could pose a major risk to generation adequacy. If we

assume, conservatively, that fuel shortage could result in the unavailability of only a single thermal plant, this single event could result in the loss of peak dependable capacity ranging between 113 MW and 300 MW resulting in an increase in the single largest contingency from 150 MW to a range of 263 MW to 450 MW.

The single largest contingency for Ghana’s wholesale power system could therefore be as low as 150 MW or as high as 450 MW. Based on the 2009 peak demand of 1,466 MW, these translate to minimum target reserve margins of 10% and 31%, respectively. There are standard Loss-of-Load-Expectation (LOLE) approaches used by the industry to properly determine the appropriate reserve margin³⁶. Such a study is beyond the scope of this report. Therefore, GRIDCo must perform such a study to determine a suitable reserve margin for Ghana’s wholesale power supply system.

For the purposes of this report, we will heuristically estimate a 20% reserve margin (the midpoint of the 10% to 31% range) as the target for Ghana’s wholesale power system. We believe this is a reasonable, though conservative estimate because it does not account fully for either water availability risk or natural gas and light crude oil supply risk or both. It is important to note however that WAPP, of which Ghana is a member, recommends reserve margins of 25%. This may be an apposite medium to long-term target reserve margin for Ghana.

Figure 4.5 - Determining an Adequate Reserve Margin



4.3 Planned Generation Capacity Additions

Due to robust growth forecasts, the addition of generation capacity over the next 5-10 years remains key to maintaining a healthy reserve margin and ensuring the reliable operation of Ghana’s electric system for the 2010 to 2018 period.

³⁶ Loss of Load Expectation (LOLE) is defined as the expected number of days per year in which available generating capacity is insufficient to serve the daily peak demand (load). LOLE is usually measured in days/year or hours/year.

In 2010, the Sunon-Asogli Power Plant (SAPP), a 200 MW natural gas/light crude oil power plant located in Kpone, is expected to begin commercial operation. Over the next five years 6 additional generation projects are scheduled to begin commercial operation, potentially adding up to 1,270 MW of nameplate generation capacity to the supply system (see Table 4.6)³⁷. These additions will bring Ghana's total nameplate generation capacity to 3,205 MW by the end of 2013, an increase of 66% over the 2009 capacity.

Table 4.6 - Generation Capacity Additions: 2010-2018

Unit Name	Owner/Operator	Unit Type	Online Date	% Of New Capacity	Nameplate Capacity (MW)
Sunon-Asogli Power Plant*	Sunon-Asogli	Thermal	2010	15.6%	200
Osagyefo Power Barge**	BEC	Thermal	2010	9.7%	125
Kpone Power Plant	--	Thermal	2011	8.6%	110
Osono	GECAD	Thermal	2011	9.3%	120
Takoradi T3	VRA	Thermal	2012	8.6%	110
Bui Hydroelectric	VRA	Hydro	2013	31.1%	400
CENPOWER (3 Units)	CENPOWER	Thermal	2013	8.6%	110
Takoradi T2 (Steam Comp.)	TICO	Thermal	2013	8.6%	110
Total Hydro				31.1%	400
Total Thermal				68.9%	870
TOTAL GENERATION					1,270

* Sunon Asogli is already built, but has not secured gas supply contracts. We assume it will have contracts in place and be operational in 2010. We believe this is a conservative assumption.

** The Osagyefo Barge has been built, but due to ongoing lawsuits we do not believe it will be put in service in 2010. We have assumed, conservatively, that it will be operational by 2011.

The capacity additions are notable because of the dominance of thermal generation and the heavy involvement of the private sector. Of the total planned capacity, approximately 30% will be hydroelectric and 70% will be thermal. This means that thermal will be the dominant generation technology by capacity starting in 2014, with a 51% capacity share. The reduced role of hydroelectricity is likely to continue for the foreseeable future. With the completion of the 400 MW Bui Power Plant, it is estimated that Ghana would have exploited more than 52% of its total capacity for large scale hydroelectricity (i.e. greater than 10 MW) and more than 41% of its total capacity for all hydroelectricity (large and small)³⁸. Beyond being limited, the remaining capacity is likely going to be more expensive to harness than Akosombo, Kpong, and Bui because the potential new hydro power sites are likely to be smaller with higher capital cost of construction per kilowatt of capacity.

Also notable is the fact that the planned generation projects are mostly sponsored by the private sector. Of the 1,270 MW scheduled to go into service, 760 MW (60%), will be privately owned. If all projects are completed successfully, the number of IPPs in the

³⁷ The estimated total capacity assumes that the Bui Power Plant will be commissioned in 2013.

³⁸ Hydropower Resource Assessment of Africa, MINISTERIAL CONFERENCE ON WATER FOR AGRICULTURE AND ENERGY IN AFRICA

generation market will increase from one to five, while the IPP share of capacity will increase from 11% in 2009 to 30% by 2015.

4.3.1 Detailed Description of Planned Generation Additions

Four key capacity additions are scheduled between 2010 and 2014. These four power plants are Sunon Asogli Power Plant (SAPP), Osagyefo Power Plant, Kpone Power Project (KPP), and Bui Power Plant (BPP).

Sunon-Asogoli Power Plant (SAPP)

The 200 MW Sunon-Asogoli Power Plant (SAPP) is expected to be completed and in-service in 2010. Of all the planned generation capacity additions, SAPP is at the most advanced stage of development and the most likely to be operational in 2010. Unlike many of the existing dual-fuel fired thermal plants, SAPP is designed to run on gas only. This makes the plant dependent on gas availability via the WAGP and the finalization of an agreement with VRA for access to gas. The operation of SAPP would increase the nominal generation reserve margin to 213 MW (14.9%) in 2010, which is almost 12% of total unforced generation capacity. It should also increase competition in the generation market.

Osagyefo Power Plant

The Osagyefo Power Plant is a 125 MW barge mounted natural gas/diesel power plant developed by Balkan Energy Corporation (BEC), an independent power producer (IPP)³⁹. The first phase of the project is the refurbishment and startup of the existing 125 MW Osagyefo Power Barge. The second phase of the project involves conversion to a 185 MW combined cycle plant, which will increase efficiency and lower marginal production costs. A third and fourth phase will see increased power production via either additional power barges or land-based units and infrastructure investments to enable the use of natural gas from nearby offshore gas fields and/or the WAGP.

Kpone Power Project (KPP)

The Kpone Power Project (KPP) will be a VRA/private partner owned and operated project featuring two 110 MW simple cycle turbines. At present, the Ghana government has given VRA a mandate to find a partner to finish the project. The project was originally slated to be located in Tema, but may be relocated to Bonyere. Such a move would allow it to take advantage of gas coming from Ghana's gas fields.

Bui Power Plant (BPP)

The 400 MW Bui Power Plant (BPP) is currently under construction at the Bui Gorge at the southern end of Bui National Park in Ghana. The Bui plant will be the first major generation facility located in northern Ghana. The location of the plant is very advantageous because it enhances the reliability and voltage stability of the wholesale power transmission system. Generation at Bui reduces the amount of power that would otherwise have to be transmitted across long distances from the south to the northern regions of the country. The project, which is a collaboration between the government of Ghana and Sino Hydro, would place Ghana's third hydro facility on the Black Volta river. The location of Bui will also provide dynamic reactive power to the transmission system to help regulate voltages at key substations in the Ashanti and northern regions. We discuss reactive power in more detail in Chapter 5.

³⁹ "Ghana West Africa Power Project", Balkan Energy Company, 2007.

Other Projects

The remaining generation projects represent a mix of new developments and upgrades to existing facilities that are scheduled to occur between 2011 and 2013:

- The Osono and CENPOWER projects are private simple cycle gas turbine facilities scheduled to begin commercial operation in 2011 and 2013, respectively.
- The Takoradi T3 project is a VRA-owned simple cycle gas turbine collocated with TAPCO and TICO in Aboadze, near Takoradi. This facility is expected to begin commercial operation in 2012.
- The Takoradi T2 Steam Component will convert the existing TICO facility from simple cycle operation to combined cycle operation by adding a heat recovery steam generator (HRSG) and steam turbine to the existing infrastructure. This plant is expected to begin commercial operation in 2013.

4.3.2 Systemic Risks

Water availability will continue to be a key risk issue going forward. In the short term, the impoundment of the Black Volta river flow during Bui's construction (2011-2013) is likely to affect reservoir yield at Akosombo. The Black Volta contributes an average of 18% of the overall inflow to the Akosombo reservoir, meaning that there is the risk of significantly reduced output at Akosombo and Kpong during the construction period. Section 4.5 discusses this possibility in more detail. In the long term, Bui will rely on the same Volta River system as Akosombo and Kpong and consequently it could face similar water supply risks. Akosombo and Kpong may be advantageously located because they rely on both the Black Volta and White Volta rivers whereas Bui relies on only the Black Volta, but ultimately both rivers and all three facilities are exposed to the same risks from seasonal rainfall patterns.

As thermal becomes the dominant generation technology over the next few years, fuel availability, and in particular natural gas availability, will become an increasingly important risk factor in future generation capacity adequacy and security. First, if supply of natural gas from the WAGP does not prove reliable, up to 48% of Ghana's forecasted generation capacity in 2014 could be unavailable. Such an event could wipe out the reserve margin and could lead to instant load shedding. This risk is mitigated to some extent by the fact that most of Ghana's natural gas fired thermal plants in 2014, Sunon-Asogli being the notable exception, have dual fuel capability and could be fired on light crude oil (LCO) or diesel fuel oil (DFO). However, unless those plants maintain a contingency supply of LCO or DFO on hand, which will require significant up-front investment in on-site storage, there will still be a short to medium term loss of capacity as new fuel is procured. In addition, most thermal plants are essentially optimized to fire natural gas; natural gas typically allows the plants to produce electricity at lower cost and reduces their forced outage rates⁴⁰. Hence a loss of natural gas supply will either cause a loss of capacity, higher generation costs (which eventually will translate to tariffs), or some combination of the two effects. The development of Ghana's indigenous oil and gas fields from the Jubilee field could potentially mitigate this fuel supply risk. It will diversify the sources of natural gas supply to two instead of the sole reliance on Nigeria and the WAGP.

Since GRIDCo has the overall responsibility for wholesale power supply reliability, GRIDCo will actively monitor water and gas availability as each of these two issues present credible systemic power supply reliability risks and may consider mandating all thermal generation facilities to maintain a minimum amount of fuel supply available to meet at least a fixed

⁴⁰ The cost of operating a thermal plant on natural gas vs. light crude oil depends on the prices for the two fuels.

number of days of operation at full capacity. Further, as a nation, it may be prudent to have sufficient storage facilities for both LCO and natural gas as shortage of these fuels could pose national security risks.

4.4 Generation Resource Adequacy: 2010

In 2010, the 200 MW Sunon-Asogli Power Plant (SAPP) is expected to become operational⁴¹. Unlike most of the other thermal generation facilities in Ghana, SAPP is only capable of firing on natural gas. Hence its operation will be dependent on the availability of gas either from the WAGP or Ghana's own Jubilee field. Nominally, 123 mmscfd (million standard cubic feet per day) of natural gas will be available from WAGP starting in the second quarter of 2010, and 70 mmscfd from the Jubilee field starting in 2011. However, there is some uncertainty around this gas availability; flow of gas through the WAGP has been inconsistent in the past and been delayed on several occasions in the past, and the Jubilee field is still under development and faces construction and project completion risks. Table 4.7 shows the projected reserve margin in 2010 assuming gas availability in 2010 and 2011, based on a peak dependable capacity of 180 MW for the Sunon-Asogli Power Plant⁴². Note that the existing Tema Thermal Plant 2 is also assumed to be operational in 2010⁴³.

Table 4.7 - Projected 2010 Reserve Margin with and without Sunon-Asogli operational in 2010

Scenario	System Peak Demand*	Total Unforced Generation Capacity	Projected Reserve Margin (%)
Sunon-Asogli in service: 2010	1,547 MW	1,760 MW	14.9%
Sunon-Asogli in service: 2011	1,547 MW	1,612 MW	4.2%

* Includes Exports

The reserve margin calculation shows that the operation of SAPP in 2010 will boost the reserve margin from the 2009 level of 10.1% to 14.9%. Without SAPP, however, the reserve margin will decline to 4.2%. Both measures are significantly below the 20% reserve margin target we have assumed. These projections are somewhat optimistic because they do not account for any variability in supply and demand assumptions.

It is clear from Table 4.7 that even if SAPP has access to the natural gas needed to make it operational, water and fuel supplies are adequate, and demand remains within the forecast, the wholesale generation will fail to meet the minimum assumed reserve margin of 20%. Generation adequacy will continue to be an issue in 2010 and the reliability of the power system looks bleak except under perfect conditions with all generation units available and demand within projected levels. The likelihood of such perfect conditions is extremely low and good utility practice requires system operators such as GRIDCo and policymakers to plan for contingencies.

⁴¹ At the time of writing, SAPP's construction is already complete and the plant is undergoing testing

⁴² We heuristically estimate that the peak dependable capacity of the Sunon-Asogli Power Plant will be approximately 10% below the nameplate capacity of 200 MW.

⁴³ Data provided by GRIDCo suggests this unit to be on temporary outage.

4.5 Generation Resource Adequacy: 2010 to 2018

Figure 4.6 shows the projected demand and 20% reserve margin, compare to the planned generation capacity additions from 2010 through 2018. Assuming all planned new generation capacity become operational as announced, the generation reserve margin is expected to increase from year to year, but at moderate levels, until 2013 when the Bui Power plant is scheduled to be operational. Beyond 2015, the reserve margin begins to decline because demand is projected to grow while there are currently no announced new generation projects. It is important for GRIDCo to address the lack of new generation capacity builds beyond 2014. GRIDCo must work with policymakers to maintain a healthy planned generation capacity build that looks forward over a ten year period, especially since it takes a long time for prospective generation investors to secure financing and at least two years to build a power plant.

Consider the situation in which all of the generation facilities listed in Table 4.6 become operational as scheduled. Let us assume this situation as the nominal case. The new plants are assumed to commence commercial operation in June of their respective online years, and operate at full capacity immediately. Hence this case is conservative in that it presents a best-case estimate of the reserve margin.

Figure 4.6 – Reserve Margin Outlook With New Generation Capacity Additions: 2010 to 2018

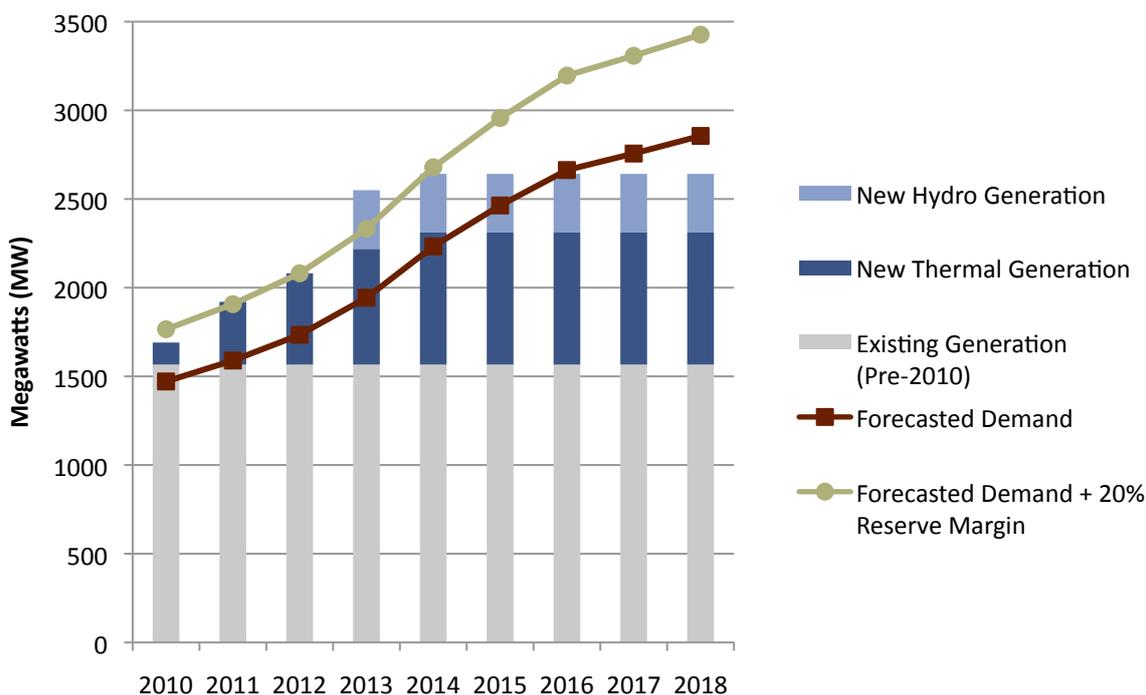
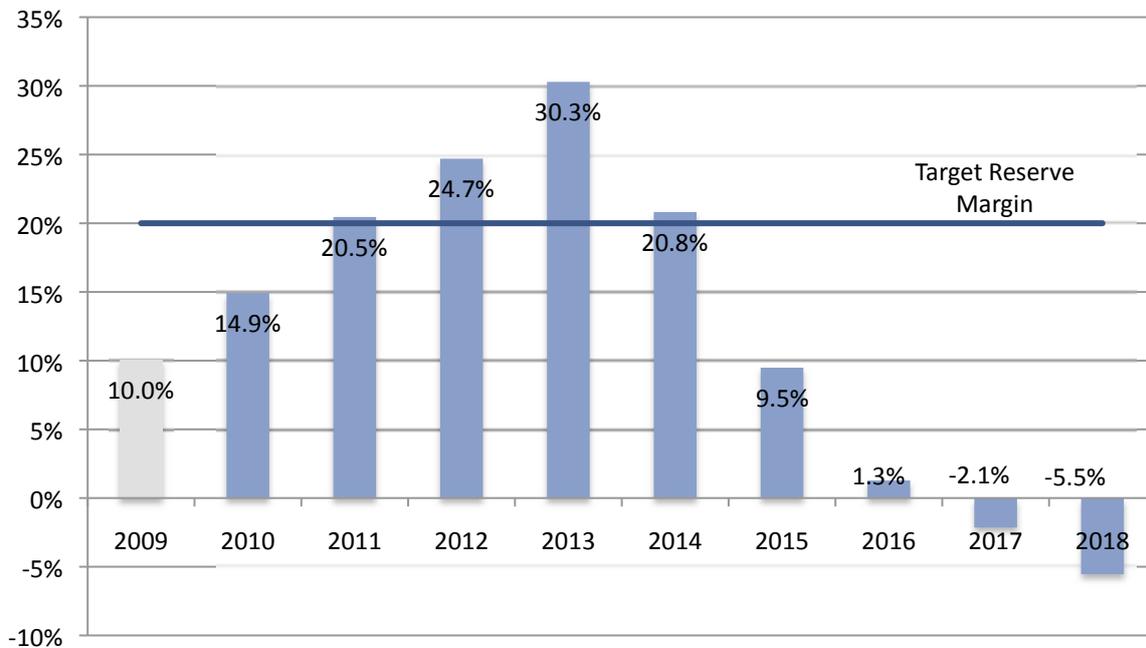


Figure 4.7 shows the projected reserve margin from 2010 to 2018 in the nominal case. The projections suggest the nominal case will see the 2010 reserve margin improve to almost 15%, but will still remain below the 20% suggested minimum and still reflect an unreliable power supply system. The reserve margin will surpass the 20% target reserve margin by 2012 and stay above that level until 2014; it will peak at approximately 29% in late 2013 when the Bui Power Plant (BPP) is scheduled to be operational. The projections also show that continued growth in demand in both industrial and non-industrial sectors will erode the

reserve margin rapidly beyond 2014, unless additional generation is built. Hence it is critical to maintain a focus on bringing even more projects online over the next 3-4 years to help Ghana maintain good supply/demand balance in 2015 and beyond.

Figure 4.7 - Projected Reserve Margin, Nominal Case: 2010-2018



Given the reserve margin outlook going forward, let us examine the effect of possible deviations from the nominal case. For example in Figure 4.8 and Figure 4.9, we show how the generation reserve margin will change under the following plausible conditions:

Fuel and Water Risk Scenarios

1. The impoundment of the Black Volta, a major tributary of the Volta Lake, at Bui reduces the capacity of Akosombo by 9% between February 2011 and December 2012.⁴⁴
2. Water shortage results in only a 60% reservoir yield at Akosombo and Kpong.⁴⁵
3. Near-term gas unavailability from the WAGP results in the Sunon-Asogli Power Plant being offline from 2010 to 2012 (prior to reliable availability of gas from Ghana's oil fields).⁴⁶

Supply/Demand Risk Scenarios

1. Each generation project scheduled for 2011 and beyond is delayed by one year, coming into service a year later than scheduled.
2. VALCO returns to operational status, running 4 potlines and adding an additional 320MW of peak demand⁴⁷

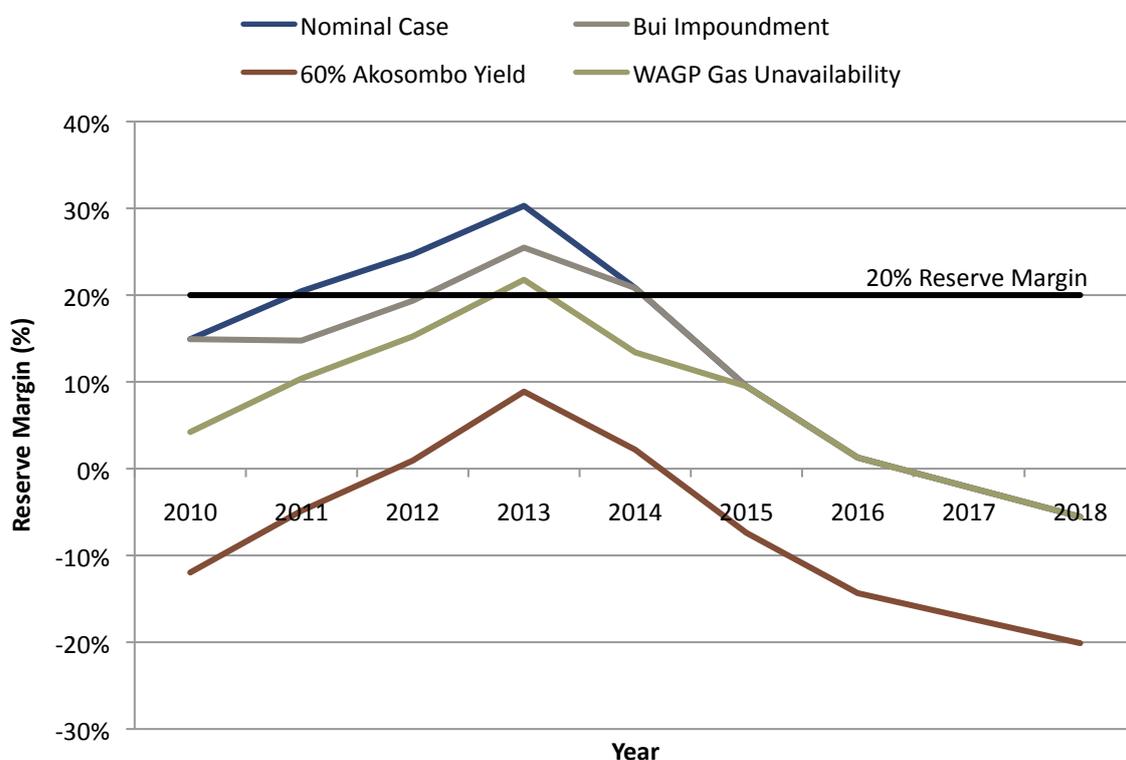
⁴⁴ GRIDCo's 2010 Supply Plan indicates that the impoundment of the Black Volta at Bui could reduce energy output from Akosombo by 18%. We assume that the impact on peak demand will be half of that on energy.

⁴⁵ Water shortages are unlikely to occur in the next 2 years based on current reservoir levels; however, the threat remains real in future years and this example is included to illustrate their effect.

⁴⁶ Dual fuel plants are assumed to switch to secondary fuel.

The outlook for reserve margin is worse under a number of the contingency scenarios. The most critical of these is low reservoir yield at Akosombo, which reduces the projected 2010 reserve margin from 15% to -12% (see Figure 4.8). Reserve margins in subsequent years would be similarly affected, meaning that even with capacity additions, Ghana would be operating at a negative reserve margin until 2012. A related scenario is the impoundment of the Black Volta flow during the construction of Bui Power Plant (BPP), which would reduce the reserve margin from 21% to 15% in 2011 and from 25% to 19% in 2012. Both of these scenarios exemplify the key role Akosombo continues to play in Ghana's generation adequacy. Another scenario is the unavailability of natural gas from the WAGP, which could reduce the projected 2010 reserve margin from 15% to 4% with similar effects in 2011 and 2012 (see Figure 4.8).

Figure 4.8 - Reserve Margin Fuel Risk Contingency Scenarios: 2010 to 2018



* No data on planned generation additions is available beyond 2014

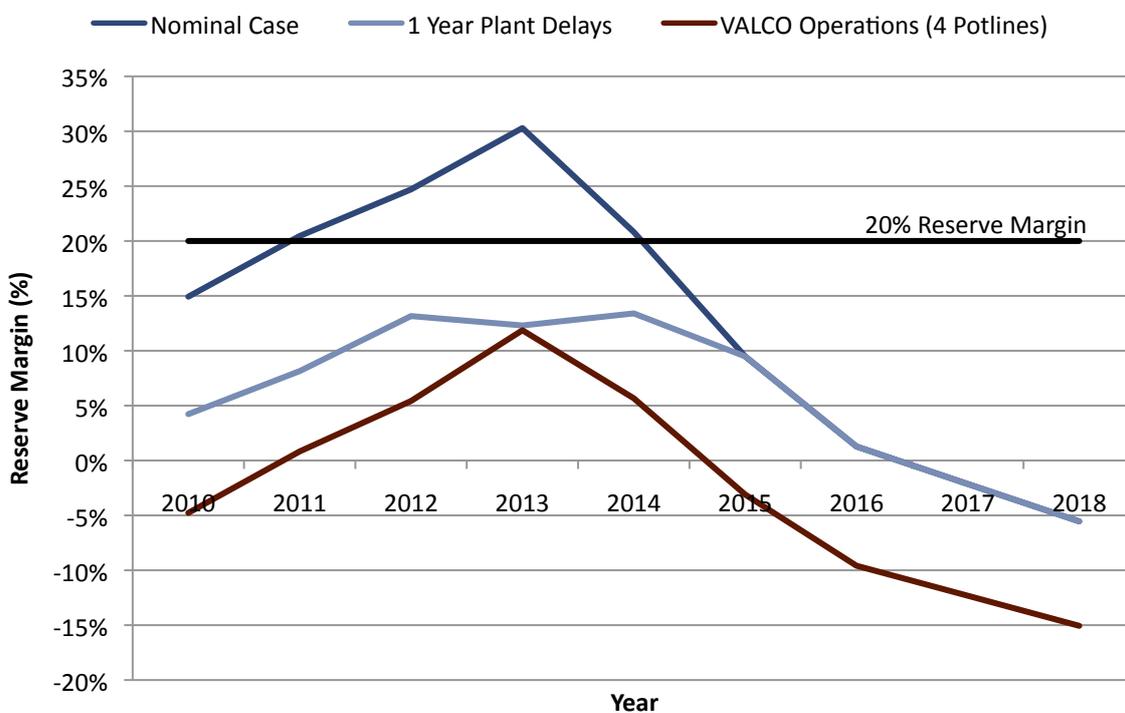
A second critical scenario is the resumption of operational activity at VALCO (see Figure 4.9). The projections show that if VALCO restarted operation of 4 potlines in mid-2010, the reserve margin would drop to -5% and remain below 10% until 2013. Perhaps it is prudent to allow VALCO to remain offline otherwise new generation sources must be secured before VALCO restarts operation. It is also important to note that while aluminium smelters like VALCO's are intensive consumers of power and energy, they are not unique in the industrial sector in this regard. Other industries such as chemicals, steelworks, timberworks, and petroleum

⁴⁷ Estimated peak demand of 320 MW based on peak demand in 2000; this is a conservative estimate relative to VALCO's all-time peak demand of 360 MW in 2001.

refineries are all also intensive users of power and energy. Thus, VALCO is just one of several possible types of energy intensive customers that the power system cannot accommodate until new generation capacity resources are secured.

A third critical scenario is the 1-year plant operational delay scenario (see Figure 4.9). Under this scenario, the projected reserve margin for 2010 would be about 4%. Beyond 2010, the reserve margin would rise steadily to 13% by 2012 and remain steady until 2014. An even worse scenario would be the cancellation of a generation project, which would drop the reserve margin below the 2009 level of 6.9%. This contingency scenario shows that although generation is being added, the power supply system will remain unreliable for an extended period because the new generation capacity continues to lag demand growth. Thus it re-emphasizes the need to continue to plan for timely capacity additions over the next 3-4 years and beyond.

Figure 4.9 - Reserve Margin Supply and Demand Contingency Scenarios: 2010 to 2018



* No data on planned generation additions is available beyond 2014

4.6 Firm Hydro Capacity

For systems with significantly large hydro generation, it is important to determine the firm annual energy capability of the hydro generators. If the output of a hydro generator is well-managed so that it stays within its firm annual energy capability, its production will be consistent and reliable on a year-to-year basis, and the risk of water shortage will be minimized. This can affect the reliable operation of the bulk power system, especially for systems such as Ghana's that are heavily dependent on hydro generation. For example, if the hydro resource is overdrafted in one year, it could experience a severe shortage in a

subsequent year. The annual energy capability of a hydro system is measured by the firm hydro energy capability.

Every hydro system has a firm hydro energy capability that relates to the historical inflows the system has experienced. It is defined as the annual level of output (GWh) that the hydro system can generate consistently, with a failure rate of once in 20 years. That is, despite the inflows, it will always generate this amount with only a 5% probability of failure (95% chance of success). For the Akosombo/Kpong system, the firm energy capability level is about 5,300 GWh. That means it can generate this level despite a high or low water inflow, and fail to deliver this amount of energy only once in 20 years. In the past, VRA has been unable to manage the production of Akosombo and Kpong to keep the annual output within the firm energy capability due to the high dependence of the Ghana bulk power system on the hydro generators and the relatively high cost of operation of the alternative generation sources such as the thermal generation facilities. A failure to adhere to the firm energy capability level compromises the firm capacity contribution of the hydro system to reserve margin. If the Volta Lake is overdrawn beyond the firm energy capability and it causes a shortfall in subsequent years, some of the units at Akosombo and Kpong will have to shut down as we have seen in the past. Such shut downs cause volatility in the firm capacity to serve load and may unnecessarily compel GRIDCo to maintain very high planning reserve margins, at significant cost to society, to assure generation reliability. Thus GRIDCo and policy makers must ensure that VRA is incentivized through the tariff structure to adhere to the firm energy capability level of the Volta river system each year, and dispatch thermal resources as necessary to meet energy requirements in excess of the firm energy capability of the hydro resources. The cost of dispatching thermal resources to meet the excess energy demand pales in comparison to the cost to society of maintaining exceptionally high planning reserve margins if the firm capacity contribution of hydro resources remains volatile.

In examining generation contingency scenarios, we described how water shortages could severely affect the reliability of Ghana's bulk power system. For example, if overdraft of the Volta Lake results in a 60% reservoir yield, Ghana's reserve margin can fall below -10%. This water risk can be mitigated or even eliminated if VRA manages the production from Akosombo and Kpong and maintains the firm capability of the hydro system. Managing the output of the hydro facilities is therefore integral to the reliability of the bulk power system. Future reliability reports should include an assessment of the operation of the hydro facilities in this context.

4.7 Conclusion

In 2009, Ghana had unforced generation capacity of 1,566 MW compared to peak demand of 1,423 MW. Thus Ghana had only 140 MW of dependable surplus generation capacity to meet any load or generation contingency, which translates to a reserve margin of only 10%. A 10% reserve margin is generally below industry-accepted levels and precariously low, especially for a small system. Most large systems maintain a reserve margin of at least 15%, and for small systems the percentage is often higher. At a 10% reserve margin, the power supply system could not withstand a major generation contingency and the frequent power outages realized during the year were in part a manifestation of such an unreliable condition.

The single largest contingency for Ghana's wholesale power system could be as high as 450 MW, and based on the 2009 peak demand of 1,423 MW, this represents a need for a reserve margin that could be as high as 31%. Since GRIDCo does not have an official reserve margin, we have heuristically assumed a 20% target reserve margin. We recommend that

GRIDCo initiate a standard Loss-of-Load-Expectation (LOLE) study to properly determine the appropriate generation capacity reserve margin for their operations.

There are a number of planned generation additions in the pipeline but the most likely to be operational in 2010 is the 200 MW Sunon-Asogli plant. Even with the potential operation of Sunon Asogli in 2010 the generation reliability continues to look bleak because the generation reserve margin improves from 10% in 2009 to 14.9% in 2010, which falls short of the desired reserve margin to assure generation adequacy. The case is even worse if the plant does not become operational in 2010 because the reserve margin declines to 4.2% given the projected 2010 peak demand. At current generation reserve margin levels, it may be prudent to have VALCO remain offline as the potential operation of VALCO will necessitate load shedding of other consumer groups.

Any risk to natural gas or crude oil supply, or risk to water availability in the Volta Lake system would further jeopardize the generation reliability situation. Since GRIDCo has the overall responsibility for wholesale power supply reliability, GRIDCo should therefore actively monitor water and gas availability as each of these two issues present credible systemic power supply reliability risks and may consider mandating all thermal generation facilities to maintain a minimum amount of fuel supply available to meet at least a fixed number of days of operation at full capacity.

Similarly, any operational delays in the announced online dates of the proposed new plant builds will mean an extended period of low generation reserve margins and poor power supply reliability through 2014. Thus GRIDCo and policy makers should mandate all generation projects in the pipeline to provide project status reports on a twice yearly basis as a means for GRIDCo to monitor generation reliability going forward. GRIDCo should also work with policymakers to address the lack of new generation capacity builds beyond 2014, especially since it takes a long time for prospective generation investors to secure financing and at least two years to build a power plant.

GRIDCo and policy makers must also ensure that VRA is incentivized through the tariff structure to adhere to the firm energy capability level of the Volta river system each year, and dispatch thermal resources as necessary to meet energy requirements in excess of the firm energy capability of the hydro resources. The cost of dispatching thermal resources to meet the excess energy demand pales in comparison to the cost to society of maintaining exceptionally high planning reserve margins if the firm capacity contribution of hydro resources remains volatile.

The reliability of the bulk power system depends on more the combined reliability of the generation and the transmission system. In this chapter we assessed generation reliability and in the next chapter we assess the reliability of Ghana's transmission system.

5 Transmission Reliability Assessment

5.1 Existing Transmission System

The transmission grid comprises a network of substations and transmission lines that link generation sources to load centres and allows the wholesale power system to transport power from generation resources to bulk consumers. Table 5.1 provides an overview of Ghana's transmission network. The network comprises over 4,000 kilometres of 161 kV high voltage transmission lines, 72 kilometres of 330 kV transmission lines, and 132 kilometres of 69 kV transmission lines. The on-going implementation of a series of 330 kV transmission projects will result in 330 kV replacing 161 kV as the primary backbone transmission voltage. The transmission lines are linked to 42 primary substations with a combined installed transformer capacity of 2,850 MVA. At the substations, voltage is reduced to 34.5 kV, 11.5 kV, 6.6kV, etc. for supply to bulk supply customers and/or for onward distribution to end-users.

Table 5.1 - Fact Sheet on Ghana's Transmission Network

Total Transmission Line Length	4,244 km
161 kV Line Length	4,038 km
225 kV Line Length	73.4 km
69 kV Line Length	132.8 km
Number of Transformers	86
Transformer Capacity	2,850 MVA
Number of Transformer/Switching Substations	42
Transformer Substation Voltages	161/34.5 kV; 161/11.5 kV

Source: "The National Grid", Ghana Grid Company Limited, 2010.
<<http://www.gridcogh.com/site/ng.php>>

Ghana's electric power transmission system is connected to Côte d'Ivoire on the west through a single circuit 225 kV interconnection and to Togo and Benin on the east through a double circuit 161 kV interconnection. Ghana also supplies electric power to Burkina Faso in the north through a low voltage distribution network, with a high voltage transmission system also under development as part of the WAPP agreement. Ghana is generally a net exporter to Togo and Benin, and a net importer from Côte d'Ivoire (see Section 3.5).

5.2 The Concept of Transfer Capability

The capability of a transmission line to carry power is limited by its physical characteristics. As power flows through a transmission line, it causes the line to heat up and sag, reducing the clearance between the conductor and the ground. For safety reasons, the line cannot be allowed to sag below an established minimum clearance. In addition, excessive heating can cause the conductor to anneal, which changes its metallic properties and ultimately causes irreparable damage. To prevent lines from sagging below the minimum clearance and from annealing, all lines have thermal ratings that specify the maximum power carrying capability.

For a single transmission line, the thermal rating is usually the limit to power flow. In a networked system that consists of many lines, other factors impose limits on power transfer

across a single line or group of lines. These factors include contingencies such as unplanned transmission facility outages, system stability, and voltage requirements. The limits they impose can be more restrictive than the thermal limits of the transmission lines.

In the event of an unplanned transmission facility outage, the pre-outage power flow on that facility is automatically redistributed on the other connected facilities that are still in operation. If any of the connected transmission facilities cannot safely and reliably accommodate the incremental flow, it could also trip out of circuit, establishing the risk of a cascading outage and ultimately, a blackout. Therefore, under normal conditions, the power system is usually operated such that all connected transmission facilities have sufficient margin to accommodate incremental power flows from an unexpected loss of another facility. Thus, the likelihood of a contingency constrains system operators to regulate the power carrying capability of connected transmission facilities within preset limits.

Another limitation on the power carrying capability of a transmission network is voltages at substations. A well-designed and operated power system must have constant voltage magnitude, therefore voltages at substations must be kept close to their rated levels for reliable operation of the system. The more voltages decline from their nominal levels, the lower the amount of power that can be safely and reliably transferred from one area of the network to another. Additionally, if substation voltages deviate significantly from their nominal levels, they can cause instability, which could lead to a blackout. For reliable operation of the power system, voltages at substations must be regulated within a 5% tolerance band of their nominal rating. This means that the voltage at a 161 kV substation must be regulated within a tolerance band of 153 kV and 169 kV. As power is transferred across the transmission network, losses cause voltages to drop. The voltage drops increase with increasing power transfer and if they are not regulated within the 5% tolerance band, voltages could drop precipitously and cause system collapse. Thus, to prevent voltages from dipping below their tolerance limits, operators set conservative voltage stability limits for power transfers across a single transmission facility or group of facilities.

Another limitation imposed on the amount of power transferred is the power angle stability limit. The amount of power transferred between two locations is determined by the angle between the voltage phasors⁴⁸ at the two locations. This angle, called the power angle, must be kept very small to preserve the capability of the power system to naturally dampen any oscillations that could cause instability. While the theoretical limit of the power angle could be as high as ninety degrees to maximize the amount of power transferred, this high limit is not achievable in practice because of the risk of uncontrollable oscillations that could cause system collapse. Therefore operators must keep transfer capability below a maximum threshold to keep the power system stable. This preset transfer level is the power angle stability limit.

Thus thermal, voltage and power angle stability considerations constrain the amount of power that system operators can transfer from one part of the transmission network to another. Transfer capability is therefore a measure of the amount of power that can be transferred across a transmission facility or a group of transmission facilities without violating any preset thermal, voltage or power angle stability limits.

In power systems, the transmission capacity available for reliable power transfers is measured by the Total Transfer Capability (TTC). TTC already accounts for thermal, voltage and power angle stability considerations. Additional transmission capacity margins must be

⁴⁸ This is the timing difference between the voltages.

reserved out of the TTC to serve local demand in case of unplanned local generation shortage. Other transmission capacity margins must also be reserved to allow the system to handle uncertainties such as load forecast errors and power flows in excess of the projected levels. The amount of transmission capacity reserved to serve firm local load is the Capacity Benefit Margin (CBM). This ensures that local demand can be served reliably. The amount reserved to handle uncertainties is called the Transmission Reliability Margin (TRM). This margin acts as spare capacity and allows the system to continue to operate reliably when unexpected conditions such as higher than expected demand arise. These two margins must be subtracted from the TTC to determine the capacity available for commercial energy transfers from one part of the network to another. Available Transfer Capability (ATC) is a measure of the transmission capability remaining for commercial energy transfers net of committed uses, i.e. it is the TTC after netting out CBM and TRM and any capacity already allocated for existing long-term power contracts. ($ATC = TTC - CBM - TRM - \text{Committed Uses}$).

As discussed in the previous chapter, both generation and transmission reliability are necessary for overall wholesale power supply reliability. A measure of transmission reliability is to determine the adequacy of ATC between various areas of the transmission system. For example, it is particularly important to ensure that sufficient ATC exists to deliver power to areas such as Accra, Kumasi, and load centres further north that have no local generation. These areas rely entirely on imports from generation resources at Aboadze, Akosombo, Kpong and Tema to meet their local demand. Insufficient ATC could pose supply risks. While it is desirable to have sufficient ATC to accommodate any anticipated power transfer from one area to another, it is reasonable to expect a few instances where constraints cause ATC across a particular transmission path to be exhausted. Transmission congestion occurs when there is more demand for power than there is available transmission capacity. In a system with no transmission congestion, the operator has the flexibility to use the most economical generation resources to serve demand. This produces the least cost to consumers.

Eliminating all transmission congestion is not necessarily economic, especially if system operators have the option to re-dispatch generation to relieve congestion on the constrained transmission facility. Due to the high cost of transmission infrastructure, it can be very expensive to build a transmission system that has no transmission congestion. Further, since the full ATC will be used only in a few hours that a high level of power transfer capability is needed, the spare ATC may be unused over long periods. However, in Ghana's situation where all generation resources are located in the south, major transmission constraints to power deliverability into areas such as Kumasi and the north could mean load shedding as operators would have no generation re-dispatch options. This is the reason why the proposed location of the Bui dam could be advantageous as this plant could provide GRIDCo with valuable generation re-dispatch options in the event of transmission congestion in the delivery of power from the south to areas such as Kumasi.

5.3 Existing Transmission Overloads and Constraints

Transmission constraints are the equivalent of "traffic" in the transmission wires. Incremental power transfer across a single transmission line, transformer or a bundle of lines may be curtailed by system operators if that transmission facility has reached or is fast approaching its preset operating security transfer limit. PSEC performed a computer simulation of the operation of the wholesale power system to determine how well the grid would operate under various generation and load conditions. A power flow analysis determines the power that would flow on all transmission facilities under various generation and load scenarios

while enforcing preset transmission facility limits. The results of the analysis and information from historical actual system operation during the year were used to determine key areas of the grid that were congested and needed capacity upgrades.

Currently, the main constraints in the transmission system are some of the key transmission facilities that serve load in Accra and Kumasi. In the case of Accra, the congested transmission facilities are the step-down transformers at the Achimota substation. These facilities are currently operated perilously close and often beyond their safe and reliable ATCs to serve Accra's peak demand. Such use of the transmission facilities embodies significant reliability risks and cannot withstand an unplanned single transmission facility outage without load shedding. For example a transformer outage at the Achimota substation will necessitate load shedding in Accra because there is insufficient transmission reliability margin across any of the connected transformers at that substation to accommodate the unplanned outage of another.

In the case of Kumasi, the congested transmission facilities are the step-down transformers at the Kumasi substation and the 161 kV Prestea-Bogoso transmission line. The recent completion of the 161 kV Kumasi-Obuasi transmission line has provided some relief, but not nearly enough to restore the ATC to Kumasi to firm capacity levels. Thus, similar to Accra, wholesale power supply to Kumasi also embodies significant reliability risks that may not withstand an unplanned single transmission facility outage without load shedding.

Table 5.2 shows exceptional high loading levels at some of the major substations within the transmission network. For example, the Takoradi substation has two installed transformers. The unplanned outage of one transformer would expose the other transformer to power flows that exceed its emergency rating and cause protective devices to disconnect the transformer out of circuit. Such an occurrence would cut off power supply to all connected loads and cause a blackout. This example demonstrates that there is inadequate transmission reliability margin at the Takoradi substation to accommodate the unplanned outage of a single transmission facility. The same is true for many of the major existing substations in the network.

It is also notable that two of Ghana's largest and most important substations – Achimota and Kumasi – have extremely high transformer loading. Achimota, for example, has five transformers with an average loading of 97.3%! Some of the transformers experience overloads on an almost daily basis. This high, sustained loading means there is no transmission reliability margin for unplanned events such as a line or transformer outage. Thus operators must make difficult choices of either sacrificing reliability by taking enormous risks to serve load, or insisting on good utility practice by reducing ATC to the level that guarantees sufficient transmission reliability margins. If ATCs are reduced in accordance with good utility practice, GRIDCo would have to institute rolling blackouts or brownouts – such actions require institutional discipline to preserve the integrity of the power system until appropriate remedial or long-term investment actions are taken.

Table 5.2 - Key Transformers and Loadings

Substation	Transformer Code	Rating (MVA)	Loading (% Of rating)
Achimota	5T1	50/66	90.8
	5T2	50/66	93.2
	5T3	50/66	95.9
	5T4	50/66	102.9
	5T5	50/66	103.9
New Tema	4T1	50/66	88.3
	4T2	25/33	N/A
	4T3	50/66	91.2
	4T4	15/20	13.1
	4T5	50/66	81.2
Kumasi	13T1	13.7/18.2	102.8
	13T2	13.7/18.2	101.2
	13T3	50/66	105.6
	13T4	50/66	101.1
	13T5	25/33	0.0
Takoradi	8T1	25/33	80.4
	8T2	25/33	80.7
Tamale	28T1	16/20	67.5
	28T2	16/20	61.0

Source: GRIDCo 2010 Supply Plan

5.4 Existing Voltage Violations

During peak load periods, when power flows across the transmission system are heavy, the transmission network experiences large voltages drops which, if unregulated, could cause voltages to dip below the 5% threshold at many substations (see Table 5.3). As voltages drop, system operators are constrained to either reduce ATC and thereby reduce power flows as a means to regulate voltages and maintain system stability, or boost voltages at substations that experience large voltage drops and thereby maintain healthy ATC levels. The industry uses reactive power from appropriately located generators or the electromechanical devices such as Static VAR Compensators (SVCs) to boost voltages. The current location of generators within Ghana's wholesale power supply system is too distant for them to be effective at boosting voltages at the substations where voltage support is needed. As a general matter, reactive power is best supplied on site and any attempt to haul reactive power over long distances to improve voltages at distant substations is practically ineffective because the transmission lines are likely to consume the reactive power themselves. For example, an attempt to regulate voltages at the substations in Kumasi with reactive power from Akosombo or Aboadze is likely to be ineffective or very expensive. The reason is that the reactive power may either not get to Kumasi where it is needed, or a large amount will have to be generated at Akosombo and/or Aboadze to overcome the potentially large transmission losses. This obviously comes at a significant cost to the generation unit

owners in terms of a reduction in equipment life and the lost opportunity (and revenue) due to being unable to dispatch their full generation capability. GRIDCo's only option is to use SVCs and capacitor banks located at Kumasi, but the transmission system does not have enough of these devices, hence the critically low substation voltages for remotely located substations relative to Akosombo and Aboadze shown in Table 5.3.

The lack of appropriately located generators and adequate SVCs and capacity banks exacerbate the ATC situation and constrain operators to sometimes sacrifice reliability and take enormous operational risk to supply power. In extreme situations, there are no other options but to reduce ATC and thereby reduce power flows through load shedding.

In Table 5.3 the voltages at Akosombo and Aboadze are much higher than their nominal levels because they provide exceptionally high levels of reactive power to help regulate remotely located substations. Remotely located substations such as Kumasi, Techiman and Tamale show voltages that are significantly below the 5% threshold at peak periods and in some cases close to levels that could precipitate system collapse. Power systems are not designed to operate under these extreme conditions and taking such risks, even if blackouts are avoided, are very costly in the long run because it reduces equipment life. Investment in voltage support equipment is an immediate need, especially at Kumasi, Techiman and Tamale.

Table 5.3 - Substation Voltages

Substation	Nominal Voltage	Actual Voltage	Deviation from Nominal	Comments
Akosombo	161 kV	168 kV	+4.3%	
Volta	161 kV	162 kV	+0.1%	
Achimota	161 kV	157 kV	-2.5%	
Aboadze	161 kV	167 kV	+3.7%	
Prestea	161 kV	155 kV	-3.7%	
Kumasi	161 kV	143 kV	-11.1%	Violation
Techiman	161 kV	141 kV	-12.4%	Violation
Tamale	161 kV	130 kV	-19.3%	Violation

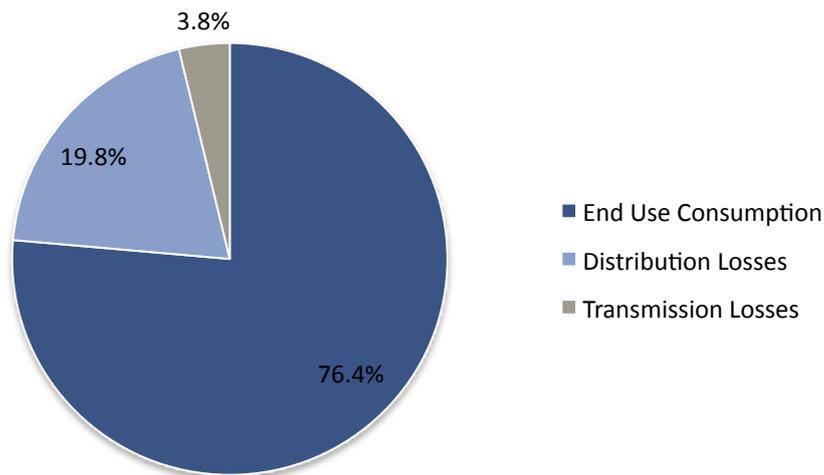
5.5 Losses

Losses occur in the process of power transmission from generator to loads. There are two varieties of losses: technical and commercial. Technical losses are largely caused by energy dissipated as heat in the resistive conductors and equipment used for transmission, transformation, and distribution of power. Commercial losses include pilferage, defective meters, and errors in accounting for electricity consumption. In practice, commercial losses are largely confined to distribution, while technical losses are present in generation, transmission, and distribution.

Figure 5.1 shows that losses account for approximately 24% of demand in Ghana, driven largely by distribution losses (both technical and commercial). In comparison, losses

account for only 6.5% of demand in the United States⁴⁹. Transmission losses in Ghana are about 3.8% compared to an industry rule-of-thumb estimate of 3%⁵⁰. We believe the high transmission losses in Ghana are the result of heavy power flows due to limited transmission capacity. As more capacity is added to the grid, losses should decline to the industry expected level of 3%.

Figure 5.1 - Losses in Transmission and Distribution



5.6 Available Transfer Capability Between Areas

ATC or TTC is a true measure of transmission reliability for operations going forward because it determines if sufficient transmission capacity exists to serve all areas of the wholesale power system reliably. Transfer capability is even more crucial in Ghana's wholesale power supply system because major load centres such as Accra, Kumasi and cities/towns in the north have no local generation and rely solely on power imports to meet local demand. Electricity is supplied through transmission ties between these load centres and generation locations in the south. It is important that the transfer capability into Kumasi be at least equal to the total demand in Kumasi and the areas to the north, otherwise load shedding may be necessary in some hours to maintain reliability. Similarly, transfer capability into Accra must be at least equal to local demand in Accra to avoid the possibility of load-shedding.

The transmission paths between areas are called interfaces. For example, the transmission path between Tema and Accra may be called the Tema/Accra interface. Each interface is made up of one or more transmission facilities. The transfer capability across an interface is usually much lower than the sum of the ratings of the individual transmission facilities that make up that interface. Several factors can limit the transfer capability across an interface. For example, if one of the lines in an interface reaches its thermal rating, it will prevent further increases in power flow across that interface, even though other lines that comprise that interface may be below their thermal limits.

⁴⁹ *State Electricity Profiles 2007*, U.S. Energy Information Administration, 2008.

⁵⁰ *2010 Supply Plan*, Ghana Grid Company Limited, 2010.

TTCs are considered as either firm or non-firm. Firm TTC refers to the maximum power that can be transferred such that the system would still operate reliably after the outage of any key system element such as a transmission line or transformer. Firm TTCs therefore provide a high level of reliability for transfers and are often used for capacity transfers. However, the reliance on capacity transfers alone results in a conservative operation of the system. Therefore operators allow Non-Firm TTC for interruptible incremental energy transfers above the firm capacity transfer level. Such interruptible energy transfers are not expected to cause load shedding or compromise reliability because operators must have generation redispatch options in case of an unplanned event. Thus, Non-Firm TTC refers to the maximum power that can be transferred such that the system continues to operate reliably when all facilities are in normal operation. Non-Firm TTC has a lower level of reliability than Firm TTC. Transfers using Non-Firm TTC can be interrupted in the event of an unplanned outage.

TTCs may also be specified as simultaneous or non-simultaneous. Simultaneous transfer capabilities are closed-loop limits or joint limits for a group of interfaces. They represent more conservative limits than non-simultaneous transfer capabilities. For example, the total import into Accra from all transmission interconnections is the simultaneous import limit. Non-simultaneous transfer capabilities are limits on individual interfaces or open-loop limits. An example of a non-simultaneous limit is the Tema/Accra interface or the Takoradi/Accra interface.

PSEC began the 2010 transmission reliability assessment by estimating the adequacy of TTCs between load centres. Electrically contiguous bulk power substations that did not have any historically significant transmission constraints between them were grouped together to form transmission zones as shown in Table 5.4. These zones are interconnected by transmission paths. PSEC performed computer simulations to determine the maximum power that could be transferred reliably across each interface.

Table 5.4 - Zone Aggregation for Total Transfer Capability Calculations

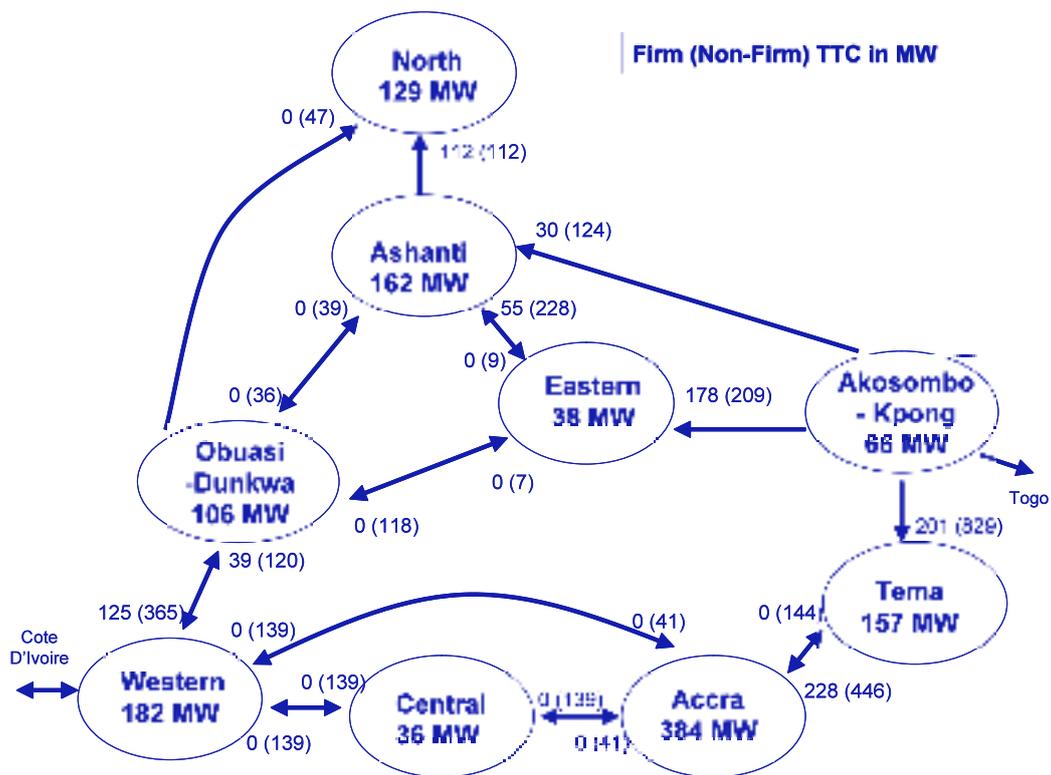
Zone Name	Major Generation and Load Centres in Zone
Accra	Accra; Winneba
Akosombo-Kpong	Akosombo; Kpong
Ashanti	Konongo; Kumasi
Central	Cape Coast
Eastern	Nkawkaw; Tafo
North	Bolgatanga; Sunyani; Techiman; Tamale;
Obuasi-Dunkwa	Dunkwa; Obuasi
Tema	Tema
Western	Aboazde; Prestea. Takoradi; Tarkwa

The results of the TTC assessment are illustrated graphically in Figure 5.2 and Figure 5.3. Figure 5.2 shows the Non-Simultaneous Firm and Non-Firm TTCs⁵¹. The TTC analysis shows that several transmission interfaces between the zones have limited capability for firm transfers. For example firm transmission capacity from the generation sources in the

⁵¹ See Table A.1 in Appendix A for more detailed information on Non-Simultaneous Firm TTCs, including the limiting and contingent transmission elements.

Western zone through the Central zone to the load centres in the Accra zone is practically zero. This means that power transfers from Takoradi to Accra would have to be treated as interruptible non-firm energy transfers because the network cannot withstand the potential loss of a single major transmission facility. Similarly, firm transfer capability between the Obuasi-Dunkwa load zone and the Eastern load zone is close to zero. This limits the ability to export firm power (capacity) from generation resources in Takoradi to the load centres in the Ashanti and North zones.

Figure 5.2 - Non-Simultaneous Firm (Non-Firm) Transfer Capabilities



The unavailability of firm transmission capacity means that some load centres will be served using interruptible non-firm energy transfers. Therefore load centres such as Accra, Kumasi, and cities and towns in the north risk load shedding if contingencies occur during normal operation of the system. The TTC analysis also estimated corresponding Non-Firm TTCs across the inter-zonal transmission interfaces and the results are shown in parentheses beside the firm TTC estimates in Figure 5.2⁵². The result of the analysis shows that there is sufficient non-firm ATC to meet the demand requirements in all load centres. Therefore it is expected that all load centres can be served with interruptible power under normal system conditions with all transmission facilities in service.

⁵² See Table A.2 in Appendix A for more detailed information on Non-Simultaneous Non-Firm TTCs, including the limiting and contingent transmission elements.

The Simultaneous Firm and Non-Firm TTCs are shown in Figure 5.3⁵³. The simultaneous TTCs are determined across five major interfaces within the power system. These interfaces divide the power system into five zones or groups of zones. The interfaces are:

1. The Accra Import Interface. This interface determines the total amount of power into the Accra zone.
2. The Ashanti Import Interface. This interface determines the total imports into the Ashanti and North zones.
3. The Central-Western Interface. This interface determines the total transfers into and out of the combined Central, Obuasi-Dunkwa and Western zones.
4. The Greater Eastern Interface. This interface determines the exports out of the combined Akosombo, Eastern and Tema zones.
5. The Western Export Interface. This interface determines the exports out of the Western zone.

The implications of the simultaneous TTCs on the ability to import firm capacity into the areas that depend on imports – the Accra zone, the combined Ashanti and North zones, and the combined Central and Obuasi-Dunkwa zones – are summarized in Table 5.5. The table compares local demand to available local generation and import capability to determine if an area or group of areas had sufficient firm capacity to serve local load. The table shows that the Accra zone has a firm capacity shortfall of 165 MW. With a peak demand of 384 MW and a firm import capability of 219 MW, the Accra zone must rely on interruptible non-firm power imports to serve 165 MW of its peak demand. Similarly, the combined Ashanti and North zones has a firm capacity shortfall of 219 MW. The total peak demand in the Ashanti and North zones was 291 MW, compared to a firm import capability of 72 MW. The two zones must therefore rely on interruptible non-firm power imports to serve 219 MW of their peak demand. Lastly, the combined Central and Obuasi-Dunkwa zones must rely on non-firm power imports to serve 67 MW of their peak demand in these two zones. These zones had a peak demand of 142 MW compared to a firm import capability of 75 MW. Therefore with no local generation and insufficient capacity for firm imports, all the zones that depend on imports must rely on interruptible non-firm power imports to meet some of the local demand. This firm capacity shortfall obviously reduces the reliability of power supply in these zones.

Table 5.5 - Simultaneous Firm Transfer Capabilities: Importing Areas

Zone(s)	Accra	Ashanti and North	Central and Obuasi-Dunkwa
Peak Demand (MW)	384	291	142
Local Generation (MW)	0	0	0
Import Requirement (MW)	384	291	142
Firm Transfer Capability (MW)	219	72	75
Firm Capacity Shortfall (MW)	165	219	67
Amount Treated as Non-Firm (MW)	165	219	67

⁵³ See Table A.3 in Appendix A for more detailed information on Simultaneous Firm TTCs, including the limiting and contingent transmission elements.

Figure 5.3 - Simultaneous Firm (Non-Firm) Transfer Capabilities

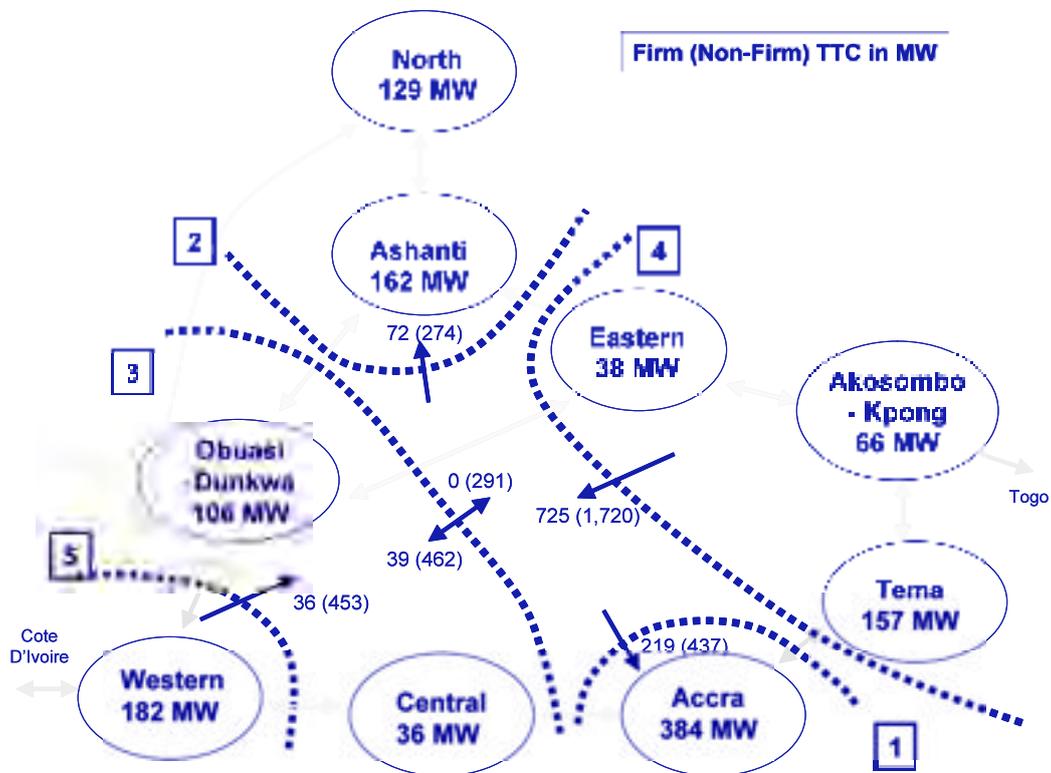


Table 5.6 shows the firm export capability of the generation exporting zones. For each zone or group of zones the generation capacity available for exports is compared to the firm export capability. If the available generation exceeds the firm export capability, then the excess generation above the firm export level is treated as interruptible non-firm power exports. Both the Western Export and the Central Western Export interfaces show limited capacity for firm exports from the generation sources in Aboadze. Firm transfers across these interfaces were limited to 36 MW for the Western Export interface and zero (0) MW for the Central Western Export interface. With a maximum generation capacity of 550 MW and a peak demand of 182 MW, the Western zone could potentially export more than 330 MW of excess generation capacity. The limited firm transfer capability implies that very little of this generation capacity could be exported on a firm basis. Most of it must be treated as interruptible non-firm power exports.

Table 5.6 - Simultaneous Firm Transfer Capabilities: Exporting Areas

Zone(s)	Akosombo, Eastern and Tema	Central, Obuasi, Western	Western
Peak Load (MW)	261	324	182
Local Generation (MW)	1385	550	550
Capacity Available for Export (MW)	1,124	226	368
Firm Transfer Capability (MW)	725	0	36
Amount Treated as Non-Firm (MW)	399	226	332

The Simultaneous Non-Firm TTCs are shown in parentheses in Figure 5.3⁵⁴. Non-firm capacities are sufficient to meet the demand requirements in all load centres. Therefore it is expected that all load centres will be served with interruptible power under normal system conditions if and only if technical conditions remain perfect.

5.7 Planned Transmission Upgrades

GRIDCo has proposed several transmission facility additions or upgrades to improve transmission reliability and boost firm ATC across many of the inter-zonal transmission interfaces. The proposed system improvements include new transmission lines to relieve existing overloads and constrained transmission facilities. They also include new capacitor banks and a new static VAR compensator (SVC). These devices will help improve voltages at substations that currently experience extremely low voltages, and reduce the amount of reactive power that must be produced by generation facilities.

The proposed transmission lines are shown in Table 5.7. Three major upgrades are planned for 2010: a new 330 kV transmission line from Aboadze to Volta, a fourth 161 kV line from Volta to Achimota, and reconstruction of the 161 kV line from Prestea to Bogosu. Each of these projects will improve transfer capabilities in some of the key constrained areas. It is important to determine if these projects will sufficiently address the shortfall in firm transmission capacity for the main importing and exporting zones. Estimating the incremental ATC that will be enabled by these upgrades is beyond the scope of this report. GRIDCo will estimate the impact of the proposed projects on total transfer capability in future TTC studies and publish the results in the 2011 reliability report.

Table 5.7 - New Transmission Projects

Project (Origin-Destination)	Nominal Voltage (kV)	Capacity (MVA)	Length (km)	In-service Date
Aboadze - Volta	330	1,000	215	2010
4th Volta-Achimota line	161	213	25.7	2010
Prestea-Bogosu	161	364	13	2010
Aboadze-Prestea-Kumasi	330	1,000	200	2016
Tumu-Han-Wa	161	182	130	2016

The new Aboadze-Volta 330 kV line will improve system reliability by reducing line loadings on existing lines and increasing transmission reliability margins on transmission facilities that connect the Tema zone. This project could also play a key role in system reliability since it will increase the firm transfer capability out of the 3 exporting zones – the combined Akosombo, Eastern and Tema zone; the Western zone; and the combined Central, Obuasi and Western zone. As shown in Table 5.6, in all 3 areas the generation available for export currently exceeds the available firm transfer capability. Approximately 399 MW of exports from the combined Akosombo, Eastern and Tema zone; 226 MW from the Western zone; and 332 MW from the combined Central, Obuasi and Western zone could be bottled up by inadequate firm export capability and would need to be treated as interruptible non-firm

⁵⁴ See Table A.4 in Appendix A for more detailed information on Simultaneous Non-Firm TTCs, including the limiting and contingent transmission elements.

exports during the peak period. Increasing the level of firm exports will improve the reliability of power supply.

The fourth transmission line from Volta to Achimota is needed urgently to improve firm capacity imports into Accra. Table 5.5 shows that Accra currently has a firm capacity shortfall of 165 MW, resulting in some demand being served using interruptible non-firm power. The planned transmission addition will provide the Accra zone with the ability to import more firm power, and improve the reliability of supply into the zone. This project must include the construction of the third Accra bulk power substation at Adjiringano to shift some of the load on Achimota and Mallam and relieve loading on existing transformers. It will also improve substation voltages at Achimota and its environs, reduce overall transmission losses and reduce the loading on the existing 161 kV Volta-Achimota transmission lines.

The 161 kV Prestea to Bogosu line is one of the transmission elements that constrains power import capability into the Ashanti zone and reconstructing of this line will improve firm transfer capability into the combined Ashanti and North zone. Table 5.5 shows that this zone has a firm capacity shortfall of 219 MW. The planned project will help address some of this shortfall. It is however likely that additional improvements will be required to eliminate the shortfall entirely.

Two additional transmission line upgrades are planned in 2016. They are the 330 kV line from Aboadze through Prestea to Kumasi, and the 161 kV line from Tumu through Han to Wa. The 330 kV line from Aboadze to Kumasi will increase the firm import capability into the Ashanti zone to address the current firm capacity shortfall in the Ashanti and North zones. It will provide additional improvement in transmission reliability margins. The timing of this project will have a critical impact of the reliability of power supply into the Ashanti and North zones. It is unlikely the near-term improvement in the area, i.e. the upgrade of the 161 kV Prestea to Bogosu line, will provide adequate firm capability. Unless GRIDCo carries out additional improvements, the shortfall will exist until 2016 when the 330 kV line from Aboadze to Kumasi is scheduled to be completed. Further, as demand is projected to increase, the shortfall is also expected to worsen. It is therefore important that GRIDCo considers methods to mitigate the impact of inadequate firm capacity into this key area.

GRIDCo has also planned transmission system upgrades to improve system voltages in some of the major load centers. They include:

- Installation of a 30 MVar SVC in Kumasi. This installation should fix the present undervoltage conditions at Kumasi and Tamale and improve them by as much as 9 kV and 15 kV respectively. It should bring voltages at the two substations into compliance with good utility practice. Installing the SVC will also reduce transmission losses by about 5% and reduce reactive power output from the Akosombo and Aboadze generation plants by about 7 MVARs on average.
- Installation of capacitor banks at several substations, including Achimota (80 MVARs), New Tema (40 MVARs), Sunyani (10.8 MVARs) and Kumasi (8.1 MVARs). This should complement the installation of the fourth Volta to Achimota transmission line, and would improve voltages at all the substations to within 5% of the nominal rating. It would also reduce transmission losses by about 12%, from 3.8% to approximately 3.3%.

In addition to improving system voltages, these projects will also improve the reliability of power supply in Ghana. In the absence of local reactive power sources to provide voltage

support in these load centers, Akosombo and Kpong would have to provide large amounts of reactive power to help maintain system voltages. This significantly reduces the amount of power that these generation facilities can provide to meet system demand. The installation of local capacitor banks and SVCs will reduce the reactive power demand on Akosombo and Kpong and increase their real power production capability.

5.8 Conclusion

Our assessment shows that the transmission system has inadequate firm transfer capability to meet peak demand requirements at many of the major load centres such as Accra and Kumasi. Therefore GRIDCo will have to use interruptible and non-firm transfer capability to meet incremental power needs at these load centres. Voltages at most major substations are precariously low because there is inadequate installed reactive power and voltage support devices to boost voltages. Additionally inadequate capacity across many transmission facilities constrains GRIDCo to utilize these transmission facilities perilously close to their capacity limit and in some instances at sustained levels above their limits. Thus operators are making tough choices by sacrificing reliability to keep the lights on. While it may be understandable that GRIDCo would shed load as a last resort, continued operation of the grid at such low voltage levels with some transmission facilities at sustained loading levels above their operating security limits exposes the entire power system to significant risk, which can be costly in the long run.

GRIDCo must enforce institutional discipline to shed load if necessary and in accordance with good utility practice, if such action can temporarily improve voltages and transmission facility loading, while pursuing long-term solutions to add transmission capacity. We also notice that the Akosombo and Aboadze generation units are being tasked to generate large amounts of reactive power to support transfer capability across the transmission system. While we understand that operators are bereft of the local reactive power resources at the substations that need them the most, using the Akosombo and Aboadze units to regulate voltages at remotely located substations such as Kumasi is ineffective and potentially harmful to the life of the generators. Lastly GRIDCo has identified projects that can alleviate the dearth in firm transfer capability and the chronic low voltages. These projects are needed urgently to meet the minimum transmission reliability necessary to support uninterruptible power to consumers and to meet the industry reliability standard of one outage in ten years.

To understand the importance of a reliable power system, it is important to determine the impact of power supply reliability failures on society. The next chapter assesses the impact of reliability failures on the Ghanaian economy and estimates the economic cost to consumers.

6 Economic Cost of Reliability Failures

In the Introduction, we mentioned that the total cost to society of reliable power is the sum of the tariff collections and the cost of reliability failures. As a society, we pay the full cost of reliable power, whether we choose to pay a low tariff and endure the deleterious effect reliability failures have on the economy or we choose to pay fair power prices to assure high availability and reliability. In this section we estimate the cost of reliability failures to society. The analyses presented in this chapter are designed to help policy makers in their decision analysis on tariffs and transmission and generation project approvals.

Power failures cause significant direct and indirect costs to utilities, consumers, and the general economy. The World Bank estimates that the direct cost of power outages to African nations is typically about 2% of GDP⁵⁵. For reference Ghana's GDP growth has averaged about 5% over the last 10 years, meaning that power unreliability negates a significant amount of potential economic growth. The World Bank estimates that Ghana's nominal GDP as of 2008 was approximately \$16.1 Billion⁵⁶, meaning that power outages potentially cost the economy more than US\$320 million per year. This amount (US\$320 million) is more than sufficient to fund all the identified reliability projects by GRIDCo from 2010 to 2016 to assure around-the-clock power for all consumers.

Direct costs to utilities include the cost of repairing damaged equipment, process restart costs, lost generation revenue and reduction in equipment life. Additionally, since electricity systems are highly connected and integrated, failure in one area can lead to damage in other areas. For example, frequency instability in transmission can cause fatigue in generators from constant speed variations and thermal cycling. Direct costs to end consumers include the cost of damage to household electrical appliances, permanently lost production, and the spoilage of products and/or goods. For example, the World Bank estimates that African manufacturing enterprises report an average of 56 days of power outages per year, resulting in an average loss of 5-6% of annual sales revenues in formal businesses and up to 20% of sales in the informal sector⁵⁷.

Indirect costs to end consumers include the opportunity cost associated with lost sales and revenue, increases in the cost of doing business due to uncertainty, and the cost of on-site power equipment such as generators and uninterruptible power supplies. These costs ripple through the economy because they unnecessarily reduce household income and the profitability of doing business in Ghana, which ultimately discourages investment and reduces the amount of money that can be reinvested in the local economy.

6.1 Value of Lost Load

Another approach to estimate the cost of failures is to perform a Value of Lost Load (VoLL) analysis. VoLL is defined as the value placed by an average consumer on an unsupplied unit of electric power. It is a critical component of evaluating the cost of power outages, because it measures consumers' willingness-to-pay to avoid such outages. VoLL measures the cost of reliability failures in the electricity sector to customers. For convenience, the VoLL will be referred to in US dollar terms.

⁵⁵ World Bank News Release No: 2008/356/AFR

⁵⁶ "World Development Indicators", World Bank, 2010. <<http://devdata.worldbank.org/>>

⁵⁷ World Bank News Release No: 2008/356/AFR

VoLL is a measure of the financial impact on a consumer of power when their power is curtailed. The impact differs depending on whether or not the power outage was planned and depending on the type of customer. The VoLL is lower for planned outages (i.e. those pre-announced to the end consumer) than unplanned outages, because given advanced warning users can plan for the outage and re-optimize their activities accordingly. In terms of different types of customers, the VoLL is usually highest for commercial consumers, followed by industrial consumers. The impact is lowest on residential consumers because they can adjust their behaviour relatively easily, and they use electricity more for leisure than productivity. For example, a residential customer can use kerosene lamps for lighting as a temporary alternative to electricity, while an office cannot realistically use kerosene powered computers.

PSEC estimated the VoLL using a three-step process. First, outage data was collected and the cost per outage estimated for each sector, reflecting the inherently different unit value of electricity to each sector. According to data provided by ECG, its average customer was without power for approximately 10 hours each month in 2007, or about 1.4% of operating hours. Using this as a proxy for the bulk power system, this translates into 120 GWh of lost load in 2009⁵⁸. Table 6.1 shows the impact of outages by sector in 2009. Note that impacts are distributed across sectors based on each sector's share of total energy demand.

Table 6.1 - Impact of Outages

Sector	Energy Load Share* (%)	Impact of Outages in 2009 (GWh)
Residential	28%	33.6
Commercial	11%	13.2
Industrial	35%	41.9
Other	2%	2.4
Total	76%**	120.1

* Ghana Energy Statistics, Ghana Energy Commission, 2009.

** About 24% of energy generated is lost in transmission and distribution (see Section 5.5)

The financial value of each unit of energy lost for each sector can be considered a function of the retail price of electricity for that sector. The ratio of the value of each unit of energy lost to the retail price is referred to as the “VoLL multiple”. There are significant differences between the residential, commercial and industrial sectors that make it likely that their valuation of electricity would be different. For example, residential customers would lose the perishables in their refrigerators, but after that, their incremental loss is likely to be small, while commercial customers would likely continue to lose sales from their businesses in direct proportion to the number of days of the outages. VoLL multiples are unavailable for consumers in Ghana, therefore VoLL multiples for four different sectors estimated by Ofori-Atta, et al were used.⁵⁹

Next the value of a unit of electricity for each sector was calculated as the product of the retail price of electricity for the sector and the corresponding VoLL multiple. Table 6.2 shows

⁵⁸ Lost Load = 8,580 GWh * 1.4% = 120.1 GWh. This estimate assumes that power outages occur at times of average demand. In fact outages are more likely at higher demands, making the estimate conservative.

⁵⁹ Ofori-Atta et al, Profiting from Transmission Investment, Public Utilities Fortnightly, October 2004.

the retail electricity price for each sector and the resulting value per unit of energy. For each sector, the VoLL was then calculated as the product of the GWh lost for that sector and the corresponding value of a unit of electricity⁶⁰. The total value of lost load can be used as a measure of the cost to the economy of generation and transmission related outages.

Table 6.2 - Value per Unit of Electricity

Sector	VoLL Multiple Estimate	Retail Price (cents/kWh)	Value of Electricity (\$/kWh)
Residential	54	11.96	6.46
Commercial	82	11.96	9.81
Industrial	119	11.96	14.23
Other	100	11.96	11.96

Table 6.3 - Value of Lost Load

Sector	Impact of Outages in 2009 (GWh)	Value of Electricity (\$/kWh)	VoLL (US \$)
Residential	33.6	6.46	217.2
Commercial	13.2	9.81	129.6
Industrial	41.9	14.23	598.4
Other	2.4	11.96	28.7
Total			\$974m

Table 6.3 shows the estimated impact of outages in terms of lost load and economic damages by consumer segment in 2009. This method estimates that power outages could cost Ghana's residents, companies, and industries as much as US\$ 974 million each year, or approximately 6% of GDP. This VoLL-based estimate is significantly higher than the World Bank's sub-Saharan Africa estimate of 2% (which would translate to US\$ 320 million per year). One major reason for this is that Ghana's level of electrification is higher than the sub-Saharan average (see Table 6.4), and hence Ghana is much more reliant on electricity than many countries in the region. A second potential reason is that customers in areas with frequent outages are better prepared to operate without grid-based electricity (i.e. the effective VoLL multiple is lower than that shown in Table 6.2). Regardless, a range of US\$320 million to \$974 million annually is a significant amount of loss, especially compared to the level of investment in electricity generation and transmission infrastructure needed to prevent outages. US\$ 320 million, for example, is more than 6 years of GRIDCo's revenues under the existing tariff structure.

⁶⁰ The value of lost load varies with the tariff, which is in keeping with the fact that as electricity prices increase those customers who are willing to pay more (i.e. assign a higher value to electricity) will continue to use electricity while those who do not will reduce their consumption. Subsidies, such as those for lifeline tariff customers do not change the VoLL, but rather change the cost of electricity to some customers (i.e. the government and/or other consumers absorb some of the cost).

Another cost that the VoLL method does not capture is the additional investment made by private citizens and corporations in their own power infrastructure to combat the unreliability of the grid. Many business and households purchase their own small power generators, which are more expensive to purchase per unit of capacity and more expensive to operate per unit of energy than their commercial counterparts. This is because they a) cannot benefit from the economies of scale and cutting-edge technology that larger plants enjoy and b) operate at very low utilization levels. Small diesel generators, for example, cost between US\$ 800 and US\$ 1,500 per kW, which translates to US \$800,000, and US\$ 1.5 million per MW. This is 50% to 250% more expensive per unit compared to a natural gas turbine⁶¹. This suggests that there is a willingness to pay, at least for high-income residential, commercial, and industrial customers, for high quality and reliable electricity. However, customers are also typically reticent to pay increased tariffs without demonstrated improvements in the quality of service.

Table 6.4 - Comparison of Electrification in Africa

Country/Region	Electrification Rate (as of 2008)		
	Urban (%)	Rural (%)	Total (%)
Ghana*	85.0	23.0	54.0
Sub-Saharan Africa	57.5	11.9	28.5
North Africa	99.6	98.2	98.9
Africa	66.8	22.7	40.0

* As of March 2010, Ghana's total electrification rate is estimated by GRIDCo to be 65%.

** Source: Electricity Access in 2008: Africa, International Energy Agency, February 2010.
<http://www.iea.org/weo/database_electricity/electricity_access_database.htm>

6.2 Impact of Reliability on Economic Development

Electricity is a key infrastructural element for economic growth. It is a versatile “energy currency” that underpins a wide range of products and services that improve quality of life, increase worker productivity, and encourage entrepreneurial activity. A reliable and accessible electricity system is critical in enabling Ghana to meet its long-run economic development goals.

At the residential level, electricity can have positive impacts on education through better lighting, on productivity through more efficient process heating and cooling, and on health through reduced indoor air pollution and the refrigeration of foods. Better educated, more productive, and healthier workers are key building blocks of economic productivity.

Traditionally the commercial/industrial consumption of electricity in Ghana has been driven primarily by the primary sector (companies that deal with the extraction and transformation of resources, like the mines and VALCO). However, looking forward, reliable and widespread access to electricity will be key to the development and sustainment of the secondary (manufacturing) and tertiary sectors (services and information). These sectors are the key drivers of modern economies and hence critical to a robust, diversified economy with higher wages.

⁶¹ U.S. Department of Energy. <<http://www.fossil.energy.gov/programs/powersystems/fuelcells/>>

The aspirations of Ghana to achieve sustained economic growth and higher living standards can only be satisfied through sustained development of electric power markets as part of its basic infrastructure. In order to meet ever-increasing demand, timely investments in new power generation as well as transmission and distribution facilities are needed. An appropriate market structure is vital in terms of attracting private investment. The next chapter discusses how market structure and economic incentives influence reliability.

7 Economic Incentives for Investment

Deregulated electricity markets must balance the profit motives of utilities and IPPs, the quality of service and reliability requirements of system operators and regulators, and the price and reliability needs of end-use consumers. Healthy competition is key in achieving and maintaining this balance. The market structure must ensure that electricity is properly valued both on the supply side and on the demand side in order to avoid over production and over consumption (i.e. waste). This chapter discusses how the structures of tariffs and other economic incentives affect the attractiveness of markets for entry and plays a role in a healthy power market and ultimately a vibrant economy.

The challenge for regulators and market operators is to structure regulations and tariffs in wholesale markets such that they provide a) the right incentives to support investments in the appropriate amount and types of electricity supply and demand-side resources and b) the right signals to consumers about the value of power. New entry in particular is critical to maintaining reliability-oriented, competitive markets and preventing any one firm from exercising market power. Beyond encouraging investment, tariff structures must also encourage an appropriate mix of resources with the types of operating characteristics that allow the electricity system to be operated reliably and efficiently. Finally, tariffs must support a competitive market by encouraging existing market players to strive for operational efficiency improvements so that a lower cost of service can be achieved compared to a strict regulatory regime. Getting the wholesale price incentives right is thus fundamental to a bulk power system that operates at the lowest sustainable cost.

The approach taken to electricity pricing and its fundamental economics must balance public needs with a healthy industry and value chain – recognizing that in the medium to long term, flawed economics creates an unhealthy industry, and is not sustainable.

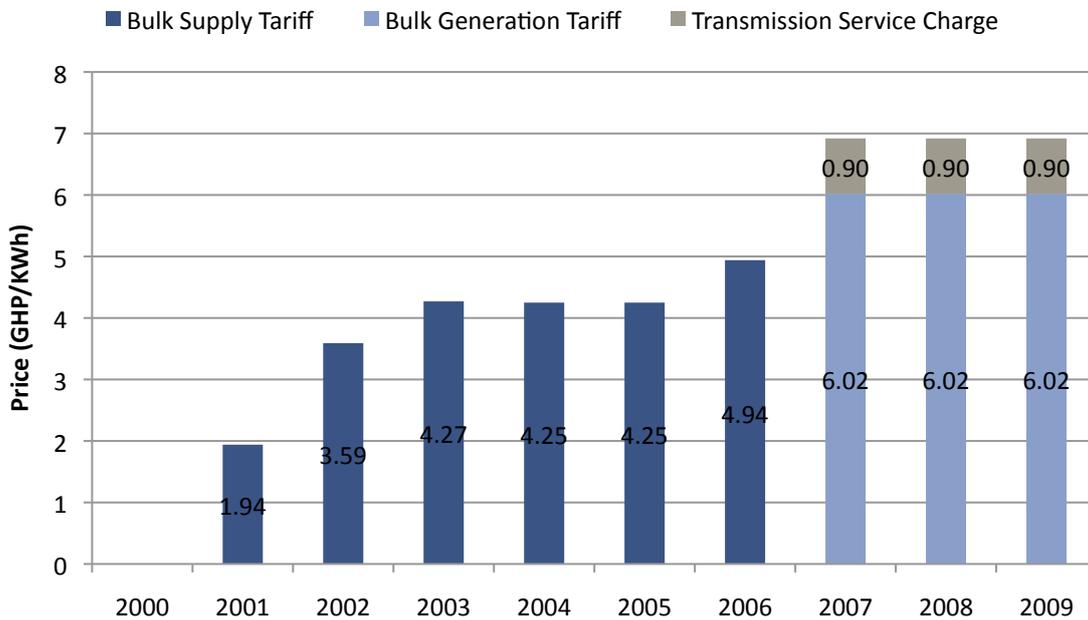
7.1 Ghana's Tariff Structure

Ghana's PURC sets electricity tariffs in consultation with key stakeholders including generators, distributors, and consumer representatives. The tariff is composed of two parts – the Bulk Supply Tariff (BST) and Distribution Service Charge (DSC) – that are summed to form the End User Tariff (EUT). The EUT is the retail price charged to the end user by distribution companies. This tariff applies equally to all customers, with the exception of “lifeline” customers who consume less than 50 kWh. These customers pay a low fixed rate commensurate with their means.

Ghana's tariffs are lower than the Sub-Saharan African average of US\$0.13 per kilowatt-hour, and are amongst the lowest in West Africa⁶². One contributing factor is Ghana's traditional reliance on hydroelectricity as its prime energy source. Hydroelectricity is characterized by high up front capital costs, and extremely low marginal production costs. Hence stakeholders in Ghana's power sector (consumers, regulators and politicians) are used to extremely low electricity costs.

⁶² Sarah Keener and Sudeshna G. Banerjee, Ghana: Poverty and Social Impact Analysis of Electricity Tariffs, ESMAP Technical Paper 088, December 2005.

Figure 7.1 - Bulk Power Tariffs, 2001-2008



* Source: *Ghana Energy Statistics*, Ghana Energy Commission, 2009.

There are several key issues with the existing tariff structure:

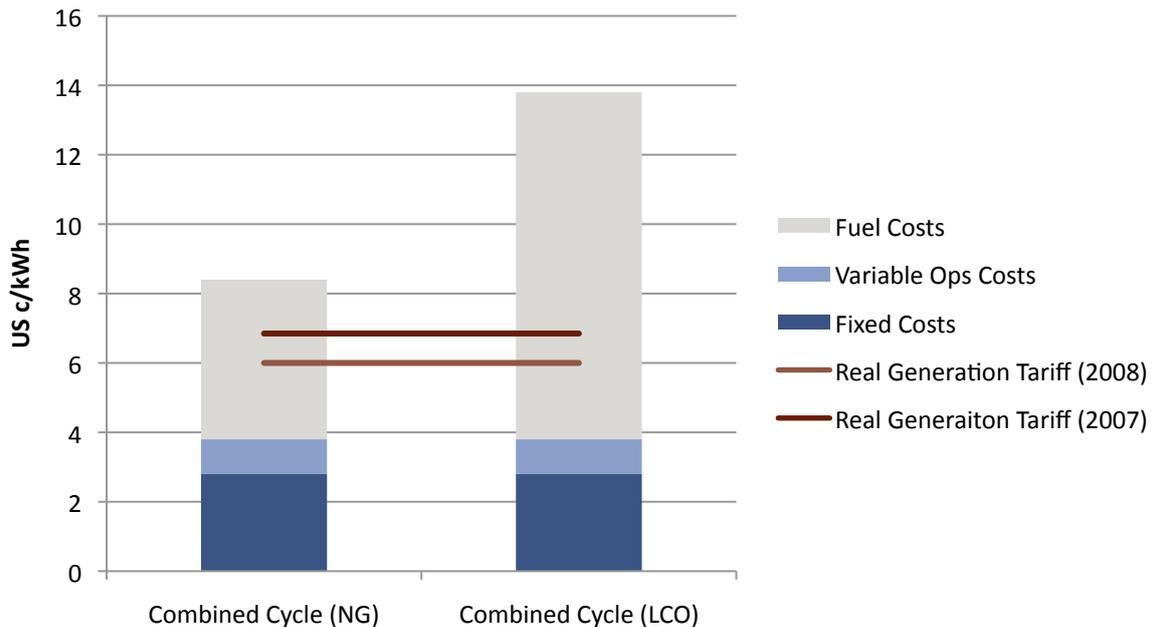
Pricing: The BST tariff is a weighted average of all generation sources, including imports, combined cycle thermal, simple cycle thermal, and hydro, combined with a margin designed to provide fair return on equity (RoE). This approach works in monopolistic markets because the public utility necessarily has a variety of generation technologies playing a variety of roles, which together produce electricity at or below the blended tariff. However, a deregulated generation market thrives on competition, and is hindered by any individual entity having too much market power. IPPs in a competitive market will each have a less diverse mix of generation types and will only produce when marginal revenue (i.e. the tariff) exceeds the marginal cost of production.

Currency Risk: The prices of generation and transmission capital equipment and infrastructure are typically defined in foreign currencies (USD, EUR, GBP, JPY, etc). Since Ghana experiences significant currency devaluation, the value of the Cedi (GHC) against major foreign currencies usually declines year-on-year. Hence a tariff set in GHC that is not frequently adjusted to account for local inflation and currency depreciation provides less real revenue on a year-on-year basis.

Inadequacy: The current tariff is inadequate to cover the true cost of operating thermal plants. Thermal plants have higher costs per kWh compared to hydroelectric plants, and are subject to volatility in fossil fuel prices. This problem is exacerbated in Ghana because of a lack of access to a stable supply of natural gas, a fuel that plays a critical role in making combustion turbine and combined cycle thermal plants economically viable. Between 2005 and 2008 the cost of crude oil on the global market increased significantly to the point that fuel cost of firing on crude oil became almost twice as much as that of firing on natural gas. Figure 7.2 shows the estimated costs of generation for a combined cycle plant operating on

natural gas and light crude oil in 2008. Given the current tariffs, a combined cycle plant like VRA's Aboadze facility, for example, would lose money on every single megawatt of energy produced, even when firing natural gas. When firing light crude oil, this loss would become enormous. VRA, as a public entity with a stated vision of generating and supplying electrical energy for Ghana, may absorb this loss for a variety of reasons. However, a private entity like an IPP would almost certainly not continue to produce power in a similar situation.

Figure 7.2 – Estimated Levelized Cost of Generation in 2008



* Real Generation Tariff based on assumed GHC to USD exchange rate of 0.95 in 2007, and 1.06 per in 2008

** Fuel costs assume light crude oil (LCO) price of US\$ 87 per barrel

Non-uniform application: New IPPs are often offered rates above BST in order to entice market entry, and these rates often include capacity charges, which provide revenue for being available. Not only does this practice implicitly recognize that the existing tariff is inadequate, it goes against the principle of unbiased market operation. Market participants like VRA that are subjected to the lower tariff, will be unable to support capital improvements and new infrastructure investments over the long run.

Incentives: The BST does not directly incentivize long-term reliability. In contrast, India's availability based tariff (ABT), for example, has incentives to promote reliability in the system. The ABT splits existing energy charges into three components – capacity charges (fixed), energy charges (variable), and UI (Unscheduled Interchange) charges. The capacity portion of the tariff rewards generators for having capacity available to help meet peak demand, thereby supporting reliability objectives.

7.2 Economics of Generation

To be self-sustaining, a generation utility must at least be able to recover its fixed and variable costs through tariffs over a plant's lifetime. Fixed costs include the levelized capital

costs and fixed operational and maintenance costs (e.g. general and administrative costs, salaries, financing, and property taxes). Variable costs are those incurred due to the operation of the plant, and they vary in magnitude and composition based on the type of plant.

As an alternative to a single-component tariff like the BST, many deregulated markets use a two-component tariff that addresses the fixed costs and variable costs of generation separately. The following sections cover **capacity payments**, which address fixed costs, and **production payments**, which address the variable costs. Together the two payments help attract entry (capacity payments) and help encourage production (production payments). This approach can help regulators better control the attractiveness of market entry and align private sector incentives with regulatory goals and consumer needs.

An Example of Payment Structure

The structure of compensation plays a large role in keeping salesmen motivated and productive, retaining existing salesmen, and attracting top quality applicants for open positions. For example, many sales jobs have compensation schemes that are a combination of salaries and commissions. A copier salesman may have a base salary of US\$500 per month and a commission of 10% sales. His or her total compensation would be the sum of the two components. The salesman's base salary is analogous to a capacity payment while his commission is analogous to a production payment.

7.2.1 Capacity Incentives

Capacity incentives give generators revenue simply for having an operational generation facility that can be dispatched on certain terms. Usually this value is derived based on the estimates and calculations of independent experts who thoroughly ascertain costs facing generation developers. Capacity incentives create a stable long-term generation market by offering existing plants stable revenue for being available to produce power. Additionally, when structured properly, it also helps ensure that there is a market-appropriate mix of peaking, mid-merit, and baseload generation in the long term. When set roughly at the cost of new entry, capacity payments also encourage new entrants and keep a healthy balance of market power in the capacity market.

Properly updating the level of capacity incentives is critical to sending accurate price signals to the market, encouraging competition, and supporting long-term reliability and facilitating investment. All of these ultimately benefit consumers. The capacity tariff is typically not a static value, but rather a dynamic value updated periodically to reflect market conditions and regulatory goals. In fact it is the key lever that regulatory bodies and independent system operators have to manage the rate of market entry and hence competitiveness of the market. Its use is analogous to a central bank's use of interest rates (e.g. the prime rate in the US or LIBOR in the UK) to try to manage inflation. A capacity tariff that is set too high will encourage the construction of too much generation and likewise a capacity tariff that is set too low will not incentivise enough generation.

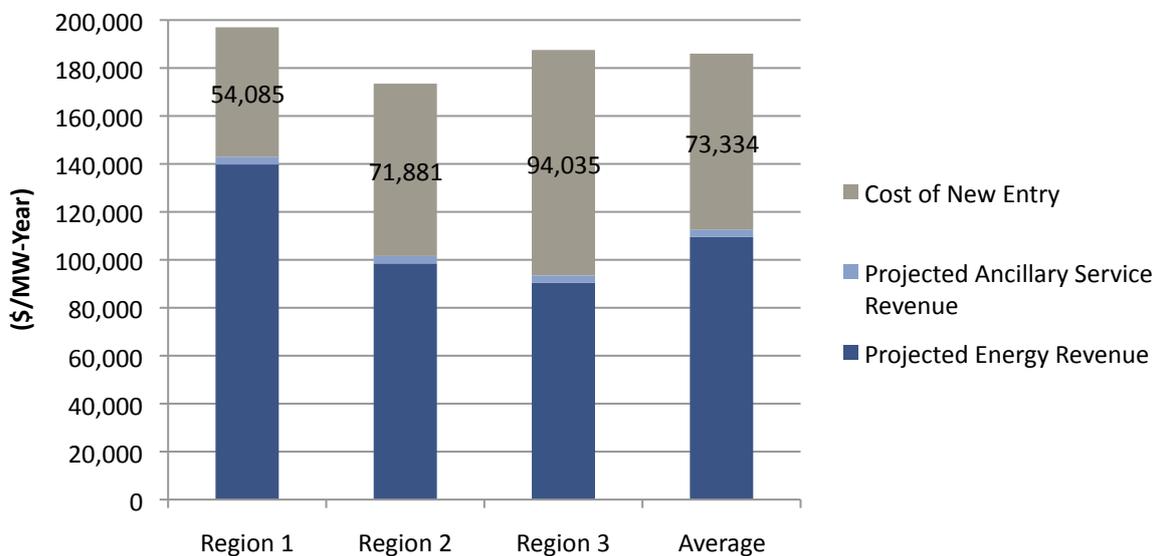
The PJM Interconnection market, which covers 13 states in the eastern part of the United States, provides an example of how capacity prices are used to manage a competitive bulk power market. In PJM, the capacity component is set at the cost of new entry (CONE), which is defined as the capital costs of installing a new plant less the infra-marginal revenues

that a new unit can expect to recover from producing energy. Figure 7.3 shows the cost of new entry for gas turbine and combined cycle plants in three different regions (roughly these correspond to the northeastern, southern, and western portions of the market) as calculated by PJM. The inter-regional differences shown are a result of inherent differences in property prices, construction labour costs, permits costs, and other factors. It also shows that the estimated CONE varies significantly between a gas turbine plant and a combined cycle plant. This is because while combined cycle plants may have higher revenue requirements than gas turbine plants, they also have much higher expected energy revenues since they operate earlier in the dispatch curve and have higher capacity factors.

Entering the Generation Market

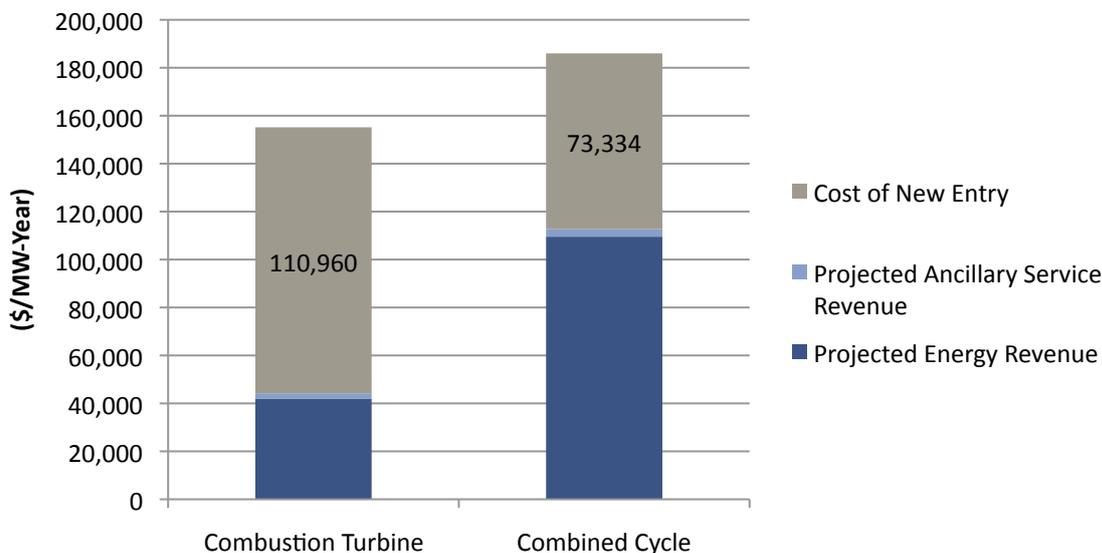
A new entrant must incur significant capital costs to bring a generation facility online. These include the cost of obtaining permits, purchasing land, financing and executing construction, generation hardware (e.g. a gas turbine or steam turbine), water and sewage interconnections, and mobilization and startup costs at completion. These costs are linked to market prices, inflation, supply constraints, and site-specific details. For example, a regional construction boom may drive up the prices of common infrastructure materials like steel and concrete, which generation facilities also depend on. Or the worldwide cost of generation hardware may increase if China and India accelerate the pace of power generation capacity building programs. In addition to capital costs, there are a variety of fixed costs associated with the operation and maintenance of plants. These include general and administrative costs, operator salaries, insurance, and property taxes.

Figure 7.3 - PJM Cost of New Entry for Combined Cycle Plant (2012 Estimate)



* Source: PJM Capacity Market Evolution Committee, "Net CONE Methodology", October 2008.

Figure 7.4 - PJM Average CONE for Different Technologies (2012 Estimate)



* Source: PJM Capacity Market Evolution Committee, "Net CONE Methodology", October 2008.

7.2.2 Production Incentives

Production payments address the variable costs of producing electricity. Baseload plants typically have higher capital costs per unit of energy produced, but lower operational costs. Hence the owner or operator of a baseload plant has the incentive to produce as much as possible. In contrast, peaking plants have lower capital costs per unit of energy produced, but higher operational costs. Hence the owner of a peaking plant has the incentive to produce when supply is constrained and bulk power prices are highest. Mid-merit plants fall in between these two extremes. For thermal plants, from baseload to peaking, the cost of fuel dominates the other variable costs such as maintenance and operations. For hydroelectric plants the cost of fuel (i.e. water) is essentially negligible and operations and maintenance are the dominant components. See Table 7.1 for a comparison of the estimated levelized costs of various generation technologies.

The value and structure of tariffs determines not only market entry, but also when and how much existing plants generate. It is critical that production tariffs are set fairly and updated frequently in order to take into account the actual market conditions and not just the nominal conditions. This is especially true for thermal plants because of their cost structures, which are biased towards operational costs. For example, many of Ghana's thermal facilities are capable of running on either natural gas (NG) or light crude oil (LCO). While technologically the difference is minimal, economically it is significant because thermal plants typically have much lower fuel costs (and consequently operational costs) when firing natural gas than when firing LCO. Tariffs set based on the assumption of natural gas will lead to significant losses for affected thermal plants. Over time, producers will not have sufficient revenues to invest in maintenance and operational efficiency measures, which will actually drive their costs up over time and reduce reliability.

As Ghana continues to develop its free market in generation, and the number of IPPs and their share of the generation load increase, it is critical that tariffs are set carefully to ensure their continued participation and the continued entry of new parties.

Table 7.1 - Estimated Levelized Cost of New Generation Resources

Plant Type*	Nominal Capacity Factor (%)	Levelized Costs (US\$/MWh)		
		Capital Cost	Fixed O&M	Variable O&M
Conventional Combined Cycle	87	22.9	1.7	54.9
Advanced Combined Cycle	87	22.4	1.6	51.7
Conventional Combustion Turbine	30	41.1	4.7	82.9
Advanced Combustion Turbine	30	38.5	4.1	70.0
Hydro	51.4	103.7	3.5	7.1
Wind	34.4	130.5	10.4	0.0

* Combined cycle and combustion turbine plants are assumed to be gas-fired

Source: *Annual Energy Outlook 2010*, United States Energy Information Administration, December 2009.

7.3 Economics of Transmission

In Ghana, a fully unbundled transmission system operator, GRIDCo, owns and operates transmission assets. This approach has a number of precedents in the electricity sector in Europe (for example the United Kingdom) and around the world. To be self-sustaining, a transmission system operator such as GRIDCo must be able to at least recover its fixed and variable costs through tariffs over the lifetime of its infrastructure. The challenge is how to properly incentivize and reward investment.

In the US, investment in transmission is recovered through an annual revenue requirement, which is designed to cover debt service payments and provide a rate of return. The annual revenue requirement is recovered through transmission service charges to transmission customers. In addition to the transmission service charge, transmission customers (e.g. mines, large industries, and electricity distribution companies) pay additional charges for various services and products that permit the safe and reliable transfer of power from one point of the network to another. Transmission customers pay a service charge for the scheduling, dispatch and system control function of the system operator; another charge for each ancillary service, such as voltage support, operating reserves and regulation; and a service charge for the system operator's administrative function and industry regulation.

Like generation tariffs, transmission tariffs can also be multi-part. Transmission tariffs in Europe, for example, typically have a fixed charge component, a capacity component, and an energy component. The capacity component is, as with generation, meant to incentivize the construction of transmission infrastructure. The energy component charges for actual use of the transmission network. The split between the capacity and the energy components of the transmission tariff in the different countries varies significantly; however in most countries energy-based charges represent about 50% of the total tariff⁶³. Another facet of transmission tariffs is geographic differentiation. Some markets use geographic

⁶³ Ignacio J. Pérez-Arriaga, et al. *Benchmark of Electricity Transmission Tariffs*, Prepared for the Directorate-General for Energy and Transport / European Commission, October 2002.

differentiation in the energy charges to include the effect of losses, and in the capacity payments in order to send long-term economic signals for efficient location.

Finally, there is the issue of the allocation of tariffs between the demand side and the supply side. Both generators and distributors (or direct transmission customers) need the transmission network to be able to sell and consume electricity, respectively. The challenge is to determine how the costs of transmission should be allocated between the two parties. Charging consumers ensures that the true cost of electricity is captured, and sends a price signal to consumers to adjust their demand accordingly. Charging generators for interconnections to the transmission grid provides incentives for new generators to consider both the transmission cost and congestion impacts of their site options. On the other hand, transmission charges to generators can potentially make market entry less attractive. Globally there is a wide range of approaches to making these allocations, driven by the unique dynamics of each market, although transmission costs tend to be allocated toward the consumer. For example, in Norway 35% of the transmission tariff is charged to the generator while in France only 2% is charged to the generator.

Given that 8,579 GWh of bulk energy was delivered through its transmission lines in 2009, GRIDCo would have earned around GHC 77 million (US\$ 54 million) in transmission revenue at the nominal tariff of 0.9 GHP/kWh⁶⁴. This revenue would have to support all transmission investments, operations and maintenance, general and administrative costs, and also provide for an RoE for the company. Table 7.2 shows the PSEC-estimated equipment replacement value (ERV) of GRIDCo's existing infrastructure to be approximately US\$1.03 billion. If one assumes that transmission infrastructure investment must match the growth in demand (5.5% annually) in a roughly linear fashion, the revenue requirement for GRIDCo to add new infrastructure to match growth alone is on the order of US\$50 million⁶⁵. On top off this must be added the cost of maintaining existing infrastructure, which typically ranges from 2-3% of ERV⁶⁶. This translates to US\$20-30 million for maintenance. Hence we estimate the revenue requirement of GRIDCo to be on the order of US\$70-80 million; the current revenue of US\$54 million falls significantly short of this estimate. Due to currency devaluation, this shortfall will increase year-on-year without tariff adjustments.

Table 7.2 - Estimated ERV of Transmission Infrastructure

Item (unit)	Cost per km*	Length (km)	Equipment Replacement Value (ERV) (US\$ millions)
161 kV Line	\$242,000	4038	977.0
225 kV Line	\$567,000	73.4	29.6
69 kV Line	\$177,000	132.8	23.5
Total Line Infrastructure			\$1,030.3

* Based on estimates from "10-Year Transmission Assessment", American Transmission Company, September 2003.

⁶⁴ GHC 0.009/kWh = GHC 9,000/GWh; 8579 GWh * GHC 9,000/GWh = GHC 77 million.

⁶⁵ Estimated Investment = ERV * Growth rate = US\$1,030 million * 5.5% = US\$56.7 million

⁶⁶ Benchmark derived from: *State of the Energy Market 2009*, Australian Competition and Consumer Commission, 2009.

Hence, the current transmission tariff is insufficient for a nation with electricity demand growing as rapidly as Ghana. Over time, this is likely to lead to chronic underinvestment in the maintenance and expansion of the system, especially given the high cost of transmission infrastructure.

7.4 Social Impact of Tariffs

The aspirations of Ghana to achieve sustained economic growth and higher living standards can only be satisfied through sustained development of electric power markets as part of their basic infrastructure. Electricity is a key infrastructural element for economic growth. It is a versatile “energy currency” that underpins a wide range of products and services that improve quality of life, increase worker productivity, and encourage entrepreneurial activity. Hence, a reliable and accessible electricity system is critical in enabling Ghana to meet its long-term economic development goals.

There is no doubt that sustainable tariffs are key to maintaining a healthy and reliable bulk power market both in the short term and long term. However, that objective must be balanced with the social impact of electricity prices in a developing nation. Higher prices reduce the viability of using electricity as a primary energy source for many. One way to achieve a balance of both objectives is to set tariffs based on the economic realities and to reflect the true cost of the product (generation and transmission) and the cost of services needed to deliver the product, and then implement targeted subsidies for needy socioeconomic groups.

8 Conclusion

In this report we have reviewed the operating status of Ghana's power system with a focus on the adequacy and security of the existing wholesale power supply system for the 2010 operating year. Projections of the expected demand in 2010 have been compared to estimates of unforced generation and available transmission capacity to determine if the supply resources for 2010 will be adequate to reliably supply the anticipated demand. Risk factors associated with both demand and supply resources have also been examined.

Based on our assessment, Ghana's bulk electric system is likely to face generation and transmission capacity shortfalls unless significant and timely investments are made in both generation and transmission resources. This chapter summarizes the key reasons for this conclusion and recommends steps that Ghana can take to provide a reasonable level of energy assurance in 2010 and future years.

8.1 Overview

The last decade brought tremendous growth in demand for electricity in Ghana. Excluding VALCO's forced curtailment, cumulative peak demand growth and energy demand growth were 44.6% and 100.7%, respectively. This growth was driven largely by economic growth, the continuing trend of urbanization in Ghana, and increased industrial activity. VALCO's curtailments, beginning in 2003, were in response to power shortages caused by low water levels at Akosombo (Ghana's largest generation facility). This extreme action, which reduced both demand and energy consumption by 20 to 30% each, masked significant deficits in investment in power generation and transmission relative to growth, and allowed the electricity system to better absorb the skyrocketing demand. Even so, Ghana continues to experience power system unreliability issues that are estimated to cause direct economic damages on the order of US\$320 million to \$974 million annually.

The ability of the current electricity system to meet the minimum required reliability standards is threatened by a number of factors, including:

- **Inadequate Reserve Margins:** Ghana has a low reserve margin based on unforced generation capacity. The reserve margin has averaged 7.1% over the last decade and it is currently at 6.9%. The industry standard minimum reserve margin for reliable operation is 15% and many countries including the United States, Mexico, and Indonesia operate at reserve margins greater than 25%. Simply put, this means that unless technical conditions are ideal or near ideal, Ghana does not have enough generation capability to deliver the power users demand.
- **Fuel Supply Risk:** As of 2009, Ghana's electricity system was 60% dependent on hydroelectric generation and 40% on thermal generation. The high dependence on hydro, and subsequently the hydrological cycle of the Volta River system, creates power shortages when low rainfall levels fail to replenish the Akosombo reservoir. Ghana's heavy reliance on the single hydrological cycle of the Volta river system exposes the generation system to significant capacity risk. Thus, for long-term planning purposes, GRIDCo will appropriately discount the capacity contribution from the hydro power plants especially when counting capacity that contributes to meet peak demand and reserve margin. Similarly, Ghana's reliance on a single gas supply source (WAGP) could also pose significant capacity risks in the event of gas

unavailability from the WAGP. GRIDCo as the entity responsible for supply reliability and the generation companies that rely on gas must explore other gas supply options to improve gas supply reliability. In the short term, GRIDCo should require all gas-only power plants to maintain a minimum amount of gas supply onsite to cover a minimum number of days of power production.

- **Inadequate Transfer Capability:** There is a lack of adequate firm transfer capability to deliver power from generation sites like Akosombo and Aboadze to the major load centres of Accra, Tema, and Kumasi, which cumulatively account for nearly 50% of national demand but only 12% of installed generation capability. Existing transmission facilities are overburdened and hence constrain system operators' ability to operate the grid in accordance with good utility practice. Again unless technical conditions are ideal or near ideal, Ghana will not have enough transmission capacity to deliver power from generation resources to satisfy users demand.
- **VALCO Operations:** VALCO potential demand continues to represent a large fraction of the total system demand. VALCO operation at 4 potlines would increase peak demand in 2010 by 320MW or approximately 20%. The result of this would be a drop in the projected 2010 reserve margin from 15% to -13%.

The challenge for Ghana's electricity sector is to address these problems in the face of incessantly robust growth in demand, which will continue to be driven by robust economic growth, urbanization, industrial growth, and now the development of an a petroleum services sector in response to the discovery of oil off Ghana's coast. Additionally, VALCO is scheduled to restart operations in the near future, reversing its shock absorber effect and adding further demand to a rapidly growing base. Hence it will be critical to add generation and transmission capacity to first stabilize system performance and then improve over the coming years.

8.2 Next Steps

In large part the electricity sector in Ghana has recognized the challenge ahead and has taken steps to meet it. A new generation project in Kpone will add 200 MW, or an additional 10%, of installed generation capacity to the system. Projects from 2011 to 2014 will add an additional 1005 MW for a total of 1,205 MW over the next four years. To put that into context, that is more capacity than Akosombo and Kpong combined. New transmission projects in 2010 will add additional transfer capability to deliver power to the urban areas of Accra and Kumasi. Other transmission projects will address power quality issues; these include the addition of static VAR compensators and capacitor banks that will improve the availability of reactive power at critically low voltage substations. But progress remains finely balanced, and the electricity sector must remain vigilant to stay on the path to reliability.

Because generation and transmission projects typically take 2-6 years to plan and execute, improving reliability will require sustained focus on investment in transmission and generation in 2010 and from 2011 to 2014 in order to be better prepared for contingencies in the short term, and to ensure reliability beyond 2014.

The current slate of generation projects is likely to improve the reserve margin, but a number of contingency scenarios show that the system is still at risk. The issues of fuel risk, water shortages, and plant delays could once again leave the reserve margin razor thin and place

Ghanaians at risk of power failures. A critical short-term risk is the impoundment of the Black Volta River flow that is part of the process of constructing the Bui Power Plant. This could expose up to 18% of the water supply to Akosombo at risk until the scheduled completion of the project in 2013. A second short term risk is the potential delay of generation plants; a one year delay on any generation project will threaten the reserve margin for that year, and multiple delays or a cancellation will make it difficult if not impossible for Ghana to achieve the 20% reserve margin target estimated in this report.

The current set of transmission projects must also be supplemented. Additional investments must be made to increase the transfer capability across Ghana's key transmission corridors and at the bulk power distribution substations. Specifically, load centres need more transformer capacity to handle unplanned outages without the need to shed load.

Because the wholesale power generation and transmission system remains below the minimum desired reliability level, and could potentially remain so for at least the next few years, we believe that it will be critical to conduct a number of detailed studies:

1. An explicit loss-of-load expectation study that will be used to establish an official generation reserve margin for the Ghana wholesale power supply system. This study must consider factors such as the loss of load probability and quantify the systemic risks identified. The outcome of this study will be used to determine adequate levels of generation capacity needed to meet acceptable reliability levels going forward.
2. A continuous assessment of the available transfer capability of the transmission system under varying system conditions. This continuous assessment will be used to identify new projects to add transmission capacity to the network.
3. Develop remedial action schemes for system operators to enforce transmission limits in accordance with good utility practice.
4. Strategies for the design and implementation of demand side management programs, which can help shape demand patterns to improve reliability.
5. An analysis of the impact of the oil find on power requirements, including both the direct impact on demand from commercial and industrial activity, and the possible indirect impact on demand from economic growth and GDP per capita

These studies will provide a better understanding of the system that can be used to develop more targeted and precise operational procedures and maximize reliability through operational performance.

8.3 An Evolving System

Ghana's electricity sector is evolving on several fronts. Based on the scheduled generation projects, the majority (51%) of Ghana's generation capacity will be thermal by 2015. This means that over just 10 short years, Ghana would have transitioned from a hydro dominated generation sector to a thermal dominated one. Hence policymakers, regulators, stakeholders and the general public must recognize that the economics of thermal generation are fundamentally different from hydro. Thermal generation has comparatively lower fixed costs but significantly higher variable costs due to the use of relatively expensive fossil fuels. Moreover, thermal generation has significantly more operational complexity than hydroelectric generation, meaning that operational efficiency and capital maintenance are absolutely critical to keeping costs down.

Looking forward, addressing fuel supply risk will be critical to a reliable power sector. The Bui Power Plant will add much needed generation to the northern part of the country. However, because it relies on the same hydrological system as Akosombo and Kpong, Ghana's other hydroelectric facilities, it compounds the risk water shortages present to the electricity system. Likewise, fuel supply risk for thermal plants is a concern. With the increasing dominance of thermal generation, the accessibility and security of natural gas will become the primary risk to the power system over the next 5 years. While most of the existing and planned thermal plants are capable of using multiple fuels, they are significantly cheaper to operate and more reliable when operating on natural gas. Without natural gas, thermal generators and subsequently tariffs will be susceptible to fluctuating crude oil prices on the world market.

Finally, Ghana continues to be in the process of transitioning from a regulated, vertically integrated monopoly to an unbundled sector with a mix of private and public participation. Market structure and proper economic incentives are critical to achieving this transition smoothly and achieving the desired end state of a competitive, reliable power sector with sustainable tariffs for both suppliers and consumers. Ghana's rapidly growing demand for electricity will require significant private investment – first in generation, and eventually in transmission as well. Market structure and economic incentives play a key role in attracting IPPs and private transmission investors.

As private participation grows to 30% by 2015, and possibly to 50% and beyond by 2020⁶⁷, a tariff structure that provides adequate returns that enable generation and transmission utilities to invest in maintenance, capital expansion, and operational improvements is critical. In the long term, this should help encourage the competition and operational efficiency needed to foster a healthy deregulated market. Moreover, tariffs must be sustainable for a more basic reason – to keep the lights on; it must be recognized that private parties are under no obligation to produce power at a loss, as VRA has often done in the past.

⁶⁷ Assuming the private sector retains its 70% share in new generation projects beyond 2015

Appendix A Transmission System Transfer Capabilities

Table A.1 - Non-Simultaneous Firm Transfer Capabilities

Source	Sink	TTC	Limiting Element	Contingent Element
Tema	Accra	228	161/34.5 kV Achimota Transformer 5	161/34.5 kV Achimota Transformer 4
Accra	Central	0	161 kV Cape Coast to Aboadze Line	161 kV Achimota to Mallam Line
Central	Accra	0	161/34.5 kV Achimota Transformer 4	161/34.5 kV Achimota Transformer 5
Accra	Western	0	161 kV Nkawkaw to Tafo Line	161 kV Akwatia to New Obuasi Line
Western	Accra	0	161/34.5 kV Achimota Transformer 4	161/34.5 kV Achimota Transformer 5
Central	Western	0	161 kV Nkawkaw to Tafo Line	161 kV Akwatia to New Obuasi Line
Western	Central	0	161 kV Takoradi to Aboadze Line	161 kV Takoradi to Aboadze Line
Western	Obuasi	39	161 kV Takoradi to Tarkwa Line	161 kV Prestea to Aboadze Line
Obuasi	Western	125	161 kV Dunkwa to Bogoso Line	161 kV Dunkwa to New Obuasi Line
Obuasi	Eastern	0	161 kV Nkawkaw to Tafo Line	161 kV Akwatia to New Obuasi Line
Eastern	Obuasi	0	161 kV Takoradi to Tarkwa Line	161 kV Prestea to Aboadze Line
Eastern	Ashanti	55	161/34.5 kV Kumasi Transformer 4	161/34.5 kV Kumasi Transformer 3
Ashanti	Eastern	0	161 kV Nkawkaw to Tafo Line	161 kV Akosombo to Kumasi Line
Obuasi	Ashanti	0	161/34.5 kV Kumasi Transformer 4	161/34.5 kV Kumasi Transformer 3
Ashanti	Obuasi	0	161 kV Takoradi to Tarkwa Line	161 kV Prestea to Aboadze Line
Ashanti	Northern	112	161/36 kV Sunyani Transformer	None
Akosombo	Tema	201	161 kV Nkawkaw to Tafo Line	161 kV Akwatia to New Obuasi Line
Akosombo	Eastern	178	161 kV Akosombo to Tafo Line Circuit 1	161 kV Akosombo to Tafo Line Circuit 2
Akosombo	Ashanti	30	161 kV Akosombo to Tafo Line Circuit 1	161 kV Akosombo to Tafo Line Circuit 2
Obuasi	Northern	0	161 kV Nkawkaw to Tafo Line	161 kV Akwatia to New Obuasi Line

Table A.2 - Non-Simultaneous Non-Firm Transfer Capabilities

Source	Sink	TTC	Limiting Element	Contingent Element
Tema	Accra	446	161/34.5 kV Achimota Transformer 5	None
Accra	Central	139	None	None
Central	Accra	41	161/34.5 kV Achimota Transformer 5	None
Accra	Western	139	None	None
Western	Accra	43	161/34.5 kV Achimota Transformer 5	None
Central	Western	139	None	None
Western	Central	139	None	None
Western	Obuasi	120	161/11.5 kV New Obuasi Transformer	None
Obuasi	Western	365	161 kV Dunkwa to Bogoso Line	None
Obuasi	Eastern	7	161 kV Nkawkaw to Tafo Line	None
Eastern	Obuasi	118	161/11.5 kV New Obuasi Transformer	None
Eastern	Ashanti	228	161/11.5 kV Konongo Transformer	None
Ashanti	Eastern	9	161 kV Nkawkaw to Tafo Line	None
Obuasi	Ashanti	39	161/34.5 kV Kumasi Transformer 3	None
Ashanti	Obuasi	36	161/11.5 kV New Obuasi Transformer	None
Ashanti	Northern	112	161/36 kV Sunyani Transformer	None
Akosombo	Tema	829	161 kV Tema to Mines Reserve Line	None
Akosombo	Eastern	309	161 kV Nkawkaw to Tafo Line	None
Akosombo	Ashanti	124	161/34.5 kV Kumasi Transformer 4	None
Obuasi	Northern	47	161/36 kV Sunyani Transformer	None

Table A.3 - Simultaneous Firm Transfer Capabilities

Interface	TTC	Limiting Element	Contingent Element
Accra Import	219	161/34.5 kV Achimota Transformer 5	161/34.5 kV Achimota Transformer 4
Ashanti Import	72	161 kV Akosombo to Tafo Line Circuit 1	161 kV Akosombo to Tafo Line Circuit 2
Central Western Import	39	161 kV Cape Coast to Aboadze Line	161 kV Achimota to Mallam Line
Central Western Export	0	161 kV Takoradi to Tarkwa Line	161 kV Prestea to Aboadze Line
Western Export	36	161 kV Takoradi to Tarkwa Line	161 kV Prestea to Aboadze Line

Table A.4 - Simultaneous Non-Firm Transfer Capabilities

Interface	TTC	Limiting Element	Contingent Element
Accra Import	437	161/34.5 kV Achimota Transformer 5	None
Ashanti Import	274	161/34.5 kV Kumasi Transformer 4	None
Central Western Import	462	161 kV Dunkwa to New Obuasi Line	None
Central Western Export	291	161 kV Nkawkaw to Tafo Line	None
Western Export	453	161 kV Nkawkaw to Tafo Line	None