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GEORGIA RESOURCE ADEQUACY STUDY

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ACRONYMS

Cal-ISO	California Independent System Operator
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
DER	Distributed Energy Resources
ERCOT	Electric Reliability Council of Texas
EU	European Union
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rate
GRAM	Georgia Resource Adequacy Model
GSE	Georgian State Electrosystem
GWh	Gegawatt Hour
HPP	Hydro Power Plant
IOU	Investor Owned Utility
ISO	Independent System Operator
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MISO	Midwest Independent System Operator
MW	Megawatt
MWh	Megawatt Hour
NEM	Australian National Electricity Market
NEPOOL	New England Power Pool
NERC	North American Reliability Council
NYISO	New York Independent System Operator
PJM	Pennsylvania, New Jersey, Maryland
PRM	Planning Reserve Margin
RA	Resource Adequacy
ROR	Run of River
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TPP	Thermal Power Plant
US	United States
USAID	United States Agency for International Development
WASP	Wind Atlas Analysis and Application Program

CONTENTS

EXECUTIVE SUMMARY

This report summarizes a Resource Adequacy (RA) study performed for Georgia's electric power system. RA is an electric utility planning process that ensures supply of electricity to customers at a level of reliability they can afford to pay for. RA can also be thought of a risk mitigation measure to balance extremely high cost of electricity interruptions with the cost of building new generation for uninterrupted supply. There are four major components of this study:

- Introduction and a review of international RA practices (mostly US);
- Discussion of data requirements for a RA study and the relevant data for Georgia;
- Description of Georgia Resource Adequacy Model (GRAM) developed to carry out the study;
- Discussion of results, scenarios and recommendations.

RA studies are performed to estimate how much supply side resources will be needed to meet future electricity demand during the next month, next year or four to five years into the future. RA of a system is measured by various indices like: Planning Reserve Margin (PRM – ratio of additional supply relative to the peak demand expressed as a percentage of peak demand), Loss of Load Hours (LOLH – expected number of hours of supply shortages in a year), Loss of Load Probability (LOLP – probability of power supply shortage in a year), or the Expected Unserved Energy (EUE – amount of energy curtailed due to shortages). Typical values of these RA indices for some developed power markets are:

- PRM — 10–16% (US);
- LOLH — 2.4 hours per year or one day (24 hours) in ten years (US), 3–8 hours in EU;
- LOLP — 0.05 to 0.1 per year or one day outage in ten to 20 years (US);
- EUE — 0.002% of the total energy served (Australia).

This study uses GRAM to estimate values of these RA indices for Georgia's power system for the year 2024. Data used in this study includes:

- Electricity demand forecast;
- Operational and reliability characteristics of Georgia's power generation fleet;
- Forecasted hydro generation;
- Availability of supply from neighboring systems;
- Assessment of how many planned new power plants will be built by 2024.

The data was received from Georgian State Electrosystem (GSE) under a confidential agreement. GSE has developed three different load growth forecasts. We used low and medium growth cases. For the supply side data, we used GSE's tradition to assume that 25% of all the generation projects in various planning stages will be built for the base scenario and only 10% will be built for the pessimistic case. Based on the historical hydro flows, we assumed that the drought year will have 10 percent less energy production relative to an average year. Based on these data, we developed 16 scenarios to cover a wide range of uncertainties inherent in a future year forecast.

GRAM is a spreadsheet based hourly chronological simulation model that mimics the hourly operation of Georgia's power system in 2024. Since Georgia has plenty of hydro resources available during the summer months and the peak demand occurs in winter, RA analysis was only performed for the winter months of December, January and February. Basically, GRAM compares available supply from all resources (thermal, hydro, wind and imports) with the expected load every hour for the winter months of December, January and February (31+31+28 = 90 days or 2,190 hours). Monte Carlo simulation method is used to model the randomness in the supply system availability with 1,000 random draws. Simulation results were produced as values of various RA indices: PRM, LOLH, LOLP and EUE.

One of the key findings of the study is that RA can only be ensured with local resources. Based on the international practices, we recommend Georgia should only count on imports for up to 3% of its peak demand (about 75 MW) for RA purposes. Actual imports (or exports) in any hour could be much higher due to economic interchanges, but the reliance for RA should be limited to 75 MW.

The study also finds that Georgia should plan for about 8–10% PRM and 10–12 hours of LOLH per year. 10% PRM means that for every 100 MW of expected peak demand, 110 MW of generation should be available at the time of peak. While thermal resources are available at full capacity at all the times, hydro and wind resources are only available at 30–40% level during the December evening hours when annual peak occurs. This means, for every 100 MW of incremental peak demand, Georgia should be building 110 MW of thermal or 270 MW of wind or about 350 MW of Hydro.

To meet the RA criteria discussed above, Georgia will need to build about 650 MW[1] of additional thermal generation or equivalent effective capacity of hydro, wind, or other sources of energy or mix of those resources to meet December 2024 peak demand of 2,638 MW as forecasted by the GSE in its low demand growth scenario (3.36% annual growth rate). If the load growth is expected at GSE's growth scenario of 5.19% per year, an additional 300 MW of generation will be needed to meet the peak demand of 2,936 MW in 2024. This generation will need to be built in addition to building 25% of all the hydro, wind and solar projects currently under various stages of development.

Results from various scenarios show the risks associated with the recommended plan. For example, if all the resources are built as planned and 2024 happens to be a drought year (with 10% less hydro energy), the expected LOLH will go up 3 times. Similarly, if the projects under development are delayed and only 10% of the projects are completed by 2024, LOLH will be about 3 times the base case due to the lower capacity available to meet peak demand.

[1] Additional 650 MW includes 250 MW of Combined Cycle Gas Turbine (CCGT) that is planned to be commissioned in 2020. Therefore, 400 MW additional new thermal capacity will be needed.

INTRODUCTION

Electricity is an essential commodity for public welfare and safety. Inadequate electricity supply can disrupt public life and if it happens routinely, it can curtail economic growth. Common electricity outages are caused by disruptions in the “delivery system”, i.e., transmission and distribution network. Delivery system problems are typically localized and impact a small number of customers. The problems in the “supply system”, i.e., generation system, due to inadequate supply can be more sustained and may have major political and economic ramifications. Typically supply system shortages are experienced by utilities facing hyper demand growth or heavy reliance on a single source of generation. For example, many developing countries face rapid electricity demand growth as the economies expand, but the supply system expansion can’t keep up due to capital shortages or the long time required to plan and build new generation capacity. Countries like Georgia or Brazil with heavy reliance on hydrogeneration can also face supply shortages during drought years.

Electric utility planners use a planning process called “Resource Adequacy” (RA) to ensure enough power supply is available to meet customer demand in future years under all reasonable demand and supply growth scenarios. For predominantly thermal systems, this means there should be enough installed capacity and fuel available to meet demand every hour of a future year. For hydro dominated systems, this means there should be enough water left in reservoir(s) after the rainy season to sustain a steady level of power generation. If water storage system is not large enough to hold water for the remainder of the year, RA requires installing enough backup thermal generation or establishing firm transmission contracts with neighboring systems to import power during the dry season. Hydro dominated systems are also referred to as capacity rich and energy poor. When the reservoir level drops after water drawdown, machine capability (capacity) is still there but the head (water level) is not high enough to produce energy at the full capacity, hence capacity rich and energy poor.

In order to serve all the customer load in a future year, Resource Adequacy refers to having sufficient resources:

- Generation;
- Distributed Energy Resources (DER – generation at customer side, demand response programs, battery storage, etc.);
- Import Capacity of the Transmission System.

RA ensures the availability of enough effective generation capacity[2] to meet a utility’s load obligations during the full year. If the firm load obligations (customer demand after shutting any interruptible load) exceed the instantaneous generating capability of a system at any time, some firm load customers will experience a supply cut. This is a load shedding event. While it is impossible to *totally eliminate* the possibility of load shedding, it is possible to minimize the probability of such an event. Most North American utilities plan their systems to allow *one* outage in ten years. This is referred to as 1-in-10 Resource Adequacy criteria and defined as one outage or one day outage in ten years. Utilities in the Pacific Northwest US which rely heavily on hydro resources, use a more stringent criteria of 1-in-20 years. Pacific Northwest defines 1-in-20 as one bad (drought) year every 20 years which may have several outages as opposed to thermal systems which plan for only one outage in ten years.

Utilities ensure RA by providing a Planning Reserve Margin (PRM – a percentage measure of additional effective capacity relative to the forecasted peak demand in a future year). For example, most of the North American utilities plan for 15% PRM which means they plan to have 15% more capacity available relative to the forecasted peak demand in a future year.

PRM is calculated as:

(effective capacity less peak demand)/peak demand)

Some utilities use the term Capacity Margin which is calculated as:

(effective capacity less peak demand)/effective capacity)

While 15% is typical, individual utilities can have PRM in the range of 10-16% depending on their particular circumstances.

[2] Effective Capacity is the generating capability at the time of peak demand and it may be different from the installed capacity or the nameplate capacity. For example, if a 100 MW hydro plant can only supply 50 MW at the time of peak demand in winter due to reduced reservoir level, its effective capacity is 50 MW. Similarly, a 100 MW solar plant will have zero Effective Capacity if the peak demand occurs after the sunset (as in the case of Georgia).

RA AND RELIABILITY

Reliability is defined as the ability of a system to perform consistently well. RA is not the same thing as power system reliability, it is a component of it. Power system reliability has two components: *adequacy and security*. A power system is *adequate* if it can supply the customer demand *all the time,* taking into account reasonable breakdowns of the generation or transmission system, by having sufficient generation, DER and import capacity.

Power system *security* is defined as the ability of the power system to withstand sudden disturbances such as an outage of an element (line, generator, etc.) in real time. Power system security is ensured by providing spinning reserve or quick start reserve (also referred to as operating reserve). The reserve requirement is frequently expressed in terms of a percentage of load or the largest single contingency, e.g., the loss of the largest generating unit. PRM for resource adequacy and Operating Reserve for system security are additional resource requirements for a reliable power system.

RA IN NORTH AMERICA

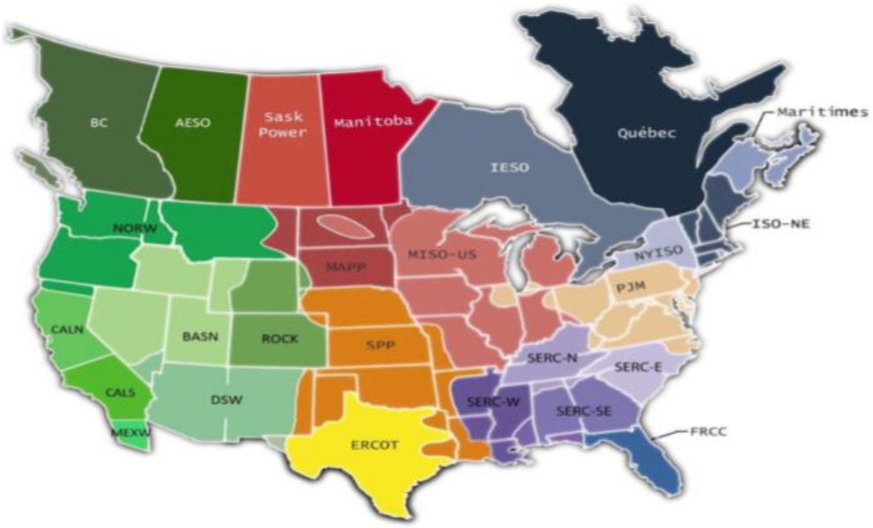
As mentioned earlier, many North American utilities use 1-in-10 RA criteria but define this metric in different ways. Most utilities interpret 1-in-10 as one outage event in ten years and refer to it as LOLP or as Loss of Load Expectation (LOLE). Numerically, this is defined as the probability of 1.0 for an outage in ten years or a probability of 0.1 per year (10% chance of at least one outage in a year). Another interpretation of 1-in-10 is one full day (24 hours) outage in ten years. This translates into 2.4 hours of outage every year, also referred to as the LOLH. First RA criteria of 0.1 LOLP is more stringent than 2.4 LOLH. Hydro dominated utilities in the pacific northwest plan for 1-in-20 and interpret it as one bad (drought) year in 20 years. These utilities use an LOLP criteria of 0.05 or 5% per year.

The above criteria do not measure the depth of outages (how many customers lost power for how long?). Another metric referred to as the EUE is used to address this concern. It is the sum of all load sheds during a year, measuring the exact duration, depth and frequency of outages. More detailed definitions of these criteria are given in Appendix A.

North American power sector is a very complex mesh of networks and organizations, including Investor Owned Utilities (IOUs), Government owned utilities (Public Utilities), Municipally owned utilities, Cooperative utilities (owned by the customers) and power pools or Regional Transmission Organizations (RTOs). IOUs are regulated by the state regulators while the Federal Energy Regulatory Commission (FERC) regulates wholesale markets, RTOs, power pools and transmission lines that span across the states. IOUs supply about 70% of the power in the US while other entities supply the remaining 30%. Many US states (especially, in the Southeast and Northwest) did not deregulate or unbundle their power sectors and the state regulators oversee vertically integrated utilities and enforce reliability standards. In other parts of the US, wholesale power generation has been deregulated and the RTOs manage competitive power pools and operate the transmission system. PJM (Pennsylvania, New Jersey, Maryland), MISO (Midwest Independent System Operator (ISO)), NEPOOL (New England Power Pool) and SPP (Southwest Power Pool) are examples of multistate RTOs. There are some states which have competitive power pools within the state like NYISO (New York ISO), ERCOT (Electric Reliability Council of Texas) Cal-ISO (California ISO).

NERC (North American Reliability Council) monitors and enforces reliability and resource adequacy standards in the US and Canada. NERC was formed by North American utilities as a *voluntary* organization in 1968 to jointly plan and operate the synchronized and interconnected North American power grid following a large blackout in 1965. NERC reviews the short-term and long-term reliability of the North American power sector through its reports for summer outlook, winter outlook and ten-year outlook. Major RTOs that run competitive power markets across multiple states are regulated by FERC and have their own reliability requirements and RA standards. For the purpose of assessing reliability, NERC has divided North America in different areas as shown in Figure 1.

Figure 1: NERC Reliability Assessment Areas



NERC is not very prescriptive in enforcing reliability standards for different areas. It lets individual areas decide their own criteria based on their specific regional supply demand balances, resource mix and traditions. Table 1 below shows RA criteria used by some NERC areas. Figure A1 in Appendix A shows the expected PRM for various planning entities.

Table 1: Resource Adequacy Criteria Adopted by Different NERC Areas

NERC Area	Reliability Criterion
FRCC	1in-10 or 0.1 LOLP translated into 15% regional reserve margin
SERC	No region wide criteria but utilities plan for 1-in-10 criteria to minimize overall customer costs
PJM	1-in-10 or 0.1 LOLP
MISO	1-in-10 or 0.1 LOLP
NPCC-NY ISO	1-in-10 or 0.1 LOLP
NPCC-ISO-NE	1-in-10 or 0.1 LOLP
NPCC- Quebec	1-in-10 or 0.1 LOLP
NPCC-IESO	1-in-10 or 0.1 LOLP
Manitoba	Reserve margin of at least 12%
MAPP	1-in-10 or 0.1 LOLP. Some members use 15% PRM
ERCOT	1-in-10 or 0.1 LOLP
CA-ISO	15% PRM
Northwest	1-in-20 or 0.05 LOLP

LIMITATIONS OF IMPORTED POWER FOR RA

The sole purpose of Resource Adequacy planning is to minimize the probability of power supply shortages. In this way RA is a risk mitigation measure. Like most risk mitigation measures, RA relies on diversity and certainty of supply to enhance RA. To achieve resource adequacy, it is imperative that the supply sources be available with the highest degree of certainty during the hours of peak demand. Practically, this means most, if not all, supply sources should be physically and electrically in the proximity of demand. The supply must pass the deliverability test to ensure the delivery of electrons to the customers when and where they need them. While transmission systems are generally very reliable to transport large amounts of power across long distances, RA planning limits reliance on generation resources outside of the region of interest. For example, a very mature power market like Cal-ISO mandates utilities to provide a certain amount of resources from the local generation. Interconnected transmission systems and interconnected power markets crossing state boundaries provide great opportunities for *economic power exchange* and *real time support* to each other during emergencies. However, for planning purposes and for ensuring resource adequacy over the long term, individual markets/pools rely very little on power imports from outside regions for a variety of technical, business and political reasons as discussed below:

Technical reasons for minimal dependence on imports

- **Limited Diversity.** Neighboring systems have very little resource diversity (spatial, temporal and fuel mix) to substantially support RA for each other. For example, neighboring systems in the same physical geography generally have the same seasonal demand profiles, experience similar weather patterns and generally experience peak demand at the same time, leaving little capacity to help each other during peak hours (See Appendix B Figure B1, showing the limitations of available power during peak demand). Additionally, neighboring systems generally have identical generation or fuel mix. For example, Southeast United States relies on coal and natural gas as a fuel source for power generation. Most of the coal in this region is supplied from Central Appalachian region or Powder River Basin. If there is any interruption in coal supply during extremely cold weather, it impacts all the utilities in the region. During extreme winter conditions, gas demand increases across the country, constraining the supply of gas for power generation to the whole region. Due to these potential limitations, many state regulators require a certain amount of on-site fuel storage and limit the maximum reliance on neighboring utilities to 3% of the peak demand for RA planning.

  Similarly, Northwest United States relies heavily on hydro power generation. During the drought season, all utilities are impacted equally, constraining their ability to help the neighbors. To summarize, neighboring systems have very little capacity to help each other at the time of peak demand. Therefore, RA planning limits the reliance on imported supply to a minimal level.

- **Transmission System Limitations**. Transmission system congestion and loop flows are well known phenomena in power systems. During high demand periods, certain lines or paths can be congested, reducing the power transfer capability across those paths. See Figure B2 in Appendix B. Loop flows are also common in large power systems where the electrons take the path of least electrical resistance rather than the contracted or intended path, thereby constraining the ability of net power movement across regions. RA is all about ensuring the delivery of power at the time of the peak. If transmission constraints limit the certainty of power delivery when it is needed the most, there is little value in having generation resources far away from the load.

Business reasons for minimal dependence on imports

Prudent business management requires cost and risk minimization. Import of lower cost power from neighboring systems reduces the operating cost of a utility but relying on imported power for Resource Adequacy increases the *risk* of supply shortage during peak demand hours. In mature markets where commercial agreements can be fully enforced, utilities do rely on firm power imports or capacity purchases across regions but limit it to small amounts. There are two main reasons for putting this limit:

- Disproportionate relation between the savings realized with imported power and the cost of unserved energy in the case of interruption. Most sellers limit the penalties for non-supply equal to or slightly above the cost of power supply, but the loss to the receiving party may be much higher. For example, if utility A buys power from utility B at an average price of $50/MWh, the penalty for non-delivery will likely be capped at 1 to 2 times the cost, i.e., $100/MWh. But if the receiving utility A had to shed load or buy emergency power due to non-supply from utility B, its cost could be as high as the cost of EUE (Expected Unserved Energy) which is in thousands of dollars per MWh (such as $9,000/ MWh in some parts of the US). In other words, the cost of this risk is too high and it is hard to buy any kind of insurance.

- Technical difficulties in precisely allocating responsibilities for non-delivery of supply during extreme events. The power supply from a neighboring system can be interrupted for a variety of reasons, including an outage of an unrelated power plant or weather elements impacting a distant third region. This complicates allocating responsibility for interruption and getting any compensation. Due to this complex business risk, Midwest ISO, one of the largest power pools in the US, limits the reliance on outside resources to 2.5% for RA while its actual imports average 5% of its total energy consumption.

In the case of Georgia, it may be very difficult to sign firm power import contracts with penalties and consequential damages with neighboring countries. Even if such an import contract is signed, its implementation and dispute resolution will have to be done in neutral countries through lengthy legal and technical investigation process. This will add imprudent amount of cost and risk for the Georgian Power Sector. While Georgia should maximize economic power exchanges with neighbors to reduce cost and provide/receive emergency support, it should minimize the dependence on imported power for RA.

Political reasons for minimal dependence on imports

There are many examples of countries using energy supply as a political instrument to achieve certain strategic objectives. The example often cited is the Arab embargo of oil during the 70s. Georgia relies heavily on imported gas. Any dependence on imported power for RA will further expose the country to energy supply risks.

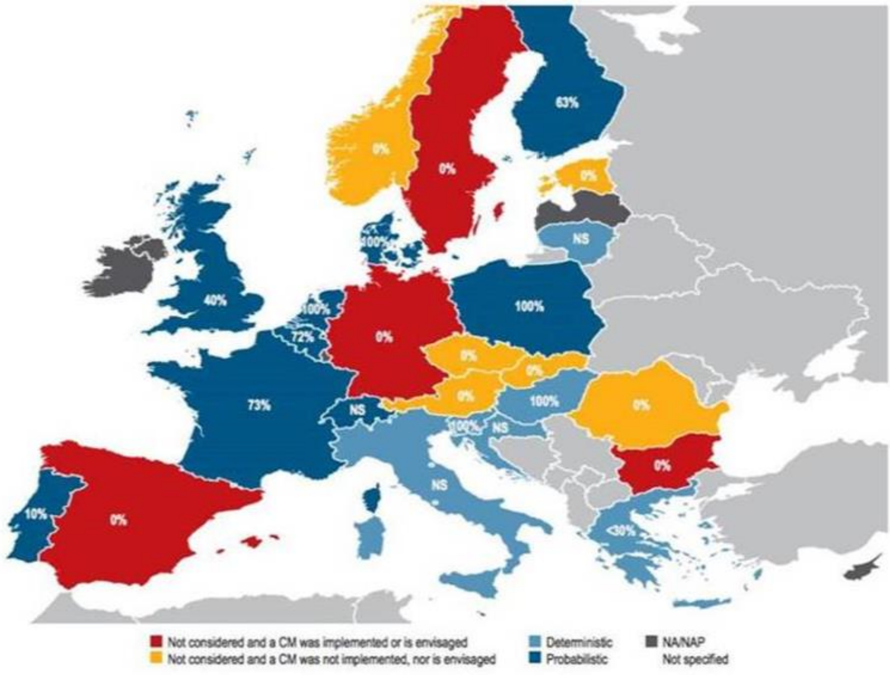
To summarize, regional power transmission networks are built to allow economic power flows and real time support for power system security but their value is limited for Resource Adequacy support. The following table shows RA criteria of selected US power pools/regions and their maximum import dependence for RA.

Table 2: RA Criteria of Selected US Power Pools/Regions

NERC Area	Reliability Criterion	Reserve Margin	Import Dependence
SERC	1-in-10	15.0%	3.0%
PJM	1-in-10	15.3%	1.9%
MISO	1-in-10	16.7%	2.5%*
NY ISO	1-in-10	16.1%	8.6%
ISO-NE	1-in-10		5.5%
CA-ISO		15-17%	7%
SPP	2.4 LOLH	12%	0%

The following map shows how much some of the European countries rely on outside resources for RA.

Figure 2: Treatment of Interconnectors in National Generation Adequacy Assessments, in Europe-2016[3]



It is clear that most power pools in the US and many European Union (EU) countries with strongly interconnected power systems and with very deep political and business relations between power suppliers, rely minimally on imported power for RA. Georgia's power sector does not enjoy very deep commercial relationships with its neighbors, therefore, any reliance on imported power would not be prudent. Consequently, for 2024 RA estimates, we limit the reliance on imported power to zero MW in the base case and show scenarios with three percent or 75 MW import.

[3] Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016, ACER/CEER

RA ANALYSIS BY US UTILITIES

US utilities or RTOs (or power pools) routinely perform RA studies. Results of RA studies are used to develop PRM requirements. These PRM requirements are then enforced on a yearly basis (or more frequently) to procure existing or build new resources. For the purpose of RA calculations, the selected future year is not too distant that there are too many unknowns to influence RA results and not too close that new capacity can't be built – may be 4 years into the future. For the selected future year, hourly operation of the utility (or the power pool) is simulated. During such simulations, all the available generation resources are stacked up to meet electricity demand every hour just like an economic dispatch performed by a power control center. Neighboring systems are also modeled with transmission constraints and uncertainties of import availability during high demand conditions. During hourly simulation, hours when supply is unable to meet demand are recorded along with the volume of supply shortage (MWh). Simulation is repeated several hundred (or thousand) times to ensure all the possible future uncertainties have been considered and the shortage events are recorded. Simulation needs to be repeated enough times to get reasonable convergence for average values of the *rare* supply shortage events. The supply shortage events are then summarized as LOLP, LOLH, EUE, etc. Many utilities use home grown simulation models while others use commercially available models like SERVM[4]. During the simulation, uncertainties are modeled as scenarios while generation resource availability is modeled with Monte Carlo[5] draws. Typically, the following variables are modeled along with their uncertainties:

1. **Load Forecast.** Hourly load forecast for the future year is modeled along with scenarios of high, medium and low demand growth (3 scenarios);
2. **Weather.** Weather (temperature, humidity, cloud cover, wind speed, etc.) drives electricity demand and the production of solar and wind energy. Weather variation is a large driver of electricity demand and supply variability. Most US utilities have weather records going as far back as 50 years. A good simulation will model past thirty years. (3x30 scenarios);
3. **Rainfall.** Most US and Canadian utilities rely on hydro generation to meet part of their demand. Utilities with heavy reliance on hydro, model historical rain fall going as far back as 30 years to consider maximum variations of river flow. Variability of water available during the peak demand season significantly impacts resource adequacy for hydro dependent utilities. As a result, the number of scenarios for hydro dependent utilities will be 3X30X30=2,700;
4. **Thermal Generation.** Thermal generating units are modeled as always available unless they are down for planned or unplanned repairs. Availability of each thermal unit is determined through a random draw based on its Forced Outage Rate (FOR[6]). In the simplest form of modeling, a unit is deemed available for a day if the drawn random number is below the FOR of the unit. More complex modeling considers the mean time to repair and mean time to failure to model thermal unit availability;
5. **Fuel Supply Constraints.** Any constraints in the fuel supply chain such as maximum monthly or weekly limits can be modeled in most modeling systems;
6. **Hydro Generation.** Hydro power plants are modeled with their seasonal, monthly, weekly, daily and hourly constraints for both Run of River (ROR) or Storage type units. Rainfall and flow diversity are modeled based on the historical weather data as mentioned in item #3 above. For hydro dominated systems, utilities use specialized custom-built models to capture the intricacies of river flows, cascaded plant generation and other important details related to hydro generation. Typically, hydro energy optimization algorithms are layered over thermal generation dispatch to get a realistic simulation of hydrothermal coordination as practiced during real time dispatch in a power control center;
7. **Import Availability**. For interconnected systems, import power availability from the neighboring systems is modeled as a fixed number, a weather dependent value or like a regular generator with less than 100% availability;

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[4] SERVM model was originally developed by the Southern Company – a large US utility based on Atlanta, Georgia. It is now being managed by ASTRAPE Consulting (www.astrpe.com). There are many other similar tools available in the market.
[5] Monte Carlo draws take their name from the randomness of gambling results in the city of Monte Carlo.
[6] FOR is defined as the ratio of time when a generating unit is on an unplanned outage (failure) to the time it is available for generation. A typical combined cycle plant has a FOR of 3% which means on average, the plant will be unavailable for generation about 11 days during a year.

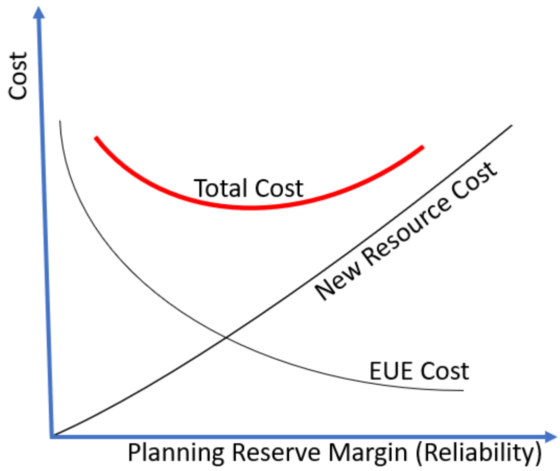
8. **Interruptible Load.** Demand side management and interruptible load is modeled as per the contract limitations. Typically, interruptible loads have limitations on how many times they can be interrupted and for how long, during a year.

During each of the 90 (or 2,700 in the case of hydro dependent utilities) scenarios, hourly chronological operation of the power system is simulated like an economic dispatch in a power control center. For each hour, available generation is stacked up to meet hourly demand. If during an hour, supply is below the demand, a loss of load event is recorded. At the end of full year (or peak season), values of RA indices like LOLP, LOLH and EUE are computed for each of the simulation year. This yearly simulation is repeated at least 200 times to ensure most if not all possible events and combination of events have been considered. A simple example taken from NERC reports explains the computation process to determine the values of RA indices in Appendix C.

If the system is reasonably planned, most of the simulation years will not have any load shed or unmet demand events, giving zero value to the RA indices. Scenarios with high demand growth, extreme weather and drought conditions may have some load shed or unserved energy events. Values of RA indices are averaged over all the simulations. If these values are higher than the target values, new generation resources are added to bring down RA values to the target levels. For example, if a utility plans for one day outage in ten years (LOLP of 0.1 or LOLH of 2.4) and its LOLP is coming higher than 0.1, new capacity is added until LOLP drops below 0.1 and the system is adequate.

If a system experiences higher number of load-shed events, its EUE value is also high. Since the cost of unserved energy is extremely high, total incremental cost of running such a system is high. As more resources are added to this system, PRM increases, EUE reduces and the incremental cost comes down, but at the same time cost of adding new generation capacity increases total costs. A plot of EUE cost and the carrying cost of new capacity shows an optimum level of total cost and the associated PRM. This PRM value is one of the main outcomes of RA analysis and it is used in building future capacity. A typical chart showing RA study results is shown in Figure 3.

Figure 3: Optimum Cost vs. Reliability - RA Study Outcome



As mentioned earlier, US utilities with mostly thermal resources require 15% PRM to meet 0.1 probability of outage in a year (or one day outage in ten years). Utilities in the Pacific Northwest with large hydro resources require a lower PRM, about 10% to meet their RA criteria.

RA MODEL FOR GEORGIA

Georgia, like the US Northwest, is heavily reliant on hydro resources to meet its electricity needs. According to the GSE 2018 Electricity Supply Demand Balance, 83% of total electricity was supplied from hydro resources. Figure 4 below shows monthly energy supply-demand balance.

Figure 4: 2018 Georgia Demand-Supply Balance

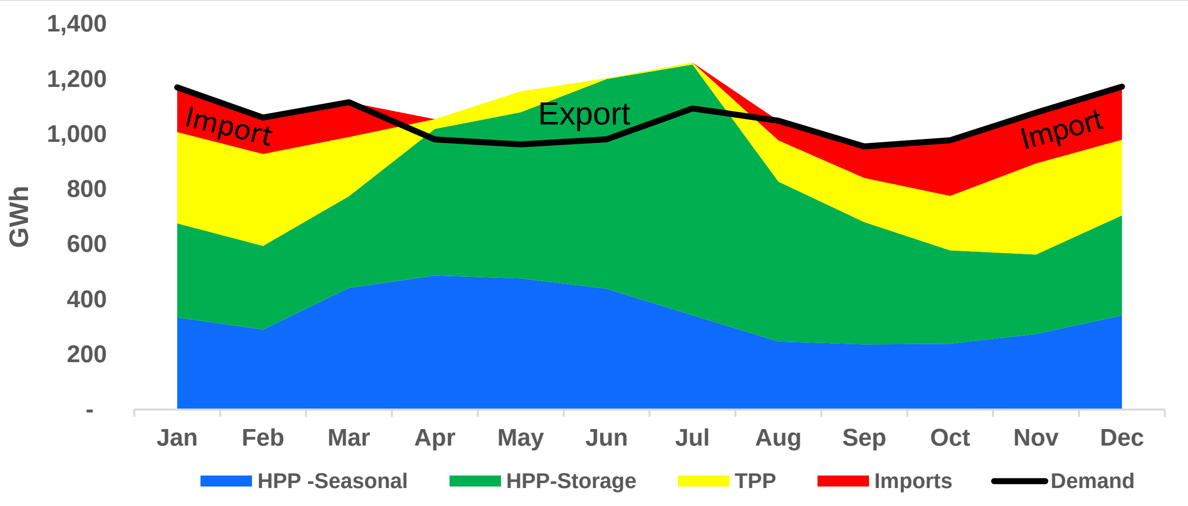
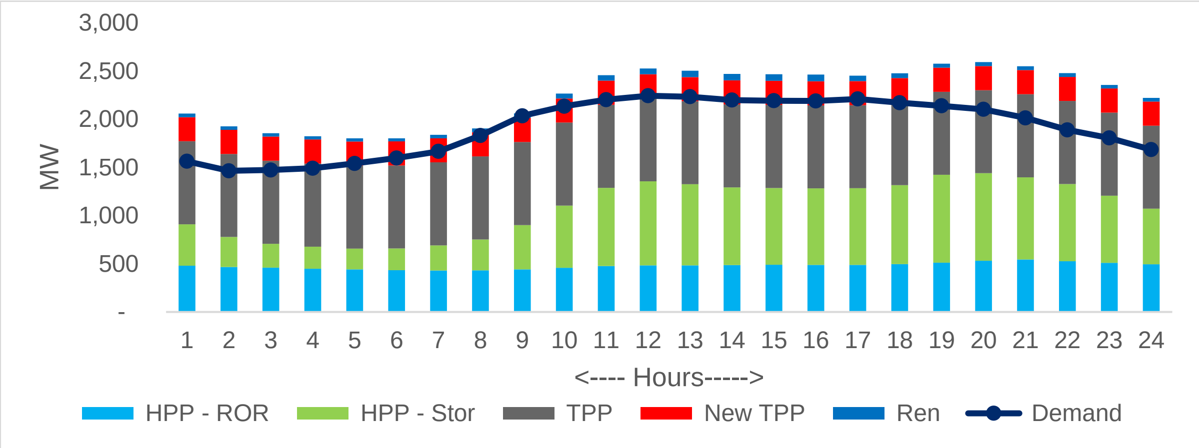


Figure 4 shows that hydro resources can comfortably meet Georgia's summer demand and some excess power is exported. However, during winter when hydro level is low and the system experiences peak demand, thermal resources and imports are needed to meet customer demand. The exact amount of excess generation during summers and the deficit during winters depends on the seasonal rain falls and vary from year to year. As new hydro resources are built, there will be more excess energy during summer, but the winter deficit will likely stay. Since winter is a peak demand season, resource adequacy is critical during winter months to avoid any shortages. To analyze this winter supply criticality, we built GRAM. GRAM estimates supply shortages and RA indices of LOLH, EUE and LOLP during the winter months of December, January and February of 2024. During non-winter months of the year, enough supply is available, thus RA is not a concern.

GRAM is an hourly chronological simulation model that stacks all supply side resources to meet demand and captures any shortage events to estimate RA indices. GRAM includes a detailed modeling of the hourly operation of Georgia's generation system during winter months to estimate Resource Adequacy metrics such as LOLP, LOLH and EUE. It captures all the possible reliability or generation inadequacy events and estimates the *likelihood*, *magnitude* and *the economic cost* of each event. The model can produce a full distribution of reliability events and associated cost to help the policy makers and planners devise plans and strategies to reduce the probability of supply shortages. The GRAM can be used to develop a comparison of the cost of unserved energy with the cost of building a new capacity to help determine the optimal level of PRM or the acceptable value of LOLH for Georgia. The model was designed to estimate RA for the winter months of 2024, but it is capable of analyzing any other year or consecutive three months period. The excel based model is capable of running many scenarios and for each scenario it can generate up to 10,000 Monte Carlo iterations. Recommended number of iterations is 1,000 as it provides acceptable results in about 1 minute on an average desktop computer. A simulation run with 10,000 iterations takes more than an hour and the file size grows significantly without any noticeable improvement in accuracy.

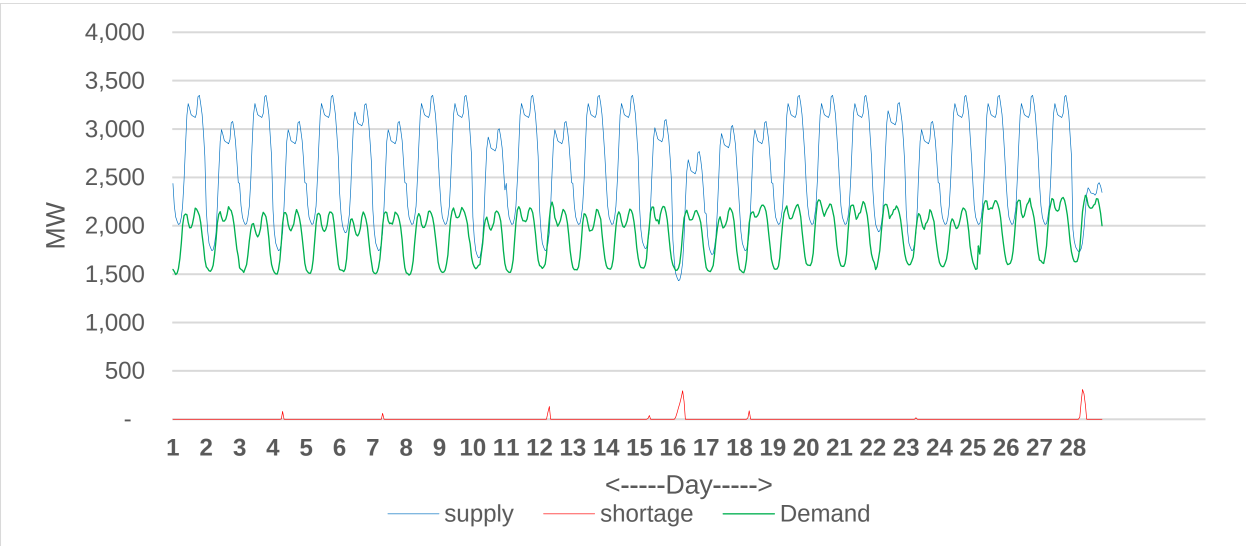
The model takes annual Hydro Power Plant (HPP) energy forecast and distributes it on a monthly, daily and hourly basis using historical profiles for ROR plants. Following the dispatching of ROR energy, storage HPP energy is optimally allocated on an hourly basis to shave daily peak and flatten post hydro load shape. Fixed profiles for wind and solar generation are then dispatched. The model then overlays Thermal Power Plant (TPP) and imports to meet hourly demand. All these supply side resources are stacked up against hourly demand as shown for a day in December in the following chart.

Figure 5: December 2024 Day 1 Supply Demand Balance



As one can see, ROR generation in light blue color is stacked up at the lowest level. It has a very little variation across the day. Then the storage hydro in green is allocated across the day to meet peak demand during the day and basically flatten the residual load shape. Existing and new TPP resources are stacked up next and finally, solar and wind resources are dispatched on the top. The solid blue line shows hourly demand for this day. For this day, available resources are greater than demand and there is no supply shortage during any of the 24 hours. Similar hourly resource allocation is repeated for every day of the simulation period as shown in the following chart for the month of February.

Figure 6: February 2024 Supply Demand Balance



The chart shows available supply in blue and demand in green. Redline at the bottom shows any shortages. It can be seen that during this particular simulation run, there are some shortages as the red line is greater than zero for a few days. These shortage events are aggregated for all three months. This process is repeated 1,000 times to estimate expected values of RA indices.

GRAM summary input data table is shown below.

Figure 7: GRAM Data Input Table

Georgia Resource Adequacy Model (GRAM)

Scenario	1	L1 C1 H1 I1
Iterations	1000	

Run

Name	Name Plate Capacity MW	Availability Factor %	Effective Capacity December MW	Effective Capacity January MW	Effective Capacity February MW	Daily Energy December MWhrs	Daily Energy January Mwhrs	Daily Energy February Mwhrs
Demand			2,638	2,354	2,315	50,122	46,615	46,000
Supply								
ROR HPP	1,319	100%	544	533	542	11,515	11,268	11,455
Storage HPP	2,449	100%	745	733	706	14,626	14,312	13,142
Tbilresi	270	95%	270	270	270			
G-power	86	95%	86	86	86			
Mtkvari	270	95%	270	270	270	Average Daily Energy		44,386
Gardabani	236	95%	236	236	236			
Firm Imports	-	-	-	-	-			
CC 2020	250	97%	250	250	250			
New TPP	407	97%	407	407	407			
New Solar	30	97%	-	-	-			
New Wind	80	97%	41	41	41			
Total	**5,397**	**99%**	**2,849**	**2,825**	**2,807**	26,140	25,580	24,598
Planning Reserve Margin			**8.0%**	**20.0%**	**21.3%**	Total Hydro Energy		
Total HPP	3,768	100%	1,289	1,266	1,247	52%	55%	53%
Total TPP	862	95%	862	862	862			
Imports	-	-	-	-	-			
New TPP	407	97%	657	657	657			
Ren	110	97%	41	41	41			

The top boxes have red inputs, first one to select the scenario number (1 through 16) and the second input to select the number of iterations. Then there are three main boxes containing demand-supply data for the year 2024. Left box shows the installed or nameplate capacity of all the supply resources along with expected availability. For example, nameplate capacity of all ROR plants is 1,319 MW and their availability is 100%. The list contains the nameplate capacities of all the existing and planned resources for 2024 including new thermal and renewable resources. The TPP labelled as "New TPP" is not an actual resource. It is the amount of new thermal capacity that needs to be added to achieve the required level of Resource Adequacy. The table in the middle shows monthly peak demands for the three simulation months in the top box and effective capacity (capacity available at the time of peak demand) of all the generation resources for each of the respective months of December through February. It can be seen in the table that the effective capacity of ROR is 544 MW in December vs. the installed capacity of 1,319 MW due to declining water flows in December. Furthermore, ROR effective capacity drops to 533 MW in January and rises to 542 MW in February with the start of snow melting. For TPPs effective capacity is the same as the nameplate capacity while for wind and solar, the effective capacity is different from the installed capacity. In fact, the effective capacity of solar is zero because no solar energy is available at 8PM when the system experiences peak demand.

As described above, one of the key values in RA is the PRM which shows how much excess capacity is available at the time of peak demand. PRM is calculated from the input data before the simulation starts. This is shown in bold green letters. Below the PRM values, there are two smaller tables summarizing the demand-supply balance. The table to the right shows daily energy demand and available HPP energy. It can be seen that during winter months HPPs only provide about half of total energy needs. Once the red button is pressed, GRAM starts the simulation process and populates the results tables upon completion. These tables are shown in the following Figure and discussed below.

Figure 8: GRAM Results Table – Simulation 1

Simulation Results: Computed Resource Adequacy Indices vs. Targets

Planning Reserve Margin (PRM)		Loss of Load Hours (LOLH)			Expected Unserved Energy (EUE)		Loss of Load Probability (LOLP)	
GRAM	US Values	GRAM	US Value	EU Values	GRAM	Australia Value	GRAM	US Values
8.0%	11 -16%	11	2.4	3-8	0.006%	0.002%	71.5%	5-10%

This table shows simulation results. It also shows a comparison of the computed RA indices from GRAM relative to the targets. GRAM computes four indices as discussed below:

- **PRM**. For this simulation Georgia PRM was 8.0% while the range for US utilities is 10-16%;

- **LOLH**. Computed value from GRAM was 11 hours. US utilities plan for 2.4 hours per year while European utilities plan for 3-8 hours;
- **EUE**. Computed value from GRAM was 0.006%. While EUE is very important in RA, there is no common target value except in Australia which uses EUE target of 0.002%;
- **LOLP**. Computed value from GRAM was 71.5%. Most US utilities plan for LOLP of 10%.

As already mentioned, RA is a winter concern in Georgia due to high demand and low hydro availability. GRAM simulates months of December through February and the results are annualized with the assumption that there will be no RA issues outside of these months. This is a reasonable assumption as there is plenty of energy and capacity in the hydro system outside of the winter months. Even if Georgia becomes a summer peaking system due to fast rising summer demand, RA will continue to be an issue for the winter when demand is high, and hydro is at its minimum levels.

GRAM considers many drivers of future uncertainty through scenario analysis as discussed below:

1. **Load Forecast Uncertainty.** GSE provided three demand growth scenarios: low, medium and high growth. GRAM considers low and medium growth scenarios only, as these two scenarios provide enough insight for RA purposes (2 Scenarios);
2. **New Capacity Uncertainty.** Two scenarios were considered based on the traditions of GSE planning. In the base scenario, 25% of all the projects in different stages of planning are assumed to be built while in the pessimistic scenario, only 10% of the projects in the pipeline are built. RA will not be an issue for the optimistic case where all the projects in the pipeline are built. So, the optimistic case was not considered in GRAM. Number of Scenarios: 2x2;
3. **Hydro Energy Uncertainty.** Two scenarios were considered: average rainfall and drought. In case of drought, HPPs generate 10% less energy. There is no need to consider wet year from RA perspective. Number of Scenarios: 2x2x2;
4. **Import Power Uncertainty.** The base case considers no imported power while the optimistic case assumes 3% of the total demand or 75 MW of power import is available for RA. In reality, more import may be available, but for RA purposes only small amount should be considered. Number of Scenarios: 2x2x2x2 = 16;
5. **TPP Availability Uncertainty**. All TPPs are modeled with less than 100% availability and their availability is drawn randomly every day during the simulation. Simulation is repeated 1,000 times to get good averages for all of the RA indices.

The sixteen scenarios mentioned above are shown in Figure 9. Each of the 16 scenarios has a distinct label which indicates if the scenario represents base or high values of Load, New Capacity, Hydrology and Imports with “1” representing base case and “2” representing high case. Color green indicates the impact on RA is positive while the red color indicates the impact on RA is negative (all else equal). For example, high load growth will have a negative impact on RA (assuming everything else, including new capacity built, is the same as in the base case), while high imports will have a positive impact on RA.

Figure 9: Sixteen (16) Scenarios in GRAM

No.	Scenario Label	Load Growth		New Capacity Build		Hydrology		Imports	
		Base	High	Base	Low	Base	Low	Base	High
1	L1 C1 H1 I1	✓		✓		✓		✓	
2	L2 C1 H1 I1		✓	✓		✓		✓	
3	L1 C2 H1 I1	✓			✓	✓		✓	
4	L2 C2 H1 I1		✓		✓	✓		✓	
5	L1 C1 H2 I1	✓		✓			✓	✓	
6	L2 C1 H2 I1		✓	✓			✓	✓	
7	L1 C2 H2 I1	✓			✓		✓	✓	
8	L2 C2 H2 I1		✓		✓		✓	✓	
9	L1 C1 H1 I2	✓		✓		✓			✓
10	L2 C1 H1 I2		✓	✓		✓			✓
11	L1 C2 H1 I2	✓			✓	✓			✓

No.	Scenario Label	Load Growth		New Capacity Build		Hydrology		Imports	
12	L2 C2 H1 I2		✓		✓	✓			✓
13	L1 C1 H2 I2	✓		✓			✓		✓
14	L2 C1 H2 I2		✓	✓			✓		✓
15	L1 C2 H2 I2	✓			✓		✓		✓
16	L2 C2 H2 I2		✓		✓		✓		✓

DATA USED IN RESOURCE ADEQUACY

DEMAND DATA

Demand data was taken from GSE 2024 hourly demand forecast. GSE forecast includes three load growth scenarios: low, medium and high at the respective annual growth rates of 3.36%, 5.19% and 7.14%. A summary of 2024 peak demand for winter months is provided in the following table.

Figure 10: Power Demand Forecast by GSE

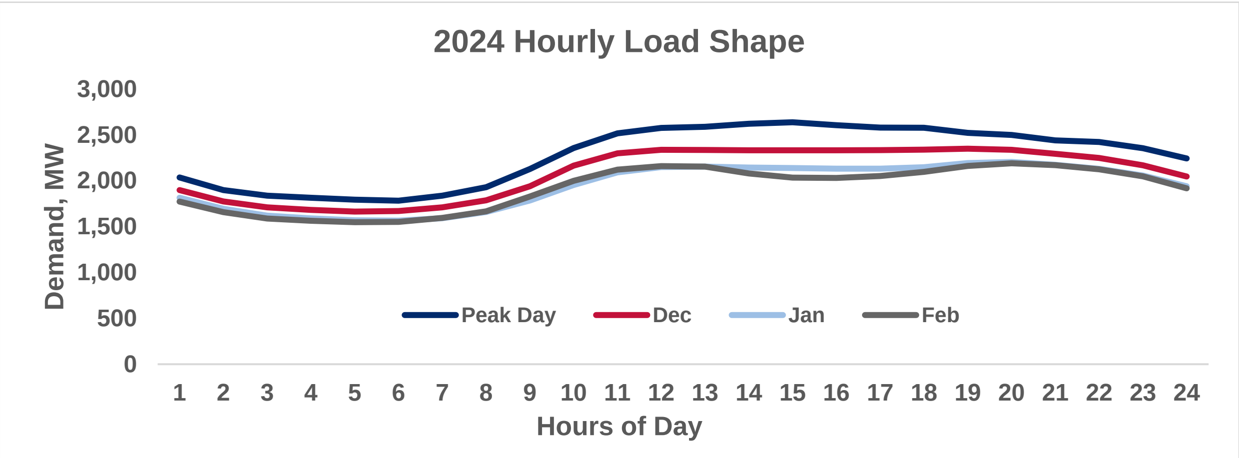
	2024 Peak Demand – MW			
	Annual	December	January	February
Low Growth Case (3.36%)	2,638	2,638	2,354	2,315
Medium Growth Case (5.19%)	2,936	2,936	2,675	2,577
High Growth Case (7.14%)	3,281	3,281	2,920	2,879
Difference - Medium & Low	298	298	321	262
Difference - High & Medium	345	345	245	302

As of 2019, Georgia is a winter peaking system. GSE informed RA team that the summer demand is growing at a faster rate than the winter demand because of rising air conditioning load. This means, at some point in the future, Georgia will be a summer peaking system. For now, the forecast provided by GSE for 2024 shows that Georgia will experience the peak demand in December. This simplifies RA analysis, as resource adequacy issue arises during winter months only. However, when Georgia becomes a summer peaking system, RA analysis will be needed for the full year. Even when Georgia becomes a summer peaking system, winter will continue to be more critical for RA due to lower reservoir levels and associated lower hydro power generation capability.

GSE's forecasted three growth rates differ by about 2% annually and the cumulative difference in 2024 peak demand between medium and low growth cases is 298 MW (about 10%) while the difference between high and medium cases is 345 MW (about 12%). For RA planning, we will consider low and medium cases only. These cases will give us enough insight into the RA requirements for Georgia. The high growth case will just need 345 MW of additional capacity to meet RA criteria.

RA is very sensitive to the peak demand and hourly load shapes. Hourly load shapes for the winter months of December, January and February show a flat demand pattern during the day as shown in the following chart. As a reference, we also show hourly load for the peak day which occurs on December 27th. It is interesting to note that the annual peak demand on December 27th occurs in the afternoon hours while most of other days experience peak in the evening hours.

Figure 11: Winter Months Hourly Demand Shape



HPP GENERATION PROFILE

HPPs provide most of the electricity in Georgia. As a result, an analysis of hydro energy production, hourly production profile and seasonality is a key component of RA planning.

Typical future hydro energy forecasts provide annual energy generation only. Since RA focuses on winter months and provides risk assessment for drought years, we analyzed power generation data from GSE for 2007 through 2018 to answer the following questions:

1. How low is energy generation during drought years?
2. What is the monthly distribution of generation?
3. What is the hourly energy generation profile?

The first question can be easily answered by analyzing annual power generation from HPPs and TPPs. Since Georgia added many new ROR HPPs after 2007, energy generated by these newer plants was separated to see the true annual energy production variations. The following chart shows annual generation from ROR, Storage and TPPs from 2007 to 2018.

Figure 12: Historical Annual Power Generation from Different Sources

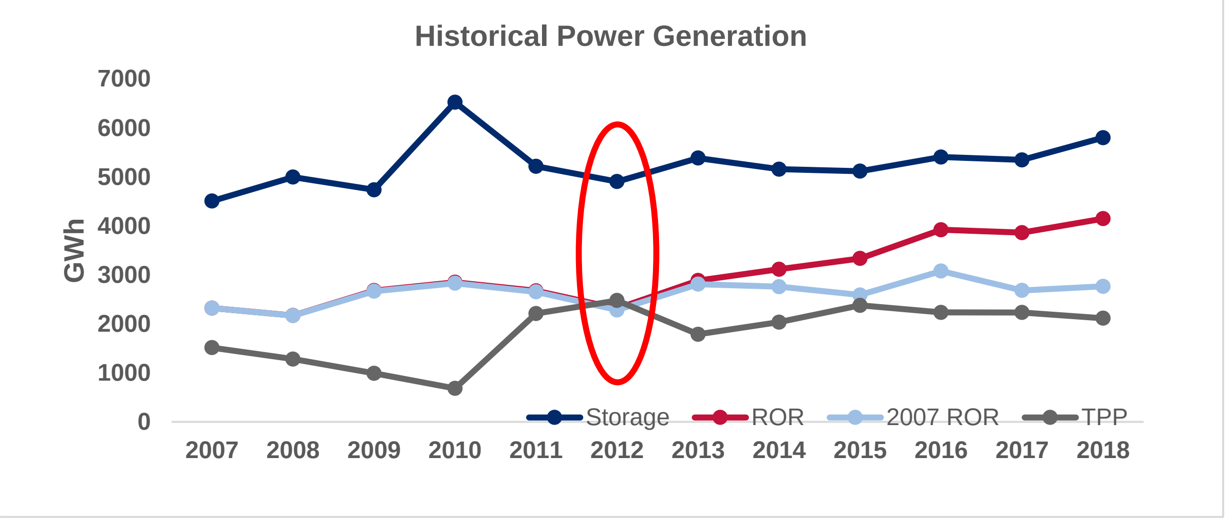


Figure 12 shows that HPP generation during the years 2008 and 2012 was low. Since 2008 is very distant year, we ignore it and consider 2012 as low HPP generation or drought year. Additionally, the TPP generation during 2012 was one of the highest on record — another evidence that 2012 was a drought year. This is because TPPs were called on to generate more power when hydro generation was low.

Based on the above data analysis, ROR plants generated about 13% less power in 2012 relative to the average annual generation of 2007–2018. Storage plants produced about 7% less in 2012 relative to the average. Since this data sample is not big enough to conclusively use separate ratios for ROR and Storage HPPs, we take an average of 13% and 7% and assume that the drought year power generation will be 10% less than the average year generation for both types of HPPs.

To forecast future HPP generation, we use 2018 as the base year as it was the last full year and power generation was kind of average.

Monthly HPP Energy Distribution

As mentioned earlier, RA analysis focuses on the winter months of December through February. In order to estimate monthly HPP generation for 2024, we averaged the monthly generation, for both ROR and Storage HPPs, of the historical years from 2007 to 2018 to get a good picture of monthly generation distribution. Next two charts show monthly power generation from ROR and Storage plants.

Figure 13: ROR Monthly Generation

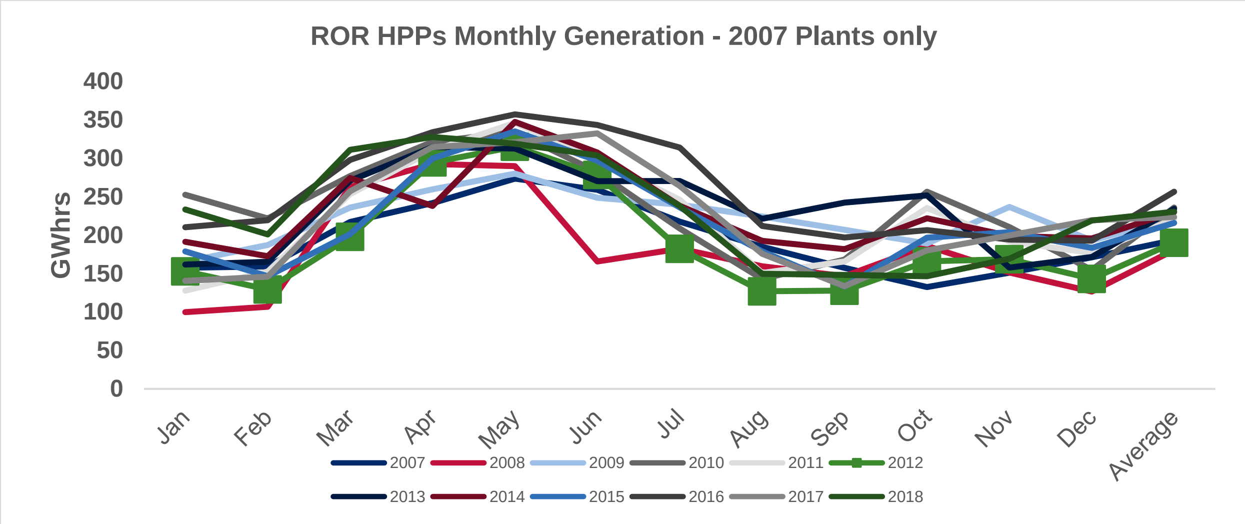
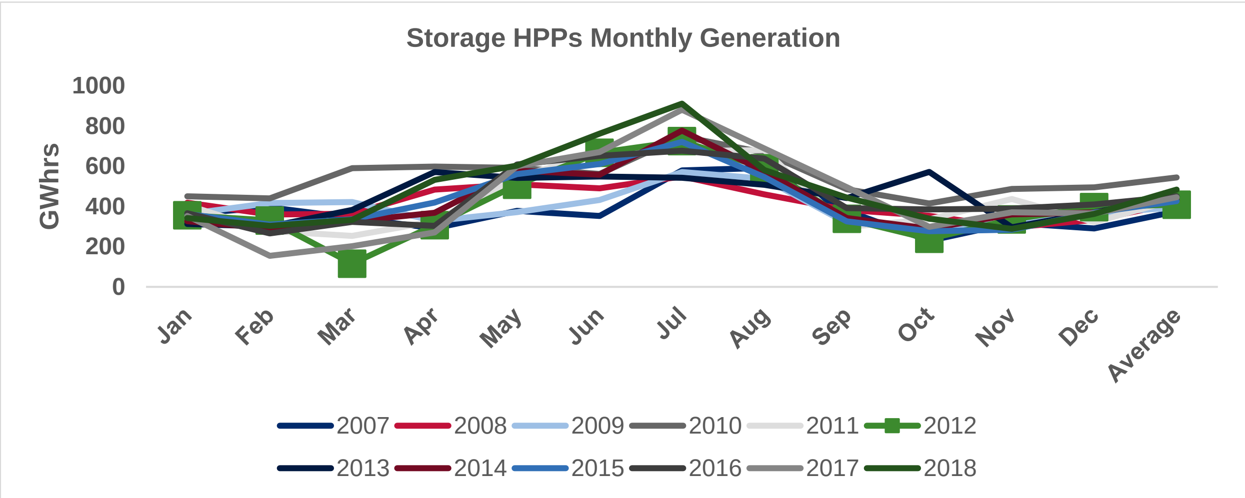
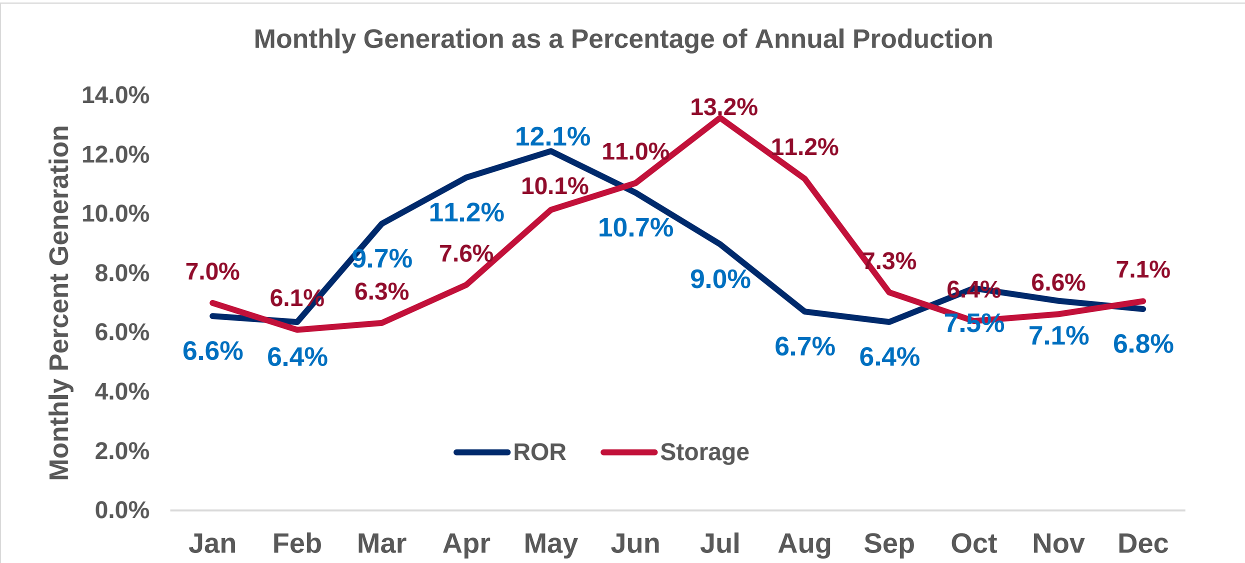


Figure 14: Storage Monthly Generation



We used the data in the above charts to get the *average* monthly energy produced as a percentage of annual generation as shown in Figure 15.

Figure 15: Monthly Hydro Generation Profile



It is important to note that ROR generation is maximum in early summer *during* the rainy season while Storage generation is maximum in late summer *following* the rainy season. As we are interested in winter months only, we summarize the energy generation from ROR and storage plants in December, January and February as a percentage of annual generation:

Figure 16: Winter Months Hydro Generation as a Percentage of Annual Generation

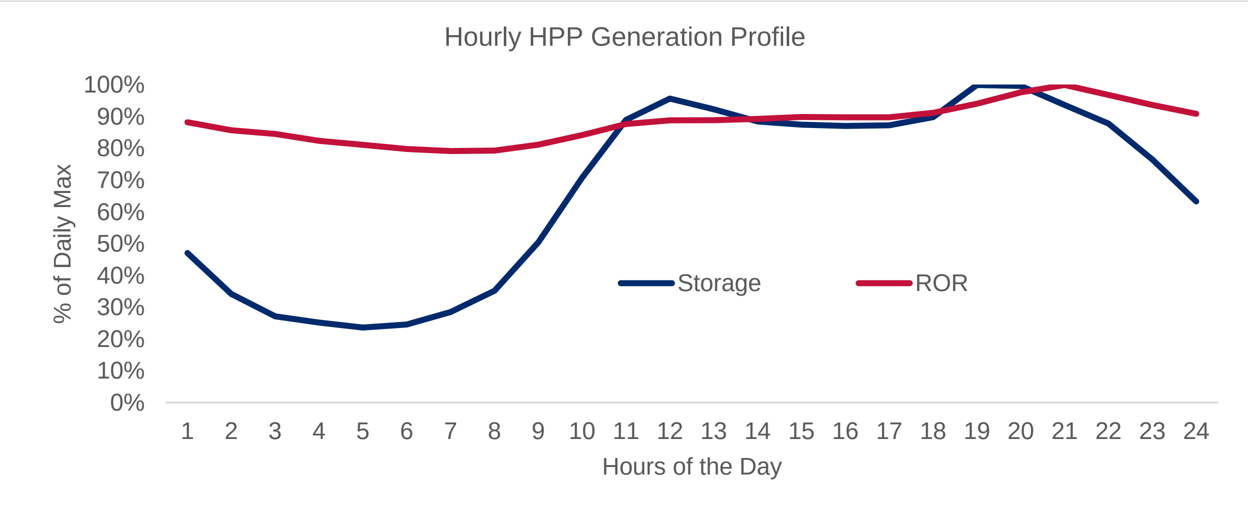
	Dec	Jan	Feb
ROR	6.8%	6.6%	6.4%
Storage	7.1%	7.0%	6.1%
Average	**6.9%**	**6.8%**	**6.2%**

For RA calculations in 2024, we will use the average values for ROR and Storage HPPs as shown in the last row of the table above.

Hourly HPP Energy Generation Profiles

Historical hourly power generation data provided by GSE was very helpful in estimating hourly shapes and profiles for HPPs. A review of the hourly generation data for the past three years shows that there is no change in the hourly profile or shapes between December and February. Average daily power generation profile for ROR and storage plants is shown in the following figure.

Figure 17: Hourly Profile of Hydro Generation During Winter

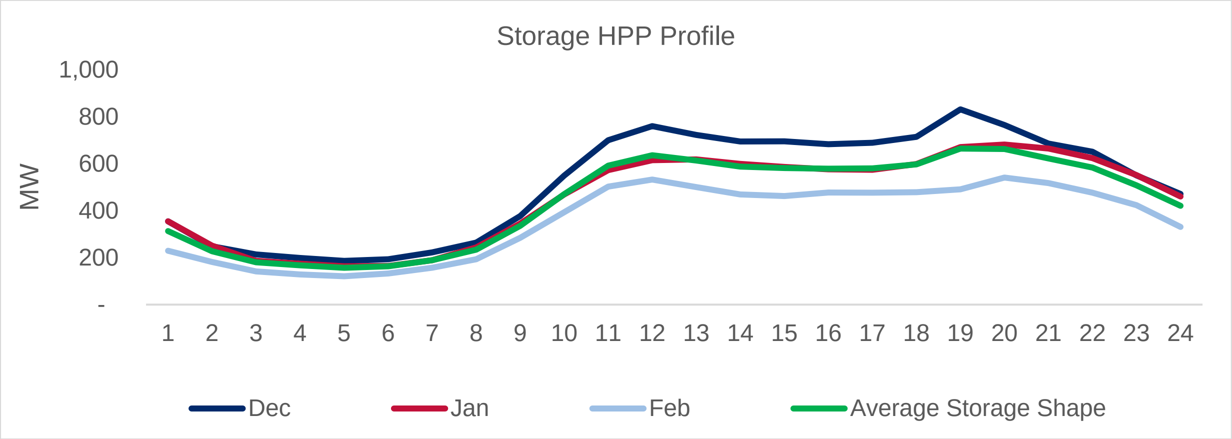


Some observations about these profiles are:

1. The output of Storage HPPs goes as low as 20% during late night to early morning hours to supply peak demand during day. It seems like there is a morning peak and there is an evening peak for storage dispatch. A review of the hourly demand shapes during winter months does not show double peaks during the day. We tested this shape for storage and did not use it in GRAM. Rather than using a fixed shape for the whole winter season, we developed a more dynamic way of allocating daily energy as discussed later in this section.
2. ROR is not exactly flat across the day. There is about 15 to20% variation across different hours which is good for RA.

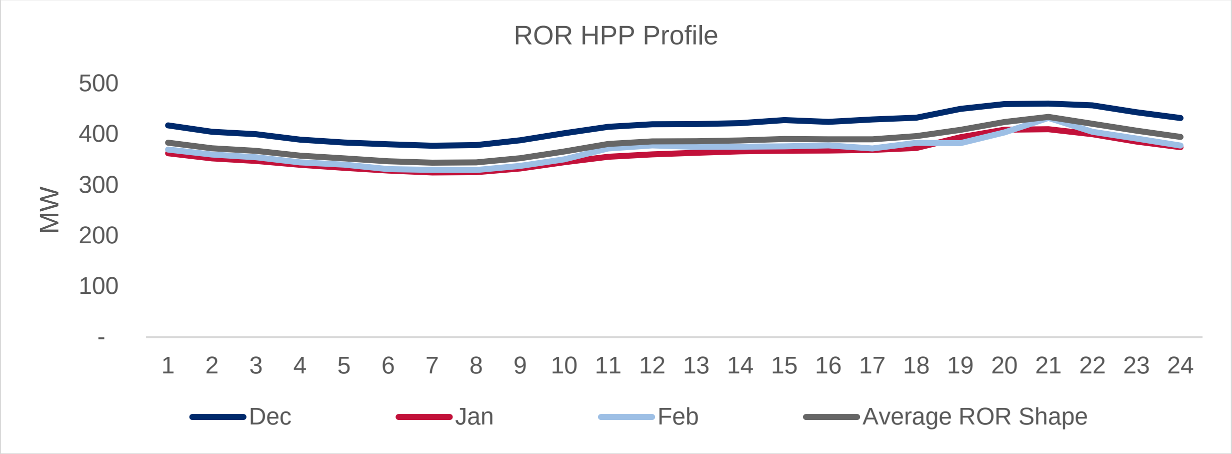
While the hourly HPP generation *shapes* are the same for the whole winter season, the actual MW production changes across the months due to changes in water flow and storage availability as shown in Figure 16 and the following two charts. Power generation drops gradually from December to February.

Figure 18: Hourly Storage HPP Generation Profile Across Winter Months



Similarly, hourly ROR *shapes* are the same across winter months as shown below.

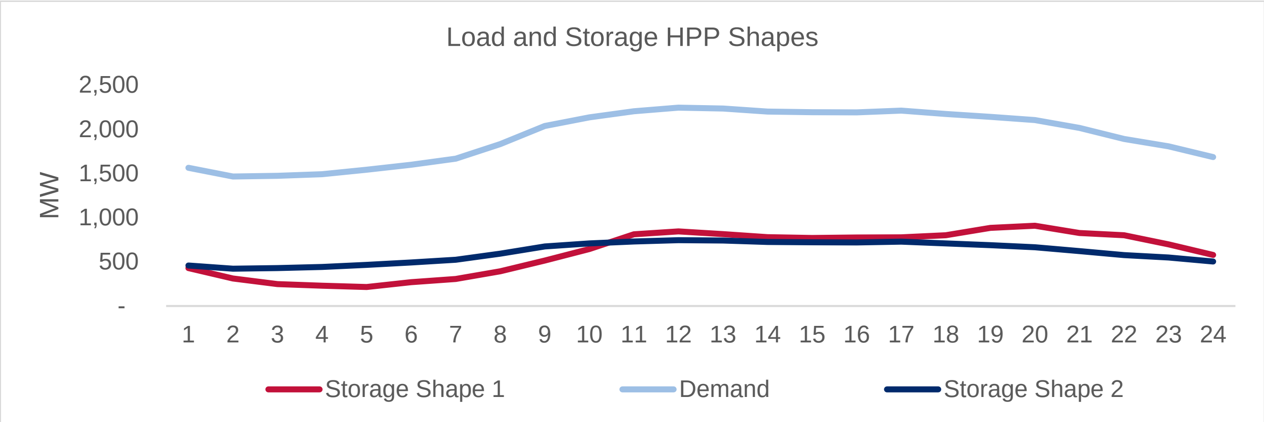
Figure 19: Hourly ROR HPP Generation Profile Across Winter Months



Further Analysis of Storage Hydro Shapes

In real time economic dispatch, Storage HPPs are optimized to meet hourly demand while minimizing the cost of operation. The shapes discussed above were averaged according to the past three years of hourly dispatch of HPPs. While these shapes reflected history very well, the hourly dispatch for the year 2024 indicated that this Storage HPPs shape was not compatible with the future load shape. It resulted in higher LOLH during the early morning hours. Also, this shape was static for all the 90 days of simulation. In order to better follow the load shape, we dispatched available daily storage energy against the hourly power demand **after** ROR dispatch. This shape resulted in improving RA indices and lowering LOLH. This shape is dynamic and changes every day based on the daily demand shape and daily ROR energy available during the course of the 90 days simulation. The following chart shows hourly load, historical shape labelled as Storage Shape 1 and the load following shape labelled as Storage Shape 2.

Figure 20: Comparison of Two Different Hourly Profiles of Storage Hydro Generation

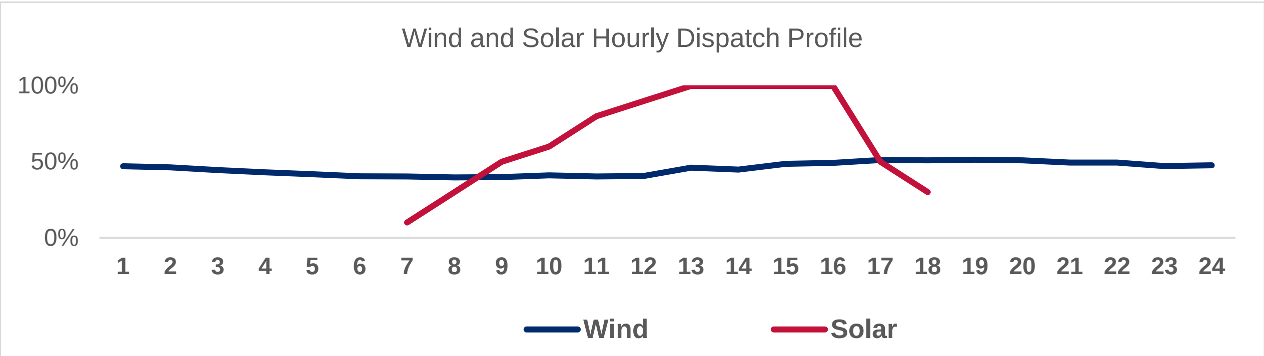


It is clear that Storage Shape 2 is more compatible with 2024 load shape. Storage Shape 2 was used in GRAM.

WIND AND SOLAR GENERATION PROFILE

Wind profile was obtained from the historical GSE data while the winter solar profile was taken from WASP (Wind Atlas Analysis and Application Program) data[7]. It is interesting to note that wind generation is almost flat across the day but is only 50% of the maximum installed capacity. So, a 100 MW wind plant will only generate 50 MW at the time of peak on average. Winter solar profile shows the shortened days of winter and the generation reduces to zero MW by 6 PM before the peak demand occurs later in the evening. This means that the solar generation will not support peak hour as shown in the chart below.

Figure 21: Wind and Solar Hourly Generation Profiles

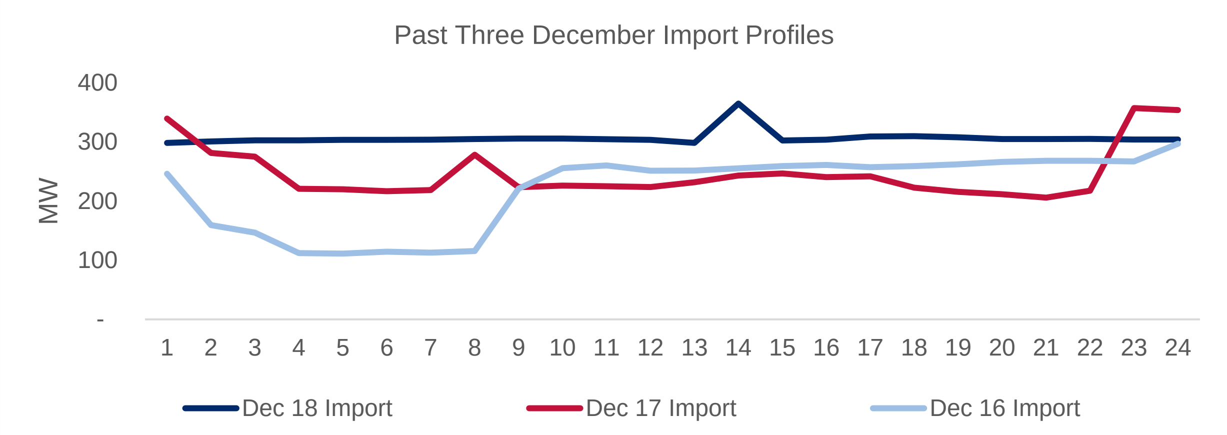


IMPORT POWER PROFILE

As can be seen in the import power chart below, power import is pretty much flat across the day with no specific shape. There are variations across hours based on availability, but the actual imported MWs range between 100-300 MW. For the purpose of our modeling, we will consider a flat fixed shape with 95% availability. As discussed earlier, for the base case, we assume zero imports while for the high import scenario, we assume import capacity capped at 3% of the peak demand i.e., 75 MW as in developed markets.

[7] WASP model for Georgia was developed under USAID funded G4G project. The corresponding data input for the WASP model was shared by G4G subcontractor organization.

Figure 22: Hourly Power Import Profiles



2024 GENERATION CAPABILITIES

The following table shows the nameplate capacity and average availability of all the existing power plants in Georgia.

Figure 23: Existing Power Plants Data

Power Plants - Name Plate Capacity Data		
Existing 2018	MW	Availability %
ROR HPP	1,061	100%
Storage HPP	2,169	100%
Tbilsresi	270	95%
G-power	86	95%
Mtkvari	270	95%
Gardabani	236	95%
Wind	20	97%
Total HPP	3,230	100%
Total TPP	862	95%
Total Current	4,112	99%

For the existing power plants, we assume 2024 capacity will be the same as in 2018. For power projects in different stages of planning and development, we assume two scenarios according to GSE's assumptions. For the base scenario, we assume 25% of the projects in the pipeline will be built, while for the pessimistic or low scenario we assume only 10% build out. The following table shows 2024 capacity for both scenarios.

Figure 24: New Power Plant Data

Additional Capacity by 2024			
	Base Case MW	Low Case MW	Availability %
Firm Imports	-	-	-
CC2020	250	250	99%
New ROR	258	103	100%
New Storage	230	0	100%
Wind	60	30	99%
Solar	30	10	99%
Generic New Capacity			
New TPP	As needed		99%

In 2024, energy generation by HPPs was estimated by scaling up 2018 actual generation by the new capacity for the base and low build scenarios (2024 generation = 2018 generation *(2024 capacity/2018 capacity)). The annual energy generated was then distributed to winter months based on the monthly generation percentages discussed earlier. 2024 HPP generation derived with this methodology and used in GRAM is given in the following tables.

Figure 25: ROR HPP Monthly Energy Generation

Regular Season	**Annual**	**Dec**	**Jan**	**Feb**
Energy Distribution	100%	6.9%	6.8%	6.2%
Base, GWh	5,157	357	349	321
Low Build, GWh	4,551	315	308	283
Dry Season	**Annual**	**Dec**	**Jan**	**Feb**
Energy Distribution	100%	6.9%	6.8%	6.2%
Base, GWh	4,641	321	314	289
Low Build, GWh	4,096	284	277	255

Figure 26: Storage HPP Monthly Energy Generation

Regular Season	**Annual**	**Dec**	**Jan**	**Feb**
Energy Distribution	100%	6.9%	6.8%	6.2%
Base, GWh	6,550	453	444	407
Low Build, GWh	5,801	402	393	361
Dry Season	**Annual**	**Dec**	**Jan**	**Feb**
Energy Distribution	100%	6.9%	6.8%	6.2%
Base, GWh	5,895	408	399	367
Low Build, GWh	5,221	361	354	325

DISCUSSION OF GRAM RESULTS

Main output of GRAM is the set of RA indices: PRM, LOLH, EUE and LOLP. We simulated "Scenario "1 with 593 (~600) MW of new capacity to get PRM close to the standard US value of 15%. The indices computed by GRAM for Georgia are compared with international benchmarks. Results of "Scenario 1" simulation are shown below:

Figure 27: GRAM Results – Annual – Scenario 1

Simulation Results: Computed Resource Adequacy Indices vs. Targets

Planning Reserve Margin (PRM)		Loss of Load Hours (LOLH)		
GRAM	US Values	GRAM	US Value	EU Values
15.0%	11 -16%	4	2.4	3-8
Expected Unserved Energy (EUE)		**Loss of Load Probability (LOLP)**		
GRAM	Australia Value	GRAM		US Values
0.003%	0.002%	27.2%		5-10%

- **LOLH** of 4 hours per year is higher than the US value of 2.4 hours but within the range of EU values of 3–8 hours;
- **EUE** values from the simulation is .003%. This is 50% higher than the Australian National Electricity Market (NEM) figure;
- **LOLP** value from the simulation is 27%. It is significantly higher than the US values.

Since the model simulates hourly and daily operations for December, January and February (31+31+28 = 90 days), monthly indices are also available for more detailed insights.

Figure 28: GRAM Results - Monthly

Monthly Results

	December	January	February
Reserve Margin %	15.0%	27.9%	29.3%
Monthly LOLH (Hours)	2.7	0.5	0.6
EUE (Mwhrs)	406	300	59

Figure 28 shows that December has the lowest PRM and the highest values for LOLH and EUE. Since the annual peak occurs in December, PRM for December is the key measure for annual RA. PRM for January is much higher indicating that the peak demand for January is lower and there is more spare capacity available to meet the demand. As a result, January LOLH and EUE are lower than December. Similarly, February indices are better due to even higher PRM.

We also present here the results from "Scenario 2". This scenario is based on higher demand growth as provided by GSE (5.14% per year vs. 3.36% for Scenario 1). With this higher growth rate, 2024 annual peak demand is 2,936 MW vs. 2,638 MW for "Scenario 1". This is the only change between the two cases. Due to higher demand and the same level of resources, RA indices are expected to be worse. Simulation results for this case are shown below:

Figure 29: GRAM Results – Annual - Scenario 2

Simulation Results: Computed Resource Adequacy Indices vs. Targets

Planning Reserve Margin (PRM)		Loss of Load Hours (LOLH)		
GRAM	US Values	GRAM	US Value	EU Values
3.2%	11 -16%	30	2.4	3-8
Expected Unserved Energy (EUE)		**Loss of Load Probability (LOLP)**		
GRAM	Australia Value	GRAM		US Values
0.022%	0.002%	94.8%		5-10%

- **PRM** drops to 3.2% in this case, significantly below the reference US values;
- **LOLH** jumps to 30 hours, meaning the customers are expected to see many hours of outage due to lower level of resource adequacy;
- **EUE** value jumps to .022%, roughly 11 times the reference value;
- **LOLP** value jumps to 95% indicating that the supply shortages are almost certain.

Similarly, monthly results from this simulation also indicate worsening values of RA indices.

Figure 30: GRAM Results – Monthly – Scenario2

Monthly Results

	December	January	February
Reserve Margin %	**3.2%**	**12.6%**	**16.0%**
Monthly LOLH (Hours)	**18.0**	**6.1**	**6.3**
EUE (MWh)	**3,896**	**2,270**	**810**

OPTIMAL RA CRITERIA FOR GEORGIA

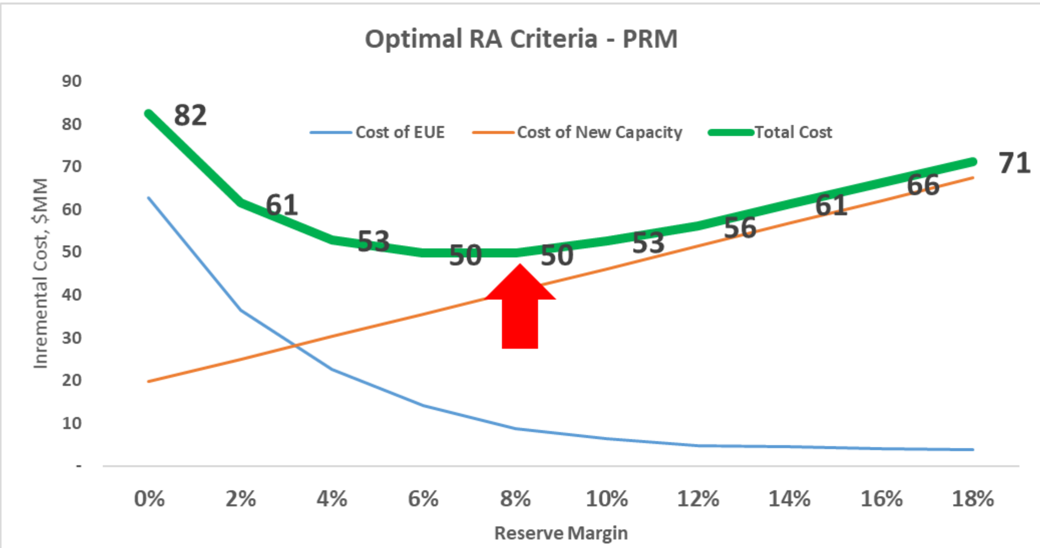
RA criteria of a utility or country depends upon the “value” placed on supply reliability. This “value” is a balance between the societal cost of unserved energy and the cost of building new capacity. In other words, this is a balance between what the customers are willing to pay for electricity vs. how much tolerance they have for supply interruptions. As a society develops, its dependence on electricity goes up. At the same time, its ability to pay a premium for supply reliability goes up and its tolerance for interruptions goes down. A remote village in a developing country will have a very low capacity to pay any premium for supply reliability relative to a highly developed society. For example, Texas power pool uses $9,000/MWh as the cost of unserved energy vs. the average cost of producing electricity of $40-50/MWh. This means, customers in Texas are willing to pay a premium up to 200 *times the cost* to ensure supply continuity. Texas power pool (and other utilities) minimize the probability of interruption by ensuring there is enough spare capacity available during peak demand hours. This spare capacity is needed to reasonably cope with unusual conditions, such as a drought, extreme cold or a breakdown in power generation plants. As already mentioned, US utilities typically use 15% spare capacity labelled as PRM in power planning parlance.

GRAM model can be used to develop an optimal level of PRM and other RA indices for Georgia. In addition to the data discussed above, two more inputs are needed for this optimization: the cost of unserved energy and the carrying cost of new generation capacity. These values were derived as follows:

- A simple way to derive EUE cost for Georgia is to link it to the cost of EUE in developed markets and use $9,000/MWh for Georgia as well;
- The cost of new capacity for Georgia was estimated using EIA (US Energy Information Administration) data at $800/kW as the overnight cost of new capacity (Combined Cycle – CC), 8% as the cost of long term debt and 16% as the cost of equity, with equity weighting of 25%. This gives the annual carrying cost of CC capacity of $110/kW/yr.

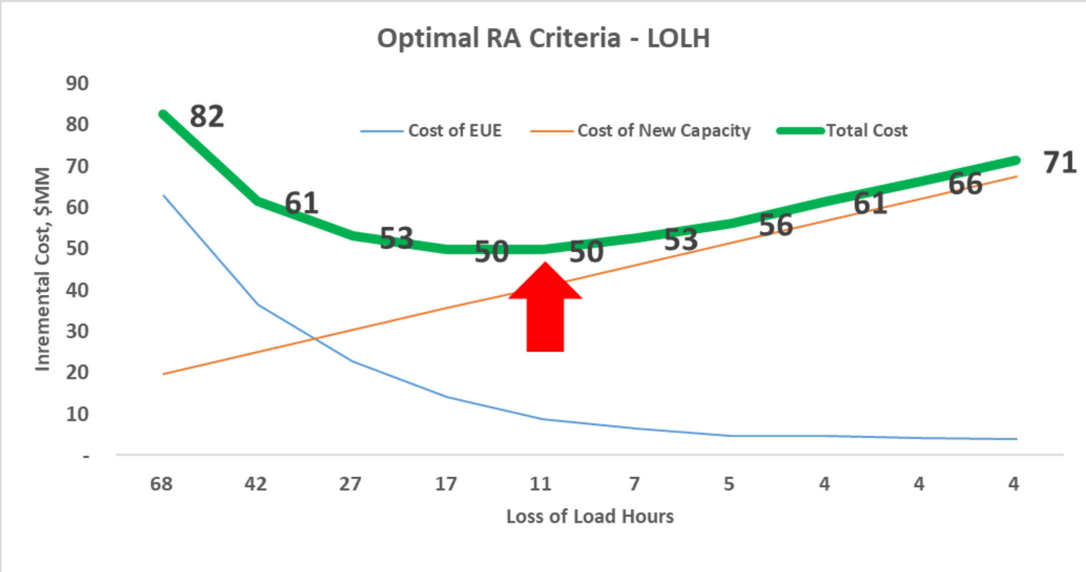
Using the above costs of EUE and the annual cost of new capacity, we ran multiple GRAM simulations with varying values of PRM. We started with PRM of 0% which required 200 MW of new TPP capacity in 2024. This low value of PRM results in a high value of EUE at 0.043% or 6,977 MWh (~21 times the target). The cost of this much EUE comes out to be about $63 millions. The annual carrying cost of a 200 MW TPP added in this simulation comes out to be $20 million. Then the simulation was repeated multiple times with new TPP in the increments of 2% PRM. The results of this analysis are plotted in the following chart. As expected, EUE declines (along with the associated cost) as PRM increases with the addition of more TPP. Blue line shows the declining cost of EUE while orange line shows the increasing cost of new capacity with increasing levels of PRM. The bold green line is the combined cost of EUE and new capacity. It can be seen in Figure 31 that the combined cost is minimum at about 8% PRM. This is the optimal level of PRM where the cost of EUE is balanced by the cost of new capacity. This means, Georgia should plan for a PRM of 8–10%.

Figure 31: GRAM Results – Optimal PRM Criteria



A similar chart showing LOLH as a function of additional new capacity is shown below. The incremental cost is minimum at LOLH value of 11. This means, based on the given assumptions, optimal level of LOLH for Georgia is 10-12 hours. This is only a guideline and as we saw earlier, if Georgia plans for 15% PRM, the resulting level of LOLH drops to 4.

Figure 32: GRAM Results – Optimal LOLH Criteria



As we saw in the last two charts, optimal PRM is really a function of the cost of EUE. This follows the earlier discussion in this section where we mentioned that as the dependence on electricity increases, the society is willing to pay a higher price for supply continuity, enabling the utility to invest in a higher level of PRM which in turn results in lower EUE and LOLH.

Conclusions

GRAM shows that Georgia should have at least 8% PRM with the expectations that there may be about 10–12 hours of supply shortages during the year. This means that in order to meet the peak demand of 2,638 MW in 2024, Georgia on top of 250 MW CCGT 2020 will need to build about 400 MW of new TPPs or equivalent effective capacity of hydro, wind, or other sources of energy, or mix of those resources in addition to at least 25% of new HPPs and renewable resources under various planning stages as in the GSE reference case. For all further analyses, 8% PRM is considered as the base case. The results of the base case are shown below:

Figure 33: GRAM Results – The Base Case

Simulation Results: Computed Resource Adequacy Indices vs. Targets

Planning Reserve Margin (PRM)		Loss of Load Hours (LOLH)		
GRAM	US Values	GRAM	US Value	EU Values
8.0%	11 -16%	11	2.4	3-8
Expected Unserved Energy (EUE)		Loss of Load Probability (LOLP)		
GRAM	Australia Value	GRAM		US Values
0.007%	0.002%	72.4%		5-10%

Monthly Results

	December	January	February
Reserve Margin %	8.0%	20.0%	21.3%
Monthly LOLH (Hours)	8.4	1.4	1.6
EUE (Mwhrs)	1,068	812	131

SCENARIO ANALYSIS

In addition to the base case, we analyze 15 scenarios to test the robustness of base case GRAM results. The scenarios were developed by varying four major input variables: Load, planned new Construction, Hydro availability and Import availability. The scenarios are labelled with the capital letter of the driver and a value "1" is given for base case and "2" for the change case. So, the scenario labelled as L1C1H1I1 has all the base values of the inputs while L**2**C1H1I1 has higher value of load. Following table shows the results of the base case and all the scenarios.

Table 3: GRAM Scenario Analysis

Scenario		Planning Reserve Margin (PRM)		Loss of Load Hours (LOLH)			Expected Unserved Energy (EUE)		Loss of Load Probability (LOLP)	
No.	Name	GRAM	US	GRAM	US	EU	GRAM	NEM	GRAM	US
1	L1 C1 H1 I1	8.0%	11 -16%	11	2.4	3-8	0.007%	0.002%	72%	5-10%
2	L2 C1 H1 I1	-3.1%	11 -16%	128	2.4	3-8	0.081%	0.002%	100%	5-10%
3	L1 C2 H1 I1	2.2%	11 -16%	33	2.4	3-8	0.021%	0.002%	98%	5-10%
4	L2 C2 H1 I1	-8.3%	11 -16%	274	2.4	3-8	0.185%	0.002%	100%	5-10%
5	L1 C1 H2 I1	3.0%	11 -16%	34	2.4	3-8	0.022%	0.002%	98%	5-10%
6	L2 C1 H2 I1	-7.6%	11 -16%	300	2.4	3-8	0.212%	0.002%	100%	5-10%
7	L1 C2 H2 I1	-2.2%	11 -16%	109	2.4	3-8	0.074%	0.002%	100%	5-10%
8	L2 C2 H2 I1	-12.2%	11 -16%	641	2.4	3-8	0.531%	0.002%	100%	5-10%
9	L1 C1 H1 I2	10.8%	11 -16%	5	2.4	3-8	0.003%	0.002%	45%	5-10%
10	L2 C1 H1 I2	-0.6%	11 -16%	73	2.4	3-8	0.042%	0.002%	100%	5-10%
11	L1 C2 H1 I2	5.0%	11 -16%	16	2.4	3-8	0.009%	0.002%	81%	5-10%
12	L2 C2 H1 I2	-5.7%	11 -16%	153	2.4	3-8	0.105%	0.002%	100%	5-10%
13	L1 C1 H2 I2	5.8%	11 -16%	18	2.4	3-8	0.010%	0.002%	85%	5-10%
14	L2 C1 H2 I2	-5.0%	11 -16%	182	2.4	3-8	0.119%	0.002%	100%	5-10%
15	L1 C2 H2 I2	0.6%	11 -16%	60	2.4	3-8	0.039%	0.002%	100%	5-10%
16	L2 C2 H2 I2	-9.7%	11 -16%	432	2.4	3-8	0.328%	0.002%	100%	5-10%

A brief discussion of the first 9 scenarios is given below. Scenarios 10–16 follow the discussion of scenarios 2–8 with the only exception of higher imported power which improves RA indices. We only discuss PRM and LOLH. Other measures like EUE and LOLP follow LOLH.

1. L1C1H1I1 — this is the base case. PRM is 8% and LOLH is 11 hours;
2. L2C1H1I1 — peak demand is higher. Supply is the same. PRM is negative, which means there is not enough capacity to meet demand. This scenario has a high value of LOLH. This scenario tells that if indeed the demand is expected to grow at 5.19 %, Georgia will need to add another 300 MW by 2024, otherwise RA will suffer;
3. L1C2H1I1 — construction of new HPP projects have been delayed and only 10% of all the projects in different development stage are built (instead of 25% in the base case). Due to lower capacity, this scenario results in high LOLH;
4. L2C2H1I1 — this is bit of an extreme case with demand increasing at a higher rate and the construction of new projects has been delayed. There is severe supply shortage resulting in high LOLH;
5. L1C1H2I1 — this scenario represents a drought year. The results show that reliability and resource adequacy suffer during a drought year and LOLH jumps from 11 to 34 hours due to the lack of energy in the hydro reservoirs;
6. L2C1H2I1 — this scenario builds on the last one and shows the impact of drought when load is growing at a higher rate. It obviously results in sustained supply shortfalls;
7. L1C2H2I1 — this case shows the impact of drought if new resources are delayed. The outages are higher than the base case, but better than if the demand is growing fast;
8. L2C2H2I1— this is indeed the worst-case scenario. Demand is growing at the higher rate, new construction has been delayed and there is drought. In this case, PRM has dropped to

negative 12.2% meaning the peak demand is 12.2% higher than all the resources put together which results in sustained shortfall with LOLH jumping to 641 hours;

9. L1C1H1I2 — this is the base case with higher imports (75 MW instead of 0 MW). PRM jumps to 10.8% from 8%. There are more resources to meet the demand. LOLH drops to 5 from 11. Other RA indices are also better than the “Scenario 1”;

10-16. For all these scenarios, RA indices are better because of the higher level of import.

It is clear from the results shown above that the biggest risk for Georgia RA is sustained demand growth at a high rate. If the demand is expected to grow at 5% or higher, the frequency and level of shortages will be much higher unless new capacity is brought online in a timely manner.

Risk of Dependence on Imported Power

As seen in the above chart and scenarios 9–16, imported power improves RA of Georgia. However, there is a risk of imports not being available all the time. The following table shows the results of scenarios where the imports are available only half the time. There are three following scenarios summarized in the table 4.

- The base case with zero imports;
- Scenario 9 with 75 MW imports;
- Scenario 9a with imports shut down 50% of the time.

Table 4: The Results of Three Import Related Scenarios

Scenario		Planning Reserve Margin (PRM)		Loss of Load Hours (LOLH)			Expected Unserved Energy (EUE)		Loss of Load Probability (LOLP)	
No.	Name	GRAM	US	GRAM	US	EU	GRAM	NEM	GRAM	US
1	L1 C1 H1 I1	8.0%	11 -16%	11	2.4	3-8	0.007%	0.002%	72%	5-10%
9	L1 C1 H1 I2	10.8%	11 -16%	5	2.4	3-8	0.003%	0.002%	45%	5-10%
9a	L1 C1 H1 I2	10.8%	11 -16%	8	2.4	3-8	0.004%	0.002%	61%	5-10%

One can see LOLH goes up to 8 when imports are shut half the time. This table clearly shows the risk of depending on imports for RA. If for any reason, imports are cut, RA suffers and the risk of supply shortages increases.

RECOMMENDATIONS

- Optimum PRM for Georgia is about 8%. New generation capacity should be added if PRM is expected to fall below 8% in the winter months.
- With GSE's low demand growth scenario of 3.36% annual growth rate, Georgia will need to build about 400 MW of new TPP or equivalent effective capacity of hydro, wind, or other sources of energy, or mix of those resources on top of 250 MW CCGT 2020 to maintain an acceptable level of RA. For the higher demand growth scenario of 5.19%, additional 300 MW of TPP or equivalent effective capacity of hydro, wind, or other sources of energy or mix of those resources will be needed by 2024.
- Georgia should keep minimal reliance on imports for RA as it is the practice in the EU countries and the US power pools. Reliance on imports should be capped at 3% of the peak demand or 75 MW for RA purposes. As analyzed in GRAM model, for 2024 RA purposes the reliance on imported power is limited to zero MW in the base case and in high import scenarios with three percent or 75 MW import. There should be maximum reliance on imports for economic power exchange and emergency support but not for RA.

APPENDIX A

Loss of Load Probability (LOLP), in units of percent, measures the probability that at least one shortfall event will occur over the time period being evaluated. By definition, since a probability must be greater than or equal to zero and less than or equal to one, LOLP is calculated as the number of simulations in which a shortfall occurs divided by the total number of simulations. It does not reflect the frequency of events because simulations with one or multiple shortfall occurrences are counted equally. LOLP also provides no information regarding duration or magnitude of resource shortfalls.

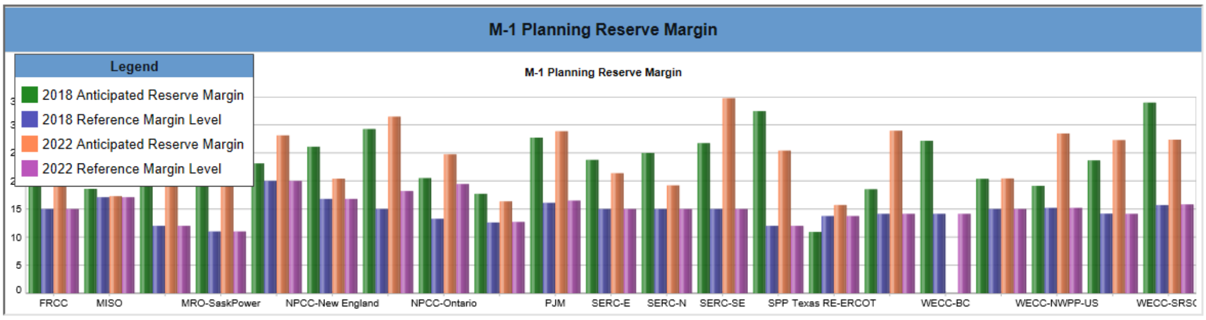
Loss of Load Expectation (LOLE), in units of days per year, is calculated as the number of days in which a shortfall occurs over every simulation divided by the total number of years simulated. Historically, many utilities have used a one-day-in-ten-year threshold (or 0.1 day/year) to plan for adequacy. This, however, can be misleading because multiple shortfall events can occur during a single day and a single event can last longer than one day. Originally, before the advent of the fast computers we use today, only the peak hour of each day was examined, thus equating an event to a day. However, most utilities now simulate the operation over each hour of the year and use the LOLH metric (described below). The LOLE provides no information regarding duration or magnitude of resource shortfalls.

Loss of Load Hours (LOLH), in units of hours per year, is calculated as the number of hours in which a shortfall occurs over every simulation divided by the total number of years simulated. Historically, many utilities have translated the one-day-in-ten-year threshold into a 0.1 day/year or into a 2.4 hours/year threshold for LOLH. As noted above, this translation is not valid since a typical shortfall event does not last 24 hours. A more typical duration for a shortfall event is on the order of 8 hours. Thus, if the intent is to limit shortfall events to one in 10 years (or 0.1 per year), the correct LOLH threshold is 8 hours/10-years or 0.8 hours/year. In this sense, the LOLH is a more precise metric for assessing adequacy than the LOLE. Like the LOLE, the LOLH provides no information regarding duration or magnitude of shortfalls.

Expected Unserved Energy (EUE), in units of megawatt-hours, measures the expected amount of energy (in megawatt-hours) not being served per year (or per hour). It is calculated by adding up all of the unserved energy over every simulation and dividing by the total number of years simulated (or by the total number of hours simulated). EUE provides some indication of the magnitude of shortfalls but only in aggregate. It does not reflect the frequency, duration or magnitude of individual shortfall events.

Overall, since no single metric provides full information, consideration should be given to all aspects of adequacy that planners value. The following provides details on how these adequacy metrics are calculated.

Figure A1: Expected PRM of Various Power Planning Areas – Pools



APPENDIX B

Figure B1 shows the availability of import power as a function of internal demand for a 30,000 MW utility in a competitive power pool. It can be seen that the availability is at maximum when the utility's own demand is around 50-60% of its peak. The availability of outside power reduces sharply as the internal demand increases towards peak demand. This makes sense as the neighboring systems experience peak demand around the same time – limiting the availability of power exports.

Figure B1: Availability of Outside Power as a Function of Internal Demand

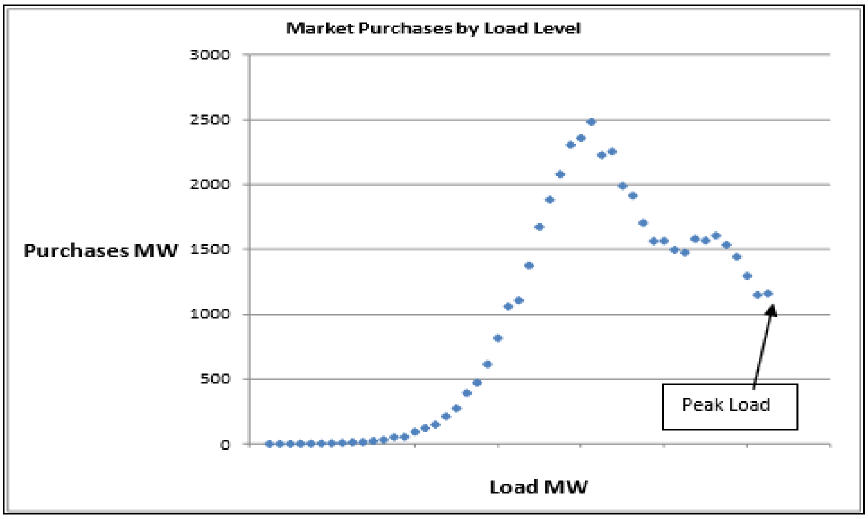
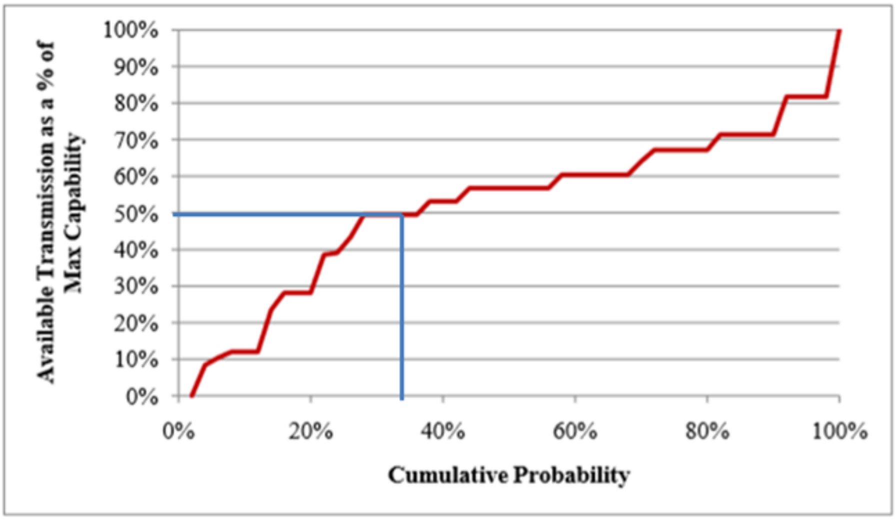


Figure B2 shows the cumulative probability of transmission capacity availability as a percentage of maximum capacity. For example, the blue lines on the chart indicate there is 35% probability that at any given time only 50% of the transmission capacity is available over the network. Similarly, the blue arrow on the curve shows there is 20% probability that the available transfer capability is about 30% of the maximum capacity. Bottomline, the actual load carrying capability of a transmission line can be significantly different than the maximum capacity. This chart further exposes the inherent risk of relying on transmission system to deliver desired amount of supply from neighboring systems at the time of peak.

Figure B2: Probability of Transmission Capacity Availability



APPENDIX C

Table C1: Computation Process to Determine the Values of RA Indices

		Available Supply each hour for Simulations 1-5					Count of LOLH	Hourly	Hourly	EUE
Hours	*Demand*	1	2	3	4	5	Hours	LOLP	EU	Propb
1	*10,221*	12,699	12,444	13,005	12,798	13,357	0	0	0	-
2	*9,878*	13,026	13,496	12,878	12,919	12,741	0	0	0	-
3	*9,622*	12,761	13,108	12,437	12,146	12,273	0	0	0	-
4	*9,487*	13,700	13,090	13,372	12,298	12,757	0	0	0	-
5	*9,476*	12,563	13,411	13,467	12,366	13,288	0	0	0	-
6	*9,659*	12,487	12,895	12,643	13,673	13,583	0	0	0	-
7	*10,141*	13,105	12,804	12,775	13,045	12,663	0	0	0	-
8	*10,907*	12,490	12,040	12,965	13,423	12,691	0	0	0	-
9	*11,937*	12,662	12,802	13,379	13,124	13,125	0	0	0	-
10	*12,453*	12,939	11,924	13,167	13,568	12,225	2	0.4	-757	0.30
11	*12,616*	13,144	12,456	12,965	12,331	12,356	3	0.6	-705	0.28
12	*12,685*	13,860	12,878	12,780	12,492	13,401	1	0.2	-193	0.08
13	*12,569*	12,938	12,691	12,512	12,679	12,332	2	0.4	-294	0.12
14	*12,386*	13,135	12,217	12,490	12,642	12,664	1	0.2	-169	0.07
15	*12,267*	13,453	12,122	13,329	12,719	12,810	1	0.2	-145	0.06
16	*12,015*	12,205	12,793	12,980	13,135	13,293	0	0	0	-
17	*11,830*	12,567	12,698	12,268	12,587	13,316	0	0	0	-
18	*12,110*	12,928	12,604	11,938	12,234	12,881	1	0.2	-172	0.07
19	*14,041*	12,863	13,629	11,985	13,503	13,130	5	1	-5095	1.81
20	*14,379*	12,213	13,035	13,177	12,857	14,484	4	0.8	-6234	2.17
21	*14,062*	13,276	12,867	13,177	12,942	12,402	5	1	-5646	2.01
22	*13,497*	13,276	13,016	12,772	13,021	13,563	4	0.8	-1903	0.70
23	*12,419*	13,432	13,028	13,477	12,929	12,576	0	0	0	-
24	*10,900*	13,159	12,580	13,341	13,092	12,636	0	0	0	-
1	*10,266*	12,700	12,444	13,012	12,800	13,357	0	0	0	-
2	*10,196*	13,033	13,500	12,887	12,921	12,743	0	0	0	-
3	*9,846*	12,767	13,111	12,439	12,152	12,280	0	0	0	-
4	*9,729*	13,701	13,094	13,382	12,307	12,760	0	0	0	-
5	*9,829*	12,568	13,420	13,473	12,370	13,296	0	0	0	-
6	*9,949*	12,495	12,901	12,647	13,675	13,586	0	0	0	-
7	*10,412*	13,109	12,804	12,776	13,050	12,669	0	0	0	-
8	*11,064*	12,495	12,050	12,966	13,428	12,695	0	0	0	-
9	*12,397*	12,666	13,811	13,386	13,128	13,130	0	0	0	-
10	*12,714*	12,948	11,926	13,173	13,569	12,232	2	0.4	-1270	0.50
11	*12,901*	13,148	12,460	12,969	12,334	12,364	3	0.6	-1545	0.60
12	*13,013*	13,861	12,884	12,783	12,502	13,403	3	0.6	-870	0.33
13	*13,030*	12,946	12,694	12,521	12,686	12,340	5	1	-1963	0.75
14	*12,658*	13,137	12,227	12,498	12,647	12,668	3	0.6	-602	0.24
15	*12,340*	13,456	12,130	13,330	12,723	12,815	1	0.2	-210	0.09
16	*12,095*	12,213	12,793	12,986	13,143	13,301	0	0	0	-
17	*11,982*	13,025	12,946	12,278	12,594	13,321	0	0	0	-
18	*12,315*	12,933	12,606	11,938	12,243	12,884	2	0.4	-449	0.18
19	*14,329*	12,866	13,636	11,989	13,510	13,138	5	1	-6506	2.27
20	*14,593*	12,214	13,037	13,179	12,861	14,492	5	1	-7182	2.46
21	*14,104*	13,283	12,873	13,180	12,946	12,407	5	1	-5831	2.07
22	*13,826*	13,280	13,016	12,774	13,024	13,569	5	1	-3467	1.25
23	*12,533*	13,442	13,035	13,483	12,932	12,580	0	0	0	-
24	*11,366*	13,164	12,583	13,341	13,094	12,644	0	0	0	-

Figure C1: Supply-Demand Balance

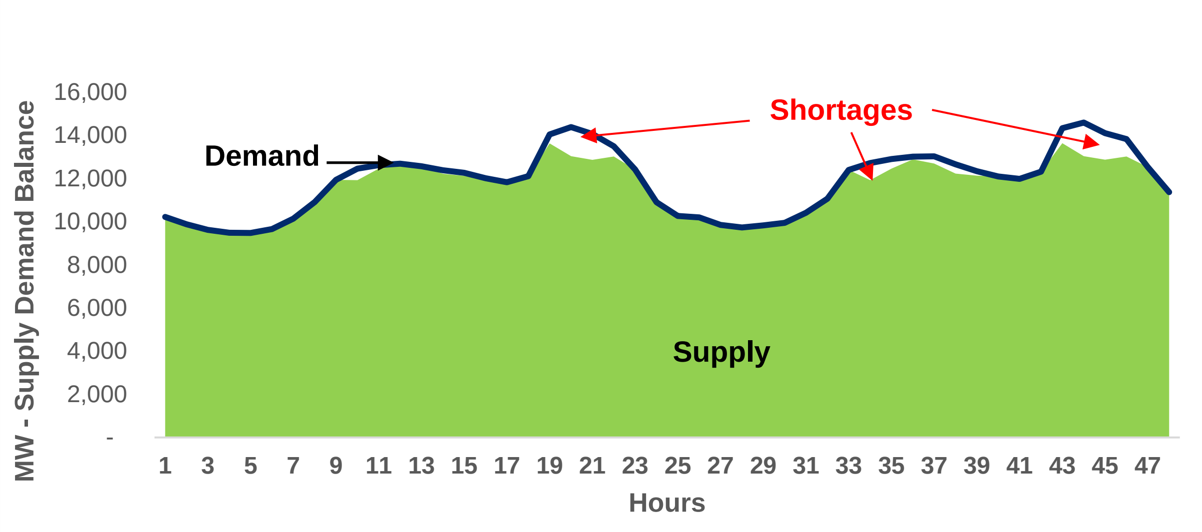


Table C2: RA Statistics

Simulation	1	2	3	4	5	Average
LOLH	9	18	14	15	12	13.60
LOLP	0.19	0.38	0.29	0.31	0.25	0.28
Loss of Load Occurrences (LLO)	3	5	4	4	7	4.60
LOL Event (Peak Hours) - Days/Period	2	2	2	2	1	1.8
EUE – MWh	9,644	11,060	12,103	10,150	8,251	10,242

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