AN OPTIMAL POWER FLOW MODEL TO GUIDE NATIONAL GRID EXPANSION IN ETHIOPIA FOR GROUNDWATER IRRIGATION

by
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Abstract

Ethiopia is a low-income country with an agrarian based economy that is susceptible to shocks, such as drought. Expanding groundwater irrigation (GWI) technologies can increase agricultural yields by providing a water source for crop production. There are upcoming mega-dams– the Grand Ethiopian Renaissance Dam, Genale Dawa III, and Koysha – that will triple the generation capacity and can supply electricity for GWI. To utilize this generation capacity, the transmission capacity of the national electricity grid, or Interconnected System (ICS), needs to expand into regions with high GWI potential.

This thesis builds a regional-scale linear optimal power flow model to guide cost-optimal generation operations and transmission expansion of the ICS to satisfy electricity demand from GWI. The model determines cost-optimal generation and transmission expansion for a baseline case and five scenarios that consider combinations of present and future estimations of internal demand, including domestic regional demand and electricity demand for GWI (low irrigation; high irrigation), and international export demand (current exports; future exports). Compared to the Baseline Scenario, seasonal capacity factors for electricity generation output in the five model scenarios increased or remained the same depending on the location of demand increase.

Results from four of the scenarios where internal and/or external demand increases indicate varying levels of expansion for five transmission lines in the regional network. The Ethiopian Electric Power Company (EEPCo) has a planned expansion of 1090 MW across these same five lines. All scenarios with higher domestic regional demand than the present baseline independent of irrigation and export changes surpass the transmission expansion planned by EEPCo, suggesting that the current expansion plan is not cost optimal.

This thesis contributes to the literature by modeling endogenous infrastructure decisions under different scenarios for internal and external demand. Modeling such decisions requires integrating the electricity network with energy demands from the agricultural sector and international export markets. The thesis builds a framework for answering research questions at the intersection of such topics that is broadly applicable to low-income countries. Further, the thesis provides a systematic framework for modeling electricity network infrastructure in data-poor settings through estimation, verification, and incorporation of unavailable data.

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List of Acronyms

AC	Alternating Current
CE/FE	Current Exports/Future Exports
DC	Direct Current
EEA	Ethiopian Energy Authority
EEPCo	Ethiopian Electricity Power Company
EEU	Ethiopia Electric Utility
GAMS	General Algebraic Modeling System
GDP	Gross Domestic Product
GERD	Grand Ethiopian Renaissance Dam
GIS	Geographic Information System
GW	Groundwater
GWI	Groundwater Irrigation
HVDC	High Voltage Direct Current
ICS	Interconnected System
JICA	Japanese International Cooperation Agency
LI/HI	Low Irrigation/High Irrigation
MOWIE	Ministry of Water, Irrigation, and Energy
NARUC	National Association of Regulatory Utility Commissioners
O&M	Operation and Maintenance
OPF	Optimal Power Flow

Chapter 1 – Background

Ethiopia is a low-income country with an agrarian based economy that is susceptible to shocks, such as drought. Its GDP and GDP per capita are $84 billion and $700, respectively (2018)[i]. For context, the U.S. GDP and GDP per capita are $20 trillion and $63,000, respectively (2018)[ii]. The agriculture sector is the biggest contributor to GDP, and rain-fed agriculture is the predominant method of crop production. Drought and other economic shocks to the agricultural sector can reduce crop yields, impacting economic development and domestic food security. The 1984-85 famine is an example of how both drought and economic shocks can impact food security for millions of Ethiopians[iii].

Ethiopia can expand groundwater irrigation (GWI) technologies to increase agricultural yields and mitigate the effects of drought and economic shocks to crop production. Less than 5% of arable land in Ethiopia is irrigated[iv]. Compared to surface water resources, groundwater (GW) is largely underutilized for irrigation. A reliable energy supply is needed to pump GW; however low rural electrification rates are a constraining factor to GWI expansion.

There is upcoming hydropower capacity that can supply electricity for large-scale GWI. However, the central electricity grid, the Interconnected System (ICS), is not developed to efficiently transmit power from these generation sources. Three upcoming mega-dams – the Grand Ethiopian Renaissance, Genale Dawa III, and Koysha – have a combined capacity that is more than double the existing generation capacity. The electricity network is not able to efficiently transmit this power due to transmission capacity constraints and low electrification rates. Ethiopia is seeking to expand the ICS to increase electrification throughout the country for both residential, industrial, and agricultural purposes. To increase GWI, the ICS must be expanded into regions with GW resources.

This thesis builds an optimal power flow model to determine cost-optimal generation operations and expansion of the ICS transmission capacity to satisfy electricity demand from GWI. The model analyzes how the upcoming influx of hydropower generation capacity can expand GWI throughout Ethiopia.

1.1 Ethiopian Electricity Sector

1.1.1 Current Electricity Consumption

Electrification rates in Ethiopia are low with 40% of the population having access to electricity; 29% of these connections are in rural communities and 85% in urban regions[v]. Total electricity consumption in 2018 was approximately 10 TWh [vi]. The total population with access to electricity is approximately 44 million, averaging an annual electricity consumption of 230 kWh for each person with access. To put in context, the total electricity consumption in the U.S. is 4,000 TWh, which includes both industrial and residential demands[vii]. U.S. residential electricity consumption per capita is approximately 11,000 kWh[viii]. On average, an American consumes almost 50 times more electricity than an Ethiopian.

1.1.2 Actors in the Energy Sector

There are various actors responsible for electricity generation, transmission, and regulation. Ethiopia's energy sector is not fully vertically integrated. Many low-income nations have vertically integrated power sectors where one entity, usually state-owned, is the sole operator for generation, transmission, distribution, and regulation. Ethiopia has split these responsibilities into different institutions, though they are all run by the state. The Ethiopian Electric Power Company (EEPCo) is the utility responsible for generation and transmission[ix]. It owns all generators and transmission lines in the country and operates the national grid. The Ethiopian Electric Utility (EEU) is the utility responsible for distribution, and the Ethiopian Energy Authority (EEA) is responsible for regulation [ix]. The Ministry of Water, Irrigation, and Energy (MOWIE) is the coordinating body for energy developments in Ethiopia. MOWIE is also in charge of capacity building, R&D, and supervision of institutions in the energy sector [ix].

1.2 Current National Grid System

1.2.1 Current Power Generation Mix

Ethiopia has an installed generation capacity of approximately 4,200 MW; 3,800 MW come from hydroelectric sources, 300 MW from wind, and 100 MW from thermal sources [v]. Since hydropower is more than 90% of the installed capacity, only hydropower is considered in this thesis. Table 1.1 is a list of the existing hydropower generators, their types, and capacities.

Table 1.1: Current Hydropower Plants and Capacities (MW)

Name	Type	Capacity (MW)
Takeze	Hydro - Reservoir	300
Awash II	Hydro – Run of the river	32
Awash III	Hydro – Run of the river	32
Amerti Neshi	Hydro - Reservoir	95
Fincha	Hydro - Reservoir	134
Tis Abbay I	Hydro – Run of the river	11.4
Tis Abbay II	Hydro – Run of the river	73

Beles	Hydro - Reservoir	460
Koka (Awash I)	Hydro - Reservoir	43
Gilgel Gibe I	Hydro - Reservoir	184
Gilgel Gibe II	Hydro – Run of the river	420
Gilgel Gibe III	Hydro - Reservoir	1870
Aba Samuel	Hydro - Reservoir	6.6
Melka Wakena	Hydro - Reservoir	153
		Total = 3814 MW

1.2.2 Transmission

The ICS is largely undeveloped, especially in rural regions as indicated by low rural electrification rates[x]. Currently, there are over 17,000 km of transmission lines ranging between 45 and 400 kV[xi].

1.3 Future Developments in the Electricity Sector

As stated above, energy, specifically electricity, is a critical input for GWI. EEPCo aims to expand the ICS, increase grid connections, and increase generation capacity to improve electrification rates. This section provides a brief assessment of future, on-grid developments to the ICS.

1.3.1 On-grid Developments

As previously stated, there is upcoming hydropower generation capacity in Ethiopia that is more than double the current installed generation capacity. The Grand Ethiopian Renaissance Dam

(GERD), Gilgel Gibe III, and Genale Dawa III are three mega-dams that are under construction. Table 1.2 provides capacities of these plants. The largest of these dams, the GERD, is a 6,000 MW dam that will become the largest dam in Africa. This influx of power can aid Ethiopia in its goal in achieving 100% electrification by 2025[xii]. Ethiopia's neighbors can also benefit from this influx of capacity by increasing their export demands.

Table 1.2 : Upcoming Hydropower Plants and Capacities (MW)

Name	**Type**	**Capacity (MW)**
GERD	Hydro - Reservoir – under construction	6000
Genale Dawa III	Hydro - Reservoir – under construction	254
Koysha	Hydro - Reservoir – under construction	2160
		Total = 8414 MW

EEPCo has plans to expand the ICS, including expanding lines to neighboring countries for exports. Approximately, 2,500 km of transmission lines are under construction and EEPCo has plans for further expansion [xi]. Kenya and Sudan have export agreements with Ethiopia. Kenya is building a HVDC line connecting the two countries and a double-circuit 500 kV will connect Sudan to the GERD [xi, xxxvii].

1.3.2 Future Demand

Domestic and export demand is expected to increase in the future. EEPCo estimates that there will be a 12.3% annual growth in domestic electricity consumption [xxxvii]. Kenya, Sudan, and Djibouti established export agreements with Ethiopia and are expected to increase their export allocation once the GERD is online. Sudan currently has a 100MW export agreement with Ethiopia and aims to increase the agreement to 1200 MW; 1000 MW will be for domestic use in Sudan and 200 MW will be sold to Egypt [xxxvii]. Kenya and Ethiopia have finalized a 400 MW export agreement [xxxvii]. Djibouti has a 100 MW agreement with Ethiopia and is in talks to expand its agreement [xxxvii]. Other nations such as Eritrea, Saudi Arabia, and Yemen are interested in purchasing electricity from Ethiopia.

1.3.3 Seasonal Effects of Electricity Supply

While the GERD and the other upcoming hydropower plants will increase power generation capacity, a changing climate may make electricity supply unpredictable. In dry years, the streamflow in river systems throughout Ethiopia is reduced, which impacts hydropower production [x]. A changing climate poses risks to electricity supply for countries that are dependent on hydropower production, such as Ethiopia, which has a power mix consisting of 99% hydropower[xiii].

1.4 INFEWS coupled model

This electricity model is one component of a larger coupled model that is studying the food, energy, water (FEW) nexus in Ethiopia. The project name is “Innovations at the Nexus of Food Energy Water Systems (INFEWS): Understanding multi-scale resilience options for climate-vulnerable Africa."[xiv] (NSF Award #1639214). The following are the INFEWS research questions:

(1) How are current energy and agricultural development strategies influencing food security and economic well-being at local levels, particularly considering climate variability and change?

(2) Can integrated FEW development strategies—including distributed (off-grid renewable energy, enhanced agricultural management) and centralized (large scale electrification, agriculture development, trade policies) approaches—improve local food security and economic well-being under changing climate and water resource conditions?

(3) Are there commonalities in FEW development policies and investment strategies in different countries?

The electricity model in this thesis aims to understand how future energy developments and climate change can impact food and water systems in Africa. As mentioned in the previous section, upcoming hydropower capacity has the potential to revolutionize various economic sectors, especially the agriculture sector. However, energy production will vary under a changing climate. This model is an optimal power flow model that will compute cost optimal generation operations and grid expansion by considering the transmission constraints, generation constraints, and nodal balances of the electricity network.

To be consistent with the INFEWS model, the optimal power flow model will disaggregate Ethiopia into regions. The INFEWS project has divided Ethiopia into 14 regions using Thiessen Polygons[xv] illustrated in Figure 1.1. Each region has a city, which functions as a regional hub. Every point in each region is closest to the regional hub than other regional hubs.

These cities are the largest cities in Ethiopia and are included as the electricity demand nodes in the model. The electricity model will maintain the same regions constructed in Figure 1.1.

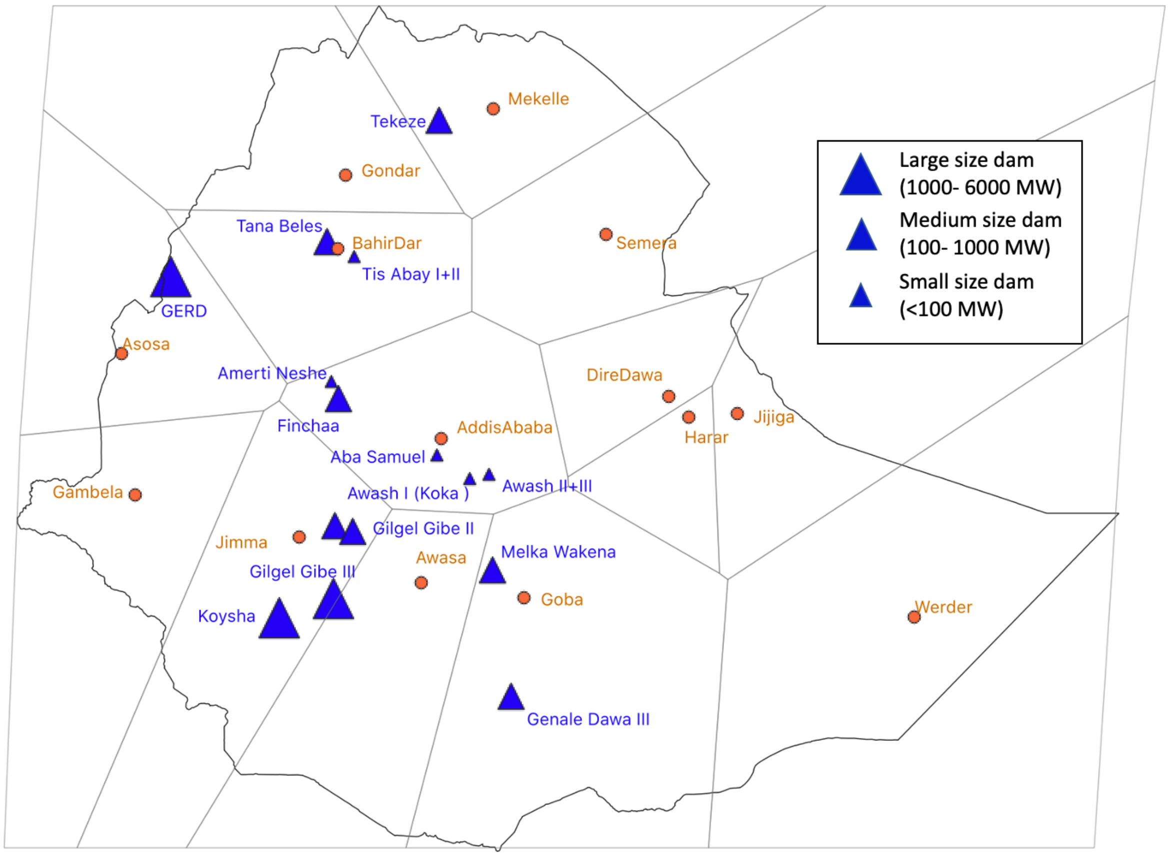

Figure 1.1: Regional Disaggregation of Ethiopia with City Nodes and Dams

Chapter 2 – Research Objectives

The overall research objective is to create a regional-scale linear optimal power flow model to guide cost-optimal generation operations and grid expansion in Ethiopia for GWI. The model will consolidate information on existing generation and transmission infrastructure and estimate future demands. Due to the data-poor environment, this thesis does not claim to accurately depict the functions of the ICS, rather it provides a framework for a transmission expansion model that can be updated once more accurate data is collected.

2.1 Specific Research Objectives

The specific research objectives are the following:

1. Build a regional optimal power flow model in GAMS[xvi], specifically a linear program that minimizes costs and includes generation constraints, transmission constraints, and nodal balance constraints.
2. Create a regional transmission network representation that consolidates existing published data from the Ethiopian Electric Power Company and the World Bank.
3. Create a regional 24-hour load curve by disaggregating the annual domestic 24-hour load curve according to spatial population data.
4. Estimate the following demand inputs:
    a. Electricity demand from GWI in dry and wet seasons
    b. Future domestic and export electricity demand

Chapter 3 – Literature Review

This section is a brief literature review on three topics related to this thesis: (1) optimal power flow models and their applications, (2) existing literature on the electricity sector in Ethiopia, and (3) GWI research in Ethiopia. This literature review aims to indicate the research gap in transmission expansion modelling in Ethiopia for GWI.

3.1 Optimal Power Flow Models for Grid Expansion:

Optimal power flow (OPF) optimization models are cost minimization problems with constraints that enforce power balances at each node, limits on generation, and power flow limits on network lines. Several formulations exist for the optimal power flow models, including linear programs [xvii], nonlinear programs [xviii], and mixed integer programs [xix]. Common versions of these models are the polar power-voltage formulation, the rectangular power-voltage formulation, the rectangular current-voltage, and the direct current (DC) approximation [xx].

There is significant literature on optimal power flow models to determine cost-minimization of transmission expansion [xxi]. Direct Current OPF (DCOPF) is the prominent model using in transmission planning literature [xxii]. DC OPF models are the linearized versions of AC OPF models that are computationally easier to solve. However, they exclude a lot of details in the network that are considered in AC OPF models [xxiii].

There are also other linear and nonlinear OPF models that further reduce grid details by excluding information on reactance, voltage angles, and transformers. These types of transmission expansion models are useful in situations where data are unavailable or when grid detail is not necessary to the study. Alguacil *et al.,* (2003) build a mixed integer linear program to analyze long term transmission expansion planning for the Brazilian electricity network [xxiv].

Fu *et al.,* (2005) create an OPF pricing model to analyze system congestion by considering the market environment that drives pricing of electricity [xxv].

Currently there is no OPF model to determine transmission expansion in Ethiopia that is publicly available. The National Load Dispatch Center runs a dispatch model to determine generation and power flow in the network. However, it is limited in its ability to include future generation and is not used for transmission expansion planning [xxvi].

3.2 Electricity Sector in Ethiopia and Grid Expansion

Literature on the ICS is predominantly centered on generation and demand estimation. A review paper on electricity literature in African countries collected 20 papers on electricity in Ethiopia [xxvii]. Ten of these papers study renewable energy systems, and six of these ten papers focus on implementing renewable energy systems to increase rural electrification. Three papers study hydropower operations and investment in future capacity. Three papers are centered on policy in the electricity sector. And the remaining four papers study future demand estimation.

There are few papers focused on on-grid transmission expansion in Ethiopia. One reason may be that this type of research requires data on the transmission network—such as reactance or transmission lines, voltage angles, an updated network map, and hydraulic parameters—which are not publicly available. Some papers have collected data from the utility [xxviii]; however, these data have yet to be applied to transmission expansion literature in Ethiopia. Another reason why research on the central grid expansion is low is due to the high investment costs to expand the ICS. Compared to on-grid expansion, off-grid electrification is both faster and cost-effective for areas that do not already have existing transmission lines. It is difficult and expensive to build transmission lines because of dispersion of rural communities from the grid, geographical barriers, and lack of existing transmission infrastructure that can be readily extended[xxix].

There are other methods of analyzing transmission expansion apart from optimal power flow models. Mentis *et al.,* (2016) use spatial analysis to determine population density around the ICS [xxx]. While this paper provides a spatial understanding to expansion it is limited in understanding the physical constraints to transmission expansion. Optimal power flow models can determine grid expansion possibilities by including details on the physical constraints of the transmission network.

3.3 Groundwater Irrigation and Electricity Needs

Existing literature on GWI in Ethiopia predominantly focus on GW quality and land irrigability. Worqlul *et al*., (2017), You *et al.,* (2011), and Tesfagiorgis *et al.,* (2011) study land suitable for irrigation in Ethiopia [iv, xxxi, xxxii]. Villholth (2013) notes that GW is a reliable source of water for farmers because it is not sensitive to climate variability [xxxiii].

There are few papers that focus on GWI and the electricity needed to expand GW pumping technologies in Ethiopia. There are studies that correlate low GWI use to low electrification rates. Villholth (2013) states that electrical pumping has lower running costs, but it is constrained by low rural electrification rates; there is an increase in GWI when there is an increase in rural electrification. There are papers that study the distribution of decentralized technologies to supply electricity for GWI. Schmitter *et al.,* (2018) use GIS to determine areas that are suitable for solar PV pumping technologies through spatial analysis of solar radiation and GW potential [xxxiv].

Chapter 4 – Model Formulation

As mentioned in Chapter 2: Research Objectives, this thesis develops an optimal power flow model that is used to study cost-optimal generation and expansion of Ethiopia's ICS on a regional scale. The features included in this model are the following:

1. Transmission infrastructure that is existing and under construction
2. Hydropower plants that are existing and under construction
3. Present and future estimates of domestic electricity demand disaggregated regionally
4. Estimates of electricity demand for GWI in dry and wet seasons
5. Present and future export demands

This optimization model minimizes generation and transmission expansion costs and is constrained by transmission capacity limits, generation capacity limits, and nodal balance constraints. Table 4.1 lists the sets, decision variables, and parameters in this model. The data inputs into the model is detailed in the following Chapter 5: Data Inputs. The GAMS code for this model is in Appendix A.

Table 4.1: Sets, Decision Variables, and Parameters

Symbol	Unit	Type	Description
i	unitless	Set	Set of regional nodes. i = 1, 2, …, N, where N is the total number of nodes. In this model N = 20.
j	unitless	Set	Set of regional nodes. j = 1, 2, …, N, where N is the total number of nodes. In this model N = 20.
$j \in G_i$	unitless	Set	Set of regional nodes j connected to node i.
t	hours	Set	Time periods. t = 1, 2, …, τ where τ is the total time periods.

			In this model τ = 24.
s	unitless	Set	Seasons in the model. s = 1, 2; S = {1,2} There are only 2 seasons considered in this model. (1) Dry season (2) Wet season.
$P_g(i,\ t, s)$	MW	Decision Variable (continuous)	Real power generation at node *i* during time period *t* in season *s*.
$T(i, j, t, s)$	MW	Decision Variable (continuous)	Real power flow from node *i* to node *j* during time *t* in season *s*.
$Exp(i, j)$	MW	Decision Variable (continuous)	Transmission capacity expansion.
$P_{g\_max}(i, s)$	MW	Parameter	Maximum generation capacity of generation at node *i* in season *s*.
$P_{g\_cap}(i)$	MW	Parameter	Installed capacity of generation at node *i*.
$P_d(i, t, s)$	MW	Parameter	Demand at node *i* during time *t* in season *s*.
$T_{max}(i, j)$	MW	Parameter	Transmission capacity on the line connecting node *i* to node *j*. This is calculated by the following equation: $T_{max}(i, j) = I * V(i, j)$ where *I* is the current carrying capacity and is the voltage of the line.
$T_{length}(i, j)$	miles	Parameter	Length of line connecting node *i* to node *j*.
d_s	days	Parameter	Days in season *s*.
VC	$\frac{\$}{MWh}$	Parameter	Variable O&M costs. In this model the variable cost is constant for each hydropower plant.
FC	$\frac{\$1000}{MW}$	Parameter	Fixed cost.

			In this model the fixed cost is per MW capacity for each plant. This cost is constant for each plant.
EC	$\frac{\$}{MW \cdot mile}$	Parameter	Expansion cost per MW-mile.
L_{ij}	unitless	Parameter	Transmission loss factor along the transmission line connecting node *i* to node *j*.
Y	years	Parameter	Total number of years to recover investment costs.
R	percentage	Parameter	Discount rate.

4.1 Objective Function

As stated above, the objective function includes generation and transmission expansion costs, which are minimized in this model. Generation costs considered in this model are generic annual fixed costs and variable O&M costs specified in the East African Power Pool's 2014 Master Plan[xxxv]. Transmission expansion costs are the total cost per MW-mile of expansion.

4.1.1 Total Annual Generation Costs

Generation costs include generic annual O&M fixed costs and variable O&M costs

$$Fixed\ cost = FC \sum_{i \in N} P_{g\_cap}(i) \qquad \text{Eq 4.1}$$

where FC is the annual fixed O&M cost ($1000/MW); $P_{g\_cap}(i)$ is the installed capacity (MW) at node *i*. The fixed cost is not time dependent and does not change seasonally; therefore, it is summed over all nodes.

$$Variable\ cost = VC \sum_{s \in S} d_s \sum_{t \in \tau} \sum_{i \in N} P_g(i,\ t,\ s) \qquad \textit{Eq 4.2}$$

where VC is the variable O&M cost ($/MWh); $P_g(i,\ t,\ s)$ is the real power generation (MW). To calculate total cost per year, the variable cost is calculated over all nodes in the system for one year. There are two seasons in the model, dry and wet; d_s is the total days in each season.

4.1.2 Total Annualized Expansion Costs

$$Expansion\ cost = \left(\frac{r(1+r)^Y}{(1+r)^Y - 1}\right) EC \sum_{i \in N} \sum_{j \in G_i} Exp(i,j) * T_{length}(i,j) \qquad \textit{Eq 4.3}$$

where EC is the expansion cost ($/MW- mile). $Exp(i,j)$ is the total MW capacity expanded on the line; $T_{length}(i,j)$ is the length of the line; G_i is the set of all nodes *j* connected to node *i.* The term $\left(\frac{r(1+r)^Y}{(1+r)^Y-1}\right)$ is the capital recovery factor that annualizes the expansion costs.

4.1.3 Objective Function

Eq 4.1 - Eq 4.3 form *Eq 4.4,* which is the objective function for the model.

$$\underset{\substack{P_g(i,t,s) \\ Exp(i,j) \\ T(i,j,t,s)}}{\text{Minimize:}} \quad FC \sum_{i \in N} P_{g\_cap}(i) + VC\left(\sum_{s \in S} d_s \sum_{t \in \tau} \sum_{i \in N} P_g(i,\ t,\ s)\right) + \left(\frac{r(1+r)^Y}{(1+r)^Y - 1}\right) EC \left(\sum_{i \in N} \sum_{j \in G_i} Exp(i,j) * T_{length}(i,j)\right) \qquad \textit{Eq 4.4}$$

4.2 Constraints

The objective function is constrained by nodal balance, transmission capacity, transmission expansion capacity, and generation constraints. In addition, all decision variables are continuous and non-negative.

4.2.1 Nodal Balance Constraint

$$P_g(i,t,s) = \sum_{j \epsilon G_i} T(i,j,t,s) - (1 - L_{ij}) \sum_{j \epsilon G_i} T(j,i,t,s) + P_d(i,\ t,s) \qquad \textit{Eq 4.5}$$

Eq 4.5 is a nodal balance constraint, which states that power flowing into a node must equal the power flowing out of the node. This equation is rearranged to solve for $P_g(i,t,s)$; $T(i,j,t,s)$ is the real power flowing from node *i* to node *j*; $T(j,i,t,s)$ is the real power flowing from node *j* to node *i*; L_{ij} is the fraction of power lost flowing from node *j* that reaches node *i*.

4.2.2 Transmission Capacity Constraint

$$T(i,j,t,s) \leq T_{max}(i,j) + Exp(i,j) \qquad \textit{Eq 4.6}$$

$$T_{max}(i,j) = I * V(i,j) \qquad \textit{Eq 4.7}$$

where $T_{max}(i,j)$ is estimated as the product of the current carrying capacity, I (Amps), and the voltage of the line, $V(i,j)$. In this model each line has the same value for current carrying capacity; I is a constant.

4.2.3 Expansion Capacity Constraint:

$$\sum_{i=1}^{N} \sum_{j \epsilon G_i} Exp_{length}(i,j) * T_{length}(i,j) \leq 0.1 \sum_{i=1}^{N} \sum_{j \epsilon G_i} T_{max}(i,j) * T_{length}(i,j) \qquad \textit{Eq 4.8}$$

Eq 4.8 is the expansion capacity constraint. For this model, the total expansion has an upper limit of 10% of the total MW·mile of existing transmission lines.

4.2.4 Generation Constraint

$$P_g(i,\ t,\ s)\ \leq\ P_{g\_max}(i,s) \qquad \textit{Eq 4.9}$$

The real power generation at each node is constrained by the generation capacity at that node. The capacity varies seasonally.

4.2.5 Nonnegativity

Negative values for real power generation, transmission, or expansion cannot exist; therefore. Since both $T(i,j,t,s)$ or $T(j,i,t,s)$ can exist in the model, all transmission flows are non-negative.

$$P_g(i,t,s) \geq 0,\ \ T(i,j,t,s) \geq 0,\ Exp(i,j) \geq 0$$

Chapter 5 – Data Inputs

Chapter 5 will detail the calculations and data sources of the following model inputs:

1. Generation data
2. Transmission network, capacity, and loss estimates
3. Estimates of electricity demand from GWI
4. Seasonality in generation data and GWI demand
5. Export demand
6. Regional 24-hour electricity load curves

Data-Poor Environment:

An accurate optimal power flow model that considers the physical constraints of the electricity network is not possible due to the lack of data needed for this type of model. Data that are needed include reactance of transmission lines, an updated and verified transmission network map from the utility, ramp rates of dams, and an hourly demand time series. The utility, EEPCo, does not have this information publicly available. Obtaining these data from EEPCo would provide a more realistic model. However, due to the constraints in data collection, the focus of the thesis is to create a model framework for grid expansion in Ethiopia that can later be updated with accurate data inputs.

Disaggregating Ethiopia into Regions:

There are 14 regions that are selected for this model that align with the INFEWS model indicated in Chapter 1: Background. Each region consists of a city node. Collectively, these 14 cities are the most populous and spatially distributed cities in Ethiopia. The country is disaggregated into the 14 regions by constructing Thiessen Polygons[xv] around the city nodes. The space in the polygon constructed for a node is the closest to that node than any other node. Figure 1.1 in Chapter 1: Background is a map of these cities and their associated Thiessen polygons.

5.1 Generation

This section provides details on the generation inputs, including generation costs and capacities. According to EEPCo's 2014 Master Plan, each hydropower plant has a generic fixed cost of 45.53 $1000/MW and a variable cost of 3.25 $/MWh [xxxv]. There are 14 operating hydropower plants and three plants under construction that are considered in this model. Figure 5.2 below is a map of the hydropower plants. Table 1.1 in Chapter 1: Background are the capacities of each hydropower plant. Because this model is studying regional power flows, the hydropower capacities will be aggregated to the regional nodes. This is process is detailed later in Section 5.2.3. Table 5.1 indicates the aggregated generation capacity for each regional node, which are mapped in Figure 5.5.

Table 5.1: Hydropower Capacity (MW) Aggregated to Regional Nodes

Region	Total Capacity (MW)
Addis Ababa	345
Asosa	0
Awasa	0
Bahir Dar	545
Dire Dawa	0
Gambela	0
GERD	6000
Genale Dawa	254
Goba	153
Gondar	0
Harar	0
Jijiga	0
Jimma	604
Koysha	4030
Mekelle	300

Semera	0
Total	**12231**

5.2 Transmission Network Model and Data

This section provides details of the data consolidation and network reduction process to create the transmission network used in the model. The estimates for transmission capacity are also detailed below.

5.2.1 Data Sources

All transmission network data considered in this model come directly from the World Bank's Ethiopia Transmission Network Map or from EEPCo [xi, xxxvi, xxxvii]. Data collected from EEPCo comes from the company's website or its report in the National Association of Regulatory Utility Commissioners (NARUC) publication database. Figure 5.1 is an illustration of the high-voltage transmission network from EEPCo. This figure includes existing and planned lines that are 230 kV or higher. Figure 5.2 is a GIS map of the country's transmission network from the World Bank that includes both existing and planned lines. Georeferenced city nodes, export nodes, and dams of interest are added to the map.

All of the existing lines in the EEPCo map, Figure 5.1, are georeferenced in the World Bank Map. Figure 5.2 is used to construct the transmission network for the model.

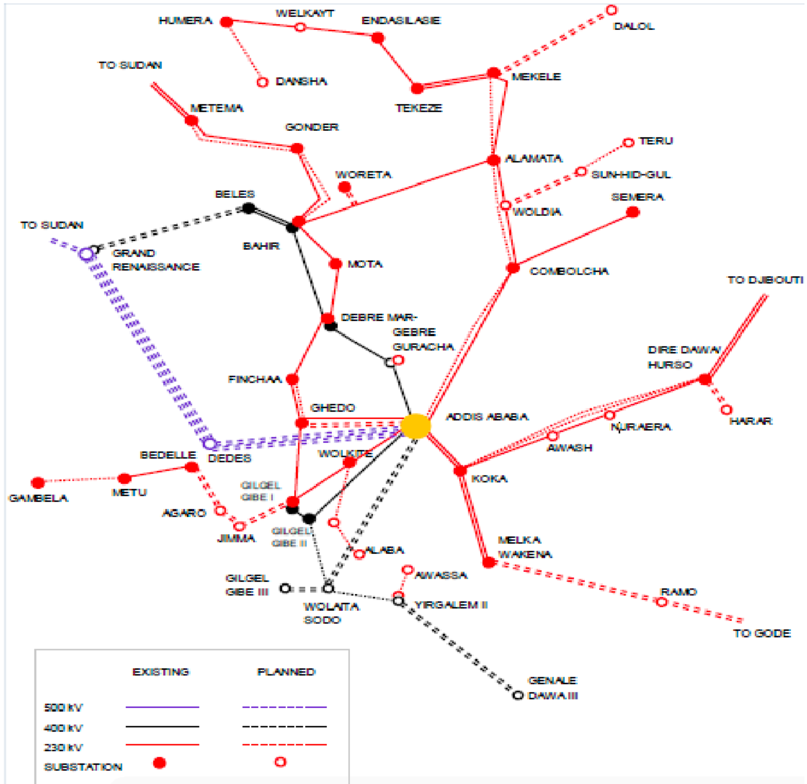

Figure 5.1: EEPCo Transmission Network Representation of 230-500kV lines

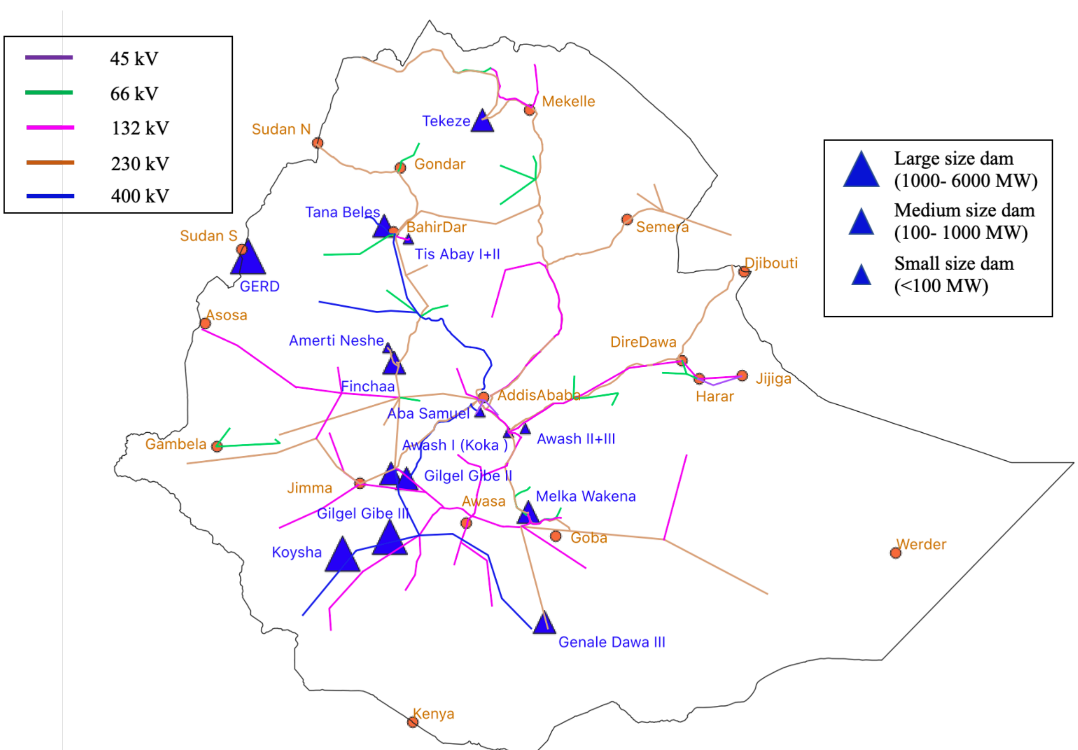

Figure 5.2: Transmission Network from The World Bank Including City Nodes, Export Nodes, and Hydropower Dams

5.2.2 Network Simplification

Using Figure 5.2, non-critical lines and nodes are eliminated and critical lines that are under construction are added. Non-critical lines include all lines that are < 230 kV except those that are the sole connecting line from the city node to the main grid. This study is mainly considering the bulk of power flow on transmission lines in Ethiopia, which flows on transmission lines with voltages of 230 kV or higher[xxxviii]. Since low voltage lines have more losses, only higher voltage lines will be used in situations when higher voltage lines are parallel to a lower one. Therefore, these lower voltage lines are also eliminated.

There is one non-critical node in the model, which is Werder, a city in the southeast. Werder is a non-critical node because it is not connected directly to the transmission grid as illustrated in Figure 5.2. Even though Werder is removed, the original Thiessen polygons are kept to align these regions with the regions in the INFEWS project discussed in Chapter 1: Background.

Additional lines added to these maps include 230kV, 400 kV, or 500 kV lines that are under construction and connect city nodes, export nodes, or dams to the main grid. Table 5.2 indicates the lines added to the grid, including the source of these data. Figure 5.3 is the consolidated map that eliminates the non-critical lines and node and includes lines under construction.

Table 5.2 Transmission Lines Added to Transmission Network Map

From Node	To Node	Type	Source
Awasa	Kenya	500kV HVDC line	xxxix
GERD	Bahir Dar	Double circuit 400 kV	EEPCo xxxvii
GERD	Addis Ababa	Four circuit 500 kV	EEPCo xxxvii
GERD	Sudan S	Double circuit 500 kV	EEPCo xxxvii
Awasa	Addis Ababa	Double circuit 400 kV	EEPCo xxxvii

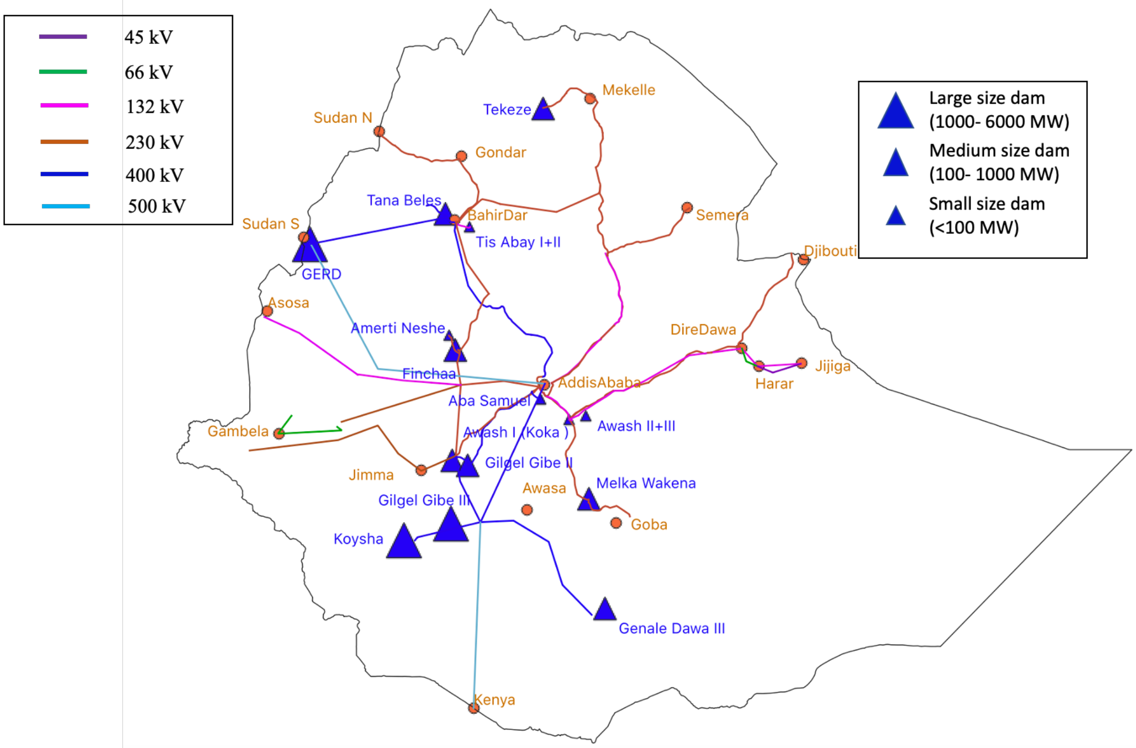

Figure 5.3: Transmission Network Map with Critical Lines Added and Non-critical Lines Removed

Figure 5.3 is the final transmission network that includes all critical connections to the dams, city nodes, and export nodes used in the model. In conclusion, this is the most updated network map that could be constructed from consolidating data from EEPCo and the World Bank.

5.2.3 Regional Disaggregation of Network

The research objective is to study regional power flows and grid expansion in Ethiopia; therefore, this model simplifies the national electricity grid into a regional electricity network. This simplification is conducted by overlaying the Thiessen polygons from Figure 1.1 onto Figure 5.3 and combining the transmission capacity between each region. Figure 5.4 is the regional network map. The lines in the map are representations of power flow pathways, but the lengths of these lines are calculated using the original World Bank transmission network map in Figure 5.3. Each node is labelled corresponding to the city node or dam that it represents.

While there are 14 regions, 13 of them with city nodes, there are a total of 20 regional nodes. Four of these nodes are export nodes. Three nodes are added because the original transmission network map indicates that these nodes have generation capacity that is not directly connected to the city node. There are three examples of this situation:

1. The Koysha node includes the Koysha dam and Gilgel Gibe III dam. These two dams are not connected to Jimma, the city node of that region.
2. Genale Dawa III is not directly connected to Goba but has a line under construction connecting the dam to Awasa.
3. The GERD is not directly connected to Asosa and is directly connected to the southern Sudan export node.

For each regional node, the dam capacity is aggregated at the closest regional node. These aggregated capacities were listed in Table 5.1 above. Figure 5.5 indicates the total capacity at each regional node.

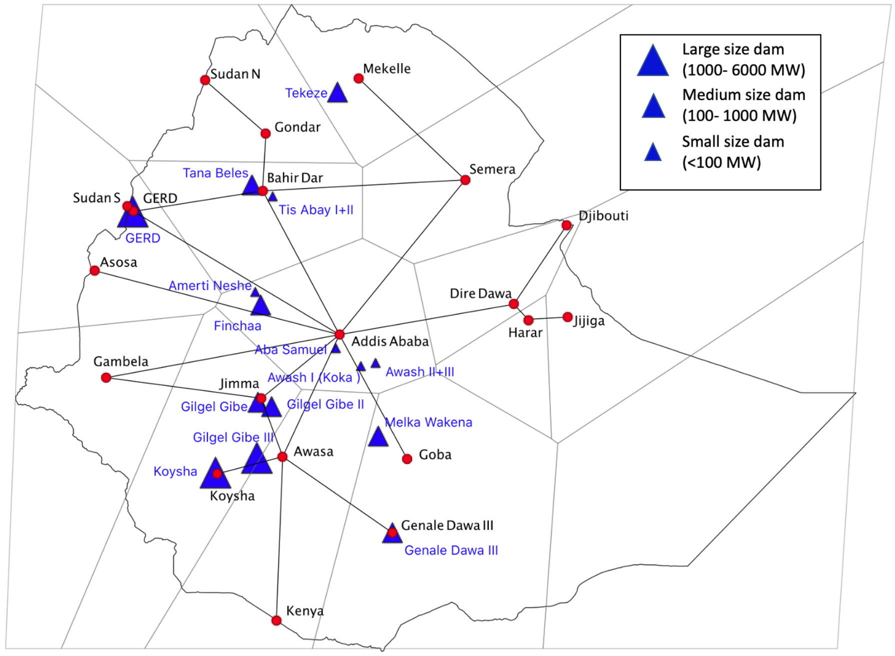

Figure 5.4: Regional Transmission Network Map with Disaggregated Generation Capacity

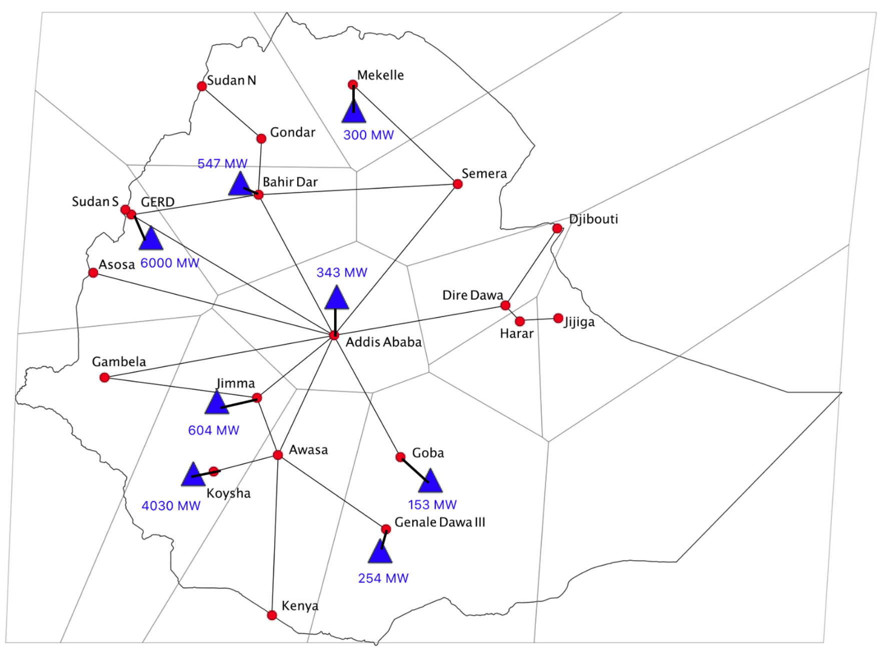

Figure 5.5: Regional Transmission Network Map with Regionally Aggregated Generation Capacity

5.2.4 Transmission Capacity Calculation

There are no public data on transmission capacity; therefore, Ohm's Law is used to approximate the power transmission capacity (MW) of each line. Eq 5.1 is used to calculate the power flow capacity of each line by assuming the current carrying capacity, I, is 1,000 amps. V is the voltage of the regional line, which aggregates voltages listed in the World Bank GIS file. Table 5.3 below is the combined transmission capacity between each region.

$$P = IV \qquad \text{Eq 5.1}$$

Table 5.3: Regional Transmission Line Capacity (MW)

From Node	To Node	Transmission Capacity (MW)
Mekelle	Semera	230
Semera	Bahir Dar	230
Bahir Dar	Gondar	230
Gondar	Sudan N	230
Bahir Dar	Addis Ababa	630
Bahir Dar	GERD	800
GERD	Addis Ababa	2000
Addis Ababa	Semera	230
Addis Ababa	Dire Dawa	230
Dire Dawa	Harar	198
Harar	Jijiga	177
Dire Dawa	Djibouti	460
Addis Ababa	Goba	460
Addis Ababa	Asosa	132
Addis Ababa	Awasa	800
Addis Ababa	Gambela	230
Addis Ababa	Jimma	630
Gambela	Jimma	230
Jimma	Awasa	400
Awasa	Koysha	400
Awasa	Kenya	500
Awasa	Genale Dawa	400
GERD	Sudan S	1000

5.2.5 Transmission Loss

Transmission losses are included in the model through parameter L_{ij} listed in Table 4.1, Chapter 4, – Model Formulation. The losses are included to ensure that the closest demand is met by the closest generation and do not represent accurate line loss characteristics. In this model, the longest line is assigned a 10% loss value ($L_{ij} = 0.1$) and the shortest line is assigned a 0% loss value (L_{ij} = 0). Losses of line lengths in between the shortest and longest lines are determined through linear interpolation. Table 5.4 are the line losses, L_{ij}, for each line connecting node *i* to node *j*.

Table 5.4: Transmission Line Loss Factor

Node	Node	Transmission Line Length (miles)	Transmission Loss Factor
Mekelle	Semera	327.90	7.28
Semera	Bahir Dar	348.78	7.76
Bahir Dar	Gondar	83.98	1.70
Semera	Addis Ababa	219.33	4.80
Bahir Dar	Addis Ababa	249.55	5.49
Dire Dawa	Harar	26.85	0.40
Harar	Jijiga	43.86	0.78
GERD	Addis Ababa	446.77	10.00
Asosa	Addis Ababa	313.88	6.96
Gambela	Addis Ababa	107.51	2.24
Koysha	Awasa	77.48	1.55
Gambela	Jimma	250.11	5.50
Addis Ababa	Goba	197.89	4.31
Dire Dawa	Addis Ababa	247.45	5.44
Awasa	Genale Dawa	173.63	3.75
Awasa	Addis Ababa	164.46	3.54
Gondar	Sudan N	96.23	1.98
Dire Dawa	Djibouti	123.31	2.60
GERD	Sudan S	9.56	0.00
Awasa	Kenya	200.26	4.36
GERD	Bahir Dar	158.49	3.41
Jimma	Addis Ababa	121.95	2.57
Jimma	Awasa	76.37	1.53

5.2.6 Annualized Transmission Expansion Cost

The model optimizes yearly cost; therefore, the investment cost for transmission expansion must be annualized. Generally, transmission investment costs are paid over multiple years. Annualizing the cost calculates the yearly cost to recover the investment in Y years. A discount rate is applied to determine the present value of future payments. Eq 5.2 is the capital recovery factor used to annualize cost. The annualized cost is listed in Eq 4.3 in Chapter 4: Model Formulation. In this model, the discount rate, r, is 10% and Y is 20 years.

$$\frac{r(1+r)^Y}{(1+r)^Y-1} \qquad \textit{Eq 5.2}$$

5.3 Groundwater Irrigation Demand

This section provides details of the process of calculating the electricity demand for GWI in both the dry and wet seasons.

5.3.1 Data Sources

The following analysis calculates the regional irrigation demand for both dry and wet seasons using an irrigation suitability map, Figure 5.6, created by Worqlul *et al.,* (2017) [iv]. This map was constructed in ArcGIS using the using Weighted Overlay analysis tool. This tool weighted six factors soil, land use, population density, road proximity, rainfall deficit, and slope to determine the suitable area.

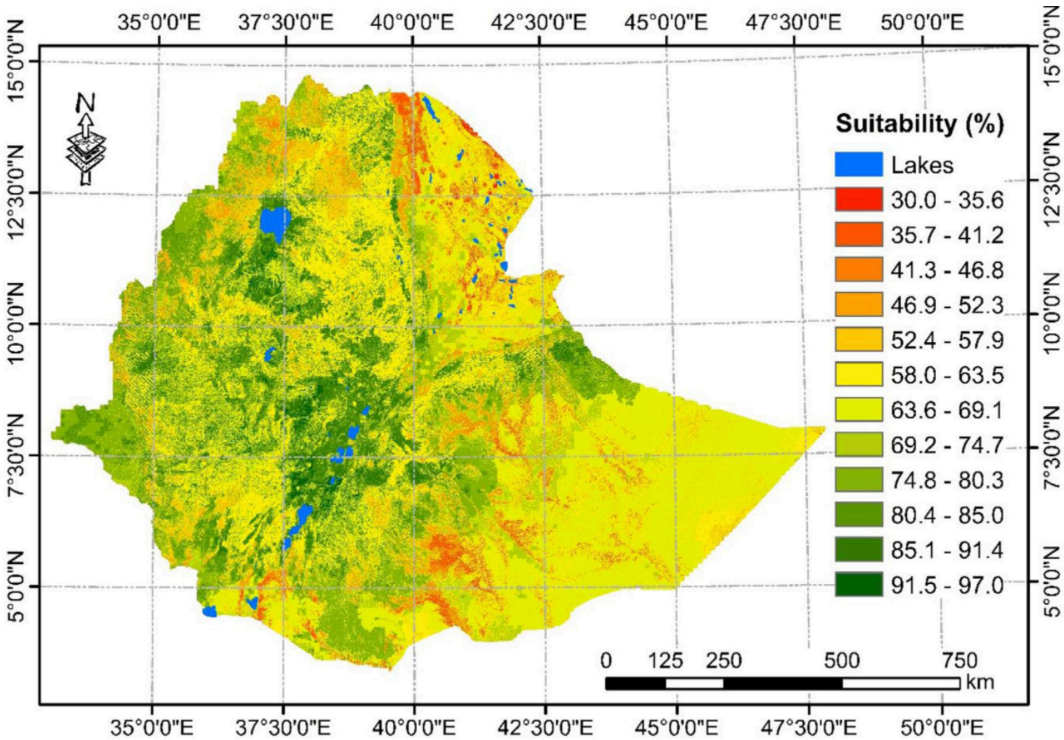

Figure 5.6: Groundwater Irrigation Suitability Map from Worqlul et al., (2017)

To estimate the amount of GW needed for irrigation, 2018 CHIRPS rainfall data were used to calculate the water deficit for daily crop production [xl].

5.3.2 Calculating Water Deficit Volume

A water deficit was calculated to determine the water needed from GWI. First, areas suitable for irrigation were identified using the irrigation suitability map. The map from Figure 5.6 was uploaded as a raster into ArcGIS. Each pixel in the raster is 1000 m x 1000 m. The Thiessen polygons are overlaid onto the raster and the total area with a suitability of 85% or higher in each polygon is calculated.

Using 2018 CHRIPS rainfall data and assuming that 6mm/day is needed for crop production, the following Eq 5.3 was used to calculate the water deficit (mm/day) that must be supplied through irrigation.

$$6\frac{mm}{day} - rainfall\left(\frac{mm}{day}\right) = water\ deficit\ (\frac{mm}{day}) \qquad \text{Eq 5.3}$$

Using the water deficit (mm/day) value calculated in Eq 5.3, the daily water deficit volume for each pixel is calculated in Eq 5.4.

$$W = (1000\ m) * (1000\ m) * \left(water\ deficit\ \frac{mm}{day}\right) * (1e^{-3}\frac{m}{mm}) \qquad \text{Eq 5.4}$$

5.3.3 Calculating Electricity Demand for Pumping Groundwater

The total volume of GW needed in each pixel is calculated from the previous section can be used to determine the electricity demand to pump this volume of water. Eq 5.5 is used to estimate the total electricity demand (GWh), P_W, to pump this water in each pixel, where $\rho = 1000\ \frac{kg}{m^3}$, h is the depth (m), g is $9.81\frac{m}{s^2}$, and W is from Eq 5.4 above. For this study h is 20m, which is an average GW depth. By completing the process from Eq 5.3 - Eq 5.5 for all pixels and aggregating these pixels in each region, a 2018 daily time series of regional electricity demand for GWI is constructed.

$$P_W = mgh = \rho W g h \left[\frac{1\ hour}{3600\ seconds}\right]\left[\frac{1\ GigaWatt}{1e^9\ Watt}\right] \qquad \text{Eq 5.5}$$

Since the model will run over both dry and wet seasons, the daily time series was split into two groups (1) days that fall in the dry season and (2) days that fall in the wet season. The dry season in Ethiopia is from October to May. For this model January 1, 2018 – May 31, 2018 and October 1, 2018 – December 31, 2018 are considered days in the dry season, which occurs for 243 days. The wet season is from June 1, 2018 – September 31, 2018, which occurs for 122 days.

This model runs 10% GWI and 100% GWI scenarios. For the 10% GWI scenario, 10% of the pixels in the irrigation suitability map that have a suitability of 85% or higher are aggregated in each region to calculate electricity demand. The average daily electricity demand (GWh) for irrigation was determined for each season. Dividing this daily demand by 24 hours gives us the approximately hourly electricity demand to pump the GW need for irrigation in each region in both seasons. The values for the 10% GWI scenario listed in Table 5.5 below and illustrated in Figure 5.7 for both seasons. Values for the 100% GWI scenario are listed in Table 5.6 and illustrated in Figure 5.8.

Table 5.5: Dry and Wet Season Regional Irrigation Demand (MW) for 10% GWI

Region	**Dry season – Daily electricity demand for irrigation (MW)**	**Wet season – Daily electricity demand for irrigation (MW)**
Asosa	8.66	3.45
Awasa	36.77	33.74
Bahir Dar	32.76	12.83
Dire Dawa	2.53	2.05
Gambela	10.52	5.38
Goba	9.47	8.26
Gondar	6.00	2.71
Harar	3.25	2.86
Jijiga	3.53	3.17
Jimma	27.77	18.30
Mekelle	7.28	4.30
Semera	4.80	2.92
Addis Ababa	46.592	27.36
Total	**199.93**	**127.32**

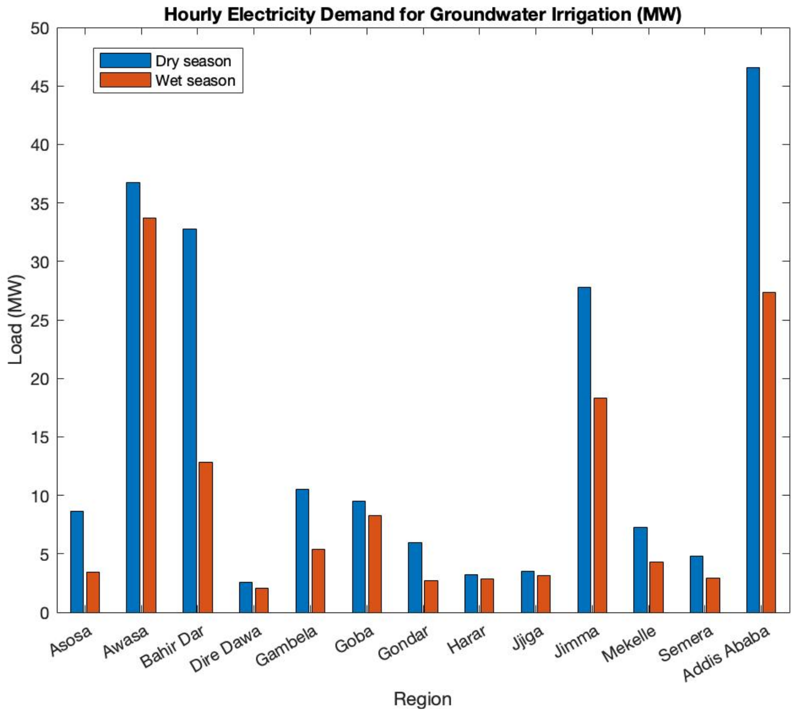

Figure 5.7: Hourly Electricity Demand (MW) for 10% GWI

Table 5.6: Dry and Wet Season Regional Irrigation Demand (MW) for 100% GWI

Region	**Dry season – Daily electricity demand for irrigation (MW)**	**Wet season – Daily electricity demand for irrigation (MW)**
Asosa	86.63	34.49
Awasa	367.70	337.42
Bahir Dar	327.56	128.32
Dire Dawa	25.30	20.51
Gambela	105.24	53.78
Goba	94.66	82.59
Gondar	59.96	27.14
Harar	32.47	28.61
Jijiga	35.33	31.70
Jimma	277.71	182.96
Mekelle	72.80	42.98
Semera	48.03	29.18
Addis Ababa	465.92	273.56
Total	**1999.32**	**1273.25**

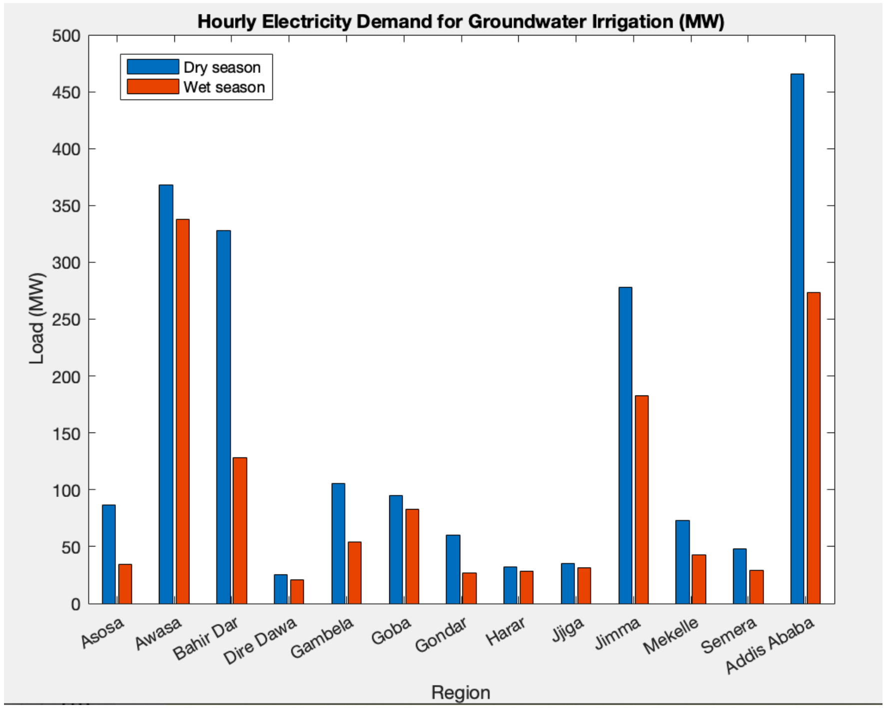

Figure 5.8: Hourly Electricity Demand (MW) for 100% GWI

The MATLAB code that calculates the hourly electricity demand for irrigation from the 2018 time series of regional daily electricity demand is in Appendix B.

5.4 Seasonal Factors in Generation and Groundwater Irrigation Demand

Seasonality was considered in the electricity demand from GWI in the previous section and is also considered in hydropower production. Hydropower production is dependent on dam inflow, which varies according to rainfall. As indicated in Section 5.3 Groundwater Irrigation Demand, GW demand during dry seasons is higher than in wet seasons.

Estimates of the seasonality variability of generation capacity can be incorporated into the model. Simulations of the GERD using historical streamflow indicate a reduction in hydropower production during dry seasons. In flooding seasons (July - September), the GERD operates at 100% capacity; however, in dry years, flooding seasons can experience almost a 50% reduction in average monthly hydropower production. In dry seasons (January – April), the GERD can drop from a 6000 MW capacity to less than 1000MW. To roughly capture this dynamic in dams, the model will simulate changes in hydropower capacity in both wet and dry seasons. In this model the following is considered for generation capacity and GWI demand in each of these seasons:

1. Wet season simulation (June – September):
    a. 100% hydropower capacity
    b. Average irrigation demand determined during wet months (please see Section 5.3).
2. Dry season simulation (October- May):
    a. 50% capacity for months in the dry season
    b. Average irrigation demand determined during dry months (please see Section 5.3).

5.5 Exports

This section will provide details on how current and future export agreements will be included in the model. Table 5.7 indicates current and future export demands between Ethiopia and neighboring countries. Ethiopia has two export agreements with Djibouti, 100 MW, and Sudan, 100 MW [xxxvii]. Sudan is increasing its export agreement to 1200 MW, and Kenya has finalized an export agreement of 400 MW [xxxvii]. For this model it is assumed that the export demand in Table 5.7 is the hourly demand.

Table 5.7: Current and Future Export Agreements (MW)

Country	Current export demand (MW)	Future export demand (MW)
Sudan	100	1200
Djibouti	100	100
Kenya	0	400

5.6 Regional Demand 24-hour Load Curve

This section provides details on the 2017 regional 24-hour load curve constructed for the model. To construct these regional curves, regional peak demands and the timing of peak and off-peak demand must be known. According to a report published by the Ethiopian Energy Authority (EEA) in the NARUC publication database, Ethiopia has two peak periods (1) 11AM – 2PM and (2) 7PM – 9PM [xli] . Figure 5.9 is the daily load curve plotted by the EEA for 8/20/2004 and 8/22/2003.

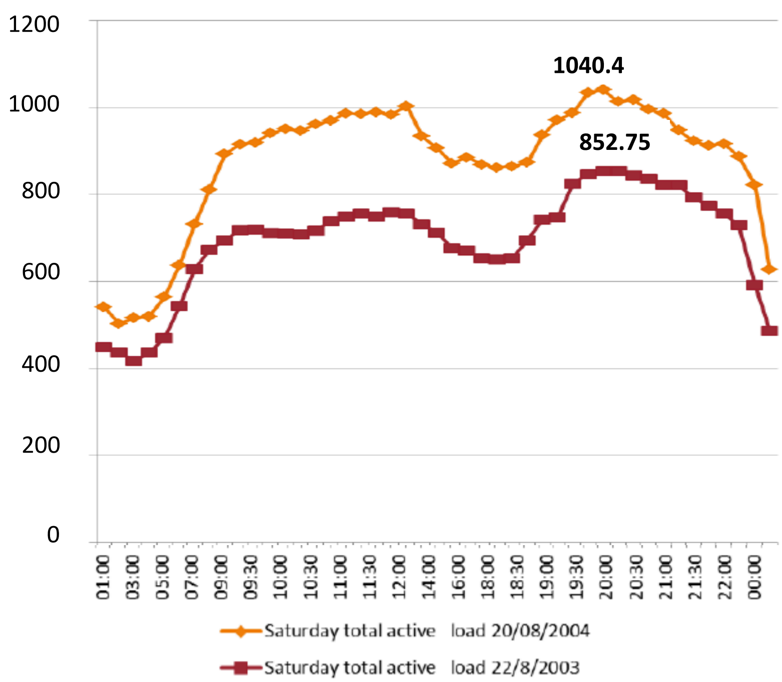

Figure 5.9: Daily Load Curve for 8/20/2004 and 8/22/2003 (MW) [xli]

An approximate load curve was created in MATLAB to model Figure 5.9. Table 5.8 lists the fraction of the peak demand for each hour approximated from Figure 5.9. Figure 5.10 is the approximate 24-hour load curve generated as a proportion of peak demand. This load curve will be applied to all regions.

Table 5.8: Fraction of Peak Demand for all Hours of the Day

Hour	Fraction of Peak Demand
1:00	0.5
2:00	0.5
3:00	0.5
4:00	0.5
5:00	0.5
6:00	0.5
7:00	0.5
8:00	0.5
9:00	0.5
10:00	0.5
11:00	1
12:00	1
13:00	1
14:00	1
15:00	0.75
16:00	0.75
17:00	0.75
18:00	0.75
19:00	1
20:00	1
21:00	1
22:00	0.5
23:00	0.5
24:00	0.5

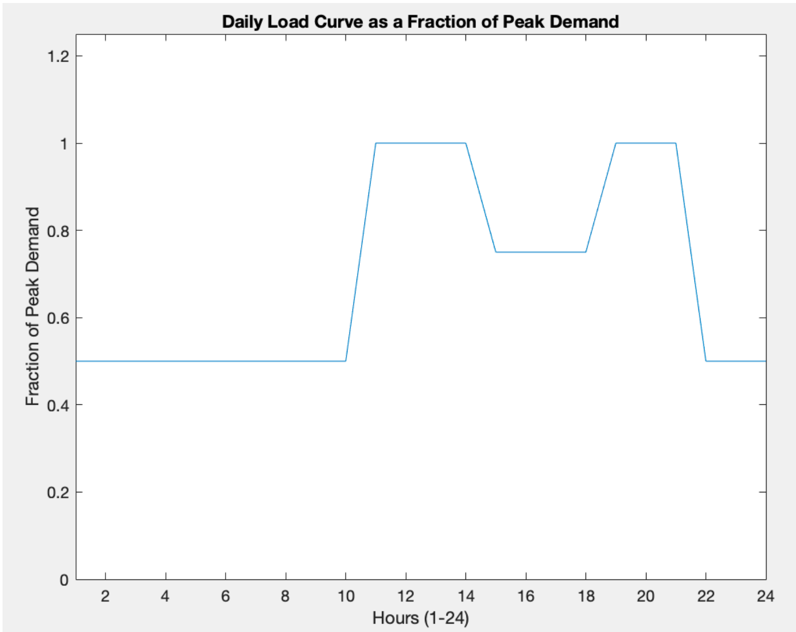

Figure 5.10: Daily Load Curve as a Fraction of Peak Demand (MW)

5.6.1 Calculating Regional Peak Demands

The next step is to calculate the peak demand for each region for 2017 to build the load curve. EEPCo calculates the domestic peak demand in 2012 to be 1,232MW [xxxvii]. The Japanese International Cooperation Agency (JICA) estimates that the peak demand in Addis Ababa in 2014 is 835MW [xlii]. EEPCo states that Addis Ababa contributes to 60% of the domestic peak demand [xxxvii]. Using this assumption and the JICA 2014 estimate above, the 2014 domestic peak demand is 1,392 MW. Linear extrapolation of these two domestic peak demands gives us a domestic peak demand in 2017 of 1,632 MW. By maintaining the assumption that Addis Ababa contributes to 60% of peak demand in 2017 results in 979.2 MW peak demand. The remaining 40% of the peak demand was disaggregated proportionally according to the population in each region using spatial population data from the 2015 CIESIN UN WPP-Adjusted Gridded Population Count raster.

Table 5.9 is the total population for each region, the proportion of the regional population to the total population, and the peak demand. 2017 regional peak demand was calculated using Eq 5.6.

$$Regional\ Peak\ Demand = \frac{Regional\ Population}{Total\ Population} * 1{,}632\ MW \qquad \textit{Eq 5.6}$$

Table 5.9: Regional Population and Proportion Using 2015 UN-WPP Adjusted Gridded Population Data

Region	**Regional population**	**Percentage of total population (%)**	**2017 Peak demand (MW)**
Asosa	1,868,038	2.36	15.41
Awasa	19,131,493	24.18	157.84
Bahir Dar	11,056,191	13.97	91.22
Dire Dawa	4,529,379	5.72	37.37
Gambela	3,818,427	4.83	31.50
Goba	6,139,442	7.76	50.65
Gondar	4,597,266	5.81	37.93
Harar	3,332,659	4.21	27.50
Jijiga	2,124,208	2.68	17.53
Jimma	11,755,495	14.86	96.99
Mekelle	6,241,174	7.89	51.49
Semera	4,529,379	5.72	37.37
Total population	**79,123,151**		

5.6.2 Calculating Regional Daily Load Curves

Using these peak demands, the daily load curves for each region is calculated using Table 5.8 and illustrated in Figure 5.11.

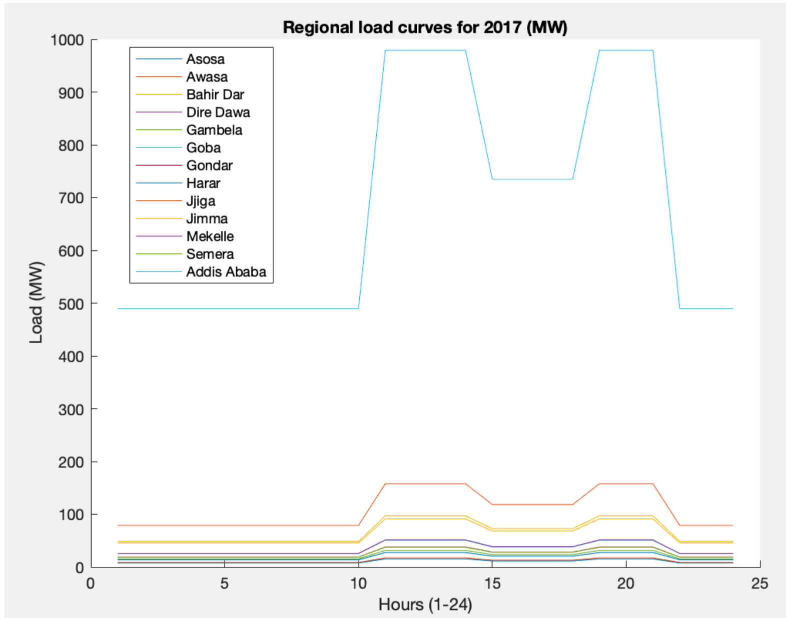

Figure 5.11: Regional Load Curve for 2017 (MW)

5.6.3 Calculating Future Demand

Another model input is future regional demand load curves by estimating future domestic peak demand. EEPCo estimates that annual electricity consumption will grow 12.3% annually [xxxvii]. Future domestic peak demand can be calculated using Eq 5.7 where d_0 is the domestic peak demand in 2017, d_n is the future peak demand in year *n*, and *r* is the growth rate. Total future electricity peak demand can be calculated using Eq 5.8. Here, d_i is the total electricity demand for GWI and d_e is the export demand. However, since generation capacity will not be expanded, this model is constrained by the total dry season generation capacity. The total capacity listed in Table 5.1 is 12,231 MW. However, as indicated in Section 5.4, in dry seasons this is reduced by 50%, resulting in a capacity of 6115 MW. Eq 5.9 can be solved for the year to which regional electricity demand is constrained by the generation capacity in the dry season. This is solved in Eq 5.10 by replacing d_n with *D*, the known generation capacity during a dry season and solving for *n*.

$$d_n = (1+r)^n * d_0$$ *Eq 5.7*

$$d_n = (1+r)^n * d_0 + d_i + d_e$$ *Eq 5.8*

$$D = (1+r)^n * d_0 + d_i + d_e$$ *Eq 5.9*

$$\frac{\ln\left(\frac{D - d_i - d_e}{d_0}\right)}{\ln(1+r)} = n$$ *Eq 5.10*

Table 5.10 are the values plugged into Eq 5.10.

Table 5.10: Variables Plugged into Equation 5.9

Symbol	Value/s	Description
D	6115 MW	Dry season generation capacity assuming 50% of capacity is available
d_i	(1) 200 MW (2) 2000 MW	10% of irrigable land uses GW for irrigation in the dry season 100% of irrigable land uses GW for irrigation in the dry season
d_0	1,632 MW	Baseline peak demand in 2017
d_e	(1) 200 MW (2) 1700 MW	2017 exports: - Sudan 100 MW - Djibouti 100 MW Future exports: - Sudan 1200 MW - Djibouti 100 MW - Kenya 400 MW

r	12.3%	Annual electricity consumption growth rate according to EEPCo[xxxvii]

Eq 5.11 solves for n considering 2017 export levels.

$$\frac{\ln\left(\frac{6115-200-200}{1632}\right)}{\ln\,(1+0.123)} = \; n = 10.8 \qquad \textit{Eq 5.11}$$

According to Eq 5.11, the current generation capacity can satisfy domestic electricity peak demand for the next ten years under current export agreements. Eq 5.12 solves for *n* considering future export levels and indicates that the current generation capacity can satisfy domestic electricity peak demand for the next eight years if future export agreements are introduced.

$$\frac{\ln\left(\frac{6115-200-1700}{1632}\right)}{\ln\,(1+0.123)} = \; n = 8.18 \qquad \textit{Eq 5.12}$$

The *n* values, 10 and 8, can be plugged into Eq 5.7 to determine the domestic peak demand for 2027 and 2025, respectively. Plugging in $n = 10$ into Eq 5.7 gives a domestic peak demand of 5206 MW for 2027. Plugging in $n = 8$ into Eq 5.7 gives a domestic peak demand of 4128 MW for 2025. Plugging these peak demands into Eq 5.8 gives a total peak demand of 5,606 MW for 2027 and 6,028 MW for 2025. Because transmission losses up to 10% are considered in this model, the total peak demand must be at least 5% less than the dry season hydropower capacity for market constraints to be met. Market constraints in this model enforce that supply is equal to demand at all hours. While the 2027 peak demand has greater than a 5% margin between the hydropower capacity and demand under the current export scenario, the 2025 peak demand violates this margin under future exports, meaning it will not satisfy market constraints. Under future exports, a 2024 peak demand of 3676 MW will be considered.

These peak demands can be used to construct domestic load curves using Table 5.8 and Figure 5.11. Figure 5.12 has the domestic 24-hour load curves estimated for 2027 and 2024. Note that this does not include irrigation demand or export demand.

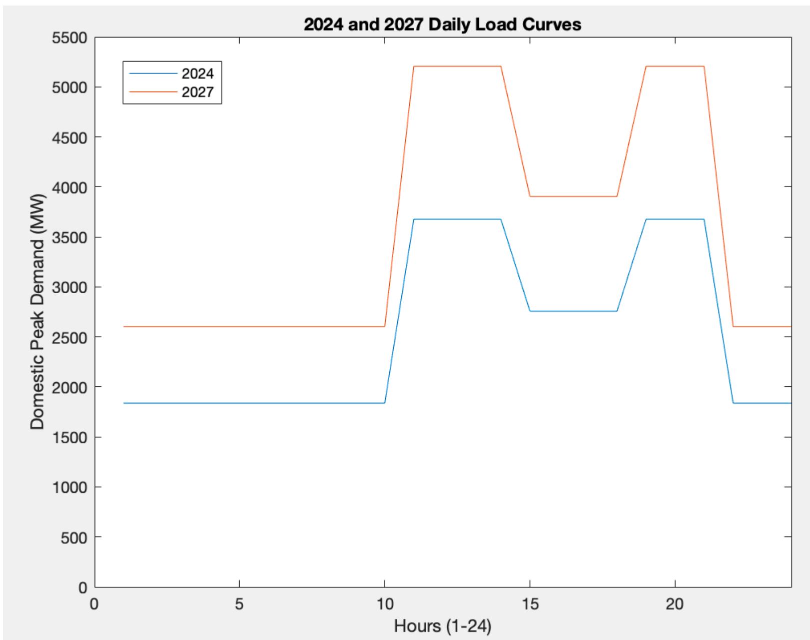

Figure 5.12: Domestic Load Curve for 2024 and 2027 (MW)

Similar to Figure 5.11 this domestic load curve can be disaggregated into regional load curves by assuming that 60% of peak demand comes from Addis Ababa and disaggregating the remaining peak demand according to 2015 regional population proportional indicated in

Table 5.9. Figure 5.13 illustrates the regional 24-hour load curves for 2024 and Figure 5.14 illustrates the regional 24-hour load curves for 2027.

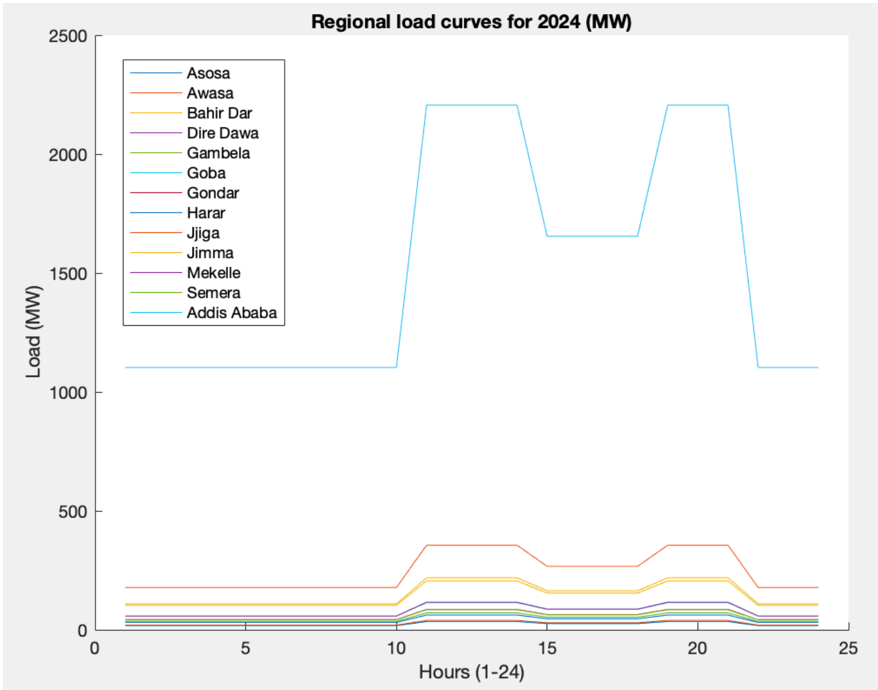

Figure 5.13: Regional Load Curves for 2024 (MW)

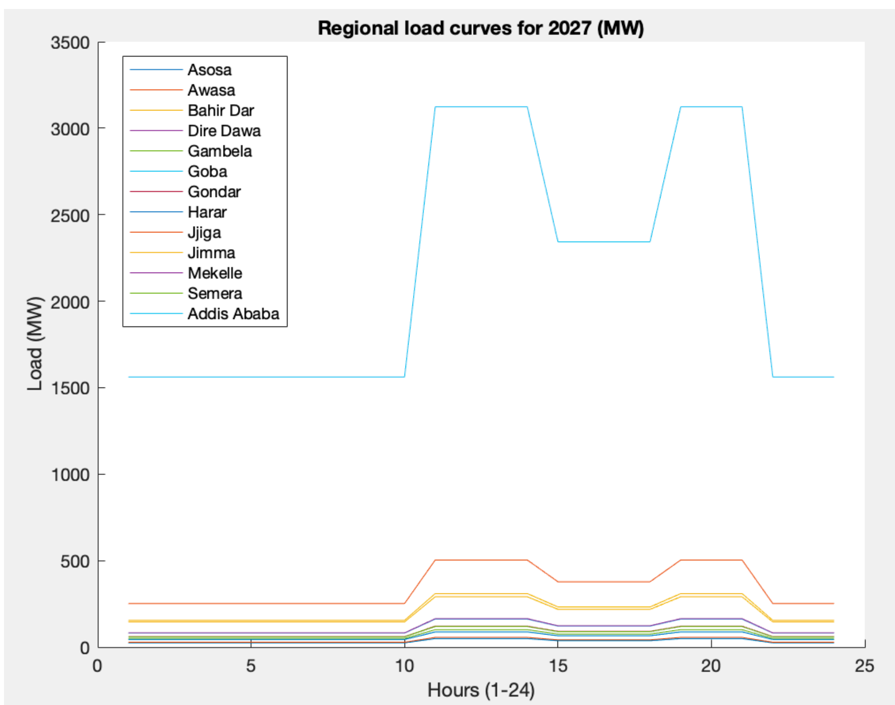

Figure 5.14: Regional Load Curves for 2027 (MW)

One of the model runs will consider a 100% GWI scenario, which is approximately 2000 MW when GW use for irrigation peaks. By plugging in 2000 MW for the year when regional demand is constrained by the dry season hydropower capacity can be determined and is solved in Eq 5.13 . This equation also considers future exports.

$$\frac{\ln\left(\frac{6115-200-1700}{1632}\right)}{\ln\left(1+0.123\right)} = n = 3.37 \qquad \textit{Eq 5.13}$$

Plugging $n = 3$ in to Eq 5.7 results in a domestic regional demand of 2311 MW and plugging this value into Eq 5.8 gives a total country demand of 6011 MW; however, this violates the 5% margin need to ensure that when factoring transmission losses this peak demand does not violate market constraints. Instead, $n = 2$ will be considered. This results in a domestic regional demand of 2058 MW in 2019 and a total country demand of 5758 MW. Figure 5.15 illustrates the regional 24-hour load curves for 2019.

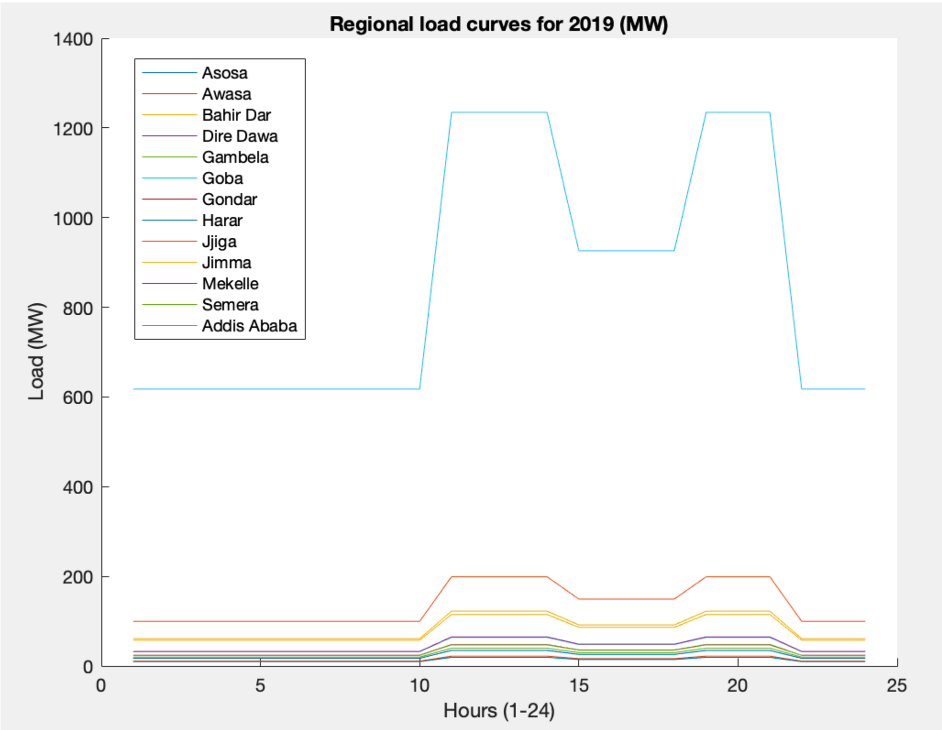

Figure 5.15: Regional Load Curves for 2019 (MW)

Chapter 6 – Model Baseline and Scenarios

6.1 Baseline Scenario

The Baseline Scenario considers 2017 as the reference year for the model. The following are considered in the generation, transmission, and demand inputs.

- Generation:
  - Existing hydropower dams and those under construction are aggregated on a regional level as indicated in Table 5.1.
  - The wet season considers 100% of hydropower capacity and dry season considers 50% of hydropower capacity.
- Transmission:
  - Simplified regional network that includes existing transmission lines and those under construction as indicated in Figure 5.5.
  - Transmission loss is included in the model ranging from 0-10% dependent on the lengths of the transmission lines as indicated in Table 5.4.
- Demand:
  - 2017 domestic regional electricity demand as indicated in Figure 5.11.
  - No GW irrigation.
  - 2017 exports as indicated in Table 5.7.

6.2 Model Scenarios

Table 6.1 is a summary of all model scenarios. Each scenario is named according to the year of domestic regional demand, level of electricity demand for GWI, and export demand, which are the three types of electricity demand considered in this model. The following scenarios study how increases in internal demand – domestic regional demand and electricity demand for GWI – and external demand – international export demands – impact hydropower operations and grid expansion.

Domestic regional demand projections are estimated under the assumption that there is a 12.3% annual growth in electricity consumption. However, hydropower capacity is fixed in the model, which means that growth in electricity consumption is constrained by the installed hydropower capacity. Specifically, future demand is constrained by the dry season hydropower capacity, which is a 50% reduction in total capacity. The estimate of future domestic regional demand is determined in section 5.6.3 Calculating Future Demand.

GWI demand is considered in the following scenarios. First, the scenarios consider a 10% GWI scheme, to determine if the current grid infrastructure can satisfy a low level GWI. The last scenario considers a 100% GWI scheme to look at an extreme case of GWI usage and study how hydropower operations and grid expansion are impacted by an increase in this internal demand. The 10% and 100% GWI calculations are determined in section 5.3 Groundwater Irrigation Demand.

There are two export levels considered in the model – current exports (200 MW) and future exports (1700 MW). The scenarios considered these two levels to see how an increase in external demand prompts grid expansion and impacts hydropower operations.

The first scenario, 2017D_LI_CE, includes 2017 domestic regional demand (D), a low irrigation (LI) level of 10%, and current exports (CE). This scenario is run to study the impact of an increase in internal demand from GWI on grid expansion.

The second scenario, 2017D_LI_FE, includes 2017 domestic regional demand, a low irrigation level of 10%, and future exports (FE). This scenario differs from 2017D_LI_CE in that it assumes Ethiopia abides by future export agreements, which is an increase of 1500 MW compared to the previous scenario. This scenario tests whether an increase in external demand prompts expansion of the grid infrastructure.

The third scenario, 2027D_LI_CE, includes 2027 domestic regional demand, a low irrigation level of 10%, and current exports. Under this irrigation and export scheme, the domestic regional demand can grow until 2027, which is when total demand – both internal and external – is constrained by the dry season hydropower capacity. Satisfying internal and external demands are competing objectives in this system, which this scenario allows us to study. While export agreements may increase revenue, exports will constrain domestic demand growth and GWI expansion.

The fourth scenario, 2024D_LI_FE, includes 2024 domestic regional demand, a low irrigation level of 10%, and future exports. The year 2024 is when total demand is constrained by the dry season hydropower capacity. Compared to scenario 2027D_LI_CE, the total demand is constrained three years earlier. This scenario studies grid expansion if Ethiopia prioritizes electricity supply for external demand rather than domestic demand.

The fifth scenario, 2019D_HI_FE, includes 2019 domestic regional demand, a high irrigation (HI) level of 100%, and future exports. This scenario studies an extreme case if Ethiopia prioritizes GWI for the purpose of increasing year-round crop production. Under a 100% GWI and future export scheme, the domestic regional demand can grow until 2019, which is when total demand – internal and external – is constrained by the dry season hydropower capacity. ,

Table 6.1: Inputs for Scenarios. D- demand; LI/HI – low irrigation/high irrigation; CE/FE – current exports/future exports

	Model Scenario				
	(1) 2017D_LI_CE	**(2) 2017D_LI_FE**	**(3) 2027D_LI_CE**	**(4) 2024D_LI_FE**	**(5) 2019D_HI_FE**
Generation	Dry season (50% of total generation capacity) Wet season (100% of total generation capacity)				
Transmission	Allows for 10% grid expansion Transmission loss between 0-10% as a linear function of transmission length				
Demand	2017 regional demand 10% irrigation Current export agreements	2017 regional demand 10% irrigation Future export agreements	2027 regional demand 10% irrigation Current export agreements	2024 regional demand 10% irrigation Future export agreements	2019 regional demand 100% irrigation Future export agreements

Chapter 7 – Results and Discussion

This section provides the results for the Baseline Scenario and five scenarios with changes in domestic regional demand, GWI, and exports. The maps below include the MW expansion for each line determined by the model. The total system cost, which includes generation and transmission expansion costs, is optimized. The cost of electricity is calculated, which is the fraction of total system costs to total generation ($/kWh). The seasonal capacity factor is calculated for each run and compared to the baseline.

A capacity factor is defined as the proportion of actual hydropower production (MWh) to the theoretical hydropower production (MWh). Eq 7.1 calculates the actual hydropower production for each node and Eq 7.2 calculates the theoretical hydropower production for each season; h is 1 hour and τ is 24 hours. The capacity factor is calculated in Eq 7.3 and is calculated for each season since both the actual and theoretical hydropower production change seasonally.

$$Actual\_hydropower\_production(i,s) \; = d_s \sum_{t \, \epsilon \, \tau} P_g(i,t,s) * h \qquad \textit{Eq 7.1}$$

$$Theoretical\_hydropower\_production(i,s) \; = d_s * \tau * \; P_{g\_max}(i,s) \qquad \textit{Eq 7.2}$$

$$Capacity\_factor(i,s) = \frac{Actual\_hydropower\_production(i,s)}{Theoretical\_hydropower\_production(i,s)} \qquad \textit{Eq 7.3}$$

7.1 Baseline Scenario Results

The total optimized network cost is $596 million, which includes only generation costs because there is no grid expansion. The cost of electricity is 0.0495 $/kWh. Figure 7.1 is a grid expansion map for the Baseline Scenario. Table 7.1 includes the total cost of the system in the Baseline Scenario and seasonal capacity factors for each node with generation.

As expected, the capacity factors at the node with generation are greater in the dry season than in the wet season since the theoretical hydropower production decreases. The generators at the Addis node see no change in the capacity factor because the generators are operating at maximum capacity in both seasons. The Addis node only has 343 MW of generation capacity, while peak demand for the node in the Baseline Scenario is approximately 980 MW. Even in the off-peak demand, 490 MW, is greater than the total generation capacity at the node. This means that the generators in the Addis node are always operating at maximum capacity and this node must always import electricity. This node is also an intermediary export node to Awasa and Dire Dawa, which rely on exports from Addis for electricity since they do not have any generation capacity. This is an additional reason why the Addis node will always be importing electricity.

In the dry season, Jimma, Goba, and Bahir Dar nodes are operating at max capacity and have the highest capacity factors in the wet season apart from the Addis node. These nodes rank third, sixth, and fourth in demand, respectively. They are also the nodes closest to the Addis node; therefore, these nodes will be the predominant sources of imported electricity for the Addis node.

The generation at Genale Dawa, the GERD, and Koysha nodes operate the least in both seasons. Note that the Koysha node includes two dams – Koysha and Gilgel Gibe III. These nodes do not have any demand, rather they function as sources of generation capacity for the network. The Genale Dawa node operates the most relative to its generation capacity because it is closer to demand nodes than the GERD and has a smaller generation capacity than the capacity at the Koysha node. Generation at the Koysha node is operating more in absolute generation because it is closest to demand nodes.

Mekelle is exporting from its node to other nodes throughout the year. This is clear because the capacity factor in the Mekelle node is greater than the proportion of the node's peak demand to generation capacity at the node.

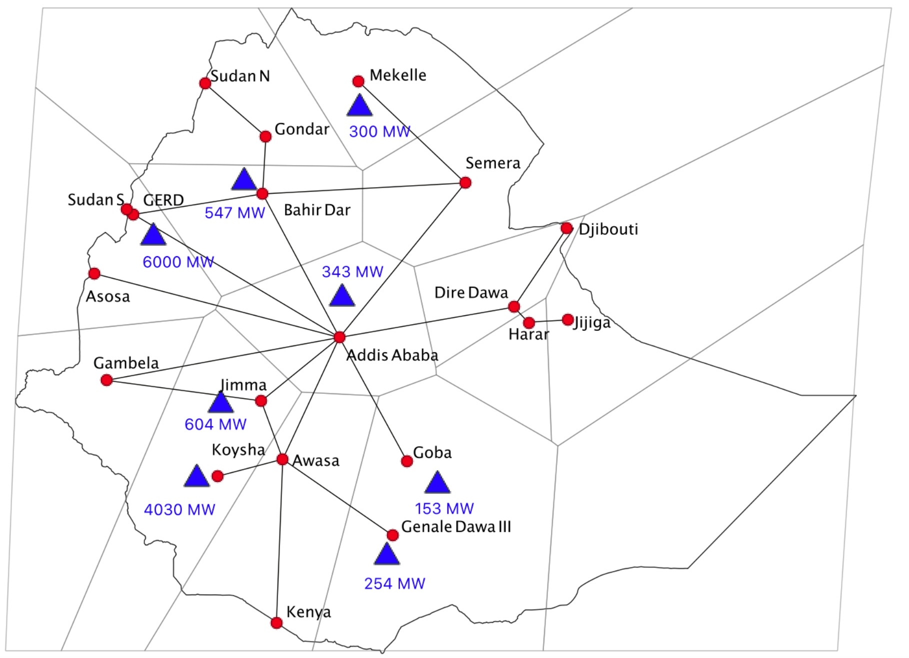

Figure 7.1: Baseline Scenario Results Map

Table 7.1: Baseline Scenario Total Cost ($) and Capacity Factors

Regional node	Capacity Factor Dry Season	Capacity Factor Wet Season
Mekelle	1	0.174
Addis Ababa	1	1
Goba	1	0.519
Jimma	1	0.89
Bahir Dar	0.792	0.388
Genale Dawa	0.458	0
GERD	0.051	0
Koysha	0.169	0.034
TOTAL COST ($)	**5.96E+08**	
Cost ($/kWh)	**0.0495**	

7.2 Scenario 1: 2017 demand, 10% irrigation, current exports

The optimized network cost is $601 million, which includes only generation costs because there is no grid expansion. The cost of electricity is 0.0440 $/kWh. Figure 7.2 is grid expansion map for Scenario 2017D_LI_CE. Table 7.2 includes the total cost of the system and the seasonal capacity factors for each node with generation.

In both seasons, all nodes with generation produce more due to the electricity demand for GWI. The exceptions are the nodes that were already operating at max capacity and except for the Genale Dawa node since there is no GWI demand at that node. Generation at Koysha increases significantly because it is adjacent to Awasa, which has increase in GWI demand.

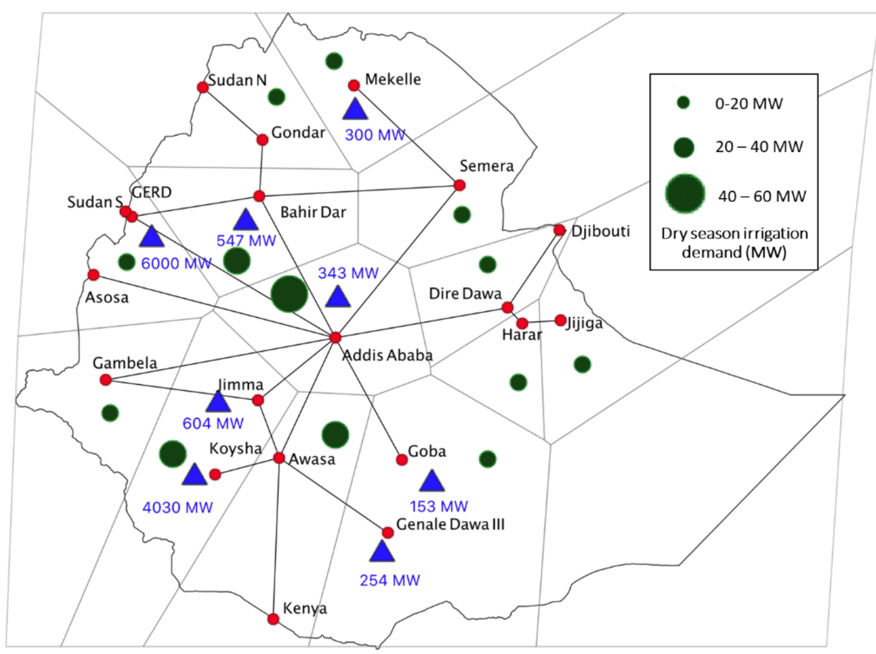

Figure 7.2 Scenario1: 2017D_LI_CE Results Map

Table 7.2: Scenario 1: 2017D_LI_CE Total Cost ($) and Capacity Factors

Regional node	Capacity Factor Dry Season	Percentage Change from Baseline Dry Season (%)	Capacity Factor Wet Season	Percentage Change from Baseline Wet Season (%)
Mekelle	0.504	19.71	0.193	10.92
Addis Ababa	1	0.00	1	0.00
Goba	1	0.00	0.577	11.18
Jimma	1	0.00	0.981	10.22
Bahir Dar	0.96	21.21	0.474	22.16
Genale Dawa	0.458	0.00	0	n/a baseline is 0
GERD	0.082	60.78	0	n/a baseline is 0
Koysha	0.199	17.75	0.037	8.82
TOTAL COST ($)	**6.01E+08**			
Cost ($/kWh)	**0.0440**			

7.3 Scenario 2: 2017 demand, 10% irrigation, future exports

The optimized network cost is $645 million, which includes annualized grid expansion costs of $220,000. The cost of electricity is 0.0237 $/kWh. Figure 7.3 is a grid expansion map for Scenario 2017D_LI_FE. Table 7.3 includes the total cost of the system and seasonal capacity factors for each node with generation.

Only one line is expanded in this scenario. There is a 22.27 MW transmission capacity expansion on the line connecting Bahir Dar to Gondar. In the original network there is a 230 MW transmission capacity limit on this line. This is not sufficient to supply electricity to the Gondar node and to the Sudan N node, which requires 200 MW due to the export agreement. The line connecting Gondar to Sudan N is not expanded because it is a double circuit 230 MW line, which is sufficient to supply the 200 MW needed in the Sudan N node.

In both seasons, there is an increase in the capacity factors at all nodes with generation except for those operating at full capacity in the baseline. Production from the GERD increases because of the 1000 MW export to Sudan S. The generators at Koysha and Genale Dawa nodes increase in production because of the 400 MW export demand to Kenya. The closest nodes to the Addis Ababa node, which are Jimma, Goba, and Bahir Dar are operating at full capacity. Genale Dawa is also operating at maximum capacity. The percent change values in the wet season are N/A for the GERD and Genale Dawa because the baseline capacity factors were 0; however, the capacity factors have increased in comparison to the baseline. The GERD and Genale Dawa were not operating in the wet season of the previous Scenario 2017D_LI_CE, which implies that the increase in export demand forces these generators to operate.

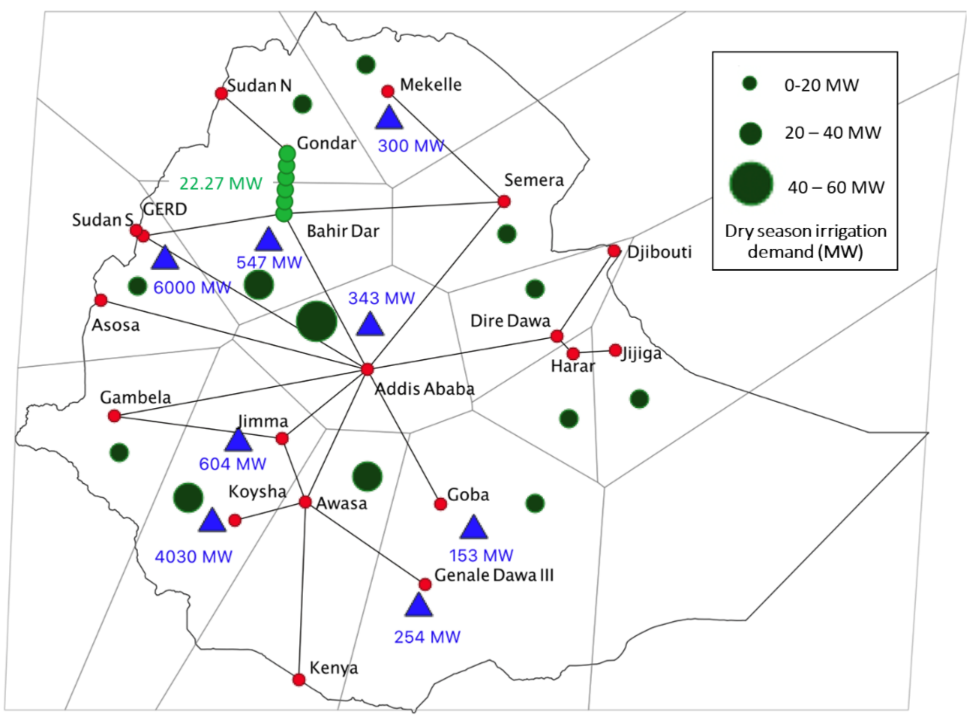

Figure 7.3: Scenario 2: 2017D_LI_FE Results Map

Table 7.3: Scenario 2: 2017D_LI_FE Total Cost ($) and Capacity Factors

Regional node	Capacity Factor Dry Season	Percentage Change from Baseline Dry Season (%)	Capacity Factor Wet Season	Percentage Change from Baseline Wet Season (%)
Mekelle	0.504	19.71	0.2	14.94
Addis Ababa	1	0.00	1	0.00
Goba	1	0.00	0.577	11.18
Jimma	1	0.00	1	12.36
Bahir Dar	1	26.26	0.689	77.58
Genale Dawa	1	118.34	0.412	n/a baseline is 0
GERD	0.573	1023.53	0.175	n/a baseline is 0
Koysha	0.199	17.75	0.099	191.18
TOTAL COST ($)	**6.45E+08**			
LCOE ($/kWh)	**0.0237**			

7.4 Scenario 3: 2027 demand, 10% irrigation, current exports

The optimized network cost is $701 million, which includes annualized transmission expansion costs of $24.6 million. The cost of electricity is 0.0191 $/kWh. Figure 7.4 is a grid expansion map for Scenario 2027D_LI_CE. Table 7.4 includes the total cost of the system and seasonal capacity factors for each node with generation.

There are five lines that are expanded in this scenario run. The line connecting Addis Ababa to Dire Dawa is congested in the 2017 domestic demand scenario. The increase in domestic regional demand in 2027 forces this line to expand. The line connecting the generation at Koysha to adjacent nodes is the shortest line compared to other connections. The Koysha to Jimma line expansion is prompted because this is the shortest expansion path to the Addis node and because Awasa and Jimma have the second and third largest peak demands, respectively.

This expansion path is shorter than the line connecting Genale Dawa to Awasa. The line from GERD to Bahir Dar expands as well since Bahir Dar has the third largest peak demand. This expansion pathway is also the cheapest compared to the expansion path from Mekelle to Bahir Dar. Mekelle is also operating at maximum capacity at all hours in the dry season; therefore, exports to Bahir Dar are constrained.

In the dry season, generation at Mekelle operates at capacity because the two nodes closest to Mekelle, Semera and Bahir Dar, rely on exported electricity in 2027. The GERD operates more in the dry season to supply electricity to not only Addis Ababa but also to Bahir Dar. Generation at the Koysha node increases because the demand at Awasa increases. Once the expansion from the Koysha node to the Awasa node occurs, Genale Dawa operates less, as indicated in the negative percent change in generation. This decrease in generation because the line connecting the Koysha node to the Awasa node is shorter than the line connecting the Genale Dawa node to the Awasa node.

In the wet season, all nodes with generators are operating more due to the increase in domestic regional demand; however, Genale Dawa does not operate because once the line Koysha and Awasa is expanded, this becomes the shortest transmission pathway to Awasa.

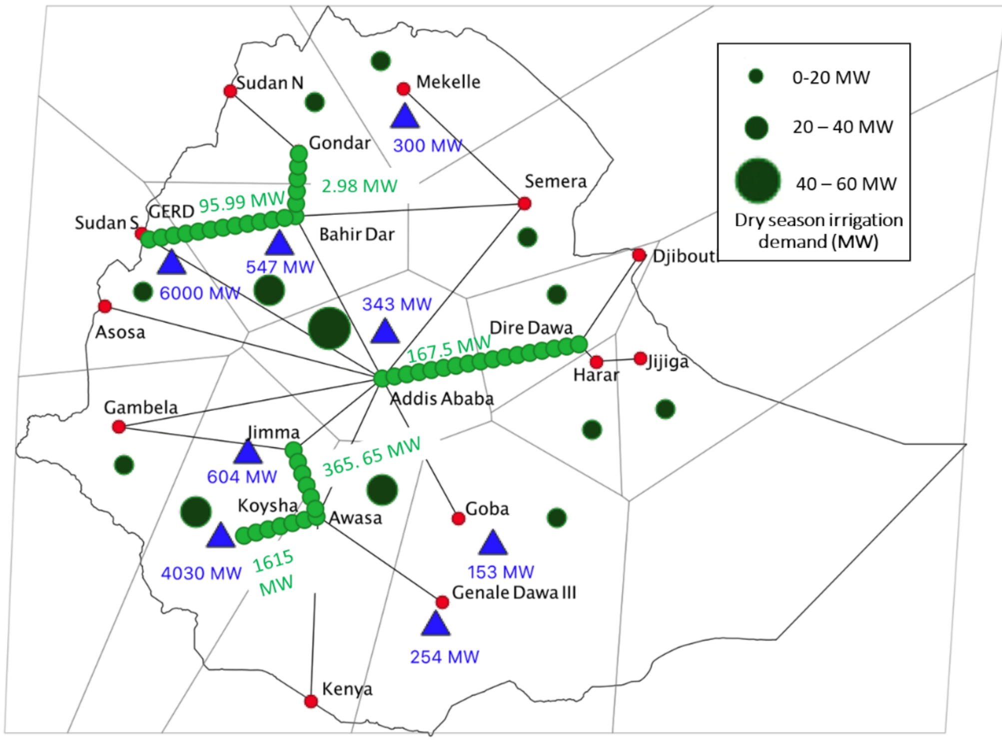

Figure 7.4: Scenario 3: 2027D_LI_CE Results Map

Table 7.4: Scenario 3: 2027D_LI_CE Total Cost ($) and Capacity Factors

Regional node	Capacity Factor Dry Season	Percentage Change from Baseline Dry Season (%)	Capacity Factor Wet Season	Percentage Change from Baseline Wet Season (%)
Mekelle	1	137.53	0.696	300.00
Addis Ababa	1	0.00	1	0.00
Goba	1	0.00	1	92.68
Jimma	1	0.00	1	12.36
Bahir Dar	1	26.26	1	157.73
Genale Dawa	0.292	-36.24	0	n/a baseline is 0
GERD	0.461	803.92	0.128	n/a baseline is 0
Koysha	0.908	437.28	0.366	976.47
TOTAL COST ($)	**7.01E+08**			
LCOE ($/kWh)	**0.0191**			

7.5 Scenario 4: 2024 demand, 10% irrigation, future exports

The optimized network cost is $703 million, which includes annualized transmission expansion costs of $15.8 million. The cost of electricity is 0.0175 $/kWh. Figure 7.5 is a grid expansion map for Scenario 2024D_LI_FE. Table 7.5 includes the total cost of the system and seasonal capacity factors for each node with generation.

There are three lines that are expanded in this scenario. The line connecting Bahir to Gondar expands because of a 200 MW demand at the Sudan N node. The line connecting Addis Ababa to Dire Dawa was close to congestion in the 2017 domestic demand scenario. The increase in domestic regional demand in 2024 forces this line to expand. The line connecting Koysha to Awasa is expanded because this is the shortest pathway to provide electricity to Awasa and Kenya.

In the dry season, all generators except for those that were already operating at maximum capacity in the baseline all increase in generation because the domestic regional demand and the export demand increase. Production from the GERD increases because it is providing 1000 MW to the Sudan S node. The generators at the Koysha node are operating more due to the expansion. The lines connecting Koysha to Awasa, Jimma, and Kenya are the shortest transmission pathways for these respective nodes; prompting Koysha to export more electricity to these nodes. In the wet season, there is an increase in production from all nodes with generation.

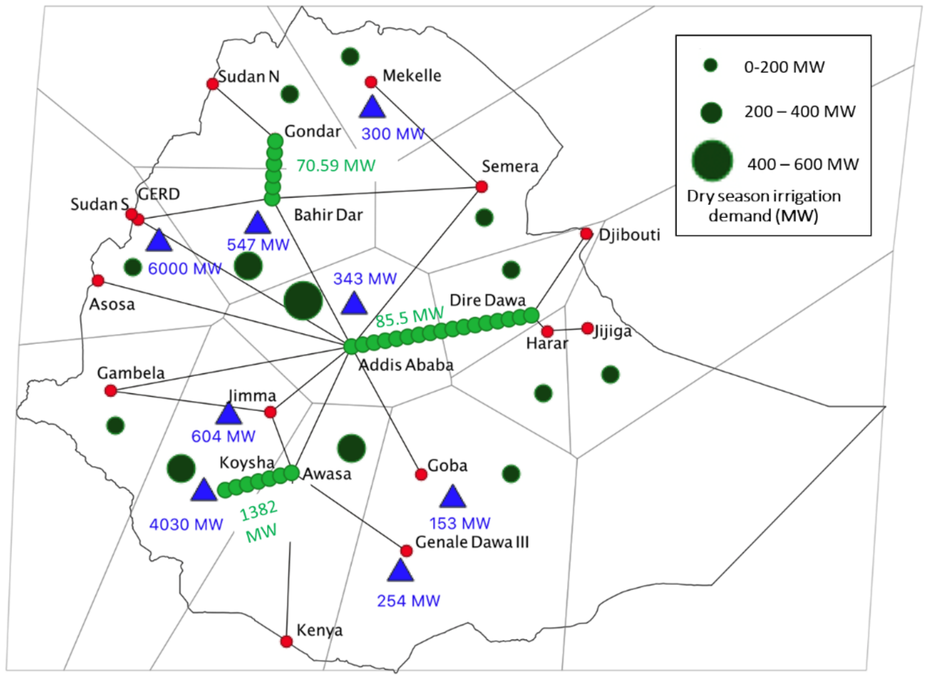

Figure 7.5: Scenario 4: 2024D_LI_FE Results Map

Table 7.5: Scenario 4: 2024D_LI_FE Total Cost ($) and Capacity Factors

Regional node	Capacity Factor Dry Season	Percentage Change from Baseline Dry Season (%)	Capacity Factor Wet Season	Percentage Change from Baseline Wet Season (%)
Mekelle	0.877	108.31	0.499	186.78
Addis Ababa	1	0.00	1	0.00
Goba	1	0.00	1	92.68
Jimma	1	0.00	1	12.36
Bahir Dar	1	26.26	0.824	112.37
Genale Dawa	0.548	19.65	0.267	n/a baseline is 0
GERD	0.605	1086.27	0.212	n/a baseline is 0
Koysha	0.885	423.67	0.362	964.71
TOTAL COST ($)	**7.03E+08**			
LCOE ($/kWh)	**0.0175**			

7.6 Scenario 5: 2019 demand, 100% irrigation, future exports

The optimized network cost is \$719 million, which includes annualized transmission expansion costs of \$17.6 million. The cost of electricity is 0.0162 \$/kWh. Figure 7.6 is a grid expansion map for Scenario 2019D_HI_FE. Table 7.6 includes the total cost of the system and seasonal capacity factors for each node with generation.

There are three lines that are expanded in this scenario. The line connecting Bahir Dar to Gondar is expanded due to the increase in exports to Sudan N and increase in total demand in the Gondar region. There is expansion on the line from Addis Ababa to Dire Dawa that is prompted because of an increase in total demand in the Dire Dawa, Harar and Jijiga nodes. As seen in previous scenarios, the line connecting Koysha to Awasa is expanded predominantly because it is the shortest length connecting a node with generation to adjacent nodes. Due to an increase in total demand, this line is expanded to supply electricity to the system.

In the dry season, all nodes increase in overall generation because of an increase in total demand. Mekelle is operating at 100% capacity due to a simultaneous increase in irrigation demand, domestic regional demand, and export demand. Koysha is operating at near capacity due to the large irrigation demand in Awasa and Jimma and an increase in the Kenya export demand. In the wet season, all nodes increase in overall generation.

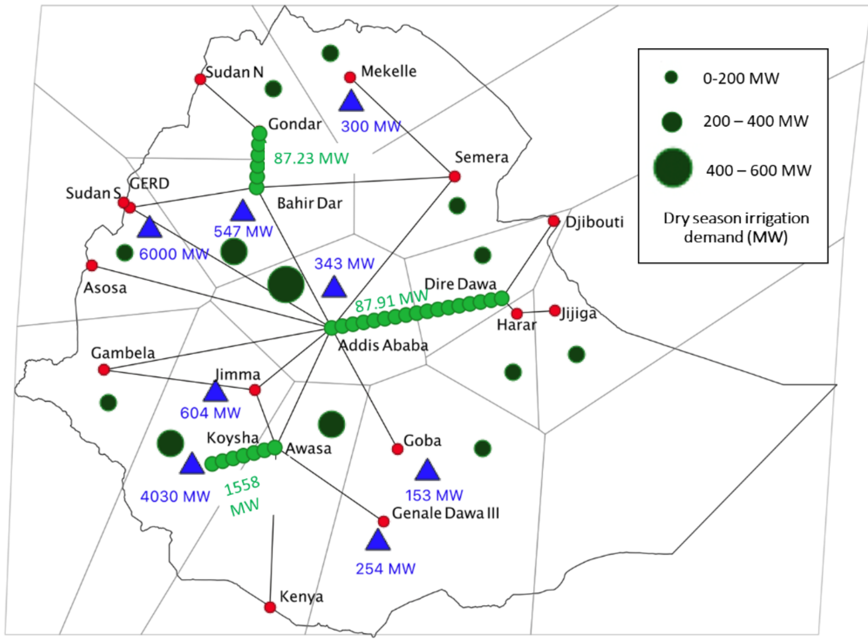

Figure 7.6: Scenario 5: 2019D_HI_FE Results Map

Table 7.6: Scenario 5: 2019D_HI_FE Total Cost ($) and Capacity Factors

Regional node	Capacity Factor Dry Season	Percentage Change from Baseline Dry Season (%)	Capacity Factor Wet Season	Percentage Change from Baseline Wet Season (%)
Mekelle	1	137.53	0.513	194.83
Addis Ababa	1	0.00	1	0.00
Goba	1	0.00	1	92.68
Jimma	1	0.00	1	12.36
Bahir Dar	1	26.26	0.899	131.70
Genale Dawa	1	118.34	0.271	n/a baseline is 0
GERD	0.763	1396.08	0.175	n/a baseline is 0
Koysha	0.972	475.15	0.41	1105.88
TOTAL COST ($)	**7.19E+08**			
LCOE ($/kWh)	**0.0162**			

7.7 EEPCo Planned Expansion Comparison

The previous sections 7.1 – 7.6 detail the grid expansion and generation results from each scenario run. These results can be compared to the EEPCo planned transmission expansion in

Figure 5.1, which is network map of planned and existing 230- 500 kV lines. Table 7.7 compares the planned expansion between nodes in the EEPCo map to the expansion results from the scenarios where grid expansion occurred – scenarios 2017D_LI_FE, 2027D_LI_CE, 2024D_LI_FE, and 2019D_HI_FE. Eq 5.1, which calculates transmission capacity, is applied to the EEPCo map by assuming the current carrying capacity is 1000 amps and voltage is the kV value designated in the map. Values in red, are transmission capacity expansion values indicated by the model that surpass EEPCo's planned expansion.

Table 7.7: Comparing EEPCo Planned Expansion to Scenario Expansion

Node	**Node**	**Expansion (MW)**				
		EEPCo planned	**(2) 2017D_LI_FE**	**(3) 2027D_LI_CE**	**(4) 2024D_LI_FE**	**(5) 2019D_HI_FE**
Bahir Dar	**Gondar**	230	22.27	2.98	70.59	87.23
Addis Ababa	**Dire Dawa**	460	0	167.5	85.5	87.91
Koysha	**Awasa**	400	0	1615	1382	1558
GERD	**Bahir Dar**	0	0	95.99	0	0
Awasa	**Jimma**	0	0	365.65	0	0
Total Expansion (MW)		**1090**	**22.27**	**2247.12**	**1538.09**	**1733.14**

Three scenarios – 2027D_LI_CE, 2024D_LI_FE, and 2019D_HI_FE - indicate that the line connecting Koysha and Awasa should be expanded three to four times more than what EEPCo has planned. Compared to the Baseline Scenario, these scenarios have increased internal and external demands, which leads to the grid expansion. In addition, it is important to note that this expansion is prompted because the lines connecting the generators at Koysha to its adjacent nodes has a shorter length compared to other lines. Also, Koysha is connected to Addis Ababa, Jimma, Awasa, and the Kenya export which are the nodes with the highest nodal demands in this model. A quadrupling of transmission capacity may not be physically feasible; the expansion prompted by the scenarios indicate the importance of the Koysha node to the system in terms of cost effectiveness and in meeting market constraints for future demand.

In addition, Scenario 2027D_LI_CE suggests an increase in transmission capacity between the GERD to Bahir Dar and Awasa to Jimma. Awasa has the second highest nodal demand after Addis Ababa. Jimma and Bahir Dar have the third and fourth highest nodal demands. The results from this scenario suggest that in the future there will be congestion in these lines if they are not expanded since these lines are connected nodes that have the highest regional demands in the system.

7.8 Model Data Improvements

Accurate data inputs on generation, transmission, and demand can improve this model. Generation inputs such as dam inflow time series or hydraulic parameters can create more realistic generation results. In addition, only hydropower generation was considered in the model because over 90% of the power generation capacity comes from hydropower. However, wind generation capacity, which is approximately 300 MW could be considered. Wind generation complements hydropower generation; as hydropower generation decreases in the dry season, wind generation increases. Transmission network data, such as reactance, voltage angles, and transformer characteristics could be collected to run an AC OPF or DC OPF models, which can provide more realistic results. Additionally, a demand time series from EEPCo could provide important load data in the model.

Chapter 8 – Conclusion

Ethiopia is a low-income country with an agriculture-based economy that is susceptible to drought. GWI technologies can help increase year-round agricultural yields and mitigate the effects of drought. However, GWI expansion is constrained by low rural electrification rates. Upcoming hydropower plants – The Grand Ethiopian Renaissance Dam, Genale Dawa III, and Koysha – will triple the existing generation capacity and can supply electricity for pumping GW for irrigation. However, the ICS needs to be expanded to utilize this generation for GWI.

The thesis builds a regional-scale linear optimal power flow model to guide cost-optimal generation operations and transmission expansion of the ICS to satisfy regional electricity demand from GWI. The following model data inputs were estimated: (1) a regional transmission network representation that consolidates existing published data, (2) regional 24-hour load curves, (3) seasonal effects on generation capacities, (4) GWI electricity demand estimates in dry and wet seasons, and (5) future domestic and export electricity demand.

The model determines cost-optimal generation and transmission expansion for a baseline case and five scenarios. The baseline for the model includes current domestic regional demand and export demand. The scenarios in the model include combinations of present and future estimations of domestic regional and export demands along with 10% and 100% GWI. In both seasons for the five scenarios, capacity factors for all nodes with generation increased or remained the same due to an increase in total demand. The percentage change of the capacity factor from the baseline was dependent on the location of the demand increase. For example, nodes with generation closest to export nodes operated more when future exports were considered. In addition, regions with greater GWI potential increased their hydropower production in the region or imported more electricity from other regions.

Four of the scenarios where internal and/or external demand increase indicate varying levels of transmission expansion across five lines in the system as noted in Table 7.7, and these results were compared with EEPCo's transmission expansion planning. EEPCo has a total planned expansion of 1090 MW across these five lines. The results of scenarios 2017D_LI_FE, 2027D_LI_CE, 2024D_LI_FE, and 2019D_HI_FE determine a total expansion capacity of 22.27, 2247.12, 1538.09, and 1733.14 MW, respectively. The total grid expansion indicated in the last three scenarios surpasses the expansion planned by EEPCo, suggesting that the current expansion plan is not the cost-optimal method of expansion for GWI needs.

Overall, the model analyzes transmission expansion possibilities to increase GWI throughout Ethiopia. This thesis provides an initial framework for transmission expansion in Ethiopia and can be improved through more accurate data inputs, such as transmission network data, generator characteristics, and demand estimations.

This thesis studies endogenous grid infrastructure expansion decisions under competing objectives in satisfying internal or external demands. Due to the data-poor environment, the thesis systematically consolidates available data to estimate model inputs. By integrating the electricity network with water resource planning and export markets, this thesis builds a framework that studies the intersection of such topics and can be broadly applied in data-poor and low-income country settings.

Appendix

Appendix A: GAMS Code

```
*$title "Optimal Power Flow Model for Ethiopia"
*
* Filename: Eth_Nodal_Bal.gms
*
* Description: Optimal Power Flow Model for Ethiopia that determines cost-optimal generation operations
* and grid expansion by considering transmission capacity constraints, tranmission expansion constraints,
* and nodal balance constaints
*
*Input data file:
*ETHREGnodal2.xlsx
*
*==== SECTION: DATA DECLARATION
sets
   t          "time (hour)"
   bus        "set of all buses in the system"
   s          /1, 2 /
;

alias(bus,i,j);

parameters
  Pd(bus,t,s)     "bus real power demand (MW)"
  Pg(i,t,s)       "real power produced by generators at bus (MW)"

  d(s)            "number of days in sesaon 's' "
  Pmax(i,s)       "maximum real power generation output at bus (MW)"
  cap(i)          "capacity of generation at bus (MW)"
  Pmin(i)         "minimum real power generation output at bus (MW)"
  cap_fact(i,s)   "capacity factor of generator (MWh/MWh)"

  totalgen(t,s)   "total generation at each hour (MW)"
  totaldem(t,s)   "total demand at each hour (MW)"

  rate(i,j)       "line tranmission capacity limit (MW)"
  branchstatus(i,j) "line status: '0' indicates not online '1' indicates online"
  trans(i,j)      "lengths of transmission lines (mi)"
  bs(i,j)         "another line status variable: '0' indicates not online '1' indicates online"
  r               /0.1 / "discount rate for annualizing cost (%)"
  N               /20/   "number of years investment cost will be paid back"
;

*==== SECTION: DATA INPUT
$CALL GDXXRW I=ETHREGnodal2.xlsx O=ETHREGnodal2.gdx trace=3 INDEX=Index!A1
$GDXIN ETHREGnodal2.gdx
$LOAD bus, t, branchstatus, bs
```

```
$LOAD Pmax, Pmin, Pd, cap, d
$LOAD rate, loss
$LOAD trans
$GDXIN

*===== SECTION: VARIABLE DEFINITION
free variables
   V_P(i,t,s)         "real power generation at bus (MW)"
;

positive variable
   V_LineP(i,j,t,s)    "power flow on line conneting node 'i' to node 'j' (MW)"
   exp(i,j)           "total expansion on line connecting node 'i' to node 'j' (MW)"
;
free variable
   V_objcost          "total cost of objective function ($)"
;
*===== SECTION: EQUATION DEFINITION
equations
   c_node(i,t,s)    "nodal balance equation"
   c_obj          "objective function"
   Linemax(i,j,t,s) "transmission capacity constraint"
   exp_tot         "transmission capacity expansion constraint"

;
*===== SECTION: EQUATIONS Part 1: Objective Function
*Objective function
c_obj..
   V_objcost =e=
    sum((i,t,s),d(s)*3.25*V_P(i,t,s) + 45.53*1000*cap(i))
    + ((r*(1+r)**N)/((1+r)**N-1))*sum((i,j)$branchstatus(i,j), 1000*trans(i,j)*exp(i,j));

*===== SECTION: EQUATIONS Part 2: Constraints
*Nodal balance equation
c_node(i,t,s)..
V_P(i,t,s) =e= - sum(j$branchstatus(j,i), (1-loss(i,j))*V_LineP(j,i,t,s)) + sum(j$branchstatus(i,j),
V_LineP(i,j,t,s))
+ Pd(i,t,s)
;

*Tranmission Capacity Constraint
Linemax(i,j,t,s)$branchstatus(i,j)..
V_LineP(i,j,t,s) =l=  rate(i,j) + exp(i,j)
;

*Tranmission Expansion Capacity Constraint
exp_tot..
sum((i,j), exp(i,j)*trans(i,j))  =l= 0.1*sum((i,j), rate(i,j)*trans(i,j))
;

*===== SECTION: VARIABLE BOUNDS
```

```
* Generator power generation limits - Load Flow Analysis
V_P.lo(i,t,s) = Pmin(i);
V_P.up(i,t,s) = Pmax(i,s);

*===== SECTION: MODEL DEFINITION
model m_nodal /c_node, c_obj, Linemax, exp_tot/;

solve m_nodal min V_objcost using LP;

*==== SECTION: SOLUTTION ANALYSIS

Pg(i,t,s) = V_P.l(i,t,s);
cap_fact(i,s) = sum(t, Pg(i,t,s))/(Pmax(i,s)*24);

Display Pg, V_lineP.l, V_objcost.l, cap_fact;
```

Appendix B: MATLAB Code

```
%% Regional Demand Curve Calculations

%Thesis Title: An Optimal Power Flow Model to Guide Electricity Grid
%Expansion in Ethiopia for Groundwater Irrigation Use
%Author: Prathibha Juturu

%Description: This code calculates regional demand curves for each of the
%13 regions in the MME model. (Note: Werder is excluded because irrigation
%demand is 0 MW and it is not connected to the national electricity grid).
%Part 1: calculate the hourly irrigation demand (MW) for wet and dry seasons
%Part 2: calculate regional peak demand (MW) and uses that to create the
%regional demand curves
%Part 3: combine the regional demand curves and hourly irrigation demand
%Part 4: add export demand to array
%Part 5: match region number to the bus number in GAMS input data

clear all

format shortG
%% Part 1: Hourly Irrigation Demand Calculation in Wet and Dry Seasons
% Check 5.3 Groundwater Irrigation Demand for process to calculate the
% electricity demand for groundwater irrigation

% Loading data
% Need to rearrange to start row 1 with Oct 1
% Column #:     Region Name:
%   1           Asosa
%   2           Awasa
%   3           Bahir Dar
%   4           Dire Dawa
%   5           Gambela
%   6           Goba
%   7           Gondar
%   8           Harar
%   9           Jijiga
%   10          Jimma
%   11          Mekelle
%   12          Semera
%   13          Addis Ababa

x = csvread('irrig_elec_2018_2.csv', 1, 1); %removes row 1 and column 1 headings
A = 13; %row and column length of data

%% Averaging irrigation demand (MW) over days in wet season and dry season
% 1-243 corresponds to Oct 1, 2018 - Dec 31, 2018 and Jan 1 2018- May 31, 2018
% 244 - 365 corresponds to June 1, 2018 to September 20, 2018

for i = 1:A %each region
    dryhourlyMW(i) = (sum(x([1:243],i))/(243*24))*1000;
    %average daily irrigation load for dry season (MW)
```

```
end

for i = 1:A %each region
        wethourlyMW(i) = (sum(x([244:365],i))/((365-243)*24))*1000;
        %average daily irrigation load for wet season (MW)
end

%Plotting bar graph for dry and wet season irrigation demand (MW)
for i = 1:length(dryhourlyMW)
    Y(i,1) = dryhourlyMW(i);

    Y(i,2) = wethourlyMW(i);
end

figure (3)
X = categorical({'Asosa', 'Awasa', 'Bahir Dar', 'Dire Dawa', 'Gambela', 'Goba', 'Gondar', ...
'Harar','Jjiga', 'Jimma', 'Mekelle', 'Semera', 'Addis Ababa'});
X = reordercats(X,{'Asosa', 'Awasa', 'Bahir Dar', 'Dire Dawa', 'Gambela', 'Goba', 'Gondar', ...
'Harar','Jjiga', 'Jimma', 'Mekelle', 'Semera', 'Addis Ababa'});
bar(X,10*Y)
legend('Dry season', 'Wet season')
title('Hourly Electricity Demand for Groundwater Irrigation (MW)')
xlabel('Region')
ylabel('Load (MW)')
ylim([0 500])

%% Part 2: Creating regional demand curves
% Check Section 5.6 Regional Demand 24-hour Load Curve for calculation
% process

% Calculating regional peak demand
%Peak demand Addis is 60% of country peak demand
%(Source:https://pubs.naruc.org/pub.cfm?id=537C14D4-2354-D714-511E-CB19B0D7EBD9)
%Need to disaggregate 40% of country peak demand according to regional
%population

Pop = 79123151;     %Total country population excluding Werder and Addis
%(Source: CIESIN 2015 UN adjusted gridded population)

P = csvread('Ethiopia_Regional_population.csv', 1, 1); %loading percentage of
%population in each region excluding Addis Ababa (Calculated from CIESIN raster)

P_percent = P/Pop;

%Below are the options for peak demand
%Tot_peak_calc = 1632;    % (MW) 2017 peak demand check research notes for this calculation
%Tot_peak_calc = 5206;    % (MW) future demand 2027 n = 10
%Tot_peak_calc = 3676;    % (MW) future demand 2024 n = 7
Tot_peak_calc = 2058;     % (MW) future demand 2019 n = 2
%Tot_peak_17_source = 5000;  % (MW) (Source:https://pubs.naruc.org/pub.cfm?id=537C14D4-2354-D714-511E-
CB19B0D7EBD9)

Reg_peak = P_percent*Tot_peak_calc*0.4; %disaggregating 40% of the total peak demand
Reg_peak(13) = 0.6*Tot_peak_calc;       %peak demand for Addis in 2017
```

```
%% Creating regional demand curves
%Two peak periods: 1) 11AM-2PM 2)7-9PM
%graph of 24 hour load curve in source below
%(Source:https://pubs.naruc.org/pub/5379AB21-2354-D714-5178-2172830B66EA)

% Hourly points as percentage of peak demand (starts at 1AM)
h = 1:24;
hour_percent = [0.5 0.5 0.5 0.5 0.5 0.5 0.5 0.5 0.5 0.5 1 1 1 1 0.75 0.75 0.75 0.75 1 1 1 0.5 0.5 0.5];

%Plotting the daily load curve proportion to peak demand
figure (1)
plot(h, hour_percent)
title('2019  Daily Load Curve')
xlabel('Hours (1-24)')
ylabel('Domestic Peak Demand (MW)')

for i = 1:length(Reg_peak)
   for h = 1:24
   Reg_dem_curve(i,h) = Reg_peak(i)*hour_percent(h);
   end
end
z =  Reg_dem_curve([1:13],:);

%Domestic regional load curve
figure (2)
hold on
for ii = 1:13
 plot(z(ii,:))
end
legend('Asosa', 'Awasa', 'Bahir Dar', 'Dire Dawa', 'Gambela', 'Goba', 'Gondar', ...
'Harar','Jjiga', 'Jimma', 'Mekelle', 'Semera', 'Addis Ababa')
title('Regional load curves for 2019 (MW)')
xlabel('Hours (1-24)')
ylabel('Load (MW)')

%Reformats the regional load curve
for h = 1:24
   for i = 1:length(Reg_peak)
      Reg_dem_hourly((i-1)*24 + h,3) = Reg_dem_curve(i, h);
      Reg_dem_hourly((i-1)*24 + h,2) = h;
      Reg_dem_hourly((i-1)*24 + h,1) = i;
   end
end



%% Part 3: Combining regional demand curve and hourly irrigation demand
%Combining the domestic regional demand and the groundwater irrigation
% demand
for h = 1:24
   for i = 1:length(Reg_peak)
      Tot_dem_dry((i-1)*24 + h,3) = 10*dryhourlyMW(i) + Reg_dem_hourly((i-1)*24 + h,3);
      Tot_dem_dry((i-1)*24 + h,1) = i;
```

```
        Tot_dem_dry((i-1)*24 + h,2) = h;
        Tot_dem_wet((i-1)*24 + h,3) = 10*wethourlyMW(i) + Reg_dem_hourly((i-1)*24 + h,3);
        Tot_dem_wet((i-1)*24 + h,1) = i;
        Tot_dem_wet((i-1)*24 + h,2) = h;
    end
end


%% Part 4: Adding export demands
%Check Section 5.5 Exports for export demand values

%Two options for export demands
%export = [100 0 100 0];
export = [200 1000 100 400];
for x = 1:length(export)
    for h = 1:24
        Tot_dem_dry(312+(x-1)*24+h,1) = 13+x;
        Tot_dem_dry(312+(x-1)*24+h,2) = h;
        Tot_dem_dry(312+(x-1)*24+h,3) = export(x);
        Tot_dem_wet(312+(x-1)*24+h,1) = 13+x;
        Tot_dem_wet(312+(x-1)*24+h,2) = h;
        Tot_dem_wet(312+(x-1)*24+h,3) = export(x);
    end
end


%% Part 5: Matching region number to the bus number in GAMS input data
% Column #:     Region Name:    bus #:
%   1            Asosa          7
%   2            Awasa          10
%   3            Bahir Dar      13
%   4            Dire Dawa      3
%   5            Gambela        12
%   6            Goba           9
%   7            Gondar         8
%   8            Harar          5
%   9            Jijiga         4
%   10           Jimma          11
%   11           Mekelle        1
%   12           Semera         2
%   13           Addis Ababa    6
%   14           Sudan N        17
%   15           Sudan S        18
%   16           Djibouti       20
%   17           Kenya          19

M = size(Tot_dem_dry);
for i = 1:M(1)
if Tot_dem_dry(i,1) == 1
   Tot_dem_dry(i,1) = 7;
   Tot_dem_wet(i,1) = 7;
elseif Tot_dem_dry(i,1) == 2
   Tot_dem_dry(i,1) = 10;
   Tot_dem_wet(i,1) = 10;
elseif Tot_dem_dry(i,1) == 3
```

```
    Tot_dem_dry(i,1) = 13;
    Tot_dem_wet(i,1) = 13;
elseif Tot_dem_dry(i,1) == 4
    Tot_dem_dry(i,1) = 3;
    Tot_dem_wet(i,1) = 3;
elseif Tot_dem_dry(i,1) == 5
    Tot_dem_dry(i,1) = 12;
    Tot_dem_wet(i,1) = 12;
elseif Tot_dem_dry(i,1) == 6
    Tot_dem_dry(i,1) = 9;
    Tot_dem_wet(i,1) = 9;
elseif Tot_dem_dry(i,1) == 7
    Tot_dem_dry(i,1) = 8;
    Tot_dem_wet(i,1) = 8;
elseif Tot_dem_dry(i,1) == 8
    Tot_dem_dry(i,1) = 5;
    Tot_dem_wet(i,1) = 5;
elseif Tot_dem_dry(i,1) == 9
    Tot_dem_dry(i,1) = 4;
    Tot_dem_wet(i,1) = 4;
elseif Tot_dem_dry(i,1) == 10
    Tot_dem_dry(i,1) = 11;
    Tot_dem_wet(i,1) = 11;
elseif Tot_dem_dry(i,1) == 11
    Tot_dem_dry(i,1) = 1;
    Tot_dem_wet(i,1) = 1;
elseif Tot_dem_dry(i,1) == 12
    Tot_dem_dry(i,1) = 2;
    Tot_dem_wet(i,1) = 2;
elseif Tot_dem_dry(i,1) == 13
    Tot_dem_dry(i,1) = 6;
    Tot_dem_wet(i,1) = 6;
elseif Tot_dem_dry(i,1) == 14 % Sudan N
    Tot_dem_dry(i,1) = 17 ;
    Tot_dem_wet(i,1) = 17 ;
elseif Tot_dem_dry(i,1) == 15 % Sudan S
    Tot_dem_dry(i,1) = 18 ;
    Tot_dem_wet(i,1) = 18 ;
elseif Tot_dem_dry(i,1) == 16 % Djibouti
    Tot_dem_dry(i,1) = 20 ;
    Tot_dem_wet(i,1) = 20 ;
elseif Tot_dem_dry(i,1) == 17 % Kenya
    Tot_dem_dry(i,1) = 19 ;
    Tot_dem_wet(i,1) = 19 ;
end
end

%Writing into excel file
Tot_dem_dry = array2table(Tot_dem_dry);
Tot_dem_wet = array2table(Tot_dem_wet);

filename = ''Insert Model Run'__demand.xlsx';
writetable(Tot_dem_dry,filename,'Sheet',1);
writetable(Tot_dem_wet,filename,'Sheet',2)
```

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Curriculum Vitae

Prathibha Juturu

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EDUCATION

Johns Hopkins University - Whiting School of Engineering – Baltimore, MD
Expected Graduation: May 2020
Master of Science in Environmental Engineering

- 2018 Donald M. Payne International Development Fellow
- *GPA 3.9/4.0; concentration in Environmental Management and Economics*
- ***Relevant Coursework:*** *Energy Planning and Policy Modeling, Applied Microeconomics, Energy Systems Analysis, Risk and Decision Analysis, Collaborative Water Dispute Modeling, GIS Remote Sensing Environmental Applications*
- ***Thesis:*** *Using an Optimal Power Flow Model to Guide Optimal Electricity Grid Expansion in Ethiopia for Groundwater Irrigation Use*

Duke University - Pratt School of Engineering - Durham, NC
Graduation: Summer 2018
Bachelor of Science in Environmental Engineering

- Minor in Arabic; *GPA 3.65/4.0* Dean's List (Spring 2014, Fall 2014, Fall 2015, Spring 2017)
- Chi Epsilon Civil Engineering Honors Society
- Duke in the Arab World (May - June 2014) Deepened understanding of Moroccan culture through courses (Religious Citizenship in Morocco & Moroccan Dialect).

WORK & RESEARCH EXPERIENCE

Innovations at the Nexus of Food, Energy, and Water Systems - Baltimore, MD
Researcher - Mathematical Optimization for Decisions Lab (November 2018 – Present)

- Researching in an NSF funded modeling group on optimal electricity grid expansion in Ethiopia for groundwater irrigation use.
- Estimated city-level electricity demand using NASA Nightlights data from the VIIRS satellite images.
- Conducted a literature review on hydropower and irrigation development tradeoffs for Ethiopia.

USAID West African Regional Mission - Regional Economic Growth Office - Accra, Ghana
Donald M. Payne International Development Fellow (June - August 2019)

- Acted as Site Officer #2 for Speaker Pelosi's congressional delegation visit to the Dignity-Do The Right Thing apparel factory.
- Participated in a collaboration meeting between RISE II and SERVIR in Burkina Faso on ground water resources in Niger.
- Observed a Technical Evaluation Committee for a WASH contract and obtained contractor past performance information.

U.S. House of Representatives - Congressman Donald M. Payne Jr. - Washington, D.C.
Congressional Intern (June - August 2018)

- Drafted a bill to implement an EPA green infrastructure research grant program for universities and businesses.
- Drafted a letter to Governor Phil Murphy on allocating funds to improve stormwater management practices in New Jersey.
- Wrote an office memo on the impact of water privatization in the U.S., using Bayonne, New Jersey as a case study.

CARE International - Food Security and Livelihoods in South Syria - Amman, Jordan
Program Assistant (Nov 2017 – May 2018) Intern (Aug 2017 – Oct 2017)

- Supported in finalizing and editing the draft strategy for the Food Security and Livelihoods (FSL) Program in South Syria.
- Collaborated with partner organizations in writing proposals for the FSL program for donors DFID, SIDA, BMZ, and EC.
- Attended trainings in value chain analysis and gender mainstreaming in food security and livelihoods activities.
- Created a value chain development plan to inform stakeholders of interventions in food processing and livestock value chains.

Bass Connections - Auto-Mechanic Village Contamination - Durham, NC & Kumasi, Ghana
Researcher (August 2016 - May 2017)

- Collected soil, water, and human nail and hair samples to evaluate health risks and environmental damage associated with contamination of used motor oil in auto-mechanic villages in Ghana.
- Analyzed human hair and nail samples for heavy metal concentrations using atomic absorption spectroscopy.

PROJECTS

Master's Thesis January 2019 - May 2020

- Researching on energy developments in Ethiopia and building an engineering-economic model to determine optimal grid expansion for groundwater irrigation use.

Remote sensing Kenya cropland destruction - Baltimore, MD January - May 2020

- Identifying cropland in Kenya destroyed by 2020 locust swarm using NASA's MODIS satellite imagery.
- Creating a vegetation anomaly map comparing average EVI in Feb 18- March 4, 2020 to a ten-year average.

Traffic Density Prediction Model - Baltimore, MD January - May 2020

- Using machine learning techniques, such as Principal Component Analysis, K-Nearest Neighbors and Artificial Neural Networks, to create a traffic congestion prediction model for roads with high traffic in New York state.

LECTURES

Energy and Environment Seminar - Johns Hopkins University April 2020

- Direct Current Optimal Power Flow Model for National Grid Expansion in Ethiopia.

Energy and Environment Seminar - Johns Hopkins University November 2019

- Multi-player Microeconomic Model: Food, Energy, and Water Nexus in Ethiopia.

Intro to Engineering for Sustainable Development - Johns Hopkins University March 2019

- Humanitarian and Resilience Interventions: South Syria Case Study.

- **Second Year Arabic** - Johns Hopkins University
  February 2019
- Title: Culture - Jordan, Morocco, and Oman (ثقافة: أردن, المغرب, وعمان).

CERTIFICATES AND HONORS

Donald M. Payne International Development Fellow June 2018 - Present

- Selected from 400+ applicants to join USAID's fellowship for future foreign service officers.

Critical Language Scholarship – U.S. State Department - Ibri, Oman May - August 2017

- Received scholarship among 5,500+ applicant pool to study Advanced Modern Standard Arabic and Dialect 20+ hours a week.

SKILLS AND INTERESTS

Skills: MATLAB, ArcGIS, QGIS, GAMS, AutoCAD, Solid Works, Microsoft Excel, Mathematica, Conversational Arabic, Native fluency in Telugu
Interests: Decarbonizing Power Sectors, Rural Electrification, Remote Sensing, Traveling, Social Entrepreneurship, Weightlifting, Hip Hop Music, Duke Basketball