Decarbonization Pathways for Paraguay’s Energy Sector

Potential Options for Paraguay’s Electric System to Meet Its Future Energy and Power Needs:

Observations from Experience and a Modeling Exercise

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Summary

Paraguay's electricity system is broadly dominated by residential loads on the demand side and hydropower on the supply side. The rest of the energy system is a mix of liquid fossil fuels or biomass-derived solid fuel. Liquids serve a combination of transport (vehicles) and industry, whereas biomass is used primarily for thermal needs of industry and small-scale household cooking needs.

We first make some general observations from our experience in other countries. These initial observations are qualitative in nature and not formally analyzed further in this part of the report.

The nature of electric utility operation is changing with increasing need to leverage newer technologies- both hardware and software for efficient (low technical losses), easy to manage (monitor growth, loading of assets, and maintenance), resilient (in case of faults, disruptions) and nimble (addressing changes in demand and supply) operation. Additional innovations in tariff policy, time-of-day pricing, valuing customer side investments in storage and load management are also being enabled by technology. However, this technological transition is not simple to execute as the core expertise of the utility generally lies elsewhere. A parastatal utility is also subject to the overall constraints of the national exchequer, and the political economy of the country.

Paraguay is endowed with low-cost and plentiful electric power and being a small nation with a large urban core can also be nimble at change. Yet to unlock the benefits of electricity, one needs to be mindful of four constraints. First, efficient operation of the distribution system. Second, ensuring that load factors improve as load growth occurs. This implies mechanisms and incentives to ensure a balanced growth of load especially at hours of the year when the grid does not experience peak loads. The third constraint is on the consumer side, especially for the large majority that do not enjoy high incomes. This constraint is the inability to purchase efficient electric appliances that would allow them to affordably utilize electricity to begin a transition away from fuelwood for cooking. A mirror of this constraint is also on the industry side, where industry does not have the capital to switch from biomass to clean power for their thermal needs. The fourth constraint is the lack of a coherent vision for sustainable housing that would begin with requiring new higher-end construction to be grid-responsive and efficient at the same time.

A shift is underway where modern economies are expecting 24-7 power, load-growth in emerging markets can be strong, universal access is a must, and tariffs cannot be simply cost reflective for parastatals, especially in view of rising costs for the utility to maintain and upgrade infrastructure- especially in urban settings. It is in this context that we pay significant attention to managing peak loads in a planned way, and without leading to power outages. We propose that near-term additional focus be also on creating a modern distribution system, with data-driven planning and upgrades, and the ability to work closely with the housing sector to ensure that at least new buildings follow guidelines that are a win-win in the long term for managing peak loads for the utility and for making it worthwhile for the private sector to invest in efficiency and measures to reduce peak loads. Unlike simply providing electric power, the utility will have to imagine context-specific ways to incentivize adoptions of efficiency and load management technologies.

The overall objective of the energy system is to meet multiple goals:

1. Long-term economic growth of Paraguay
2. The bottom-up needs of the entire population as embodied in SDG 7, with particular attention to the underserved.

3. Meeting Paraguay's decarbonization pathway in line with Paraguay's commitment under the Paris Agreement.
4. While the above are undisputed, the challenge is in achieving them
    a. Cost-effectively for the citizens of Paraguay: so that the consumer of energy sees a win-win with the long-term goal of affordability by the consumer and affordability by the government and associated public/private institutions.
    b. While building trust and confidence between the energy users, providers and those responsible for managing and regulating the sector.
    c. While keeping an eye on the long-term goals, ensuring that short-term measures are indeed not overly burdensome to the exchequer and the consumer.
    d. While ensuring that capacity to test, prescribe, assemble, manufacture, maintain, measure and monitor systems is built into the process so that local and regional talent can be gainfully employed.
    e. While ensuring that the electric utility works in tandem with the goals of sustainable housing and transport, in tandem with goals of reducing dependence on unsustainable biomass use.

This specific report works with disaggregated data collection regarding power generation, specific energy sources and the nature of their supply, and finally with their power/energy consumption, using 2019 as a base year to develop a simple but useful mixed integer linear model (MILP) to capture the main drivers without the attempt to be fully granular. The goal here is to ensure that the large drivers of growth are captured. These inevitably are the built environment, transport, and industry with the electricity sector dominating the first and over time the second one as well. The rough period under study is from year 2019 to year 2040.

With the data and models, we project the near-term to mid-term options for grid growth, and examine how this would impact the Levelized Cost of Electricity (LCOE) of the grid, impact infrastructure investments for electrification of loads, and consumer financing.

We explore how conventional technologies and price-points of battery storage, thermal storage, rooftop solar, wind turbine, flexible operation of hydropower, and demand side management methods might complement the cost-effective options. Given that the demand in Paraguay is dominated by cooling, thermal storage we modelled was in the form of ice-storage in plastic tanks. We note that this effort is not a comprehensive engineering study of the entire network from transmission to distribution. Instead, through empirical utility costing knowledge, we try to capture the overall investment needs of transmission and distribution under suitable load growth scenarios. Cost structure requirements of applicable options are shared as well.

The high-level summary of recommendations for energy sector:

1. This study is not a detailed engineering study of the full electricity distribution, transmission and system of Paraguay and its neighboring countries. Instead, it carries out modelling as an aide to suggest potential pathways for Paraguay to explore. Any modelling of the future is fraught with challenges of assumptions- whether of demand, supply or of costs.
2. Paraguay is blessed with ample low-cost hydropower that is able to meet nearly all its current electricity needs. The current demand is dominated by building loads, that peak during times when the air-conditioning loads are high. A simple regression model shows that the temperature dependent load can be as high as 46% of total load during peak summer time. It should be noted that the possession rate of air conditioning units is still rising rapidly during recent years,

according to ANDE's survey, from 36.5% in 2013 to 42.7% in 2017.[1] Given that the load shape is not changing as the average load increases, one can reasonably conclude that air-conditioner ownership is only increasing. The resulting load needs to be characterized and modelled carefully as the present load profiles do not follow the conventional wisdom elsewhere in hot climates. While one would expect the loads to predominantly follow temperature and humidity patterns, in Paraguay the combination of space occupancy patterns and the use of window air-conditioning units, drive night-time summer loads that peak late in the night.

3. Our first recommendation is to consider digitization within the utility, prioritizing homegrown solutions that can leverage local talent and expertise. The need for this is driven by:

   a. A backlog of deferred distribution system maintenance leading to both reliability issues and poor operational performance.
   b. High losses in the distribution system.
   c. The end-use appliance efficiency (anecdotally) appears to be low, driven by price-conscious consumers. This could explain purchase of low-capex window air-conditioners without adequate benchmarking and standards. New construction, urbanization and income can drive rapid adoption which in turn can make it difficult for the utility to keep up with heterogeneous load growth and hence potentially creating a backlog of retrofit unless monitored.

4. Digitization is a broad term for electric utilities, but given the availability of educated work force in Paraguay, it should be possible to start with some very simple but potentially effective measure. One needs to bring together the data of the commercial department of ANDE with the data of the technical department to ascertain which specific parts of the distribution system have the largest losses. For establishing this it would be important to assign "digitally" each existing consumer to a specific element of the distribution system: transformer, feeder and the sub-station. These elements would be meters first and their metered measurements would need to be tallied against the consumption of all consumers at that element. Such information systems would also set the stage for a future with grid-interactive and efficient buildings. The nature of this effort would not require large multi-national corporations for execution but could be carried out by ANDE with support of local engineering and research establishment talent.
5. We recommend that Paraguay examine the viability of low-cost power at off-peak hours and in distribution networks with ample room for load growth. Such a program would need to be coupled with a large-scale dissemination of safe, efficient and smartly subsidized appliances for electric cooking and water heating. Electricity at $20/MWh is one-fifth the cost of retail LPG cylinders, and there is already the distribution network, i.e. the ANDE network to bring that clean power to one's home. It is however essential to leverage digitization and technology to manage these time-of-day tariffs and manage distribution system loading. Experience shows that well designed incentivized adoption over a number of years is needed to create a shift in practices that can first start with urban populations.
6. We suggest that Paraguay examine the creation of a bureau of energy efficiency within the appropriate government structures, a bureau that can test performance, create a standards/labelling program with appropriate controls of the minimum standard products that are sold. Ideally the bureau is somewhat independent of the utility, line ministries and has mandate to work across silos of energy, industry, academia, housing and construction. While this measure is easier to imagine, soon Paraguay will need to ensure that every building above some

[1] ANDE (2018), Balance Energetico Nacional 2017; ANDE (2014), Balance Energetico Nacional 2013

threshold size would be required to meet some specified target criterion of efficiency per sqm of constructed area. It is important that such guidelines are set early on. Meter measurements and energy audit requirements could make it easier to set such targets.

7. We recommend Paraguay to examine the business case for newer housing that is both efficient and grid-responsive to allow ANDE start the process of freeing up head room for peak loads in the future. With Paraguay's unique load profiles, lower-cost thermal storage possibly combined with rooftop solar could be an option for newer modern buildings so that new buildings can be grid-responsive.
8. While higher income countries move towards battery powered personal mobility that relies on largely imported hardware, countries such as Paraguay could examine how an infrastructure-led approach which creates more local investment and more jobs, and addresses higher throughput on road networks, through affordable above-ground electrified public transit (e.g. trams, light rail, buses, or BRT) in the Asuncion metropolitan area. Such an approach would have a disproportionate balance of jobs when one considers a public transit system backbone consisting of a "combination of overhead catenary wire and limited onboard storage" creates- this option should be examined. We suggest that Paraguay examine the gap-financing needed for electrification of public passenger transport to shed light on what policy incentives would be required, coupled with the needed urban planning and roadway designs that can facilitate clean, reliable and speedy public transit.
9. There are also high T&D losses in the Paraguay system. A suggested target of reducing losses by 10% (fraction of the overall supply) could come from halving the losses in the distribution system in the near term. This would enhance current revenue recovery by 10%. This of course assumes that this reduction is primarily from reductions in non-technical losses and would add to new revenue if reduced. Based on 2025 anticipated sales figures, these added revenues could be more than $160M per year. This represents a massive opportunity as well.
10. We study ANDE's master plan on distribution, ANDE expects that the upgrade and expansion of the distribution system will cost approximately 2.2B USD. Of this 2.2B, about 1.5B is for transformer and wires expansion of existing system, and the rest is to electrify remote and isolated areas. This was an estimate for 2016 to 2025. While we don't know what was already accomplished of this estimate- we assume that bulk of the upgrades are yet to come. The plan is supposed to accommodate load growth from a peak load of 3165 MW at year 2016 to 6721 MW in 2025. The actual peak capacity of the distribution system infrastructure is of course much higher. Regardless of how one thinks of the investments, the utility expects to spend at a minimum $400 per kW of peak load that will emerge. The corresponding amount is annually $30 to $50/kW. A similar number can be obtained when looking at ANDE's new master plan 2021-2030. From our reading these investments are primarily to improve reliability and keep up with demand growth.
11. Above suggests that the 2.2B distribution system upgrades should be seen as an opportunity to simultaneously address the issues of:

    - Upgrades in distribution systems along with digitization of the distribution system.
    - Reducing losses using above data and commercial department data.
    - Implementing measures for both new electrical appliances as well as a longer-term strategy for building envelope retrofits.
    - Upgrades in metering systems for new larger buildings so that incentives for reducing peak loads can be implemented.

12. Overall, utility-side investment portfolio should go beyond generation, transmission and distribution to ensure that resources are also needed to address consumer-side end use equipment needs especially those of the poor

The summary of modelling results:

1. We present a co-optimized capacity-planning and dispatch model over a year of hourly operation. The model takes electricity load records, topology of transmission lines between the countries' six load zones, renewable energy resources availability, cost structure of power generation and purchasing, and new power plant proposals as input, indicating investment in generation and interzonal transmission and details of hourly energy dispatch with the time scope from year 2019 to 2040 that minimizes the annual power system operational cost and annualized capital investment. Details on model inputs and assumptions can be found in section 1.2 and 1.3, while mathematical formulation of the model can be found in Appendix D. We assume the load shape remains similar to what it today as the average load growth. Hence, we assume that peak loads will grow with energy requirements or the "average load". Multiple technology combinations and peak load management methods were studied. It is important to note that there are several sets of factors, some specific to Paraguay and new emerging technologies and electricity system operation paradigms that challenge the conventional views of long-term electricity planning.
2. With current growth projections, power capacity shortages could begin to appear by the end of this decade and as early as year 2028 when considering an annual growth rate of 5% in demand. This finding is slightly earlier compared to IPPSE's study,[2] as we considered the worst hydropower potential among recent 20 years. Indeed, slower growth, however that arises, would to delay capacity shortages. Without constraining rightful growth, it is possible that efficiency measures if aggressively implemented could allow slower growth rates.
3. Simply put, the cost of addressing the growth in peak loads can be high, as in the absence of large storage reservoirs, or large peaking capacities, the costs of such peaks accumulate from investments needed in generation, transmission and distribution.
4. The potential uncertainty of Itaipu power purchasing price posed by the upcoming revision of Annex C of Itaipu will affect the electricity price structure. Model result indicates a price drop in Itaipu power will significantly reduce the levelized cost of electricity (LCOE) in the short term. However, its impact on electricity price reduces as demand continuously grow.
5. Upon capacity shortage occurs, new generation capacities are supposed to be built. In our base scenario (i.e. only invest in hydropower, solar PV and battery), the model suggests Ana Cua and the expansion of Yacyreta proposed by IPPSE to be put in service no later than demand doubles from year 2019 level (or year 2034, for a 5% in-average annual growth rate in demand). Corpus Christi as well as around 800MW in total domestic hydropower plants are expected to start operate before year 2040 when considering the same growth rate. As the expansion of electricity generation capacity requires large amount of time and resources, especially for new hydropower constructions, Paraguay might want to plan and make actions from now on.
6. Upon capacity shortage occurs, maintaining electricity balance between demand and supply merely by the anticipated hydropower constructions outlined by ANDE's master plan and IPPSE's report is not economically optimal. In addition, both temporal and spatial correlation between major hydropower plants that are located on Parana River makes it tougher to provide reliable power supply without adding variety to the system.
7. Variable renewable energy (VREs, i.e. solar photovoltaic, wind power) can be a valuable supplement to hydropower. We simulate solar and wind potential based on open-source

[2] IPPSE, Requerimientos de generación eléctrica del Paraguay, periodo 2019 – 2038

databases[3,4], and assume future-looking installation expenses. We find fixed solar PV panels and wind turbines have largest capacity factor in the northwestern area of the country. The value of VREs is amplified when introducing energy storage technologies. Distributed renewable energy generator is able to provide additional benefits to the distribution system, which is not evaluated in our model.

8. Existing interzonal transmission capacity is generally capable to fulfill the need of electricity transmission by 2040. Minor enhancement is suggested to be made between East and Metropolitan load zones.
9. We also expect rather large shifts to occur in the way energy planning is carried out. We may be entering a phase where firm loads, or "baseload" are actually met from distant supply whereas the peak loads are met/managed by measures closer to demand.
10. Load profiles might shift over time. At least with the current load profiles there are opportunities that could leverage a regular diurnal use of electricity peaking at night, and allow one to consider storage given the low cost of energy but high cost of peak power. As the peak is mainly driven by thermal demands for cooling in Paraguay, ice storage, district cooling and high temperature thermal storage for industries are feasible lower-cost alternatives to batteries. The economic benefits of several peak load reduction methods were examined and summarized below (refer to section 2 and 3.3, 3.4 for details). We suggest Paraguay take comprehensive study to verify their feasibility in Paraguay.
From supply side:

    a. Battery storage's ability to improve VRE integration has been shown extensively in existing studies.[5] In the scenarios we computed, battery is always selected, if allowed, by our model when solar and wind generation is invested.
    b. Hydropeaking (i.e. a few hours storage capacity, and additional generation capacity that is available during peak load periods) among hydropower plants to be built in the future is able to improve the dispatchability of hydropower. Our model shows at least 7% reduction of total energy cost (i.e. Levelized cost of electricity. Note, additional cost for conducting flexible operation is not considered) is achievable if implementing this method when load growth to 2.5 times year 2019 level. This reduction can be attributed to smaller investment in generation and transmission to accommodate peak demand. Additional benefit lies in alleviating stress of power dispatch in Metropolitan area.

From demand side,

    c. Ice-storage, a form of thermal storage is ideally suited since the manufacturing, assembly and installation all leverage low talent and create jobs. Our model shows its potential benefit for Paraguay's energy system lies in three aspects - reducing peak generation capacities, encouraging the installation of VREs, and alleviating transmission line stress. Note that the time-time of thermal storage is at civil construction standards as opposed to that of batteries.
    d. District cooling system helps commercial and residential customers reducing their heating energy usage.
    e. Demand response program (DR) creates economic incentives to customers who are able to reduce or shift their electricity usage during peak hours. We analyze the adoption of DR

[3] European Commission EU Science Hub, Photovoltaic Geographical Information System (PVGIS).
[4] Integrated surface data, NCEI, 2021, Url: https://www.ncdc.noaa.gov/isd
[5] Zhou, Y., Scheller-Wolf, A., Secomandi, N., & Smith, S. (2019). Managing wind-based electricity generation in the presence of storage and transmission capacity. *Production and Operations Management*, *28*(4), 970-989.

program in New York state, and show both utility and customer are benefitting from it. Analogously, model result indicates a saving for Paraguay on generation of $30~40 USD for each kW power reduced per year is achievable. If we consider hydropower or solar PV to be the marginal investment for peak load, this saving can amount to $120~200/kW-yr. DR program is also beneficial to transmission and distribution system. Based on the investment outlined by ANDE's master plan, we believed the overall fiscal value of DR program to system operator can be $75~275 for each kW reduced per year. With such an incentive, building owners will be able to consider Shifting energy intensive activities during peak hours, installing distributed sustainable resource generators, enhancing efficiency of air conditioning systems, and investing thermal storage devices.

f. Yet another means to improve the load factor and manage peak load growth is to consider time-of-day tariffs for large customers whose internal cost of capital is low enough to signal investment.

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1. Paraguay Electricity Resource Adequacy Model (PY-RAM)

1.1 Introduction

1.1.1 Objective

This chapter introduces major assumptions, cost structures and modeling methods. Paraguay Electricity Resource Adequacy Model (PY-RAM), a robust mixed integer linear program (MILP), is created to simulate Paraguay power system expansion. The model minimizes the total annual system operational cost and annualized capital investment, while maintaining equilibrium between power generation and projected load at an hourly resolution. It takes year 2019 as a base year and outlooks power system planning for the period 2020-2040 under various growth scenarios.

PY-RAM is a deterministic model that all of its investment and operation decisions are made to meet the uploaded hourly load with predefined parameters. This characteristic allows detailed study on multiple scenarios of power grid expansion, both on demand side and supply side. Given the projected demand growth, energy harvesting potential, and cost structure of future generation technologies of interest, the model will indicate investment and details of hourly energy dispatch. To be noted, the model is not meant to provide solid capacity investment numbers, but to give insights on technology integration and system expansion options.

1.1.2 National power system topology

ANDE manages Paraguay's national electricity grid, Sistema Interconectado Nacional (SIN). For operational purpose, SIN is divided into 6 interconnected load zones, [6] as shown in figure 1.

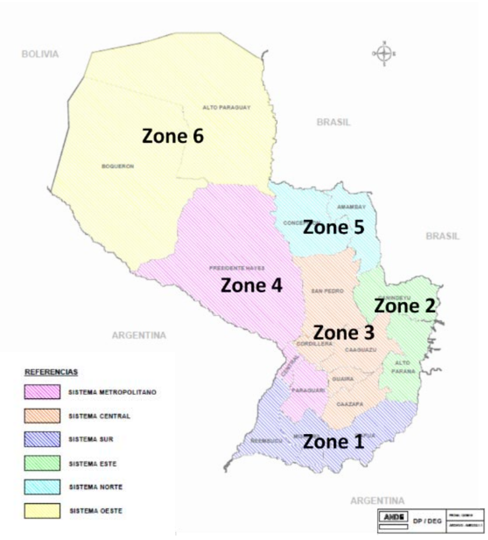


Figure 1. Power grid sub-system map, according to ANDE

Zone 1 (Sistema Sur) populated 11.5% of the country's population.[7] The southern border of the region is divided by Parana River from Argentina. Therefore, water resources for energy harvesting is abundant. Yacyreta, the binational generation entity, capacitates with 20 Kaplan turbines (10 belongs to Paraguay and 10 belongs to Argentina) that amounts to 3200 MW. Its generation of the

[6] ANDE, PLAN MAESTRO DE GENERACIÓN PERIODO: 2016-2025
[7] DGEEC, https://www.dgeec.gov.py/vt/Poblacion-Paraguay-2020-por-departamento-y-sexo-segun-proyeccion.php

year 2019 is 17.28 TWh. Moreover, four proposed binational hydropower constructions are also located in this zone, which will ideally result in additional 3181 MW capacity available to ANDE. [8]

Zone 2 (Sistema Este) homes 14.7% of the population, while producing most hydropower electricity of the country. Itaipu, jointly owned by Paraguay and Brazil, has 14000MW capacity in total, with half possessed by Paraguay and the other by Brazil. The total annual generation of Itaipu is 79.45 TWh for year 2019. Acaray, the third largest hydropower station in the country, capacitates 210 MW that connected with Paraguay's national grid entirely.

Zone 3 (Sistema Central) populates 23.9% of the nation's population while consumes 10.2% of the country's total electricity. The region has lowest possession rate of air conditioning in residential building, which primarily attributes to poverty. In addition, zone 3 has considerable hydropower potential (e.g. Paraguay River) that can be exploited in the future.

Zone 4 (Sistema Metropolitano) is the most populated region in the country, it's home to 42.9% of the Paraguayan population. While holding no centralized generation units other than backup diesel generator, the region consumes 54.9% of the country's total electricity demand. Two 500kV transmission lines starting from Itaipu and Yacyreta, as well as several 220kV lines guarantee the demand is met at most time for this zone. Moreover, this region has the most developed public transport services, with around 100 bus lines.[9] Electrification of the public transport fleet should be prioritized when consider introducing electric vehicle (EV) into the country.

Zone 5 (Sistema Norte) consumes 5.1% of national electricity demand. Some hydropower potential can be exploited in this region (e.g. Ypane).

Zone 6 (Sistema Oeste) only populates 1.2% of the nation's population. The region has the best solar potential among the six load zones. Investing solar PV in this zone can be a possible substitution of excessive biomass usage in the area of industry intensive Chaco.

Table 1. Summary of relevant sub-system data

Zone	Population ratio	Annual electricity consumption ratio	Installed centralized Generation capacity
1	11.5%	8.5%	1600MW
2	14.7%	19.5%	7210MW
3	23.9%	10.3%	0
4	42.9%	55.0%	0
5	5.9%	5.1%	0
6	1.2%	1.5%	0

1.1.3 Current transmission capacity

Detailed transmission line information (e.g. direction and capacity) is provided by CRECE based on data shared by ANDE. The major interzonal connections and the nominal capacities of the

[8] Columbia Center on Sustainable Investment (CCSI), Quadracci Sustainable Engineering Lab at Columbia University, and Centro de Recursos Naturales, Energía y Desarrollo (CRECE). "Chapter 2: The Electricity Sector in Paraguay." In Decarbonization Pathways for Paraguay's Energy Sector, 31–66. New York: CCSI, September 2021

[9] Dinatran, 2018, Anuario Estadistico De Transporte

existing transmission lines are listed in *Appendix C*. In Figure 2, the total transmission capacities for any two zones are aggregated in the matrix, where the vertical axis indicates the transmission exports load zone and the horizontal axis corresponds to the destination zone. In the model, 3% transmission losses between adjacent zones are assumed, which is not precise but contributing to the model total transmission losses closes to the documented national number, 5.4% of the total generation.[10] And no specific distribution losses are applied in the model, because the load input is the national grid value including this part implicitly.

to / from	R1	R2	R3	R4	R5	R6
R1	0	0	0	2516	0	0
R2	180	0	1783	2000	350	0
R3	0	0	0	1217	200	0
R4	235	0	0	0	350	0
R5	0	0	0	0	0	240
R6	0	0	0	0	0	0

Figure 2. Existing inter zonal transmission limits, unit: MW. The vertical indexes and horizontal indexes are the starting zones and the destinations of the transmission line respectively.

1.1.4 Power system operation records

High resolution national wide electricity generation and grid load data were made available for this study by Centro de Recursos Naturales, Energía y Desarrollo (CRECE), thanks to Administración Nacional de Electricidad's (ANDE) generous disclosure of its operating records for the past 20 years. Hourly national load record together with annual average and peak, and hourly Paraguayan share of electricity generated from Itaipu Binational and Yacyreta Binational Entities are shown in figure 3 and 4 respectively.

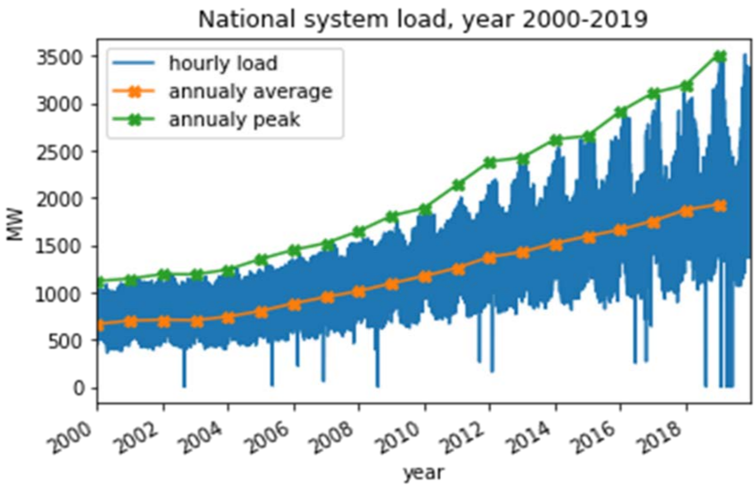


Figure 3. Hourly electric load of national power system, with annual average and peak load, year 2000-

[10] ANDE (2019), Balance Energetico Nacional 2018

2019

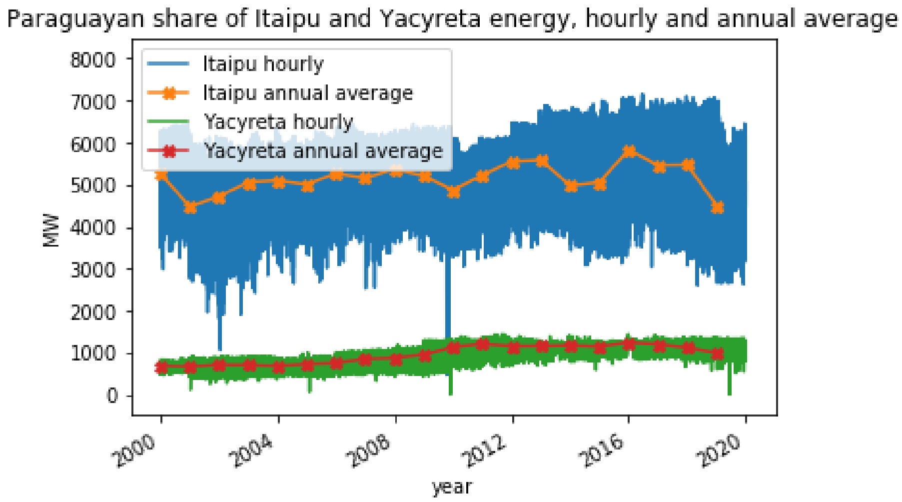


***Figure 4**. Hourly Paraguayan possession energy from Itaipu and Yacyreta, year 2000-2019*

1.2 Quantifying electricity generation potential

1.2.1 Hydropower generation potential

According to the previous study, Paraguay has the resources to produce 130 TWh/year of hydropower electricity, of which 101 TWh/year are thought to be economically exploitable.[11] This number is around twice as much as the country generated currently. However, most unexploited hydropower resource locates on the southern part of Parana River that borders Argentina. As a result, fully utilize the nation's water resources requires diplomatic negotiation and binational cooperation. For this study, we set aside political issues and only focus on the existing hydropower potential and its economic returns.

The proposed hydroelectric power plants, according to ANDE and IPPSE, can be mainly divided into two categories for this modeling study, small hydropower plants and binational hydropower plants.[12,13] Although power plants that will be built on Paraguay River is classified as central hydropower station in ANDE's plan, but their proposed capacity and construction cost is similar to that of small hydropower plants. Therefore, they are included in the consideration of small hydropower plants in our model.

Three potential hydropower reservoirs that are suitable for small hydroelectric plants are identified by ANDE in its master plan for generation, and listed in table 2. The capital cost estimation is obtained by taking mathematical average of multiple small power plants proposed according to ANDE's plan.

***Table 2**. Relevant data of three hydropower reservoirs that can be exploited. The capital expenses are*

[11] Columbia Center on Sustainable Investment (CCSI), Quadracci Sustainable Engineering Lab at Columbia University, and Centro de Recursos Naturales, Energía y Desarrollo (CRECE). "Chapter 2: The Electricity Sector in Paraguay." In Decarbonization Pathways for Paraguay's Energy Sector, 31–66. New York: CCSI, September 2021
[12] ANDE, 2016, Plan Maestro De Generacion, period 2016-2025
[13] IPPSE, 2019, REQUERIMIENTOS DE GENERACIÓN ELÉCTRICA DEL PARAGUAY Periodo 2019 – 2038

extracted from ANDE's plan for generation

Location	Load zone	Potential (MW)	Capital cost (million $/MW)
Basins of the eastern region of Paraguay	North	326	5.1
	Central		3.6
Basins connected with Itaipu	East	379	3.0
	South		4.3
Paraguay river	Central	168	3.6
Total		873	

Binational hydropower station planning is listed in IPPSE's technical report. Ideally, there will be 3 new binational hydroelectric plants to be built and 1 additional capacity upgrade for Yacyreta in the future 20 years according to this report. Detailed information about these proposed hydropower stations are shown in table 3. All of the 4 new binational hydropower constructions will be jointly built with Argentina, but the construction and generation will involve political factors that our study cannot capture.

***Table 3**. Proposed binational hydropower stations listed in IPPSE's report.*[11]

Station	Potential capacities (MW)	Capacities for PY (MW)	Estimated total cost (million $)	Capital cost (million $/MW)	Expected online year
Ana Cua	270	135	600	2.2	2024
Yacyreta new	1550	776	3300	2.1	2026
Itacora-Itaiti	1600	800	6000	3.6	2031
Corpus Christi	2875	1440	9000	3.1	2031
Total	6295	3181			

1.2.2 Solar and wind generation potential

The hourly solar power potential is calculated based on solar clearness correction model. The hourly observed global irradiation record is retrieved from Photovoltaic Geographical Information System (PVGIS).[14] Six major cities were chosen for this calculation to represent their respective load zones. The detailed method is described in *Appendix A*. The resulting 6 time series are concluded by average values and shown in table 4.

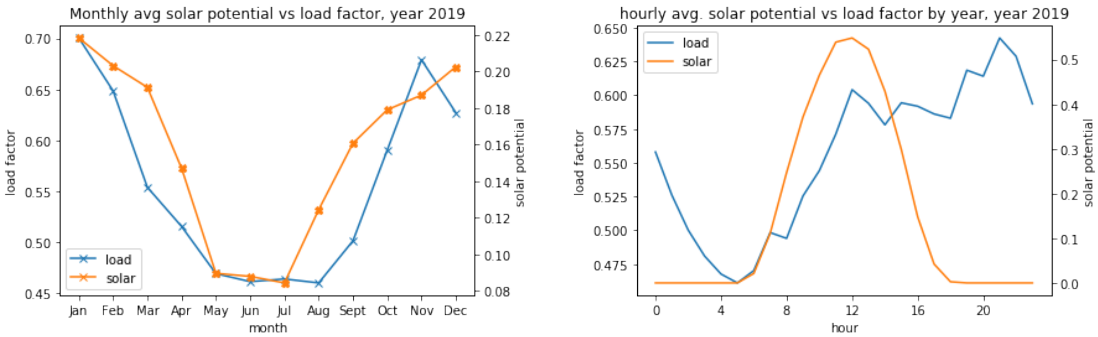
***Table 4**. Solar capacity factor by load zone, annual average*

Load zone	South	East	Central	Metropolitan	North	West

[14] European Commission EU Science Hub, Photovoltaic Geographical Information System (PVGIS). Url: https://ec.europa.eu/jrc/en/pvgis

Annual average CF	0.142	0.145	0.153	0.156	0.156	0.168

Figure 5 takes a closer look at monthly average and daily pattern compares to load profile for Metropolitan area. The seasonal pattern of solar capacity factor (CF) aligns well with that of electric load, while there are a few hours shift between daily peaks of solar potential and electricity load. This character is not preferred for PV usage, and might prevent the large deployment of solar power technologies, without a low-cost storage strategy.



(a) (b)

Figure 5. Solar CF compares to national electric load (a) monthly average (b) daily profile

Although ANDE wrote in its master plan for the period 2016~2025 that not much surface wind potential can be exploited in Paraguay, asked by the vice ministry of mines and energy, we quantify the value of wind generator with limited available data of wind profile in Paraguay. In this study, the hourly CF of wind generation is simulated based on 2019 historical observation data from NCEI's Integrated Surface Data (ISD) database in each load zones.[15] The development of hourly wind energy for each zone is described in *Appendix B.* The annual average CFs of resulting time series are shown in table 5.

Table 5. Annual average wind generation CF potential

Load zone	South	East	Central	Metropolitan	North	West
Annual average CF	0.19	0.23	0.05	0.28	0.27	0.28

1.3 Assumptions and electricity generation cost structure

1.3.1 Load zone electricity load assumption

Ideally, high temporal resolution grid load data broken by sub-system is preferred. However, hourly load data that are available to us only exists at the national grid level. Alternatively, monthly load profile of each zone is available. Hence, an assumption that each zone has exactly the same load pattern, and the allocation of power load for each zone at each hour is proportional to their monthly load has to be made as equation (1), in order to simulate the zonal electricity load profiles.

$$L_r(t) = \frac{L_r^{mo}}{\sum_{r \in R} L_r^{mo}} * L(t)$$

[15] Integrated surface data, NCEI, 2021, Url: https://www.ncdc.noaa.gov/isd

(1)

We have validated the accuracy of PY-RAM (see section 1.5). A good fit of model results with real power grid operational data collected during the year 2019 has been shown.

1.3.2 Electricity load growth projection

Future load is projected to increase proportionally by a multiplier at each hour based on the 2019 load profile. It is difficult to know how load profiles will grow in the long-term future, especially as the energy sector is poised for change. At the same time, we do know that the load profile has not changed significantly over the last several years in spite of significant increase in electricity consumption. This appears to be driven by cooling loads. This assumption of load profiles implies that the peak loads grow in proportion to the growth in electricity demand. Of course with additional electrification, additional commercial buildings, possible electric vehicles, and possible move towards electric cooking and the use of efficient appliances, the peak loads and when they occur could change. Simulations are carried out with nine load multipliers, the resulting average and peak load can be corresponded to ANDE's 'optimistic scenario' load projection year respectively[16], as shown in Table 6.

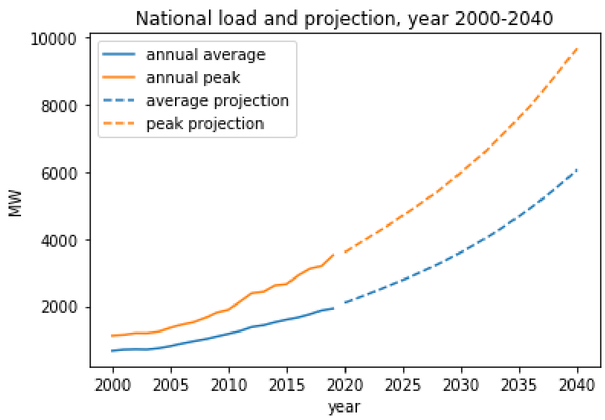


Figure 6. Annual average and peak load growth projection by ANDE, under 'optimistic scenario'.

Table 6. Average and peak load under each of the nine load multipliers, corresponding to happening years according to ANDE's projection, 'optimistic scenario'.

Multiplier	Avg. load (MW)	Projection year	Peak load (MW)	Projection year
1	1954	2019[a]	3519	2019[a]
1.25	2443	2022	4399	2023
1.5	2931	2026	5279	2027
1.75	3420	2029	6158	2030

[16] ANDE, Proyecciones de la Demanda Nacional de Electricidad Período 2020-2040

2	3908	2031	7038	2033
2.25	4397	2033	7918	2035
2.5	4885	2035	8798	2037
2.75	5374	2037	9677	2040
3	5862	2039	10557	-

[a] This is real world data from 2019, not projected.

1.3.3 Itaipu cost assumption

The price of electricity purchases from Itaipu Binational is one of the most uncertain parameters that is captured in our model. It is not only decided by economic consideration, but also influenced by political and diplomatic decisions.[17] According to current Annex C of the Itaipu Treaty, once Itaipu's debt is fully recovered the Unit Cost of Electricity Service (CUSE, 'Costo Unitario de Servicios de Electricidad')[18] of Itaipu will drop significantly to about 37% of that at present. In order to have an edge in the upcoming revision of Annex C, system planner has to be aware of the uncertainty raised by the negotiation with Brazil on Itaipu's future electricity tariff, and foresee the impact of cost change put on national power system. In this study, we capture Itaipu pricing as three fixed scenarios that are most possible in the near future.

Electricity purchasing from Itaipu basically follows the manner provisioned by the Itaipu Treaty signed by Brazil and Paraguay in 1973[19] and the power contract commitment signed in 2007[20]. At present, both Paraguay and Brazil are expected to contract generator power capacity with Itaipu entity in advance at a cost of $22600 per megawatt per month of 12,135 MW/month available. According to the generation profile of year 2019, this power contract price can be ideally converted to $43/MWh within the limits of guaranteed power, which sum up to 75,000 GWh. However, for the electricity beyond contracted capacity (i.e. additional energy associated with the contract power, and energy addition to the contract power), a much cheaper hour-to-hour purchase option at a cost of $5/MWh is available to both countries. This could be attributed to the operation and financial protocols of the Itaipu entity. Because Itaipu maintains its budget by selling its generation capacity each month, and the revenue from its generated energy beyond the contract is only subject to the payment of royalties to both countries. This cost is significantly lower than the power contract price that meant to cover both operational and financial expenses.

A cost minimizing model cannot capture this diplomatic matter, because intuitively the model will only choose the lowest price option for the same amount of energy supply. Thus, we add a constraint that the monthly contracted capacity from Itaipu by Paraguay has to be no less than 45% of the peak power purchased from Itaipu in that month. This ratio is rounding from the 2019 real world situation (44%), according to the former president of ANDE Ing. Luis Villordo[21].

[17] Columbia Center on Sustainable Investment (CCSI), Quadracci Sustainable Engineering Lab at Columbia University, and Centro de Recursos Naturales, Energía y Desarrollo (CRECE). "Chapter 2: The Electricity Sector in Paraguay." In Decarbonization Pathways for Paraguay's Energy Sector, 31–66. New York: CCSI, September 2021

[18] For simplicity, 'Electricity tariff' or 'electricity rate' is used later to replace 'CUSE' for Itaipu electricity.

[19] https://www.itaipu.gov.br/en/company/official-documents

[20] ANDE-ITAIPU BINACIONAL-ELETROBRAS, 2007, Contratos de compra y venta de los servicios de electricidad de la Itaipu, resolucion N CADOP 176/19

[21] https://www.abc.com.py/edicion-impresa/economia/2019/12/21/acuerdos-del-2007-vigentes-en-su-totalidad-sostiene-titular-de-ande/

Since PY-RAM is a forward-looking model, future variations in Itaipu price should also be captured. There are three projections for pricing starting from the year 2023, when Itaipu entity has paid off its debt from ELETROBRAS, namely continuation of today's price, intermediate price, and low-price scenario. The price of each scenario is listed in table 7. In addition, the ceded electricity from Paraguay to Brazil is at an additional cost of around $10/MWh.

Table 7. Three projection of the future cost of Itaipu electricity.

Cost scenario	Contract price ($/MW-mo)	Energy price ($/MWh)	Notes
Current	22600	43.8	If PY and BR agreed on continue to days' price
Intermediate	15000	29.9	Creation of a fund for sustainable development
Low	9610	19	If PY and BR can't reach any agreement before 2023

1.3.4 Transmission line assumption

According to data collected by CRECE, inter zonal transmission limit is listed in figure 2. PY-RAM allows to build new transmission lines only between load zones already connected or have proposed connection projects, at a capital cost extracted from ANDE's plan on investing new transmission lines[22]. The costs are listed in figure 7 in the unit of $\$/(\mathrm{MW}\cdot\mathrm{km})$, where the cost fluctuation is subject to the transmission grid voltage and infrastructure required. No upper limits of transmission system expansion are constrained in PY-RAM.

from \ to	R1	R2	R3	R4	R5	R6
R1		595		586		
R2	595		297	304	249	
R3		297		666	300	
R4	586	304	666		605	
R5		249	300	588		806
R6					806	

Figure 7. Transmission line capital cost for every two load zones within ANDE's transmission system expansion plan, unit: $\$/MW\cdot km$. The vertical indexes and horizontal indexes are the starting zones and the destinations of the transmission line respectively. The blank cell means no transmission line would be allowed.

1.3.5 Use of low-load factor dispatchable resources

In order to provide economically viable options for Paraguay's power system expansion while maintaining reliability we introduce the concept of a dispatchable resource that is introduced to

[22] ANDE, 2016, Plan Maestro De Generacion, period 2016-2025

ensure that load is met at all hours as a result from PY-RAM. This allows one to also estimate an upper bound of the cost of meeting this reliability using a known but expensive (and not sustainable) diesel generation. An annualized capital cost of $30/kW-year, and a fuel cost around $300/MWh is utilized. Note that these technologies are high in energy cost but low in capacity cost- so that they are only used occasionally. We expect PY-RAM only choose this option at spiky peaks of electricity load, where installation of other renewable energy generators or batteries are too expensive to achieve, due to very limited times of use during a year. We propose several approaches in later sections to mitigate the usage of expensive resources, as largely using fossil-based generator is inconsistent with Paraguay's sustainable development goal.

1.3.6 Cost structure assumptions for electricity generation

Relevant capital cost and operation expense assumptions that serves as inputs for PY-RAM are shown in table 8.

Table 8. Relevant pricing and thermal performance inputs for PY-RAM

Hydro power	
Annualization capital rate for all hydro resources	0.05 (interest rate: 5%, 50 years)
Itaipu energy purchase price	Described in section 1.3.3
Yacyreta Energy purchase price	40.7 ($/MWh) [23]
Yacyreta Energy ceded to Argentina	3.6 ($/MWh) [24]
Acaray Energy price	3.2 ($/MWh) [25, a]
New hydroelectric plants investment	Described in section 1.2
New hydroelectric plants operating cost	3 ($/MWh) [b]
Solar PV	
Annualization capital rate	0.08 (interest rate: 5%, 20 years)
Installation cost	400 ($/kW)[c]
Wind turbine	
Annualization capital rate	0.07 (interest rate: 5%, 25 years)
Installation cost	1000 ($/kW)[26]

[23] Reversal Note No. 2 - Yacyretá Binationa Entity
[24] EJERCICIO ECONOMICO 2018, EBY
[25] Estado de resultados - diciembre_2019, ANDE
[26] Projected mid-cost scenario, NREL, 2017, Annual Technology Baseline: Electricity. Url: https://atb.nrel.gov/electricity/2019/index.html?t=lw

Battery	
Annualization capital rate	0.13 (interest rate: 5%, 10 years)
Installation cost	156 ($/kWh)[27]
Expensive dispatchable resources	
Annualization capital rate	0.08 (interest rate: 5%, 20 years)
Installation cost	400 ($/kWh)
Fuel cost	1 ($/Liter)
Fuel LHV	10.6 (kWh/Liter)
Generator efficiency	30%

[a] This is an estimated value based on *Estado de resultados - diciembre_2019* published by ANDE. [b] The operating cost is similar with that of Acaray. [c] A low cost, future looking solar capital expense.

1.4 Model formulation

PY-RAM minimized the sum of annualized capital cost and hourly operational costs over a year of hourly resolution. The optimal economic performance is subject to constraints considering energy balance, resources availability and generator capacity investments. The model is easy to change when a particular scenario is being studied. Details regarding the model formulation are provided in the Appendix D. PY-RAM is formulated in Python and solved by Gurobi.

1.5 Model validation

The model is first validated by inputting hourly electricity load and hydroelectric potential data for year 2019, and allowing no new power plant to be installed. Then, the results are compared with the real grid dispatch data for the same year. We find good alignment between the model results and real data with a reasonable discrepancy. This difference can be attributed to the assumptions that have been made, and the model's incompetence to capture detailed diplomatic decisions for monthly power contract from Itaipu.

The model results on energy production and real data for year 2019 is listed in the following table 9. Energy purchased from each hydropower plant is shown in the manner of annual average and peak.

PY-RAM works well in predicting Itaipu generation, with an error of 2.4% in average and 6.6% in peak . Yacyreta results also show good match if the error is compared with its total generated energy. The annual average ratio of difference to capacity is also within the level of 20%, while the error at peak hour is slightly above this range, which can be mainly attributed to the optimized Itaipu contracting strategy. Thus, the model is valid to make prediction of energy usage for Paraguay's national grid,

[27] Fernández-Blanco, R., Dvorkin, Y., Xu, B., Wang, Y., & Kirschen, D. S. (2016). Optimal energy storage siting and sizing: A WECC case study. IEEE Transactions on Sustainable Energy, 8(2), 733-743.

allowing a reasonable error.

Table 9. Comparison of model results and real data on energy usage for the year 2019. Results for both annual average and peak load hour are shown.

	Model results	2019 system data	Avg/peak available power	Modelling difference[a]
Annual average				
Itaipu (MW)	1852	1742	4503	6.3% (2.4%)
Itaipu monthly contract (MWmo.)	1055	1340	6300	-21% (-4.5%)
Yacyretá (MW)	72	137	992	-47% (-6.6%)
Acaray (MW)	112	112	-	0 (-)
LCOE ($/MWh)	21.8	-		
Peak load				
Itaipu (MW)	2345	2808	7000	-16% (-6.6%)
Yacyretá (MW)	901	600	1361	51% (22%)
Acaray ($/MWh)	140	-	-	-

[a] Modelling difference is shown associated with both energy used in year 2019 and total available capacity (in the bracket).

2. Peak load shaving strategies and modeling

During recent years, Paraguay power grid is growing rapidly to meet the country's sharp increase in electricity demand. It can be shown in figure 3, the national demand has increased by 190% in terms of average demand and 215% in terms of peak load during the last 20 years, with an average annual growth rate of 5.5%. Rapid growth of peak load makes it hard for ANDE to maintain its transmission and distribution system expansion at the same pace as demand growth. Currently, the increasing demand has caused for transmission line over load and frequent power cuts.[28] Thus, peak load management should be regarded as a significant role in Paraguay's power system expansion. A comprehensive review of technologies can be found in chapter 2 of the integrated report jointly published with CCSI and CRECE.[29]

In this section, we introduce some powerful peak load shaving technologies and integrate their functioning principles into PY-RAM to explore the value of respective method.

2.1 Energy storage provided from utility side

Peak load shaving can be achieved by several approaches, including methods from both supply side and demand side. However, as the resources is limited for Paraguay, immediate improvement in residential appliance's efficiency and sharp upgrade of transmission system may not be realistic. Therefore, energy storage technologies can be considered by the system operators, ANDE, in Paraguay's case. The value of storage is not only reflected by peak shaving, but also minute-to-minute frequency regulation and energy arbitrage.[30]

Battery is one of the most common form of storage. However, large scale power system storage by battery has not been an option at present due to batteries' high cost. According to our result introduced in later sections, PY-RAM model won't choose much battery, even if we foresee a considerable low-price scenario in the near future. However, as Li-ion batteries are growing rapidly in industrial, commercial applications and novel forms of batteries (e.g. solid state batteries) are making their way to commercialization, cost reduction of battery in the future might be far greater than what we can expect today.

Other forms of storage that may apply on the supply side include hydropeaking. Although all existing hydropower stations in Paraguay are designed to be operated in the type run-of-river, building a 6-hour daily storage capacity is an economically feasible option for those proposed hydropower stations that are yet to be built. This storage capacity will only require an additional small reservoir and flexible operation, yet provide valuable power dispatch abilities. At the meantime, extra turbine capacity can be desired to provide more power during peak load hours in a day.

For the purpose of discovering whether hydropeaking can be an efficient way to meet the peak load, an option that enables 6-hour daily hydropower storage for those new hydropower plants is added

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[28] ANDE, *Compilación Estadística 1998-2018* (Asunción: ANDE, 2019).
[29] Columbia Center on Sustainable Investment (CCSI), Quadracci Sustainable Engineering Lab at Columbia University, and Centro de Recursos Naturales, Energía y Desarrollo (CRECE). "Chapter 2: The Electricity Sector in Paraguay." In Decarbonization Pathways for Paraguay's Energy Sector, 31–66. New York: CCSI, September 2021
[30] Davis, S. J., Lewis, N. S., Shaner, M., Aggarwal, S., Arent, D., Azevedo, I. L., ... & Clack, C. T. (2018). Net-zero emissions energy systems. Science, 360(6396).

in PY-RAM. We allow new small hydropower stations that are under planning to build additional 50% capacity and a small reservoir that enables 6-hour daily storage in this option. For new binational hydropower stations that are under negotiation with Argentina, the model is allowed to choose extra capacity itself that will be used for hydropeaking operation with 6-hour storage capacity. All storage capacity is not allowed maintaining overnight, and is forced to go to zero at 2am each day. The mathematical constraint formulation is shown in Appendix D.3

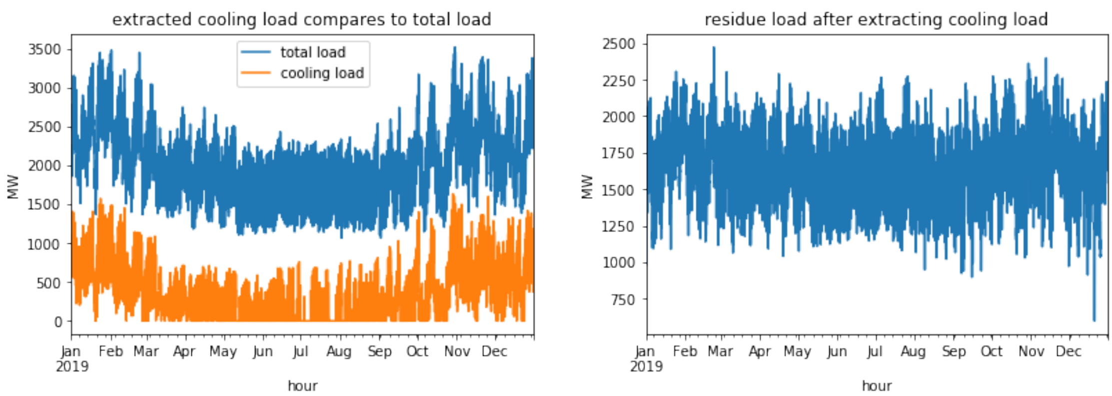
2.2 Residential load reduction method

Two specific methods of peak load reduction from building side is introduced. Adopting centralized cooling system with thermal storage capacity and demand response program.

2.2.1 Temperature dependent load extraction

We notice that Paraguay's electric load varies greatly with seasons, which can be mainly attributed to the increasing demand of cooling at hot summers. According to ANDE, household air conditioner possession rate rises to 42.7% in year 2017 from 36.5% by year 2013, and it's still rising[31]. In order to smooth load variation at hottest days, we first try to understand how national electric load is changing with outdoor temperatures. Since detailed building thermal performance as well as indoor thermal comfort preference is unknown, simple regression model is applied to extract cooling demand from the hourly gross electricity consumption based on time and temperature. This process is documented in *Appendix E*.

Figure 8a shows the resulting cooling load compares to total national grid load, while figure 8b is the residual load that exclude cooling load According to this model, annual cooling energy for year 2019 amounts to 328 MW load in average, which accounts for 16.8% of total electricity consumed. The peak cooling load in summer can be as high as 1634 MW, 46% of peak load.



(a) (b)

Figure 8. *Simulated cooling load compares to SIN total load and residual load*

2.2.2 Ice storage modeling

Once cooling load has been extracted, the potential of thermal storage is therefore presented. While the cooling demand increases rapidly, the majority of air conditioner's efficiency is not properly regulated. While gradually improving air conditioner's performance by regulation is of great

[31] ANDE (2018), Balance Energetico Nacional 2017; ANDE (2014), Balance Energetico Nacional 2013

importance, installing building or district level ventilation system with thermal storage among new constructions can prevent further decrease of seasonal load factor by several reasons. First, it can provide storage capacity at demand side. An elaborated distinguish of peak and valley electricity price by system operator will make this storage economically preferred by residents. Second, it helps eliminate obsolete air conditioners with low efficiencies that otherwise might be economically preferred by individual households. Third, it enables the use of technologies that has better cooling performance, since there's not much heating demand in Paraguay. Detailed analysis on improving energy efficiency for the building sector is introduced in chapter 3 of the integrated report jointly published with CCSI and CRECE.[32]

In this study, electric chillers with ice storage is chosen to illustrate energy storage's role in residential sector, and how it can help Paraguay reduce the spiky peak load hours during summer times. Ice storage is an emerging cheaper option for supplementary load regulation at demand side, its low cost and compatibility with high cooling efficiency chiller makes it perfect for residential building and neighbors to achieve smart operation. For the purpose to show how ice storage can help with the challenges that Paraguay's power system is facing, we assume a scenario that 100% air conditioning demand is covered by electric chillers (i.e. CL% is 100%). The model will choose how much ice storage capacity is needed to achieve best economic returns.

The formulation of ice storage in PY-RAM is shown in Appendix D.4, while most model parameters can be found in table 10.

Table 10. Cost structure and performance factor of ice storage and chiller

Ice storage	
Annualization capital rate	0.08 (interest rate: 5%, 20 years)
Installation cost	50 ($/TR-h)
Minimum charge hour	6 hours
Charge efficiency	98%
Discharge efficiency	98%
Electric chiller	
Charge COP	2.1
Cooling COP	1.8

2.3 Demand Response Programs

Demand Response (DR) programs offered by the electric grid operators can balance the demand and supply by reducing the participants' load; subsequently, the former could gain savings by reducing the peak and the latter will lower their bill or get rewards. Many operators and utilities provide different programs currently, and box 1 shows the New York State's DR program as an example case.

[32] Columbia Center on Sustainable Investment (CCSI), Quadracci Sustainable Engineering Lab at Columbia University, and Centro de Recursos Naturales, Energía y Desarrollo (CRECE). "Chapter 2: The Electricity Sector in Paraguay." In Decarbonization Pathways for Paraguay's Energy Sector, 31–66. New York: CCSI, September 2021

We identify DR as one of the top options for power systems to remove burdens from extremely spiky peak load periods, and we are going to find out how much benefits the DR could bring to Paraguay's future electricity system. Quantitative methods we used to roughly estimate the value of DR programs are described in Appendix D.5

Box 1. New York state demand response (DR) program

New York state is offering multiple DR programs providing by New York Independent System Operator (NYISO) and local utilities respectively.

4 DR programs are offered by NYISO currently, and 1 additional program designed exclusively for the New York city. Two of them (Emergency Demand Response Program "EDRP", Installed Capacity – Special Case Resource Program "ICAP-SCRP") are designed to increase system reliability and handle extreme scenarios and system emergencies. The difference lies in whether participants are mandatory or voluntary to reduce usage when demand response events are stated by NYISO. The other two DR programs (Day-Ahead Demand Response Program "DADRP", Demand-Side Ancillary Services Program "DSASP") allow participants voluntarily offer load reduction opportunities in their best economic endeavor. However, the latter two were seldom conducted in reality. The New York City exclusive program (Targeted Demand Response Program "TDRP") also requires voluntary load reduction by participants when called by NYISO.

According to program record disclosed by NYISO[33], during year 2020, 5 TDRP, with an estimated average load reduction of 164 MW each time, and 3 ICAP/SCRP testing events, with 912 MW (~3% peak load) estimated average reduction, were issued by NYISO.[34] The program is a win-win project. Participants involved in TDRP events during 2020 received around $2910 per MW reduction per event. On the other side, according to NYISO's pervious report,[35] during year 2006, the grid operator saved up to $91 Million annually by the program, with an average peak load shaving of 865 MW.

Participants of NYSIO programs can also be enrolled in local utilities' DR program to maximize their economic returns. Take New York City as an example. Con Edison operates most part of power system in the city, and is now offering 2 types of DR programs – 2-hour notification program (DLRP) and 21-hour notification program (CSRP). The benefit for participants can amount to $180/kW-year for each kW pledged to curtail during periods that power demand is highest.

[33] NYISO 2020 Annual Report on Demand Response Programs

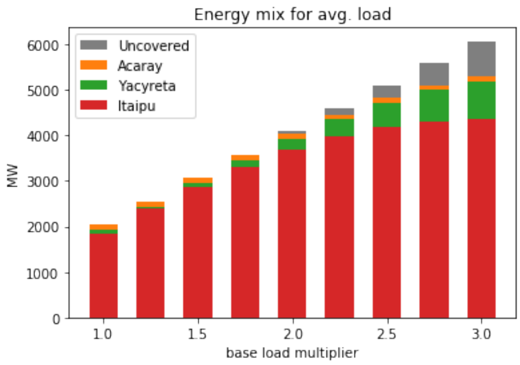
[34] Estimated reduction is calculated as the arithmetic average of reduction estimated by using 'CBL' as baseline demand of each event, according to NYSIO report. CBL – customer baseline load, which is the base line demand estimated based on most recent 30 days' power usage pattern of each event participant.

[35] Federal Energy Regulatory Commission, 2010, ISO/RTO metrics report, Appendix G (NYISO)

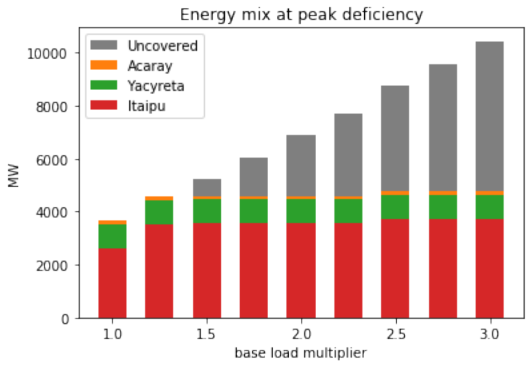
3. Model result

3.1 Electricity insufficiency detection with current generation capacity

With the nine multipliers of electricity load that discussed in section 1.3.2, PY-RAM model is first used to detect energy deficiency as load increases. The model finds optimized economic dispatch at each load level and indicates any imbalance between supply and demand. No new generation investment is allowed at this stage. The model results are shown in figure 9.



(a)



(b)

Figure 9. Current hydropower generation and the energy deficiency with the power load growth. (a): the annual average energy usage. (b): the energy usage at the peak load hour.

Figure 9(a) shows the annual average usage of each energy resources. It can be shown that even with triple load, the national power system can still meet most of its need by using existing resources, which can be attributed to the abundance of water resources on the Parana river. In the contrast, figure 9(b) shows a different story. The country starts to facing power shortage at some peak demand hours from 1.5 times electric load of the year 2019, which corresponds to year 2026 according to ANDE's projection. As the existing power plants have to dispatch at their maximum level at those peak hours, when demand continuously growth, energy shortage is increasing accordingly at a rapid speed. When the load is tripled, 54% of the peak load demand cannot be met with existing generation capacity. This is a huge gap that has to be filled in the following 20 years.

3.2 Power system expansion planning

With the understanding of challenges facing by the national power system from previous section, detailed studies on future energy investment with multiple technology choices to cope with demand growth were conducted. In order to accommodate the gap between generation and demand at peak load hours, and maintain a safety reserve margin, new generation capacity has to be built, even though it means high capital investment for a few hours' usage.

According to ANDE's plan and IPPSE's suggestion for power system expansion, Paraguay is committed to further exploit domestic sustainable hydropower resources and solar power to meet its demand growth in the future. PY-RAM is thus used to simulate investment planning and operation of the country's power system by allowing the investment in new hydropower stations and solar PV, as well as expansion of transmission system. To fully explore the role of solar PV in Paraguay, as PV cost is experiencing rapid drop in recent years, battery is allowed to be built as well in this model. Our intention is to integrate solar power and battery for continuous generation.

As discussed in section 1.3.5, a much more expensive but dispatchable generation resources has to be added for model's selection. The choice of this option simply means it would be too expensive to meet some of the spiky peaks in the year only with renewable generation capacities. This statistic also shows the need to shave peak load and improve load factor.

Thus, a base scenario is generated where PY-RAM is able to choose to expand generation capacity by adding new hydropower stations, solar PV panels, storage batteries, expensive resources generators and transmission lines. System expansion planning result is shown in Table 11. The names and expected put-in-service year of the specific Binational hydro power are listed in Table 12. It is important to note that the cost structure of these power plants do change.

Table 11. New generation capacity needed at each level of electricity load.

Load multiplier	Binational Hydro capacity (MW)	Small hydro Capacity (MW)	Solar PV Capacity (MW)	Expensive resources capacity (MW)	Battery capacity (MWh)	New Transmission Capacity (MW)
1	0	0	0	0	0	14
1.25	0	0	0	0	22	83
1.5	0	0	0	545	316	119
1.75	0	0	0	1444	553	166
2	910	0	0	1731	787	0
2.25	910	256	97	2418	1120	404
2.5	910	809	678	2842	1562	575
2.75	2351	517	535	3086	1513	279
3	2351	809	1698	3434	3223	455

Table 12. Estimated new binational hydropower plants in service by load growth

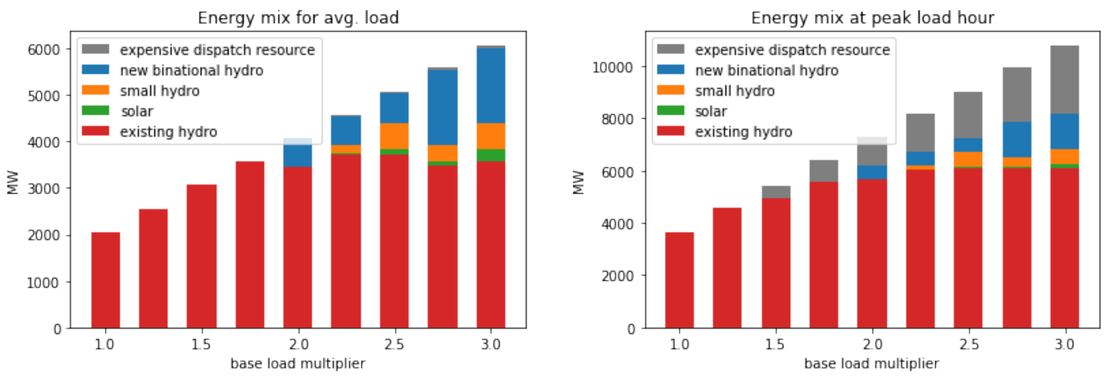
Load multiplier	Projected year by average load	Binational hydropower plants in service by load growth
1	2019	
1.25	2022	
1.5	2026	

1.75	2029	
2	2031	Ana Cua construction and Yacyreta expansion
2.25	2033	
2.5	2035	
2.75	2037	Corpus Christi
3	2039	

Figure 10 shows annual average and peak energy dispatch of each resources including new generation capacities that are suggested by the model. Note that given ambitious installed solar PV costs of $400/kW, utility-scale solar is not selected in considerable amount by the model given the assumed costs of hydropower plants. This result doesn't necessarily indicate solar power is not a promising technology.

There are multiple reasons for why this option may be viable in the future. Many countries find that the actual overnight costs of hydropower are higher than those estimated years earlier. Some hydropower plants end up having lower capacity factors than estimated in a way that is difficult to predict. Hydropower has to be located where the resource is and solar power can be located closer to demand. Detailed studies for ecological and social-economic impacts, especially downstream, of hydropower are also difficult to come by.

On the other hand, costs of installed solar and battery storage are becoming more and more competitive over time. In situations where the cost of upgrading local distribution capacity is high, the ability of distributed solar and storage to quickly overcome short duration peaks could become increasingly viable. While currently as we understand there are no government incentives to stimulate wider adoption or strong consumer demand for installing distributed PV systems, this could change in the future. In particular there are still pockets of Paraguay that lack universal access to power and migration might be creating an increasing need for new connections- solar with storage may be a viable option when the cost of extending medium and low voltage wire to those is high. To fully appreciate the value proposition and for other reasons as well- we recommend that real-time monitoring at transformer or at least feeder level of the entire distribution network in Paraguay to be able to dynamically assess changes in peak load requirements. Indeed, there are additional benefits to such measures as they also assist with monitoring and addressing losses. Such monitoring can assist with diagnosing and alleviating the stresses on distribution systems as well as providing electricity to areas with no connection to the grid.



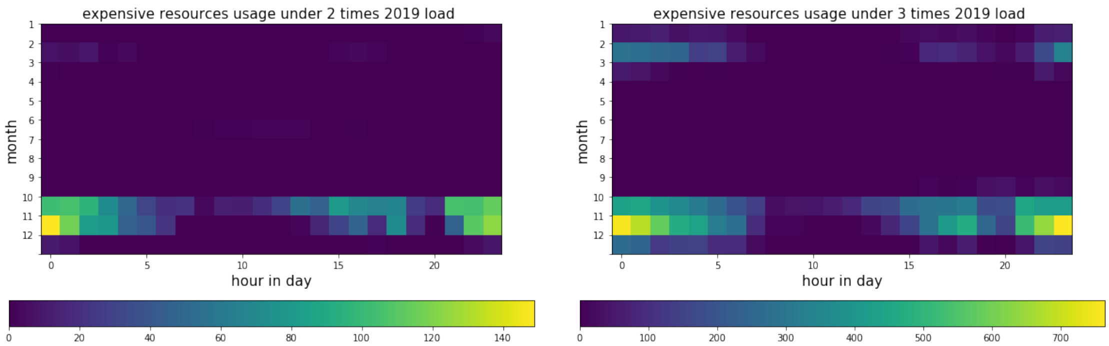
(a) (b)

Figure 10. Energy usage broken by sources with the demand growth. (a): annual average energy usage. (b): energy usage at peak load hour.

It shows investing binational hydropower plants will play an important role in maintaining power balance between demand and supply in the future, by comparing figure 10(b) with figure9(b). PY-RAM also suggests, that ideally, Ana Cua construction and Yacyreta expansion should be completed before the national electric load doubles. According to the correspondence between electricity load growth and projected year shown in table 6, these 2 new plants are expected to be put into service between the year 2031~2033. Another hydroelectric station, Corpus Christi, is also chosen by PY-RAM once load reaches 2.75 times year 2019 level, which should be expected to operate between year 2037~2040. The construction period of binational hydropower stations can be as long as 8 to 10 years, plus the time spends on bilateral negotiations. So, Paraguay should pay immediate effort on planning these proposed hydropower constructions. Small hydropower plants are not as favored by PY-RAM as binational counterparts, which can be attributed to their relatively high construction costs.

Figure 10(b) shows considerable amount of expensive dispatchable resources has been chosen to meet the demand at peak load hours. This observation indicates without any peak load reduction method, the role of sustainable resources cannot be fully exploited economically. Although battery is allowed, its high cost and short operation period preventing the model to choose large amount of it as the flexibility provider of the system. This result also encourages to study alternative storage and peak load shaving methods discussed later.

Year-round pattern of peak load hours has to be identified as well. Figure 11 presents expensive resources usage under double and triple load level. Each pixel corresponds to a monthly (vertical axis) averaged usage of expensive resources at a specific time during a day (horizontal axis). Most imbalances of demand that cannot be economically covered by sustainable energy appear in October and November, from 22:00 to 2:00 next day. Some peak load shaving methods like improving air conditioning efficiency and smart energy management are therefore valuable to be studied.



(a) (b)

Figure 11. The usage expensive resources electricity generation in time domain, unit: MW. (a) doubled 2019 demand; (b) tripled 2019 demand.

Transmission capacities and usages between each pair of load zones are shown in figure 12. The width of arrows in the plot are made proportional to transmission capacity between the two load zones. Red arrows represent the fraction of capacity used during a year, while green and blue arrows record capacity surplus and new capacity required respectively.

It can be easily observed that current trans-zonal transmission infrastructure is sufficient to fulfill the need in the short term. However, in the mid-term when load growth to 2.5 times, most transmission lines go beyond load zones will be fully occupied at peak hours. Most insufficient transmission resources will occur between zone east and zone metropolitan, where not surprisingly is located the country's biggest electricity generation center and largest demand center respectively. Other transmission lines will still be able to fulfill transmission requirements under their maximum transmission capacities. It should be noted that capacity reservation is not considered in our model.

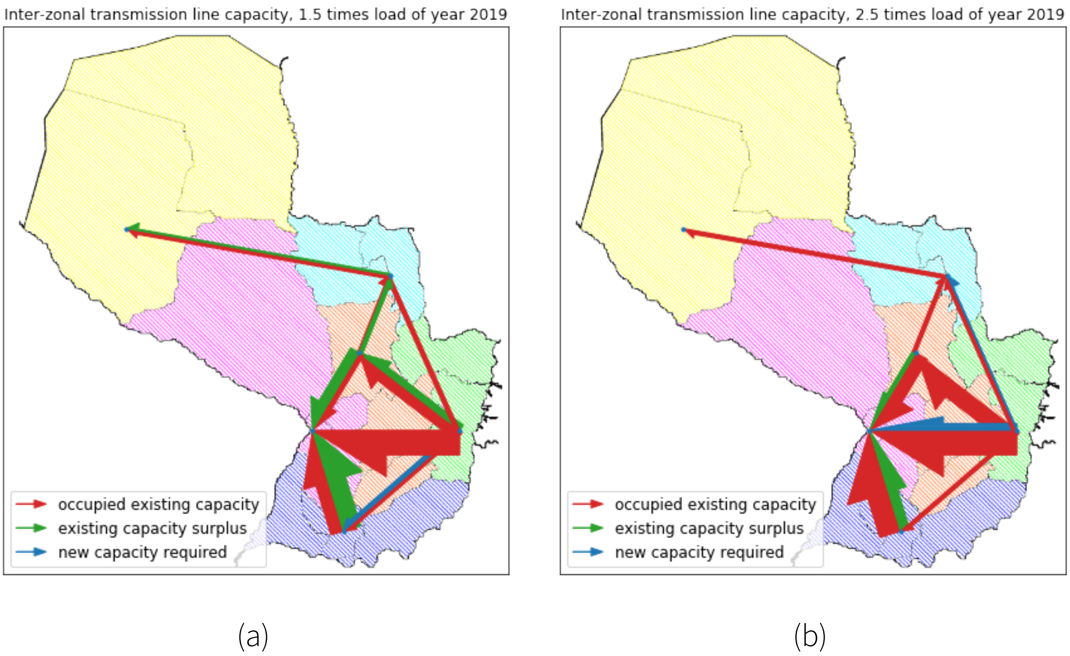


Figure 12. Major inter-zonal transmission line capacity and usage at (a) 1.5 times load of year 2019, (b) 2.5 times load of year 2019. line width is proportional to transmission capacity

3.3 Alternative scenario

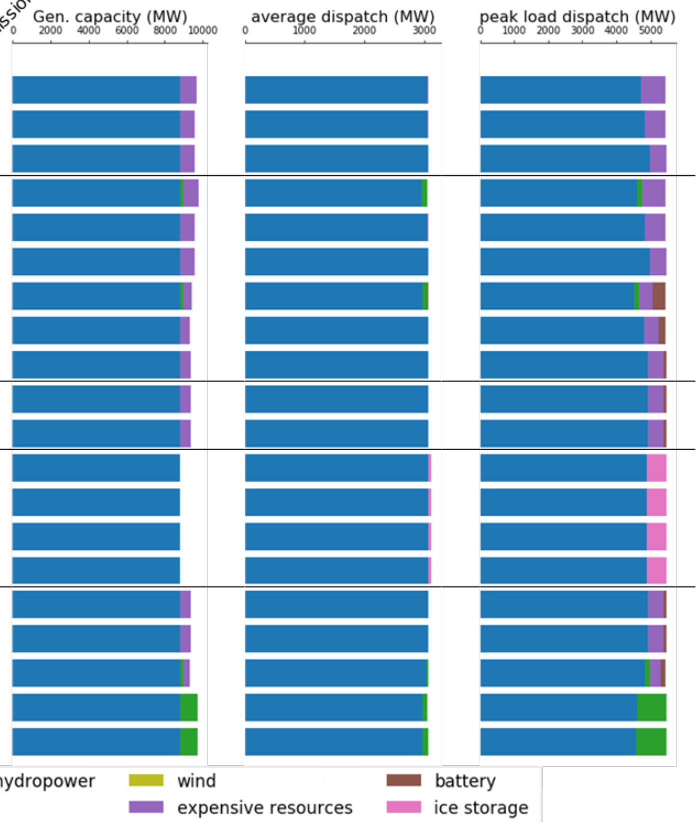
3.3.1 Scenario and results overview

In this section, we examine the impact of deploying various technological possibilities associated with development uncertainty on Paraguay's national power grid.

Differently from the previous section, multiple scenarios are put in comparison at two load levels (with a multiplier of 1.5 times and 2.5 times of the load at year 2019). As shown in figure 13, each row concludes the result from one particular growth scenario. The first nine rows (scenario group A and B) are designed to examine the influence of future cost of electricity purchased from Itaipu, given three combinations of electricity generation technologies that are allowed to invest, in order to keep the capacity expansion rate consistent with demand growth. More specifically, only proposed new hydroelectric stations are allowed to be chosen for the first group. 6-hour storage is added to be an option for PY-RAM in scenario B1~B3. Scenario B4~B6 additionally includes solar and battery investment. In 10 to 11 rows (group C), wind turbine generation is added. Our result shows wind generation can be a potent competitor with solar PV in Paraguay. Ice storage, introduced in section

2, is taken into consideration for the following group D, with different generation technology combinations. The last part of figure 13 is supposed to quantify the benefits of allowing exportation of redundant energy from new binational hydropower plants that are to be built in the future. Five different exportation rates are chosen to be studied.

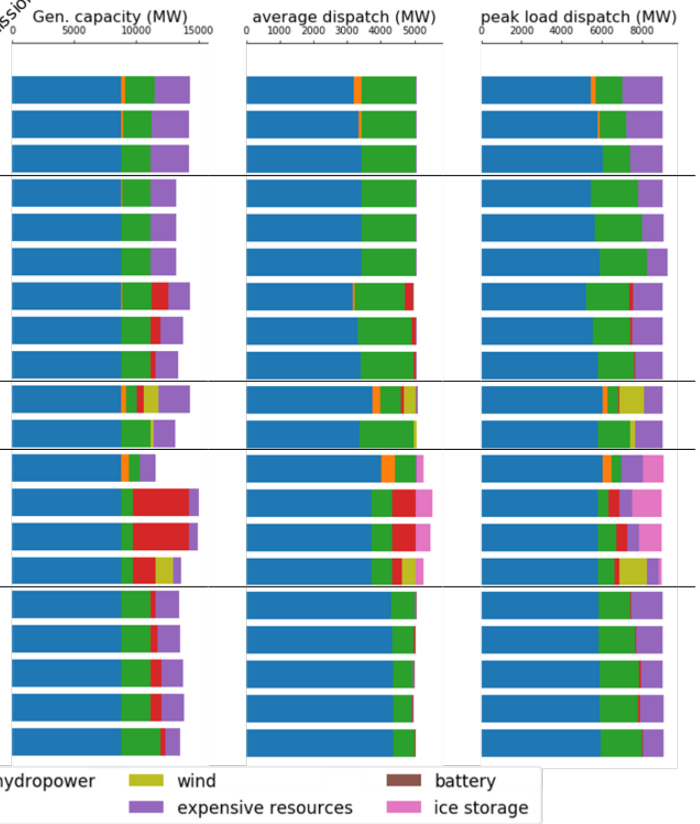
Scenarios [1]								Results			
Scenario Index	Itaipu cost	New Hydropower	Hydro peaking	Solar & Battery	Wind	Ice Storage	Export electricity Price $/MWh	LCOE $/MWh	Battery MWh	Ice Storage MWhe	New Transmission MW
A1	H	✓					0	23.3	-	-	103
A2	M	✓					0	17.1	-	-	110
A3	L	✓					0	12.7	-	-	122
B1	H	✓	✓				0	23.3	-	-	24
B2	M	✓	✓				0	17.1	-	-	110
B3	L	✓	✓				0	12.7	-	-	122
B4	H	✓	✓	✓			0	23	783	-	5
B5	M	✓	✓	✓			0	17	434	-	110
B6	L	✓	✓	✓			0	12.6	316	-	119
C1	L	✓		✓	✓		0	12.6	316	-	119
C2	L	✓	✓	✓	✓		0	12.6	316	-	119
D1	L	✓				✓	0	11.7	-	3679	112
D2	L	✓		✓		✓	0	11.7	0	3679	112
D3	L	✓	✓	✓		✓	0	11.7	0	3679	112
D4	L	✓	✓	✓	✓	✓	0	11.7	0	3679	112
E1	L	✓	✓	✓			3.6	12.6	316	-	119
E2	L	✓	✓	✓			5	12.6	316	-	119
E3	L	✓	✓	✓			10	12.5	316	-	80
E4	L	✓	✓	✓			15	11.9	0	-	73
E5	L	✓	✓	✓			25	10.2	0	-	86



(a)

Scenarios [1] → Results

Scenario Index	Itaipu cost	New hydropower	Hydro peaking	Solar & Battery	Wind	Ice Storage	Export electricity Price $/MWh	LCOE $/MWh	Battery MWh	Ice Storage MWhe	New Transmission MW
A1	H	✓					0	30.2	-	-	129
A2	M	✓					0	25.8	-	-	87
A3	L	✓					0	22.4	-	-	59
B1	H	✓	✓				0	28.5	-	-	388
B2	M	✓	✓				0	24.1	-	-	327
B3	L	✓	✓				0	20.8	-	-	187
B4	H	✓	✓	✓			0	28.2	444	-	373
B5	M	✓	✓	✓			0	24.0	523	-	239
B6	L	✓	✓	✓			0	20.7	499	-	97
C1	L	✓		✓	✓		0	21.5	2510	-	711
C2	L	✓	✓	✓	✓		0	20.7	485	-	85
D1	L	✓				✓	0	20.3	-	32647	512
D2	L	✓		✓		✓	0	18.5	0	52937	0
D3	L	✓	✓	✓		✓	0	18.3	0	51724	0
D4	L	✓	✓	✓	✓	✓	0	17.8	0	25870	0
E1	L	✓	✓	✓			3.6	20.5	410	-	100
E2	L	✓	✓	✓			5	20.2	367	-	110
E3	L	✓	✓	✓			10	19.1	519	-	215
E4	L	✓	✓	✓			15	18.1	524	-	244
E5	L	✓	✓	✓			25	15.7	286	-	1033



(b)

Figure 13. Sensitive of new technology deployment and cost uncertainty. (a) To meet 1.5 times load of year 2019 (short-term); (b) to meet 2.5 times load of year 2019 (mid-term). [1]Each scenario under study is defined. The baseline for every scenario includes existing hydropower plants and the new hydro plants. Three Itaipu cost scenarios is denoted by 'H' (current), 'M' (intermediate), 'L' (low) respectively; Hydro peaking, solar & battery, wind, ice storage would be checked in the cells if selected; Export surplus electricity from new binational hydro plants is only allowed in E- scenarios with various export rate shown in each cell.

In the meantime, seven categories of results are shown as columns in figure 13, which are identified as overall LCOE in $/MWh, battery capacity in MWh, ice storage capacity in MWh, new investment of trans-zonal transmission capacity in MW, electricity generation capacity broken by source type in MW, , annual average dispatch by source type in MW, and peak load hour dispatch by source type in MW respectively. The results would be further revealed in section 3.3.2 to 3.3.7.

3.3.2 The effect of future Itaipu cost

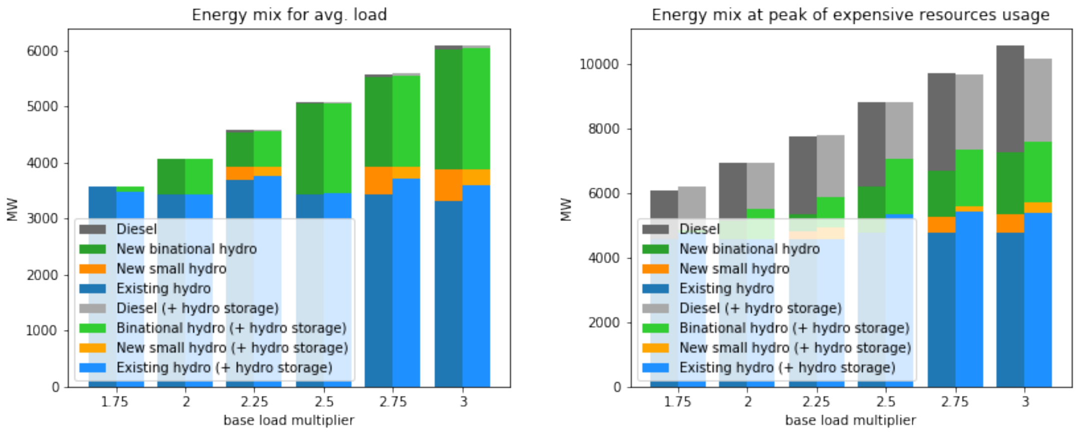
As discussed in section 1.3.3, based on scenarios analyzed by the Economic Working Group, three possible alternatives are chosen for the Itaipu electricity tariff ('CUSE') starting from year 2023. It can be shown clearly from the first three rows of figure 13, a sharp cost reduction in levelized cost of electricity (LCOE) occurs in the short-term if the Itaipu contracting price can reach the lowest possible alternative. However, the cost reduction effect is milder in the mid to long term, especially when competitive energy storage technology is considered.

On the contrary, reducing purchasing price of Itaipu electricity wouldn't have much capability to reduce the model's selection of usage of expensive dispatchable resources. This can be mainly attributed to the fact that Itaipu's electricity is already very cheap. Therefore, for the purpose of allocating limited resources for sustainable development, we suggest Itaipu maintain the electricity price at the same level, or lower its rate to somewhat higher than the future generation cost, while creating a sustainable development fund to provide financial support to the country's pioneer projects in the field of sustainable development.

3.3.3 The effect of hydropeaking for hydropower plants to be built

Although we didn't study the effect of retrofitting existing hydropower stations to allow them to have some daily storage capacity, the benefit of hydropeaking among new hydropower stations is shown in our result. Flexible operation of projected hydropower constructions to be built in the future are capable to reduce the usage of expensive dispatchable resource, and thus has positive effects on reducing the LCOE. Considering the newly built hydropower station only accounts for a small part of generation supplies, the effect on cost reduction by this method is substantial. Therefore, we believe the effect of hydropower storage will be fully exhibited if some retrofit could be conducted on the three central hydropower stations under operation to provide a few hours of storage capacity.

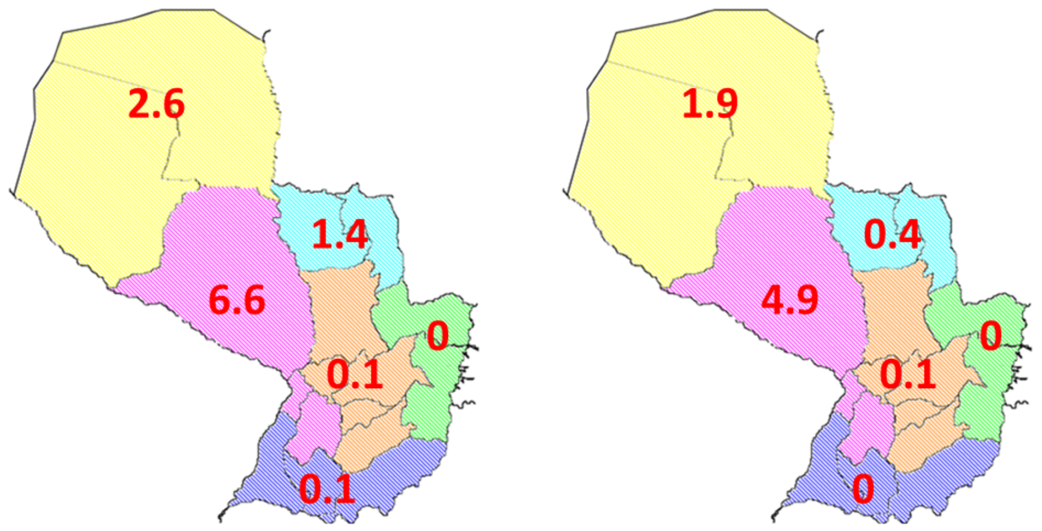
Figure 14 compares energy resources dispatch with and without hydropower storage for projected hydropower plants. When endowing newly built hydropower stations with the capacity to provide 6-hour storage service on a daily basis, PY-RAM will choose to consume a lot more hydropower from the three existing plants, which no doubt will lower the supply cost. The reason can be linked to Itaipu's monthly contracting rules. Due to the agreements, ANDE cannot contract power for less than a fraction of the energy it actually purchases. So, the best economic interest can only be achieved when hourly purchasing is at a flat level that minimizes the fraction between energy contracted and total purchasing, while still maintaining this fraction above a diplomatic preference threshold. Without the need of providing flexibility and power regulation, more energy can be purchased from the much cheaper Itaipu binational power plant.



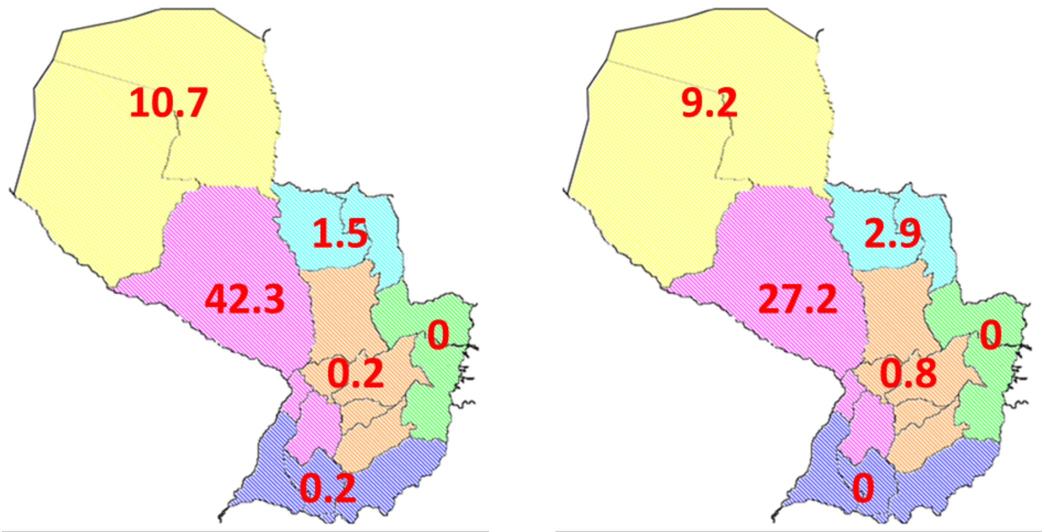
(a) (b)

Figure 14. Comparison of energy dispatch with and without hydro storage for new hydropower plants as demand growing. (a) annual average values; (b) annual peak load hour values.

Figure 15 shows average expensive resources usage in each geographical zone, and compared the result with and without hydro storage among new hydropower stations. It shows a sharp reduction in expensive resource usage in Metropolitan area when operating new hydropower station flexibly. This character is preferred by the system operator as most power shortage nowadays is occurred in this densely populated area.



(a) (b)



(c) (d)

Figure 15. geographical distribution of average usage of expensive dispatchable resources (unit: MW) with and without hydro storage. (a) and (b) are at 2 times year 2019 load, (c) and (d) are at 3 times year 2019 load. Whereas (a) and (c) without any storage, (b) and (d) allows hydro storage for new hydropower plants

3.3.4 The effect of solar PV and battery

Our result indicates that at current cost of solar and battery, they are not as competitive as building new hydropower plants and conducting daily based hydro storage. PY-RAM won't choose much solar and battery even if we input a considerable low price of batteries. This can be primarily attributed to the Paraguayan citizens' daily and seasonal load pattern that is not aligning well with solar potential. More specifically, solar peaks at around 13:00 on a daily basis, however the electricity load curve maximizes at evening hours. For the seasonal pattern, battery is only useful for a few load spike hours, which makes it extremely expensive to use, so that causing solar PV to be less favorable than more reliable hydropower.

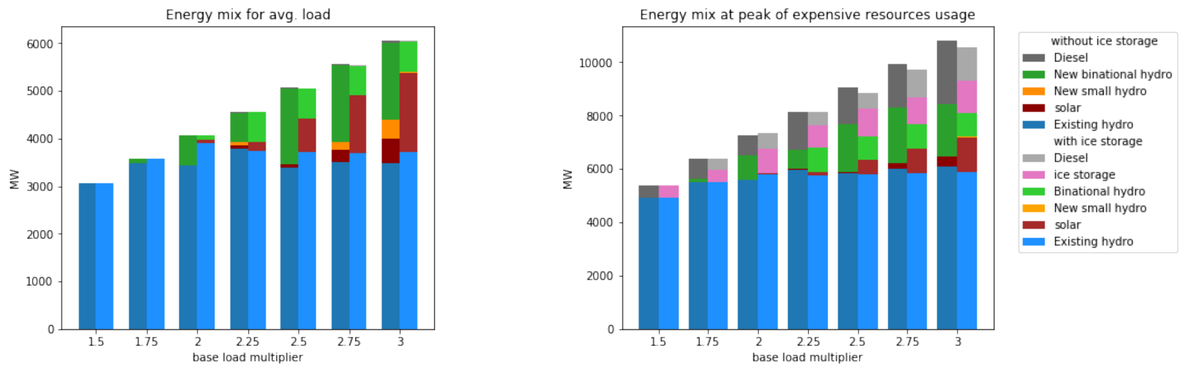
However, the benefit of distributed solar and future cost reduction in PV cost are not considered in our study, which may influence the investment decisions for the future. In addition, figure 13 shows that the presence of the ice storage, which is much cheaper and suitable for mass deployment, can extremely promote the role of solar PV in Paraguay's power system. In the cost assumption we propose in this study, solar PV is even more attractive than constructing new binational hydroelectric plants when coupled with ice storage. Same effects can also be found for wind generator.

3.3.5 The effect of wind

Our model shows optimistic results of investing in wind turbines in the future. Figure 13 shows wind power is competing with solar PV at each level of load, although both options still seem expensive for Paraguay's energy market. However, same as solar, wind generation can be preferred if a low cost storage technology can be adopted in Paraguay's residential electricity sector.

3.3.6 The effect of ice storage

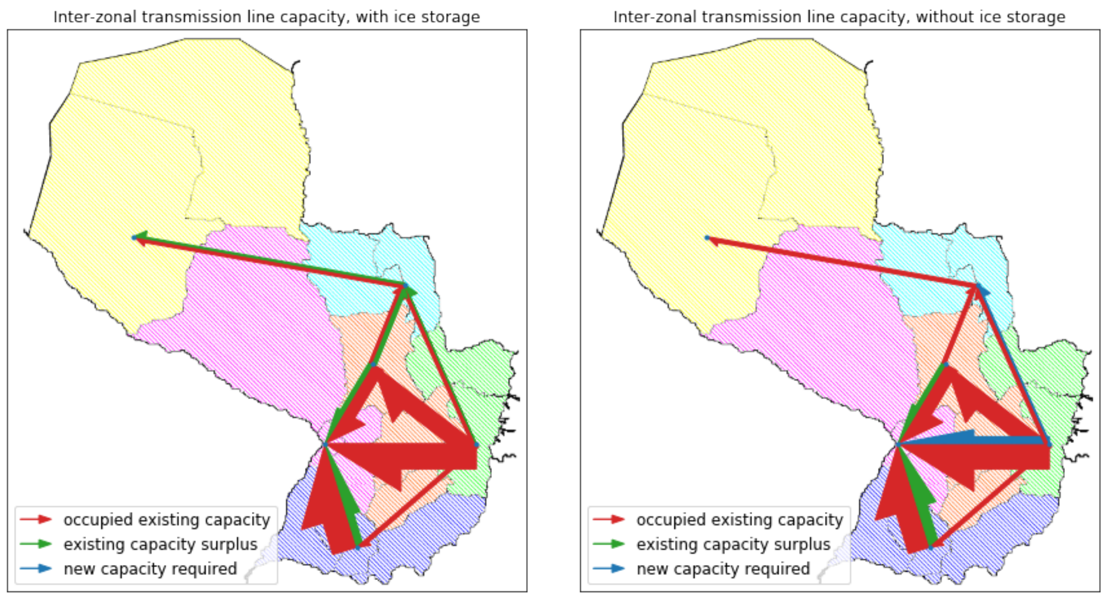
The long-term energy dispatch option changes quite a lot when assuming all current demand is fulfilled by electric chillers and allowing the model to choose ice storage as discussed in section 2.2. Our intention of making this modelling scenario is to advocate the benefit of installing more efficient cooling devices and block level storage options. The energy mix for different load projection with and without the use of ice storage are shown in figure 16.



(a) (b)

Figure 16. Comparison of energy dispatch with (right bar) and without (left bar) ice storage for future residential buildings (without showing charge of batteries or ice storage). (a) annual average values; (b) annual peak load hour values

A considerable amount of solar PV is chosen in the scenario that allows to invest in ice storage. This character is in line with our expectation. As discussed in the previous chapter, the pain point of solar deployment is solved by the cheap ice storage technology, and a considerable amount of solar PV is chosen in these scenarios. With the load growing in figure 16(b), less than half of the expensive resources is chosen at annual peak load hour compares to the scenario without ice storage. The benefit of the combination of solar PV and ice storage also applies to reduce the burden of transmission lines at the peak load periods, which is shown in figure 17. This figure maps out the transmission lines requirements at 2.5 times electric load of year 2019.



(a) (b)

Figure 17. Interzonal transmission usage comparison between with and without ice storage, at 2.5 times electric load of year 2019

We take a further inspection on the pattern of expensive resources usage. Figure 18 shows the comparison of expensive resource usage between scenarios with and without ice storage. It's obvious to see from figure 18(a) that annual deficiency of economically feasible renewable resources will only occur in some summer months, when hydropower potential is low and cooling demand is high. Figure 18(b) shows the effect of ice storage on peak load shaving at the most challenging 3 days of dispatch during the year. The result also verifies that ice storage can be served as a powerful tool for peak load shaving in the future.

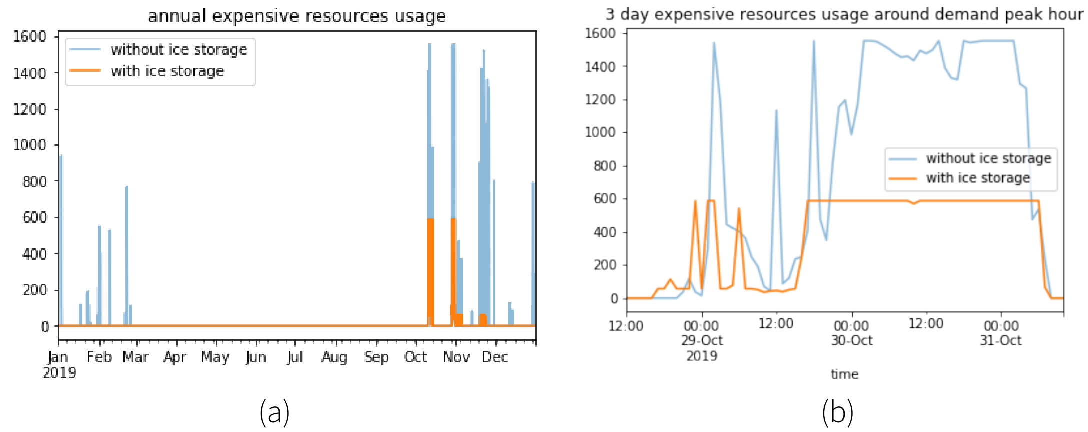


Figure 18. Expensive dispatchable resources usage with and without ice storage. load at 2.5 times year 2019 load (a) annually; (b) three days peak usage window

3.3.7 Effect of exporting unused electricity from new hydropower plants to Argentina

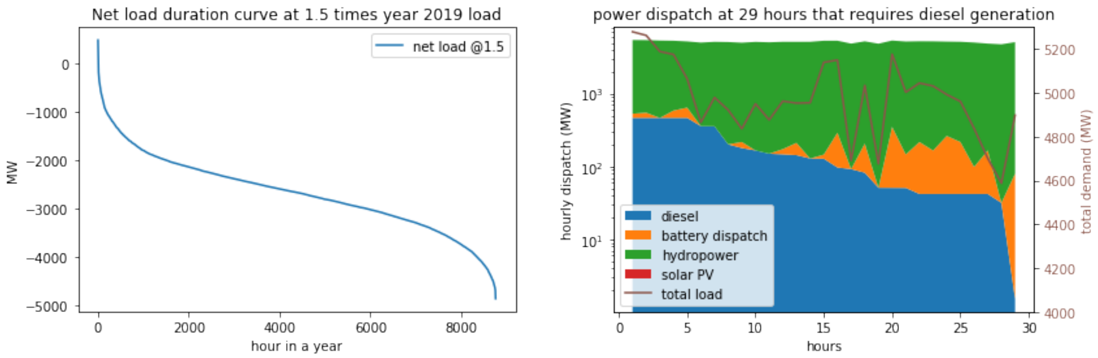
As shown in the last five rows in figure 13, with the ability to export surplus energy generated from new binational hydropower stations to Argentina at a reasonable price, the entire system dispatch cost would be lower, as the usage of expensive resources is curtailed. This effect is especially amplified if an export price can be higher than 15 $/MWh, under current power system currency and inflation rate. Thus, negotiating bilateral cooperation on hydropower exploitation with Argentina is especially necessary, in order to benefit both sustainable energy system expansion and economic power dispatch options for Paraguay.

3.4 Demand response program designing based on the model results

We observe that resources deficiency starts to occur at 1.5 times load scenario, under the base scenario introduced in section 3.2. So we choose this scenario to design the DR programs first. And then 2.5 times load scenario is used to understand the benefits from DR when the load continuously increasing.

3.4.1 Demand response in 1.5 times load scenario

We use the concept of net load to show residual demand, which is obtained from subtracting total load by existing hydroelectric generation potential. The duration curve of net load is shown in figure 19(a). It indicates the imbalance between demand and existing generation capacity occurs only at a few hours during the year. Figure 19(b) shows detailed dispatch planning by resource type at those particular hours, based on results from PY-RAM. The vertical axis has been made into logarithmic scale, in order to show the imbalance clearly.



(a) (b)

Figure 19. (a) Net load duration curve at 1.5 times year 2019 load. (b) Power dispatch at imbalance hours by source. Note: net load is defined as total load minus the generation potential of existing hydropower plants.

Then, a plan of DR program is made to limit the load among those 30 hour- period that cannot be met by the existing capacity. 8 DR events are required in order to shave peak demand by 466 MW, or equivalently, eliminate the use of expensive dispatchable resources. Each DR events will last various from 1 hour to 12 hours. Detailed event numbers aggregated by the length of coverage period is shown in table 13. Ideally, the 8 DR events will be able to reduce resources deficiency by as much as 5002 MWh.

Table 13. Proposed DR events aggregated by lasting hours

Hours in an event	1	2	3	4	12
Number of events	2	1	3	1	1

3.4.2 Demand response in 2.5 times load scenario

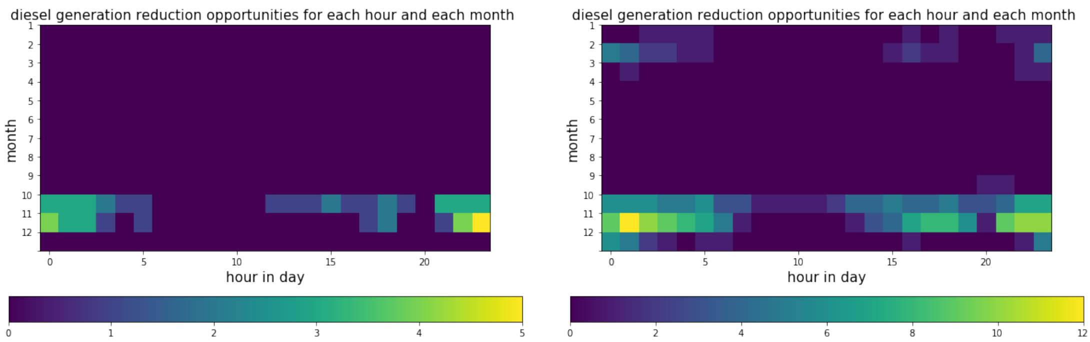
Same analysis can be implemented to plan DR events while power demand growth to 2.5 times. Table 14 provides multiple DR planning options for various peak load reduction targets, as well as estimated economic benefits. With more action hours are involved, the overall saving provided by each MW reducible capacity is increasing. However, the unit value of each MWh energy curtailed is reducing. Since this table didn't show savings on transmission and distribution system due to data availability issue, to find out the preferred amount of peak load reduction for the whole system still needs further rigorous studies.

Table 14. Demand response program options targeted at different amount of peak load reduction at 2.5 times load scenario

Peak load reduction (MW)	100	200	300	500	750	1000	1500	2000
Number of events	1	3	4	6	8	10	36	-

Total hours involved	5	9	10	17	39	60	152	499
Expensive resources generator capital cost reduction (MW)	100	200	300	500	750	1000	1500	2000
Expensive resources energy reduction (GWh)	0.5	1.1	1.8	4.0	9.8	20.9	64.9	168
Battery capital reduction (MWh)	0	0	19	19	19	19	356	783
Reduced annualized capital cost (MM$)	3	6	10	16	24	32	55	80
Value of peak load reduction ($/kWh)	6.4	5.9	5.6	4.1	2.5	1.6	0.9	0.5
Average annual saving ($/kW-year)	34	34	34	34	34	34	34	34
Fuel saving ($/kWh)	0.3 $/kWh							

Take a further look at the temporal distribution of these DR options listed above. Figure 20(a) and 20(b) shows number of hours involved during each month if the program aims at 1000 MW and 2000 MW peak load reduction respectively. Figure 20(a) indicates all peak load reduction opportunities occur in October and November, while 66% of them should be held during 21pm – 2am, a 6-hour window. This character is typically preferred by system operator to initiate a DR program, as peak load is predictable and favorably distributed that minimize the number of events. Similar pattern can also be found in figure 20(b).



(a) (b)

Figure 20. Number of DR event hours at each time slot each month, for (a) 1000 MW and (b) 2000 MW peak load reduction program

4. Discussion

4.1 Value of peak load reduction

Our result shows DR program proposed in section 3.4 can save \$1~3 per kWh reduction on generator and battery investment, together with additional \$0.3/kWh fuel saving. If converted to annual savings, DR program could save system operator amount to \$30~40/kW-yr for every 1 kW peak reduced. This estimation amplifies significantly if peak load is required to meet by sustainable generation, and can approximately reach \$120~200/kW-yr.

Apart from reduced investment in generator capacities, the benefit of DR program is reflected in transmission and distribution system as well. Saving on transmission system expansion is estimated based on ANDE's master plan of transmission 2016-2025.[36] According to the plan, in order to secure 20% operation margin for the 10-year period, during which peak load growth from 3165 MW to 6721 MW, ANDE will spend around \$1.1 Billion USD to expand transmission lines for more than 2.6 Million MW-km, and additional \$1.5 Billion USD to build new substations. We simplify the math here by assuming investment is proportional to peak load. An intuitive value of peak load reduction on transmission system can be obtained to be around \$15/kW-yr, with the assumption of a 5% annualization rate.

Similarly, saving on distribution system can be estimated based on ANDE's master plan of distribution 2016-2025.[37] ANDE plans to spend \$1154 Million on system expansion and \$299 Million on wires for the period. Using the same method, we get \$30~50/kW-yr annualized reduction of investment in distribution system.

In conclusion, the value of peak load reduction in Paraguay's future electric system can be as high as \$75~275USD/kW-yr. When converting to direct fiscal expense, more than \$1500/kW can be saved in investment. With a saving at this level, demand response program should be able to find its role alleviating burdens of the power system caused by rapid growing of demand. On the other hand, by participating DR program, building owners therefore find financial incentives to invest in distributed sustainable generators, building or block level storage devices, digitalization, and enhance electrical efficiencies.

4.2 Uncertainty of hydropower generation

A 20-year hydroelectric generation record is shown in figure 4. We choose to use year 2019 data as the hydropower input for PY-RAM because it represents the worst case to system operator, as extreme drought happened to Parana river during the year. Therefore, PY-RAM can be regarded as a robust optimization model, where uncertainty is settled by planning for the worst scenario.

As the results from PY-RAM indicates, hydropower will not be able to meet 100% of Paraguay's power demand economically in the future, even with new construction of hydroelectric dams. This is because the run-of-river operation cannot align well with electric load pattern. The uncertainty of

[36] ANDE, 2016, Plan Maestro De Generacion, period 2016-2025
[37] ANDE, 2016, Plan Maestro De Generacion, period 2016-2025

hydropower generation comes in by two dimensions – temporal and spatial.

Figure 21 shows the distribution pattern of monthly average generation potential of Itaipu during a 20-year period. It indicates Itaipu generation potential varies greatly between years. The worst water year generation typically only equals to 3/4 that of the best water years. If converted this fraction into Paraguayan share of Itaipu energy, on average, there is up to 1500 MW power generation difference at each hour between the best and worst water years. This issue can bring huge challenges once Paraguay's peak electricity load reaches total generation potential of the country's hydropower stations.

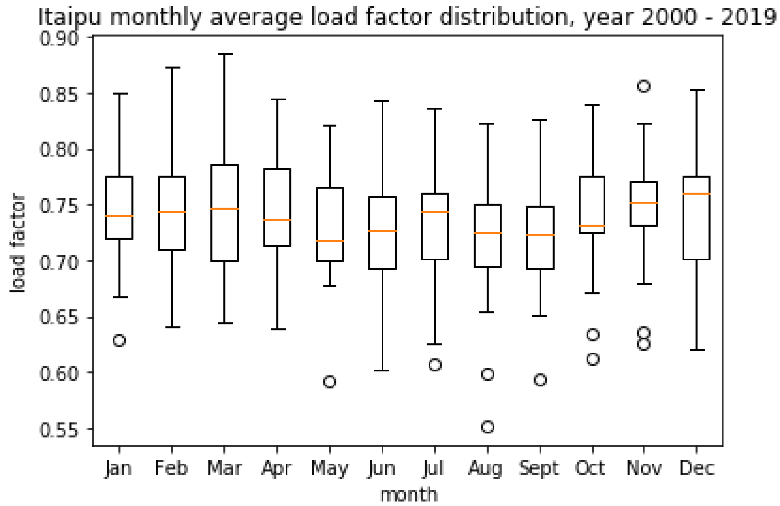


Figure 21. Itaipu monthly average load factor box plot, year 2000-2019. The orange line in each box represents the median of each month. The boxes indicate the range between two quantiles. And the whiskers show the range between lowest data point plus $Q1 - 1.5(Q3 - Q1)$ *and largest data point minus* $Q3 - 1.5(Q1 - Q3)$*. Where Q1 and Q3 represent the first quantile and third quantile respectively.*

Simultaneously, Paraguay's major hydropower plants, including 4 proposed binational hydropower constructions, are all located along Parana river. This undesired spatial pattern amplifies temporal variation between years. Records show that the electricity generation of Itaipu and Yacyreta are highly correlated, with a cross-correlation up to 90%. Without storage capacity, both hydropower plants will peak and valley at the same time, which jeopardize the capacity of dispatch. Integrating electricity generation from other resources and implementing peak load shaving strategies discussed above is therefore crucial for grid stability for Paraguay in the near future.

4.3 Opportunity of transport electrification

Transport sector is not included in PY-RAM as electrifying the fleet in Paraguay constrains by several factors. The biggest obstacle lies in the lack of potent regulation on importation of used cars. Currently, the second-hand car market is more than twice as big as new car market in the country, and a considerable number of imported vehicles have an age exceed 10 years. These imported cars are sold too cheap so that curb the market competition of cars with higher efficiencies, or powered by cleaner energy resources.

While the price of fuel cell vehicles (FCV) are still very high, our analysis below focuses only on battery electric vehicles (BEV or EV). In many countries, public transit is an ideal starting point of transport electrification, as their traveling pattern is preferred by an EV vehicle, and the economic cost and return is easier to be predicted. Paraguay's public transit is mainly run on private companies and allocated mainly within Metropolitan area. According to Dinatran[38], around 1800 buses are currently serving for 88 routines across the Asuncion Metropolitan area. Among these public service fleet, more than 50% of them have an age of more than 7 years, and 24% of them even used for more than 14 years. It's therefore an opportunity for Paraguay to promote ambitious target of electrification its public transports.

However, our source suggests EV buses is not economically favorable for private companies in Paraguay without government's sponsorship. The reason is as follows. Currently, the cheapest option of EV buses importation comes from China, but still, a single bus can be 125,000 dollars premium than a diesel powered one, as well as an extra maintenance expense average to $25,000 each operating year ($125,000 for 5-year battery lifetime). For a typical private operator bus runs around 270km/day (kilometer per day), we assume an average fuel consumption rate at 0.5 L/km (liter per kilometer) for traditional bus run on diesel, while 300 kWh/day electricity consumption for EV bus. With a highly idealized estimation, fuel savings can be as much as $130 per day per EV bus substitution. The resulting fuel saving in a typical 5-year lifetime of EV battery is around $200,000, which cannot even make up for the capital and maintenance cost. Thus, economic incentives are necessary for the sustainable transition in transport sector.

Apart from the green road project leads by Itaipu Technology Park (PTI)[39], incentives for transport electrification can be provided more than governmental sponsorship. Building catenary systems on main traffic lines across the country and piloting battery leasing for EVs can benefit both public and private transport sectors, as well as logistics. Case studies for each of the 2 options is shown below.

Box 2. Catenary systems

Trolleybuses are existing in many of the metropolitan cities throughout more than 43 countries.[40] Although it's a technology with a long history, its capability of emission reduction, low cost, and technological maturity makes it still a vibrant technology today. Many countries expanded trolleybus systems recently, including Itaily, Turkey, Morocco, and China.

E-highway with a catenary line is first proposed by Siemens in year 2012, when Siemens envisioned the electrification of freight transport.[41] The initiative has already conducted several demonstrative projects in Sweden (2016), German (2018), and United Sates (2018). Hybrid cars with a pantograph can constantly acquiring electricity from the overhead cable with an electric-to-wheel efficiency of more than 80% while running on a e-highway. For customers, without the need of purchasing large volume of batteries, individual investment on the hybrid trucks will be significantly lower than a BEV counterpart. Accompanying with additional fuel saving, e-highway would become an effective incentive to electrification of

[38] Dinatran (2018), Anuario Estadistico de Transporte
[39] https://www.itaipu.gov.py/es/sala-de-prensa/noticia/pti-proyecta-poner-en-funcionamiento-la-ruta-verde-en-el-2019
[40] Webb, Mary (ed.) (2012). *Jane's Urban Transport Systems 2012–2013*,
[41] https://www.mobility.siemens.com/global/en/portfolio/road/ehighway.html

freighters and long-range public buses.

Box 3. Battery leasing commercial (battery-as-a-service model) proposed in China[42]

Battery leasing for EVs was initiated by a Chinese EV manufacturer – Nio Inc. last year. The proposed EV model, ES6 SUV, will be available to customers for two purchasing options. One is buying an entire car for ￥343,600 (yuan), the other is purchasing only the shell of vehicle at ￥273,600 and rent a battery unit for an additional cost starting at ￥980 per month. The incentive of this initial lies in significant reduction of capital investment, and can will be able to extend the vehicle shell's lifetime to as long as a traditional car by changing batteries once in a few years.

[42] https://www.bloomberg.com/news/articles/2020-08-20/buy-an-ev-lease-the-battery-now-you-can-under-nio-s-new-model

Appendix

Appendix A. Solar PV energy simulation

First, hourly extraterrestrial radiation on a horizontal surface in the unit kW/m², I_0, is calculated as,

$$I_0 = 1.367 * \left(1 + 0.033 * \cos\left(\frac{360 * (n-3)}{365}\right)\right) * \cos \theta_z \tag{1}$$

Where n is the number of days in a year. θ_z stand for solar zenith, which is calculated based on basic solar geometry. And then, the sky clearness index k_T is obtained by,

$$k_T = \frac{I}{I_0} \tag{2}$$

Where I represents the observation value of global irradiation. Then, diffuse radiation I_d and beam radiation I_b is calculated respectively by,

$$I_d = \begin{cases} (1.02 - 0.248k_T)I & if\ 0 \le k_T < 0.3 \\ (1.45 - 1.67k_T)I & if\ 0.3 \le k_T < 0.78 \\ 0.147I & if\ 0.78 \le k_T \end{cases} \tag{3}$$

$$I_b = I - I_d \tag{4}$$

Therefore, solar power on a panel can be obtained by,

$$I_T = I_b * \frac{\cos(\gamma)}{\cos(\theta_z)} + I_d\left(\frac{1 + \cos\beta}{2}\right) + I * \rho_g * \left(\frac{1 - \cos\beta}{2}\right) \tag{5}$$

Where γ denotes incidence angle between solar beam and panel. β is the surface tilt. ρ_g represents the albedo of the ground. This result is then corrected by air temperature and Photovoltaic (PV) panel's thermal and electric performance,

$$T_{cell} = T_{air} + \frac{NOCT - 24}{800} * I_T \tag{6}$$

$$\mathrm{I} = [1 - \eta_T * (T_{cell} - 25)] * I_T * \eta_e \tag{7}$$

Where, $NOCT$ is the normal operating cell temperature provided by panel manufacturer. η_T is the temperature coefficient of power output. η_e stands for the efficiency of electric inverter. In this study, η_T and η_e were chosen to be -0.39%/°C and 94% respectively.

The above procedure is iterated for each hourly interval for each load zone.

Appendix B. Wind energy simulation

Since plenty of stations were not recording on an hourly basis, and have frequent missing records, multiple observation stations across each load zone are chosen and integrated to formulate 6 groups of hourly wind record, each group regards as the representative profile of one corresponding load zone. The numbers of hourly entries of each resulting wind profile for year 2019 are listed in table AX-B, which ideally should cover all 8760 hours during a year. It also shows how many observation stations are chosen to generate hourly wind speed series.

Although we integrate multiple datasets, there are still numerous time slots missing. We fill the blanks by linear interpolation as no more data can be found on wind profile.

Table AX-B. Numbers of observation stations chosen and hourly entries collected

Load zones	Number of selected observation stations	Number of hours are recorded (ideally 8760)
South	3	5829
East	2	8757
Central	5	2920
Metropolitan	3	8760
North	3	4326
West	1	2698

And then, we utilize the method described in Brown et al[43] to obtain hourly CF of wind generation from wind speed records. A brief introduction of the method is shown below.

The measured air density at each hour is first calculated using the ideal gas law,

$$n_{meas} = \frac{(p_{meas} - p_{water})}{R_{dry}T} + \frac{p_{water}}{R_{water}\,T} \tag{8}$$

Where p_{meas} is the measured air pressure (unit: Pa), p_{water} is the partial pressure of water vapor (unit: Pa), T is the measured air temperature (unit: K). Two gas constant R_{dry} and R_{water} is set to be 287.1 J/(kgK) and 461.5 H/(kgK) for dry air and water vapor respectively.

since wind turbine power curves are reported for a standardized air density, hourly wind speed observation records are normalized by measured air density as,

$$v_{std} = v_{meas}(\frac{n_{meas}}{n_{std}})^{1/3} \tag{9}$$

Where v_{meas} is measured hourly wind speed, n_{std} is the air density at standard condition, 1.225

[43] Brown, P. R., & Botterud, A. (2021). The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System. Joule, 5(1), 115-134.

kg/m³.

Then, wind profile power law is adopted to roughly estimate wind speed at turbines' hub height.

$$\frac{v_{hub}}{v_{std}} = (\frac{z_{hub}}{z_r})^{\alpha} \tag{10}$$

Where z_{hub} is the hub height, (unit: m), z_r is the height where observation is conducted, we take 10 meters as an average height for all surface data collected.

The resulting wind speed distribution histograms are shown in figure AX-B for every load zone. In order to approximately estimate power generation potential, wind power curve for a specific commercial wind turbine – Leitwind LTW90/1000 is utilized to correspond hourly standardized wind speed with hourly generation CF. To be noted, this particular wind turbine is preferred to be installed at where wind speed is relatively low.

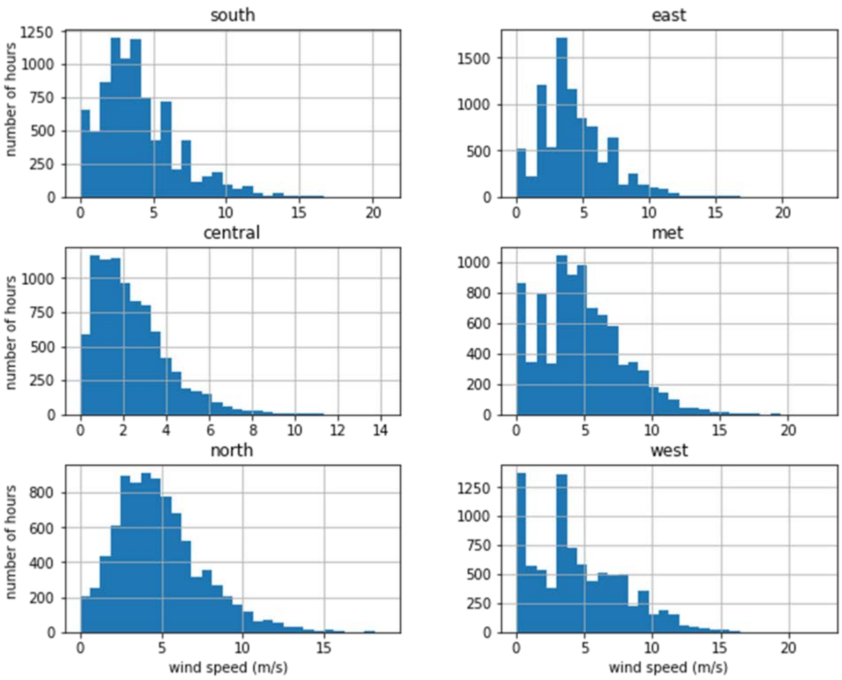


Figure AX-B. Standardized wind speed histogram for each load zone

Appendix C. Existing inter-zonal transmission lines

Table AX-C. Trans-zonal transmission lines[44]

Operating voltage (kV)	Substation 1	Substation 2	Load zone index	Nominal capacity (MW)
500	Right Margin	Villa Hayes	E → M	2000
500	Ayolas	Villa Hayes	S → M	2000
220	Coronel Oviedo	Pirayu	C → M	305
220	Coronel Oviedo	Eusebio Ayala	C → M	305

[44] ANDE, requested data, 2020.

220	Coronel Oviedo	Guarambare	C → M	305
220	Santa Rosa	Horqueta	C → N	200
220	Carayao	Altos	C → M	230
220	Acaray	Coronel Oviedo	E → C	229
220	Acaray	Coronel Oviedo	E → C	229
220	Itakyry	Vaqueria	E → C	248
220	Itakyry	Carayao	E → C	248
220	Kilometro 30	Mallorquin	E → C	229
220	Kilometro 30	Campo Dos	E → C	300
220	Kilometro 30	Caaguazu	E → C	300
220	Curuguaty II	Capitan Bado	E → N	350
220	Villa Hayes	Concepcion II	M → N	350
220	Guarambare	San Juan Bautista	M → S	195
220	San Juan Bautista	Guarambare	S → M	238
220	Vallemi	Acueducto	N → W	240
220	Carlos A. Lopez	Paranambu	S → E	180
220	San Patricio	Valle Apua	S → M	238
66	Villeta	Guarambare	S → M	~40
66	Guarambare	Villeta	M → S	~40
66	Eusebio Ayala	Itaugua	S → M	~72

Appendix D. Paraguay Electricity Resources Adequacy Model (PY-RAM) formulation

D.1 Nomenclature

$AC(t)$: Acaray total generation at time step t [MW]

C_{AC}: Acaray energy cost [$/MWh]

$C_{batt,e}$: annualized battery capital cost [$/MW]

$C_{ch,h}$: annualized binational hydropower station h generation capital cost [$]

C_{exp}: annualized expensive dispatchable resource generation capital cost [$/MW]

$C_{exp,fuel}$: expensive dispatchable resource unit fuel cost [$/MWh]

$C_{generation}$: energy generation cost [$]

$C_{IT,contract}$: Itaipu contract power cost [$/MW-mo]

$C_{IT,above}$: Itaipu above contract energy usage cost [$/MWh]

$C_{new\ capacity}$: annualized new capacity capital cost [$]

C_{pch}: annualized small hydropower generation capital cost [$/MW]

C_{solar}: annualized solar generation capital cost [$/MW]

$C_{trans,rr'}$: annualized capital cost of upgraded transmission from zone r to adjacent zone r' [$/MW-km]

C_Y: Yacyreta energy cost [$/MWh]

$CF_{ch,r}(t)$: capacity factor of new binational hydropower plants in zone r, at time step t

$CF_{pch,r}$: capacity factor of small hydropower plants in zone r

$CF_{PV,r}(t)$: capacity factor of solar PV generation at time step t

$CL^{th}_{d,r}(t)$: cooling energy delivered by chilled water directly from electric chillers in zone r, at time step t [MW_{th}]

$CL^{th}_{s,r}(t)$: cooling energy goes to ice storage from electric chillers in zone r, at time step t [MW_{th}]

COP_{cool}: coefficient of performance of chillers under normal cooling operating conditions

COP_{ice}: coefficient of performance of chillers under ice-making operating conditions

$D_{exp,r}(t)$: expensive dispatch resource generation in zone r, at time step t [MW]

$E_{batt,r}(t)$: aggregate battery storage state of charge in zone r, at time step t [MWh]

$E_{ch,r}(t)$: New binational hydropower plants stored hydropower potential in zone r, at time step t [MWh]

$E_{pch,r}(t)$: stored hydropower potential of new small hydropower plants in zone r, at time step t [MWh]

$G_{i,r}^{e}(t)$: power generation by resource i in zone r, at time step t [MW]

$H_{ch,r}(t)$: new binational hydropower generation in zone r, at time step t [MW]

$H_{pch,r}(t)$: small hydropower station generation in zone r [MW]

$IT(\mathrm{t})$: Itaipu total generation purchased by Paraguay at time step t [MW]

IT^{max}: maximum generation (Paraguay share) at a time step [MW]

$IT_{above}(t)$: Itaipu above contract generation purchased by Paraguay [MW]

$IT_{contract}(t)$: Itaipu contracted generation purchased by Paraguay [MW]

$IT_{contract}^{mo}(mo)$: Itaipu monthly contract power [MW-mo.]

$L(t)$: hourly load of SIN at time step t [MW]

$L_r(t)$: hourly load of sub-system r in zone r, at time step t [MW]

L_r^{mo}: monthly average load of sub-system r [MW]

$L_{rr'}$: existing transmission flow limit between zone r and adjacent zone r' [MW]

$lim_{ch/dis}\%$: ice storage maximum hourly charge/discharge thermal power constraint as the percentage to thermal capacity of ice storage

LCOE: levelized cost of electricity [$/MWh]

$Max_{mo}(IT(t))$: monthly peak of Itaipu generation purchased by Paraguay [MW]

$Max_y(IT(t))$: annual peak of Itaipu generation purchased by Paraguay [MW]

$S_{PV,r}(t)$: electricity energy generated by solar PV at time step t [MW]

$S_r^{th}(\mathrm{t})$: thermal energy stored in ice storage tank in zone r, at time step t [MW_{th}]

$u_{ch,h}$: decision variable for proposed binational hydropower station h

$X_{batt,e,r}$: battery storage energy capacity installed in zone r [MWh]

$X_{ch,r}$: capacity of new binational hydropower generation installed in zone r [MW]

$X_{ch,h}^{max}$: capacity of proposed new binational hydropower station h in IPPSE report [MW]

$X_{chiller,r}^{th}$: chiller thermal energy capacity installed in zone r [MWh_{th}]

$X_{exp,r}$: capacity of expensive dispatch resource generation in zone r [MW]

$X_{ice,r}^{th}$: ice storage thermal energy capacity installed in zone r [MWh_{th}]

$X_{pch,r}$: capacity of small hydropower generation installed in zone r [MW]

$X_{solar,r}$: capacity of new grid connected solar PV panel installed in zone r [MW]

$X_{solar,r}^{max}$: maximum capacity of grid connected solar PV can be built in zone r [MW]

$X_{trans,rr'}$: capacity of new transmission from zone r to adjacent zone r' [MW]

$Y(\mathrm{t})$: Yacyreta generation purchased by Paraguay at time step t [MW]

$Z_{rr'}(t)$: energy transmitted from zone r to adjacent zone r' [MW]

$\delta_{batt,r}(t)$: decrease in battery storage state of charge in zone r, at time step t [MW]

$\delta_{ice,r}^{th}(t)$: decrease in ice storage state of thermal charge in zone r, at time step t [MW]

$\gamma_{batt,r}(t)$: increase in hydrogen storage state of charge in zone r, at time step t[MW]

$\gamma_{ice,r}^{th}(t)$: increase in ice storage state of thermal charge in zone r, at time step t [MW]

κ: storage self-discharge

η_{batt}: battery storage efficiency

$\eta_{ice}^{ch,dis}$: ice storage charge/discharge efficiency

D.2 Mathematical formulation

Objective function. As a deterministic cost minimizing program, the objective function of PY-RAM is set to minimize the sum of electricity generation cost and annualized cost of new generator investment. Maintenance cost is not included as no relevant data is available for this study.

$$\mathrm{obj} = \mathrm{minimize}(C_{new\ capacity} + C_{generation}) \tag{11}$$

$$C_{new\ capacity} = \sum_{r\in R}[C_{solar} * X_{solar,r} + C_{pch} * X_{pch,r} + \sum_{h\in Hr} C_{ch,h} * u_{ch,h} + C_{batt,e} * X_{batt,e,r} + C_{exp} * X_{exp} + \sum_{r'}(C_{trans,rr'} * d_{rr'}) * X_{trans,rr'}] \tag{12}$$

$$C_{generation} = \sum_{mo\epsilon M}[\,C_{IT,contract} * IT_{contract}^{mo}(mo)] + \sum_{t\epsilon T}[\,C_{IT,above} * IT_{above}(t) + C_Y * Y(t) + C_{AC} * AC(t) + \sum_{r\epsilon R}[C_{exp,fuel} * D_{exp,r}(t)]] + \sum_{r\epsilon R}[\,C_{pch,opex} * H_{pch,r}(t) + C_{ch,opex} * \ H_{ch,r}(t)] \tag{13}$$

Zonal energy balance. In each load zone, total supply of electricity should always meet the demand requirement. The subscripts ‘r’ in IT_r, Y_r, AC_r is just for notation convenience, while Itaipu, Yacyreta, and Acaray are located in load zone East, South, and East respectively.

$$\mathrm{IT}_r(t) + Y_r(t) + AC_r(t) + H_{pch,r}(t) + H_{ch,r}(t) + S_{PV,r}(\mathrm{t}) + D_{exp,r}(t) - \ \gamma_{batt,r}^{t} + \ \delta_{batt,r}^{t} + \sum_{r'}[\,(1-l) * Z_{r'r}^{t} - \ Z_{rr'}^{t}] \geq Load_r(t) \tag{14}$$

Existing hydropower plants constraints. Electricity purchased from Itaipu has two mechanisms as described in chapter 1.3.3. In PY-RAM, monthly contracted power and hourly above-contract power are optimized simultaneously, while maintaining both monthly and annually contracting power no less than 45% of the monthly and annual peak power purchased respectively. Yacyreta and Acaray are constrained to produce energy less than their generation potential at each hour obtained from year 2019 record.

$$IT_{contract}(t) + IT_{above}(t) = IT(t) \leq IT^{max}(t) \tag{15}$$

$$IT_{contract}(t) \leq IT_{contract}^{mo}(mo) \times CF(t) \tag{16}$$

$$IT_{contract}^{mo}(mo) \geq Max_{mo}\big(IT(t)\big) \times 45\% \tag{17}$$

$$\sum_{mo=1}^{12} IT_{contract}^{mo}(mo)/12 \geq Max_{y}\big(IT(t)\big) \times 45\% \tag{18}$$

$$Y(t) \leq Y^{max}(t) \tag{19}$$

$$AC(t) \leq AC^{max}(t) \tag{20}$$

Transmission constraints. Hourly transmission between any two inter connected load zones are subject to the constraint of installed transmission line capacity.

$$Z_{rr'}(t) \ \leq L_{rr'} + X_{trans,rr'} \tag{21}$$

New small hydropower station. Installation of small hydropower station should not exceed the potential outlined by ANDE described in chapter 1.2.1, according to ANDE's plan. Hourly capacity factor is set to be 0.7 constantly.

$$X_{pch,r} \ \leq X_{pch,r}^{max} \tag{22}$$

$$H_{pch,r}(t) \leq X_{pch,r} * CF_{pch,r} \tag{23}$$

New binational hydropower station constraints. Four proposed binational plants described in section 1.2.1 are under consideration. To best model the scaling factor of centralized hydropower stations, decision binary variables are used for each of the proposed station in our model. These binary variables indicate the station's construction status, such that 0 is for"unavailable for operation", and 1 for "already in operation". In addition, the order of constructing these four plants is set to be fixed in PY-RAM, and corresponding to the timeline proposed by IPPSE's report (e.g. Itacora-Itati can only be built once Ana Cua and new construction at Yacyreta have been built). The MILP model will choose the best combination of new capacity at each electricity load expansion level. The capacity factor is assumed to be the same with that of Yacyreta, as all of them being located on the southern part of Parana River.

$$X_{ch,r} = \sum_{h=0,r}^{N} X_{ch,h}^{max}\, u_{ch,h} \tag{24}$$

$$H_{ch,r}(t) \leq X_{ch,r} * CF_{ch,r}(t) \tag{25}$$

Solar PV constraints. Grid connected solar photovoltaic panel can be installed in each load zone, while subject to respective hourly constraints of solar capacity factor that described in section 1.2.2.

$$S_{PV,r}(t) \leq X_{solar,r} * CF_{PV,r}(t) \tag{26}$$

Wind turbine constraints. Hourly wind generation should not exceed the installed capacity and subject to hourly capacity factor.

$$W_r(t) \leq X_{wind,r} * CF_{wind,r}(t) \tag{27}$$

Battery storage constraints. It is an explicit function of hourly charge and discharge of the battery. And the battery state of charge should not exceed its capacity.

$$\frac{\delta_{batt,r}(t)}{\eta_{batt}} - \eta_{batt} * \gamma_{batt,r}(t) = (1-\kappa) * E_{batt,r}(t-1) - E_{batt,r}(t) \tag{28}$$

$$E_{batt,r}(t) \leq X_{batt,e,r} \tag{29}$$

Expensive dispatchable resources constraints. Hourly expensive dispatch should not exceed the installed available capacity.

$$D_{exp,r}(t) \leq X_{exp,r} \tag{30}$$

D.3 Hydropeaking

For new small hydropower stations:

$$X_{pch,r} \leq X_{pch,r}^{max} \times 1.5 \tag{31}$$

$$H_{pch,r}(t) \leq X_{pch,r} \tag{32}$$

$$X_{pch,r} * CF_{pch,r} - H_{pch,r}(t) - H_{pch,r}^{curtail}(t) = E_{pch,r}(t) - E_{pch,r}(t-1) \tag{33}$$

$$E_{pch,r}(t) \leq 6 * X_{pch,r} * CF_{pch,r} \tag{34}$$

$$E_{pch,r}(t) = 0, \text{when } \mathrm{t} = 2 + 24\mathrm{k}, \mathrm{k} = 0,1, \ldots, 364 \tag{35}$$

For new binational hydropower stations:

$$X_{ch,r} = \sum_{h=0,r}^{N} X_{ch,h}^{max}\, u_{ch,h} \tag{36}$$

$$X_{ch,r}^{flex} \leq X_{ch,r} \times 0.5 \tag{37}$$

$$H_{ch,r}(t) \leq (X_{ch,r} + X_{ch,r}^{flex}) * CF_{ch,r} \tag{38}$$

$$X_{ch,r} * CF_{pch,r} - H_{ch,r}(t) - H_{ch,r}^{curtail}(t) = E_{ch,r}(t) - E_{ch,r}(t-1) \tag{39}$$

$$E_{ch,r}(t) \leq 6 * X_{ch,r} * CF_{ch,r} \tag{40}$$

$$E_{ch,r}(t) = 0, \text{when t} = 2 + 24\text{k}, \text{k} = 0,1, \dots, 364 \tag{41}$$

D.4 Ice storage

Energy balance. Energy balance becomes two parts to accommodate cooling load and the rest of load respectively. While maintaining hourly energy balance in each load zone, cooling demand has to be fulfilled by chilled water either from chillers directly or from ice storage discharge. The superscripts 'e' and 'th' in eq.42 to 48 represent the quantity as measured in electric power and thermal power respectively.

$$\frac{1}{COP_{cool}} CL_{d,r}^{th}(\text{t}) + \frac{1}{COP_{cool}} \delta_{ice,r}^{th}(t) \geq cooling\ load_r^e(\text{t}) \times CL\% \tag{42}$$

$$\sum_i^n G_{i,r}^e(t) \geq residual\ load_r^e(\text{t}) + \frac{1}{COP_{cool}} CL_{d,r}^{th}(\text{t}) + \frac{1}{COP_{ice}} CL_{s,r}^{th}(t) \tag{43}$$

Ice storage constraints:

$$S_r^{th}(\text{t}) - S_r^{th}(\text{t} - 1) = \eta_{ice}^{ch} * CL_{s,r}^{th}(\text{t}) - \frac{\delta_{ice,r}^{th}(t)}{\eta_{ice}^{dis}} \tag{44}$$

$$S_r^{th}(\text{t}) \leq X_{ice,r}^{th} \tag{45}$$

$$\delta_{ice,r}^{th}(t)/\eta_{ice}^{dis} \leq X_{ice,r}^{th} * lim_{dis}\% \tag{46}$$

Chiller constraints:

$$CL_{d,r}^{th}(\text{t}) + CL_{s,r}^{th}(\text{t}) \leq X_{chiller,r}^{th} \tag{47}$$

$$CL_{s,r}^{th}(\text{t}) * \eta_{ice}^{ch} \leq X_{ice,r}^{th} * lim_{ch}\% \tag{48}$$

D.5 Demand response program

The system cost savings by such programs could come from deploying fewer system-wide peaky generators, calculated in equation (49), and planning for smaller size of transmission and distribution systems, which is discussed in section 4.1 based on ANDE's master plan. In the meantime, the rewards for participants providing them incentives to applying demand-side technology such as behind-the-meter solar panels or on-site ice storage system.

Unit energy cost saving provided by reduction in generation capacity is estimated by:

$$\frac{C_{exp} * R_{exp} + C_{batt,e} * R_{batt}}{r} \tag{49}$$

Where R_{exp} represents reduced capacity of expensive resources generator, R_{batt} denotes reduced capacity of battery, and r is total energy reduced by the program. Fuel cost is not included in above equation. Grid operators' annual saving for each KW generator reduction is estimated as:

$$\frac{C_{exp} * R_{exp} + C_{batt,e} * R_{batt}}{R} \tag{50}$$

Where R represents reduction of peak load by the DR event. The benefit for program participants for every 1 kW peak they pledged to reduce upon called for DR reactions can be calculated as:

$$\frac{C_{exp} * R_{exp} + C_{batt,e} * R_{batt} + C_{exp,fuel} * r}{\frac{r}{h}} \tag{51}$$

Where h represents total hours of DR events involved by the participant during a year.

Appendix E. Cooling load extraction methodology

As most air conditioner possession is in Metropolitan area, as shown in table AX-E1, hourly outdoor temperature record for this study is obtained from the observation station at Silvio Pettirossi International Airport.[45]

Table AX-E1. Air conditioner (AC) possession aggregated by load zones[46]

Load zone	Household in zone	AC possession	AC possession rate
South	235773	96226	41%
East	283931	138899	49%
Central	380728	101602	27%
Metropolitan	869015	497072	57%
North	114296	34306	30%
West	20865		

Figure AX-E1 shows the relation between power load associated with Asuncion's temperature for each hour in year 2019. Intuitively, there is an obvious dependence between national electric power load and outdoor temperature. The red line is plotted by the 'local fit' function. We assume the seasonal change in power load can be perfectly explained by the change of weather, and can be attributed to cooling demand. A 2-stage piecewise linear relation can be approximated between load and temperature based on observation of figure AX-E1. Since gross electric load is almost irrelevant with temperature at lower temperature stage, the only thing that is mattered at this first stage is a threshold temperature that separate the two stages, which coarsely represents the lowest temperature most people start to turn on their air conditioner. Thus, a linear model is fitted only for the second stage.

The linear model we fit is shown in equation (52). The second variable in the equation serves as a seasonal cooling behavior correction factor, which designed to reduce unreasonable cooling demand during cool winter days. This factor is also preferably chosen by an evolutionary symbolic regression tool47 among other options that are correlated with national electric load.

$$load = x_1 * temp(^oC) + x_2 * \cos(2\pi * \frac{hour}{8760}) + x_3 \tag{52}$$

[45] Integrated surface data, NCEI, 2021
[46] DGEEC, Encuesta Permanente de Hogares 2000-2016, Encuesta Permanente de Hogares Continua, 2017-2019
[47] Schmidt, M., & Lipson, H. (2009). Distilling free-form natural laws from experimental data. science, 324(5923), 81-85.

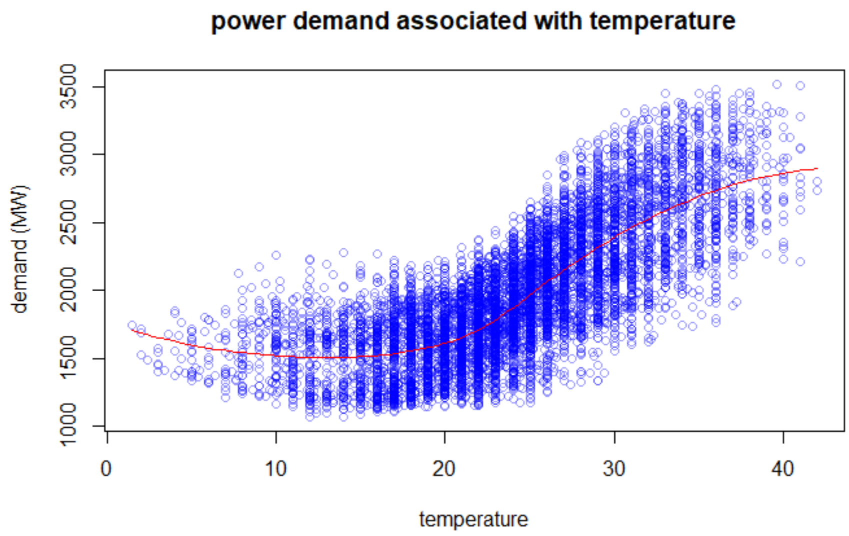


Figure AX-E1. SIN load associated with outdoor temperature for each hour in year 2019

In order to find the starting temperature that effect electricity load, multiple models with different starting temperature were fitted and we choose the best model by statistic inference provided by model R^2 statistic and standard deviation. The result is recorded in table AX-E2.

Table AX-E2. Regression model inference

Base load temp (°C)	Sample size	Model R^2	std
12	8368	0.648	286.3
13	8271	0.651	284.6
14	8155	0.655	282.7
15	8009	0.659	280.8
16	7794	0.658	280.0
17	7460	0.658	278.1
18	7089	0.658	276.6
19	6730	0.650	277.4
20	6318	0.638	279.4
21	5842	0.624	281.0
22	5249	0.603	283.0
23	4669	0.571	288.0
24	4105	0.532	294.9

We choose the best model that started from 18°C. Then, we fit the model by aggregating data by hour in a day and by weekdays and weekends.

The resulting model parameters are shown in figure AX-E2, which can reflect the power load's dependency on outdoor temperature at each hour. It can be noted that the daily pattern of model parameters shown good alignment with the national electricity load profile.

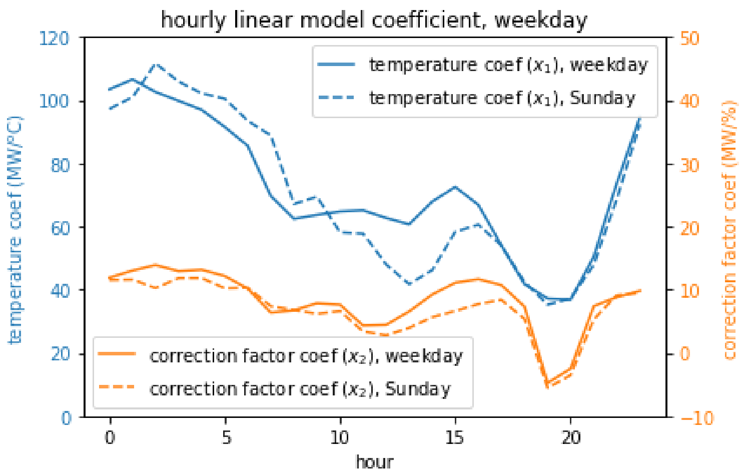


Figure AX-E2. Linear model parameters, model fitted for each hour in a day and divided into weekdays and weekends

Refit the model with temperature records of year 2019 and correlation factors, the approximate hourly cooling load is therefore obtained.

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