Limitations of thermal power plants to solar and wind development in Brazil

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Abstract

Some three fourths of electricity generation in Brazil come from renewables. Most of it is supplied by hydro, complemented by biomass-fueled thermal power plants and wind, while solar is still irrelevant. However, in the medium and long terms, a strong growth is expected for wind and solar in the country. Solar and wind resources are variable in time, partially unpredictable and cannot be dispatched to meet the load. These characteristics require system flexibility, which is the capacity of the power grid to adapt to different supply and demand patterns. Given that most thermal plants are not designed for a large frequency of operating cycles, renewables penetration may result in higher maintenance and operating costs, increased fuel consumption and reduced lifetime. Furthermore, some units might be called out-off-merit to maintain voltage and frequency levels. This paper presents preliminary results on the ability of thermal units to provide flexibility to the country´s grid, through an analysis for the Northeast region bounded by transmission constraints among 65 nodes (out of 196 nodes along the country). Results show that the power sector in Brazil might not be well equipped to deal with high penetration rates of variable renewable energy sources, with impacts on the capacity factor, and on the efficiency, of thermal power plants in the country. They also reveal that while wind energy increases the need of ramping capabilities, solar has greater impacts on the number of starts and shutdowns of conventional units.

Keywords: Variable Renewable Energy, Wind Power, Solar Photovoltaic Power, Operation Model, Brazil

1 - Introduction

Intermittent or variable renewable energy (VAR) is characterized by an inconstant generation in time, partially unpredictable and *undispatchable*. The issue of VAR has been gaining notoriety around the world due to the increasing contribution of wind and solar photovoltaic generation in power systems. Presently, the overall world electricity system is estimated to comprise 370 GW of installed wind turbines [1] and 140 GWp of installed photovoltaic systems [2].

At low levels of penetration, VAR should be treated as any other normal fluctuation in supply and demand and which cannot be predicted accurately [3]. This stage requires load/supply real-time monitoring, but not much more than the already commonly addressed in load sensitive regions as Brazil. In fact, along the different regions of the country, wide load peaks due to extreme temperatures and weather events can lead to high load ramp in a short period of time. Moreover, even *dispatchable* sources such as coal or natural gas thermal power plants have unplanned downtime events, bringing this other aspect to be considered by the system operator.

However, large levels of VAR integration bring additional complexity to the system and the already existing flexible sources may no longer be sufficient. For instance, countries like Germany and Italy, already with large VAR installed capacities, found themselves obliged to slow down penetration of renewables due to operational and financial constraints [4]. From the inherent system adaptation, a marginal cost of integration should be considered for the system design and operation [3,5].

Hence, there may be an upper limit for VAR participation, from which the marginal utility with the incremental VAR installed capacity decreases [6]. This would increase the levelized cost of energy, implying in the need for complementary technologies [7,8].

A primary effect usually noticed with VAR integration is the need to increase or reduce the system load in a short time. With this increase/decrease of the net load in a short time, one or more of the following measures should be implemented in order to maintain the balance between supply and demand [9]:

- Dispatch eligible generators should increase/decrease power;
- Demand should increase/decrease load;
- Variable energy must be stored or stored energy must be released; and
- Variable energy must be exported or energy must be imported through high voltage transmission lines.

The most remarkable aspect for determining the power plant capacity to provide flexibility in a given moment is its situation in the previous moment. For example, plants in operation at full power are able only to decrease power, as well as plants out of operation require a minimum time to reach minimum stable power to begin operation. In this sense, the designated mode of operation of the plant (based, mi-merit or peak) may indicate in which *power stage* a specific power plant is more likely to be, depending on the technology used and its operational costs. Fuel availability, specific operational guidelines, flood maintenance in rivers, fish preservation or maintenance of water resources domestic use are strict delimiters of flexibility capacity [10,11].

This study is part of a larger investigation addressing the impacts of variable renewable integration in the Brazilian power grid. As a first step and targeting this goal, the Brazilian Northeast was considered, since this region presents the largest VAR (wind plus solar) installed capacity in the country. To do so, Northeast operation profiles were tested for different sun and wind integration throughout a year. In summary, the main objective of this paper is to analyze how extensive VAR integration in the Northeast region of Brazil will affect the performance of thermal power plants and consequently the efficiency of the system.

The paper is organized as follows. Section 2 describes the Brazilian electricity system and in particular the Northeast transmission network, along with the modeling approach and data used for the analysis. It also makes an overview of the electricity production system in the Northeast. Results are detailed and analyzed in section 3 and conclusions and directions for future work are summarized in section 4.

2 - Study Area, Methods and Data Preparation

The Brazilian dispatching process follows a traditional incremental cost approach including not only operational aspects but also socio-environmental ones. The problem is addressed by establishing a ranking of the power plants according to their marginal costs, resulting in a merit order from the least to the highest cost. This problem presents high complexity due to the need to include other issues such as the stating costs, ramp-up and ramp-down restrictions or transmission and environmental restrictions. Once in operation, the power group must be kept in operation during a certain time interval before being shut-down. Once this happens, the plant must be kept out of the grid during a minimum time before starting operation. These and other technical and operational conditions must then be fully recognized and included in the dispatching model.

The Brazilian electricity system is complex and relies on a mix of technologies, with high prevalence of hydropower plants. In 2014, more than 60% of electricity produced in the country came from hydropower plants, followed by natural gas, biomass, nuclear and others. Wind and photovoltaic have yet a small expression but are planned to play a relevant role in the near future [12]. The Brazilian electricity system comprises about 140 GW in installed capacity, which includes 128 GW of synchronous generation (hydro and thermal units). The national interconnected system has about 129 thousand kilometers in transmission lines [13]. In order to reduce complexity and in a first attempt to model the Brazilian electricity system, this paper addresses the particular case of the northeast region characterized by high wind and solar energy potential, where important projects are planned to be installed during the next years.

Here, the Northeast system is modelled using the PLEXOS software, a dispatch simulation program from Energy Exemplar widely applied on energy studies [14-17]. The program uses a set of input parameters such as maximum capacity, minimum stable level, ramp constraints, reserve provision, forced outage rates, among much others. Generation constraints in an hourly, daily or yearly basis could also be added, such as max/min energy, max/min capacity factor, max/min unit starts and must run units. As a result, the model determines the optimal generation schedule of each individual power station.

The PLEXOS model was populated here with individual unit characteristics and technical details for each of the northeast power plants. The region has been modelled as an *autonomous* grid exchanging electricity with the north and mid-west/southeast Brazilian regions. Regarding the natural resources, hourly wind and sun profiles for different sites in the region were assessed.

The Brazilian ten-year energy plan for 2024 [12] suggests that wind installed capacity will be four times higher than it is today, reaching 24 GW for the entire country in that year. Solar PV capacity is also expected to present a high growth, reaching 7 GWp also in 2024. For this study, five different VAR integration cases have been assumed based on the Brazilian ten-year plan, including the base case which is the current Northeast installed capacity. Although this expected future capacity comprises the entire country, higher integration scenarios were tested in case that this entire capacity power was installed in the Northeast, as follows:

- Base Case: Current Northeast Energy System (5 GW Wind)
- Case PV 7 GW: Current Electricity System + PV Additional Capacity (7 GW)

- Case Wind 12 GW: Current Electricity System + Wind Additional Capacity (Additional Wind 7 GW)
- Case Wind 24 GW: Current Electricity System + Wind Additional Capacity (Additional Wind 19 GW)
- Case PV 7 GW + 24 GW: Current Electricity System + Wind Additional (Additional 19 GW) + PV Additional (7 GW)

2.1 - Study Area

The quality of wind and sun resources for electricity generation is very high in the northeast region. The solar resource is prominent in the northeast, notably in the north of Bahia due to the semi-arid climate of the region, characterized by its low cloudiness throughout the year [18]. The best wind resource is observed in the northeast coastal area. In the northeastern countryside inside there is good availability in heights of inner Bahia [19].

According to [20], the photovoltaic potential from centralized power plants in Brazil is around 360 GWp. The approach has taken into account the availability of land not intended for other activities, areas with a distance up to 5 km from high voltage transmission lines and assuming that 1 km^2 could fit 50 MWp in installed capacity. Then a reduction coefficient of 1.67% has been applied based on the work of [21]. From socio-economic characteristics such as household income, energy consumption, availability of roofs, load curve, cost of capital and financing conditions, [22] found a technical potential of approximately 40 GWp or about 54 TWh/year for solar photovoltaic distributed generation.

According to [23], the Brazilian gross wind potential is 7,374 GW, in which approximately 10% is technically feasible for generation. The northeast has a technical feasibility about 38 GW over an area of 4,124 km^2.

2.1.1 – Northeast Transmission Network

For the proposed model, the transmission network is described by nodes and lines. A node represents a bus in the network and the line represent any type of transmission line (AC or DC). In order to measure transmission losses in AC lines, the impedance of the network is represented through resistance and reactance values. The model simulates the transmission between two nodes under the Kirchhoff's circuit laws determining the level of losses in the system and the incidence transmission constraints along it.

The northeast transmission network has 72 thousand km in total, including 500 kV and 230 KV lines[1]. For this study, it was assumed that transmission lines connect 65 nodes along the region (Figure 1). For each of the 114 lines considered, the specific value of maximum flow capacity was inputted from [24] assumed to be directly proportional to its operational voltage and current. Initially, only the so-called *operation current in the long run* has been considered, that is the amount of capacity that the line is able to transport at normal conditions [25].

The Northeast region exchanges energy along North and Midwest/Southeast through high voltage transmission lines (colored in blue in figure 1). The flow in/out depends on the regional prices of electricity, defined on a weekly basis by the system operator. Usually, northeast is a net importer on a daily basis, although it has been a net exporter in many days of 2014, due the drought in southeast reservoirs [26]. From this example, it can be

[1] Distribution network have not been considered.

noted that the energy generation as well as the import/export among regions aims at the optimization of generation costs in the short run, constrained by technical aspects of transmission and physical issues of the energy sources. Particularly relevant is the need to maintain certain levels of water in Brazilian hydroelectric reservoirs. Thus, the system operator has to quantify the present benefit of water use and the future benefit of storage (or energy storage), measured in terms of the expected fuel consumption (or savings) in Brazilian thermal plants. The lower the level of hydro reservoirs, the greater will be the energy regional prices [27].

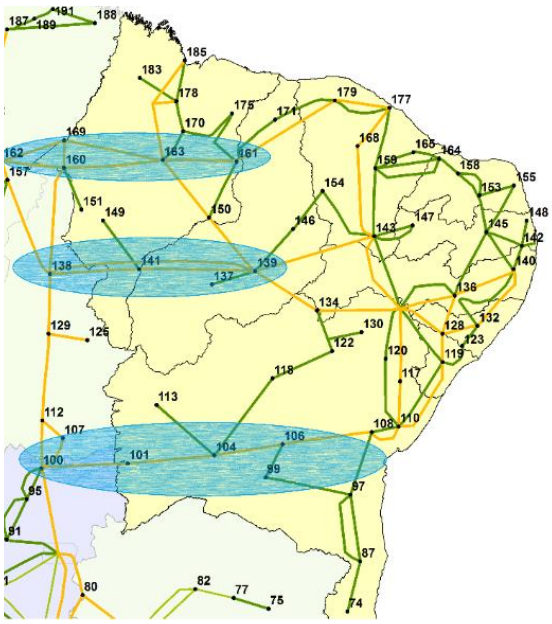

Figure 1- Northeast transmission network and nodes

Having in mind that the system has been modelled for a one-year operation future aspects beyond that period were not considered. Regional pricing dynamics aspects have been not included also. Instead, in order to quantify the interchange of external energy from the north and mid-west/southeast, a simple generator approach was applied in each of these regions with no operation costs. The total installed capacity was defined as equal to the maximum flow capacity that the northeast could import from each of these regions. Besides, a maximum energy import was defined (MWa) from each of these regions for every month, based in the historical exchange among these regions [28].

Each node is characterized by an object of the systems – generating units and load points – which act as positive (generation) or negative charges (demand load) (Table 1). For every hour of the year, each node generates, imports or exports certain amount of energy. An over generation and a resulting energy waste may be observed at a node in certain conditions such as the lack of transmission capacity out of the node and/or constrains applied to a specific generating unit, that are forcing certain levels of generation. This might be the case of non-storable variable renewable energy or may derive from some inflexibility capacity constraints of conventional generating units.

Table 1 – Node Characteristics for all cases (upper) and for the specific cases (below)

All cases	**Nodes in Service**	79	**AC Lines**	114	**AC Paths**	105
	Load Points	56	**Total Lines**	114		

		Base	**PV 7GW**	**Wind 12 GW**	**Wind 24 GW**	**Wind 24 GW + PV 7 GW**
Specific Cases	**Generators in Service**	256	522	571	1,034	1,299
	Gen. Injection Points	60	62	62	62	62
	Total Injection Points	77	79	79	79	79

After the first simulation, some transmission lines were found congested at specific times of the year. To fix it, the *operation current in the short run* has been added on specific lines, that is an additional capacity, technically available, but that by regulation should be used only for 4 hours at overload periods and in emergency cases [29]. The measure allowed for a better energy flow along the system reducing non-load service rate.

2.1.2 – Load Data

All northeast cities have been related to a node, through a geographic information system process. Load data was considered on an hourly basis departing from real information taken from the northeast operation, according to data obtained from generation units under the system operator decision. These values comprise about 87% of the total load of the Northeast region[2]. The remaining capacity is not dispatched by the operator and consists of small diesel oil generators, distributed generation and others. In 2013, the total demand was 81.34 TWh, with a peak power of 11,702 MW. This peak moment occurred on December, 4th, at 15h.

Since the load data curve is aggregated to the whole region, a further step was needed in order to get a proxy for disaggregation of the energy consumption in each city. For each one of 1,794 northeast cities, the disaggregation of the electricity consumption was assumed to be proportional to the number of households within specific electricity consumption levels according to [30]. Through this approach, it was possible to harness each city to a small share of the total northeast load curve (Figure 2).

[2] Data have been accessed by personal contact direct to the system operator (ONS) staff.

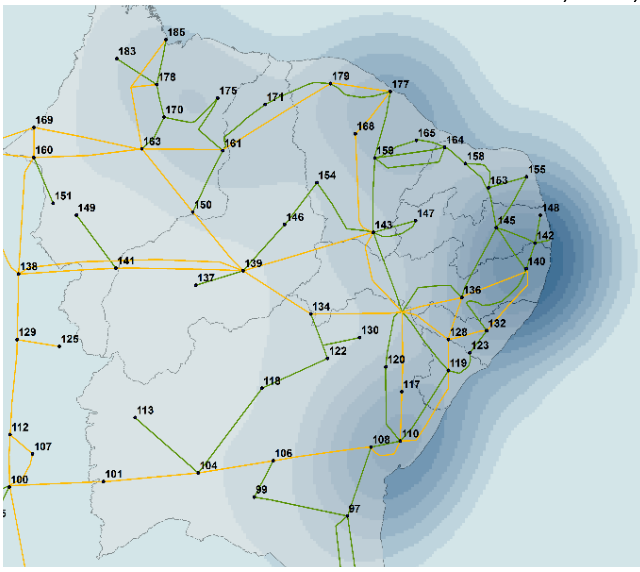

Figure 2- Northeast Load share distribution

2.2 –Northeast Installed Capacity

Fossil fuels share in the northeast power system are close to the values for the entire Brazilian system (31%), while hydro is lower (45%) and wind is significantly higher (18%) [31,32]. For this study, the base case system assumed a total installed capacity of 34.13 GW (Table 2). For the modelling, the addition wind and solar PV capacity is assumed as previously mentioned.

Table 2- Base Case Northeast Installed Capacity

	Power Plants	**Capacity (MW)**
Biogas	1	19.73
Biomass*	25	1,266.29
Coal	4	1,520.60
Diesel Light Oil	12	896.86
Dual Fuel (NG + Oil)	1	346.803
Fuel Oil	13	2,241.37
Solar PV	1	11,65
Hydro	10	10,245
Natural Gas (CCGT)	8	1,776.73
Natural Gas (OCGT)	1	219.077
Wind	165	4,086.01

*sugar cane, elephant grass, wood residues and black liquor

Source: ANEEL [2015]

2.2.1 – Variable Renewable Energy

According to the Brazilian ten-year plan [12], about 7 GW of the power system will consist of centralized photovoltaic plants and 24 GW of wind plants in 2024. The photovoltaic distributed generation may reach 3.5 GW in 2025, from which 578 MW would be allocated in the northeast [22].

The first new wind and solar plants should emerge firstly in high potential regions as well as high-density urban locations and/or high electricity requirements in case of distributed systems. For this study, the location and installed capacity of new power plants is based on projects that have been already registered in the government (Figure 3 and Figure 4). The Electricity Energy National Agency (ANEEL) publishes the geographic location of all wind and solar photovoltaic projects that already has the required documentation to apply on government auctions or a license to build. Many of these projects may never be implemented, but are excellent indicators of suitable sites (registered projects in figures 3 and 4). The documents present also the intended nominal capacity of the project representing a good proxy for the possible installed capacity in the medium and long term [33]. Specifically, for solar distributed generation locations were taken from [22].

Solar PV hourly generation has been modelled through the System Advisor Model (SAM) from the National Renewable Energy Laboratory (US Department of Energy). SAM is a deterministic model, so an input data set always results in the same output data set. The Brazilian solar resource was taken from [34,35]. The hourly resource was created from measurements at weather stations of the National Institute of Meteorology (INMET), between the years 2000 and 2010. In order to simplify the modelling, twenty solar resource sites were chosen in the northeast region. Thus, every new PV power plant uses the closest solar resource data (Figure 3).

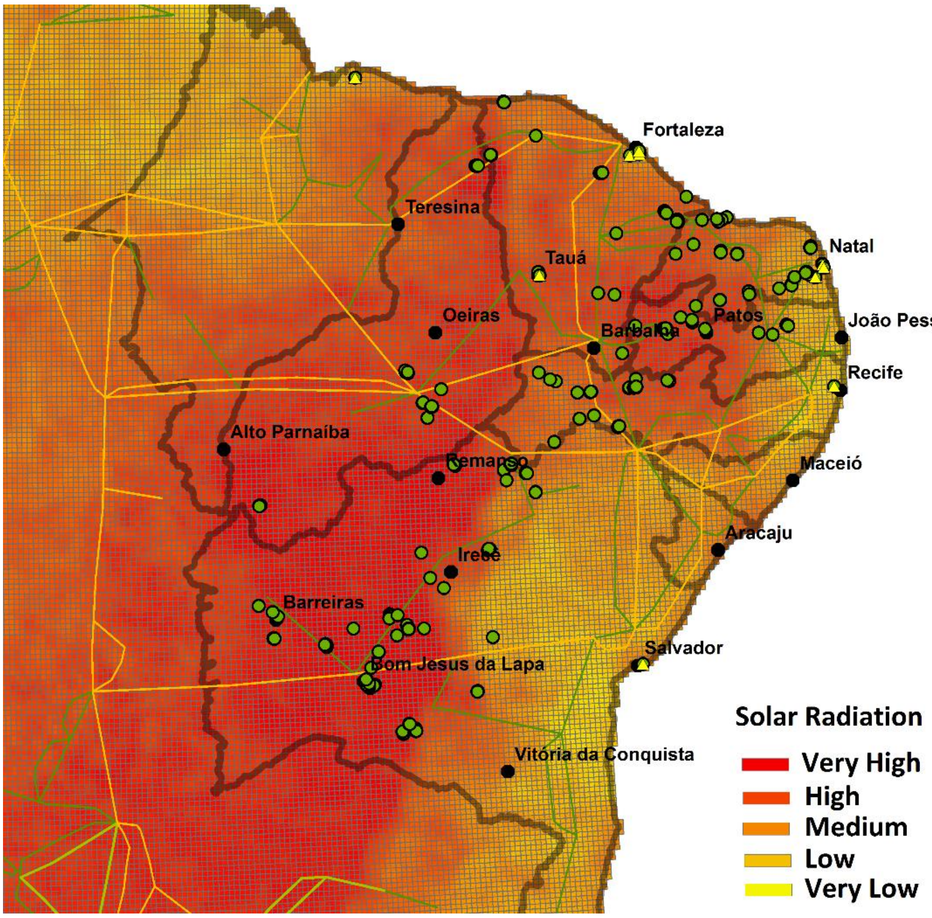

Figure 3- Northeast Solar Resource Map (10 km), Solar Resource Spots (black dots), Current PV Plants (yellow triangles) and Registered Projects (green dots)

Source: Own development, based on [18,34-36]

Like the solar resource, wind data was taken from [34,35]. Similarly, eight wind resource sites were chosen in the northeast region making sure that for each one of the included wind power plant the closest wind resource data was considered (Figure 4).

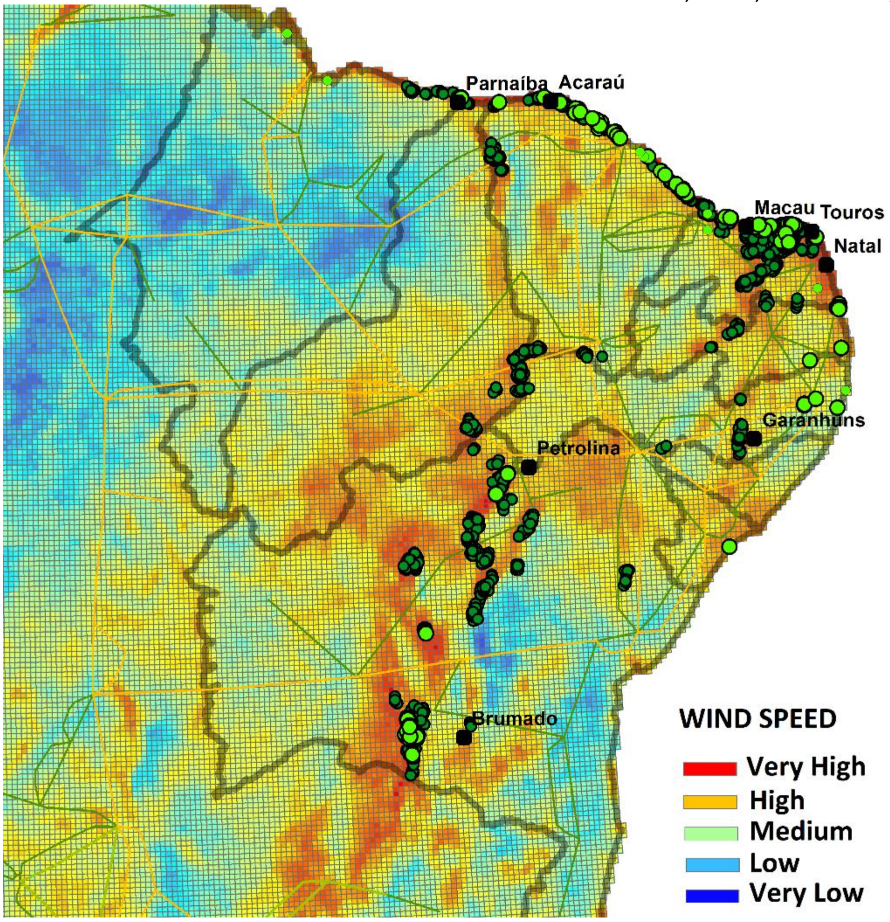

Figure 4- Northeast Wind Speed Resource Map (10 km), Wind Spots (black dots), Current Wind Plants (light green dots) and Registered Projects (dark green dots)

Source: Own development, based on [18,34-36]

2.2.2 – Thermal Power Units

For this study, only thermal power plants with an installed capacity of at least 15 MW were included in the model. The thermal power fleet reaches 8.28 GW and is composed by coal, natural gas, fuel oil-, diesel oil-, biomass- and biogas-fueled power plants. All thermal units were related to a specific node through the GIS tool. The thermal power unit commitment has been modeled considering a set of technical and economic constraints, as follows.

- Start run up rate and Operational Minimum stable level
- Heat Rate Curve
- Ramping gradients
- Min up/down time

Technical information about these operational performances was obtained from different sources [37-44].

Run up rate is defined in the model by a ramping limit that applies to the generator profile while it is running from zero to a minimum stable level. Otherwise, the model would consider that generating units would run up instantaneously. Ramping gradients defines the amount of power that can increase between minimum stable capacity and full load.

Minimum up/down time are the minimum number of hours the unit must be on/off in any commitment cycle.

Costs related to heating/cooling boilers, fuel used to start turbines, water losses and others, commonly defined as startup costs were taken from [45,46]. Variable costs (CVU) have been taken from Brazilian operation official data [47] for each of thermal plants, comprising all operational costs, as maintenance and fuel. Fixed costs for the connection to the grid and by the use of the transmission network have not been considered, since those are assumed to be similar for all technologies.

Operation of thermal power plants below full load design usually runs with an additional cost due to a less efficient operation. The further from the designed power operation, the smaller is the plant conversion efficiency and thus the higher will be the fuel consumption per unit of electricity produced (Figure 5). Heat rate curves used for this study were taken from manufactures and previously studies.

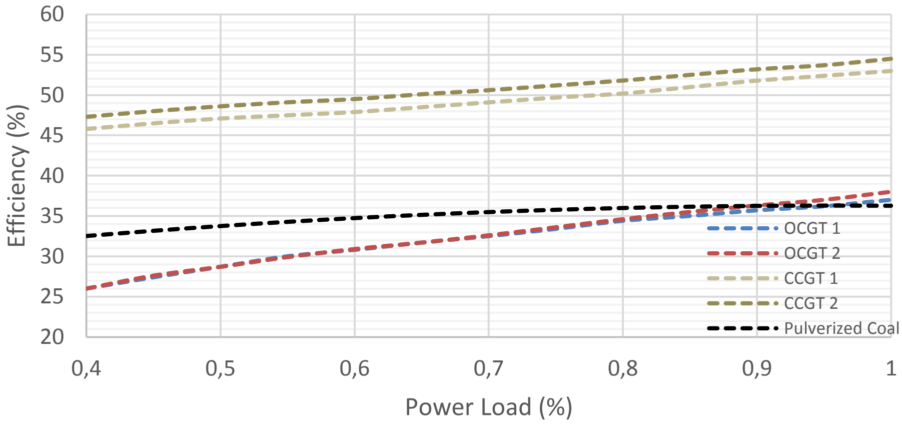

Figure 5 – Thermal power plants efficiency at 25 ºC for distinct operation load points

A capacity inflexibility was also considered in some power plants, which in practice means a constraint of minimum generation that should not be violated. In the Brazilian operation, this inflexibility is usually related to the power plant fuel contract that requires the purchase of a pre-defined amount of the product, as occurs in take-or-pay schemes for natural gas. It may occur also due to technical constraints related to equipment or the plant processes [48,49]. It should be noted, however, that fuel availability itself has not been considered in this study, with the exception of biomass.

Unlike conventional thermal generation, biomass yearly profiles have been assessed based on the resource availability throughout the year [50-51]. Resources used in thermal units are sugarcane, elephant grass, wood residues and black liquor. The seasonal variability of all crops were based on sugarcane´s information given its importance in the region, although at least black liquor should have a more stable availability during the year. The northeast sugar cane crop begins in September and stands until around May. It should be noted the difference between the harvest to the southeast, where this cycle starts in May [52].

2.2.3 – Hydro Power Units

Only medium and large hydropower units were included in the model and the installed capacity reaches around 10 GW in the northeast region. All hydro units were related to a specific node through the GIS tool. Hydroelectric is the most suitable and flexible source of energy to balance load and supply power variations, coupled with a relative small loss of efficiency when operating below its power design.

For modelling purposes, it should bear in mind that hydro unit almost do not work under a start engine profile, given its great speed to increase power. For all units modelled, a maximum ramp up of 50 MW/min was considered based on previously studies, which may be considered conservative. It was assumed that all hydro units can generate up to the maximum hydro energy registered in the northeast in 2015 generation [53]. Aiming to stress thermal plants operation under VAR integration, hydropower potential have been simplified for this study. To do so, a maximum power capacity have been delimited on a monthly basis. The hill graph below (Figure 6) represents a hydraulic production equation for *Sobradinho* hydro plant, where one axis is volume (hm3), the other is outflow (m3/s) and results in power (MW). It also takes into account the turbine and generator efficiency [54].

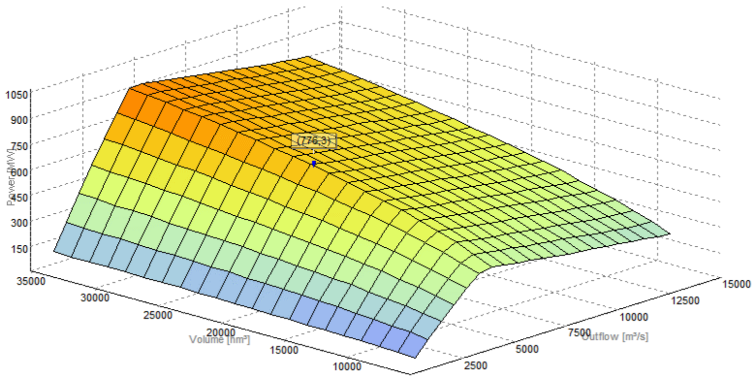

Figure 6 - Sobradinho Power Plant Hill chart

Source: 53

The hydroelectric production hill chart has been analyzed for 10 hydropower plants out 13 units modelled within the model (the remaining 3 are small units) in combination with historical inflow [55] (Figure 7). Finally, the maximum power capacity for each month was taken from the hill chart, given the average inflow value and considering the lower volume value available for this configuration.

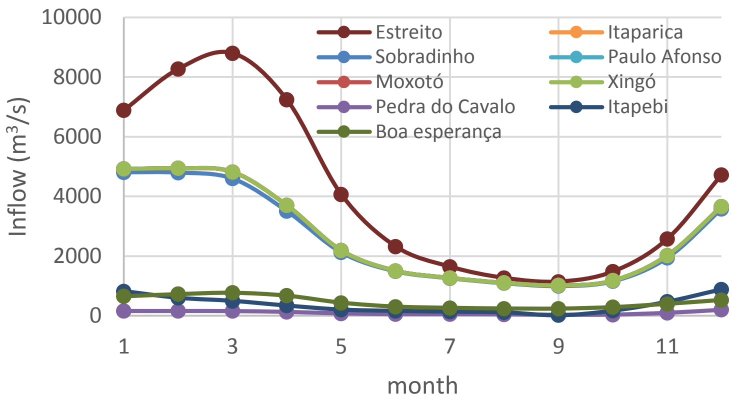

Figure 7- Inflow Average (year 1934-2015)
Source: [55]

3 – Results

The analysis carried out in this study examines preliminary results related to the dispatch operation of conventional power plants due the integration of wind and solar in the Brazilian Northeast. In this section, generation profiles for some of the case studies are presented for a week in January and another in August, in order to detect two distinct moments during the year regarding the availability of hydro, sun and wind resources.

The first impact on the conventional power generation sources is the decrease of their capacity factor, as wind and sun are "must run" units (Table 3). Diesel and fuel oil are too expensive and have already low operation in the base case, which remains valid for VAR integration simulations[3]. Biomass and biogas are almost zero-cost operation and these plants run whenever possible. This explains their operation at the base load during months with biomass fuel availability as January. Among gas and coal, the latter presents lower operational cost[4] and fits better in the base load because of its lower flexibility. Natural gas role as a flexibility provider seems to become evident when one observes the significant decrease of the capacity factor even for the relative low wind or PV integration (Wind 12 GW or PV 7 GW) case, but quite enough to keep it much of the time as a power modulator. This becomes even clearer when one looks for the smaller reduction of the capacity factor of natural gas power plants from the low wind and pv cases to the following ones. This is exactly the opposite of what is noted for coal, as for small wind penetration the capacity factor decrease is not as sharp, but becomes more pronounced for large wind penetrations. This shows that as wind power increase, coal power plants tend to reduce their role as base load producers.

Table 3- Capacity factor and Fuel Use for each of the cases assessed

	Capacity Factor (%)				
	Base	**PV 7 GW**	**Wind 12 GW**	**Wind 24 GW**	**Wind 24 GW + PV 7 GW**
Biomass/Biogas	50.29	50.32	48.99	45.13	40.66
Coal	97.33	84.14	75.63	36.03	18.10

[3] It should bear in mind that only operation costs were considered for all power plants.
[4] Environmental costs such as with local pollution or greenhouse gases emissions were not considered.

Diesel Oil	4.17	0.45	0.43	0.33	0.32
Dual Fuel	81.76	36.09	42.76	30.42	13.09
Fuel Oil	4.10	4.62	3.15	2.66	2.40
Solar PV*	14.71	12.18	13.59	13.52	11.66
Wind**	23.05	20.48	16.07	12.56	14.07
Hydro	71.91	69.56	73.05	70.94	64.00
Natural Gas	45.53	24.71	20.92	15.96	8.99
	Fuel Use of Thermal Plants				
Specific Fuel Cons.*** (TJ/GWh)	9.55	10.10	10.11	10.26	10.68
Total**** (TJ)	251	204	178	103	70

*PV reference capacity factor: 14.85 percent

**Wind reference capacity factor: 24.06 percent

*Specific fuel consumption of thermal power plants

**Thousands

One may ask why wind and PV capacity factors decrease with their increasing installed capacity. This occurs because of the wind and PV energy surpluses in a given node (thus not consumed in the node) and that are also not transmitted out of the node, either because of a lack of transmission capacity or because of a lack of demand outside the node. Actually, this energy is not produced and this is reflected for example in the shutdown of wind turbines. Precisely this aspect might be one frame for the maximum wind and PV penetration viable in the system. For the very large VAR penetration (Wind 24 GW+PV 7 GW), wind decreases to around 14%, which should not be economically feasible. This means a reduction of 10% if compared to wind reference capacity factor, that refers to the average among all the chosen sites if the same amount of capacity were installed in each one (for instance 1 MW). In other words, reference would be the wind and PV capacity factor (or a proxy of it, since one site may have a bigger installed capacity than other) if all the energy that the systems are able to produce were actually consumed.

In the case of the thermal units, the less efficient operation (fuel consumed per energy produced) to some extent occurs because of the lowest capacity factors, since for these cases power plants tend to operate closer to its minimum stable level. For the low wind case, the highest efficiency loss occurs in the gas units. The reduction of efficiency is also higher from the base case to the low wind case, than from the low wind case to the high wind case. It should be noted that heat rate curves were not applied on biomass, fuel and diesel oil in this study, so the fuel use variation is due only to a non-optimal operation in both coal and natural gas plants. On the other hand, since the thermal units produce less energy with VAR integration, they also consume less fuel (TJ). The high and wind and PV cases consumes around 28% of what was consumed in the base case.

The base case it supposed to be a picture of the current operation dispatch in the northeast region (Figure 8). In general, coal and biomass act as base load and at some extent hydropower. It should be noted that, for this exercise, hydropower was not modelled with the obligation to provide some power to baseload, as may occur in real operation.

The main differences between the operation in January and August regards the water and biomass availability. For this reason, the second semester presents a significant increase on the generation and ramping from natural gas turbines. This also results in the increase of imports from the north and mid-west/southeast regions. Regarding sun and wind, the latter presents some decrease in its generation, while sun is still negligible.

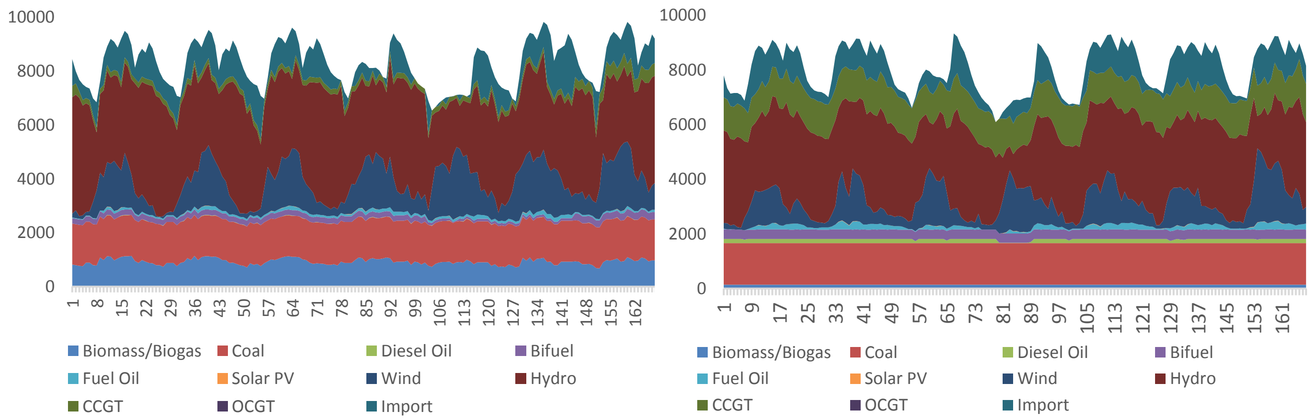

Figure 8 - Generation profile for the base case i) week in January ii) week in August

It seems that while the wind integration has greater impacts on ramping occurrence of conventional power plants, solar photovoltaics has more influence on the number of starts and shutdowns (Figure 9). This may be explained by each resource profile. While wind has small and medium variations during 24 hours (ramping need events), the sun produces a *block of electricity all at once* (Figure 10) that appears in the morning (shutdown need) and ends by the sunset (startup need). It is obvious that the solar resource also presents variations during the day (cloudiness, environmental obstructions) but that seems to be balanced when there are various systems producing at different sites.

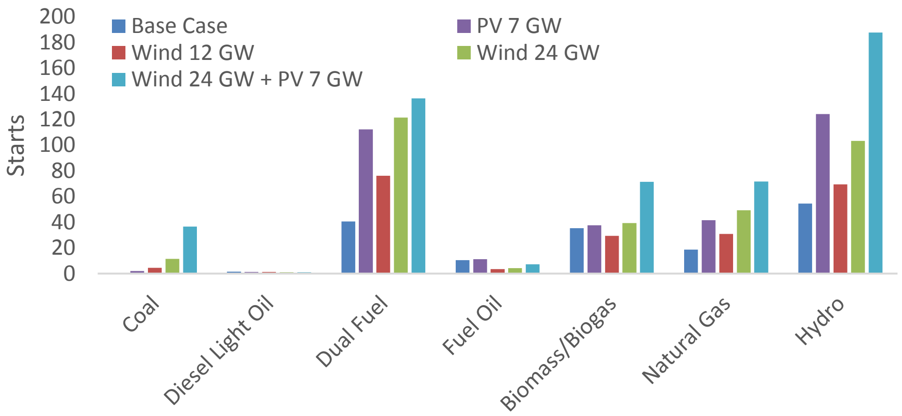

Figure 9 - Power plants start on average per technology category

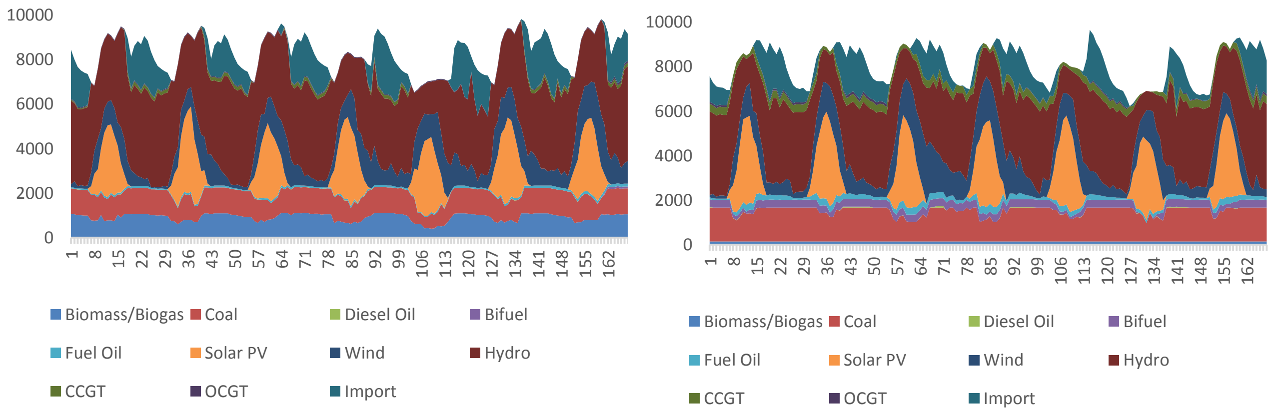

Figure 10 - Generation profile for the PV 7 GW case i) week in January ii) week in August

For the low and high wind cases (Figure 11), the increase in profile ramping is considerably more evident. The wind profile, and therefore hydro generation (since it is the main flexibility supplier), faces several up and downs. To a lesser extent, this aspect also influences coal and biomass-base generation that now is not as flat as in the base case. While in the base case the largest coal ramp up (7.2 MW/min[5]) occurs only one time, for the low wind case it occurs for 26 moments a year. For the base case, all coal units have spent 646 hour ramping up/down during the year. On a larger scale, the same applies for gas turbines, which for the base case ramps up/down for 1,937 hours and in the high wind case ramps during 3,841 hours a year. These values are even higher for the hydroelectric plants. The same happens for the high wind and PV case, although there is some balance between sun and wind, slightly easing ramping magnitudes (Figure 12 and Table 4).

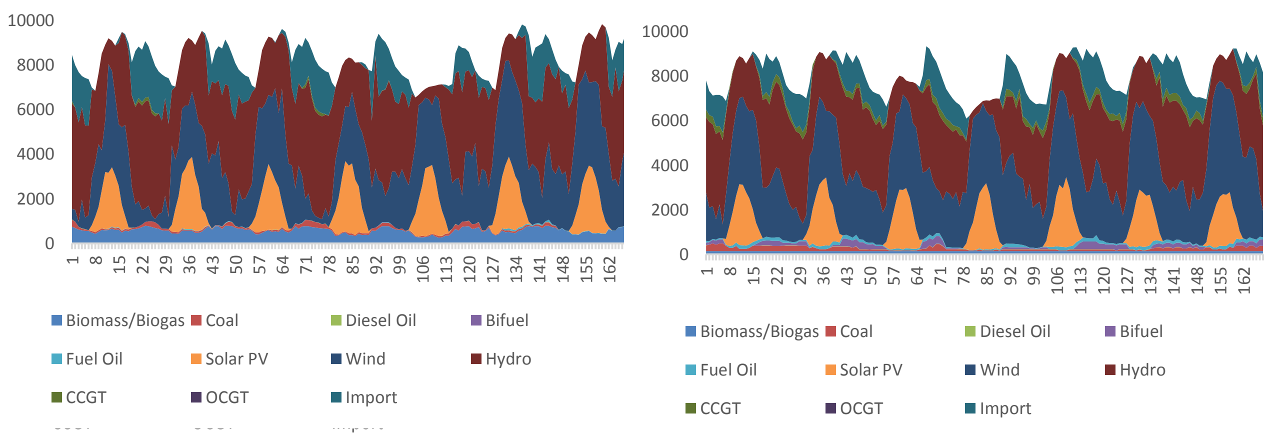

Figure 12- Generation profile for the PV 7 GW/Wind 24 GW case i) week in January ii) week in August

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[5] Observed in the largest coal power plant in northeast, that has 720 MW installed capacity. This power plant could ramp until 9.3 MW/min.

Actually, conventional power plants stay longer periods offline and remains longer times ramping when dispatched for the high VAR integration. An interesting aspect is the apparent influence of wind and solar resources in the ramp profile. While the solar profile increases ramping-up occurrence (positive ramp values), wind seems to has the opposite effect (negative ramp values) (table 4). It seems that when the sun goes into operation in the morning, the demand is not too high to require a large power reduction in conventional units. However, when it goes out in the evening, besides the decrease of the solar power at the end of the day, the system must remain at higher power levels due to the Brazilian peak period starting.

Table 4- Ramping Profile for Hydro, Natural Gas and Coal Units

	Base	PV 7 GW	Wind 12 GW	Wind 24 GW	Wind 24 GW + PV 7 GW
No ramp* →	78,32%	87,69%	81,57%	84,32%	84,32%
Ramp up ↗	10,83%	6,19%	9,20%	7,83%	7,83%
Ramp down ↘	10,84%	6,12%	9,23%	7,85%	7,85%
Máx Ramp** (MW)	1339	1533	1363	1811	1407
Higher Incidence Range (91%-93% ramps)	-11MW / +15MW	-1MW / +27MW	-26MW / +1MW	-31MW / +2MW	-10MW / +18MW

*No ramp – It means that power output is exactly the same of the time just before, including shutdown power plants that remains offline.

** Maximum ramp observed at a specific power plant, hourly ramp needs for the entire system could be even higher in this case. Because of its large magnitude, these ramps were necessarily met by hydro units.

Furthermore, it seems that there is a certain complementarity between the sun and wind that lowers the maximum ramp of conventional units in the high wind and solar case. Thus, to a greater or lesser degree, maximum ramps always increase with the integration of VAR, but it still represents a relative small share of the plant activity (Figure 13). At least 90% of yearly lifetime occurs on the ramp rage from around -30 MW to 30 MW for all cases, including no-ramp steps (Table 4 and Figure 13).

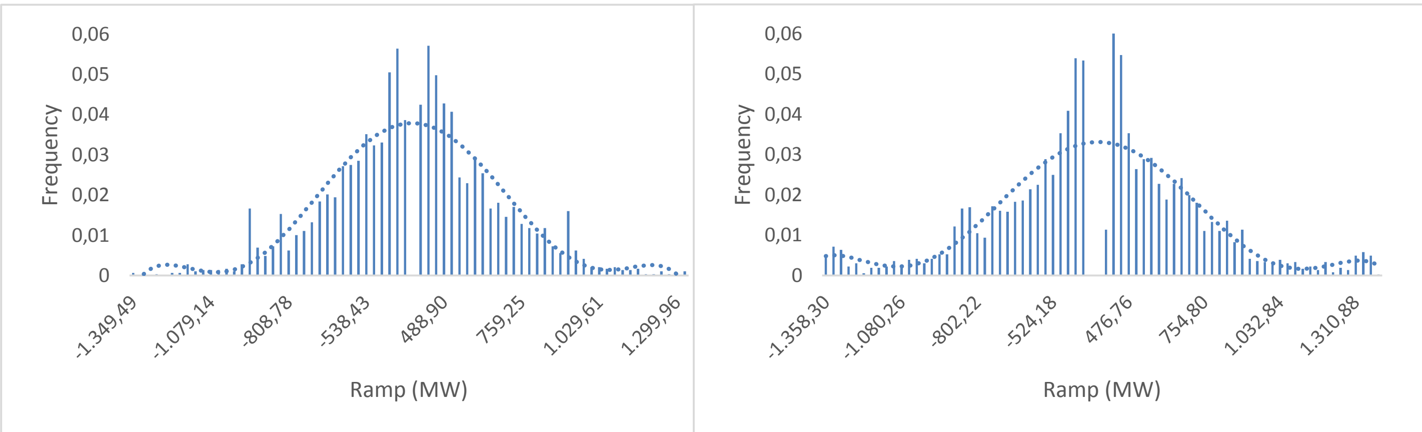

Figure 13 - Frequency within ramps greater than 400 MW for i) base case ii) PV 7 GW + Wind 24 GW

4 – Conclusions and Future Works

This paper presented a preliminary assessment of the impacts of variable renewable integration in the Brazilian power grid. As a first step, the Brazilian Northeast region was evaluated, which has outstanding wind and solar resources. Different levels of wind and solar integrations were modelled in PLEXOS software.

According to the results, the wind and solar penetration should impact the northeast electricity system, mainly through the modification on conventional units´ operation patterns. The capacity factor of conventional units tends to decrease with VAR integration, since part of the load demand is supplied by sun and wind power. This results mainly from their first position in merit order, as must run units. The decrease of the capacity factor of conventional units may result in the increase of operational costs, although we have opted to not go into detail on this point by now. It should be noted that the wind and solar capacity factor also decreases for each case. In that sense, we have shown that typical capacity factors of wind and PV system based only on their geographical resource availability (called reference capacity factor in this study) must not be considered on system energy planning scenarios, since they do not reflect reality.

From the operation model, we have found that wind and solar PV may impact the system in different ways. While wind energy increases the need of ramping capabilities, solar has a huge impact on the number of starts and shutdowns, since some conventional units will be removed from the system from long periods while solar provides a significant share of the load. With VAR integration, conventional plants tend to stay longer offline, increasing cycling values, which in turn may increase maintenance costs.

For all results, it should have in mind that the hourly model does not allow to perceive variations of minutes or even seconds in sun and wind resources or even in load demand, which may change some aspects the power plants operations.

Further steps need to go deeper in this analysis, taking in mind power plants geographic localization as well as the most important load hotspots. Besides, the flexibility from conventional units that remains at certain levels of VAR integration needs to be assessed in order to define an upper limit for it. Some operation constraints also need to be refined to better reflect the functioning of the system.

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