OPTIMUM ENERGY GENERATION MIX IN BULGARIA

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Abstract

Bulgaria's energy generation mix has been changing rapidly in the last decade. Solar photovoltaic power (PV) has grown from 3% share of electricity generation to 16% in 2025, while coal generation has fallen from 49% to 24%. This paper explores how Bulgaria can reduce its carbon dioxide (CO_2) emissions from coal generation while keeping electricity supply affordable and dependable. Using a simplified model based on actual Bulgarian data, I determine the maximum economically viable PV penetration to be 7.8 GW, supported by energy storage of 13.2 GWh. PV generation is 10.9 GWh of which 55% is fed to the grid, 43% used to charge battery energy storage systems (BESS) and 2% is curtailed. Consumers experience a benefit of €588 million per year or a 14% reduction in electric utility bills. Return on invested capital falls to the weighted average cost of capital for PV and is above the cost of capital for BESS. The share of CO_2 emissions from coal generation falls by 44% relative to 2019, which exceeds the EU guideline for the green energy transition in Bulgaria. Coal will continue to be used in the winter months but at lower levels than today, only in the four coldest months of the year, for a total generation of 6 GWh or 17% of demand. The analysis suggests there is no space for new gas capacity, while new nuclear power should be considered as replacement of existing reactors instead of capacity additions.

1. Introduction

Bulgaria has a population of about 6.5 million and uses around 35 terawatt-hours (TWh) of electricity per year. Most electricity is generated by the Kozlodui nuclear plant (about 41%) and lignite coal plants (about 24%). Solar power has reached 16% share in the last 12 months from July 2025 (“LTM”). The shares of other generation sources have been stable, with wind (3%), heating plants (CHP, 5%), and hydropower (6%) remaining small contributors.

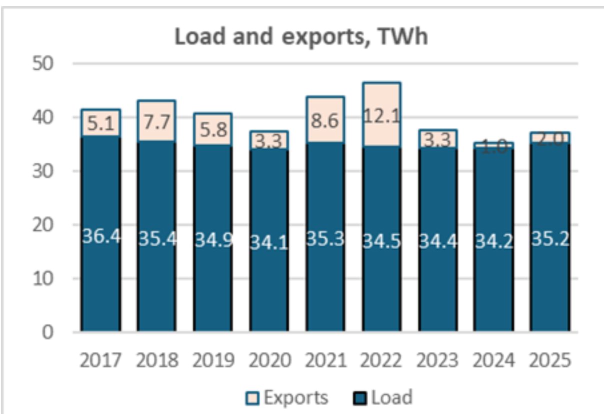

Figure 1: Bulgaria generation LTM July 2025
Source: energy-charts.info

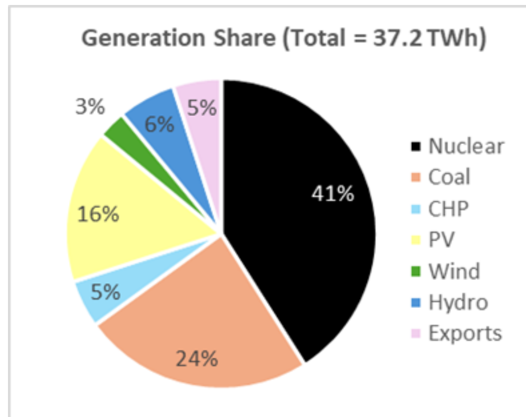

Figure 2: Generation mix

The country is well connected to its neighbors Romania, Türkiye, Greece, Macedonia, and Serbia. Temporal imbalances of daily/seasonal supply and demand have been met through exports/imports as Bulgaria has very few flexible power generation facilities. For example, there are no Combined-Cycle Gas Turbine plants (CCGTs) in the country. The generation mix in Greece and Romania is much more flexible (42% gas plant share in Greece and 21% in Romania). In a typical year, Bulgaria provides baseload power to the region with its nuclear and coal plants, while Romanian and Greek CCGTs provide flexible power generation when needed (i.e. absorb power exported from Bulgaria at noon, during the PV peak, then supply Bulgaria in the evening peak hours).

A major portion (75%) of the large power generation facilities are government owned or controlled, including the nuclear power plant Kozlodui (2 reactors at 1 GW power each, 15 TWh or 41% of the LTM energy produced), the Maritsa East 2 coal power plant (1.6 GW, 14% of the energy), the large hydro power stations (6% of the energy) and the only CHP (combined heat and power) plant (5% of energy), the 630 MW coal plant managed by AES through a long-term power purchase agreement (PPA) (9%). The remaining part of the energy is supplied by two independent coal plants, the 630 MW Bobov Dol plant and the 800 MW Maritsa East 3 plant and by many PV, wind, and small hydro independent power producers (IPPs). The average utilization of the coal plant capacity is below 30%. All producers are required to sell their output on the Bulgarian Energy Exchange at market prices; hence the wholesale market is fully competitive.

The EU requires Bulgaria to cut CO_2 emissions by 40% compared to 2019 levels by reducing lignite usage, which emits about 1.3 tons of CO_2 per megawatt-hour (MWh). Replacing coal too quickly could risk power shortages, especially during nuclear plant outages. The government is hesitant to force coal plant closures for security of energy supply reasons, as well as for social reasons (at least 20,000 people engage in mining coal, producing energy from coal, and maintaining coal plants). For example, the 2022 gas price shock increased power prices to the levels where all coal plants were profitable, and Bulgarian coal plants supported the entire region with energy. This can be seen in the exports section in Figure 1, when exports reached 12.1 TWh. A second, more recent shock occurred in November 2024, when due to delayed maintenance of one of the nuclear power plant reactors, the region again became short on energy, leading to an emergency government order to restart mothballed coal plants. Hence, any permanent reduction in coal output should be weighed against the country's security of supply needs.

1.1 Purpose of this study

The main goal of this study is to find an optimal mix of energy sources. In my context, we consider optimum to include a reduction in CO_2 emissions, keeping electricity prices stable or lower, as well as gain for investors. The only way to change the energy mix of a country is through investments in new generation sources. Therefore, the proposed changes to the mix should provide a positive return on investment, otherwise these investments are not likely to happen. The focus is on proven technologies that can be deployed in the country, such as power, battery storage, and potentially new nuclear or gas plants. The wind generation potential is also evaluated. The approach assumes minimal government involvement since government policies in the last few years have been described as inconsistent. Due to the frequent government changes (six in the last three years), the country has not been able to follow a comprehensive energy strategy.

1.2 Literature review

Scholarly papers I reviewed do not provide direct answers to the questions investors ask: "How much capital should be deployed in which generation sources?" Some predict a generation mix, but the accuracy of their predictions is inconsistent 2-3 years after publication. Often this is either because they extrapolate past trends in aggregate without accounting for the hourly generation profile for PV or because they fail to model the actual costs to investors through adapting published levelized cost of energy (Lazard LCOE+, 2025) to local conditions. For example, Kacsor, E., et al. (2025) in *Integrating solar plants into the European power grid − What is the optimal capacity combination of PV and battery storage?* assume PV capex of €430/kW which is in line with market, and BESS capex of €570/kW for a 2h battery which is 2.5x higher than actual capex of BESS deployed today. They arrive at an optimal level of BESS penetration of 5% of installed intermittent renewables power. I believe the optimal level is significantly higher and the difference is driven by the assumed LCOE difference. Other papers put faith in new generation technologies that have not yet been commercialized yet, such as hydrogen or thermal energy, etc. My analysis focuses only on mature, investable technologies, such as PV and BESS.

The Bulgarian Electric System Operator (ESO) publishes an annual 10-year network development plan (ESO, 10-year plan, 2025) that discloses total connection capacity requested by investors. The latest ESO 10-year plan predicts 7.1 GW of new PV, 0.9 GW of new wind, and 4.8 GW (equivalent to 9.6 GWh of storage at 2h) of BESS grid connection requests for the period 2025-2030 but projects only a portion of these will be installed, specifically 35% of the PV requests and 80% of the wind requests. The transmission systems operator (TSO) also suggests an alternative scenario, with full elimination of coal by 2030, by meeting the winter peak demand with 1.1 GW of newly built CCGTs and 1.4 GW of imported power. However, the economics and investor return behind this scenario are not addressed in the government report. In this research, we suggest that new CCGT capacity is likely to be ineffective in the Bulgarian environment due to low projected utilization which makes positive return on investment unlikely.

Trifonova, M. et al., (2025) in *Flexibility Assessment of the Bulgarian Power Grid* highlights the importance of system stability and flexibility services as renewables increase dramatically, especially in the summer noon peak for PV. There are different technologies to provide these services, including converting some coal plant units into synchronous compensators that can provide system stability when needed. As those solutions are novel and not fully deployed yet, this model assumes a minimum amount of coal that needs to run throughout the year, for grid reliability reasons. Moving to high renewables penetration requires the provision of frequency control. The book notes that the Bulgarian system needs around 500 MW of power for primary and secondary frequency control that is currently provided by the coal plants. Since my model forecasts high BESS penetration, that will significantly exceed the reserve power requirement, I do not include reserve capacity as a constraint following the rapid growth in BESS capacity.

The *Bulgarian National Energy and Climate Plan* (NECP, 2025) is a key policy document that highlights 1) Bulgaria as one of the more energy intensive EU economies, suggesting significant improvements to energy efficiency are possible; 2) the importance of local energy security as provided by lignite coal capacity; 3) sets a target for renewable penetration of 35% by 2030 which is **equivalent to 25% for PV** after subtracting hydro (6%) and wind (4%).

The current model uses information from interviews with current and past industry executives based on actual data on capital and operating expenditure for current projects, which formed the basis of my LCOE cost calculations.

Consulting companies such as Baringa, Aurora and others forecast capture prices by technology to aid investors in their return-on-investment (ROI) calculations. They use sophisticated, iterative models run on a regional basis. I did not have access to such models for this research. Other papers highlight the importance of government action, including renewable support schemes, and grid connection development to accelerate the speed of energy transition away from fossil fuels. Governments often do not follow a straightforward plan, and investors would not wait for the perfect opportunity indefinitely. Thus, this paper aims to offer an optimum generation mix that is both economically viable and that depends as little as possible on government intervention.

1.3 Objectives of this study

Determining the optimal generation mix of a country is a complicated exercise that involves many considerations. My objective is to create a simplified but robust model that can help answer these questions. Since the mix can only be changed through investment decisions, I consider two main inputs to the model, PV capacity, and BESS capacity. For a given set of these inputs, the model computes utilization factors, new capture prices, investor returns and society benefits. Then I use the Excel Solver tool to vary the inputs until the target returns/benefits to society are achieved. The model adds complexity where it is needed and takes short cuts where the complications will not significantly impact the end results. A key objective is to make the model transparent and interactive.

2 Comparison of generation costs across technologies

The cost comparison is based on interviews with industry executives in Bulgaria and supplier data. Some assumptions are different from published industry benchmarks that do not take local conditions into account. I use LCOE as the comparison methodology adjusted for economic lifetime, utilization factor, and actual observed construction costs. LCOE is the Levelized Cost of Energy and aims to calculate the present-day cost per MWh of energy of building and operating a power plant over its projected lifetime. I use the simplified formula:

$$LCOE = \frac{CRF * CapEx + FixedCost}{Annual\ Energy\ Production} + VarCost$$

Where:

· LCOE is the cost in €/MWh

· Capacity factor is the amount of time a plant operates at maximum capacity

· CapEx is the initial capital expenditure in € '000

· FixedCost is the cost for maintaining and operating the plant per year in €/MW (power)

· VarCost is the cost in €/MWh for fuel, consumables, and balancing cost for intermittent sources. For energy storage, the variable cost includes the price of battery charging power, noting that 15% more energy is required for charging than will be available for discharging.

· Annual Energy Production is the number of MWh produced by plants at projected utilization.

· CRF is the Capital Recovery Factor which spreads the upfront capital cost of building and decommissioning the power plant over its lifetime of *N* years given a cost of capital *r*, specific to the country/investor:

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

It is important to consider that normal return on investment equal to the cost of capital is included in the LCOE cost. Therefore, in a perfect world investors should continue investing until prices captured by their investments (Capture prices) fall to the point where price equals LCOE. If the LCOE is lower than the capture prices, this means that there is room for more investors to come to the market.

Table 1: LCOE comparison for the Bulgarian market

Generation Type	Old NPP	New NPP	Coal	CCGT	PV	Wind	BESS
Installed power LTM (MW)	2,032	-	3,400	-	4,270	700	2h
Capacity Factor (CF)	85%	90%	30%	30%	16%	22%	1 cycle
Capex in €k/MW – Local[1]	-	10,275	-	1,100	480	1,400	120
Capex in €k/MW – Lazard	-	10,275	-	1,207	990	1,600	350
Variable cost in €/MWh[2]	12	15	121	99	10	12	11
Fixed cost in €k/MW[2]	170	120	45	35	15	25	5
Discount rate (r)[4]	-	6%	-	10%	9%	9%	8%
Lifetime (years)	20	60	10	20	30	30	25
Capital recovery factor	-	0.062	-	0.117	0.097	0.097	0.094
LCOE / LCOS (€/MWh)	**€35**	**€111**	**€138**	**€161**	**€53**	**€86**	**€56**

Notes to Table 1: LCOE comparison for the Bulgarian market

I use actual costs whenever available. For the existing fully depreciated nuclear power plant (NPP), all costs come from published results and the calculated LCOE is consistent with the Regulator set recovery mechanism. [1]Capex for a new nuclear plant is the overnight cost of building a nuclear power plant based on recent publications in the Bulgarian press on the potential construction of 2 AP-1000 units targeting operation in 2035, adjusted for construction time. It is also the midpoint of the Lazard capex range for new nuclear power. The capex for the other technologies is based on actual projects deployed or considered for deployment in Bulgaria in 2025. PV and BESS capex is much lower than Lazard's projections due to the low duties on Chinese products (e.g., 2.7% for PV/BESS). [2]Variable and fixed costs are based on regulatory market published data for current operators in the market. We add balancing costs for intermittent resources such as PV (€10/MWh) and wind (€12/MWh) due to the need to balance their output. CCGT variable cost is calculated at Eur 35/MWh gas cost and 58% efficiency factor but only 30% utilization (or capacity factor). The capacity factor for PV and wind is based on actual output observed in the country. New wind projects claim approx. 10-30% higher efficiency due to larger diameter blades, but this assumption has not been proven and is thus not utilized in this analysis. [3]The variable cost for BESS is calculated as 15% x a charging price of €76 (LTM) = €11 which represents the losses in charging the battery. This gives us LCOS or the Levelized Cost of Storage for comparison purposes. In addition, in the model, we assume that charging volume is 15% higher than discharging volume. The LCOS always varies based on the charging price, so the value in the table above is only representative of the LTM average charging price of €76/MWh for one cycle. The charging price is calculated in the model dynamically. [4]Cost of capital is based on available financing for renewables of 70% debt, 30% equity and 10% tax rate based on the WACC formula. The NPP cost of capital is lower due to government guarantees while the CCGT cost of equity is higher due to the uncertainty of the EU position on gas as a transition fuel and the potential short project life span.

The table above is compiled based on interviews with industry executives and publicly available data, some of which changes over time. For example, the EU CO_2 tax on carbon emissions, assumed at its current level of Eur 70/ton has varied in the past from €40 to over €100. If the carbon price increases, coal generation suffers the most as it emits 1.3 tons/MWh while gas suffers less as it emits 0.35 tons/MWh. Similarly, the CCGT LCOE is calculated on Eur 30/MWh gas price but gas prices in the EU have varied from €25/MWh to €50/MWh.

The marginal cost of electricity supply in Bulgaria is typically the cost of coal generation (as it is the only variable source that provides that las bit of supply when needed) or sometimes the marginal cost for energy imported into Bulgaria is typically the cost of gas generated electricity. There is a substitution effect between gas and coal generation. This is of secondary importance to me in this analysis because my main objective is to minimize coal generation (or more broadly fossil fuel generation) with greater use of renewables. Whether fossil fuel generation comes from domestic coal or imported gas is important, but it is not the focus of this paper. It should be clear from the LCOE table above that the projected usage of a potential new CCGT plant is so low at 30% that its LCOE becomes significantly higher than coal (i.e., €138/MWh for coal vs. €161/MWh for gas).

3 Demand analysis

Energy demand in Bulgaria has been constant at 35 TWh annually. The main factors that influence demand are continued improvements in energy efficiency (e.g. replacement of resistive heating with air-conditioning or heat pumps), global warming (i.e. with the increase in average temperatures, air-conditioning demand in the summer increases while heating demand in the winter decreases), electrification of transport (additional energy demand from electrical vehicles or EVs) and new industry demand for AI data centers. EVs are flexible as they can be charged at night when nuclear power is plentiful or at noon when PV produces excess power while data center demand is typically baseload (i.e., constant throughout the day).

We estimate that EV impact on demand will be gradual. For example, there are about 62k vehicle registrations per year (passenger cars, vans, trucks) in Bulgaria. Assuming EVs reach 100% share of new registrations in 10 years, there will be (62k*10 years / 2) = 300k EVs in Bulgaria by 2035. Based on average km of 21k km/year, 250 Wh/km x charging efficiency of 80%, this will result in an additional annual energy demand of 300,000 EVs x 21,000 km x 250 Wh / 80% = 2.0 TWh which is meaningful but not significant relative to total load.

Data center demand is potentially more significant, but data centers require baseload power. Bulgaria's only source of inexpensive baseload power is the existing nuclear power plant at LCOE of Eur 35/MWh. It is unlikely that the government owned plant will remove inexpensive energy from the market and push up consumer prices. Therefore, I conclude that data centers will develop jointly with new inexpensive baseload power, either generated in Bulgaria or imported. For these reasons, data center demand is not considered in this model.

Another factor is the variability of demand on a daily, weekly, and seasonal basis. Even if Bulgaria is self-sufficient on an aggregate annual basis (net exports represented only 5% of generated energy in LTM to June 2025), the picture is quite different on a daily/seasonal basis. The chart below shows demand, supply, and prices on LTM basis for the last 12 months:

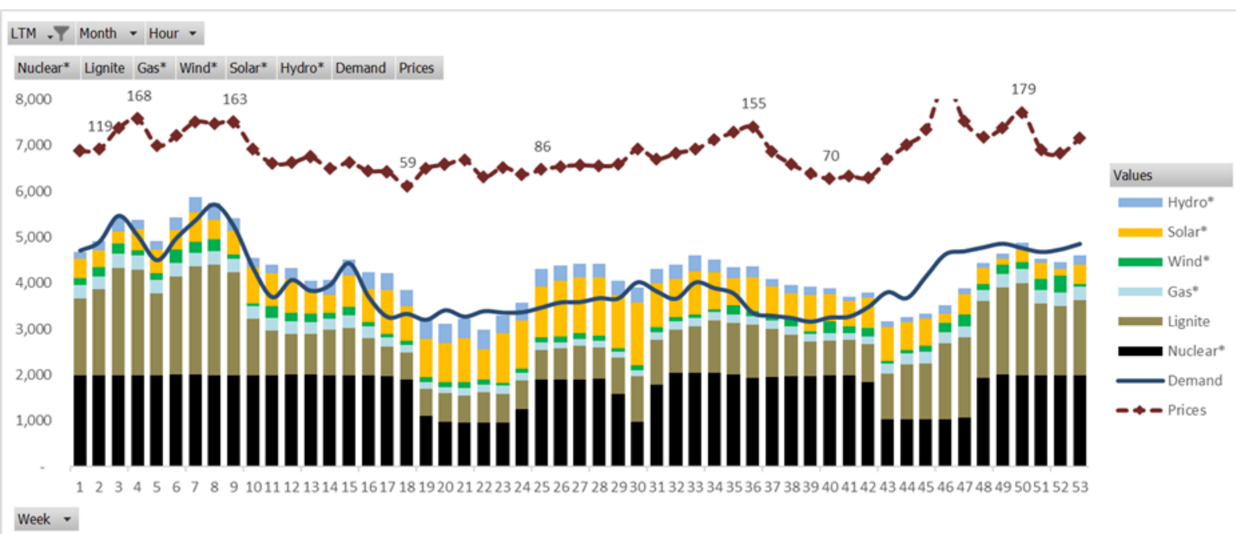

Figure 3: Demand, supply and prices on weekly basis, LTM July 2025

On a seasonal basis, it is evident from the chart that demand is significantly higher in the winter. Net exports are not explicitly shown on the chart, but they can be inferred from the demand (load) curve. Whenever generation is above load, the country exports electricity whereas the country imports electricity. The nuclear power plant maintenance outages are scheduled at times of lowest demand and highest hydro output (due to melting snow, weeks 19-24). However, if the maintenance window extends late into fall and wintry weather arrives, the coal plants are unable to ramp up generation quickly enough to cover the gap and the entire region becomes short on energy. This was the case in weeks 43-47, November 2024, when the government requested mothballed coal plants to restart.

This variability on a seasonal daily basis is even more extreme if we compare demand and generation on an average winter day and an average summer day. Figure 4 shows generation, demand and power prices for each hour, averaged in January, and Figure 5 shows the hourly averages in July:

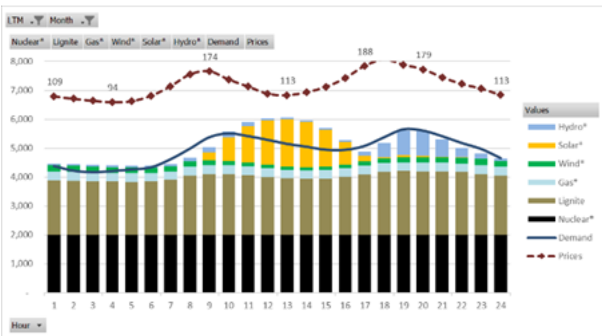

Figure 4: Average winter day generation

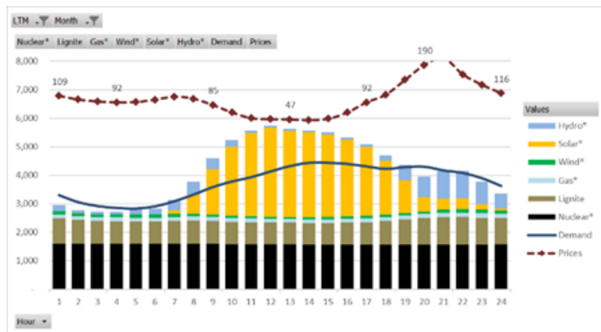

Figure 5: Average summer day generation

The PV contribution is small in the winter (8% of daily generation), and significant amounts of coal generation capacity are needed to meet demand in non-daylight times. Coal provides 41% of total winter demand in this case. Further, even small shortages of power, when demand exceeds supply around 8-9 am and 5-6 pm local time, lead to large increases in power prices. This means that in the winter, there is no spare generation capacity from the neighboring countries. Even if enough batteries are installed to shift the solar generation at noon to the evenings, there is simply not enough energy to be time-shifted (i.e., approx. 4 GWh available excess energy vs. coal generation of 48 GWh) to consider not running the coal plants in the winter.

4 Model Description

This is Excel-based with two main inputs: installed PV capacity and installed BESS capacity. There is no timeline for completion, just an optimal end-state generation mix that is likely to be achieved in the next 3-5 years. Demand is held constant at 35.2 TWh annual energy consumed. The generation volume from nuclear, gas, hydro, and wind are also held constant. The historic generation data is sourced from energy-charts.com and cross-checked with published data. The model uses hourly data, split for the analysis in 12 months x 24 hours. It performs calculations on hourly data averaged over a month. The input data is for the last twelve months to the end of July 2025 (called “LTM”).

Global model assumptions

1. Exports are capped at 1.0 GW power in any given hour, consistent with current values.

2. Minimum coal capacity is one unit running at 140 MW for grid reliability purposes.

Modelling steps and intermediate assumptions

1. Average PV power installed for LTM 2025 is 4,270 MW (4.3 GW). This capacity at 16% capacity factor x the typical solar profile for Bulgaria gives the same energy output as the historic data for the period. Actual installed PV capacity was 3,500 MW in July 2024 and 4,700 MW in July 2025. For a given input of installed PV capacity, the model calculates the new PV output for every hour based on an hourly PV generation profile. The charts below show the model impact if PV generation increases by ~50% to **6.5 GW** for the months of January and August, without coal and without storage. Even a 50% increase in PV will not help much in December (as there is a significant gap still to be filled up by coal), while this amount of PV will produce so much energy in July that most of it will need to be curtailed (or wasted, the red area). The presence of fixed nuclear generation that cannot be varied exacerbates this problem:

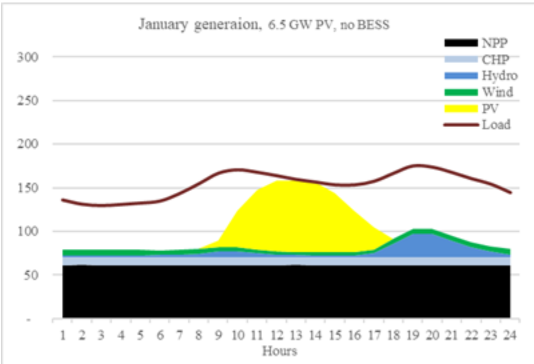

Figure 6: PV hourly at 6.5 GW in the winter

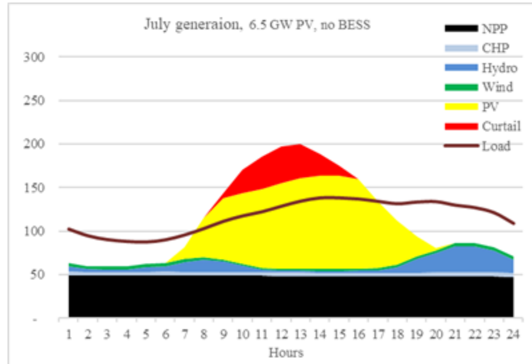

Figure 7: PV hourly at 6.5 GW in the summer

2. In this step, I calculate the actual gap between actual load and the actual generation from nuclear, wind, hydro, gas, and **modelled** PV generation. This gap is currently filled by coal generation.

3. Next, I calculate the desired amount of BESS capacity to <u>flatten the gap above</u> fully by taking the difference between the <u>value of the gap</u> for a given hour (for each month) and the <u>average value of the gap</u> across the hours of the day. Negative values indicate excess energy that should be used to charge the BESS if available. Positive values indicate the need to discharge the batteries. The desired amount of BESS capacity varies by month and is highest in the summer.

4. Next, we plot the actual hourly LTM prices, in Eur/MWh to determine battery cycles:

Figure 8: Actual LTM prices, simple hourly average over LTM

Based on the observed prices, the BESS can operate on 2-cycles today. In the morning cycle, the prices are lower due to the fixed output of the nuclear power plant against the reduced night-time demand. The evening cycle or the PM cycle is the typical cycle induced by the high PV output at noon vs. the higher evening peak demand. However, it turned out that modelling two cycles is complicated and unnecessary. As more PV is installed, the prices at noon become so low that it would be more advantageous to charge the batteries at noon and then discharge them partially in the evenings and sometimes the following morning. Therefore, I am modelling only one cycle per day, but the available batteries are charged at the lowest price as computed by the model (it could be at night or at noon) and discharged at the highest price.

5. Next, we take the installed BESS capacity and spread it out in the same proportion to the desired capacity to flatten the gap. The chart below illustrates the case for the month of August with 4.3 GW of PV (no change from today) and 4.5 GWh of BESS capacity. Negative values indicate charging, positive values discharging:

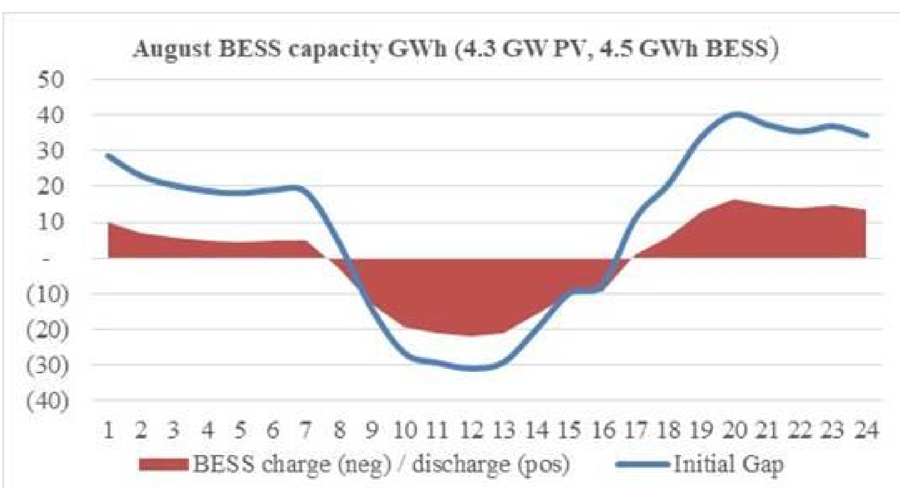

Figure 9: Illustration of BESS distributing PV energy over 24h. We have not made the decision whether installing 4.5 GWh of BESS capacity is economically justifiable. The model only says more BESS is needed to flatten the curve.

6. Next, following the spreading of energy across the day, incl. there required 15% higher volume to charge the batteries vs. what is discharged, we fill up the rest of the gap with coal. If coal is not needed (e.g., in the summer, if enough PV and BESS are available to flatten the curve), then we set a minimum coal output of 1 unit (140 MW) for system stability purposes. Then we check if exports exceed our export power limit of 1.0 GW per hour. In any hour where this limit is exceeded, the PV output is curtailed.

7. Next, we model the impact of the volume changes on the capture prices (the average market price earned by a generator) in two steps:

   a. Increased PV output reduces prices in the same proportion to the volume of increased PV generation. The actual formula is (the sum of generation from all sources in the LTM case) / (sum of generation from all sources including the new PV / BESS installed capacity). This is a linear price adjustment that can be justified by the fact that PV has negligible marginal cost.

   b. The second price adjustment component is to compute the price change due to the use of BESS to flatten the curve. Here we use the same approach as in capacity modelling, we take the difference in price for each hour from the average price across all hours and reduce this difference proportionately to the ratio of installed BESS to desired BESS. If the installed BESS is equal or higher than the desired BESS amount to flatten the gap, the price curve becomes completely flat, equal to the daily average price. Furthermore, if the BESS is significantly higher than the desired BESS, it could lower the prices below average. However, this is a two-edged sword: if too much BESS floods peak periods, prices can fall as far as zero. This is good for consumers, but detrimental to producers. Thus, we must find an optimal balance:

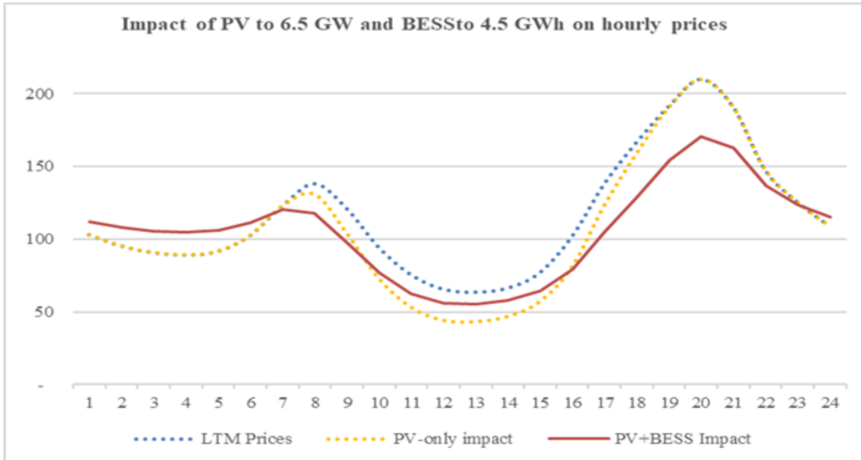

Figure 10: Example of price changes due to higher PV and BESS

8. Next, we calculate the weighted average capture prices for each generation source and compare these to the recalculated LCOE of PV and BESS. The PV LCOE is impacted by curtailment, while the BESS LCOE is driven by the charging price. Then we calculate the ratio of the capture price to the LCOE as a percentage change. If this percentage is higher than 0%, this means that the installed amount of capacity generates positive, excess returns for the investors, so they will continue to invest.

9. The output of the model is the CO_2 emissions reduction, calculated as the amount of needed coal to plug the gap x 1.3 tons of CO_2 per net and the total price to consumers, calculated as the weighted average price of all generation sources x their capture price. The capture price is the generation of each source x the calculated price. Typically, nuclear, a baseload generator will have a capture price remarkably close to the simple average of the prices, while PV will have lower capture prices due to much of its output being at noon when there is excess generation. The consumer price is typically above the simple average price because consumption of electricity (load) is weighted towards the evening hours. Below is a table comparing LTM capture prices to a model run with 6.5 GW PV and 4.5 GWh BESS:

Table 2: Prices per power generation type

Prices/MWh	Nuclear	Coal	CHP	Hydro	PV	Wind	BESS	Load
Actual								
LTM actual	**€116**	€159	€121	€142	€73	€121	€153	€121
LCOE actual	€35	€138	€120	€45	€53	€86	€131	€85
Return (price/LCOE)	233%	15%	1%	216%	38%	41%	29%	42%
Model Test Run								
Modelled prices	€106	€161	€112	€124	€58	€113	€134	€110
Modelled LCOE	€35	€138	€120	€45	€56	€86	€105	€86
Excess Return	204%	16%	-7%	175%	3%	32%	27%	27%

The actual LTM average price is €116/MWh, equal to the nuclear capture price. The average load price is higher at €121 because consumers need more energy in the evenings, when prices are higher. The excess returns for both PV and BESS are high, 38% and 29%, respectively. The excess return on the load (or the consumers) is 42%. We want the excess return (or the premium that consumers pay over the cost of generation in the hours they purchase electricity) to be as low as possible. **In the proposed model test run** with 6.5 GW PV and 4.5 GWh BESS, the consumer price has fallen to €110/MWh, the PV margin has decreased as the price is lower due to BESS charging, and the cost is higher due to curtailment. The excess return of PV is now only 3%, which means investment in PV is near its limit, while the system still needs more BESS with its positive excess investor return of 27%.

10. While evaluating the model, I noticed that using coal as a plug is not entirely realistic. The optimization routine in Excel would charge the BESS from any source, including coal if the margins are positive. The model would boost coal output at noon in the winter (when PV is not enough to charge the batteries), then reduce coal immediately. This is not possible with coal plants as discussed with industry executives. Coal plants typically vary output <35% of maximum power. I introduce another constraint in the model, where coal output must stay relatively constant, where the maximum power cannot exceed the average power by more than 35%. Below is an example of the constraint. The second case, with 44% variability where coal output drops close to zero at noon and then ramps up, is not physically possible.

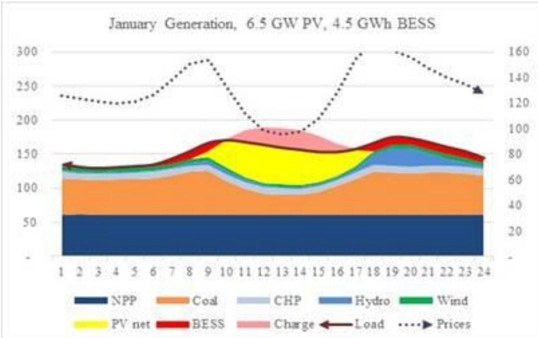

Figure 11: January output, coal variability 25%

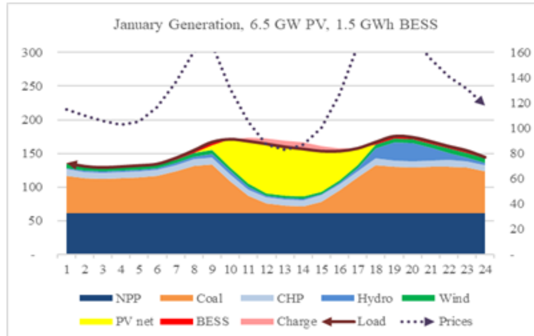

Figure 12: January output, coal variability 44%

11. Lastly, we introduce the benefit of a government capex subsidy scheme for BESS deployment. The currently announced subsidy is 40%. We model this by reducing the LCOE of BESS by the corresponding amount.

Utilization of the model

The model can be used either by inputting various installed capacities for PV and BESS, then observing the results or by using the Solver tool in Excel that varies the inputs until it meets our constraints and target criteria. We constrain investor returns to be positive for both PV and BESS and target either minimum CO_2 emissions or consumer benefit:

A. Set CO_2 reduction target to -40%, with positive investor returns for PV and BESS

B. Minimize consumer prices, positive returns, subject to coal variability limit

C. Minimize consumer prices, positive returns, with BESS subsidy

D. Minimize consumer prices, positive returns, with subsidies, relax variability and exports

Table 3. Model Output by Scenario

Model Inputs	LTM	Sc. A	Sc. B	Sc. C	Sc. D
PV installed base (GW)	4.3	6.7	7.8	7.8	8.5
Installed BESS (GWh)	0.5	5.0	13.2	13.2	20.6
Max export power (GW)	1.0	1.0	1.0	1.0	2.0
Coal variability limit (<35%)	35%	24%	35%	35%	112%
BESS capex subsidy	0	0%	0%	40%	40%
Model Results					
PV Excess return (Price / LCOE)	38%	0%	0%	0%	0%
BESS excess return (Price / LCOE)	17%	15%	4%	16%	11%
PV curtailment (%)	-1%	-8%	-2%	-2%	0%
Net energy exported (GWh)	35	568	1,750	1,750	2,547
Required coal generation (GWh)	8,787	6,780	6,357	6,357	6,188
CO2 emissions vs. 2019 (-40% target)	-22%	**-40%**	-44%	-44%	-45%
Benefit to consumers					
Consumer wholesale price (Eur/MWh)	€ 121	€ 108	€ 104	€ 104	€ 103
Consumer wholesale price reduction	0%	-10%	**-14%**	**-14%**	**-15%**
Consumer benefit vs. LTM (Eur m)	€ -	€ 433	€ 588	€ 588	€ 639

The LTM case is a representation of the last twelve months. Both PV and BESS are attractive, max exports limit is 1 GW, there is minimal PV curtailment. The CO_2 emissions are at 22%, well below the target. Note, that is the scenario, the coal output limited to the minimum required domestically, i.e., to fill the gap in the model. Hence, the net exports are 35 GWh. In the actual LTM data, coal was running in the winter to support exports and therefore the net exports were closer to 2 TWh.

A) In scenario A I target CO2 emissions reduction of 40%. Excess returns for PV + BESS are set to be positive, then we look for a solution with the Solver tool. The optimum solution is for PV to increase to 6.7 GW, supported by 5.0 GWh of BESS storage. It should be noted that more BESS supports more PV and vice versa. Consumer prices will be 10% lower, which is a significant benefit. This is a likely scenario for Bulgaria in the 2026-27 period.

B) In scenario B I switch to targeting the lowest possible consumer price, which also minimizes emissions. The model suggests a 14% in consumer prices can be achieved with 42% reduction can be achieved if PV increases to 7.8 GW PV supported by 13.2 GWh BESS. CO_2 emissions are 44% lower and **consumer benefit is €588m.** Note that in both scenario A and B, BESS investors enjoy excess returns, while PV excess return is 0 (equivalent to just meeting the cost of capital).

C) In scenario C I introduce the 40% capex subsidy program that improves the investor business case for installing more BESS. The additional BESS should allow more PV to be installed but this turns out not to be the case as the batteries are saturated – i.e., we can speak of BESS curtailment at this point. The impact of the BESS subsidy is only to increase the already positive investor return in BESS. This is our optimal scenario, since the capex subsidy has already been announced and is expected to be distributed and it indicates that other things being equal investors should first invest in more BESS, then in more PV.

D) In scenario D I relax certain constraints, such as removing the coal variability constraint (for example, if we fill the gap with imported energy generated from gas, which does not have the variability constraint) and increasing max export power to 2.0 GW per hour. This is not a realistic scenario today, because increasing the export limit requires investment in infrastructure and it also depends on how much PV and BESS the neighboring countries will install but it is a useful scenario to consider what would be possible in the absence of the constraints. The results are not significantly different from scenario C. PV increases slightly to 8.5 GW, BESS to 20.6 GWh and consumer prices decrease by 15%. It is difficult to justify this scenario that involves removal of major constraints for a minimal improvement in prices.

5 Evaluation of results

Scenario C is the best outcome as it exceeds the CO_2 reduction target, it is based on current costs and state of technology and results in a significant consumer benefit of €588m. I could not reduce coal output further with any combination of the inputs. My assessment of the core limitation of energy generation in Bulgaria is that the PV output varies on a seasonal basis (determined by the geographic position of the country), whereas the electricity demand variation is driven by the heating needed in the winter. BESS helps even out the peaks, but it only shifts supply during the day, not between seasons if its impact is partial. Changing the heating mix for the country (i.e., heating with gas as in Western Europe) is a slow process and difficult to justify without further analysis. However, if the recent trend of warmer winters and hotter summers continues, the demand will change where more energy will be needed in the summer due to more air-conditioning and less in the winter. This will improve the business case for more PV.

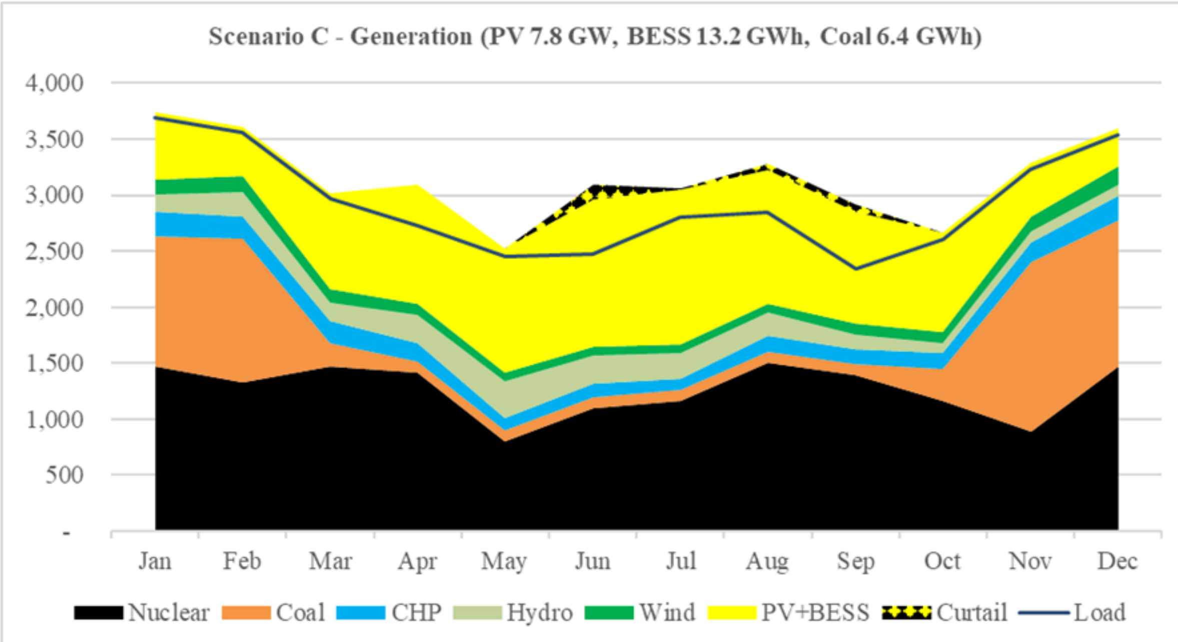

Figure 13. Scenario C. Model output of total generation, PV at 7.3 GW and BESS at 12.8 GWh. The yellow area is PV generation which is split into 55% direct consumption, 43% BESS charging and 2% curtailment.

Coal generation requirement

Coal generation of around 6 TWh is needed in the preferred scenario C. Furthermore, this generation is concentrated in the winter months with average power (over 30 days) of 2.2 GW. While this power can be supplied either by domestic coal or gas generated electricity imports, it is important that Bulgaria can meet this requirement on its own. Therefore, the summary of Figure 13 is that Bulgaria needs a fossil fuel resource with max power around 2.2 GW that is only used for four months and then it is not needed at all.

Replacement of coal with gas generation

To provide this power with a CCGT (or an open cycle gas turbine), we need to calculate the expected capacity factor for this new installation. Assuming 2.5 GW installed power, the utilization will be (4 months x 2.2 GW) / (12 x 2.5 GW) = 29%. This is not sufficient to justify the cost of a new CCGT as its LCOE will be Eur 162/MWh which is significantly higher than the cost of coal generation. A private investor will not consider a free market, <30% capacity factor for any gas generation technology.

Nuclear power

As discussed in the modelling section, Bulgaria needs more flexible resources to address the seasonal misalignment of demand with the high seasonal variability of PV generation at our geographic latitude. Adding more fixed, non-variable generation sources increases the floor in the summer which results in higher curtailment for PV. While new nuclear installations offer variable output power (unlike the currently installed Kozlodui reactors), nuclear power has extremely high upfront costs and low variable costs, so a reduction in output will increase the LCOE significantly.

Comparing Bulgaria (with 40% nuclear generation) to the only country in Europe with higher nuclear penetration, France (with 65% nuclear generation), we note that France is well interconnected to countries with high gas generation share that is flexible. In Bulgaria, CCGTs represent a small share of the total regional generation. Looking at the summer months, where the model suggests that demand is <2,500 GWh per month from May to September (from Figure 13), nuclear power is providing 1,500 GWh on average during those months. An additional reactor will add 800 GWh to the mix, leaving little room (only 200 GWh) for all the other generation sources.

Therefore, I believe that additional nuclear power should only be considered as a replacement of the existing capacity (projected to be needed in 2047/2049) or if coupled with AI data center installations (but then it is unlikely that the energy cost will be competitive) or as a replacement for neighboring countries coal plants' (there is 3 GW of constantly running coal capacity in Serbia that would need to be replaced at some point in the future).

Wind power

Wind generation is not in scope for this study as no wind projects have been deployed in the country in the last five years. There are two key issues: 1) Bulgaria has weaker wind resources than neighboring countries as evidenced by the average existing wind farms' capacity factors of 22-23% and 2) grid connections to the few windy areas are non-existent. However, the model does suggest that wind offers positive investor return and therefore wind should be considered in future updates to the model.

6 Limitations of the analysis

There are potential improvements to the model, starting with using average generation data for the last three years, instead of LTM; a more sophisticated way to model the price decline due to PV penetration and others. I do not believe such optimizations will change the model results significantly. My goal was to create a model to find the optimum generation mix analytically and this goal is met. Future users of the model can adjust parameters to their reasoning (for example, gas price evolution, CO_2 emissions price evolution, interconnect capacity, LCOE for different technologies, etc.) but still benefit from the generation mix optimization routine.

7 Conclusion

The results of the model suggest that scenario B and C are equivalent and support the conclusion that the energy system in Bulgaria has the capacity to absorb 7.8 GW of PV and 13.2 GWh of total BESS installations. Subtracting the currently installed capacities, we project around 3 GW of new solar installations and 13 GWh of BESS installations in the next 3-5 years. Both PV and BESS are required to be able to drive the CO_2 emissions reduction to below 40% in the next 2-3 years. These results are based on a set of conservative assumptions such as flat demand (any increase in demand will open space for more capacity), self-sufficiency where Bulgaria can meet its winter peak with coal generation at about 6 TWh annual production (any substitution of coal generation with imports will reduce CO_2 emissions even further) and current technology costs.

What does it mean for investors?

Expect positive investment returns assuming PV is built below €480k/MW and BESS below €120k/MWh. The returns for BESS appear to be slightly higher than the returns for PV but the optimal approach is to build PV+BESS.

What does it mean for coal?

Coal generation can be minimized but cannot be eliminated. Around 2.2-2.5 GW of coal capacity must be available in selected months, although the average annual utilization will be below 30%. Coal plant operators must prepare for seasonal operations with or without government support.

Learnings from the modelling exercise

Creating a comprehensive energy system model is complicated and is always based on a set of assumptions. I achieved my goal in creating a simple and interactive model that can be easily verified and optimized. Future users of the model may add their own assumptions about the slope of the decline in prices or the costs of renewables for each individual investor and for the industry. Adding wind to the model will be a simple exercise if so desired by a potential future user. For me, it was a great learning opportunity, and I am looking forward to updating and further assessing the model in the future.

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