Resource Adequacy and Operational Security Interaction in the EPOC 2030-50 Project

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Contents

Abbreviations

CCGT Combined Cycle Gas Turbine

OCGT Open Cycle Gas Turbine

VRES Variable Renewable Energy Sources

UC Unit Commitment (Model)

DUCPR Deterministic Unit Commitment Model with Probabilistic Reserve constraints

1. Interaction description

Adequacy assessments and operational security analyses are two fundamental exercises in determining and ensuring the reliable operation of the electric power system. The former assesses the ability of the power system to satisfy demand for electricity in the day ahead stage, while the latter assesses (or ensures, depending on the context) that an unexpected event, such as an outage of a transmission line or generator or lower or greater than expected realisation of demand or renewable generation, does not lead to cascading failures and a possible blackout.

Typically, these exercises are performed independently. This interaction combines the two by feeding the results of an adequacy assessment to an operational security analysis.

In doing so, we deviate from typical practices in a number of ways. First, the adequacy assessment is done for a limited number of days instead of many Monte Carlo years for the sake of clarity and brevity. Indeed, doing this exercise for many Monte Carlo years would drastically increase the computational complexity while the aim of this exercise is to illustrate how such an interaction could be performed.

Secondly, the adequacy assessment is done using an unconventional Unit Commitment (Model) (UC) model, a modified version of the Deterministic Unit Commitment Model with Probabilistic Reserve constraints (DUCPR) model described in [**?**]. This model can be seen as a compromise between a computationally expensive stochastic UC model and a more tractable though less accurate deterministic UC model with operating reserve requirements. The treatment of operating reserves in this model allows a trade-off between shedding load in the day ahead stage, which would reduce day ahead adequacy, and shedding operating reserves, which should reduce operational security. By making this trade-off explicit and verifying the results in an operational security analysis we aim to elaborate on the results of [**?**], which did not consider the possibility that shedding operating reserves would lead to insecure operation of the electric power system.

All code can be found at https://github.com/junglegobs/ASoSEPOC.

The rest of this document is organised as follows. Section 2 describes the DUCPR model used to simulate power system operations and obtain day ahead adequacy and very approximate real time operational security indicators, namely scheduled load shedding and reserve shedding. Section 3 describes the stylised Belgian system analysed. Section 4 analyses a single day in order to identify sources of adequacy and security issues, while Section 5 analyses the trade-off between these two.

2. Description of a Deterministic Unit Commitment Model with Probabilistic Reserve (DUC-PR) constraints

Sets, variables and costs related to unit commitment and storage operation have been omitted for brevity though they are included in the model. The interested reader is referred to https://github.com/junglegobs/ASoSEPOC for the relevant code.

2.1. Sets

- G - Generators
- G_n - Generators located at node n
- GD - Dispatchable / thermal / conventional generators
- GR - Renewable / variable generators (Variable Renewable Energy Sources (VRES)).
- N - Nodes or buses in the network
- B - Lines or branches
- T - Time steps / intervals / slices
- L^{+} - Upward reserve levels
- L^{-} - Downward reserve levels

2.2. Parameters

- D_{nt} - Demand
- $PTDF_{nl}$ - Power Transfer Distribution Factor
- AF_{gt} - Availability Factor
- K_g - Capacity
- P_g^{min} - Minimum power output
- P_g^{max} - Maximum power output
- $D_{lt}^{L^{+}}$ - Upward reserve requirement
- $D_{lt}^{L^{-}}$ - Downward reserve requirement

2.3. Variables

All variables are positive apart from node injection variables which may also be negative.

- q_{gt} - Generation
- $\hat{q}_{gt}$ - Generation above the minimum stable operating point (0 in the case of renewables).
- ls_{nt} - Load shedding
- inj_{nt} - Node injection
- f_{lt} - Branch flow

- r^+_{gt} - Total upward reserve provision
- r^-_{gt} - Total downward reserve provision
- $r^{L^+}_{glt}$ - Upward reserve provision for reserve level l
- $r^{L^-}_{glt}$ - Downward reserve provision for reserve level l
- rs_{nlt} - Upward reserve shedding for reserve level l
- rc_{nlt} - Downward reserve provided by day ahead load shedding for reserve level l
- $rinj^{L^+}_{nlt}$ - Possible node injection due to activation of upward reserve level l
- $rinj^{L^-}_{nlt}$ - Possible node injection due to activation of downward reserve level l
- $rf^{L^+}_{nbt}$ - Possible branch flow due to activation of upward reserve level l
- $rf^{L^-}_{nbt}$ - Possible branch flow due to activation of downward reserve level l
- $d^{L^+}_{nlt}$ - Possible imbalance on node n for upward reserve level l
- $d^{L^-}_{nlt}$ - Possible imbalance on node n for downward reserve level l

2.4. Objective

$$\begin{aligned}
\min \quad & \sum_{t\in T}\sum_{g\in G} C^{var}_g \cdot \hat{q}_{gt} \\
& + \sum_{t\in T}\sum_{l\in L^+}\sum_{n\in N} P^{L^+} \cdot \sum_{g\in G} C^{var}_g \cdot r^{L^+}_{glt} + C^{shed} \cdot rs_{nlt} \\
& - \sum_{t\in T}\sum_{l\in L^-}\sum_{n\in N} P^{L^-} \cdot C^{var}_g \cdot r^{L^-}_{gnlt} + C^{shed} \cdot rc_{nlt}
\end{aligned} \tag{1}$$

From the top line to the bottom, the costs are those of dispatching generators and activating upwards or downwards reserves.

2.5. Constraints

2.5.1. Day ahead constraints

The power balance:

$$\sum_{g\in G_n} q_{gt} + ls_{nt} = D_{nt} + inj_{nt} \quad n \in N,\ t \in T \tag{2}$$

Note the use of the set G_n to only allow generators at node n to contribute to the power balance. Another way of describing this would have been through an incidence matrix.

Network constraints:

$$f_{bt} = \sum_{n \in N} PTDF_{nb} \cdot inj_{nt} \quad b \in B,\ t \in T \tag{3}$$

$$-F_b \leq f_{bt} \leq F_b \quad b \in B,\ t \in T \tag{4}$$

$$\sum_{n \in N} inj_{nt} = 0 \quad n \in N,\ t \in T \tag{5}$$

$$\tag{6}$$

Constraints on generator output:

$$q_{gt} - r^-_{gt} \geq 0 \quad g \in GR,\ t \in T \tag{7}$$

$$q_{gt} + r^+_{gt} \leq AF_{gt} \cdot K_g \quad g \in GR,\ t \in T \tag{8}$$

$$q_{gt} - r^-_{gt} \geq P^{min} \cdot z_{gt} \quad g \in GD,\ t \in T \tag{9}$$

$$q_{gt} + r^+_{gt} \leq P^{max} \cdot z_{gt} \quad g \in GD,\ t \in T \tag{10}$$

For brevity and clarity, constraints on ramping and minimum up and down times are omitted.

2.5.2. *Operating reserve (activation) constraints*

The constraints on reserve provision are as follows:

$$D^{L^+}_{lt} = \sum_{g \in G} r^{L^+}_{glt} + \sum_{n \in N} rs_{nlt} \quad l \in L^+,\ t \in T \tag{11}$$

$$D^{L^-}_{lt} = \sum_{g \in G} r^{L^-}_{glt} + \sum_{n \in N} rc_{nlt} \quad l \in L^-,\ t \in T \tag{12}$$

$$\sum_{l \in L^-} rc_{nlt} \leq ls_{nt} \quad n \in N,\ t \in T \tag{13}$$

$$r^+_{gt} = \sum_{l \in L^+} r^{L^+}_{gnlt} \quad g \in G,\ t \in T \tag{14}$$

$$r^-_{gt} = \sum_{l \in L^-} r^{L^-}_{gnlt} \quad g \in G,\ t \in T \tag{15}$$

The amount of reserve shedding can be limited to a fraction of the total upward reserve requirements RSL:

$$\sum_{n \in N, l \in L^+} rs_{nlt} \leq RSL \cdot \sum_{l \in L^+} D^{L^+}_{l't} \quad t \in T \tag{16}$$

There are several matters to note here:

- The operating reserve balance is performed over the entire network, not per node.
- The operating reserve balance is split into reserve levels. Higher reserve levels (values of l) are less likely to occur.
- It is possible to shed upward reserves, and this is more likely to occur for higher reserve levels. This model is therefore able to make a trade-off between day ahead adequacy and real time operational security, albeit crudely.
- Shedding load in day ahead allows additional downward reserves to be provided through the variable rc_{nlt}. Implicitly this assumes that load can be 'activated' in real time to provide downward reserves.

2.5.3. Operating reserve activation network constraints

The following constraints attempt to take network constraints into account (albeit very weakly):

$$\sum_{g \in G_n, l'=1:l} (r^{L^+}_{glt} + rs_{nlt}) = d^{L^+}_{nlt} + rinj^{L^+}_{nlt} \quad n \in N,\ l \in L^+,\ t \in T \tag{17}$$

$$-\sum_{g \in G_n, l'=1:l} (r^{L^-}_{glt} + rc_{nlt}) = d^{L^-}_{nlt} + rinj^{L^-}_{nlt} \quad n \in N,\ l \in L^-,\ t \in T \tag{18}$$

$$\sum_{n \in N} d^{L^+}_{nlt} = \sum_{l'=1:l} D^{L^+}_{l't} \quad l \in L^+,\ t \in T \tag{19}$$

$$\sum_{n \in N} d^{L^-}_{nlt} = -\sum_{l'=1:l} D^{L^-}_{l't} \quad l \in L^-,\ t \in T \tag{20}$$

$$rf^{L^+}_{blt} = \sum_{n \in N} PTDF_{nb} \cdot rinj^{L^+}_{nlt} \quad b \in B,\ l \in L^+,\ t \in T \tag{21}$$

$$rf^{L^-}_{blt} = \sum_{n \in N} PTDF_{nb} \cdot rinj^{L^-}_{nlt} \quad b \in B,\ l \in L^-,\ t \in T \tag{22}$$

$$-F_b \leq f_{bt} + rf^{L^+}_{blt} \leq F_b \quad b \in B,\ l \in L^+,\ t \in T \tag{23}$$

$$-F_b \leq f_{bt} + rf^{L^-}_{blt} \leq F_b \quad b \in B,\ l \in L^-,\ t \in T \tag{24}$$

$$\sum_{n \in N} rinj^{L^+}_{nt} = 0 \quad l \in L^+,\ n \in N,\ t \in T \tag{25}$$

$$\sum_{n \in N} rinj^{L^-}_{nt} = 0 \quad l \in L^-,\ n \in N,\ t \in T \tag{26}$$

Note that $rinj^{L^+}_{nlt}$, $rinj^{L^-}_{nlt}$, $d^{L^+}_{nlt}$ and $d^{L^-}_{nlt}$ are all free variables and there is a change in sign between upward and downward reserve levels to ensure that the resulting addition to the line flows, $rf^{L^+}_{blt}$ and $rf^{L^-}_{blt}$, are correct.

Since imbalances are aggregated across the network, a particular reserve level activation is not associated with an imbalance at the nodal level. The above constraints therefore enforce that for each reserve level l and node n, there exists some combination of nodal imbalance, node injections, generator dispatches and line flows which would satisfy the network constraints AND the imbalance across the entire network.

2.5.4. Further constraining reserve activation network constraints

Given the formulation here, which uses reserve levels, i.e. quantiles, over the entire network to represent forecast errors, it is difficult to come up with more stringent conditions. However, we devised two ways of doing so. The first is to apply box constraints to the possible nodal imbalances:

$$d_{nt}^{min} \leq d_{nlt}^{L^+} \leq d_{nt}^{max} \quad n \in N,\ l \in L^+,\ t \in T \tag{27}$$

$$d_{nt}^{min} \leq d_{nlt}^{L^-} \leq d_{nt}^{max} \quad n \in N,\ l \in L^-,\ t \in T \tag{28}$$

It is possible to calculate d_{nt}^{min} and d_{nt}^{max} since the quantiles for D^{L^+} and D^{L^-} are calculated based on forecast error scenarios which are defined at the nodal level. These limits are shown in Figure 1. Clearly it is simply not possible to have an imbalance on some nodes, such as Coo (the location of Belgium's pumped hydro unit). Constraining $d_{nlt}^{L^+}$ and $d_{nlt}^{L^-}$ in this way is referred to as AbsImb later on.

Figure 1: Range of possible imbalances for all hours of day 309.

The other possibility is to restrict $d_{nlt}^{L^+}$ and $d_{nlt}^{L^-}$ to lie within the convex hull of all imbalances. This is illustrated in 2 dimensions in Figure 2 for the imbalances at Tihange 1 and 2. Clearly the imbalances are highly correlated, and constraining the possible nodal imbalances to lie within the convex hull exploits this in a way that box constraints would not be able to.

Figure 2: Illustration of convex hull constraints on $d_{nlt}^{L^+}$ and $d_{nlt}^{L^-}$. Blue circles are imbalance scenarios, shaded area is the convex hull, d_{nt}^{min} and d_{nt}^{max} are the x limits for TIHANGE 1 and the y limits for TIHANGE 2.

At the time of writing, this convex hull restriction led to model infeasibilities and so it is not

3. Input data - stylised Belgian grid with a large amount of variable renewable energy sources

All data used for this exercise can be found at: .

The grid and resource data used for this interaction is inspired by the case study in [**?**], omitting the gas network and power to gas technologies. This data gives a stylised Belgian system with a high penetration (8s0%) of VRES, which includes 75.7 GW of solar PV, 7.0 GW of Onshore Wind and 7.3 GW of Offshore Wind. The grid consists of 46 nodes connected by 69 lines. The total amount of conventional thermal generation is 9.9 GW, with all generators based on new Combined Cycle Gas Turbine (CCGT) units apart from one new Open Cycle Gas Turbine (OCGT) unit at Lixhe. The nuclear generators of Doel and Tihange are therefore replaced with new CCGT units.

Power to Gas is omitted but 14.1 GW of storage power capacity (1.1 GW provided by pumped hydro at Coo, the rest batteries) and 101 GWh of storage energy capacity (8.2 GWh provided by pumped hydro at Coo, the rest batteries) is included. The batteries therefore have a duration of 7.2 hours (which could be considered atypical, given current durations of 1 - 2 hours [MIT paper for this?]).

The network topology was obtained from the Belgian TSO, Elia [**?**]. It consists of 46 nodes connected by 69 lines.

The load time series used was the load as seen by Elia on the high-voltage grid from the year 2015 . For this year, the minimum and maximum load was 5,777 MW and 13,670 MW respectively, with an average of 9,934 MW. The electrical load is assigned to the different nodes in the system according to the rated capacity of the transformer feeding each node.

add cite.

The VRES availability factor time series are taken from Elia data for the year 2015, same as the load. This was done by dividing generation from offshore wind, wind and solar by the total installed capacities available. This allows scaling up the generation of VRES to the previously mentioned capacities. The distribution of onshore wind and solar photovoltaic (PV) capacity was done according to the distribution made in [**?**].

The residual load time series, aggregated across all nodes, for this system is plotted in

Plot this

.

A complete overview of the data is given in [**?**], Appendix B.

3.0.1. Methodology used to select days for analysis

Four days were selected for analysis based on the results of a full year economic dispatch model which included network constraints. The load was multiplied uniformly across all nodes by a factor of 1.5 to ensure that some load shedding occurred and then four days were selected which represented the 0, 33, 66 and 100th percentile in terms of daily load shedding. The resulting days are presented in Table 1.

Day ahead daily load shedding [MWh/day]	Day of year	Month	Day of month
0	161	6	10
449	319	11	15
1,247	285	10	12
10,062	12	1	12

Table 1: Days selected for analysis. These were selected based on the results of a full year economic dispatch model with load multiplied uniformly across all nodes by a factor of 1.5. The 0, 33, 66 and 100th percentiles in terms of daily load shedding were then selected.

It should be noted that of the four days selected, only day 285 exhibited load shedding when the load was not scaled but operating reserves were present. This finding highlights how day ahead adequacy may occur for reasons other than insufficient capacity aggregated across the network, i.e. analysis of the aggregated residual load (the load net of renewable generation) may be uninformative.

4. Analysis of Deterministic Unit Commitment Model with Probabilistic Reserve constraints model results

This analysis relates only to the 285th day of the year (12th of October). This day was selected since of the 4 days selected The aim is to investigate what are the causes of load shedding to better understand the system.

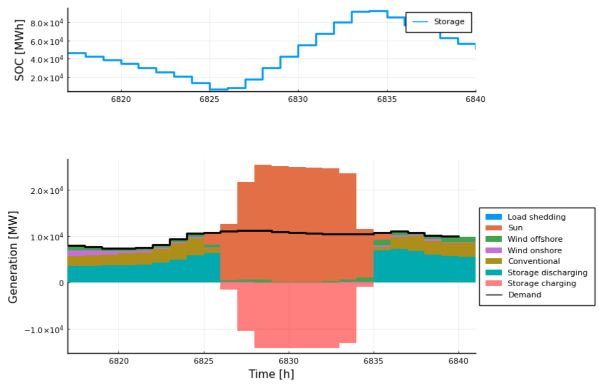
4.1. No operating reserves

Table 2 lists results for an increasing level of technical constraints or increasingly inflexible system. While the objective increases by €1,267,000 from the simple linear economic dispatch model with no network constraints to the unit commitment model with network constraints, no load shedding occurs. Preventing simultaneous charging and discharging constraints actually decreases, though this difference is within the optimality gap (0.01%). This suggests that additional energy consumption (which is not physically possible) from storage does not aid congestion in this context.

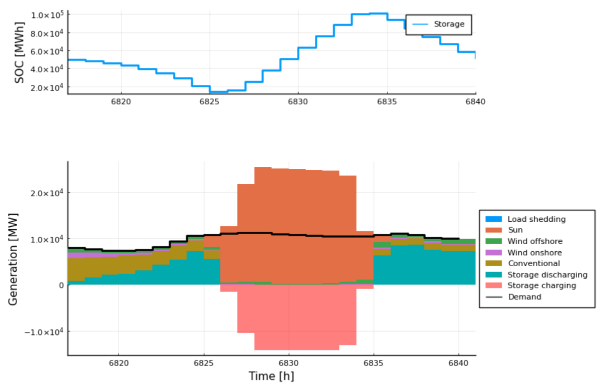
UC	DANet	PSCD	Load shedding [MWh]	Objective [€]
			0.0	3,127,814
✗			0.0	4,003,654
✗	✗		0.0	4,394,693
✗	✗	✗	0.0	4,394,513

Table 2: Analysis of model results when operating reserves are not included. UC = Unit Commitment constraints, DANet = Day Ahead Network constraints, PSCD = Prevent Simultaneous Charging and Discharging constraints.

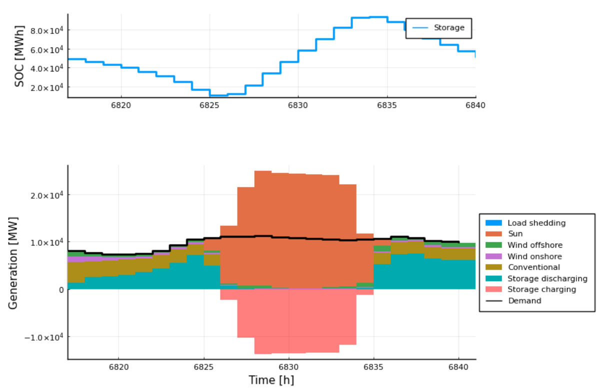
The dispatch aggregated over the entire network for the model with and without unit commitment constraints and with network constraints is shown in Figure 3. The addition of unit commitment constraints leads to less storage discharging and more conventional (thermal) units generating at the start of the day. The aggregated storage state of charge at 10AM (hour 6826) is approximately the same however. The addition of network constraints does not appear to change the aggregated dispatch significantly.



(a) Economic dispatch model



(b) Unit commitment model



(c) Unit commitment model with day ahead network constraints

Figure 3: Dispatch schedules for day 285 and increasing model complexity.

4.2. Probabilistic operating reserves

Table 4 summarises results for the model runs with probabilistic operating reserves but no reserve activation network constraints. Clearly unit commitment constraints lead to greatly increased load shedding, 3.8 GWh to be precise. They also lead to reserve shedding where there wasn't any before. Neither day ahead network constraints or preventing simultaneous charging or discharging have an effect on the objective function which is greater than the MIP gap.

UC	DANet	PSCD	RSL	Load shedding [MWh]	Reserve Shedding [MWh]	Objective
			0.0	1,575	0.0	19,508,913
			0.5	1,575	0.0	19,508,913
			1.0	1,575	0.0	19,508,913
✗			0.0	5,410	0.0	63,198,973
✗			0.5	5,410	5,683	63,136,103
✗			1.0	5,410	5,616	63,136,444
✗	✗		0.0	5,410	0.0	63,198,620
✗	✗		0.5	5,410	5,440	63,137,301
✗	✗		1.0	5,410	5,700	63,140,438
✗	✗	✗	0.0	5,410	0.0	63,198,858
✗	✗	✗	0.5	5,410	5,112	63,139,965
✗	✗	✗	1.0	5,410	5,114	63,140,337

Table 3: Analysis of model results with operating reserves but no reserve activation network constraints. UC = Unit Commitment constraints, DANet = Day Ahead Network constraints, PSCD = Prevent Simultaneous Charging and Discharging constraints, RSL = Reserve Shedding Limit.

Figure 4 shows the dispatch schedule for the case with unit commitment constraints, day ahead network constraints and operating reserve requirements but no limit on reserve shedding. Load shedding occurs at 8 - 10 AM, even though there is still energy in the storage units. This is not due to congestion issues, since some of these storage units are located at the same node as the load being shed. Rather, this is likely due to the constraint which specifies that the storage state of charge at the end of the day must be greater than or equal to that at the start of the day. This constraint was included so as not to overestimate the flexibility that storage could provide, though it is unlikely that such a situation would occur in reality.

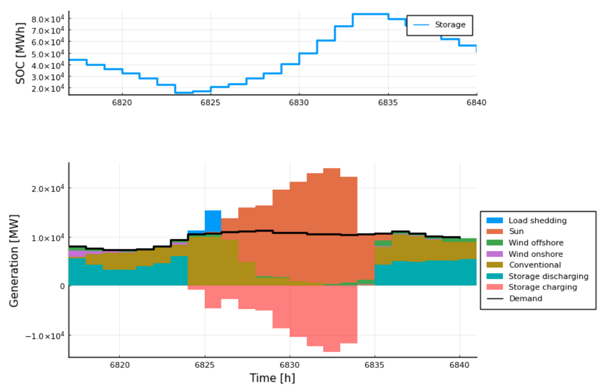


Figure 4: Dispatch schedule for day 285, unit commitment constraints, day ahead network constraints and operating reserve requirements but no limit on reserve shedding.

Considering the case with just unit commitment constraints, the reserve shedding limit can be decreased without increasing load shedding, though there is an increase (0.09%) in the objective function greater than the MIP gap. This is counterintuitive, as you would expect the DUC-PR model to shed all operating reserves before shedding load in the day ahead stage. The former is less costly than the latter after all, due to activation probabilities being ¡ 1. However, what is occuring is most likely 'economic reserve shedding' - shedding reserves because they are highly unlikely to be activated. This phenomenon was also observed in [**?**]. Figure 5 illustrates that almost all reserve shedding occurs between 14:00 and 16:00 (hour 6830 to 6832) and not 8:00 to 10:00 as with load shedding. These are hours with a lot of solar generation and very little conventional, so to avoid this reserve shedding only requires additional generator commitment and not increasing the amount of load shedding in those hours.

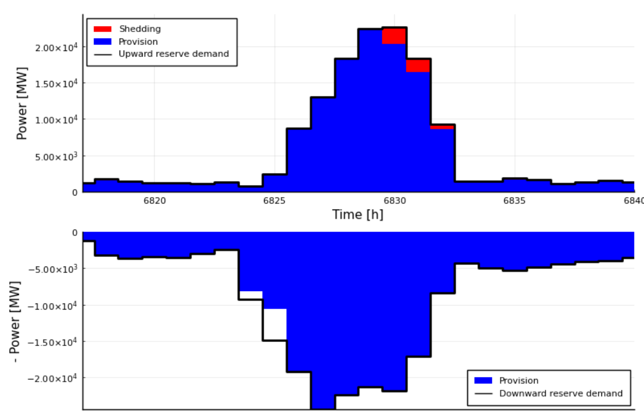


Figure 5: Dispatch schedule for day 285, unit commitment constraints, day ahead network constraints and operating reserve requirements but no limit on reserve shedding.

4.3. Probabilistic operating reserves with reserve activation network constraints

Including network reserve activation constraints, that is Constraints 17 through 17, led to no discernible change in objective. This particular instance is not able to make a trade-off between day ahead adequacy and real time operational security. As a first attempt to overcome this issue, the load at all nodes was multiplied by a factor of 1.5. This gave the results shown in Table **??**.

UC	DANet	PSCD	AbsImb	RSL	Load shedding [MWh]	Reserve Shedding [MWh]	Objective
				0.0	32,366	0	7,290,909
				0.5	0.0	36,269	447,102
				1.0	0.0	36,082	440,467
✗				0.0	32,366	0	7,433,785
✗				0.5	1,669	34,379	924,686
✗				1.0	1,669	34,308	919,363
✗	✗			0.0	33,929	0	7,822,959
✗	✗			0.5	1,967	39,234	1,249,422
✗	✗			1.0	1,941	39,160	1,245,647
✗	✗	✗		0.0	33,929	0	7,822,959
✗	✗	✗		0.5	1,967	39,234	1,249,422
✗	✗	✗		1.0	1,941	39,160	1,245,647
✗	✗	✗	✗	0.0	33,929	0	7,822,959
✗	✗	✗	✗	0.5	1,967	39,234	1,249,422
✗	✗	✗	✗	1.0	1,941	39,160	1,245,647

Table 4: Analysis of model results with operating reserves and with reserve activation network constraints with load multiplied by a factor of 1.5. UC = Unit Commitment constraints, DANet = Day Ahead Network constraints, PSCD = Prevent Simultaneous Charging and Discharging constraints, RSL = Reserve Shedding Limit.

Objective is weird for some cases...

With reference to Table **??**:

- Even in this case, the reserve activation network constraints are not binding, since the AbsImb constraints do not alter the objective function.
- On the other hand, the trade-off between reserve shedding and load shedding can be seen now in all cases. This trade-off is also obvious when observing the objective function.
- Unit commitment constraints do relatively little to increase total costs, but this is unsurprising given that costs are dominated by load shedding.
- Day ahead network constraints increase load shedding considerably i.e. congestion also plays a role in increasing load shedding.

Closer investigation at load shedding patterns for the model with UC and DANet (but no PSCD and AbsImb) and $RSL = 0.0$ reveals that load shedding is at it's highest in the mornings (8 - 10 AM) and in the evenings (17 - 20). No load shedding occurs in the middle of the day, which happens to be when load is lowest and solar generation is greatest. Load shedding is roughly equally distributed throughout the day in absolute though not relative terms.

(a)

(b) (c)

Figure 6: Load shedding distribution in time (top figure, aggregated over all nodes) and space (aggregated over the entire day) for UC, DANet, LM = 1.5 and $RSL = 0.5$.

5. Day ahead adequacy and real time operational security trade offs