A MILP Approach for the Joint Simulation of Electric Control Reserve and Wholesale Markets

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Abstract: A mixed integer linear programming (MILP) approach for the joint simulation of electric control reserve and electricity wholesale markets is described. This generation dispatch model extends an existing integrated grid and electricity market model covering the Continental European electric power system. By explicitly modelling the markets for primary and secondary control reserve, the model can reproduce the decisions of generating unit operators on which markets to get involved. Besides, the introduction of integrality conditions allows considering start-up costs and the calculus of generating units to pass through economically unattractive periods with low or even negative prices in order to avoid another start-up. Finally, the MILP approach allows to consider the fact that primary and secondary control reserves provision usually requires operation of the respective generating unit and to fully include storages into the optimization problem. In this paper, the generation dispatch model is described in detail, key assumptions are presented and the implementation status is explained.

1 INTRODUCTION

The electric power system in Europe currently experiences a strong transition. Political objectives promote the, often decentralized, generation of electrical energy from renewable energy sources (RES), the liberalization of power markets and cross-border trading and – in some countries – the decrease of nuclear power generation. The resulting system is characterized through high volatility in generation (esp. by wind and photovoltaics), increasing cross-border trading, an increasing number of atypical market situations with very low or even negative electricity prices (esp. in Germany (Genoese et.al, 2010)) and in some cases high grid expansion requirements in all voltage levels.

In order to analyze this transition scientifically, e.g. in terms of generation dispatch, electricity prices, load flows, and grid expansion demand, an integrated grid and electricity market model (IGEM) has been developed to simulate current and future electric power supply scenarios. The model focusses on the interconnected transmission grid of Continental Europe, but can also be used to analyze other regions, if respective data is provided and possibly existing differences in market structures are taken into account.

More and more, the liberalization finds its way into the markets for primary control reserve (PCR) and secondary control reserve (SCR). In the past, the provision of PCR and SCR by large power plants was instructed by the responsible transmission system operator (TSO). Nowadays, local liberalization leads to a market based allocation of PCR and SCR in some European countries, while in other countries the provision of PCR and SCR is still instructed by the responsible TSO (ENTSO-E, 2015). Driven by the new ENTSO-E (European Network of Transmission System Operators for Electricity) Network Codes (ENTSO-E, 2017), the provision of PCR and SCR will be liberalized further and cross-border trading of PCR and SCR shall be made possible (in fact it is already practiced between some countries, e.g. between Germany and several neighboring countries within the framework of the International Grid Control Cooperation (50Hertz Transmission et.al., 2014)).

In this paper, a method for the joint simulation of electricity wholesale market and the markets for PCR and SCR is developed and on this basis an extension of the generation dispatch module of IGEM is presented. While the existing module takes into account only the electricity wholesale market formulated as a linear programme, the new module

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presented shall broaden the focus with respect to

- the calculus of generating units that their costs can be covered by revenues not only from the wholesale market but also by providing PCR and SCR,
- the fact that for the provision of PCR and SCR power plant operation normally is necessary,
- power plants passing through pricewise unattractive periods to avoid start-up costs, and
- a better representation of storages.

The existing model of IGEM described in (Rendel, 2012) and (Rendel, 2015) is therefore replaced by a mixed integer linear programming (MILP) model including PCR and SCR dispatch. Within this model, the generation dispatch is calculated considering the interdependencies between the different markets, cross-border trading and storages for the whole period under consideration.

The next chapter gives a brief overview about the European power system, IGEM and key assumptions for the generation dispatch module. In chapter 3, the MILP approach for the generation dispatch module is described in detail. Chapter 4 describes the implementation status. The paper closes with a conclusion and a description of further work (chapter 5).

2 SIMULATION ENVIRONMENT AND KEY ASSUMPTIONS

2.1 Simulation Environment

The area covered by IGEM nearly matches the synchronous ENTSO-E grid area "Continental Europe", which reaches from Portugal in the West to Romania in the East and from Denmark in the North to Greece in the South and comprises 42 TSOs. To facilitate changes and extensions, the whole model is built modularly.

The basic model structure including the generation dispatch module presented in this paper is shown in Figure 1. The model is based on several data bases comprising, among others, power plant data, grid data, load data, feed-in time series of RES, population data, market information, economic indices and geographical data. Reference year for all data presented in this paper is the year 2011. The data is currently being updated to the reference year 2014, though.

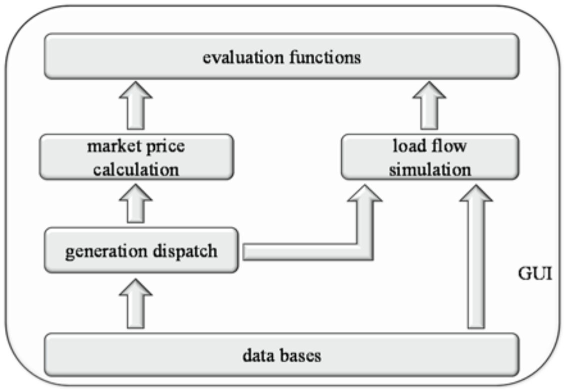

Figure 1: Basic structure of IGEM.

The power plant data base contains about 1700 power plants and 500 storages with explicit position data and about 3100 other entries with regionally aggregated installed capacity of decentralized generation. The level of regional aggregation is determined by the data available. Depending on availability, further information, such as energy source, maximum capacity, year of construction and efficiency (which is estimated using literature values), is covered (Rendel, 2015). For generating units with variable primary energy source, such as wind, PV and hydro power plants, time series of available energy for different geographical regions are used (Rendel, 2015).

Load flow simulations are carried out using the complete Newton Raphson load flow iteration and are built on results of the generation dispatch. Among others, modules to assign load, generation of conventional power plants and generation of RES to grid nodes are implemented. As different markets are involved in the generation dispatch, the market prices are no result of the dispatch module but have to be calculated in a separate module.

Beyond that, for efficient usage IGEM has a graphical user interface (GUI) and evaluation functions such as to display generation dispatch, electricity prices or power line utilization.

2.2 Key Assumptions

The model presented in this paper is based on the following key assumptions:

- The actual generation dispatch in Europe is economically optimal.
- Energy costs of PCR and SCR can be considered indirectly.
- All non-linear relations can be linearized or neglected.

- PCR and SCR can be allocated to generating units on hourly basis.

Below, these assumptions are explained in more detail and a brief description of the underlying system is given.

In the countries covered by IGEM, the details of the electricity wholesale markets (hereafter active power market for a better differentiation to PCR and SCR markets) differ, e.g. in terms of product specifications, trading times and RES integration. PCR and SCR provision is allocated partly market based and partly determined by the relevant TSOs. Additionally, not the generating units themselves but their operators, who often operate several units and have various contractual connections amongst each other, are the market participants. However, these structures are widely unknown. Assuming a market driven cost optimal generation dispatch with respect to active power production and PCR and SCR provision enables abstraction from these details, since a global optimization (cost minimization) with an appropriate model time step (currently one hour) produces the same results.

PCR and SCR are the main instruments of TSOs to react on frequency deviations caused by imbalances between load and generation by counteracting these imbalances. While PCR is designed for the first, very fast reaction within 30 seconds after the imbalance occurred; SCR is designed to displace PCR within 15 minutes. There are two types of costs related to PCR and SCR. The provision of PCR and SCR results in capacity costs caused by a more inefficient generation dispatch compared to a dispatch only considering active power production. The activation of PCR and SCR results in energy costs for the additional infeed of positive or negative power. These energy costs can either be positive or negative. More information about the approach to consider these costs in the dispatch model is given in chapter 3. The provision of tertiary control reserve (TCR), designed to displace SCR currently is out of focus of IGEM, as the requirements for TCR provision allow start-ups for several types of power plants.

The electric power system is a complex techno-economic system with various nonlinear relationships. For instance, the efficiency of power plants depends on the power output and can be influenced by PCR provision, and start-up costs of thermal power plants depend on the period of idleness. Nevertheless, these relationships are neglected or linearized in order to reduce model complexity and to enable the deployment of highly specialized MILP solvers.

Typically, PCR and SCR provision is allocated for periods of several hours up to several days or weeks. As already mentioned above, the relevant market participants are generating unit operators with various contractual relations amongst each other and often operating several units. Therefore, it is assumed that the operators allocate PCR and SCR provision to the single generating units in an optimal way for each model time step.

3 GENERATION DISPATCH MODEL

Below, the generation dispatch model is described according to the following convention: Vector variables are lowercased and bold, matrices uppercased and bold and scalars either uppercased or lowercased, following given conventions, but not bold. All variables are italicized. Variable indices are italicized (e.g. t for different points in time), notation indices are upright.

3.1 Objective Function

The optimization problem is formulated as minimization of the total variable costs of electric power production for the period under consideration as shown in (1). Fixed costs are disregarded, as they are not relevant for short-term operational planning.

$$\min \boldsymbol{f}^{\mathrm{T}} \boldsymbol{x} \tag{1}$$

The vector of optimization variables $\boldsymbol{x}$ consists of three groups of variables representing all generating devices except for storages (PP – power plants), storages (STO) and power trade (T) for each point in time.

$$\boldsymbol{x} = [\boldsymbol{x}_{\mathrm{PP}}^{\mathrm{T}}\ \boldsymbol{x}_{\mathrm{STO}}^{\mathrm{T}}\ \boldsymbol{x}_{\mathrm{T}}^{\mathrm{T}}]^{\mathrm{T}} \tag{2}$$

Power plants are described by their active power (AP) production ($\boldsymbol{p}_{\mathrm{AP,PP}}$), a binary variable indicating their operating status ($\boldsymbol{op}_{\mathrm{PP}}$), a binary variable indicating whether they start-up at the respective point in time ($\boldsymbol{st}_{\mathrm{PP}}$), and the symmetrical (i.e. PCR can only be provided in positive and negative direction) primary control reserve ($\boldsymbol{p}_{\mathrm{PCR,PP}}$), positive secondary control ($\boldsymbol{p}_{\mathrm{SCRpos,PP}}$) and negative secondary control ($\boldsymbol{p}_{\mathrm{SCRnegPP}}$) reserve provided:

$$\boldsymbol{x}_{\text{PP}}^{\text{T}} = \left[\boldsymbol{p}_{\text{AP,PP}}^{\text{T}} \ \boldsymbol{op}_{\text{PP}}^{\text{T}} \ \boldsymbol{st}_{\text{PP}}^{\text{T}} \ \boldsymbol{p}_{\text{PCR,PP}}^{\text{T}} \ \boldsymbol{p}_{\text{SCRpos,PP}}^{\text{T}} \ \boldsymbol{p}_{\text{SCRnegPP}}^{\text{T}} \right] \tag{3}$$

Contrary to power plants, storages have two operating modes that have to be considered separately, because they partially differ in key factors, such as efficiency and maximum capacity. Therefore, the variables used to describe power plant operation exist for each mode – storage mode (STOin) and generating mode (STOout). However, some adaptions are necessary to account for the specifics of storages:

While PCR as a symmetrical product is represented by one variable in power plant modelling, the total PCR of storages can be composed of different variables for both operating modes. For instance, a storage in generating mode with little load can provide negative PCR not only by reducing its generation but also by switching to storage mode. Further differences are the neglect of start-up costs and a variable representing the state of charge:

$$\begin{aligned}\boldsymbol{x}_{\text{STO}}^{\text{T}} = \Big[& \boldsymbol{p}_{\text{AP,STOout}}^{\text{T}} \ \boldsymbol{p}_{\text{AP,STOin}}^{\text{T}} \ \boldsymbol{op}_{\text{STOout}}^{\text{T}} \ \boldsymbol{op}_{\text{STOin}}^{\text{T}} \\ & \boldsymbol{p}_{\text{PCRpos,STOout}}^{\text{T}} \ \boldsymbol{p}_{\text{PCRpos,STOin}}^{\text{T}} \ \boldsymbol{p}_{\text{PCRneg,STOout}}^{\text{T}} \\ & \boldsymbol{p}_{\text{PCRneg,STOin}}^{\text{T}} \ \boldsymbol{p}_{\text{SCRpos,STOout}}^{\text{T}} \ \boldsymbol{p}_{\text{SCRpos,STOin}}^{\text{T}} \\ & \boldsymbol{p}_{\text{SCRneg,STOout}}^{\text{T}} \ \boldsymbol{p}_{\text{SCRneg,STOin}}^{\text{T}} \ \boldsymbol{e}_{\text{STO}}^{\text{T}} \Big]\end{aligned} \tag{4}$$

Power trading (T) is modelled separately for AP, PCR, SCRpos and SCRneg. Active power trading is defined between different bidding zones (market area for AP, often identical to countries) and control reserve trading between control zones (area for which PCR and SCR has to be provided, often identical to area controlled by a TSO). These zones can be, but do not have to be identical:

$$\boldsymbol{x}_{\text{T}}^{\text{T}} = \left[\boldsymbol{p}_{\text{T,AP}}^{\text{T}} \ \boldsymbol{p}_{\text{T,PCR}}^{\text{T}} \ \boldsymbol{p}_{\text{T,SCRpos}}^{\text{T}} \ \boldsymbol{p}_{\text{T,SCRneg}}^{\text{T}} \right] \tag{5}$$

The coefficients of the objective function are grouped in the same way as the optimization variables:

$$\boldsymbol{f}^{\text{T}} = [\boldsymbol{f}_{\text{PP}}^{\text{T}} \ \boldsymbol{f}_{\text{STO}}^{\text{T}} \ \boldsymbol{f}_{\text{T}}^{\text{T}}] \tag{6}$$

The PP coefficients are given in (7). The costs essentially determining the power plant dispatch are the marginal costs $\boldsymbol{mc}$ and the start-up costs $\boldsymbol{st}$. Marginal costs are the derivation of the total cost function and therefore contain only variable cost elements, essentially fuel costs and carbon dioxide emission costs. Start-up costs incur for the start-up of thermal power plants. These power plants require a certain time up to several hours to heat up and begin effective operation.

It is assumed that PCR does not cause any costs directly, because it can only be offered symmetrically by power plants, and frequency deviations occur in both directions. Though, the need for PCR and SCR provision causes costs indirectly, as it changes the power plant dispatch towards a more cost intensive state. The coefficients for SCRpos and SCRneg shall cover the fact that the activation of positive SCR directly generates costs and the provision of negative SCR saves costs. The costs depend on the deployment probability, which in turn depends on the composition of the pool providing SCR which cannot be considered within this linear model. Therefore, an ordinal scale ($\boldsymbol{os}$) is introduced. This scale, calculated as a share of the marginal costs, enables the optimizer to choose the power plants with the relatively lowest costs for SCR provision without knowing the exact costs. However, these SCR costs can theoretically bias the whole generation dispatch and should therefore be set as close as possible to the real costs.

$$\boldsymbol{f}_{\text{PP}}^{\text{T}} = \left[\boldsymbol{mc}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{sc}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{os}^{\text{T}} \ \text{-}\boldsymbol{os}^{\text{T}} \right] \tag{7}$$

Storages have no direct costs in the objective function. They provide flexibility between different points in time to the optimizer and can be used to reduce the total costs in the period under consideration:

$$\boldsymbol{f}_{\text{STO}}^{\text{T}} = \left[\boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \right] \tag{8}$$

Power trade is also not represented with direct costs in the objective function. It provides flexibility between different bidding zones (AP) respectively control zones (PCR and SCR) and can be used to reduce the costs within each point in time by a more efficient dispatch. In case of additional direct costs for the use of power lines connecting different bidding zones or control areas, they can be considered with these coefficients, though:

$$\boldsymbol{f}_{\text{T}}^{\text{T}} = \left[\boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \ \boldsymbol{0}^{\text{T}} \right] \tag{9}$$

All vector elements of $\boldsymbol{x}_{\text{PP}}$ and $\boldsymbol{f}_{\text{PP}}$ are structured as shown in (10). Each power plant n is represented with an own optimization variable and its coefficient for each point in time t. The total number of power plants is N. The model considers T different points in time.

$$\boldsymbol{p}_{\text{AP,PP}} = \begin{bmatrix} P_{\text{AP,PP},1,1} \\ P_{\text{AP,PP},2,1} \\ \\ P_{\text{AP,PP},1,2} \\ \\ P_{\text{AP,PP},n,t} \\ \\ P_{\text{AP,PP},N,T} \end{bmatrix} \qquad (10)$$

All vector elements of $\boldsymbol{x}_{\text{STO}}$ and $\boldsymbol{f}_{\text{STO}}$ are structured as shown in (11). Each storage s is represented with an own optimization variable and its coefficient for each point in time t. The total number of storages is S.

$$\boldsymbol{p}_{\text{AP,STOout}} = \begin{bmatrix} P_{\text{AP,STOout},1,1} \\ P_{\text{AP,STOout},2,1} \\ \\ P_{\text{AP,STOout},1,2} \\ \\ P_{\text{AP,STOout},s,t} \\ \\ P_{\text{AP,STOout},S,T} \end{bmatrix} \qquad (11)$$

All vector elements of $\boldsymbol{x}_{\text{T}}$ and $\boldsymbol{f}_{\text{T}}$ are structured as shown in (12) depending on whether trade is defined between bidding zones or control areas. Each combination of exporting bidding zone bze (respectively exporting control area cae) and importing bidding zone bzi (respectively importing control area cai) is represented with an own optimization variable and its coefficient for each point in time t. The total number of bidding zones is BZ (respectively CA for control areas).

$$\boldsymbol{p}_{\text{T,AP}} = \begin{bmatrix} P_{\text{T,AP},1,1,1} \\ P_{\text{T,AP},2,1,1} \\ \\ P_{\text{T,AP},1,2,1} \\ \\ P_{\text{T,AP},BZ,BZ,1} \\ \\ P_{\text{T,AP},bze,bzi,t} \\ \\ P_{\text{T,AP},BZ,BZ,T} \end{bmatrix}; \boldsymbol{p}_{\text{T,PCR}} = \begin{bmatrix} P_{\text{T,PCR},1,1,1} \\ P_{\text{T,PCR},2,1,1} \\ \\ P_{\text{T,PCR},1,2,1} \\ \\ P_{\text{T,PCR},CA,CA,1} \\ \\ P_{\text{T,PCR},cae,cai,t} \\ \\ P_{\text{T,PCR},CA,CA,T} \end{bmatrix} \qquad (12)$$

3.2 Lower and Upper Bounds

The lower ($\boldsymbol{lb}$) and upper bounds ($\boldsymbol{ub}$) of the optimization variables as defined in (13) are given in (14). They are structured in the same way as the optimization variables and therefore are time-dependent. Most of the bounds represent technical limits of the modelled system respectively its components. Each power plant and storage is designed for certain operating ranges which cannot be violated. In three cases, the upper bound is infinite ($\boldsymbol{Inf}$), because it is defined in inequality constraints. Power trading is limited by the cross-border trading capacities. The binary optimization variables defined in (15) are bound by zero and one. The remaining variables are continuous.

$$\boldsymbol{lb} \leq \boldsymbol{x} \leq \boldsymbol{ub} \qquad (13)$$

3.3 Inequality Constraints

The total power generation of a power plant n must not exceed its rated power $P_{\text{r,PP},n,t}$. The possible activation of positive PCR and SCR has to be considered by adding the PCR and SCRpos provision to the active power generation as given in (16).

Equation (17) forces the binary variable $op_{\text{PP},n,t}$ to take the value one whenever the power plant generates active power or provides PCR, as PCR provision is not possible without power plant operation. The provision of positive SCR generally is allowed in standstill given that the power plant is able to start-up quickly enough. Whether operation is necessary for SRCpos provision is considered by the coefficient $on_{\text{SCR,PP},n,t}$, taking the value 1 in case operation is necessary and zero in case it is not.

$$\boldsymbol{lb} = \begin{bmatrix} \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \boldsymbol{e}_{\mathrm{STOmin}} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \\ \mathbf{0} \end{bmatrix}; \boldsymbol{ub} = \begin{bmatrix} \boldsymbol{Inf} \\ \mathbf{1} \\ \mathbf{1} \\ \boldsymbol{p}_{\mathrm{PCRmax,PP}} \\ \boldsymbol{p}_{\mathrm{SCRposmax,PP}} \\ \boldsymbol{p}_{\mathrm{SCRnegmax,PP}} \\ \boldsymbol{Inf} \\ \boldsymbol{Inf} \\ \mathbf{1} \\ \mathbf{1} \\ \boldsymbol{p}_{\mathrm{PCRmax,STOout}} \\ \boldsymbol{p}_{\mathrm{PCRmax,STOin}} \\ \boldsymbol{p}_{\mathrm{PCRmax,STOout}} \\ \boldsymbol{p}_{\mathrm{PCRmax,STOin}} \\ \boldsymbol{p}_{\mathrm{SCRposmax,STOout}} \\ \boldsymbol{p}_{\mathrm{SCRposmax,STOin}} \\ \boldsymbol{p}_{\mathrm{SCRnegmax,STOout}} \\ \boldsymbol{p}_{\mathrm{SCRnegmax,STOin}} \\ \boldsymbol{e}_{\mathrm{STOmax}} \\ \boldsymbol{p}_{\mathrm{Tmax,AP}} \\ \boldsymbol{p}_{\mathrm{Tmax,PCR}} \\ \boldsymbol{p}_{\mathrm{TmaxSCRpos}} \\ \boldsymbol{p}_{\mathrm{Tmax,SCRneg}} \end{bmatrix} \tag{14}$$

$$\boldsymbol{op}_{\mathrm{PP}}, \boldsymbol{st}_{\mathrm{PP}} \in {}^{N\cdot T}; \boldsymbol{op}_{\mathrm{STOout}}, \boldsymbol{op}_{\mathrm{STOin}} \in {}^{S\cdot T} \tag{15}$$

$$\begin{gathered} P_{\mathrm{AP,PP},n,t} + P_{\mathrm{PCR,PP},n,t} + P_{\mathrm{SCRpos,PP},n,t} \le P_{\mathrm{r,PP},n,t}, \\ n = 1,2,\ldots,N,\, t = 1,2,\ldots,T \end{gathered} \tag{16}$$

$$\begin{gathered} P_{\mathrm{AP,PP},n,t} - P_{\mathrm{r,PP},n,t}\, op_{\mathrm{PP},n,t} + P_{\mathrm{PCR,PP},n,t} \\ + on_{\mathrm{SCR,PP},n,t} P_{\mathrm{SCRpos,PP},n,t} \le 0, \\ n = 1,2,\ldots,N,\, t = 1,2,\ldots,T \end{gathered} \tag{17}$$

Most power plants must not fall below a minimum generation limit for technical reasons. Therefore, (18) defines $P_{\mathrm{min,PP},n,t}$ as lower bound for active power generation in case the power plant is in operation. As the minimum generation is also valid during (negative) PCR or SCRneg activation, their provision is added to $P_{\mathrm{min,PP},n,t}$.

$$\begin{gathered} -P_{\mathrm{AP,PP},n,t} + P_{\mathrm{min,PP},n,t}\, op_{\mathrm{PP},n,t} + P_{\mathrm{PCR,PP},n,t} \\ + P_{\mathrm{SCRneg,PP},n,t} \le 0,\, n = 1,2,\ldots,N,\, t = 1,2,\ldots,T \end{gathered} \tag{18}$$

Start-ups are recognized by means of (21). Whenever the binary variable $op_{\mathrm{PP},n,t}$ changes from zero to one between two consecutive points in time, the binary variable $st_{\mathrm{PP},n,t}$ takes the value one for the respective power plant and point in time. For the first point in time the variable is set by (19) and (20), depending on the starting condition $c_{1,n}$.

$$op_{\mathrm{PP},n,1} - st_{\mathrm{PP},n,1} \le c_{1,n},\, n = 1,2,\ldots,N \tag{19}$$

$$\boldsymbol{c}_{1,n} = \begin{cases} 1 \text{ if } st_{\mathrm{PP},n,1} = 0,\, n = 1,2,\ldots N \\ 0 \text{ if } st_{\mathrm{PP},n,1} = 1,\, n = 1,2,\ldots N \end{cases} \tag{20}$$

$$\begin{gathered} -op_{\mathrm{PP},n,t-1} + op_{\mathrm{PP},n,t} - st_{\mathrm{PP},n,t} \le 0, \\ n = 1,2,\ldots,N,\, t = 2,3,\ldots,T \end{gathered} \tag{21}$$

Equations (22) and (23) correspond to (16) but are formulated separately for each operating mode of storages. As already mentioned above, PCR is divided into PCRpos and PCRneg for storages, because provision can include change in operating mode.

$$\begin{gathered} P_{\mathrm{AP,STOout},s,t} + P_{\mathrm{PCRpos,STOout},s,t} + P_{\mathrm{SCRpos,STOout},s,t} \\ \le P_{\mathrm{r,STOout},s,t},\, s = 1,2,\ldots,S,\, t = 1,2,\ldots,T \end{gathered} \tag{22}$$

$$\begin{gathered} P_{\mathrm{AP,STOin},s,t} + P_{\mathrm{PCRneg,STOin},s,t} + P_{\mathrm{SCRneg,STOin},s,t} \\ \le P_{\mathrm{r,STOin},s,t},\, s = 1,2,\ldots,S,\, t = 1,2,\ldots,T \end{gathered} \tag{23}$$

Corresponding to (17), (24) and (25) set $op_{\mathrm{STOout},s,t}$ respectively $op_{\mathrm{STOin},s,t}$ to one, whenever the storage generates (stores) active power or provides PCR in generating (storage) mode. Similarly to (17), SCR is only considered, if the associated coefficient is one.

$$\begin{gathered} P_{\mathrm{AP,STOout},s,t} - P_{\mathrm{r,STOout},s,t}\, op_{\mathrm{STOout},s,t} \\ + on_{\mathrm{PCR,STO},s,t} P_{\mathrm{PCRpos,STOout},s,t} \\ + on_{\mathrm{SCRpos,STO},s,t} P_{\mathrm{SCRpos,STOout},s,t} \le 0, \\ s = 1,2,\ldots,S,\, t = 1,2,\ldots,T \end{gathered} \tag{24}$$

$$\begin{gathered} P_{\mathrm{AP,STOin},s,t} - P_{\mathrm{r,STOin},s,t}\, op_{\mathrm{STOin},s,t} \\ + on_{\mathrm{PCR,STO},s,t} P_{\mathrm{PCRneg,STOin},s,t} \\ + on_{\mathrm{SCRneg,STO},s,t} P_{\mathrm{SCRneg,STOin},s,t} \le 0, \\ s = 1,2,\ldots,S,\, t = 1,2,\ldots,T \end{gathered} \tag{25}$$

Equations (26) and (27) correspond to (18). Whenever the storage generates or stores active power, the minimum generation respectively storage must be exceeded. Additional provision of PCR and SCR is considered analogously to (18).

$$\begin{aligned}&-P_{\mathrm{AP,STOout},s,t} + P_{\mathrm{min,STOout},s,t}\,op_{\mathrm{STOout},s,t}\\&+P_{\mathrm{PCRneg,STOout},s,t} + P_{\mathrm{SCRneg,STOout},s,t} \le 0,\\&s = 1,2,...,S,\ t = 1,2,...,T\end{aligned} \tag{26}$$

$$\begin{aligned}&-P_{\mathrm{AP,STOin},s,t} + P_{\mathrm{min,STOin},s,t}\,op_{\mathrm{STOin},s,t}\\&+P_{\mathrm{PCRpos,STOin},s,t} + P_{\mathrm{SCRpos,STOin},s,t} \le 0,\\&s = 1,2,...,S,\ t = 1,2,...,T\end{aligned} \tag{27}$$

Depending on the storage technology and its design, storages are able to operate in generating and storage mode in parallel. Whether this is possible for certain storages is indicated by the parameter $pop_{\mathrm{STO},s,t}$ in (28).

$$\begin{aligned}&op_{\mathrm{STOout},s,t} + op_{\mathrm{STOin},s,t} \le 1 + pop_{\mathrm{STO},s,t},\\&s = 1,2,...,S,\ t = 1,2,...,T\end{aligned} \tag{28}$$

3.4 Equality Constraints

The electric load in each bidding zone $P_{\mathrm{L},bz,t}$ must be covered for each point in time following (29). The load is virtually increased by exports and storages in storage mode. It can be covered by active power generation of power plants and storages as well as by imports. The power plants and storages are assigned to the bidding zone (control zone) they are located in by the respective element $pbi_{n,bz}$ ($sbi_{s,bz}$) of a power-plant-bidding-zone (storage-bidding zone) incidence matrix $\boldsymbol{PBI}$ ($\boldsymbol{SBI}$). The elements of this $N \times BZ$- ($S \times BZ$-) matrix are one if the power plant n (storage s) is located in bidding zone bz, otherwise they are zero .

$$\begin{aligned}&\sum_{n=1}^{N} pbi_{n,bz} P_{\mathrm{AP,PP},n,t} + \sum_{s=1}^{S} sbi_{s,bz} P_{\mathrm{AP,STOout},s,t}\\&-\sum_{s=1}^{S} sbi_{s,bz} P_{\mathrm{AP,STOin},s,t} - \sum_{\substack{bzi=1\\bze=bz}}^{BZ} P_{\mathrm{T,AP},bze,bzi,t}\\&+\sum_{\substack{bze=1\\bzi=bz}}^{BZ} P_{\mathrm{T,AP},bze,bzi,t} = P_{\mathrm{L},bz,t},\\&bz = 1,2,...,BZ;\ \forall\ t = 1,2,...,T\end{aligned} \tag{29}$$

Equations (30) to (32) correspond to (29). They ensure an even balance between PCR, SCRpos and SCRneg provision and demand for each control area. Consequently, elements of the power-plant-control-area ($\boldsymbol{PCI}$) and the storage-control-area incidence matrix $\boldsymbol{SCI}$ are used. They can be built analogously to the matrices used in (29).

$$\begin{aligned}&\sum_{n=1}^{N} pci_{n,ca} P_{\mathrm{PCR,PP},n,t} + \sum_{s=1}^{S} sci_{s,ca} P_{\mathrm{PCRpos,STOout},s,t}\\&+\sum_{s=1}^{S} sci_{s,ca} P_{\mathrm{PCRpos,STOin},s,t} - \sum_{\substack{cai=1\\cae=ca}}^{CA} P_{\mathrm{T,PCR},cae,cai,t}\\&+\sum_{\substack{cae=1\\cai=ca}}^{CA} P_{\mathrm{T,PCR},cae,cai,t} = P_{\mathrm{PCRref},ca,t},\\&ca = 1,2,...,CA;\ \forall\ t = 1,2,...,T\end{aligned} \tag{30}$$

$$\begin{aligned}&\sum_{n=1}^{N} pci_{n,ca} P_{\mathrm{SCRpos,PP},n,t} + \sum_{s=1}^{S} sci_{s,ca} P_{\mathrm{SCRpos,STOout},s,t}\\&+\sum_{s=1}^{S} sci_{s,ca} P_{\mathrm{SCRpos,STOin},s,t} - \sum_{\substack{cai=1\\cae=ca}}^{CA} P_{\mathrm{T,SCRpos},cae,cai,t}\\&+\sum_{\substack{cae=1\\cai=ca}}^{CA} P_{\mathrm{T,SCRpos},cae,cai,t} = P_{\mathrm{SCRposref},ca,t},\\&ca = 1,2,...,CA;\ \forall\ t = 1,2,...,T\end{aligned} \tag{31}$$

$$\begin{aligned}&\sum_{n=1}^{N} pci_{n,ca} P_{\mathrm{SCRneg,PP},n,t} + \sum_{s=1}^{S} sci_{s,ca} P_{\mathrm{SCRneg,STOout},s,t}\\&+\sum_{s=1}^{S} sci_{s,ca} P_{\mathrm{SCRneg,STOin},s,t} - \sum_{\substack{cai=1\\cae=ca}}^{CA} P_{\mathrm{T,SCRneg},cae,cai,t}\\&+\sum_{\substack{cae=1\\cai=ca}}^{CA} P_{\mathrm{T,SCRneg},cae,cai,t} = P_{\mathrm{SCRnegref},ca,t},\\&ca = 1,2,...,CA;\ \forall\ t = 1,2,...,T\end{aligned} \tag{32}$$

As already mentioned above, PCR must be provided symmetrically by each generating unit. The equality between positive and negative PCR provided by storages is ensured by (33).

$$\begin{aligned}&P_{\mathrm{PCRpos,STOout},s,t} + P_{\mathrm{PCRpos,STOin},s,t}\\&-P_{\mathrm{PCRneg,STOout},s,t} - P_{\mathrm{PCRneg,STOin},s,t} = 0,\\&s = 1,2,...,S,\ t = 1,2,...,T\end{aligned} \tag{33}$$

Beside power plant start-ups and the corresponding start-up costs, the state of charge of storages links the different points in time which could otherwise be considered independently. The variation in the state of charge for each storage (defined at the end of each point in time t) is represented by (34) and (35). Specific values for start and end point ($E_{\mathrm{STO,start},s}$ and $E_{\mathrm{STOend},s}$) are included by (34) and (36), while (36) is optional. Active power generation reduces the state of charge of the storage, active power storage increases it. For both operating modes, the efficiency of the respective mode ($\eta_{\mathrm{STOout},s,t}$, $\eta_{\mathrm{STOin},s,t}$) has to be considered. Additionally, the state of charge is reduced by SCRpos activation and increased by SCRneg activation. As already mentioned above, the individual deployment probability cannot be modelled in this linear model. Therefore, the SCR provision is multiplied by an activation coefficient (ac_{SCRpos}, ac_{SCRneg}) calculated as the historical mean value of SCRpos respectively SCRneg activation relative to the historical provision. Finally, tributaries or outlets (water storages) or state-of-charge-independent losses can be taken into account by $E_{\mathrm{STOtri},s,t}$. The model time step Δt is used to convert between power and energy.

$$\begin{aligned}
&-\frac{1}{\eta_{\mathrm{STOout},s,1}} P_{\mathrm{AP,STOout},s,1} \\
&+\eta_{\mathrm{STOin},s,1} P_{\mathrm{AP,STOin},s,1} \\
&-ac_{\mathrm{SCRpos}} \frac{1}{\eta_{\mathrm{STOout},s,1}} P_{\mathrm{SCRpos,STOout},s,1} \\
&-ac_{\mathrm{SCRpos}} \eta_{\mathrm{STOin},s,1} P_{\mathrm{SCRpos,STOin},s,1} \\
&+ac_{\mathrm{SCRneg}} \frac{1}{\eta_{\mathrm{STOout},s,1}} P_{\mathrm{SCRneg,STOout},s,1} \\
&+ac_{\mathrm{SCRneg}} \eta_{\mathrm{STOin},s,1} P_{\mathrm{SCRneg,STOin},s,1} \\
&-\frac{E_{\mathrm{STO},s,t}}{\Delta t} = -\frac{E_{\mathrm{STOtri},s,1}}{\Delta t} - \frac{E_{\mathrm{STO,start},s}}{\Delta t},
\end{aligned} \tag{34}$$

4 IMPLEMENTATION STATUS

The generation dispatch model described in this paper has been implemented using Gurobi Optimizer and is currently being tested. Additionally, functions reducing the optimization variables (e.g. by pooling generation with identical or similar properties within the same bidding zone and control area, mainly RES generation) and to calculate valid start values for the optimization have been implemented.

It is intended to simulate periods of one year with IGEM, as this period corresponds to most of the available statistical data. Beyond that, there are typical cycles within the electric power system, mainly influenced by the climate, that can only be fully covered by considering whole years, for instance the use of hydro storage power plants (not pumped-storage power plants) filled in winter and spring to generate power in summer and fall.

In the current implementation status the simulation of a whole year formulated as a single optimization problem is too computationally expensive. Therefore, shorter, overlapping periods are optimized and then combined. It is assumed that the horizon for operational planning of generating units apart from hydro storage plants is significantly shorter than one year. This is currently being investigated by comparison of results for periods of different length. However, this approach requires a separate strategy for hydro storage plants which is currently being investigated.

$$\begin{aligned}
&-\frac{1}{\eta_{\mathrm{STOout},s,t}} P_{\mathrm{AP,STOout},s,t} \\
&+\eta_{\mathrm{STOin},s,t} P_{\mathrm{AP,STOin},s,t} \\
&-ac_{\mathrm{SCRpos}} \frac{1}{\eta_{\mathrm{STOout},s,t}} P_{\mathrm{SCRpos,STOout},s,t} \\
&-ac_{\mathrm{SCRpos}} \eta_{\mathrm{STOin},s,t} P_{\mathrm{SCRpos,STOin},s,t} \\
&+ac_{\mathrm{SCRneg}} \frac{1}{\eta_{\mathrm{STOout},s,t}} P_{\mathrm{SCRneg,STOout},s,t} \\
&+ac_{\mathrm{SCRneg}} \eta_{\mathrm{STOin},s,t} P_{\mathrm{SCRneg,STOin},s,t} \\
&+\frac{E_{\mathrm{STO},s,t}}{\Delta t} - \frac{E_{\mathrm{STO},s,t}}{\Delta t} = -\frac{E_{\mathrm{STOtri},s,t}}{\Delta t}, \\
&s = 1,2,\ldots,S,\ t = 2,3,\ldots,T
\end{aligned} \tag{35}$$

$$\begin{aligned}
&E_{\mathrm{STO},s,T} = E_{\mathrm{STOend},s},\ s = 1,2,\ldots,S \\
&s = 1,2,\ldots,S,\ t = 2,3,\ldots,T
\end{aligned} \tag{36}$$

5 CONCLUSIONS

A MILP approach for a generation dispatch module for an integrated grid and electricity market model covering the Continental European electric power system has been presented. Beside the electricity wholesale market, the model covers the markets for PCR and SCR. By this, the model reproduces the decisions of generating unit operators on which markets to get involved. Besides, the introduction of integrality conditions allows to consider start-up costs and the calculus of generating units to pass through pricewise unattractive periods in order to avoid another start-up. Finally, the MILP approach allows to consider the fact that PCR and SCR provision usually requires power plant operation and to fully include storages into the optimization problem.

The fundamental assumption justifying the chosen modelling approach is a perfect allocation at the existing power markets. This implies that a global optimization – namely a minimization of all variable costs in the period of consideration – reproduces the power market results in terms of generation dispatch, disregarding different products and trading periods. As the results combine considerations about several markets, no market price can be derived directly from them. The different prices have to be calculated in another module of IGEM.

The generation dispatch module has been fully implemented into IGEM. First results are plausible. Though, improvements are required to simulate one full year formulated as single optimization problem. In future work, decomposition strategies and heuristics focusing on the coupling between bidding zones and different points in time will be evaluated with respect to a possible reduction of the computational effort, a market price calculation module will be implemented, and the simulation results will be evaluated by comparison to real market results.

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