MFT Energy - Interview Presentation

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Outline I

Presentation

1. Economics of Power Generation
2. Economic Dispatch of Power Plants
3. Fundamental Models with Python
4. Fundamental Models with GAMS
5. Beyond supply stack effects

Before we dive too deeply into understanding the economics of power plants, it will be useful to review some basic cost concepts:

- Total cost: The total cost of producing Q MWh of electricity (takes units of euros)
- Average cost of energy: The average cost of producing one MWh of electric energy (takes units of euros per MWh).
- Average cost of capacity: The average cost of one MW of electric power capacity (takes units of euros per MW)
- Marginal cost of energy: The incremental cost, in euros per MWh, of producing an additional unit of electric energy.
- Variable costs are those that change when output changes. Examples of variable costs for power generation include the cost of fuel, the cost of labor or materials, costs to start up and shut down plants, and some types of environmental costs.
- Fixed costs are those that remain at a fixed amount no matter how much electricity the plant produces. Examples of fixed costs include capital, some types of labor costs, insurance and land.

For virtually all power plant technologies, the cost of capital and the cost of fuel are the biggest drivers in overall power plant economics. The relative importance of fuel and capital costs vary widely by technology,

The fixed costs are relatively straightforward, but the variable cost of power generation is remarkably complex.

- The fixed costs of power generation are essentially capital costs and land
- Operating costs for power plants include fuel, labor and maintenance costs. Unlike capital costs which are "fixed" (don't vary with the level of output), a plant's total operating cost depends on how much electricity the plant produces. The operating cost required to produce each MWh of electric energy is referred to as the "marginal cost."
- In general, central station generators face a tradeoff between capital and operating costs. Those types of plants that have higher capital costs tend to have lower operating costs.
- Irrespective of technology, all generators share the following characteristics that influence the plant's operations:
  - Ramp rate : This variable influences how quickly the plant can increase or decrease power output, in [MW/h]
  - Ramp time : The amount of time it takes from the moment a generator is turned on to the moment it can start providing energy to the grid at its lower operating limit, in [h]
  - Capacity : The maximum output of a plant, in [MW]
  - Minimum Run Time : The shortest amount of time a plant can operate once it is turned on, in [h].
  - No-Load Cost : The cost of turning the plant on, but keeping it "spinning," ready to increase power output, in [euros/MWh].
  - Start-up and Shut-down Costs : These are the costs involved in turning the plant on and off, in [euros/MWh].

Variable costs refer to the costs of power generation that change as the amount of electricity is generated. The simplest model for variable cost of power generation is:

- Marginal cost of generation (euros/MWh) = Marginal cost of Fuel + Variable operations and maintenance costs.
- The marginal cost of generation for power plants that run on fossil fuels plants (coal, oil, gas) is dominated by fuel costs. Labor and maintenance are additional costs, but these are smaller.
- Marginal costs for renewable power generation and nuclear power are dominated by operations and maintenance (OM) costs.
- The short-run marginal cost measures the cost to produce a unit of electric energy (not power), given an existing power plant. So the short run marginal cost captures fuel and variable OM costs.
- The "long run marginal cost" measures the cost to produce a unit of electric energy where we don't assume that the capacity of the plant is fixed.
- The marginal fuel cost of a plant that uses coal, oil or natural gas is determined by the plant's efficiency or "heat rate," which is the the ratio of input energy to output energy, or how much fuel it takes to produce a unit of electrical energy.
- The heat rate determines the efficiency with which a power plant converts fuel to electricity.

Since electricity cannot be stored in power lines, the entity operating the power grid must continuously adjust the output of its power plants to meet electricity demand. This process is called the "dispatch" of power plants. There are actually two stages to the dispatch process, and they occur over different time horizons.

- The first stage is called "unit commitment," which occurs a day or more in advance of the need to meet real-time electricity demand. Under unit commitment, the utility or power grid operator makes decisions about which of its power plants to turn on or off in anticipation of needing to meet electricity demand.
- The second stage is what we refer to as "dispatch," where the plants that are committed are selected to run at a given level to meet total electricity demand. The dispatch decision is driven primarily by economic factors, as we'll see in the next section, but other types of operational considerations such as ramp rates and minimum run times are also used in the dispatch decision. Our focus will be on those economic factors.
- The objective of the electric utility or grid operator on an hour-to-hour basis is to minimize the total generation cost of meeting electricity demand. Economic Dispatch is the procedure by which the utility selects which of its generators it will use to meet electricity demand.

You can think about economic dispatch like clearing the electricity market, as follows:

- The utility constructs a marginal cost (supply) curve for its entire system.
- Demand is often assumed to be price-inelastic (vertical demand curve).
- The marginal cost of generation at the market-clearing point (supply = demand) is called the "System Lambda."
- The generator whose output serves the marginal kWh of electricity demand is called the "marginal unit."

We will go through the economic dispatch procedure using two models for power generation costs. The first model assumes that the marginal costs of power plants are all constant. The second assumes that the marginal costs of power plants are all linear (so marginal cost increases as more power is generated).

Economic Dispatch with Constant Marginal Cost

- If the total cost of electricity production from a power plant is linear in the amount of electricity produced:

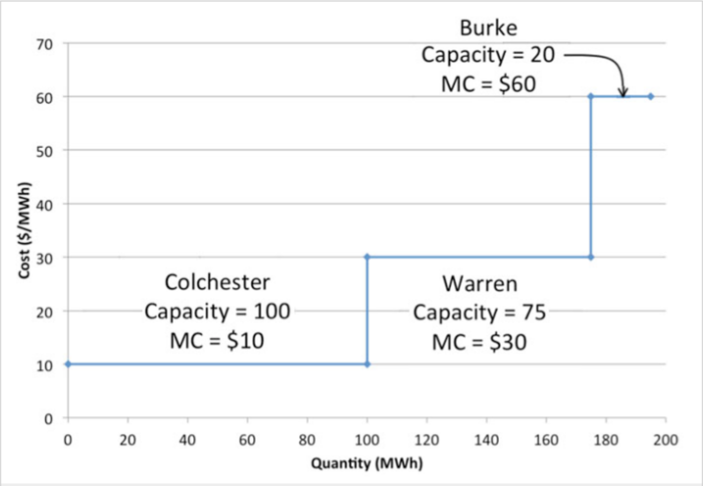
  $$TC(Q) = a + b \times Q$$

  where TC is total cost (euros), Q is total output (MWh), and a and b are constants
- Then the marginal cost of electricity production is found by taking the derivative of the total cost function:

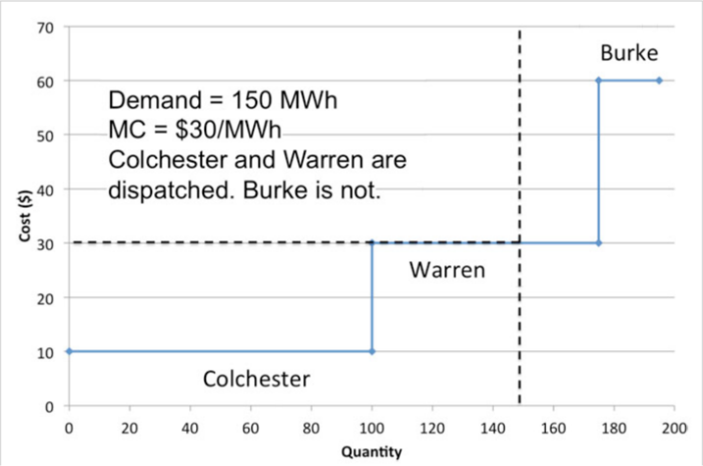
  $$\frac{dTC(Q)}{dQ} = b$$

- The way that we construct a supply curve in the presence of constant marginal costs is to stack each of the power plants in increasing cost order. This will yield a supply curve that looks like a staircase.

Plant Name	Capacity (MW)	Fixed Costs	Marginal Cost (euros/MWh)
Colchester	100	50	10
Warren	75	25	30
Burke	20	10	60


Burke
Capacity = 20
MC = $60
Colchester
Capacity = 100
MC = $10
Warren
Capacity = 75
MC = $30
Cost ($/MWh)
Quantity (MWh)
0
10
20
30
40
50
60
70
0
20
40
60
80
100
120
140
160
180
200

To determine which plants would be operating if the demand was 150 MWh, you would draw a straight vertical line through the amount 150 MWh. Any capacity to the left of this line would be dispatched, while any capacity to the right of the line would not be dispatched.



Economic Dispatch with Linear Marginal Costs

- A more realistic cost model for an electric power plant is that the total cost of generation is quadratic in the amount of electricity produced.

$$TC(Q) = a + b \times Q + c \times Q^2$$

  where TC is total cost (euros), Q is total output (MWh), and a, b and c are constants
- Then the marginal cost of electricity production is found by taking the derivative of the total cost function:

$$\frac{dTC(Q)}{dQ} = b + c \times Q$$

- Because the marginal cost functions here are linear, we can use calculus to figure out the solution to the economic dispatch problem. In the solution we present here, we'll assume that there are only two generators. The solution to the economic dispatch problem we'll find, however, is also true for cases where there are more than two generators.
- Before we get into it, we'll define a few variables:
  - g1 and g2 are the electric energy (MWh) outputs of our two power plants.
  - C1(g1) and C2(g2) are the total cost functions for the two power plants individually.
  - TC(g1 + g2) is the total cost function for the electric system as a whole. We can also write this as TC(g1 + g2) = C1(g1) + C2(g2).
  - D is total demand (in MWh).

Economic Dispatch with Linear Marginal Costs

- Economic dispatch is a kind of optimization problem. The electric utility wants to choose levels of g1 and g2 in order to minimize the total cost of serving all electricity demand.
- The utility is constrained by the fact that it has to meet all electricity demand. It cannot simply choose to black out some houses or businesses because they are too expensive to serve.
- Mathematically, we state this optimization problem as

$$\min_{g1,g2} TC(g1+g2) \quad \text{s.t.} \quad g1+g2=D$$

- First, notice that since g1 + g2 = D, we get g2 = D - g1. Also, each generator's cost function depends only on that generator's output. So we can simplify this into a much easier problem that only depends on g1:

$$\min_{g1} TC(g1) = [C1(g1) + C2(D-g1)]$$

- We will now take the derivative of this function and set it equal to zero. This is called the "first order condition" of the optimization problem, or FOC.

Economic Dispatch with Linear Marginal Costs

$$\min_{g1} TC(g1) = [C1(g1) + C2(D - g1)]$$

$$\text{FOC}: \quad \frac{dTC}{dg1} = \frac{C1}{dg1} - \frac{dC2}{dg1} = 0$$

$$\Rightarrow \frac{dC1}{dg1} = \frac{dC2}{dg1}$$

- Notice that the solution to the economic dispatch problem is to set g1 and g2 such that their marginal costs are identical. We will call these optimal level of energy outputs g1* and g2*.
- This result also holds if we have more than two power plants. In this case we can find the system lambda by calculating the marginal cost for either generator at the optimal level (g1* or g2*).
- A kind of recipe for solving economic dispatch problems with quadratic total costs (linear marginal cost) is:
  - Calculate marginal cost functions for each generator.
  - Set g2 = D - g1, and substitute in the marginal cost function for g2.
  - Set the marginal cost functions equal, solve for g1* (optimal value of g1).
  - Find g2* = D - g1*

An Example of a Model built in Python : PowNet

- PowNet is a least-cost optimization model for simulating the Unit Commitment and Economic Dispatch (UC/ED) of large-scale (regional to country) power systems.
- In PowNet, a power system is represented by a set of nodes that include power plants, high-voltage substations, and import/export stations (for cross-border systems).
- The model schedules and dispatches the electricity supply from power plant units to meet hourly electricity demand in substations (at a minimum cost).
- It considers the techno-economic constraints of both generating units and high-voltage transmission network.
- By Chowdhury, A.F.M.K., Kern, J., Dang, T.D. and Galelli, S., 2020. PowNet: A Network-Constrained Unit Commitment/Economic Dispatch Model for Large-Scale Power Systems Analysis. Journal of Open Research Software, 8(1), p.5. https://dx.doi.org/http://doi.org/10.5334/jors.302
- PowNet is implemented in Python (Pyomo) and is compatible with any standard optimization solver (e.g., Gurobi, CPLEX).

An Example of a Model built in Python : PowNet

- Indices and sets
  - n : any node in the system
  - N : set of all nodes in the system
  - g : dispatchable unit
  - G : set of all dispatchable units
  - i : import node
  - I : set of all import nodes
  - rn : variable renewable resource (e.g., hydro, wind, solar)
  - RN : set of all variable renewable resources
  - k : sink node connected by the transmission line to any node n
  - t : time-step (hour, h)
  - T : planning horizon (e.g., 24 h)
- Parameters of the dispatchable units (g)
  - $MaxCap_g$: maximum capacity (MW)
  - $MinCap_g$: minimum capacity (MW)
  - $FixedCost_g$ fixed OM cost ($)
  - $StartCost_g$ start-up cost ($/start)
  - $HeatRate_g$ heat rate (MMBtu/MWh)
  - $FuelPrice_g$ price of fuel ($/MMBtu)
  - $VarCost_g$ variable OM cost ($/MWh)
  - $Ramp_g$ ramping limit (MW/h)
  - $MinUpTime_g$ minimum up time (h)
  - $MinDownTime_g$ minimum down time (h)

An Example of a Model built in Python : PowNet

- Parameters of the import nodes (i)
  - $MaxCap_i$: maximum allowable import (MW)
  - $ImportPrice_i$: price of imported electricity ($/MWh)
- Parameters of the transmission network
  - $LineSus_{n,k}$: susceptance (Siemens) of the transmission line between nodes n and k
  - $LineCap_{n,k}$: capacity (MW) of the transmission line between nodes n and k
- Input time series (hourly)
  - $RenewAvail_{m,t}$: available electricity (MWh) from the rn-th renewable resource
  - $Demand_{n,t}$: electricity demand (MWh) (or export) at any node n
- Decision variables (at each hour t)
  - $ON_{n,t}$: binary (0,1) variable indicating if unit g is online (1) or offline (0)
  - $Switch_{g,t}$: binary (0,1) variable indicating if unit g must be started-up ($Switch_{g,t} = 1$ only when $ON_{g,t-1}$ = 0 is followed by $ON_{g,t} = 1$)
  - $Elec*_{g,t}$: electricity (MWh) generated by dispatchable unit g (*or any other powerplant)
  - $VoltAngle_{n,t}$: voltage angle (radian) at any node n
  - $SpinRes_{g,t}$: spinning reserve (MWh) at unit g
  - $NonSpinRes_{g,t}$: non-spinning reserve (MWh) at unit g

An Example of a Model built in Python : PowNet

- The objective function:

$$\min \sum_{t=1}^{T} (\sum_{g}^{G} (FixedCost_g \times ON_g + Elec_g \times (HeatRate_g \times FuelPrice_g + VarCost_g) +$$

$$StartCost_g \times Switch_g) + \sum_{i}^{I} (Elec_i \times ImportPrice_i) + \sum_{i}^{I} Elec_{rn} \times UnitCost_{rn}))$$

- The constraints. Logical constraints:

$$Switch_{g,t} \geq 1 - ON_{g,t-1} - (1 - ON_{g,t});$$
$$ON_{g,t} \in \{0,1\}, Switch_{g,t} \in \{0,1\} \forall g, \forall t$$

and

$$ON_{g,t} - ON_{g,t-1} \leq ON_{g,j};$$
$$\forall g, t \in \{2, T-1\}, t < j \leq min(t + MinUpTime_g - 1, T),$$
$$ON_{g,t-1} - ON_{g,t} \leq ON_{g,j};$$
$$\forall g, t \in \{2, T-1\}, t < j \leq min(t + MinDownTime_g - 1, T),$$

An Example of a Model built in Python : PowNet

- Ramping limits:

$$Elect_{g,t} - Elect_{g,t-1} \leq Ramp_g; \forall g, \forall t$$
$$Elect_{g,t-1} - Elect_{g,t} \leq Ramp_g; \forall g, \forall t$$

- Capacity constraints:

$$MinCap_{g,t} \times ON_{g,t} \leq Elec_{g,t} \leq MaxCap_{g,t} \times ON_{g,t} \times DerateF_{g,t}; \forall g, \forall t$$
$$0 \leq Elec_{i,t} \leq MaxCap_{i,t} \times ON_{i,t}; \forall i, \forall t$$
$$0 \leq Elec_{rn,t} \leq RenewAvail_{rn,t}; \forall rn, \forall t$$

- Energy Balance:

$$(1 - TransLoss) \times \sum Elec_{n,t} - Demand_{n,t}(-Export_{n,t})$$
$$= \sum_{k \in N} LineSus_{k,n} \times (VoltAngle_{n,t} - VoltAngle_{k,t}); \forall n, \forall t$$

An Example of a Model built in Python : PowNet

- Transmission capacity constraints:

$$-N1Criterion \times LineCap_{n,k} \leq LineSusn, k \times (VoltAngle_{n,t} - VoltAngle_{k,t}) \leq -N1Criterion \times LineCap_{n,k}; \forall n, \forall k, k \in N$$

- Electricity reserve:

$$\sum_{g}^{G}(SpinRes_{g,t} + NonSpinRes_{g,t}) \geq ResMargin \sum_{n}^{N} Demand_t; \forall t$$

$$\sum_{g}^{G} SpinRes_{g,t} \geq SpinMargin \times ResMargin \times \sum_{n}^{N} Demand_t; \forall t$$

An Example of a Model built in GAMS : Dispa-SET

- The aim of the Dispa-SET model is to represent with a high level of detail the short-term operation of large-scale power systems, solving the unit commitment problem
- To that aim, it is considered that the system is managed by a central operator with full information on the technical and economic data of the generation units, the demands in each node, and the transmission network
- The unit commitment problem consists of two parts: i) scheduling the start-up, operation, and shut down of the available generation units, and ii) allocating (for each period of the simulation horizon of the model) the total power demand among the available generation units in such a way that the overall power system costs is minimized
- The first part of the problem, the unit scheduling during several periods of time, requires the use of binary variables in order to represent the start-up and shut down decisions, as well as the consideration of constraints linking the commitment status of the units in different periods
- The second part of the problem is the economic dispatch problem, which determines the continuous output of each and every generation unit in the system.
- By Quoilin, S., Hidalgo Gonzalez, I., Zucker, A. (2017). Modelling Future EU Power Systems Under High Shares of Renewables: The Dispa-SET 2.1 open-source model. Publications Office of the European Union. https://dx.doi.org/10.2760/25400
- Based on Python (Pyomo), GAMS. Using Python for data processing.

An Example of a Model built in GAMS : Dispa-SET

- Indices and sets
  - i : Time step in the current optimization horizon
  - u : Units
  - l : Transmission lines between nodes
  - n : Zones within each country (currently one zone, or node, per country)
  - 2U : Reserve up
  - 2D : Reserve down
- Dispa-SET parameters
  - CostStartUp(u) : Start-up costs (EUR/h)
  - CostShutDown(u) : Shut-down costs (EUR/h)
  - CostFixed(u) : Fixed costs (EUR/h)
  - Committed(u,h) : Unit committed at hour h {1,0}
  - CostVariable(u,i) : Variable costs (EUR/MWh)
  - Power(u,h) : Power output (MW)
  - CostRampUp(u,h) : Ramping cost (EUR)
  - CostRampDown(u,h) : Ramping cost (EUR)
  - PriceTransmission(l,h) : Price of transmission between zones (EUR/MWh)
  - CostLoadShedding(n,h) : Shedding costs (EUR/MWh)
  - ShedLoad(n,h) : Shed load (MW)
  - VOLL () : Value of lost load (EUR/MWh)
  - LostLoadReserve2U(n,h) : Deficit in reserve up (MW)
  - LostLoadMaxPower(n,h) : Deficit in terms of maximum power (MW)
  - LostLoadMinPower(n,h) : Power exceeding the demand (MW)
  - LostLoadRampUp(u,h) : Deficit in terms of ramping up for each plant (MW)
  - LostLoadRampDown(u,h) : Deficit in terms of ramping down for each plant (MW)

An Example of a Model built in GAMS : Dispa-SET

- The objective function:

$$
\begin{aligned}
\min \sum_{u,n,i} & CostStartUp_{u,i} + CostShutDown_{u,i} + CostFixed_u.Committed_{u,i} \\
& + CostVariable_{u,i}.Power_{u,i} + CostRampUp_{u,i} + CostRampDown_{u,i} \\
& + PriceTransmission_{i,l}.Flow_{i,l} + CostLoadShedding_{i,n}.ShedLoad_{i,n} \\
& + VOLL_{Power}(LostLoadMaxPower_{i,n} + LostLoadMinPower_{i,n}) \\
& + VOLL_{Reserve}(LostLoadReserve2U_{i,n} + LostLoadReserve2D_{i,n}) \\
& + VOLL_{Ramp}(LostLoadRampUp_{u,i} + LostLoadRampDown_{u,i})
\end{aligned}
$$

- The costs can be broken down as:
  - Fixed costs: depending on whether the unit is on or off
  - Variable costs: stemming from the power output of the units.
  - Start-up costs: due to the start-up of a unit.
  - Shut-down costs: due to the shut-down of a unit.
  - Ramp-up: emerging from the ramping up of a unit
  - Ramp-down: emerging from the ramping down of a unit.
  - Shed load: due to necessary load shedding.
  - Transmission: depending of the flow transmitted through the lines
  - Loss of load: power exceeding the demand or not matching it, ramping and reserve.

An Example of a Model built in GAMS : Dispa-SET

- Load Shedding : Load shedding is when power companies reduce electricity consumption by switching off the power supply to groups of customers because the entire system is at risk. This could be because there is a shortage of electricity supply, or to prevent transmission and distribution lines from becoming overloaded.
- Spinning Reserves : The spinning reserve is the extra generating capacity that is available by increasing the power output of generators that are already connected to the power system. For most generators, this increase in power output is achieved by increasing the torque applied to the turbine's rotor. managed by a central operator with full information on the technical and economic data of the generation units, the demands in each node, and the transmission network
- Non Spinning Reserves : The non-spinning reserve or supplemental reserve is the extra generating capacity that is not currently connected to the system but can be brought online after a short delay. In isolated power systems, this typically equates to the power available from fast-start generators. However, in interconnected power systems, this may include the power available on short notice by importing power from other systems or retracting power that is currently being exported to other systems.
- Curtailment : Curtailment is a reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis. Curtailment of generation has been a normal occurrence since the beginning of the electric power industry

An Example of a Model built in GAMS : Dispa-SET

- The constraints :
  - Demand-related constraints
  - Power output bound
  - Minimum up and down times
  - Storage-related constraints
  - Network-related constraints
  - Emission limits
  - Curtailment
  - Load shedding
- GAMS Flow of coding :
  - Define Sets
  - Define Parameters
  - Define Variables
  - Define Equations
  - Write Equations
  - Solve Statement
  - Display

Main Solution Techniques :

- Characteristics of a good technique :
  - Solution close to the optimum
  - Reasonable computing time
  - Ability to model constraints
- Possible techniques :
  - Priority list / heuristic approach
  - Dynamic programming
  - Lagrangian relaxation
  - LP : Linear Programming
  - NLP : Non-Linear Programming
  - MIP : Mixed Integer Programming
  - MILP : Mixed Integer Linear Programming
  - RMIP : Relaxed MIP where integer variables are treated as continuous
  - MINLP : Mixed-Integer Non Linear Programming in which the integer variables are 0-1 and linear, the continuous variables can be non-linear
  - RMINLP : Mixed Integer Non-Linear Programming where the integer variables are treated as continuous

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

- The major strength of a fundamental modeling approach is:
  - The possibility to account for non-linearities.
  - The ability to combine time-varying information such as fuel and CO_2 prices or renewable feed-in consistently.

  What's more, fundamental approaches are flexible in the sense that existing models can be integrated for certain fundamental factors (wind forecasting tools).
- The first objective of the article is to develop a fundamental model to explain current Day-ahead and Intraday market prices in Germany. Fundamental models differ concerning the applied methodology and the forecasting target.
- The second objective of the article is to explain differences between the prices predicted by the supply stack model and the prices actually observed.
- Using multiple linear models, the price difference is tested for influences from (i) avoided start-up costs, (ii) different market states and (iii) trading behavior.
- The paper contributes to theoretical intraday pricing literature as follows:
  - The fundamental modeling approach is modified to account for Intraday market peculiarities.
  - These peculiarities include a limited technical flexibility of conventional power plants to adjust their generation within short Intraday lead-times.
  - The supply stack from the day-ahead planning is divided into scheduled and unscheduled power plants.
  - The paper also contributes to academic literature by including a representation for must-run electricity production from combined heating and power production facilities (CHP).

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

- The models developed may be used for very short term price forecasting and may thus reduce the high level of uncertainty.
- Trading in the Intraday markets requires frequent re-optimizations due to the constant improvements of information quality after the day-ahead scheduling.
- In the light of the Regulation on Wholesale Energy Market Integrity and Trasnparency (REMIT) in Europe a fundamental price estimate may provide competititive prices and thus help to evaluate effects of an increased electricity market transparency. (Nijman, 2012).
- The hedging activities, from power plant operations for their electricity production or from retail companies for their electricity consumption start several years before delivery.
- Third, the ability to understand and predict intraday price volatility may be used to optimize unit commitment and increase revenues from the operation of flexible power plants such as hydro pump storages, gas turbines or modern hard coal power plants.

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

$y_{p,t}$: Total power plant output.
$p_{fuel,t}$: Fuel prices.
$p_{CO2,t}$: Emission certificate prices.
h_{pl}: Plant heat rate.
$c_{pl,t}^{other}$: Other variable costs.

$$C_t = \sum_{pl} c_{pl,t} = \sum_{pl} [(p_{fuel,t} + p_{CO2,t}.\epsilon_{fuel}).h_{pl} + c_{pl,t}^{other}].y_{pl,t} \tag{1}$$

Equation (2) holds for $0 \leq D_t \leq K_{pl,fuel}.v_{fuel,t}$ (negative residual load). When $D_t \geq K_{pl,fuel}.v_{fuel,t}$, the resulting prices are assumed to be equal $tomax(c_{pl,t})$. Resulting quantities of undersupply can be interpreted as reserve energy demand.

$$D_t = \sum_{pl} y_{pl,t} \tag{2}$$

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

$\nu_{fuel,t}$: Power plant availabilities.
$\gamma_{fuel,t}^{sched}$: Scheduled power plant availabilities.
$\gamma_{fuel,t}^{unsched}$: Unscheduled power plant availabilities.
K_{pl}: Installed capacity K_{pl}.

$$\nu_{fuel,t} = 1 - \frac{\gamma_{fuel,t}^{sched} + \gamma_{fuel,t}^{unsched}}{\sum_{pl=fuel} K_{pl}} \tag{3}$$

$y_{pl,t}^{DA}$: Dayahead must-run production obligations.
K_{pl}: Installed capacity.
$\nu_{fuel,t}^{DA}$: Dayahead plant availability.
$y_{pl,t}^{CHP}$: Must-run production obligations.

$$y_{pl,t}^{DA} \leq K_{pl}\nu_{fuel,t}^{DA} - y_{pl,t}^{CHP} \tag{4}$$

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

$\underline{y_{pl,t}^{CHP}}$: Must-run production obligation related to combined heating and power production (CHP).

$\underline{y_{fuel,year}^{CHP}}$: Yearly must-run production obligation related to combined heating and power production (CHP).

$\underline{temp_t}$: Hourly average temperature (temp$_t$).

$\underline{K_{pl}^{CHP}}$: The capacity of must-run power plants including CHP power plants.

$\underline{\nu_{fuel,t}}$: Plant availability.

$$y_{pl,t}^{CHP} = y_{fuel,year}^{CHP}.f(temp_t)\frac{K_{pl}^{CHP}\nu_{fuel,t}}{\sum_{pl=fuel}[K_{pl}^{CHP}\nu_{fuel,t}]} \tag{5}$$

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

D_t: Residual load: gross national load after the deduction of renewable feed-in, considering foreign trade balance and reserve power demand.
L_t: Gross national load.
W_t: Wind.
S_t: Solar.
Ex_t: Exports from a country Ex_t increase the residual demand.
Im_t: Imports from a country Im_t decrease the residual demand.
RE_t^{pos}: Positive primary and secondary reserve demand are added to the load data.
$y_{pl,t}^{CHP}$: Must-run production obligation related to combined heating and power production (CHP).

$$D_t = L_t - W_t - S_t + Ex_t - Im_t + RE_t^{pos} - \sum_{pl} y_{pl,t}^{CHP} \tag{6}$$

Reviewing the article : Are fundamentals enough? Explaining price variations in the German day-ahead and intraday power market, by Pape, Hagemann and Weber

- Demand in the model is considered as residual load D_t given by Eq. (6). The residual load represents the gross national load L_t after the deduction of renewable feed-in, considering foreign trade balance and reserve power demand.
- The must-run electricity production from CHP plants is substracted from the electricity demand because the obligation to cover the heat demand is assumed to cause the marginal costs of electricity production to be equal zero.
- Similarly, the fluctuating renewable feed-in (Wind W_t and Solar S_t) is substracted because the marginal costs are zero or close to zero. An increase in production (supply) implies a reduction in demand from conventional plants and vice versa.

Fundamental Modeling of Intraday Prices

Equation (4) becomes :

$$y_t^{ID} = \begin{cases} (K_{pl,fuel} v_{fuel,t}^{ID} - y_{pl,t}^{CHP} - y_{margpl,t}^{DA}) s_{up}, pl < margpl \\ (K_{pl,fuel} v_{fuel,t}^{ID} + y_{pl,t}^{CHP} - y_{margpl,t}^{DA}) s_{down}, pl \geq margpl \end{cases} \tag{7}$$

Identifying price impacts beyond pure supply stack effects

- (Avoided) Start-Up Costs

$$Ramp_t^{Up} = |(RES_t - \frac{\sum_{i=1}^{H} RES_{t-i}}{H})^{+}| \tag{8}$$

$$Ramp_t^{Down} = |(RES_t - \frac{\sum_{i=1}^{H} RES_{t-i}}{H})^{-}| \tag{9}$$

- Market State Variables

$$LSR_t = \frac{D_t}{\sum_{pl} K_{pl} \nu_{fuel,t}} \tag{10}$$

- Trading Behaviour

$$\begin{aligned} DAP_t = c_1 + c_2.DAP_t^{fund} + c_3.Ramp_t^{DA,Up} + c_4.Ramp_t^{DA,Down} \\ + c_5.LSR_{low,t}^{DA} + c_6.LSR_{high,t}^{DA} + c_7.DAP_{t-24} + \epsilon_t \end{aligned}$$

$$\begin{aligned} IDP_t = c_1 + c_2.IDP2_t^{fund} + c_3.Ramp_t^{ID,Up} + c_4.Ramp_t^{ID,Down} \\ + c_5.LSR_{low,t}^{ID} + c_6.LSR_{high,t}^{ID} + c_7.IDP_{t-1} + \epsilon_t \end{aligned}$$