Remuneration of Power Generation Capacity in Conditions of Scarcity in Belgium

Anthony Papavasiliou, Yves Smeers

Center for Operations Research and Econometrics

Université Catholique de Louvain

September 30, 2016

Presentation at the CREG Advisory Council

Outline

- Motivation
  - Renewable energy integration
  - Nuclear capacity in Belgium
- Background
  - Paying for capacity in electricity markets
  - The shift of value in electricity markets
  - Operating reserve demand curves
- Methodology
  - Framework of the study
  - Modeling the Belgian market
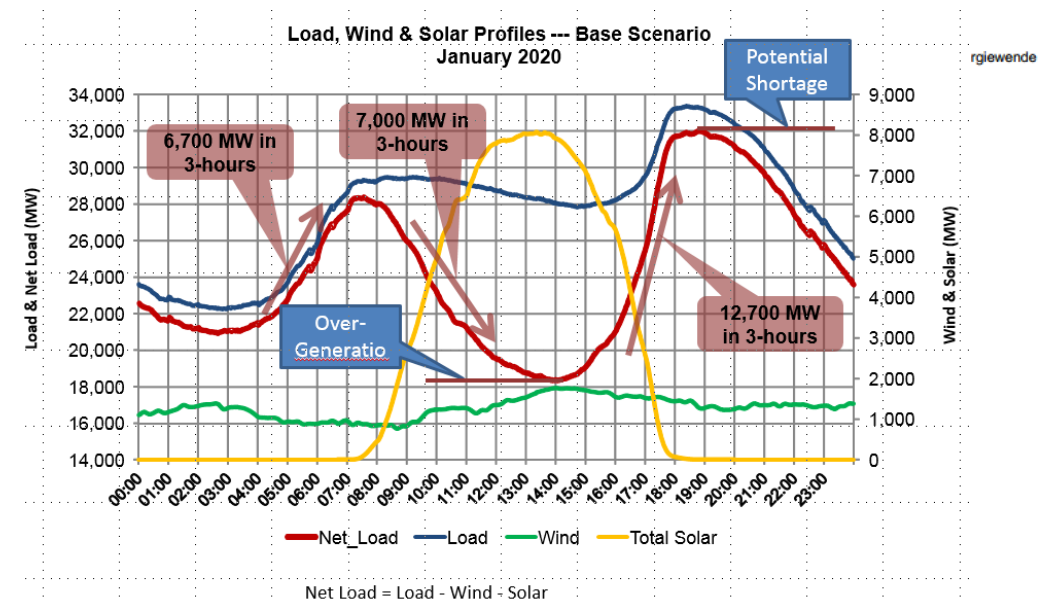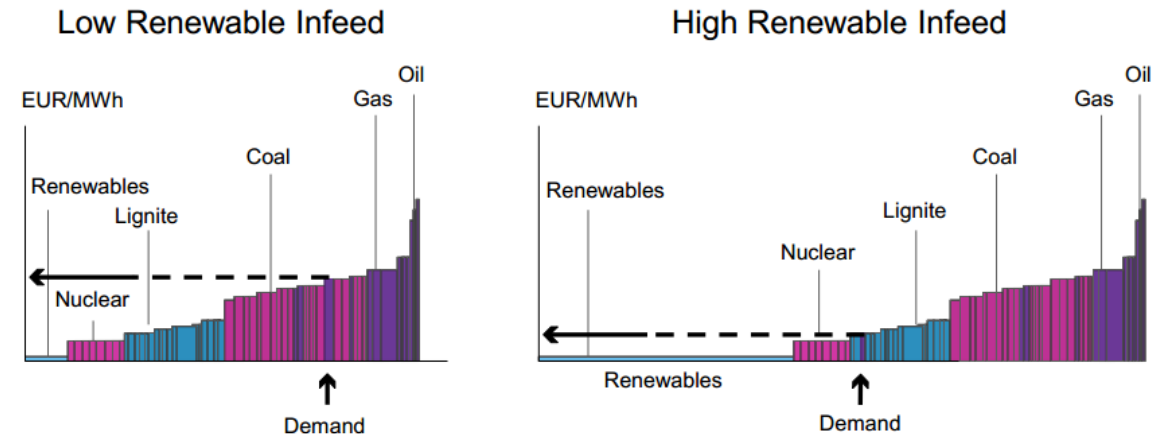- Results
  - Model validation
  - Impact of ORDC on CCGT units

Motivation

Renewable energy integration

Nuclear capacity in Belgium

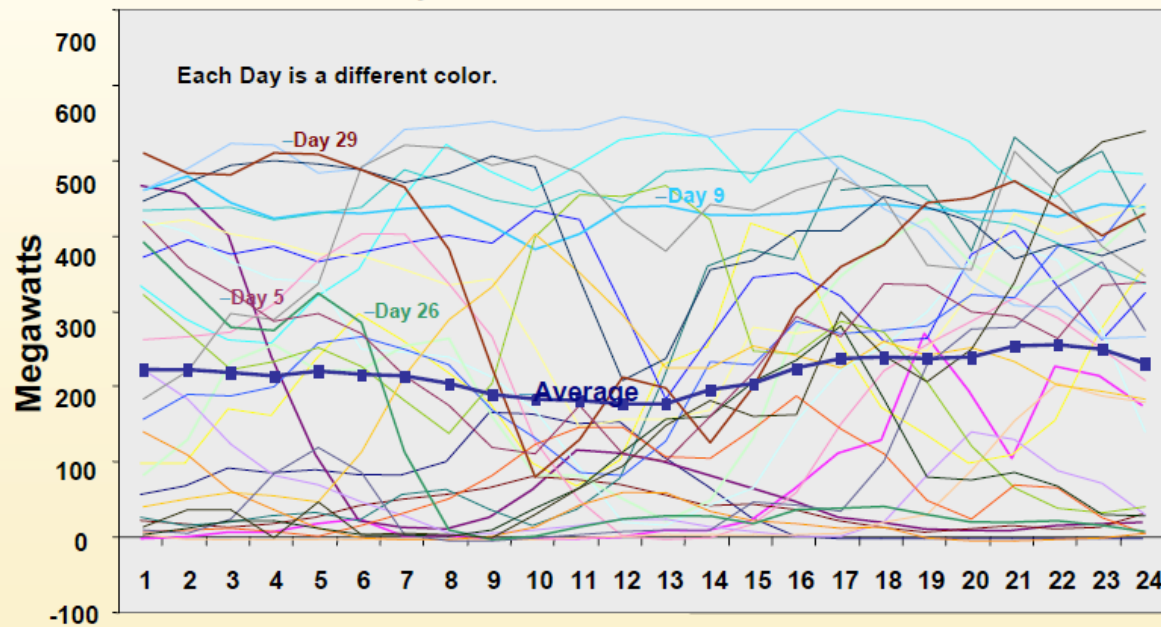# Challenges of Renewable Energy Integration

- Renewable energy integration
  - depresses electricity prices
  - requires flexibility due to
    - uncertainty,
    - variability,
    - non-controllability of output
- Demand is unresponsive
- Supply-demand must be balanced instantaneously

Low Renewable Infeed

High Renewable Infeed

Load, Wind & Solar Profiles --- Base Scenario January 2020

Net Load = Load - Wind - Solar

Challenges of Renewable Energy (II)

Tehachapi Wind Generation in April – 2005

Could you predict the energy production for this wind park either day-ahead or 5 hours in advance?
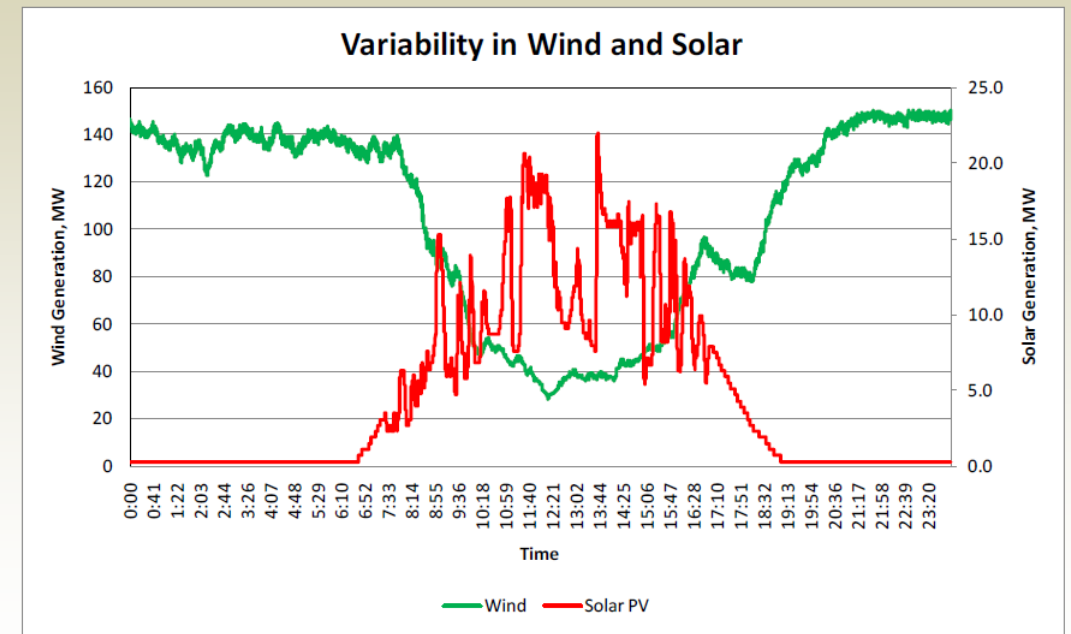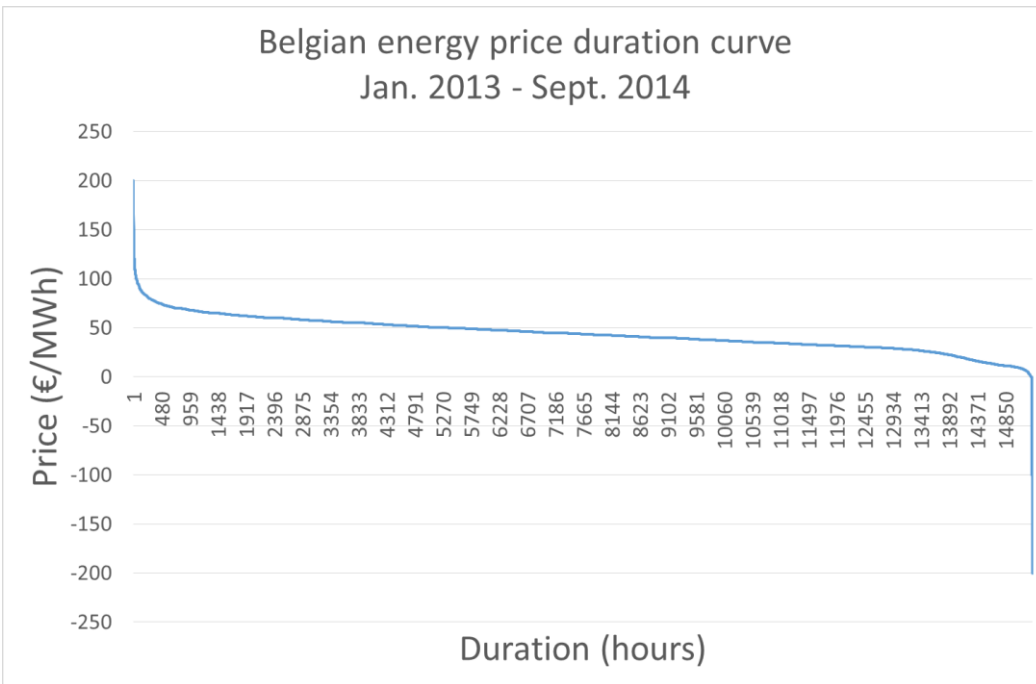
Each Day is a different color.

—Day 29
—Day 9
—Day 5
—Day 26
Average

California ISO — Your Link to Power

14

Variability of wind and solar resources - June 24, 2010

Variability in Wind and Solar

Wind Generation, MW
Solar Generation, MW
Time

— Wind   — Solar PV

A 150 MW wind plant and a 24 MW solar resource

California ISO — Your Link to Power

Slide 5

A Paradox

Belgian energy price duration curve
Jan. 2013 - Sept. 2014

Technology	Inv. cost (€/MWh)	Marginal cost (€/MWh)	Min. load cost (€/MWh)	Energy market profit (€/MWh)	Profit (€/MWh)
Biomass	27.9	5.6	0	35.6	7.7
Nuclear	31.8	7.0	0	34.2	2.4
Gas	5.1	50.2	20	0.1	-5
Oil	1.7	156.0	20	0	-1.7

- Gas and oil units are
  - extremely flexible (ramp rates, up/down times) => needed now more than ever
  - characterized by high marginal cost => mothballed or retired now more than ever

Severe Shortage in Belgian Capacity

- Belgian power production capacity: 14765 MW

- September 2014 – mid-October 2014
  - 4 nuclear units out of order simultaneously
  - Total <u>unplanned</u> outage: 4000 MW

Context for this Study

- Commission de Régulation de l'électricité et du Gaz (CREG) is concerned about whether adequate incentives are in place in order to attract investment in **flexible** power generation in Belgium

- Question addressed in this study: *How would electricity prices change if we introduce ORDC (Hogan, 2005) in the Belgian market*

(Hogan, 2005) W. Hogan, *On an Energy-Only Electricity Market Design for Resource Adequacy*. Center for Business and Government, JFK School of Government, Harvard University, September 2005.

Background

Paying for capacity in electricity markets

The shift of value in electricity markets

Operating Reserve Demand Curves

The Missing Money Problem

- Electricity demand is extremely inelastic

- Even if demand is perfectly predictable, a competitive equilibrium entails some degree of load curtailment, at which time the price of electricity is very high

- Due to market power concerns, electricity price is capped => <u>missing money</u>
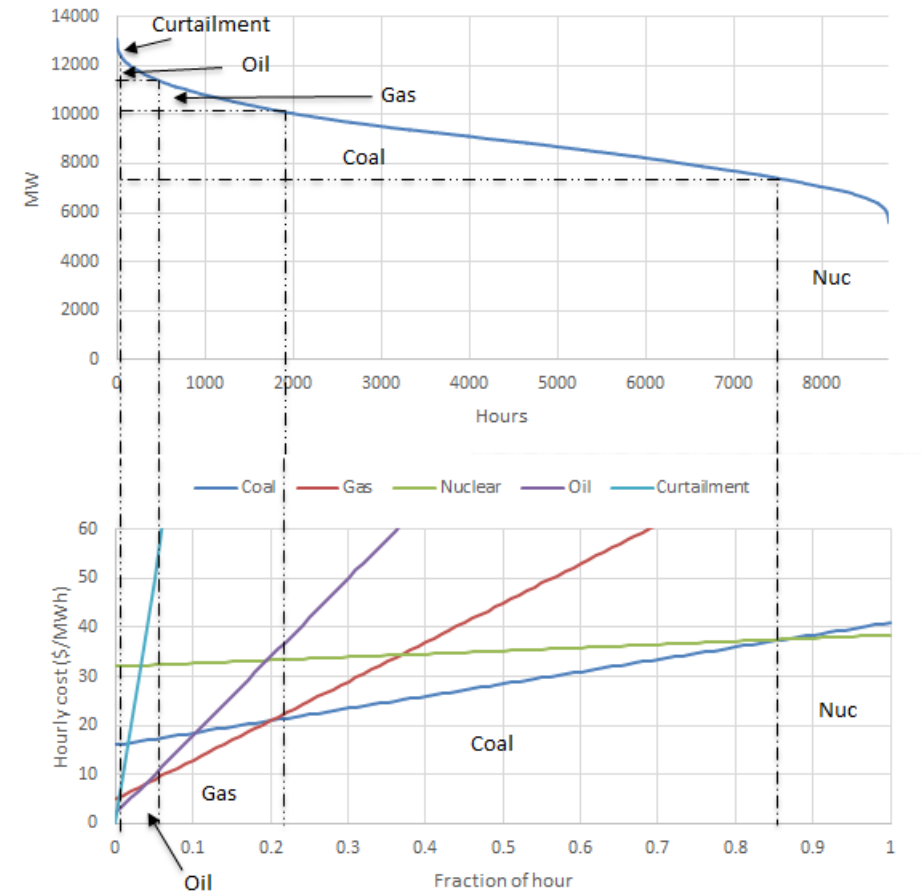
Mechanisms for Compensating Capacity

- Energy-only markets
  - The energy market without price caps is the only source of revenue
  - Risky for investors (-), politically contentious (-)
- Installed capacity requirements
  - Regulator decides on a target capacity and procures it through annual auctions
  - Safer for investors (+), capacity target is contestable/non-transparent (-), does not ensure flexibility (-), complex variations among member states (-)
- Capacity payments
  - Energy prices are uplifted by capacity payment
  - Installed capacity may err significantly (-)

Revenue Streams in Electricity Markets

- Energy
  - Day-ahead 'uniform price' auction
- Reserve
  - Monthly procurement of reserve *capacity*
  - Real-time procurement of reserve *energy*
- Capacity
  - Auctioned annually in <u>some</u> markets
- Recent migration of value away from energy markets and into flexibility (reserves)
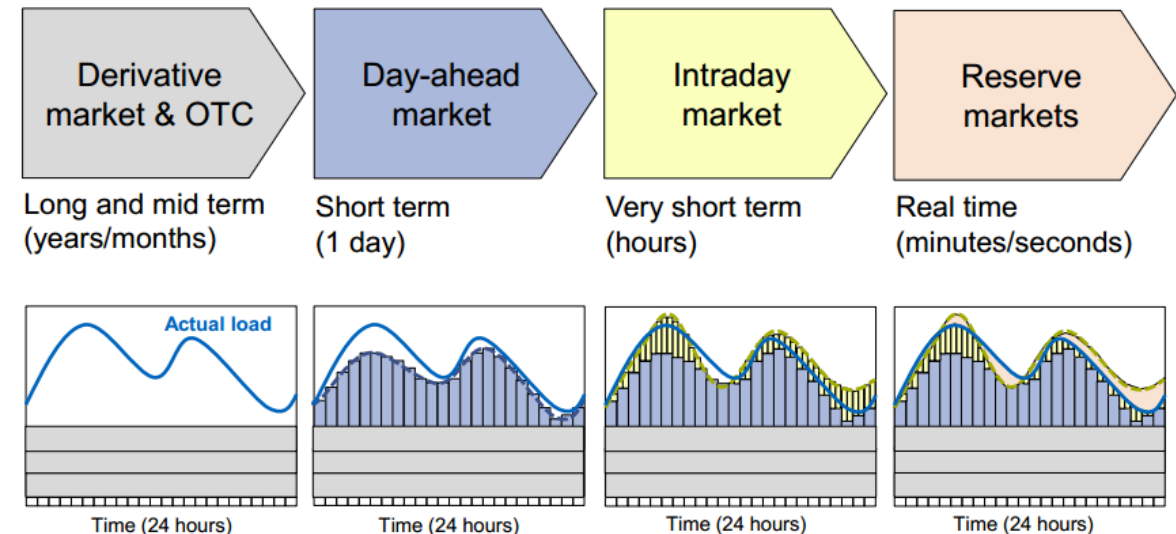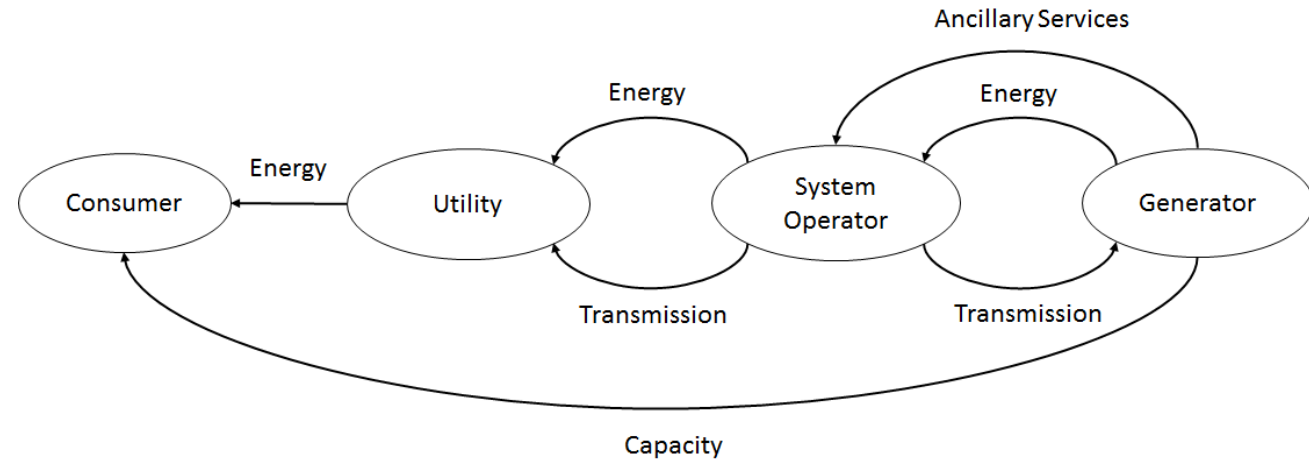
Reserves

- Primary reserve: immediate response to change in frequency

- Secondary reserve: reaction in a few seconds, full response in 7 minutes

- Tertiary reserve: available within 15 minutes

- Commitment of reserve induces opportunity cost because it displaces energy sales
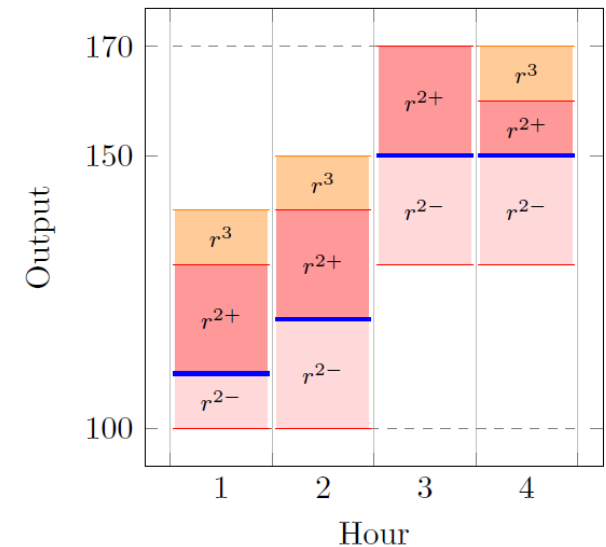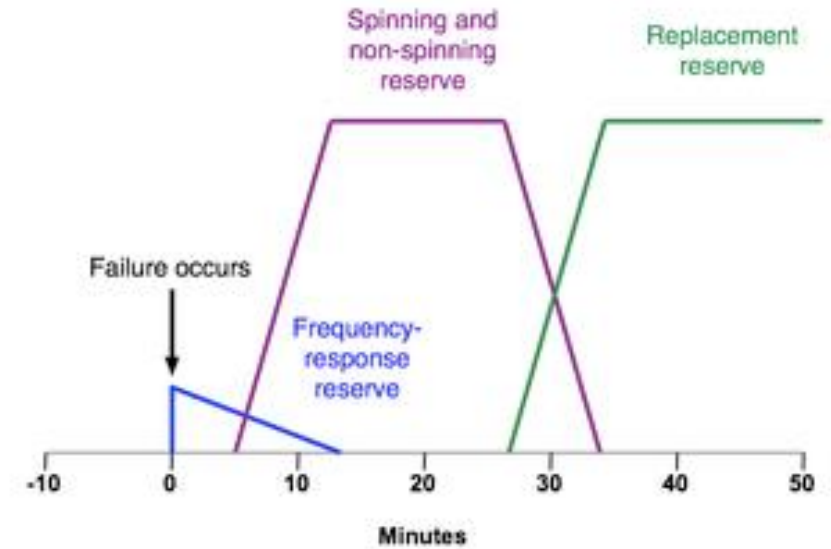
Operating Reserve Demand Curve (ORDC)

- Reserve is procured by the system operator from generators in order to ensure reliability, which is a public good

- Demand for reserve can be driven by its value for dealing with uncertainty, based on engineering principles:
  - Above a max threshold (Qmax), extra reserve offers no additional protection => (P, Q) = (0, Qmax)
  - Below a min threshold (Qmin), operator is willing to curtail demand involuntarily => (P, Q) = (VOLL, Qmin), where VOLL is value of lost load
  - At Qmin < Qi < Qmax , extra reserve increases probability of preventing load curtailment => (P, Q) = ($LOLP \cdot VOLL$, Qi), where LOLP is loss of load probability

Loss of Load Probability

- Uncertainty Δ in real time due to:
  - demand forecast errros
  - import uncertainty
  - unscheduled outages of generators
- $LOLP(x) = Prob(\Delta \geq x)$ is the probability that real-time uncertainty exceeds reserve capacity x
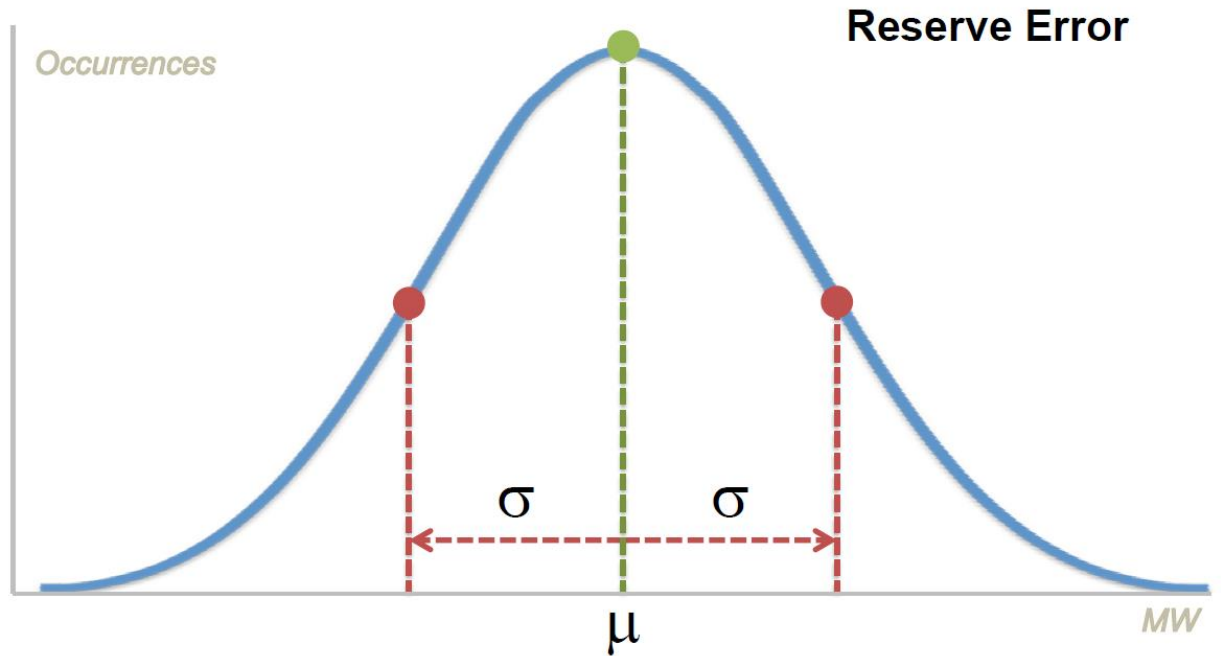
ORDC Price Adders

- Price adder: $\mu = (VOLL - \lambda) \cdot LOLP(R - X)$, where λ is the marginal cost of the marginal producer, R is the available reserve, and X is the minimum threshold of reserve

- This adder would ensure that a price taking agent that offers energy and reserve capacity would, in equilibrium, dispatch its unit according to the optimal schedule

- More frequent, lower amplitude price spikes

- Price spikes can occur even if regulator mitigates bids of suppliers in order to mitigate market power

Illustration from Texas: July 30, 2015
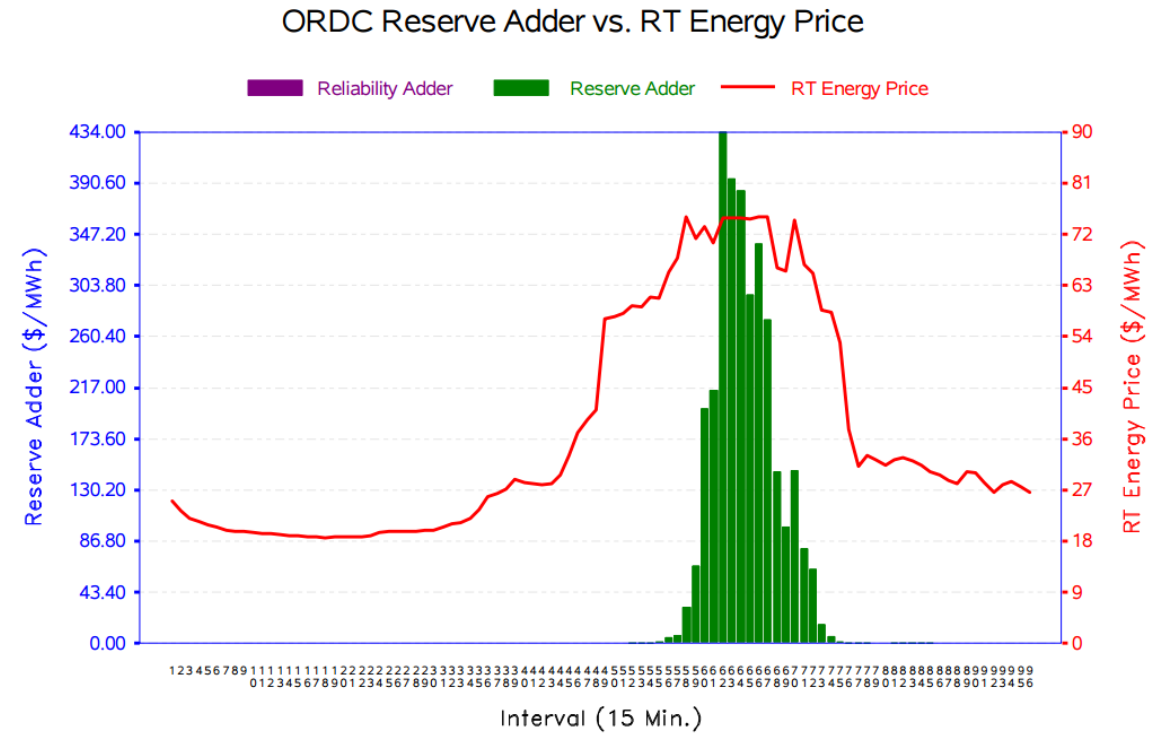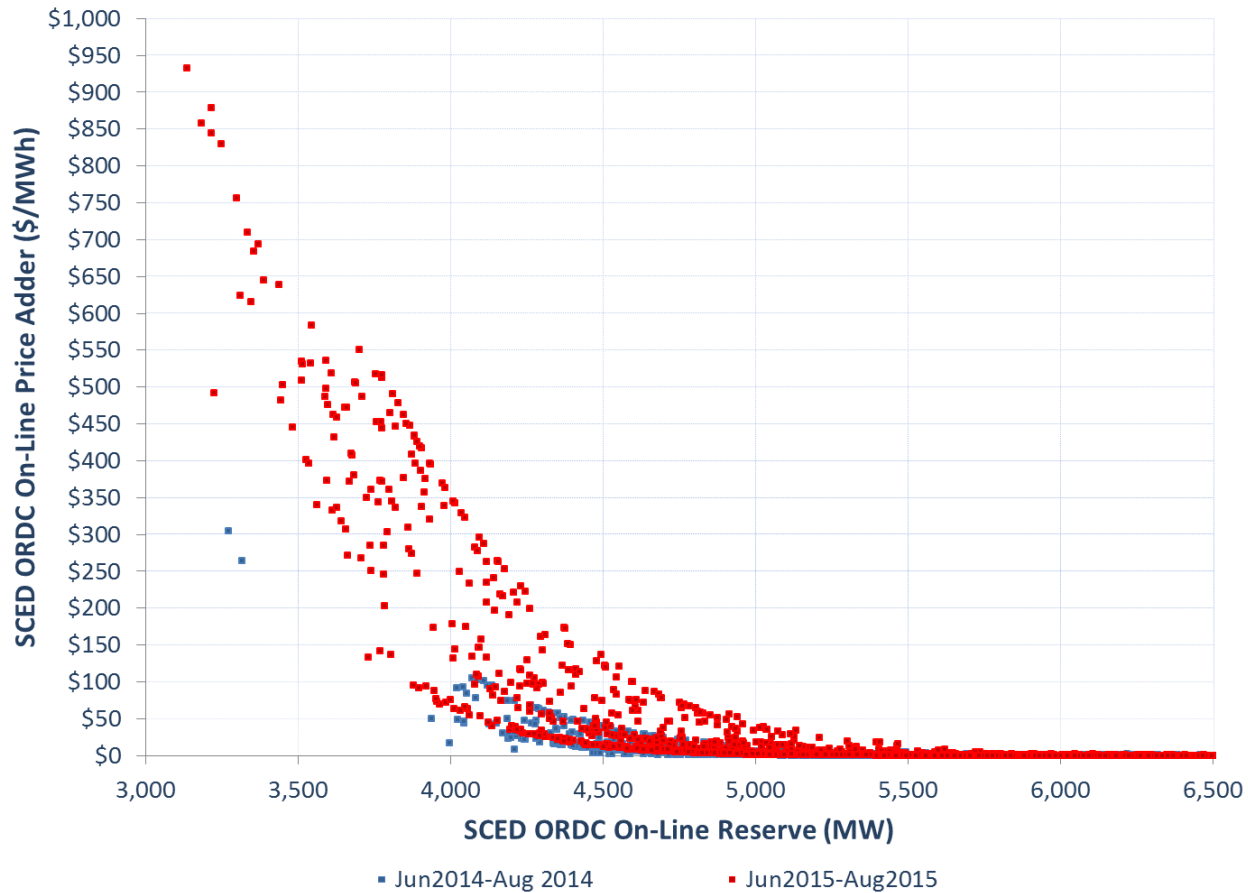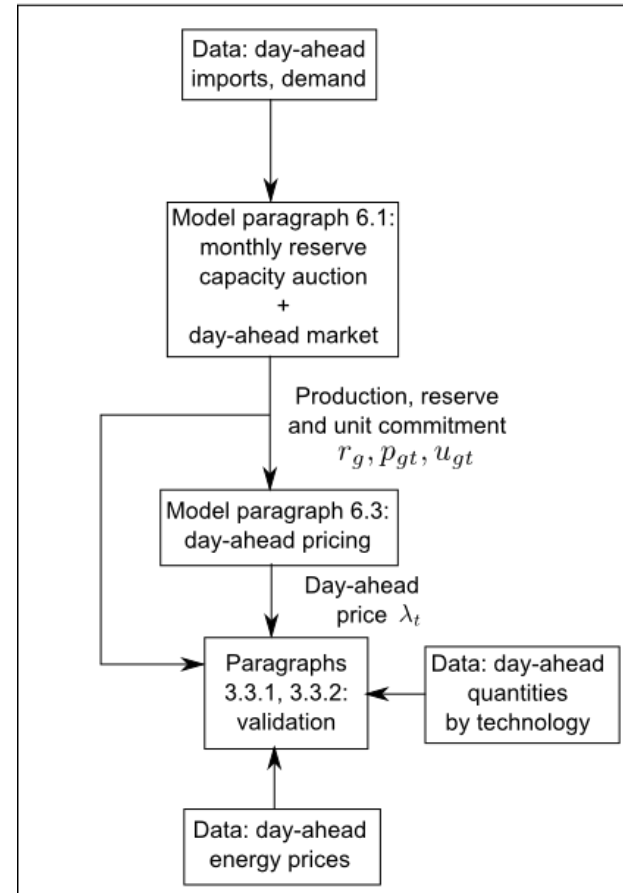
Methodology

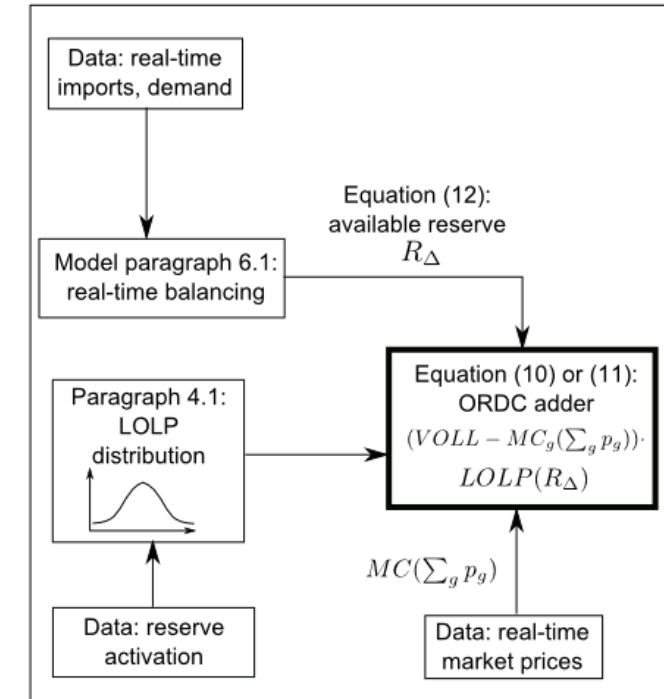Framework of study

Modeling the Belgian market

Back to the Question

- Recall the goal of the study: what would the impact of ORDC be in the Belgian electricity market?

- Steps
  - Calculate reserve commitment for each hour of the study period
  - Estimate LOLP for Belgian system
  - Calculate price adders

- This is an open-loop analysis: we do not attempt to answer the question of how generators would react to the introduction of ORDC (for now)

Validation

Data: day-ahead imports, demand

Model paragraph 6.1: monthly reserve capacity auction + day-ahead market

Production, reserve and unit commitment r_g, p_{gt}, u_{gt}

Model paragraph 6.3: day-ahead pricing

Day-ahead price λ_t

Paragraphs 3.3.1, 3.3.2: validation

Data: day-ahead quantities by technology

Data: day-ahead energy prices

Simulation

Data: real-time imports, demand

Model paragraph 6.1: real-time balancing

Equation (12): available reserve R_Δ

Paragraph 4.1: LOLP distribution

Equation (10) or (11): ORDC adder $(VOLL - MC_g(\sum_g p_g)) \cdot LOLP(R_\Delta)$

$MC(\sum_g p_g)$

Data: reserve activation

Data: real-time market prices

Available Data

- Study interval: January 2013 – September 2014
- Day-ahead price
- Day-ahead production *by technology* (not individual units)
- *Unit-by-unit* technical-economic data for coal and combined cycle gas turbine (CCGT) units

Understanding the Belgian Market

- Possible causes for variability of supply function
  - Outages
  - Unit commitment
  - Imports/exports
  - Reserves
  - Distributed renewables (not measured)
  - Pumped storage
  - Combined heat & power, must-take resources
  - Fuel price fluctuations
  - Market power
  - ~~Forward/bilateral commitments~~
  - ~~Demand side bidding~~
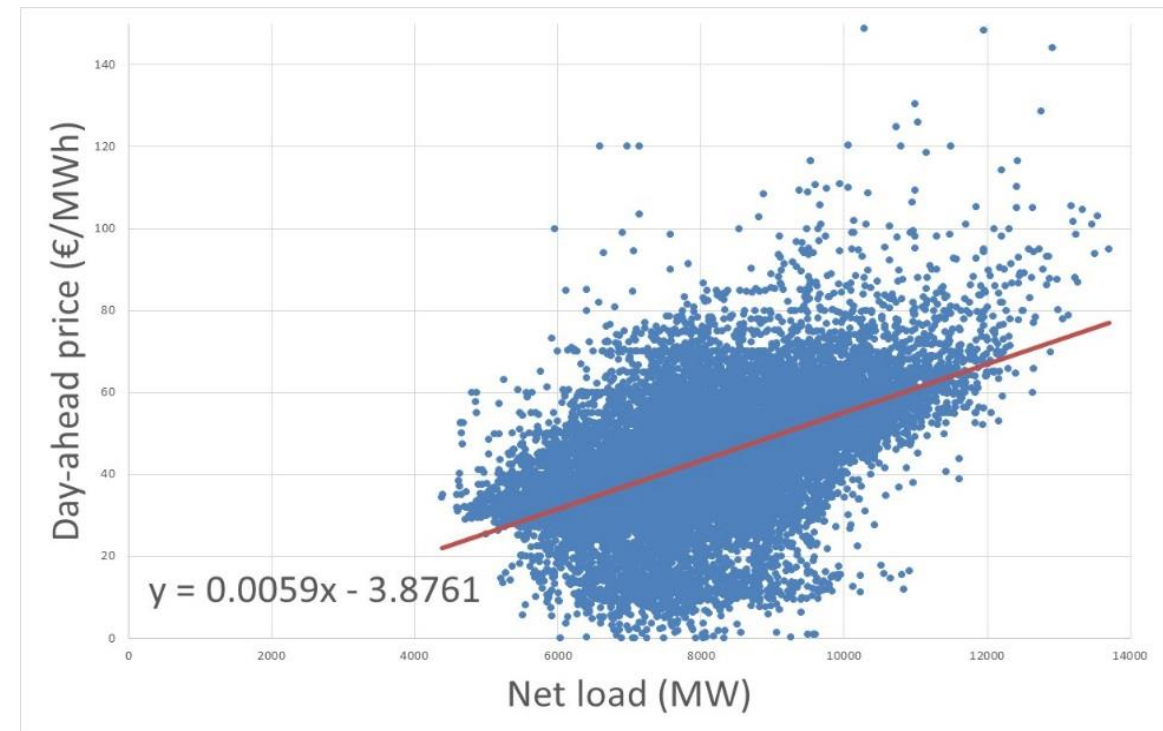
Model Description

Classification of market agents

Fit of model to data

Agents

- Generators
  - Nominated
  - Dispatchable
  - Committed
- Pumped storage
- Neighbors
- Consumers
- System operator

Nominations

- Nominated resources are resources whose output is not driven by electricity prices
  - Nuclear (6032 MW)
  - Wind (864 MW)
  - Waste (259 MW)
  - Water (101 MW)
- The production of nominated resources is fixed to its historical value

Nuclear supply

Wind
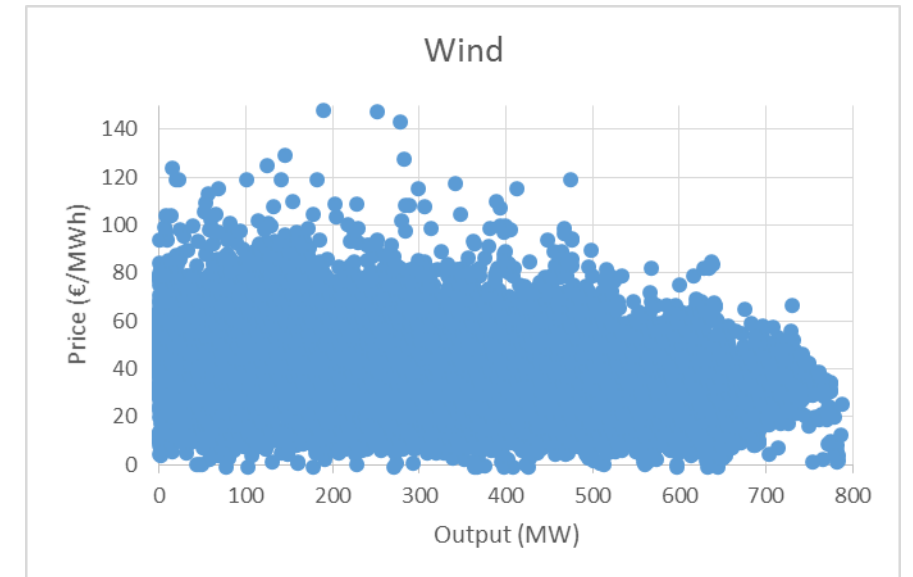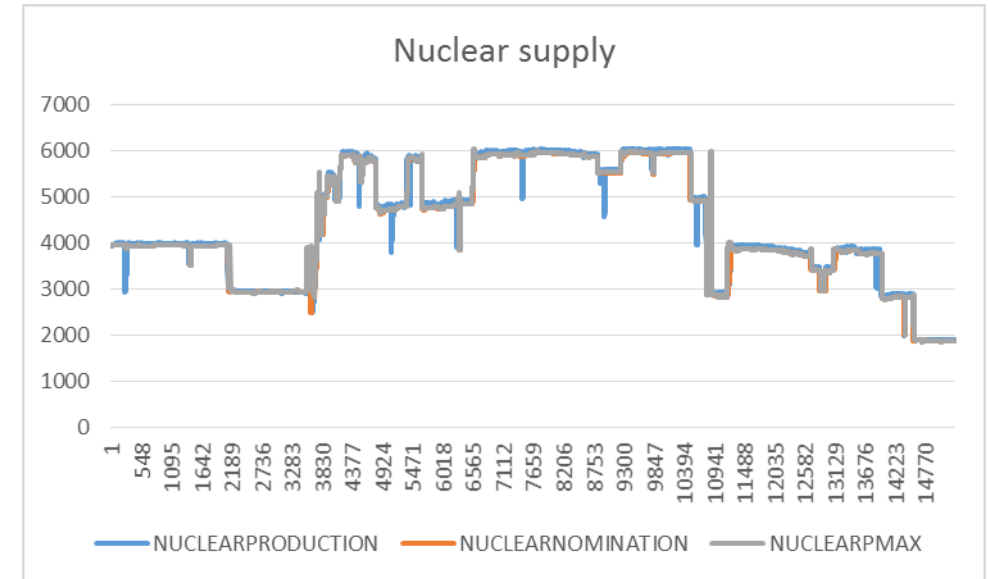
Dispatchable Resources

- Dispatchable resources are <u>aggregated</u> resources whose production is driven by market price
  - Blast furnace (350 MW)
  - Renewable (106 MW)
  - Gas-oil (82 MW)
  - Turbojet (213 MW)
- Dispatchable resource modeling
  - Linear supply functions
  - Time-varying capacity (due to outages)
  - Capable of providing primary, secondary, tertiary reserve
  - Ramp rate equal to 4% of their capacity per minute (based on CCGT)

Blast furnace
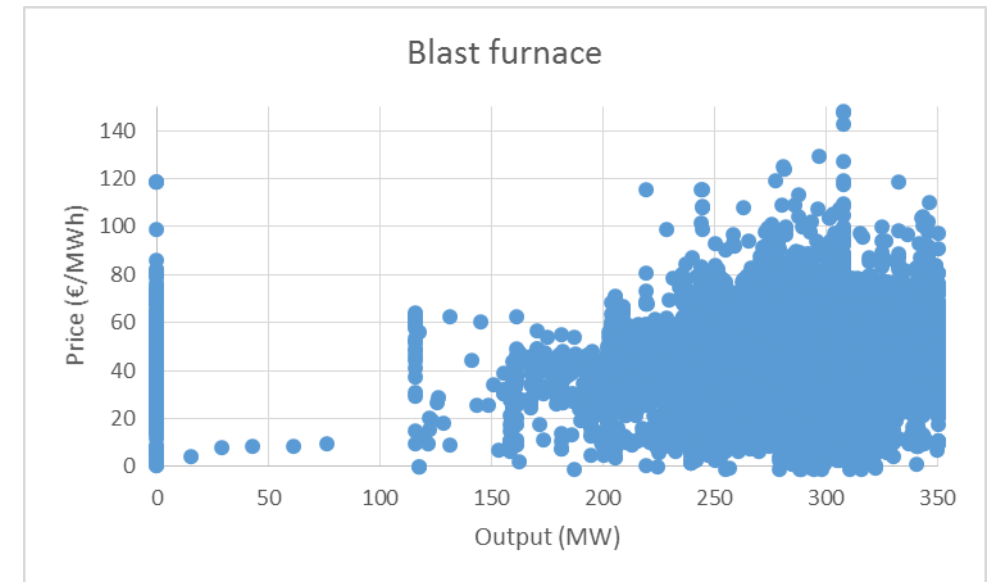
Dispatchable Resource Model

- λ_t: energy price
- $\lambda FCRU, \lambda FCRD, \lambda aFRRU, \lambda aFRRD, \lambda mFRR$: reserve prices
- $prod_t$: energy production
- $FCRU, FCRD, aFRRU, aFRRD, mFRR$: reserves (fixed over entire month)
- P_t: time-varying capacity
- R: ramp rate (MW/min)

$$\max \sum_t \left(\lambda_t \cdot prod_t - \int_{x=0}^{prod_t} (a + bx)dx \right) +$$

$$\lambda FCRU \cdot FCRU + \lambda FCRD \cdot FCRD +$$

$$\lambda aFRRU \cdot aFRRU + \lambda aFRRD \cdot aFRRD +$$

$$\lambda mFRRD \cdot mFRRD$$

$$prod_t \geq FCRD + aFRRD$$

$$prod_t + FCRU + aFRRU + mFRR \leq P_t$$

$$FCRU \leq 0.5 \cdot R, FCRD \leq 0.5 \cdot R$$

$$aFRRU \leq 7 \cdot R, aFRRD \leq 7 \cdot R$$

$$mFRR \leq 15 \cdot R$$

$$prod_t, FCRU, FCRD, aFRRU, aFRRD, mFRR \geq 0$$

Committed Resources

- Committed resources are resources described by a unit commitment model, whose technical-economic data is available unit-by-unit
  - Coal (972 MW)
  - CCGT (6506 MW)
- Committed resources modeling
  - Technical <u>minimum</u>
  - Time-varying minimum/maximum by unit (outages)
  - Time-varying fuel cost
  - Capable of providing primary, secondary, tertiary reserve
  - Ramp rates
  - Min up/down times
  - Startup cost
  - Min load cost
  - Multi-segment marginal cost

CCGT
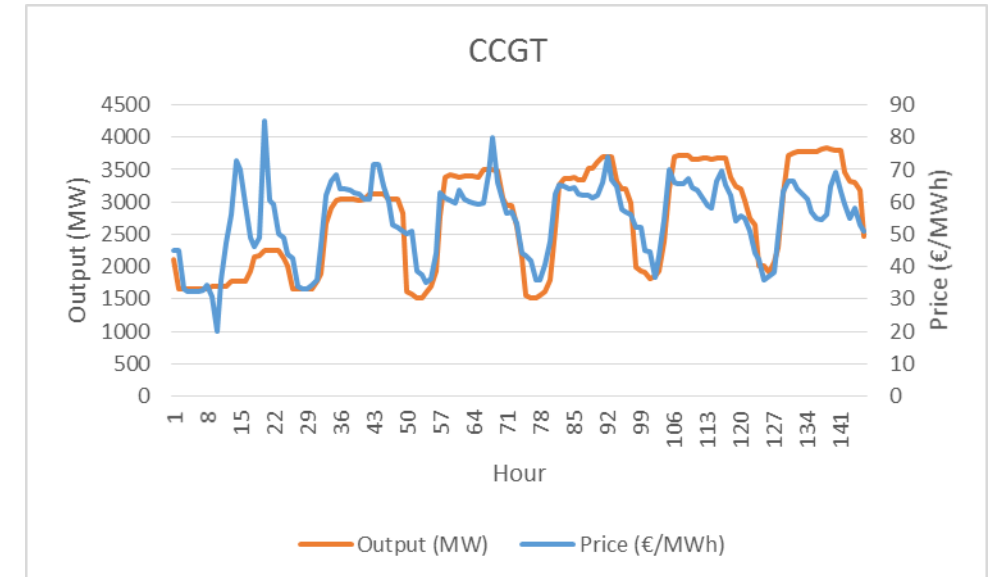
Committed Resources Model

- u_t, su_t, sd_t: unit commitment, startup, shut-down indicator variables

- SUC, MLC: startup/min load cost

- UT/DT: min up/down times

- $ProdMin_t$: minimum production limit

$$\max \sum_t \left(\lambda_t \cdot prod_t - \int_{x=0}^{prod_t} MC(x)dx - SUC \cdot su_t - MLC \cdot u_t \right)$$

$$+Reserve\ revenues$$

$$prod_t \geq (ProdMin_t + FCRD + aFRRD) \cdot u_t$$

$$prod_t + FCRU + aFRRU + mFRR \leq ProdMax_t \cdot u_t$$

$$u_t = u_{t-1} + su_t - sd_t$$

$$\sum_{\tau=t-UT+1}^{t} su_\tau \leq u_t, \quad \sum_{\tau=t-DT+1}^{t} su_\tau \leq 1 - u_t$$

$$Reserve\ limits$$

$$prod_t, FCRU, FCRD, aFRRU, aFRRD, mFRR \geq 0$$

$$u_t, su_t, sd_t \in \{0,1\}$$

Pumped Storage

- Pumped storage resources pump water when prices are low, release water when prices are high
- Pumped storage modeling
  - Tanks need to be empty in the end of the day
  - Efficiency estimated from data (76.5%)
  - Time-varying pump/production/storage capacity (outages)
  - Storage capacity estimated from data
  - Pump/production ramp rate estimated from data
  - Capable of providing primary, secondary, tertiary reserve
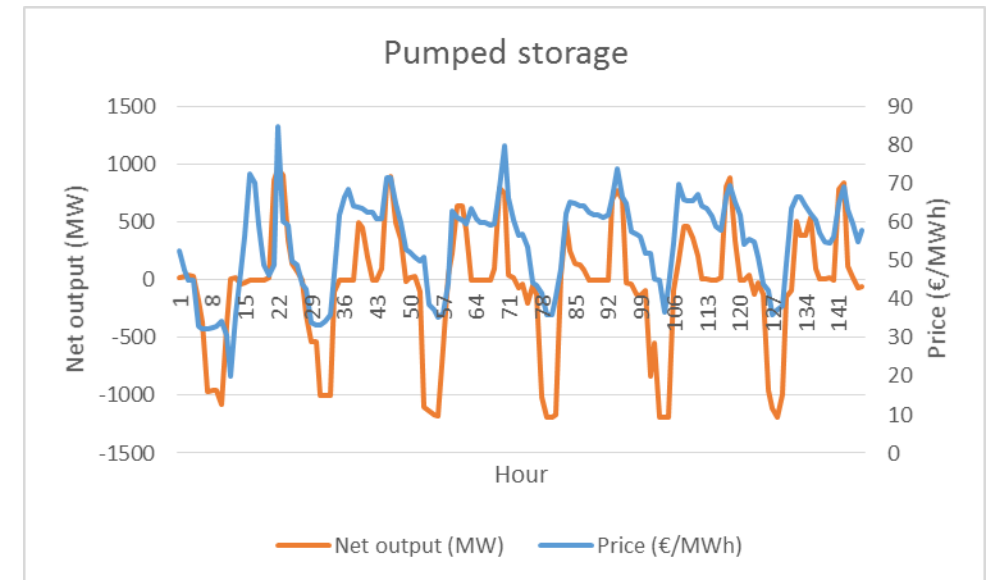
Pumped Storage Model

- $pump_t$: energy pumping
- e_t: stored energy in reservoir
- $ProdMax_t, PumpMax_t, ES_t$: production/pumping/storage capacity
- η: pumping efficiency
- $RampProd_t, RampPump_t$: production and pumping ramp rate

$$\max \sum_t \lambda_t \cdot (prod_t - pump_t)$$

$$prod_t + FCRU_t + aFRRU_t + mFRR_t \leq ProdMax_t$$

$$pump_t \leq PumpMax_t$$

$$e_{t+1} = e_t + \eta \cdot pump_t - prod_t$$

$$e_t \leq ES_t$$

$$e_1 = e_T = 0$$

$$prod_t - prod_{t-1} + FCRU_t + aFRRU_t + mFRR_t \leq RampProd_t$$

$$prod_t - prod_{t-1} - FCRD_t - aFRRD_t \geq -RampProd_t$$

$$pump_t - pump_{t-1} + FCRD_t + aFRRD_t \leq RampPump_t$$

$$pump_t - pump_{t-1} - FCRU_t - -aFRRU_t - mFRR_t \geq -RampPump_t$$

$$FCRU \leq 0.5 \cdot R, FCRD \leq 0.5 \cdot R, \ldots$$

$$prod_t, pump_t, e_t \geq 0$$

Neighboring Systems

- Belgium is interconnected to France and Netherlands
- Original idea: model neighbors through residual supply functions
- Available transmission capacity (ATC): technical limit on amount of power that can flow over transmission lines that connect BE to neighbors
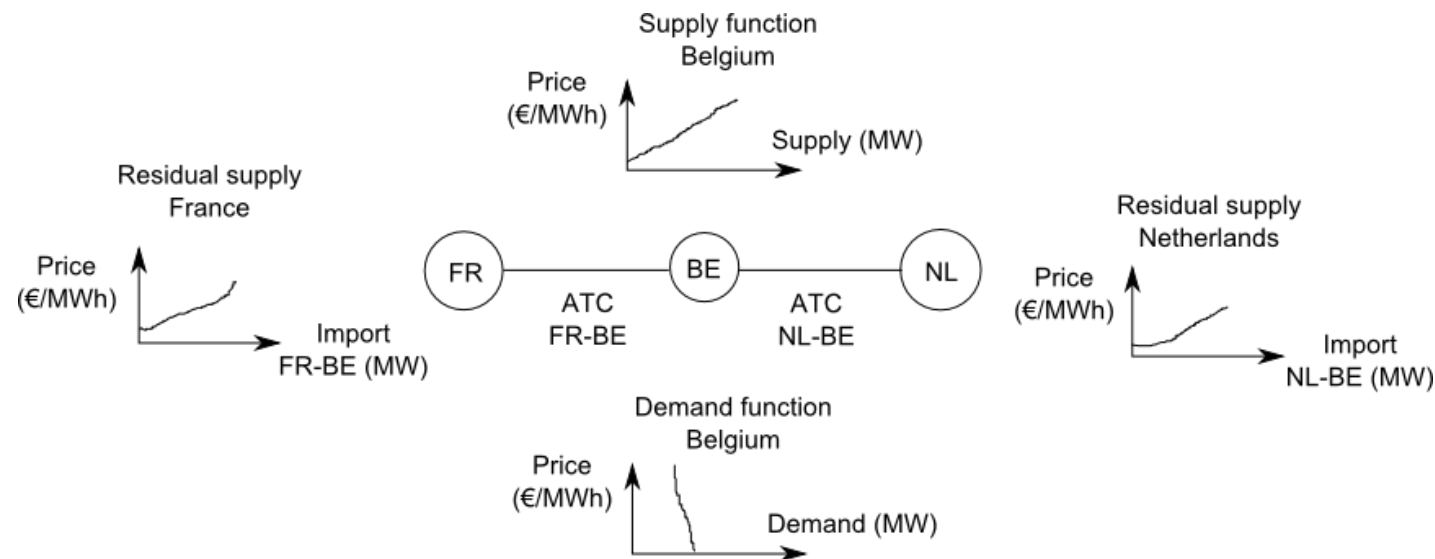
Neighboring Systems (II)

- Southern exports are increasing in price => separate modeling of neighboring countries out of the question

- Net exports are price responsive with statistical significance, but fit of the model worsens dramatically
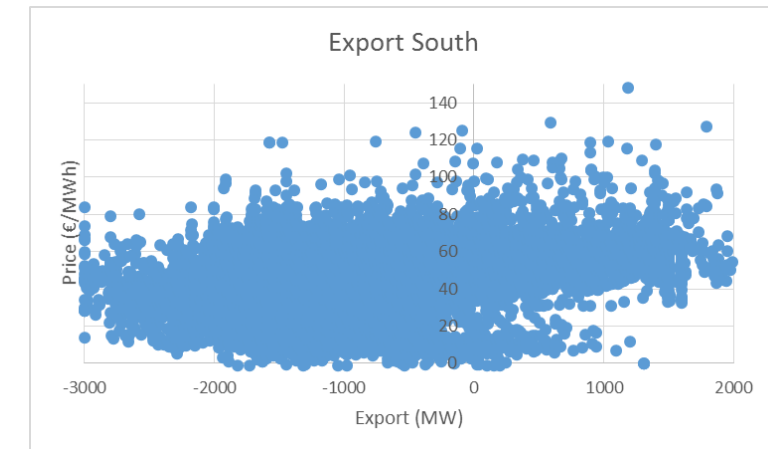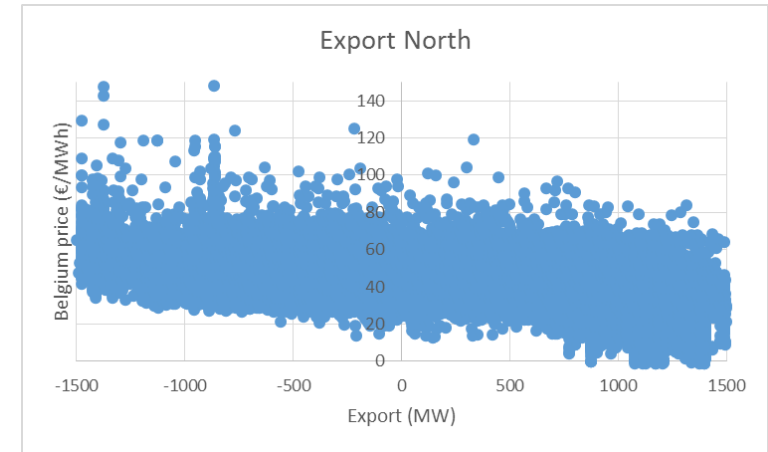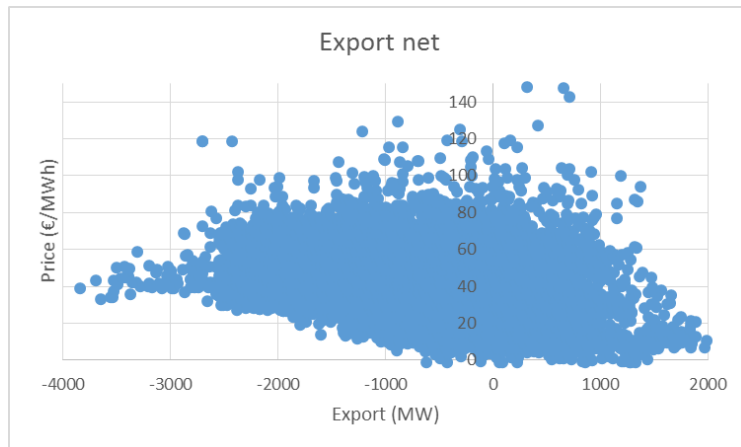
Neighboring Systems Model

- Imports are fixed to their historical values

- Time-varying capacity (representing ATCs)

- Excess capacity above historical value modeled as linear supply function
  - Intercept is equal to the 90th percentile of the day ahead price (70 €/MWh)
  - Slope is such that within 500 MW we reach marginal cost of 300 €/MWh
  - Thus, price-elastic imports are used only in case of supply shortage, with marginal costs rising steeply
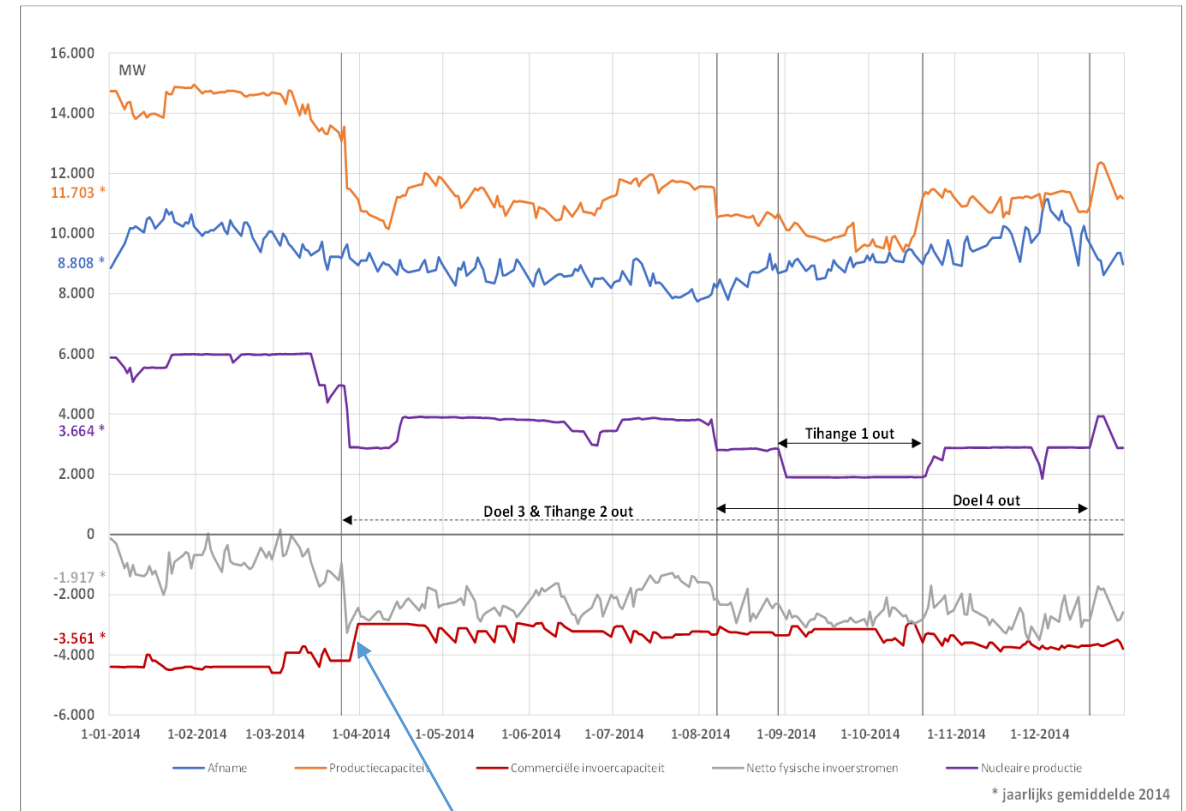
Emergency increase in imports after nuclear outage

Consumers

- We assume inelastic demand, due to lack of contrary evidence
- $VOLL$: value of lost load (3000 €/MWh)
- d_t: electricity consumption
- D_t: demand

$$\max \sum_t (VOLL \cdot d_t - \lambda_t \cdot d_t)$$

$$0 \leq d_t \leq D_t$$

Transmission System Operator

- TSO procures 5 types of reserve
    - Primary up/down: 55MW
    - Secondary up/down: 140 MW
    - Tertiary: 350 MW

Solution Methodology

- Unit commitment over an entire month is a time-consuming model
- We attempted four solution methods
  - Direct resolution by branch and bound (too slow)
  - Dual decomposition of coupling constraints (somewhat slow, numerically unstable)
  - Generator decomposition heuristic (poor performance)
  - Receding horizon heuristic (shown to perform well in transmission switching)
- Receding horizon heuristic
  - Initialize the commitment of all units for all hours to 'on'
  - For $iter = 1{:}IterLimit$
  - For $day = 1{:}30$
    - Solve the entire model for the *entire* horizon, with unit commitment decisions fixed for all days except today <u>and tomorrow</u>
    - Fix commitment for today *only*, step one day forward
- Receding horizon heuristic outperforms alternatives within a few hours of run time
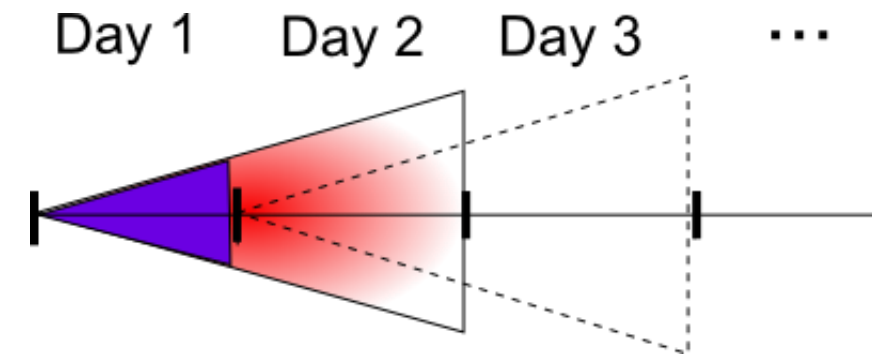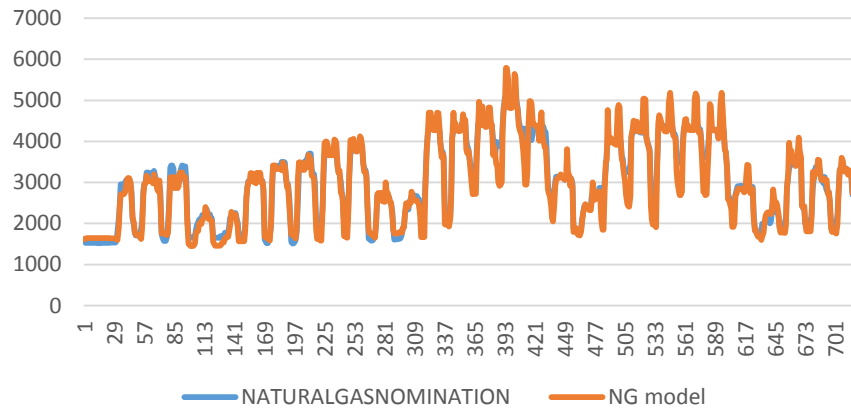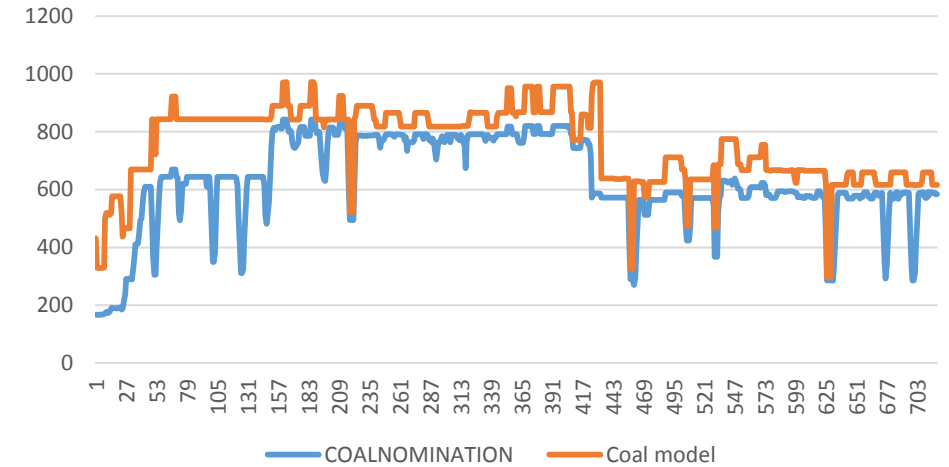
Results

Model validation

Impact of ORDC on CCGT units
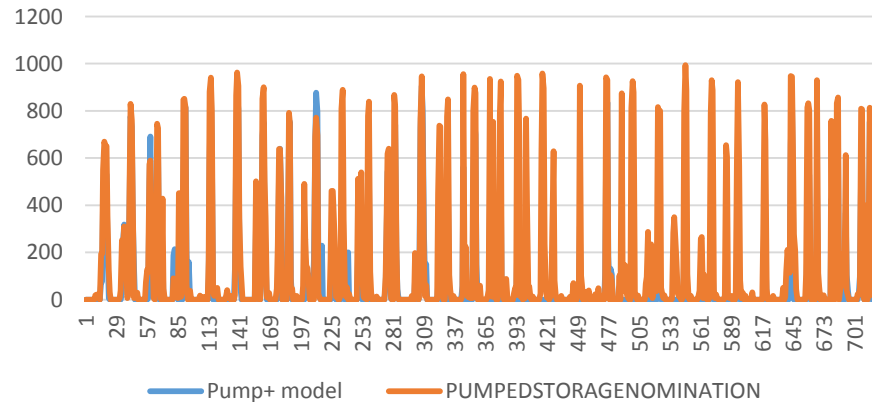
Production by Technology, January 2013
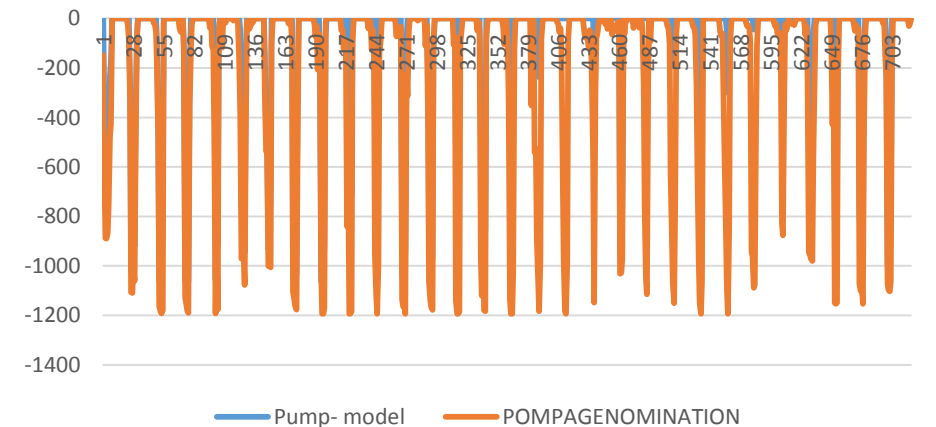
Production by Technology, June 2013
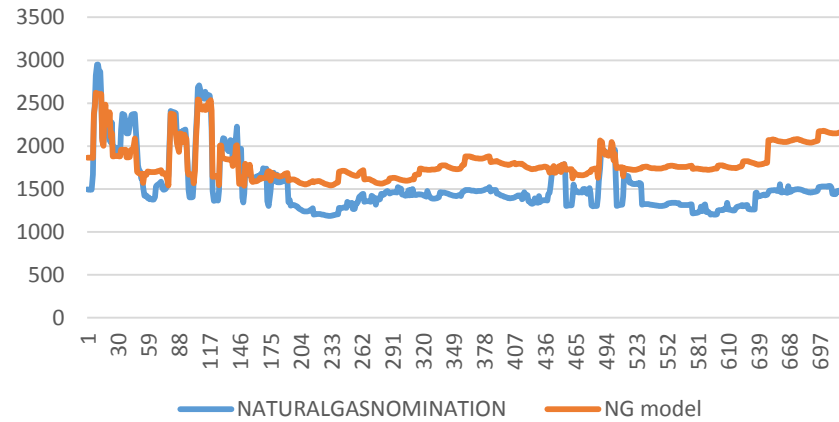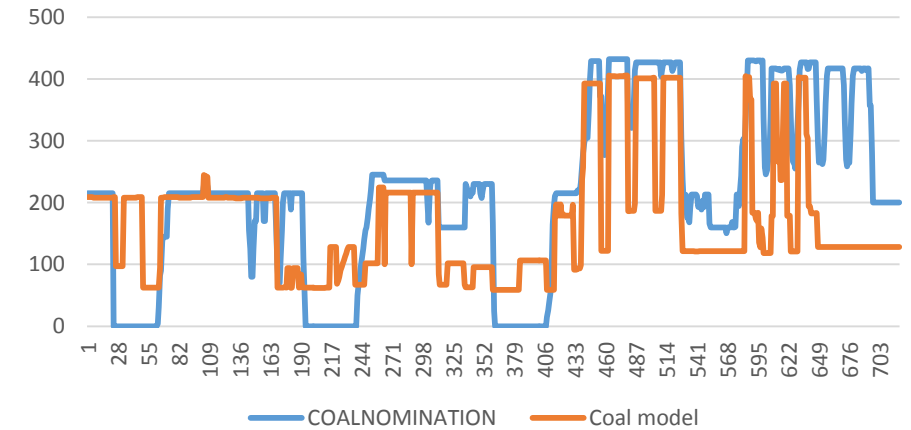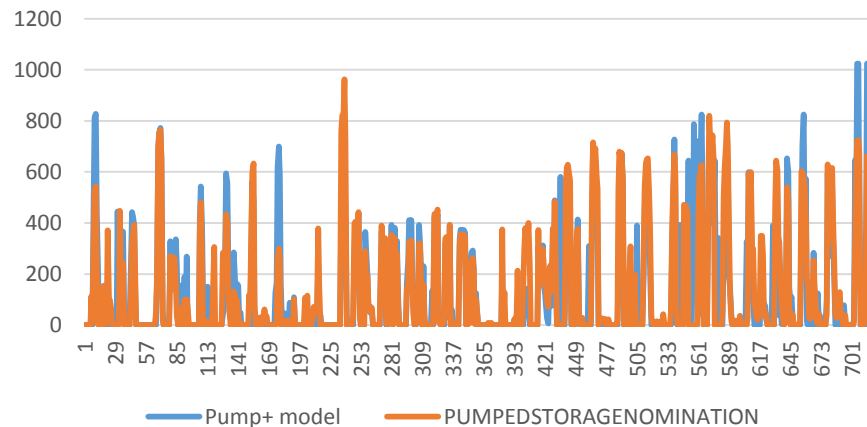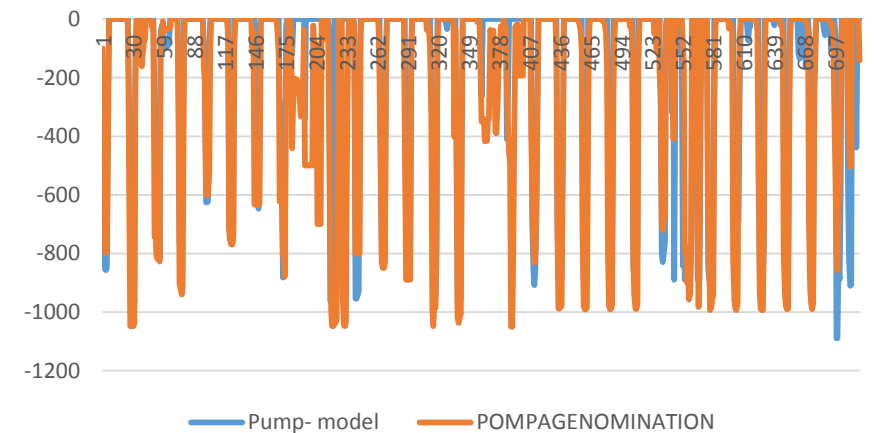
Dispatching Against Price, January 2013
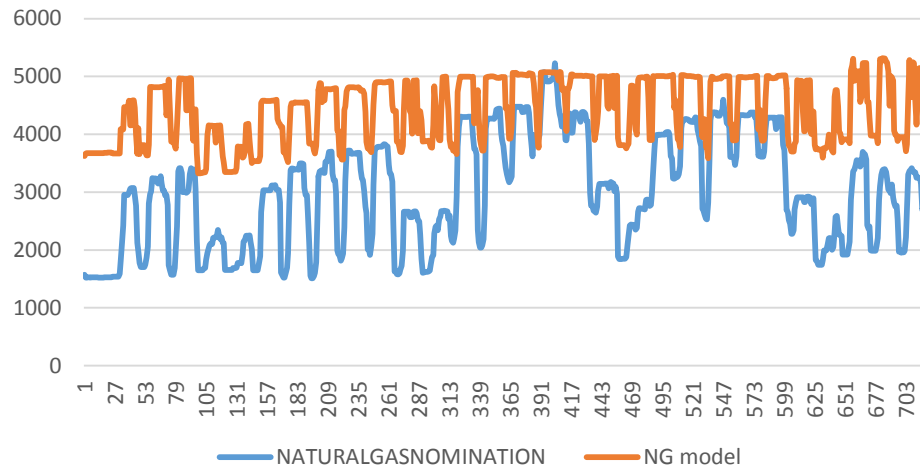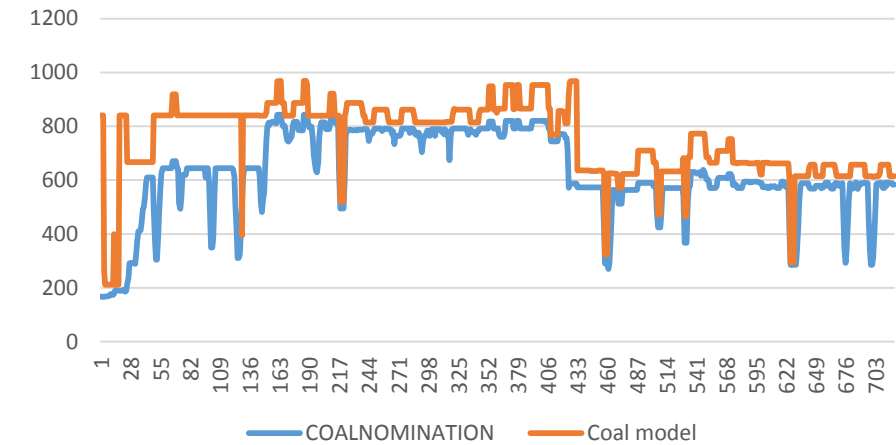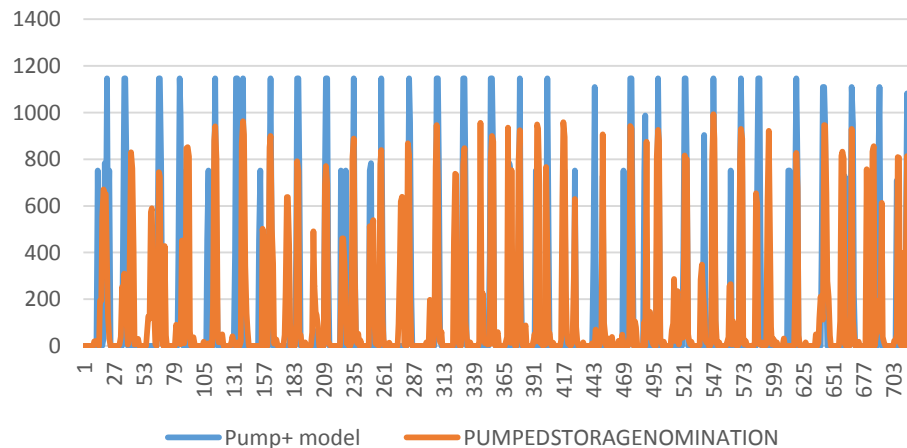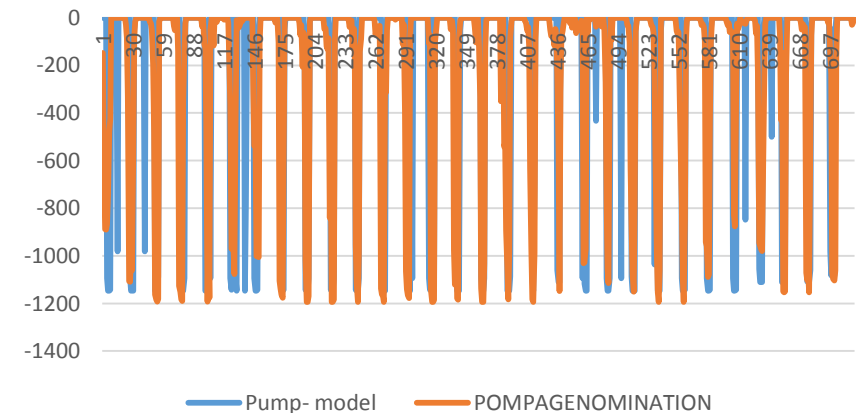
Remarks

- Model tracks production by fuel fairly accurately in months of high demand
- Model overestimates production of CCGT in months of low demand
  - One source of inaccuracy is the fact that we do not have access to data of CCGT units that were decommissioned after October 2014
  - Since price adders kick in during tight conditions, this inaccuracy should have minor effects on our results
- Centralized unit commitment dramatically outperforms alternative of dispatching units against price
- Euphemia primal (commitment and dispatch) decisions appear to be efficient if our estimated model parameters are accepted as accurate

Understanding Prices

- CWE energy market is cleared by Euphemia, an algorithm that seeks market clearing prices for continuous and discrete bids
- We have tested two models that approximate this behavior
    - Solving the dispatch problem with unit commitment fixed, and computing dual multipliers of power balance constraint
    - Solving an approximation of prices that attempts to minimize surplus losses of CCGTs, <u>given</u> their dispatch schedule
- Motivation for second approach: if we trust that our dispatch decisions are close to reality, let us find a price that minimizes deviation from what Euphemia is supposed to do
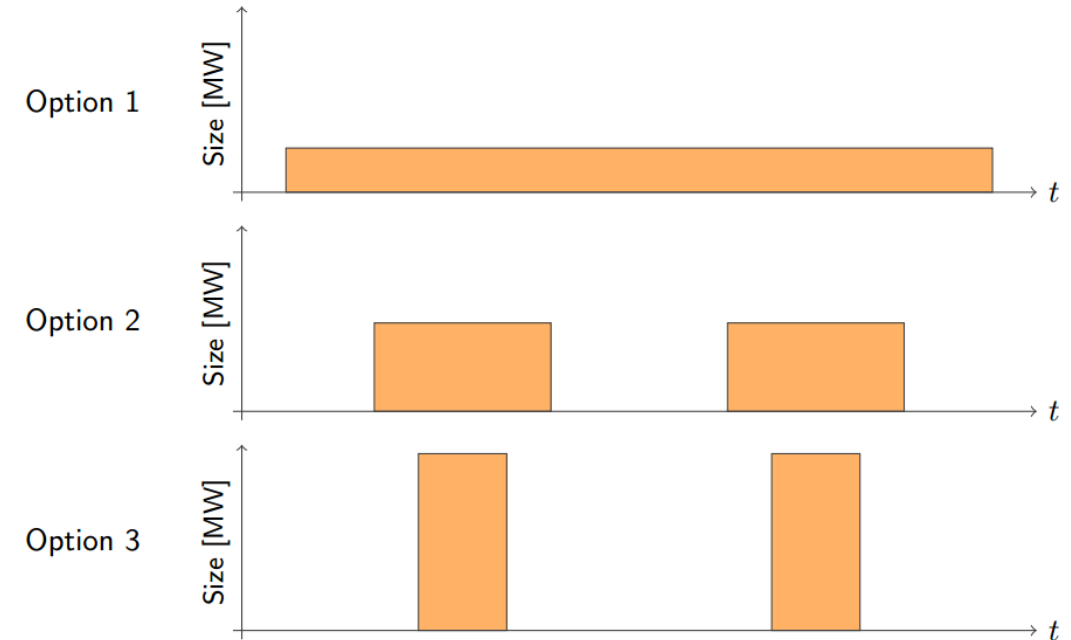
Mutually exclusive block orders

A Model for Approximating Euphemia

$$\min \sum_g surplusShortage_g$$

$$prod_t = prod_t^*$$

$$0 \leq prod_{gt} \perp MC_g(p_{gt}) - \lambda_t + scarcityRent_{gt} \geq 0$$

$$0 \leq scarcityRent_{gt} \perp ProdMax_g(p_{gt}) - prod_{gt}^* - FCRU_g^* - aFRRU_g^* - mFRRU_g^* \geq 0$$

Dispatched resources (including coal)

$$dailySurplus_g = \sum_{gt} \lambda_t \cdot p_{gt}^* - TotalCost_g(u_g^*, prod_g^*) + \textcolor{red}{surplusShortage_g}$$

CCGT

$$dailySurplus_g \geq 0$$

Price Fit, January 2013

Energy price (€/MWh), Euhpemia model

Energy price (€/MWh), LP model

Price Fit, March 2014

Energy price (€/MWh), Euphemia model

Energy price (€/MWh), LP model
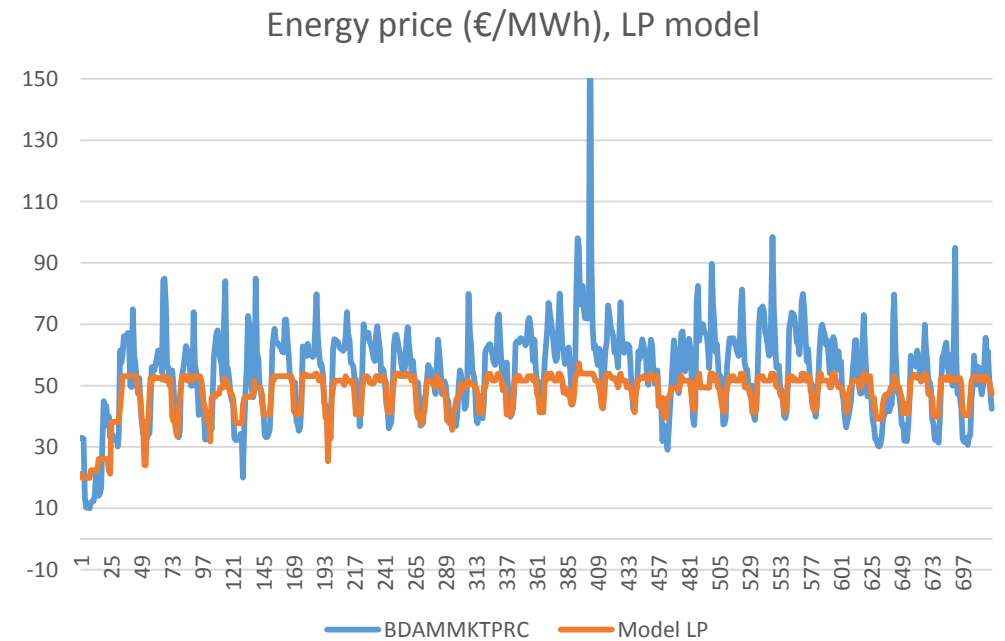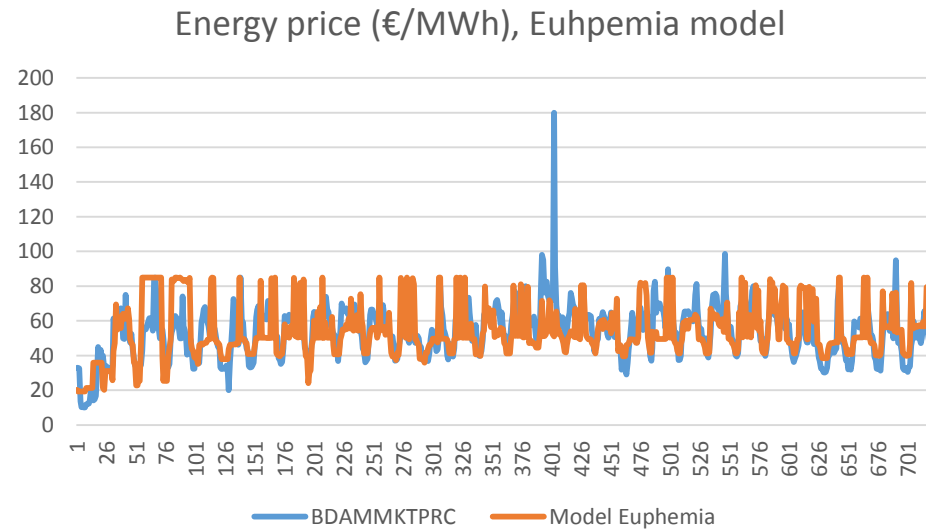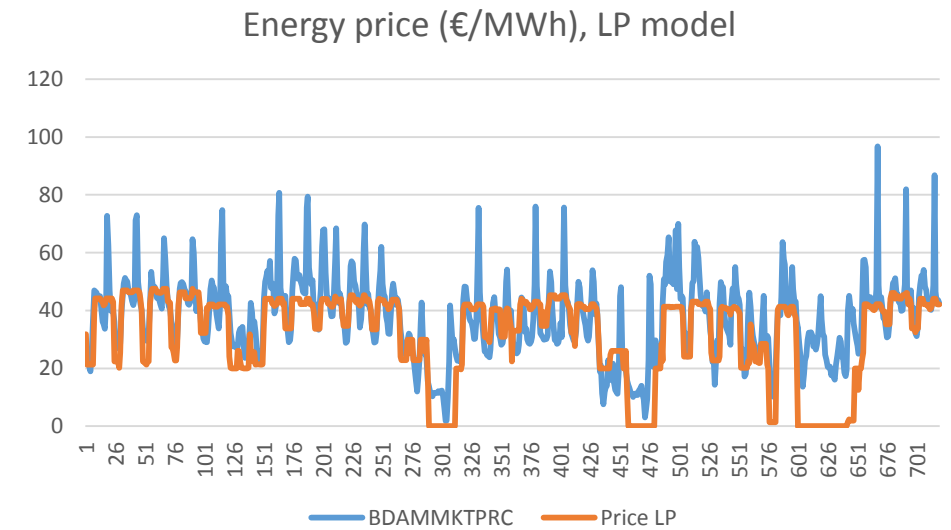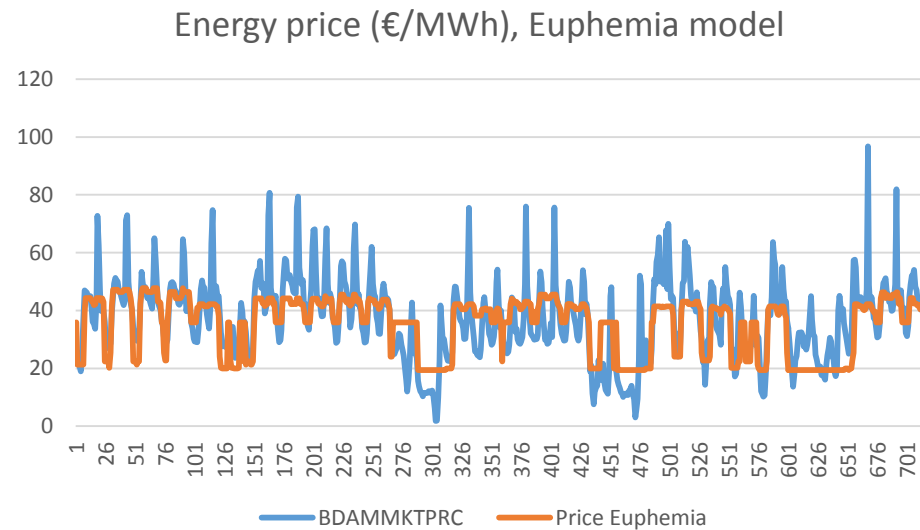
Remarks

- Euphemia approximation outperforms LP

- Price model captures some of the variability of prices
  - Price dips during the night due to coal
  - Price jumps during the day due to CCGT unit commitment costs

- Price jumps during the day cannot be explained by unit commitment costs alone

Energy Price, July 2013

- July 2013 exhibited large variations in energy prices which were impossible to model using a convex model of agent behavior

- Reserve requirements keep CCGT units online at their technical minima

- Coal units set the price in the night, at a price below the marginal cost of online CCGT units
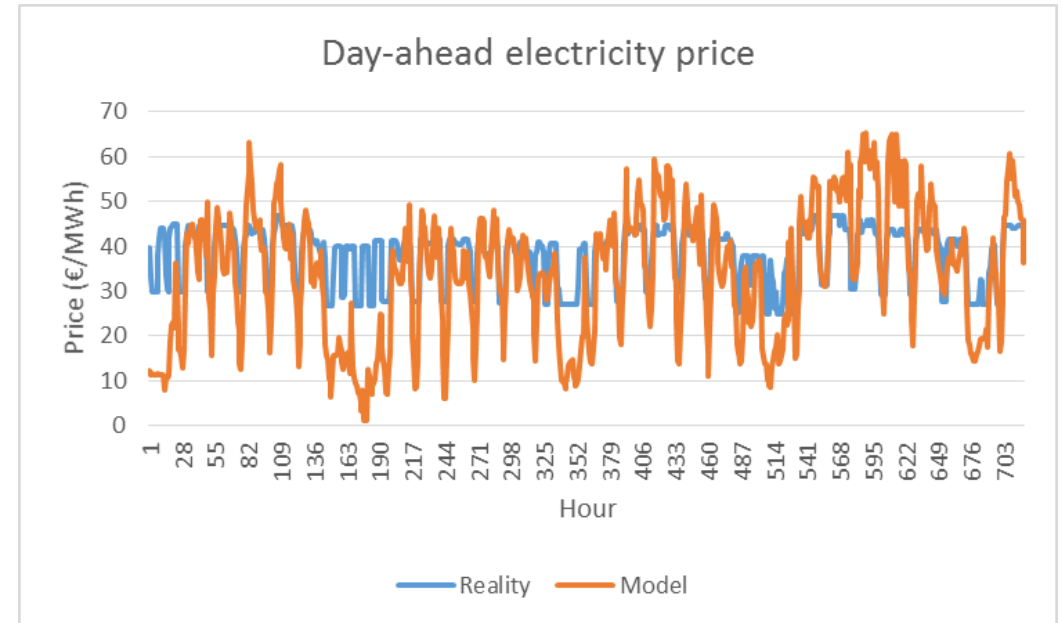
LOLP Computation

- 15-minute uncertainty is estimated based on reserve energy activation (data available)

- Following Hogan and ERCOT practice, we fit a Gaussian for each different season and 6 intervals within the day

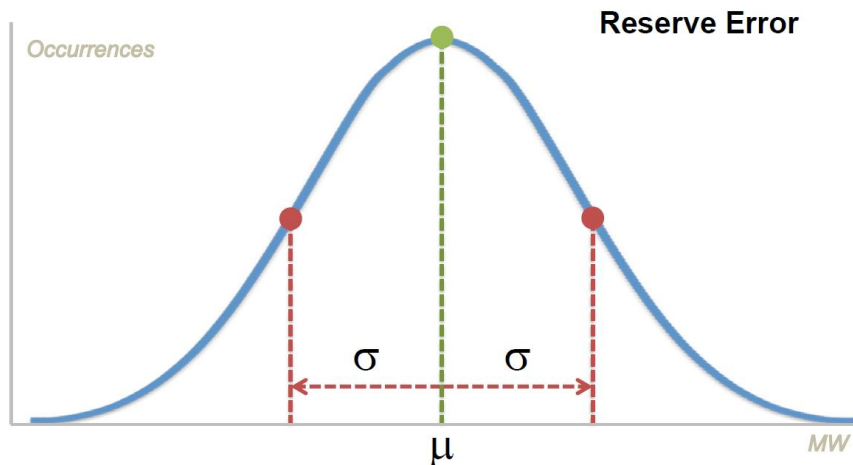| Seasons	Hours	Mean (€/MWh)	St dev (€/MWh)
Winter (month 12, 1, 2)	1, 2, 23, 24	-31.18	96.42
	3-6	-34.88	83.51
	7-10	8.20	103.47
	11-14	-26.39	185.15
	15-18	-19.74	136.75
	19-22	7.58	102.46
Spring (month 3, 4, 5)	1, 2, 23, 24	9.14	97.69
	3-6	-0.45	77.12
	7-10	14.39	103.85
	11-14	-17.89	168.62
	15-18	-58.75	175.45
	19-22	12.80	105.87
Summer (month 6, 7, 8)	1, 2, 23, 24	7.52	89.68
	3-6	-3.63	79.13
	7-10	3.03	92.52
	11-14	6.51	135.41
	15-18	0.50	127.57
	19-22	11.40	98.22
Fall (month 9, 10, 11)	1, 2, 23, 24	-27.84	86.06
	3-6	-24.24	73.11
	7-10	19.45	97.07
	11-14	-23.08	129.76
	15-18	-8.92	116.73
	19-22	6.57	94.19

CCGT Profits and Adder Benefits

	Price (€/MWh), no adder	Price (€/MWh), with adder	Adder benefit (€/MWh)
CCGT1	**3.6**	10.6	8.5
CCGT2	**1.3**	**3.6**	11.6
CCGT3	**1.1**	10.0	7.7
CCGT4	**3.8**	11.1	10.0
CCGT5	**0.9**	6.4	7.5
CCGT6	**3.9**	8.3	6.8
CCGT7	**1.0**	**3.2**	6.8
CCGT8	**1.1**	8.0	8.0
CCGT9	**2.3**	11.1	10.1
CCGT10	**1.7**	7.4	14.9
CCGT11	**1.7**	**4.3**	8.6

Price Adders, January 2013

- A deeper time horizon implies more reserves are available...
- ... but conditions are also more uncertain

System excess capacity (MW)

RT price and price adder (€/MWh)
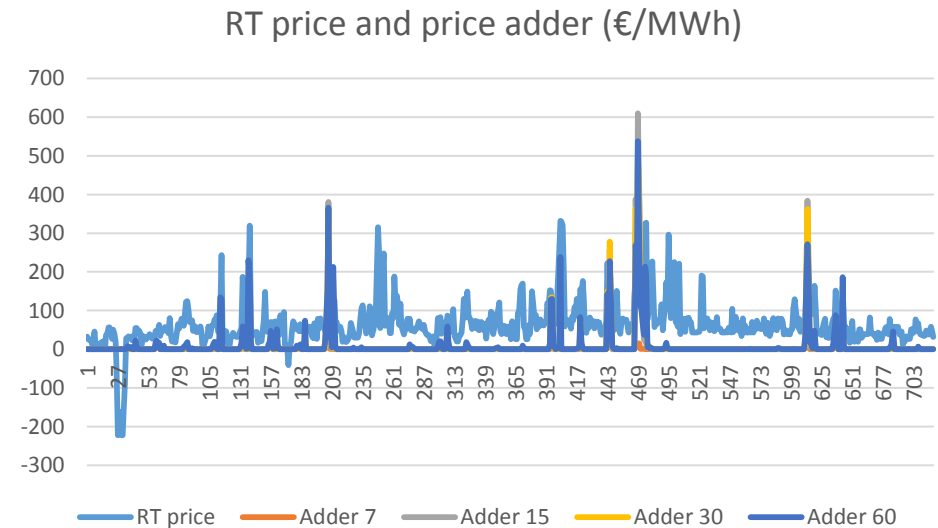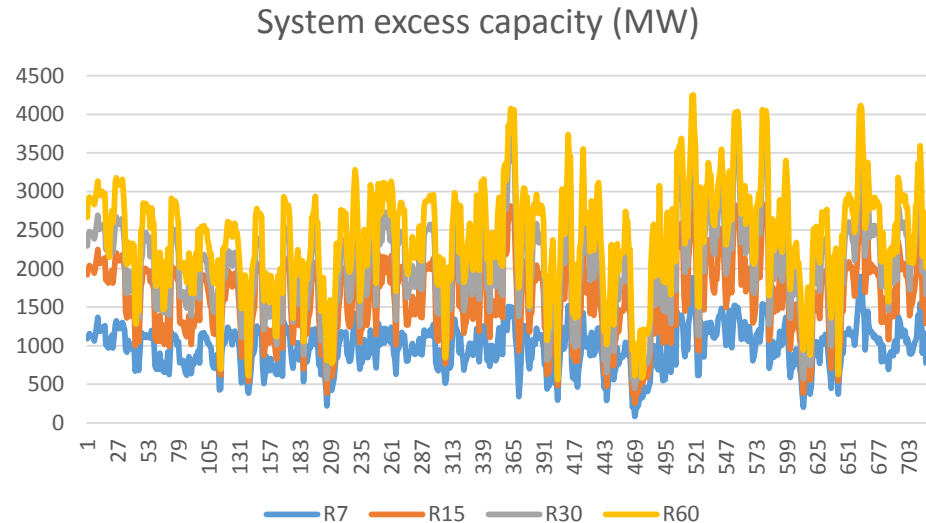
Remarks

- CCGT seems not to be viable given the market prices of the study (confirming what we have already heard in the policy debate)
- Adders, as computed in the study, could potentially change this for the majority of CCGT units, (although there are still three CCGTs that are not profitable after the intro of the adders)
- The average adder for the duration of the study is 6.06 €/MWh, but the adder is effectively much higher for CCGT units (e.g. up to 20 €/MWh for some months)
  - ORDC mechanism rewards flexibility
  - Result of positive correlation of CCGT production with adders/conditions of scarcity
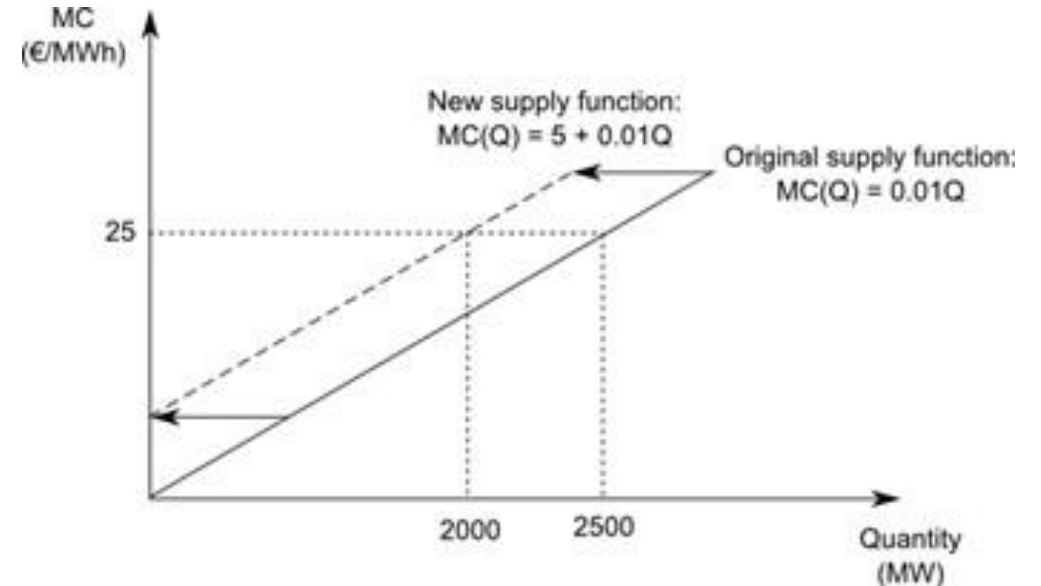
Thank you

For more information

- anthony.papavasiliou@uclouvain.be
- http://perso.uclouvain.be/anthony.papavasiliou/public_html/home.html

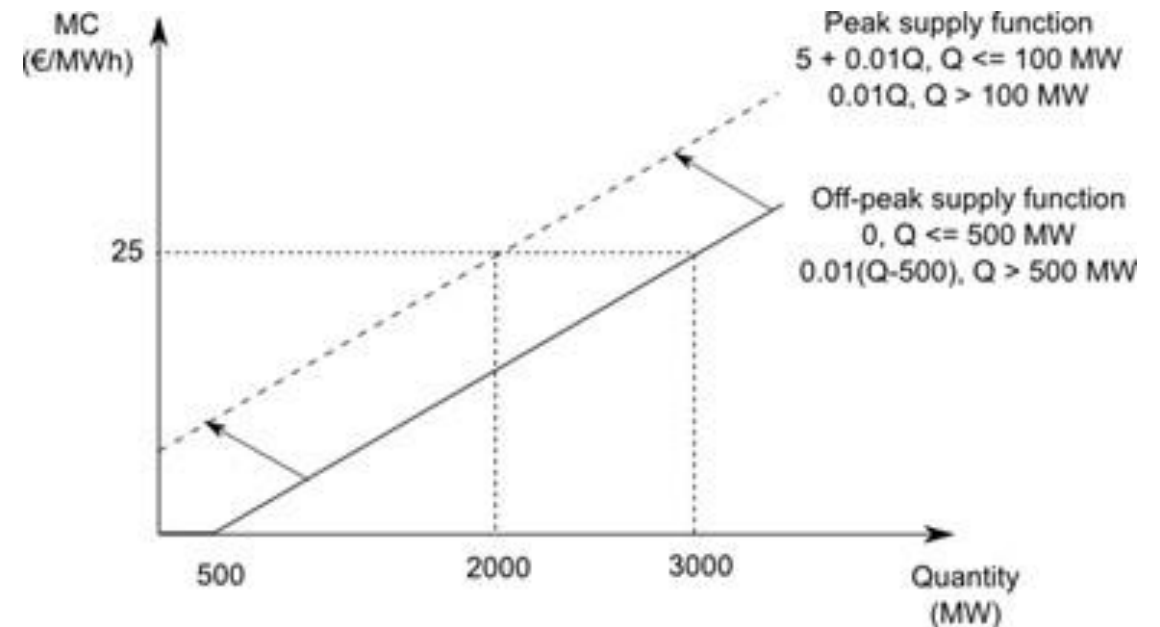# Factor 1: Outages

- Consider marginal cost function:
$$MC(Q) = 0.01Q$$

- Suppose system loses 500 MW of its cheapest capacity

- Same market price of 25 €/MWh, different cleared quantities
  - 2500 MW or
  - 2000 MW

Factor 2: Unit Commitment

- Each unit dQ in [0, 500] MW has startup cost of 60 dQ €
- Peak and off-peak periods, each lasts for 12 hours
- Units in [0, 500] MW
  - bid 0 €/MWh in off-peak period in order to ensure dispatched, avoid startup cost
  - recover startup cost in peak period by bidding 0.01Q + 5 €/MWh
- Same market price of 25 €/MWh, different cleared quantities
  - 2500 MW or
  - 3000 MW

MC (€/MWh)

Peak supply function
5 + 0.01Q, Q <= 100 MW
0.01Q, Q > 100 MW

Off-peak supply function
0, Q <= 500 MW
0.01(Q-500), Q > 500 MW

25

500   2000   3000

Quantity (MW)

Factor 3: Imports/Exports

- System is connected to neighbor with 500 MW link
- Residual marginal cost function of neighbor:
  - 0 €/MWh (oversupply)
  - 10 + 0.01Q €/MWh (undersupply)
- Same price 12.5 €/MWh, different quantities:
  - 1750 MW (cheap imports) or
  - 1500 MW (expensive imports)
- Impact of this effect limited by value of ATC (beyond 2000 MW supply functions coincide, at 25 €/MWh cleared quantity is 3000 MW, regardless of conditions at the border)
- "*Large markets 'pull' the price of small neighbors*" is a fallacy
- Imports/exports can introduce variability if ATC value changes over time (e.g. conservative declaration of ATC in Belgium)
- Flow-based market coupling creates different dynamic

MC (€/MWh)

Supply function with expensive imports
0.01Q, Q <= 1000 MW
10 + 0.005(Q-1000), 1000 MW < Q <= 2000 MW
15 + 0.01(Q-2000), Q > 2000 MW

25

12.5

1500   1750   3000   Quantity (MW)

Supply function with cheap imports
0, Q <= 500 MW
0.01(Q-500), Q > 500 MW
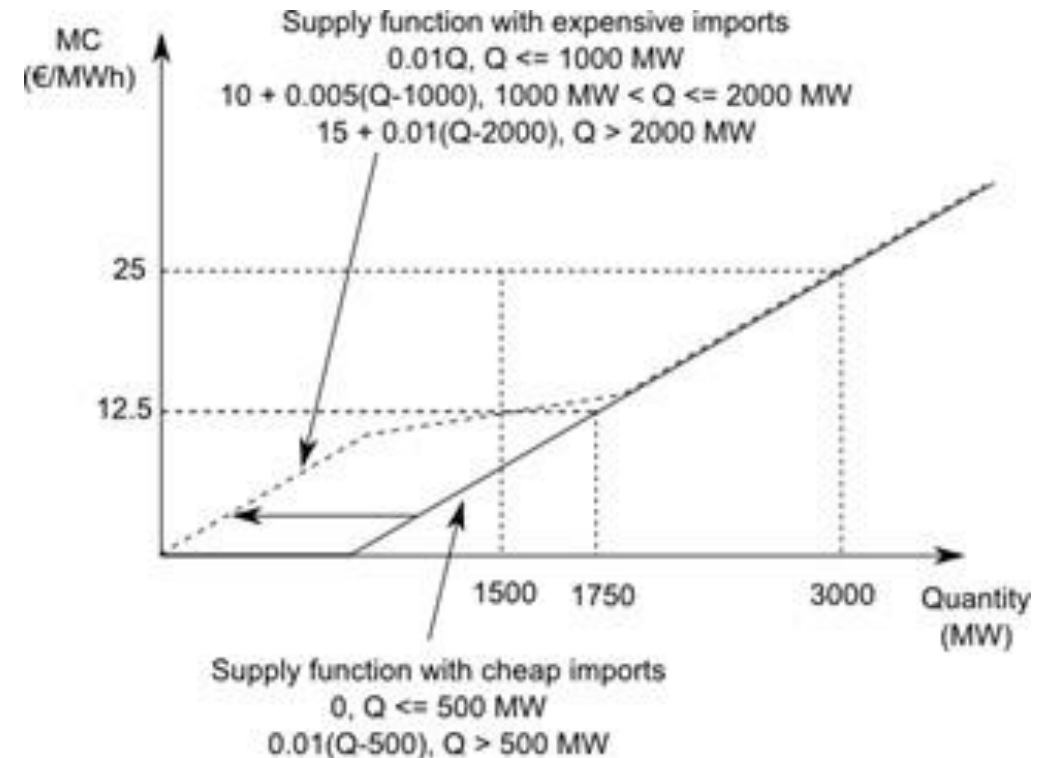
Factor 4: Reserves

- Primary reserve requirements added to system demand (equivalently, shift supply function to the left) because must be offered by online units that are in the money

- Primary reserve requirement 500 MW

- Same price 12.5 €/MWh, different quantities:
    - 2500 MW (no primary reserve) or
   - 2000 MW (with primary reserve)
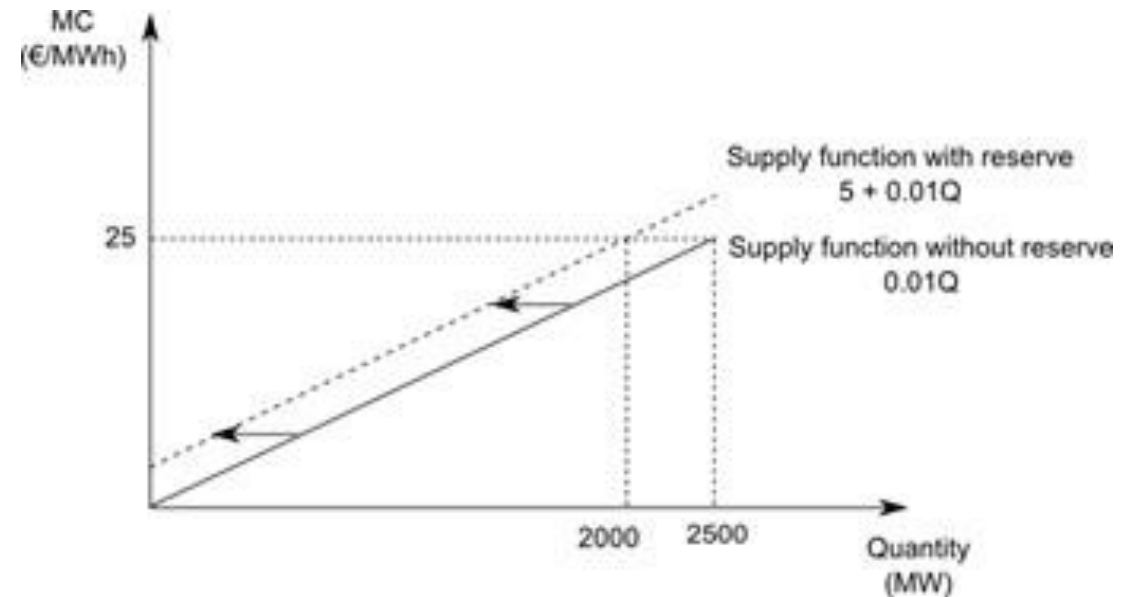
Factor 5: Forward / Bilateral Commitments

- Forward/bilateral commitments do *not* influence supply function
- *"A firm will use capacity regardless of its marginal cost in order to satisfy forward or bilateral commitments"* is a fallacy
- Firm can buy out its position in the real-time market

Factor 6: Demand Side Bidding

- Suppliers may submit bids with a low ask value in the power exchange in order to buy power for covering bilateral commitments

- This does *not* influence the supply function

- Only effect: we observe supply function at different price-quantity pair
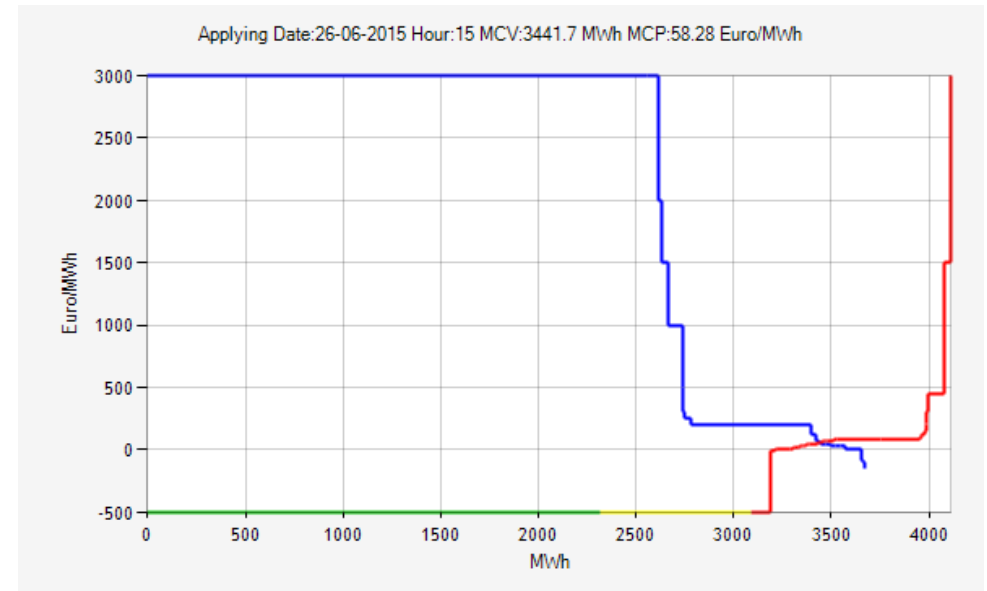
ELIA Grid Load / ELIA Total Load

- ELIA grid load: net generation of the power stations that inject power at a voltage of at least 30 kV and the balance of imports and exports
- Energy needed for pumped storage deducted from the total
- Decentralized generation injecting below 30 kV not entirely included in ELIA grid load
- Significance of distributed generation has steadily increased during the last years
- ELIA now forecasts <u>total</u> Belgian electric load
- Our data:
  - ELIA day ahead grid load until October 31, 2014
  - ELIA total load thereafter
  - Study interval: January 1, 2013 – September 30, 2014 => this effect influences our supply function
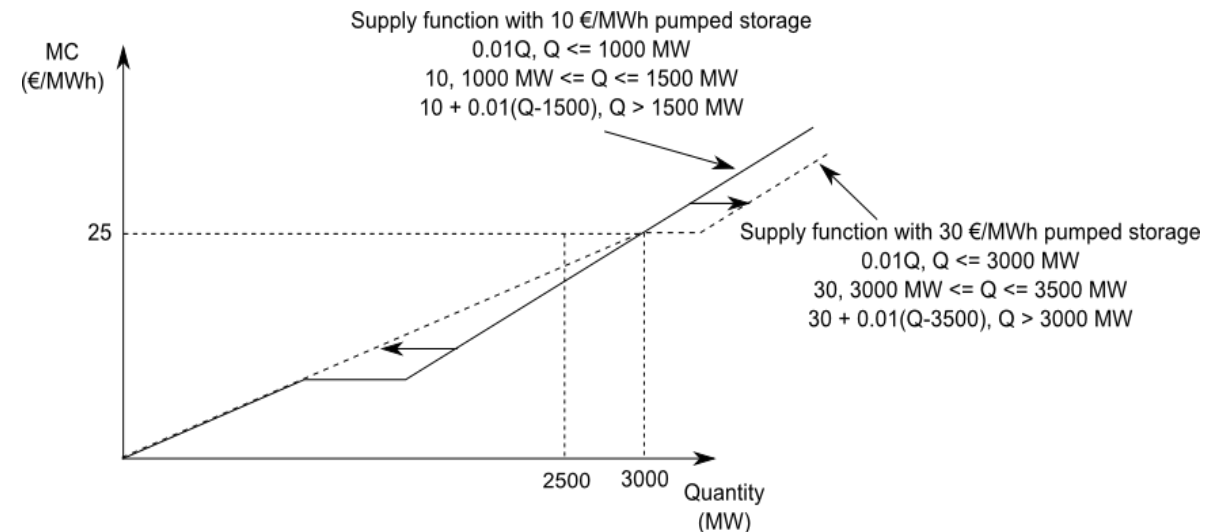
Factor 7: Distributed Supply

- Consider 500 MW of distributed renewable supply which is not measured and injected regardless of market price

- Same price 25 €/MWh, different quantities:
  - 2500 MW (without injections) or
 - 3000 MW (with injections)
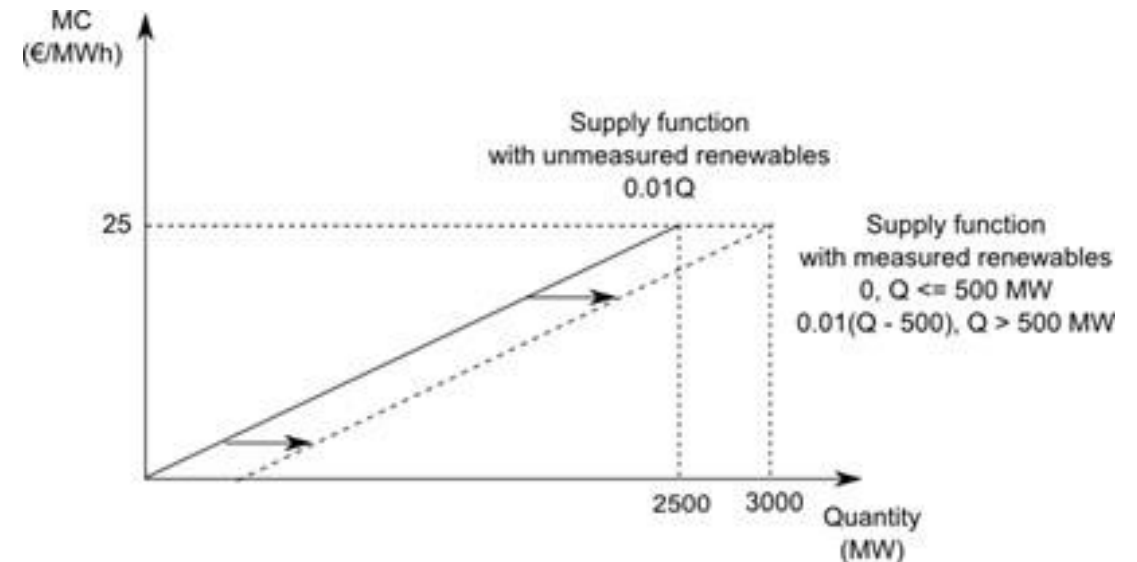
Factor 8: Pumped Storage

- Representation of storage is challenging because it depends on belief of agents about future evolution of electricity prices
- Pumped storage can act as both a supplier as well as a consumer
- Pumped storage in Belgium is 1215 MW
- Consider 500 MW of pumped storage
- Compare opportunity cost of 10 €/MWh versus 30 €/MWh
- Same price 25 €/MWh, different quantities:
  - 3000 MW (opportunity cost 10 €/MWh) or
  - 2500 MW (opportunity cost 30 €/MWh)

Supply function with 10 €/MWh pumped storage
0.01Q, Q <= 1000 MW
10, 1000 MW <= Q <= 1500 MW
10 + 0.01(Q-1500), Q > 1500 MW

Supply function with 30 €/MWh pumped storage
0.01Q, Q <= 3000 MW
30, 3000 MW <= Q <= 3500 MW
30 + 0.01(Q-3500), Q > 3000 MW

MC
(€/MWh)

25

2500 3000 Quantity
(MW)

Factor 9: CHP and Must-Take Resources

- Must-take resources produce out of merit order
- Subtracted from the system demand, equivalently shift the supply function to the right
- Belgian CHP: 1633 MW
- Consider 500 MW of must-take resources
- Same price 25 €/MWh, different quantities:
  - 2500 MW (no must-take) or
  - 3000 MW (with must-take)
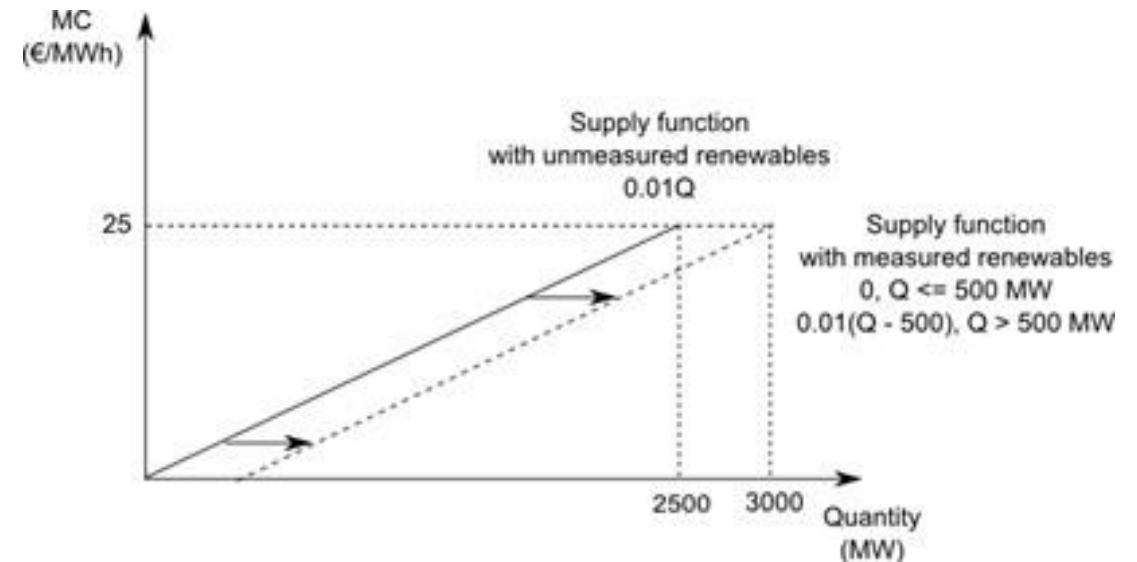
Factor 10: Fuel Price Fluctuation

- Suppose price of underlying fuel increases by 10%

- Same price 25 €/MWh, different quantities:
  - 2500 MW (reference fuel price) or
  - 2273 MW (+10% fuel price)
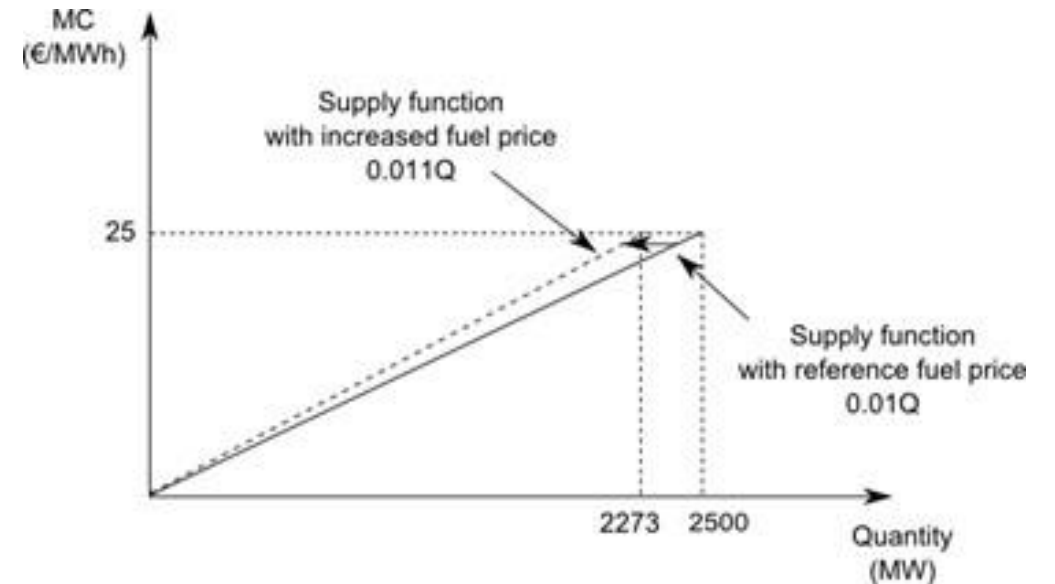
Factor 11: Market Power

- Suppose capacity above 2000 MW is kept out of the market in order to profitably increase prices

- Same price 25 €/MWh, different quantities:
  - 2500 MW (no market power) or
  - 3000 MW (with market power)

- CREG closely regulates Belgian market