Cost-minimal investments into generation capacities under a Europe-wide policy

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Agenda

1. Introduction
2. Model
3. Application
4. Results
Introduction

Several different predictions regarding the future of the European power plant portfolio exist

- **PRIMES**
  - Integrated energy system model, EU27 scope
  - Basis for EC’s scenarios

- **LIMES**
  - Long-term Investment Model for the Electricity Sector, EU28+ scope, 2010-2050
  - Investments in Generation and transmission capacity

- **DIMENSION**
  - Dispatch and Investment Model for European Electricity Markets
  - Grid representation using PTDFs

- **Many others**

→ The underlying assumptions that are input into the model significantly determine the model outcome
Agenda

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Model: Dynelmod

Scope: Europe

Objective: System Cost minimization
- Capacity Cost and Generation Cost
- Investment cost
- Generation Capacities
- Grid Expansion

Investments: ten-year steps (2015), 2020, 2030, 2040, 2050, plant dispatch: hourly resolution over set of hours

Boundary condition examples
- Country-sharp power plant portfolio development (decommissioning of existing plants)
- Electricity demand development per Country
- CO₂-Budget over time
- Market coupling: NTC or Flow-Based
Model: Dynelmod

Investments
- Conventional power plants
- Renewables (PV, Wind Onshore/Offshore, CSP)
- Storage (modeled as generic storage, 8hrs)
- Grid expansion (increase of NTCs)

Other Data
- Hourly RES feed-in and load for 2012 based on ENTSO-E and ECWMF weather data
- Increase in full-load hours of renewables over time
- Cost data based on Schröder et al. (2013)
  - Investment cost
  - Fix and variable capacity cost

Calculation over a set of hours
- Variation of time-of day
- Variation of season
- Scaling for feed-in and demand time series
EC’s Roadmap Cost assumptions

Our cost assumptions

Cost assumptions are derived from a DIW Data Documentation by Schröder et al. (2013)
Flow-based market coupling– Aggregation to a zonal PTDF

The flow based cross border interaction characteristics are derived from the actual underlying grid structure

→ Aggregation line sharp data to a country sharp PTDF

PTDF Calculation from the actual AC grid

\[ P_{TDF_{l,nn}} = \sum_{n} H_{l,n} \times B_{n,nn}^{-1} \]

Load on line using PTDF

\[ P_{l} = \sum_{n} P_{TDF_{l,n}} \times \text{netinput}_{n} \]

→ Aggregation to a zonal PTDF with maximum transfer capacities

\[ P_{co,cco} = \sum_{cco} P_{TDF_{zonal_{co,cco,cco}}} \times \text{netinput}_{cco} \]

Node sharp representation of the European high voltage grid

Blue: HVDC, red: 380 kV, yellow: 300 kV, green: 220 kV
System cost minimization model

\begin{align*}
\text{System cost} &= \min \text{cost} = \text{cost}^{\text{gen}} + \text{cost}^{\text{inv}} + \text{cost}^{\text{cap}} + \text{cost}^{\text{line}} \\
&= \sum_{co, i, y} C_{\text{var}}^{\text{co}, i, y} g_{\text{existing}}^{\text{co}, i, t, y} * DF_y \\
&\quad + \sum_{co, i, y, yy} C_{\text{var}}^{\text{newbuilt}} g_{\text{newbuilt}}^{\text{co}, i, t, y, yy} * DF_y \\
&\quad + \sum_{co, i, y, yy} C_{\text{load}}^{\text{up}} (g_{\text{co}, i, t, y}^{\text{up}} + g_{\text{co}, i, t, y}^{\text{down}}) * DF_y \\
&= \sum_{co, i, y} C_{\text{inv}}^{\text{co}, i, y} g_{\text{max, new}}^{\text{co}, i, y} * DF_y \\
&= \sum_{co, i, y} C_{\text{fix}}^{\text{co}, i, y} (G_{\text{co}, i, y}^{\text{max}} + g_{\text{co}, i, y}^{\text{max, new}}) * DF_y \\
&= \sum_{y, co, cco} 0.5 * \text{lineexp}_{y, co, cco}^{\text{co}} * DF_y \\
\text{Global balance} &= 0 = \sum_{co} Q_{\text{co}, t, y} - \sum_{co, i} g_{\text{co}, i, t, y} \quad \forall y, t \\
\text{Country-wide balance including flows} &= 0 = Q_{\text{co}, t, y} - \sum_{i} g_{\text{co}, i, t, y} \\
&\quad + \sum_{cco} \text{dcflow}_{cco, cco, t, y} * H_{\text{vdc}}_{cco, cco}^{\text{max}} \quad \forall y, co, t
\end{align*}
System cost minimization model

Generation and build restrictions

Generation ramping
System cost minimization model

Storage restrictions

AC-Grid and HVDC flow restrictions

For AC flow determination power transfer distribution factors (PTDFs) are used
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Application to a European Data Set:

- Originally plant-block- and line-sharp data accuracy for all EU-28 countries as well as Norway, Switzerland and the Balkan countries
- Hourly RES feed-in and load for 2012
- Investment cost based on Schröder et al. (2013)

Aggregation to a country resolution

- One node per country
- Distances between geographical centers are used for transmission expansion cost calculation

Other boundary conditions regarding the long-term development of prices, load, and CO$_2$ emission path are based on EC’s “Energy Roadmap 2050 Impact assessment and scenario analysis” scenario “Diversified supply technologies”
Scenarios

We vary different factors to determine the sensitivity of the results:

**Nuclear Capacity**
- EC “Reference Scenario”
- Half new Nuclear
- No new Nuclear

**Capacity Adequacy requirement**
- European
- National
- No Adequacy

**Market Coupling**
- Flow-based
- NTC

**Grid expansion cost factor**
- x0.0001, x1, x2, x500
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Capacity Development Reference Scenario (Preliminary Results from my laptop – calculations on large cluster to follow!)

Reference Scenario:
- Sun
- Wind
- Hydro & Storage
- Biomass
- Waste
- Oil
- Gas
- Hard Coal
- Lignite
- Uranium
Compared to the installed capacities from the roadmap diversified supply scenario we see a bit more investments in renewable capacities driven by the scenario assumption of no CCTS.
Three Nuclear scenarios
Nuclear Scenarios – Difference to reference scenario
Nuclear mostly replaced by Wind, Sun + Storage. Cost increase about 5%
Adequacy Requirements – Difference to reference scenario
National Adequacy requires higher capacities, mostly gas
Grid investment costs – difference to reference scenario. Grid cost only influence the result when changed strongly; cost impact negligible.
Flow-Based Market Coupling decreases installed capacities \( \rightarrow \) further look into the driving factors needed

![Graph showing decreases in installed capacities](image-url)

- Sun
- Wind
- Hydro & Storage
- Biomass
- Waste
- Oil
- Gas
- Hard Coal
- Lignite
- Uranium
In the case of national adequacy the generation investments are on average slightly higher.

But: regional differences exist.

Denmark, Germany etc. need less own capacity in case of European adequacy, as Switzerland etc. provide hub capacity. This is reduced in case of national adequacy requirement.
Conclusion & Outlook

Conclusion

- Nuclear Mostly replaced by wind and sun, some storage. ~5% higher costs in “No new nuclear”.
- Adequacy requirements are mostly met by gas fueled power plants, that do not run very often.
- National adequacy requirement increases overall generation expansion, changes the spatial distribution of investments
- Some Countries like Switzerland see increased investments in the case of European adequacy, as they provide central dispatchable capacity.
- Denmark and other countries can rely on neighbours, thus see higher investment in the national adequacy case
- Grid cost lead to increase capacity expansion needs, especially if no expansion is done (caused by the x500 cost factor). As grid costs only make up ~2% of total costs, the overall cost remain similar.
- Flow-based market coupling modeling (unintuitively?) decreases overall generation expansion.
Thank you!
Model

\[
\begin{align*}
\text{min cost} &= \text{cost}^{\text{gen}} + \text{cost}^{\text{inv}} + \text{cost}^{\text{cap}} + \text{cost}^{\text{line}} \\
\text{cost}^{\text{gen}} &= \sum_{co,i,t,y} C\text{var}_{co,i,y} \cdot g_{co,i,t,y}^{\text{existing}} \cdot DF_y \\
&\quad + \sum_{co,i,t,y,yy} C\text{var}_{co,i,y,yy} \cdot g_{co,i,t,y,yy}^{\text{newbuilt}} \cdot DF_y \\
&\quad + \sum_{co,i,t,y,yy} C\text{load}_{co,i,y} \cdot (g_{co,i,t,y}^{up} + g_{co,i,t,y}^{down}) \cdot DF_y \\
\text{cost}^{\text{inv}} &= \sum_{co,i,y} C\text{inv}_{i,y} \cdot g_{co,i,y}^{\text{max,new}} \cdot DF_y \\
\text{cost}^{\text{cap}} &= \sum_{co,i,y} C\text{fix}_{co,i,y} \cdot (G_{co,i,y}^{\text{max}} + g_{co,i,y}^{\text{max,new}}) \cdot DF_y \\
\text{cost}^{\text{line}} &= \sum_{y,co,cco} 0.5 \cdot \text{lineexp}_{y,co,cco} \cdot DF_y
\end{align*}
\]
Model

\[ 0 = \sum_{co} Q_{co,t,y} - \sum_{co,i} g_{co,i,t,y} \quad \forall y, t \quad (6) \]

\[ 0 = Q_{co,t,y} - \sum_i g_{co,i,t,y} \\
+ n_{co,t,y} \\
+ \sum_{cco} dcf_{cco,co,t,y} \cdot H_{vdc_{cco}}^{max} \quad \forall y, co, t \quad (7) \]

\[ + \sum_{cco} dcf_{cco,co,t,y} \cdot H_{vdc_{cco}}^{max} \]
Model

\[
0 = g_{co, disp, t, y}^{existing} + \sum_{yy \leq y} g_{co, disp, t, y, yy}^{newbuilt} + g_{co, disp, t, y}^{existing} + g_{co, disp, t, y}^{existing}
\]

\[0 \leq A_{co, disp, y} * G_{co, disp, y}^{\text{max}} \quad \forall co, disp, t, y \quad (8)\]

\[0 \leq A_{co, disp, y} * G_{co, disp, y}^{\text{max}} \quad \forall co, disp, t, y \quad (9)\]

\[0 \leq R_{co, ndisp, t, y}^{\text{max}} - g_{co, ndisp, t, y} \quad \forall co, ndisp, t, y \quad (10)\]

\[0 \leq G_{co, c, y}^{\text{max, inv}} - \sum_{c, y} g_{co, c, y}^{\text{max, new}} \quad \forall co \quad (12)\]

\[0 \leq G_{co, s, y}^{\text{max, inv}} - \sum_{s, y} g_{co, s, y}^{\text{max, new}} \quad \forall co, s \quad (13)\]

\[0 \leq R_{up, y}^{\text{max}} * G_{co, i, y}^{\text{max, new}} + R_{up, y}^{\text{up}} \sum_{yy \leq y} g_{co, i, yy}^{\text{new}} \quad \forall co, i, t, y \quad (14)\]

\[0 \leq R_{down, y}^{\text{up}} * G_{co, i, y}^{\text{max, new}} + R_{down, y}^{\text{up}} \sum_{yy \leq y} g_{co, i, yy}^{\text{new}} \quad \forall co, i, t, y \quad (15)\]

\[0 = g_{co, i, t, y}^{up} - g_{co, i, t, y}^{down} \quad \forall co, i, t, y \quad (16)\]

\[0 \leq G_{co, disp, y}^{\text{max}} - \sum_{t} g_{co, disp, t, y} \quad \forall co, disp, y \quad (17)\]
Model

\[
g_{co,s,t,y} = p_{sp}^v_{co,s,t,y} - p_{sp}^w_{co,s,t,y} \quad \forall co, s, t, y \quad (18)
\]

\[
p_{sp}^v_{co,s,t,y} \leq A_{va,s,y} * V_{max}^{co,s,y} + A_{va,s,y} * \sum_{yy \leq y} g_{co,s,yy}^{max_{new}} \quad \forall co, s, t, y \quad (19)
\]

\[
p_{sp}^w_{co,s,t,y} \leq A_{va,s,y} * V_{max}^{co,s,y} + A_{va,s,y} * \sum_{yy \leq y} g_{co,s,yy}^{max_{new}} \quad \forall co, s, t, y \quad (20)
\]

\[
p_{sp}^l_{co,s,t,y} \leq L_{co,s,y}^{max} + SF * \sum_{yy \leq y} g_{co,s,yy}^{max_{new}} \quad \forall co, s, t, y \quad (21)
\]

\[
p_{sp}^l_{co,s,t,y} \geq L_{co,s,y}^{min} \quad \forall co, s, t, y \quad (22)
\]

\[
p_{sp}^l_{co,s,t,y} = p_{sp}^l_{co,s,t-1,y} - p_{sp}^v_{co,s,t,y} + E_{ta_{co,s,y}} * p_{sp}^w_{co,s,t,y} \quad \forall co, s, t, y \quad (23)
\]

\[
0 \leq p_{co,cco}^{max} + \sum_{yy \leq y} lineexp_{y,co,cco} \quad \forall co, cco, t, y \quad (24)
\]

\[- \sum_{cco} PTDF_{co,cco,cco} * n_{cccco,ty} \leq H_{vd_{co,cco}}^{max} + \sum_{yy \leq y} lineexp_{y,co,cco} \quad \forall co, cco, t, y \quad (25)
\]

\[-cflow_{co,cco,ty} \leq lineexp_{y,cco,co} - lineexp_{y,co,cco} \quad \forall y, co, cco \quad (26)
\]
A. PTDF Calculation

The country-sharp PTDF is derived from the actual underlying high voltage AC grid of Europe as follows. We determine the country connection. The third set ccco is the injecting or withdrawing country.

The maximum transfer capacity between countries $P_{co,cco}^{max}$ is calculated as follows:

$$P_{co,cco}^{max} = \min_{ic} \frac{P_{l}^{max}}{PTD_{f_{1,co}} - PTD_{f_{1,cco}}}$$  \hspace{1cm} (30)

We then calculate a zonal PTDF based on all lines connecting two zones.

$$PTD_{f_{1,co}} = \sum_{n \in co} \frac{PTD_{f_{1,n}}}{\text{count}(n \in co)} \forall \text{interconnectors}$$  \hspace{1cm} (28)

Further approximation of the PTDF is conducted using an approximation of all interconnectors.

$$PTD_{f_{co,cco,ccc}} = \sum_{\text{if Start In Co Or End In Cco}} PTD_{f_{1,cco}} - \sum_{\text{if Start In Cco Or End In Co}} PTD_{f_{1,cco}}$$  \hspace{1cm} (29)