Electricity markets

Opening up to competition and investments

Lars Dittmar (TU Berlin), Dennis Volk & Matthew Wittenstein (IEA)

IEA Energy Training Week
Paris, 10.04.14
Why again did electricity matter?

US GDP and power demand growth

GDP Power demand

GDP

Power demand
Electricity is primarily a wealth creator
Electricity increases our productivity

50 watt   2000 watt
Global power investment needs > 45% of ESI

Power sector investments until 2035 (WEO/NPS)

16,867 bn USD
43% for grids
THE CONTEXT

It is relevant to identify development scenarios,

...but what can we actually do today?
## Categories of costs in power production and their relevance to Operation, Decommissioning, and Expansion

<table>
<thead>
<tr>
<th></th>
<th>Operation</th>
<th>Decommissioning</th>
<th>Expansion</th>
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</thead>
<tbody>
<tr>
<td>Costs dependent on Capacity [USD/MW\textsubscript{el}]</td>
<td></td>
<td></td>
<td>✓</td>
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<tr>
<td>Capital Costs</td>
<td></td>
<td>✓</td>
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<tr>
<td>Labor Costs</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Fixed Operation &amp; Maintenance</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Costs dependent on operation [USD/MWh\textsubscript{el}]</td>
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<tr>
<td>Fuel costs</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Other variable costs (e.g. CO\textsubscript{2})</td>
<td>✓</td>
<td>✓</td>
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Stylized Load Curve and Load Duration Curve

Load Curve

- $P_{\text{max}}$
- $P_{\text{min}}$
- Time of day

Load Duration Curve

- $P_{\text{MW}}$
- Cumulative hours

1, 2, 3, 4
Short-term Marginal Generation Costs

\[ STMCG(G) = \frac{Fuel \ Price \ (G)}{Eta(G)} + O & M_{\text{Variable}}(G) + \frac{EF_{CO_2}}{Eta(G)} \cdot P_{CO_2} \]

Where:

- \( G \) = Generation unit index
- \( STMCG(G) \) = Short-term marginal generation costs [USD/MWh\(_{el}\)]
- \( Fuel \ Price \ (G) \) = Fuel Price [USD/MWh\(_{therm}\)]
- \( Eta(G) \) = Efficiency [\(-\)]
- \( O&M_{\text{Variable}} \) = Variable O&M costs [USD/MWh\(_{el}\)]
- \( EF_{CO_2} \) = Emission factor CO\(_2\) [t CO\(_2\)/MWh\(_{therm}\)]
- \( P_{CO_2} \) = CO\(_2\) [USD/tCO\(_2\)]
Long-term Marginal Generation Costs

\[ LTMC(G) = \frac{Investment(G) \times \alpha + O & M_{\text{Fixed}}(G)}{\text{Load factor (G)}} + STMC(G) \]

Where:

- \( G \) = Generation unit index
- \( LTMGC(G) \) = Long-term Marginal Generation Costs [USD/MWh\(_{el}\)]
- \( O & M_{\text{Fixed}} \) = Fixed O&M costs [USD/MW/a]
- Investment \((G)\) = Investment cost [USD/MW]
- Load factor \((G)\) = Full Load Hours [h]
- \( STMGC(G) \) = Short-term marginal generation costs
- \( \alpha \) = Capital recovery factor (rule of thumb \( \sim 10\% \))
Long-term Marginal Generation Costs
(just an orientation)

USD/MWh\textsubscript{el}

- Nuclear
- Hard coal
- CCGT-Gas
- OCGT-Gas

Full load hours
**Screening Curve Method: Annual Costs**

\[
AC(G) = \text{Invest}(G) \times \alpha(G) + O \& M_{\text{Fixed}}(G) + STMC(G) \times T(G)
\]

Where:

- **G** = Generation unit
- **AC(G)** = Annual Costs [USD/MW/a]
- **O&MF_{\text{Fixed}}(G)** = Fixed O&M costs [USD/MW]
- **Invest (G)** = Investment cost [USD/MW]
- **T (G)** = Full Load Hours [h]
- **STMC(G)** = Short-term marginal generation costs [USD/MWh\text{el.}]
- **\( \alpha \)** = Capital recovery factor (rule of thumb ~ 10%)
Linear Screening Curves

Annual Cost [USD/MW/a]

Intercept: Tech 1

Intercept: Tech 2

Tech1 <t> Tech2

Full load hours
Linear Screening Curves: Sensitivities

Annual Cost [USD/MW/a]

(1) Higher interest rates, increasing capital cost or both alter the intercept

(2) Changes in fuel prices, CO₂ prices or both alter the slope

Full load hours
Linear Screening Curves and Load Duration Curve

Hours per Year

Tech1

Tech2

Load Demand

Annual Cost [USD/MW/a]
Screening Curve Method: Example I

USD/kW/a

Nuclear
Hard coal
CCGT-Gas
OCGT-Gas
Shedding
Screening Curve Method: Example II

USD/kW/a

- Nuclear
- Hard coal
- CCGT-Gas
- OCGT-Gas
- Shedding
- Min Costs

Hard coal to Nuclear
CCGT-Gas to Hard coal
OCGT-Gas to CCGT-Gas
Shedding to OCGT-Gas
Min Costs

USD/kW/a vs. USD (0-8000)

- Nuclear: Blue line
- Hard coal: Yellow line
- CCGT-Gas: Purple line
- OCGT-Gas: Green line
- Shedding: Brown line
- Min Costs: Red line
Many technologies available, which one to use?

- Onshore Wind
- Gas
- Gas - OCGT
- Gas - CCGT
- Hard coal
- Nuclear
- Solar PV

USD/MWh

- US - status quo
- US - high gas
- EU - status quo
- EU - low risk

Investment
Fuel
O&M
CO2
Decommissioning

Coal price (USD/t)
Gas price (USD/MBtu)

- US Coal Appalachian (Monthly Average)
- Henry Hub (Monthly Average)
De-risking of generation assets

<table>
<thead>
<tr>
<th>Category</th>
<th>Example Causes</th>
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<td>Economic</td>
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</table>
| Construction        | • Cost overruns  
                      | • Time overruns                                                             |
| Market              | • Inadequate prices or demand  
                      | • Input cost increase                                                      |
| Operational         | • Plant performance  
                      | • Fuel unavailability                                                      |
| Macroeconomic       | • Significant change in exchange rates  
                      | • Inflation  
                      | • Interest rates                                                           |
| Political           |                                                                             |
| Regulatory          | • Price controls  
                      | • Environmental obligations                                                |
| Expropriation       |                                                                             |
| Legal               |                                                                             |
| Documentation and contract | • Terms  
                      | • Validity                                                                 |
| Jurisdictional      | • Choice of jurisdiction  
                      | • Enforcement  
                      | • Lack of dispute settlement                                               |
| Force majeure       | Natural disaster  
                      | Civil unrest  
                      | Strikes                                                                    |
De-risking of generation assets

- Regulated
  - Risk shifted to consumers
    - Reduces or eliminates investment risks, but can lead to:
      - Overbuilding
      - “Gold-plating” – investing in more expensive technologies

- Restructured
  - Risk born by investor and third-parties
    - Some risks passed on in form of higher wholesale prices
    - Other risks can be shifted through financial/insurance products
  - Government interventions can reduce risk...
    - Guaranteed revenues through FiTs or CfDs
    - Loan guarantees
    - Market structures (e.g. capacity markets)
  - ... or create risk
    - New environmental regulations
    - Policy uncertainty
Q&A
Exercise – Decomposing generation costs

- You have a model with five generation technologies
- Regional specifications can influence technology costs
- Chose a region
- The next slide shows you cost differences by region and technology

Try to answer the following questions in your region:

- Identify the technolog(ies) of your choice!
- Identify key risks of your technology-choice!
- Identify ways to de-risks your technology-choice!
- Consider the role of carbon pricing to influence your choice!
**Investment costs (USD/kW):**
- Hard coal: 2000
- CCGT: 1000
- OCGT: 500
- Nuclear: 4500
- Onshore wind: 2000

**Efficiency [%]:**
- Hard coal: 45
- CCGT: 55
- OCGT: 35
- Nuclear: 35
- Onshore wind:

**Construction time [yrs]:**
- Hard coal: 6
- CCGT: 3
- OCGT: 2
- Nuclear: 10
- Onshore wind: 1

**Fuel price (USD/GJ):**
- Hard coal: 5
- CCGT: 7
- OCGT: 5
- Nuclear: 3
- Onshore wind:

**CO₂ price:** 15 USD/tCO₂

**Cost of capital [%]:**
- Hard coal: 40
- CCGT: 50
- OCGT: 40
- Nuclear: 35
- Onshore wind:

**Construction time [yrs]:**
- Hard coal: 10
- CCGT: 3
- OCGT: 2
- Nuclear: 10
- Onshore wind: 1

**Cost of capital [%]:**
- Hard coal: 7
- CCGT: 7
- OCGT: 10
- Nuclear: 10
- Onshore wind: 10

**Construction costs (USD/kW):**
- Hard coal: 2000
- CCGT: 1000
- OCGT: 500
- Nuclear: 4500
- Onshore wind: 1500

**Fuel price (USD/GJ):**
- Hard coal: 3
- CCGT: 13
- OCGT: 13
- Nuclear: 3
- Onshore wind:
Key questions arising from demand and supply balances

- How can sufficient investments attracted to serve peak demand? ("Generation adequacy")

- How to coordinate multiple generation units (e.g. Germany > 8,700 units; US > 21,500; India > 4,500)?
  - Availability at all times
  - Least cost

- What to do with the demand side in this system?
Break
Organisation of the electricity sector in liberalised markets

The “markets” (different degrees of reliance apply)
Open markets and integrated system operations can deliver

- Real-time
- Day ahead
- Months in advance
- Years in advance

Involvement of central operator

- Network operations
- Electricity markets
- Financial markets

Intraday
Open wholesale markets – Bids resulting in prices

- Used for physical supply day-ahead and intra-day markets are used
- Operational costs determines ranking order of individual plants, i.e. their competitiveness

Fuel costs → Efficiency → Price per MWh

O & M
Bids resulting in prices – operational costs count

Wholesale market (day-ahead and intra-day)

Coal plant
- Coal @ 120 USD/t
- 39% efficiency

Gas plant A - CCGT
- 11 USD/MBtu
- 55%
- 35 €/MWh
- 50 €/MWh

Gas plant B - OCGT
- 11 USD/MBtu
- 35% efficiency
- 80 €/MWh

Ranking order: Coal, Gas A, Gas B
Wholesale markets – operation and investments

Absent perfect market conditions:
Additional payments for capacity likely in the long run

- PJM, NYISO, ISO NE, CAISO
- ERCOT?
- UK
- France
- Germany?

Relevant first-order principle:
- Getting the price(s) right during scarcity
- Marginal cost represents marginal service action
- Demand response (Value of Lost Load essential)
- Price caps (Reliability target essential)
- Coordination with other services (e.g., Balancing)
- Locational differences (Underlying grid essential)

Own set of challenges exist:
- How much and which capacity?
- Implications on other investments?

Absent perfect market conditions:
Additional payments for capacity likely in the long run

- PJM, NYISO, ISO NE, CAISO
- ERCOT?
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Hourly Generation of Electricity on the 3rd Wednesday of January 2011 in Germany

Source: Destatis, TSOs
Hourly Generation of Electricity on 3rd Wednesdays in Germany 2011

Source: Destatis, TSOs
Load Demand and the Merit Order Shape Prices: Avg. hourly load and prices in Germany 2011

Sources: EPEX 2012, ENTSO, own calculation
Explaining Off Peak Electricity Prices by Coal Prices and CO2 Prices

Euro/MWh

- Coal Price / 39% + CO2 Price
- Coal Price / 39%
- Off Peak Price (EEX)

Source: EEX, BAFA, Bloomberg, Destatis
Price Duration Curves Germany (EPEX)

EUR/MWh

2011 (Ø = 51,9)
2012 (Ø = 42,8)
2013 (Ø = 37,8)
Are these returns sufficient?
Infra-marginal rents: why they matter?

- Infra-marginal (IR) rents are the difference between the market price and the individual plants production costs.
- IR are no pure profits – they cover investment costs plus margin.

For coal, IR is @ 80 USD/MWh minus 35 USD/MWh.

CCGT sets market price @ 80 USD/MWh.
Long-term reliability in Texas – now it’s about the peak

Data source: Brattle, 2012
Current concerns in Texas

- Low market prices due to gas market developments
  - Reduced infra-marginal rents in the market, also for peaking plants
- Administered reserve margin of 13.75% exceeds price cap
  - Target set by governments for 10 in ten events
- Capped spot market prices
  - Peaking plants cannot fully compensate during peaks
  - Price increase from 4500 USD/MWh to 9000 USD/MWh (by June 2015. 8% reserve margins achievable)
- No allowance to enter into long-term contracts
- Insufficient demand side participation
- Insufficient price for balancing services
- Texas to remain keen to preserve MWh payments (“energy-only”) instead of using capacity payments (used in rest of US, Chile, some EU)
Evidence of reform

Reform also can work in developing countries (Jamasb et al., 2004)

- Positive experience in Chile, Argentina, Brazil...
- Institutions and governance important
- Efficiency gains and access improved, but not for all
- Cost-reflective pricing for investments and debt reduction
Which country was the first one to reform, when and why?

- 1978: Regulator
- 1982: Electricity Act
- 1981/82: Horizontal and vertical split up and privatisation
- 1986: Large scale privatisation
  - Return from nationalisation early 70s
  - 1973: State firms @ 40% GDP and 8% losses of GDP
  - Improvement until 1980s
Case studies: Chile

- State pension fund investments allowed into private
  - Domestic investments into power
- Strong protection of property rights and information
- Established laws express regulatory rules in detail
  - Hard to overcome under democratic coalitions
  - Reliable framework for investors
Outcomes between 1982 and 2004

- Generation capacity (MW)
- Transmission (km)
- Electrification (rural - %)
- Prices (real terms - USD/MWh)
- Labour productivity (GWh sold per worker)
- Energy losses (%)
Key developments

**Start of Liberalisation**

- **Pre-liberalisation era:**
  - Inflation
  - Debt
  - High prices
  - Lack of investments

**Introduction of**

- Four spot markets with cost-based pricing for trades between generators (regulated competition)
- Regulated prices for sales to distribution based upon a 4-year forecast of spot price with bi-annual adjustments plus capacity prices plus transmission.

Proposed by regulator, accepted by Minister

**Incentive regulation for distribution value added**

**Transmission services paid by generators under negotiation** plus merchant investments and no planning

**Privatisation brought capital, but created one dominant generator**

Worked well until here, but what happened next and why?

**La Niña brought one of the worst droughts on record**

But regulated prices remained stable

**NOV 1998** Prices remained stable because the Ministry required 4 months to determine scarcity prices

**APR 1999** Water reservoirs emptied and Santiago cut off from the grid

**End of 2004**

- Implementation of “Short Law II”
  - Argentina gas supply cut
  - Another drought
  - Santiago cut off from the grid

**Early 2005**

- Implementation of “Short Law II”
- Raising retail sales prices
- Another drought allowed oil generation to compensate from the grid

**End of 2004**

- Argentina gas supply cut
- Another drought

**What do you think happened this time?**

**NOV 2008** Water scarcity allocation plan was weak

In sum

- **450 GWh** not supplied
- Could have been prevented by better use of water scarcity management or flexible power pricing

**End of 2004**

- Argentina gas supply cut
- Another drought

**Early 2005**

- Implementation of “Short Law II”
- Raising retail sales prices
- Another drought allowed oil generation to compensate from the grid

**What do you think happened this time?**
SUMMARY

- Choosing generation technologies depends on many factors

- OECD economies often use open markets to deliver

- Prices are important, especially for peaking units

- Activating the demand side delivers added benefits
Thank you for your attention

For further questions - please contact...

dennis.volk@iea.org
lars.dittmar@tu-berlin.de
yerim.park@iea.org
The background for market reform

With these ideas in mind...

- What could have been key reasons for power sector liberalisation?
The background for market reform

In the UK reasons seemed to be

- Desire to reduce governments involvement
- Reduction of public sector borrowing and spending
- Efficiency improvements
- Other (Moore, 1992)

Market reform may be perceived as

- Privatisation of state-owned assets (NOR, AUS, NZ with co-existing ownership)
- Introduction of competition due to structural changes in the organisation of power systems
- Introduction of independent electricity regulators
Evidence of reform

In general (Pollitt, 2009) concludes that:

- Privatisation and independent regulation improves efficiency
- Price effects are not significant
- Private investment is stimulated by independent regulation

Impact measurement as a task in itself:

- Utilities’ performance
- Before-after privatisation assessments
- Social cost-benefit assessments
- Macro studies
A breath of evidence-based literature exist

- Modest productivity gains, but ambiguous price developments (Steiner, 2001; Hattori and Tsutsui, 2004; Fiorio et al., 2007)
- UK Transmission/generation monopoly break-up: 6% permanent gain of 1995 turnover in UK, but consumers lose (Newberry and Pollitt, 1997)
- UK distribution privatisation: 9% permanent gain of 1995 turnover in UK, but consumers lose initially (Domah and Pollitt, 1997)
- Independent regulation supports efficiency and stimulate private investments in developing countries (Pollitt, 2009)
- PPA with IPP in Philippines: One off gain at 13% GDP (Toba, 2007)
A breath of evidence-based literature exist

- Non-fuel plant-level efficiency gains in US: up to 5% (Fabrizio et al., 2007)
- Price reduction for customers: residential 5-10% and industrial 5% (Joskow, 2006b)
- Unbundling costs are offset by gains on generation costs (Triebs et al., 2010)
- Upward prices post liberalisation (Nagayama, 2009)
- Failed reforms, e.g.: California (Besant-Jones, 2006)
References


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