Locational investment signals for electricity generation

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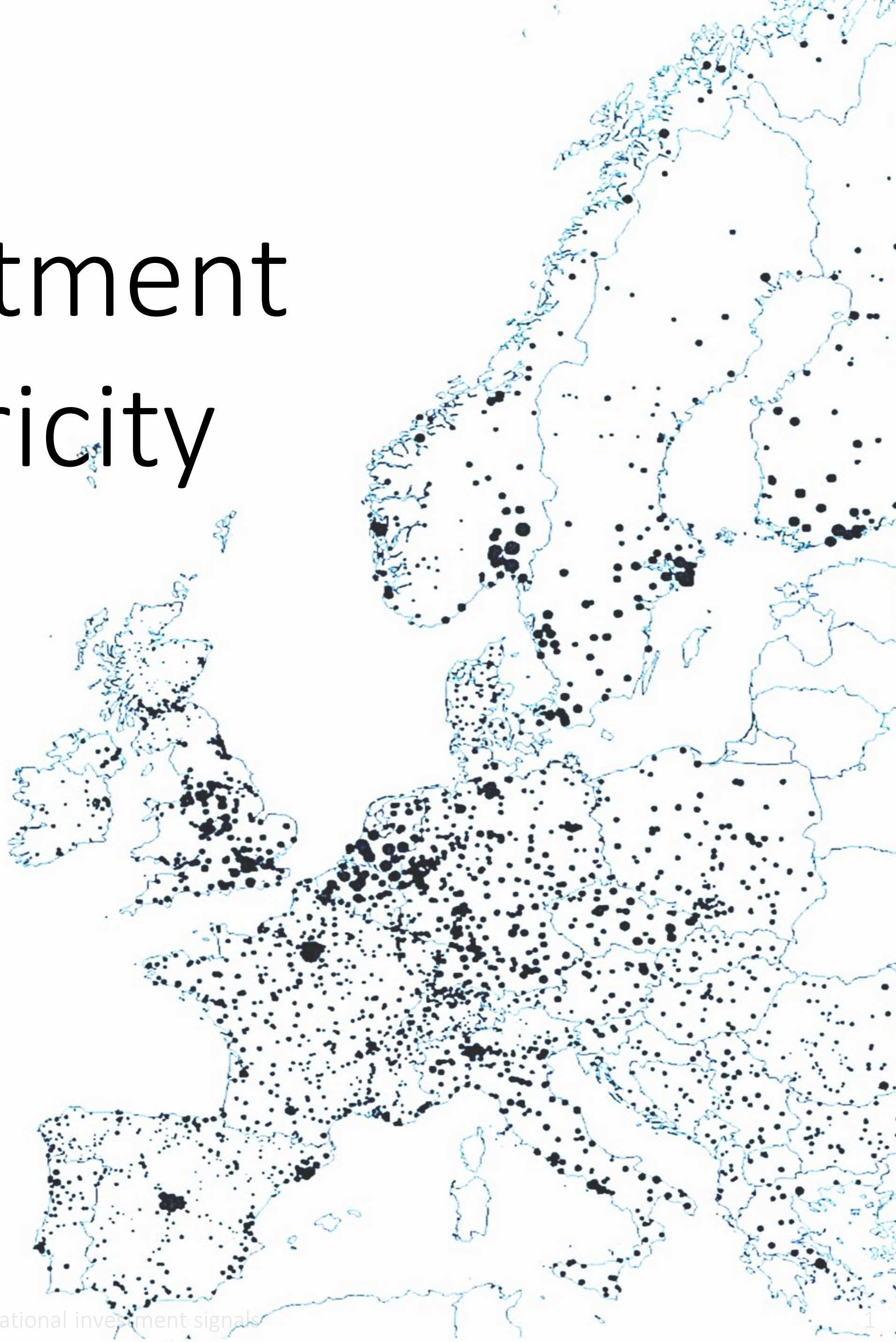


Hertie School of Governance

ENERGY TRANSITION HUB

GEFÖRDERT VOM
Bundesministerium für Bildung und Forschung

About the project

- Funded by BMBF as part of the Energy Transition Hub
- Workshop 21 Feb 2019, Hertie School, Berlin
- Hertie School project Team
  - Anselm Eicke
  - Tarun Khanna
  - Prof. Dr. Lion Hirth
- Question 1: empirical review of instruments used for locational investment signals in 10 countries – What do countries use?
- Question 2: pro's and con's of instruments

ENERGY TRANSITION HUB
an Australian-German innovation partnership

Acknowledgements

We would like to thank for valuable comments, expert insights and feedback from Lars Stephan, Dylan McConnell, Juan Pablo Carvallo, Mårten Bergman, and others.

Thank you for participating in this workshop!

Building on previous work

Project "Beschaffung von Redispatch" for BMWi with Consentec, Connect, Navigant, Fraunhofer ISI, SUER

- Neon & Consentec (2018): Zusammenspiel von Markt und Netz im Stromsystem
- Connect (2018): Konzepte für Redispatch-Beschaffung

Academic publications

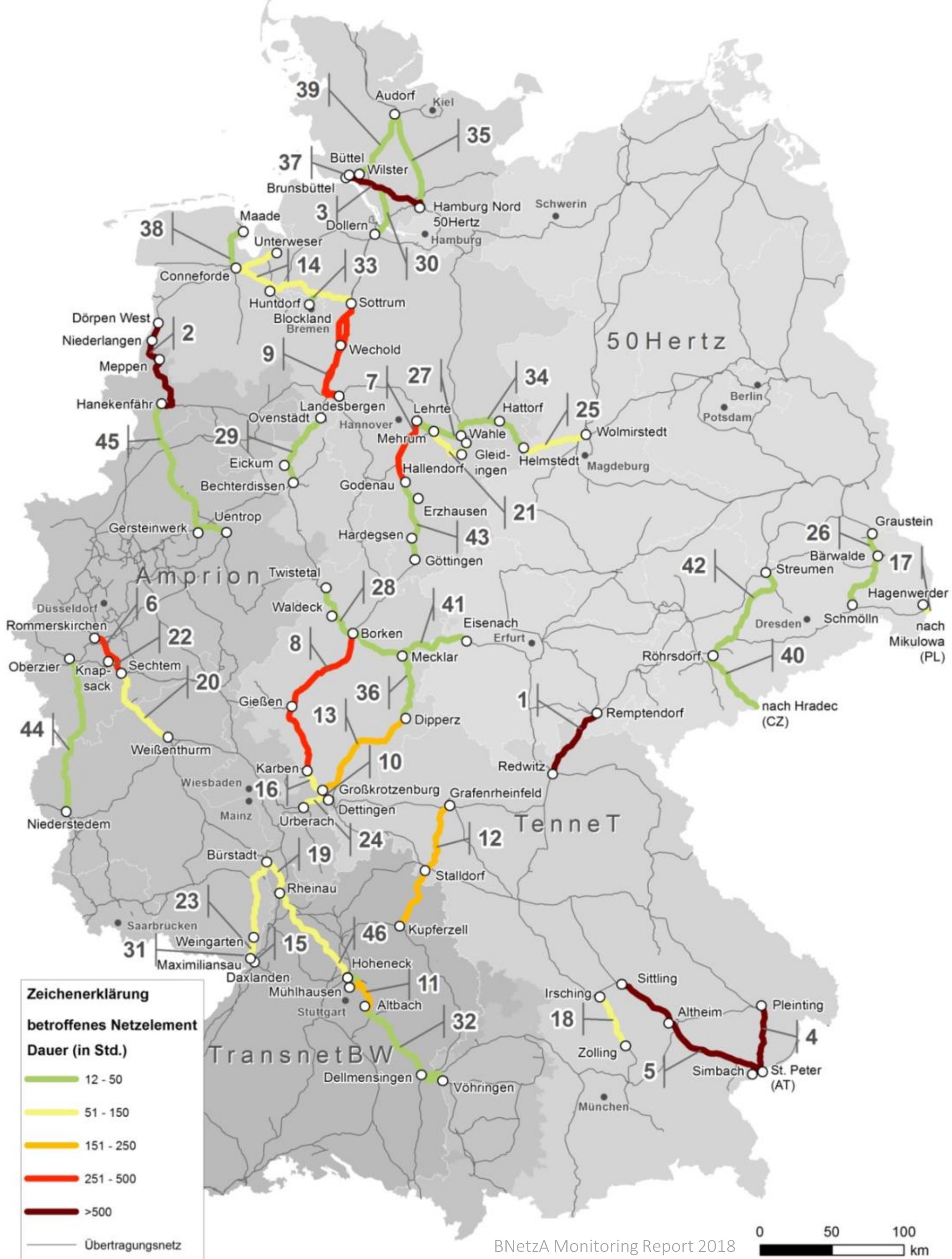
- Hirth & Glismann (2018): Congestion Management: From Physics to Regulatory Instruments. Working paper, http://hdl.handle.net/10419/189641
- Hirth & Schlecht (2018): Market-Based Redispatch in Zonal Electricity Markets. Working paper, http://dx.doi.org/10.2139/ssrn.3286798

Workshop Agenda

1. **The Problematic Status Quo**
2. Locational Incentives: A Taxonomy
3. Inc-Dec Gaming
4. Findings: What do countries use?
5. Discussion of Instruments
6. Annex: detailed results

Zonal electricity markets with cost-based redispatch: DE

- European wholesale electricity markets are organized in bidding zones
- Power price differentials may exist between zones, but not within
  - In other words, zonal pricing delivers a coarse geographic price signal (between zones), but lack a fine signal (within zones)
- Internal grid congestion is solved separately from the wholesale market through redispatch or other congestion management measures
- Redispatch in Germany
  - Participation obligatory
  - Compensation of costs and forgone profit
- Acute problems
  - Increased costs
  - Lack of upward (raise) capacity → no-exit regulation ("Network Reserve"), locational tenders ("Besondere Netztechnische Betriebsmittel")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Audorf
Kiel
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Büttel
Wilster
Brunsbüttel
3
Hamburg Nord
50Hertz
Schwerin
Dollern
Hamburg
38
Maade
Unterweser
14
33
30
Conneforde
Huntdorf
Blockland
Bremen
Sottrum
Dörpen West
Niederlangen
2
Meppen
9
Wechold
50Hertz
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Hanekenfähr
Landesbergen
Lehrte
Hattorf
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Ovenstädt
Hannover
Mehrum
Wahle
Wolmirstedt
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Potsdam
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Magdeburg
Eickum
Hallendorf
Bechterdissen
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Uentrop
Gersteinwerk
Hardegsen
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Graustein
Göttingen
Bärwalde
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Amprion
Twistetal
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Streumen
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Hagenwerder
Düsseldorf
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Waldeck
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Dresden
Schmölln
Rommerskirchen
Eisenach
nach
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Borken
Erfurt
Mikulowa
(PL)
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Mecklar
Röhrsdorf
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Oberzier
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Sechtem
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1
nach Hradec
(CZ)
Gießen
Remptendorf
13
Dipperz
44
Weißenthurm
10
Karben
Redwitz
Wiesbaden
16
Großkrotzenburg
Grafenrheinfeld
Mainz
Dettingen
Niederstedem
Urberach
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TenneT
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Bürstadt
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Stalldorf
Rheinau
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Saarbrücken
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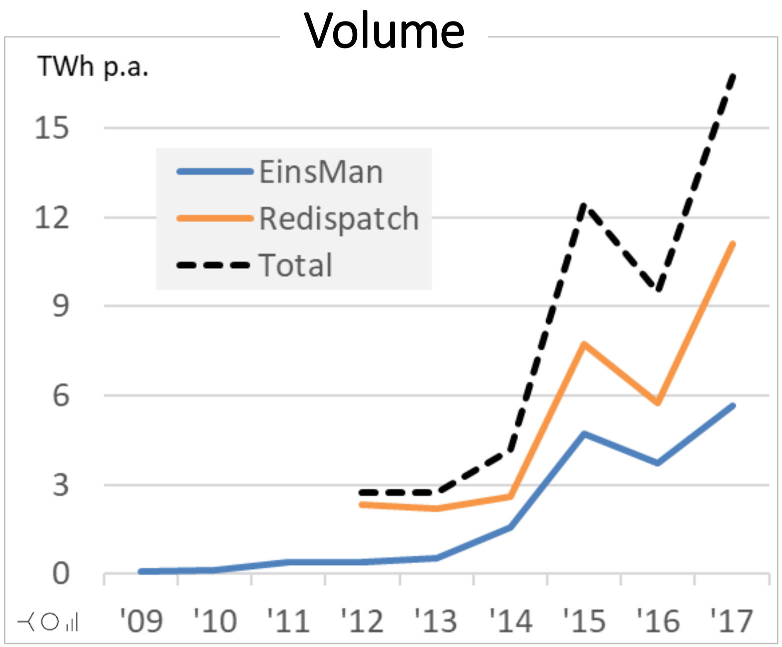
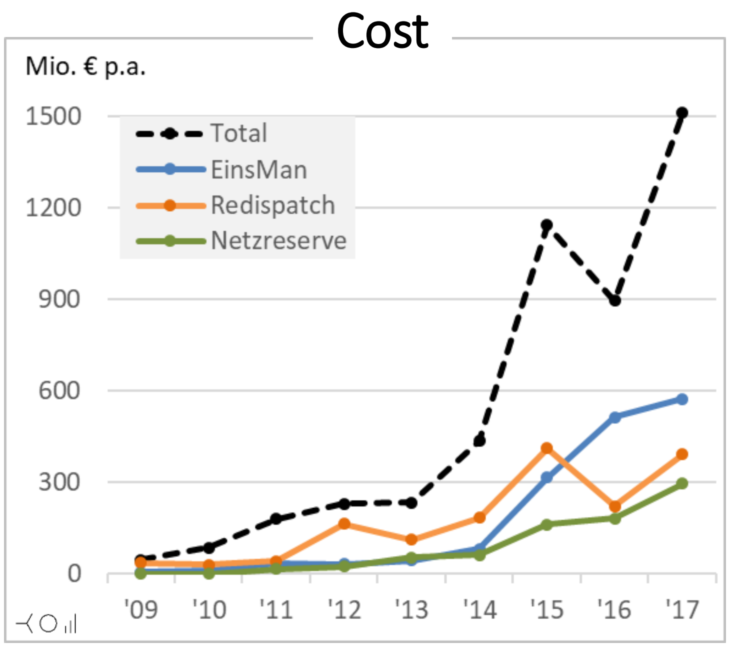
Kupferzell
Weingarten
15
31
Maximiliansau
Hoheneck
Daxlanden
11
Sittling
Mühlhausen
Irsching
Stuttgart
Altbach
Pleinting
18
Altheim
32
4
TransnetBW
Zolling
5
Simbach
St. Peter
(AT)
Dellmensingen
Vöhringen
München
Zeichenerklärung
betroffenes Netzelement
Dauer (in Std.)
12 - 50
51 - 150
151 - 250
251 - 500
>500
Übertragungsnetz
0
50
100
km

Congestion management in Germany



Neon analysis. 2017: extrapolation from Q1/2017.



The volume of congestion management increased 5-fold since 2012.

The costs for congestion management increased similarly.

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A rich variety of locational incentives…

Locational prices

- The electricity market itself can provide locational investment signals
- Market splitting (small zones)
- Locational marginal pricing (nodal pricing)
- Market-based redispatch / locational markets for flexibility
- Examples: Nordic, Italy, US ISO systems

Grid connection charges

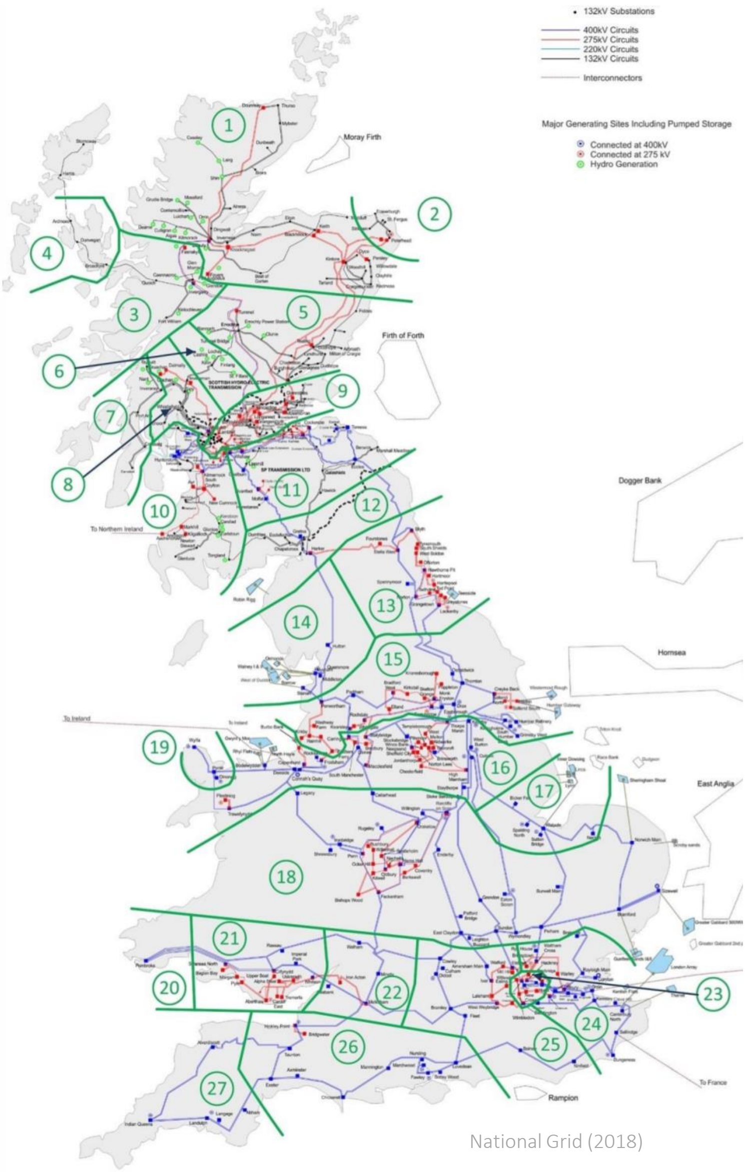
- One-off charge to be paid for grid connection
- Shallow connection charge = cost to connect to nearest substation
- Deep connection charge = include cost for “deeper” grid enforcement / extension
- Deep charges are a locational incentive
- Examples: many European countries

Country	Charge Type	Description
Albania	Shallow/Deep	Charges are based on the actual costs. No differentiation of charges for L, G, and DSO. No locational differentiation.
Austria	Shallow	In form of building-cost contribution for generation or tariff for load. Tariff for load: - Network Level 1 - 8.70 €/kW - Network Level 2 - 9.80 €/kW
Belgium	Mainly Shallow	- Onshore: Everything is socialized, except all installations between the grid user and the substation and the connection bay at the substation. - Offshore: idem. However, a support mechanism foresees in an additional subsidy for the cable connection up to 25 M€.
Bosnia and Herzegovina	Shallow	Charges are based on the actual costs. No differentiation of charges for L, G and DSO. No locational differentiation.
Bulgaria	Shallow	The price for connection is paid by the user, for installations up to the point of connection. The price for reinforcement of the grid is paid by the operator. There is no any different treatment of users.
Croatia	Deep	G – pays for the infrastructure connecting its installation to the transmission grid and extensions in existing network L – pays according to formula NVN = cVN . P (capacity kW * 1 350.00 HRK=179.67 €/kW or actual costs if difference between formula and real costs is more/less than 20%
Cyprus	Mainly Shallow	The connection cost includes all new infrastructure that will need to be built, up to the point of connection, e.g. a new substation and transmission line. No other costs are charged, e.g for upgrading existing equipment further into the transmission network.
Czech Republic	Shallow	No locational differentiation. Connection fees:

ETNSO-E (2018): Overview of Transmission Tariffs in Europe

Grid usage charge

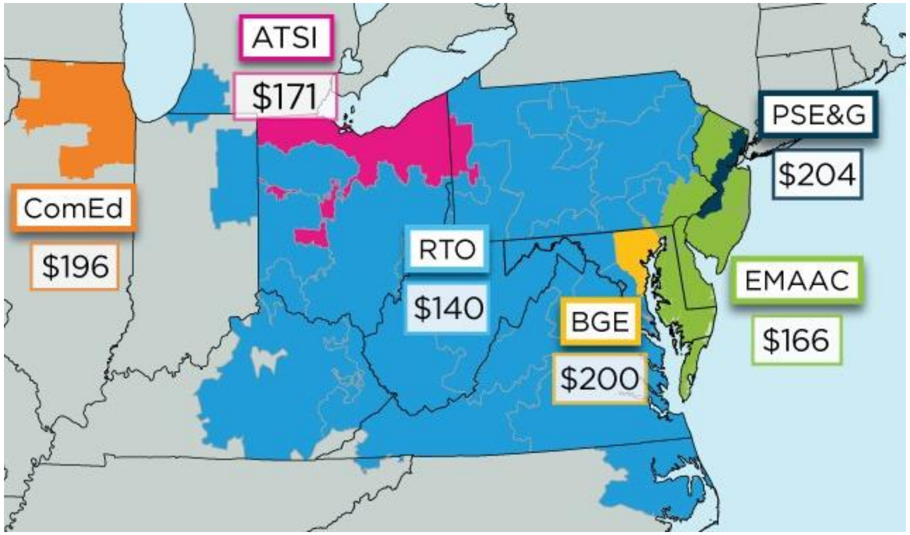
- Charge to be paid for grid usage (per kW or kWh)
- Based in location, generators pay or receive a grid usage charge
- These charges, if anticipated, serve as an investment incentive (per kWh-charges also provide a dispatch incentive)
- Examples: Great Britain, Sweden



National Grid (2018)

Location specific capacity payments

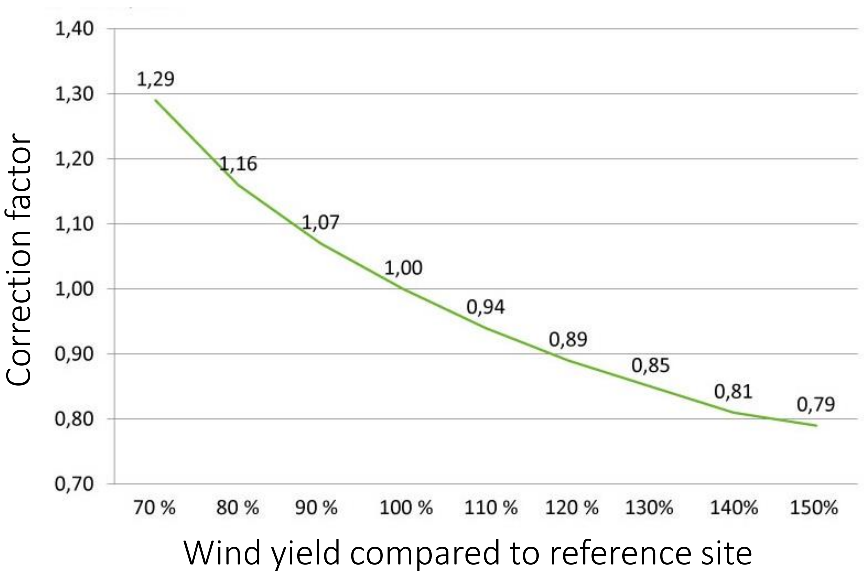
- Capacity payments / markets / mechanisms specific by location
- Example: PJM's capacity market



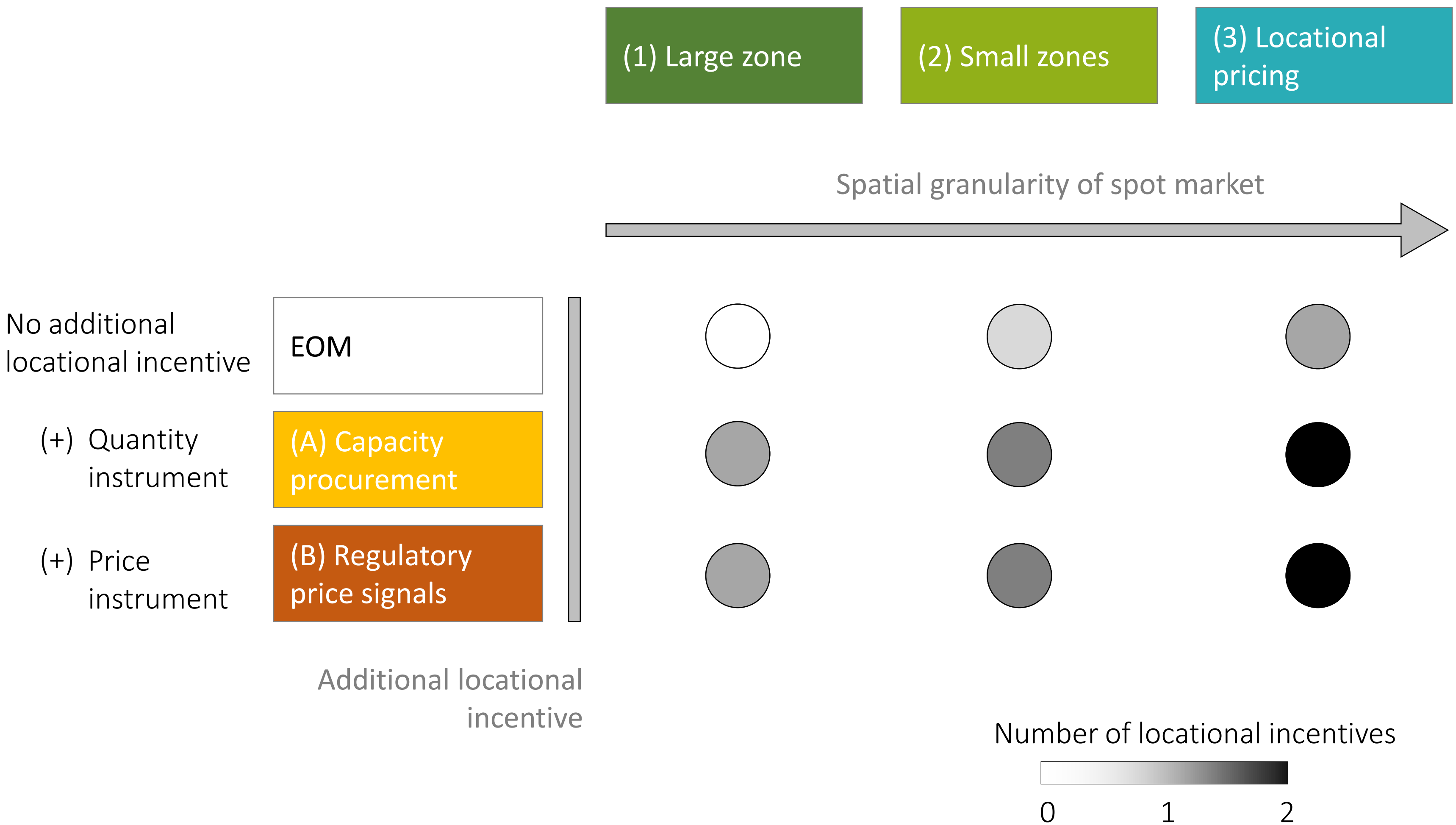
Location specific renewable energy support scheme

- Support schemes for deployment of renewables energy may be differentiated by location
- Bonus/penalty for certain regions
- Bonus/penalty for certain wind conditions
- Auctions for specific locations
- Examples: Germany's *Referenzertragsmodell*, India's pre-developed sites, Mexico's auctions with bonuses and penalties

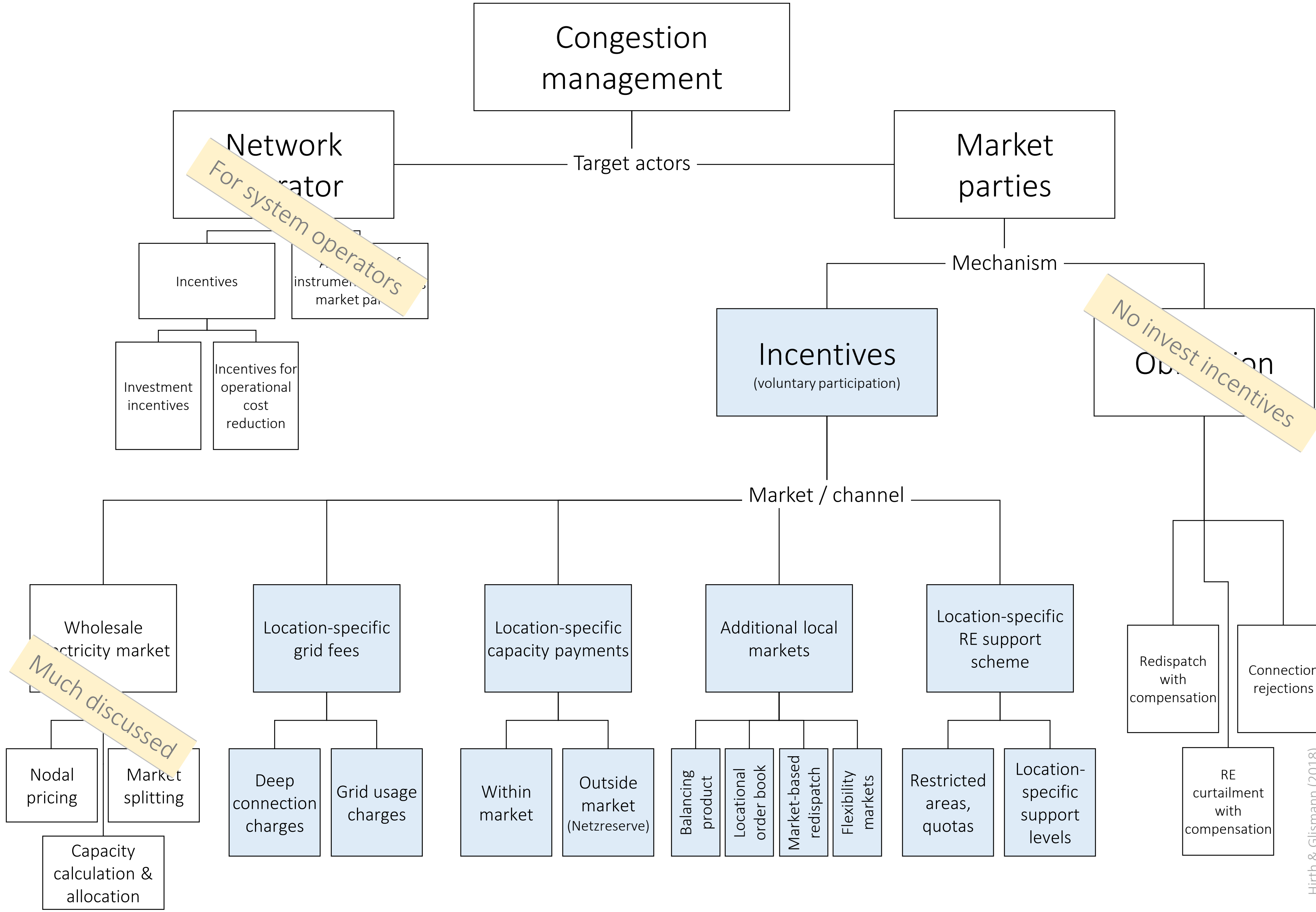
Referenzertragsmodell



Combining spot design with investment incentives



Neon & Consentec (2018)



Congestion management
Target actors
Network
For system operators
Incentives
Investment incentives
Incentives for operational cost reduction
Market parties
Mechanism
Incentives
(voluntary participation)
No invest incentives
Market / channel
Wholesale
Much discussed
Nodal pricing
Capacity calculation & allocation
Location-specific grid fees
Deep connection charges
Grid usage charges
Location-specific capacity payments
Within market
Outside market
(Netzreserve)
Additional local markets
Balancing product
Locational order book
Market-based redispatch
Flexibility markets
Location-specific RE support scheme
Restricted areas, quotas
Location-specific support levels
Redispatch with compensation
Connection rejections
RE curtailment with compensation
Hirth & Glismann (2018)

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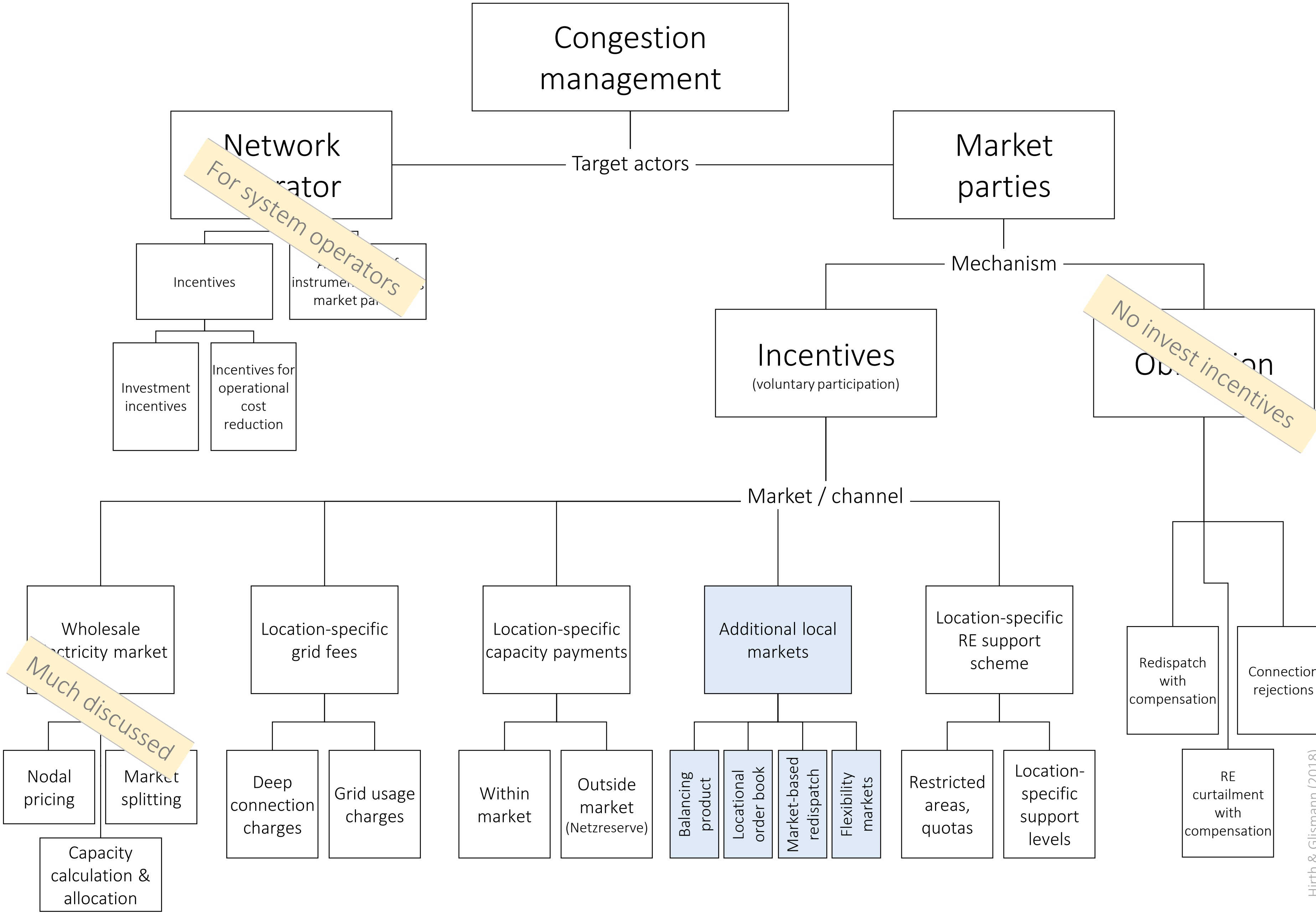


Hirth & Glismann (2018)

Inc-dec gaming in a nutshell

Our redispatch market setup

- First (zonal) spot market, then (nodal) redispatch market (RDM)
- All markets are voluntary, subject to marginal pricing, competitive (no market power)
- Two nodes: oversupplied North and scarce South

Generators in the North

- Anticipate they will be paid for ramping down – if they are available (i.e., producing)
- Bid below variable cost in spot to be eligible for this payment → aggravate congestion

Generators in the South

- Anticipate they will be paid for ramping up – if they are available (i.e., not producing)
- Bid above variable cost (“withhold capacity”) → aggravate congestion

→ Generators have an incentive for strategic bidding (not marginal cost)

Existing literature

We are not the first to note this

- Holmberg & Lazarczyk (2015), …
- Our contribution: simple example, mechanisms clearly outlined, comprehensive discussion of consequences, related to policy debate

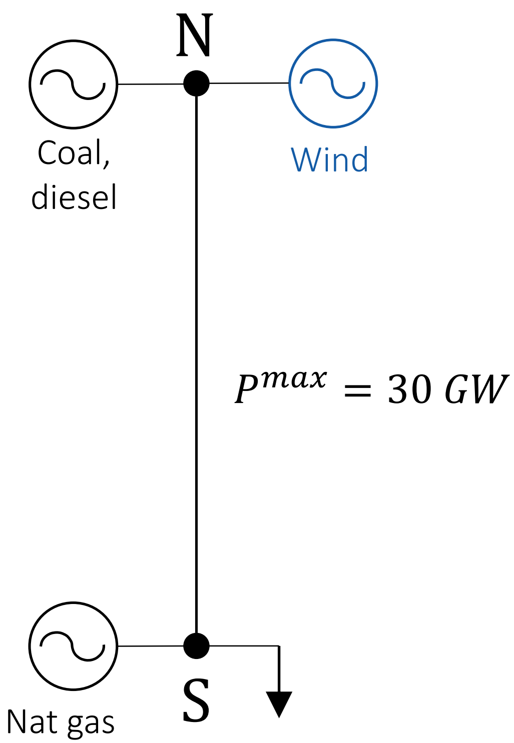
California

- Inc-dec gaming contributed to the energy crisis 2000/01, rolling blackouts
- Introduced nodal pricing in 2009
- Hogan (1999, 2001), Brunekreeft et al. (2005), CAISO (2005), Hobbs (2010)

Great Britain

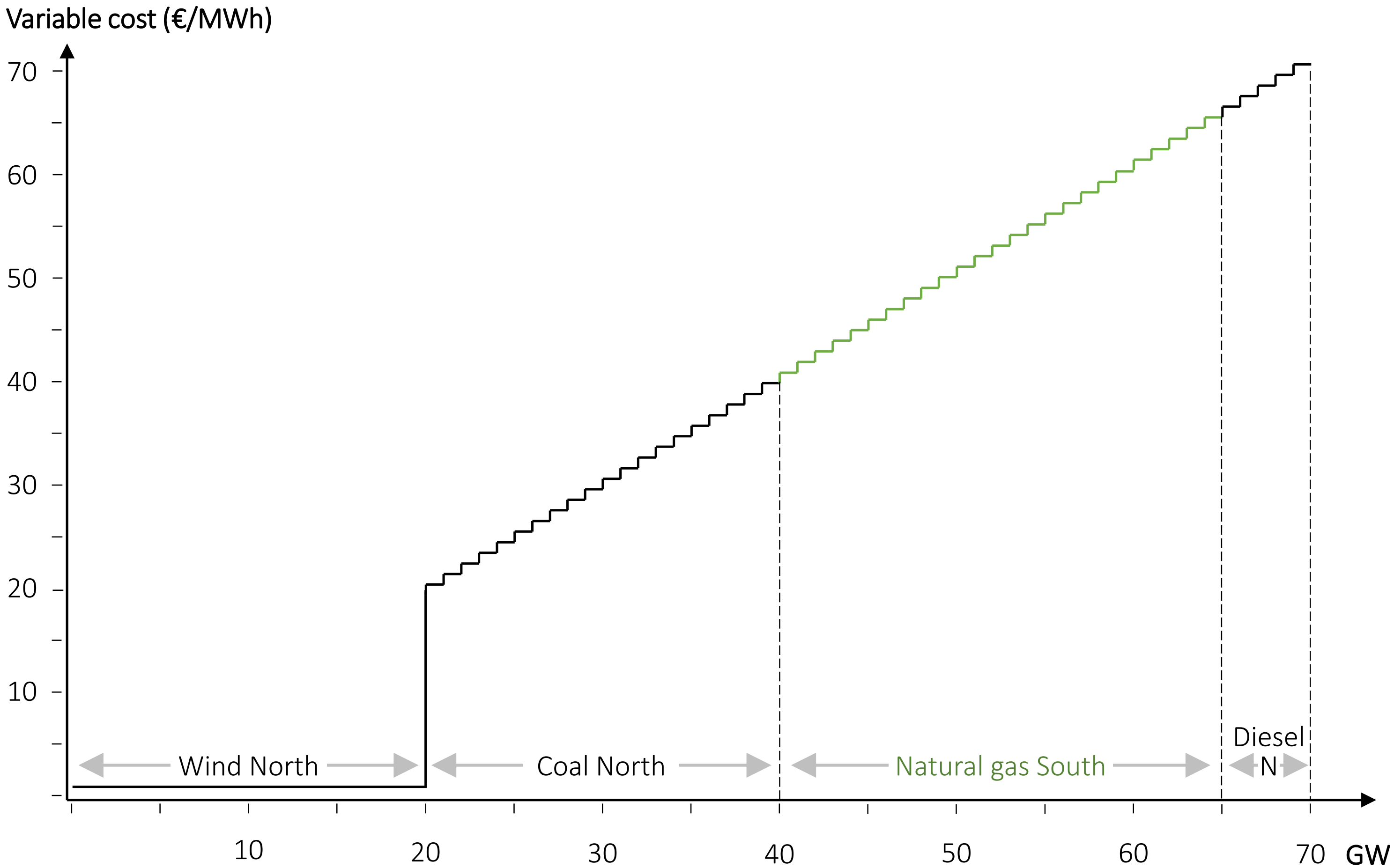
- Inc-dec gaming at Scottish-English border
- "Transmission Constraint License Condition" introduced in 2012, similar to cost-based RD
- Ofgem (2012, 2018) Konstantinidis & Strbac (2015)

Physical setup of the example



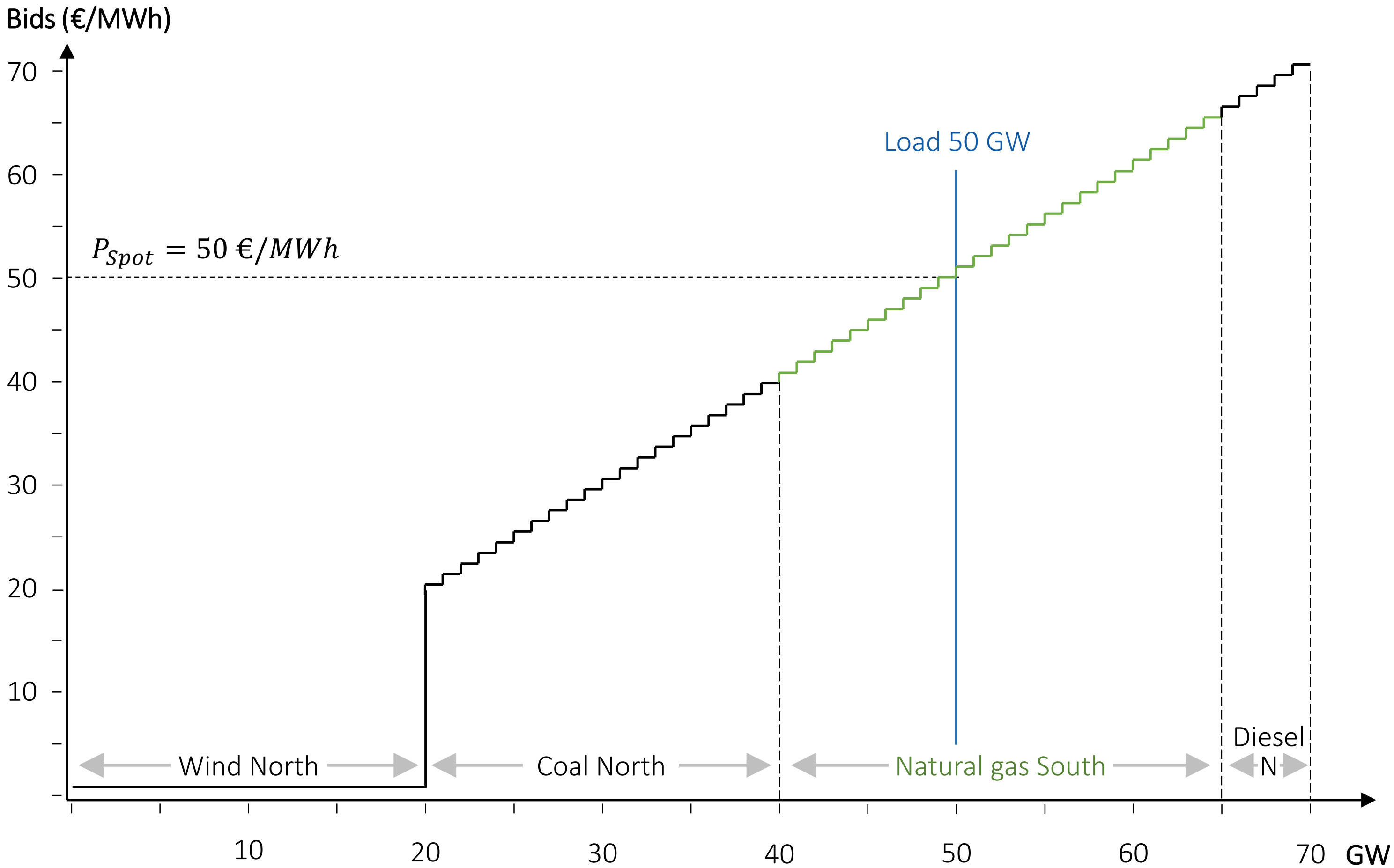
	North	South
Load	0 GW	50 GW, perfectly price in-elastic
Generation	• 20 wind parks of 1 GW each at variable cost of 1 €/MWh • 20 units of 1 GW coal-fired plants at variable costs of 21,22,23,…,40 €/MWh • 5 units of 1 GW diesel peakers at variable costs of 66,67,68,69,70 €/MWh	• 25 units of 1 GW natural gas-fired plants at variable costs of 41,42,43,…, 65 €/MWh
Line capacity	30 GW	

System-wide merit order (variable costs)

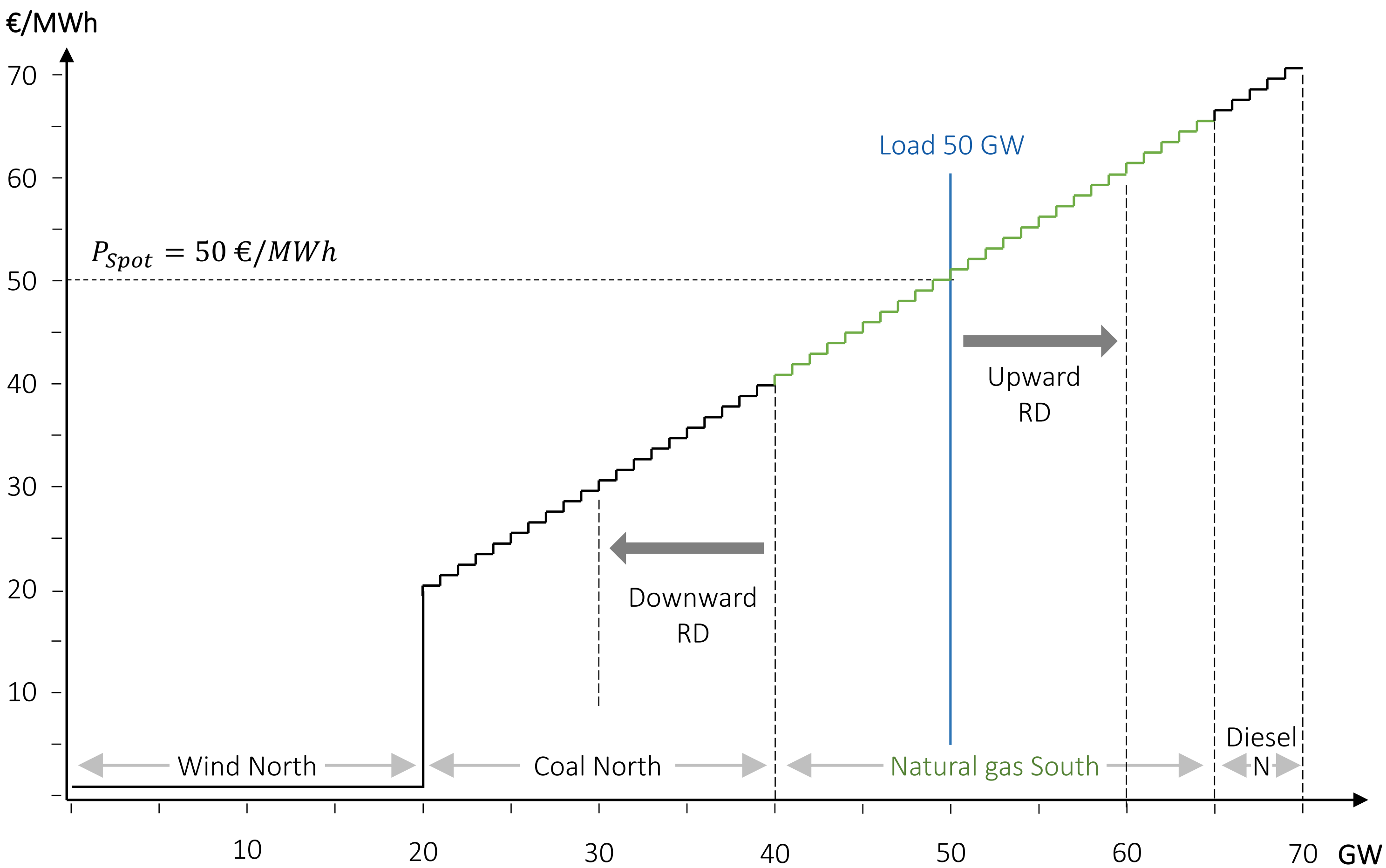


Spot market (regulatory RD)

Price	$P_{Spot} = 50\ €/MWh$
Market power	No suppliers is pivotal
(Desired) dispatch	20 GW wind N + 20 GW coal N 10 GW nat gas S
Line flow	40GW → infeasible



Redispatch

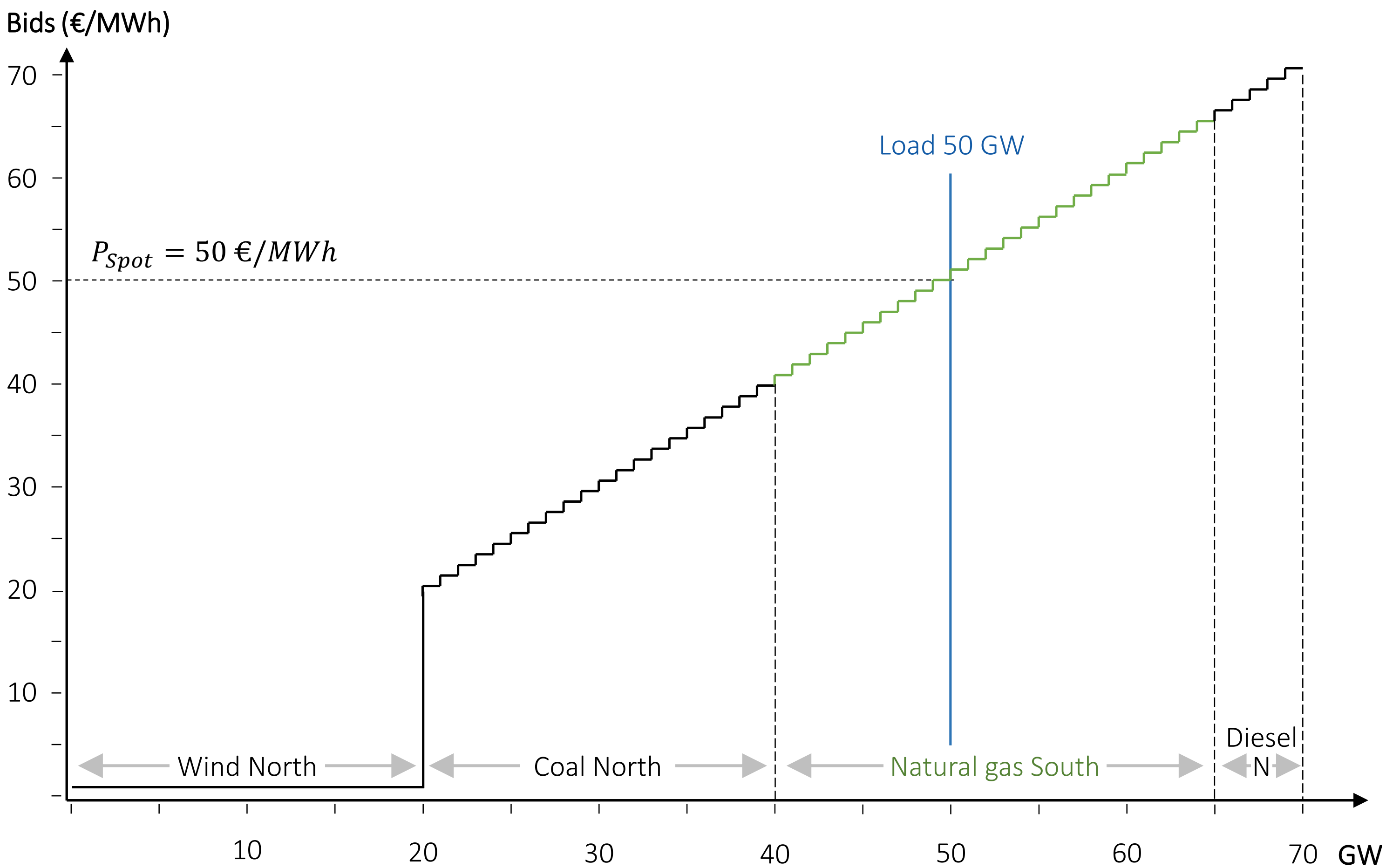


€/MWh
70
60
50
40
30
20
10
$P_{Spot} = 50\,€/MWh$
Load 50 GW
Upward
RD
Downward
RD
Wind North
Coal North
Natural gas South
Diesel
N
10
20
30
40
50
60
70
GW

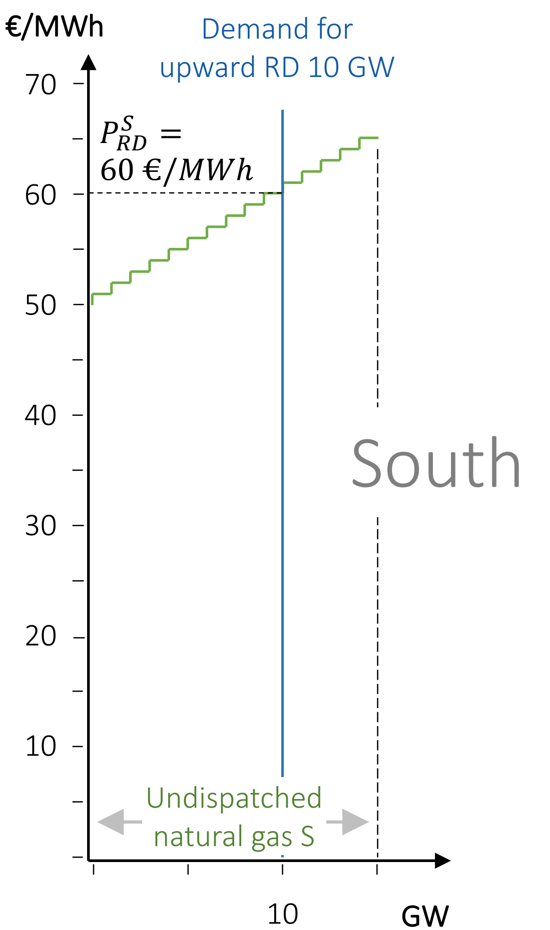
RDM w/o Anticipation

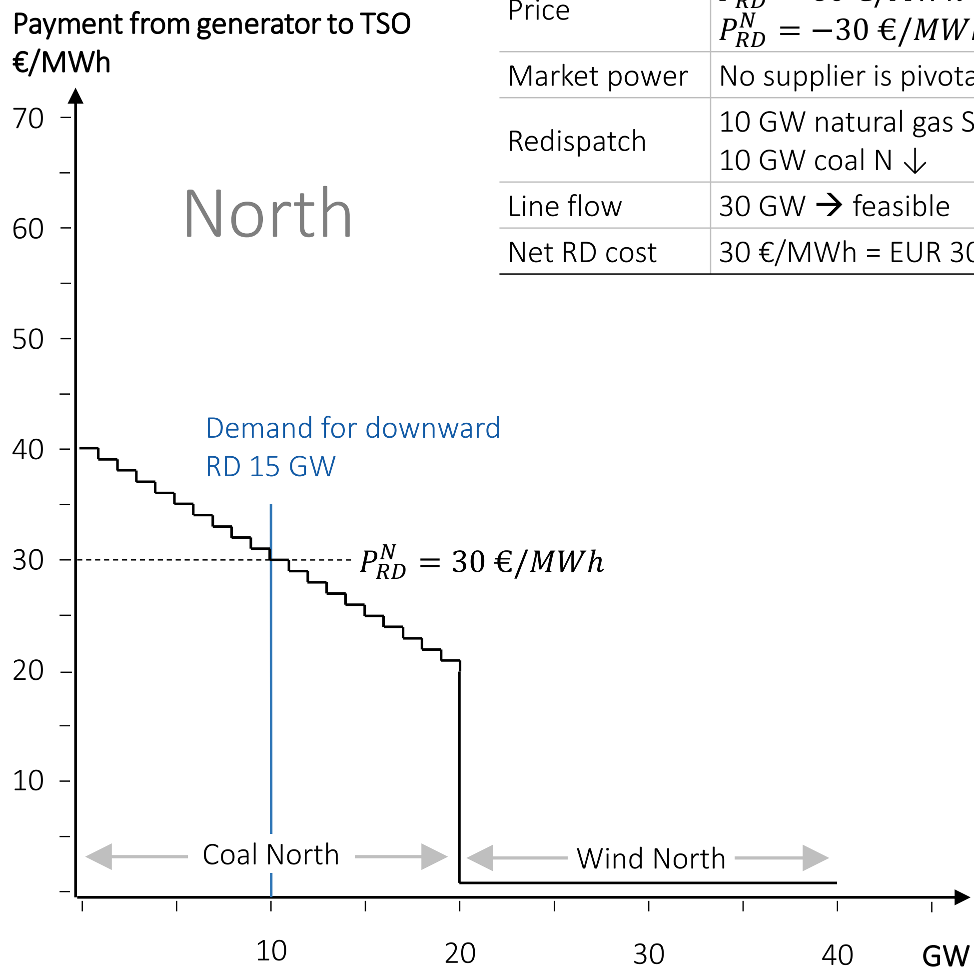
Spot market (regulatory RD)

Price	$P_{Spot} = 50\ €/MWh$
Market power	No supplier is pivotal
(Desired) dispatch	20 GW wind N + 20 GW coal N 10 GW nat gas S
Line flow	40GW → infeasible



Redispatch markets (no anticipation)

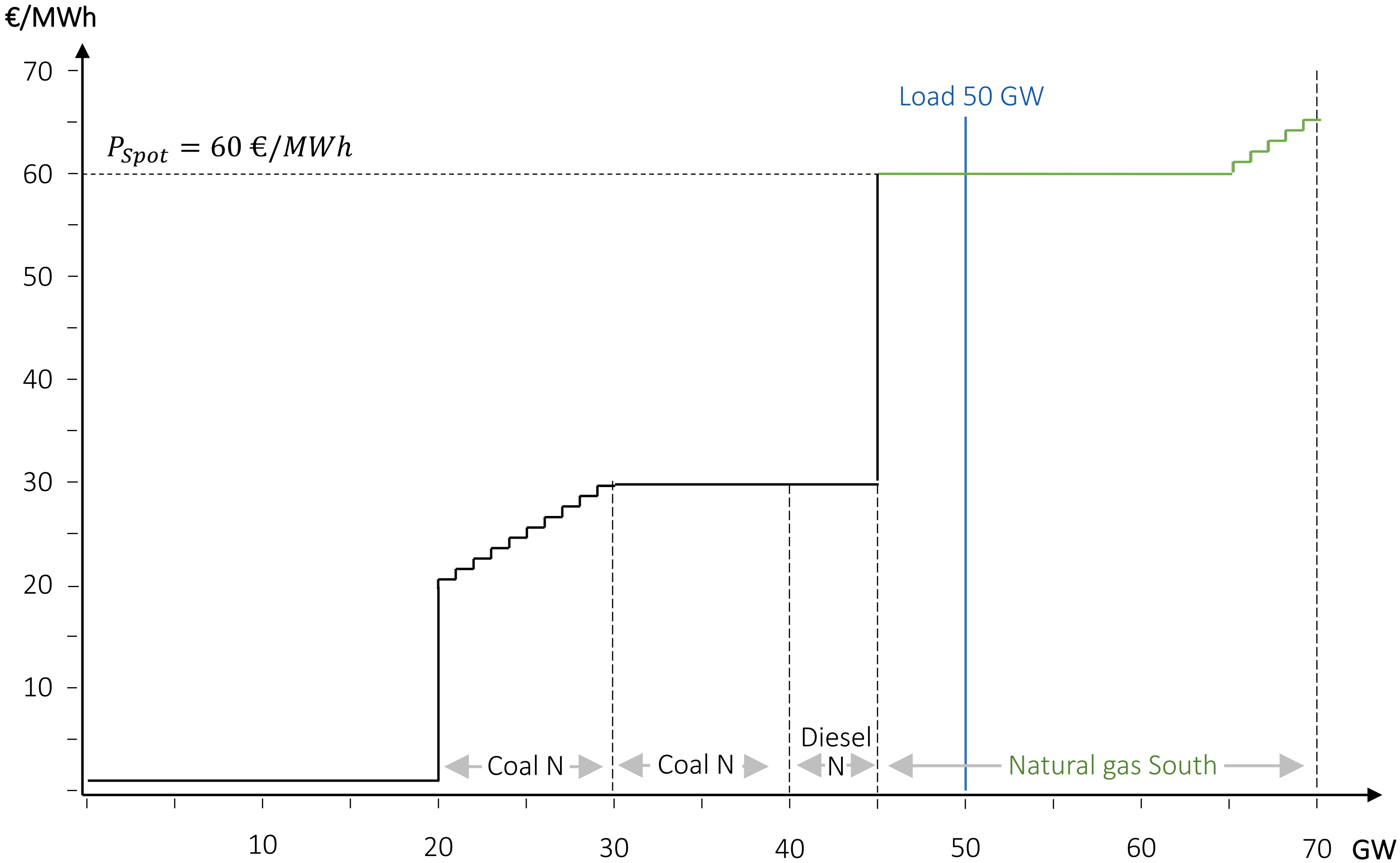




Price	$P_{RD}^{S} = 60\ €/MWh$ $P_{RD}^{N} = -30\ €/MWh$
Market power	No supplier is pivotal (both nodes)
Redispatch	10 GW natural gas S ↑ 10 GW coal N ↓
Line flow	30 GW → feasible
Net RD cost	30 €/MWh = EUR 300,000

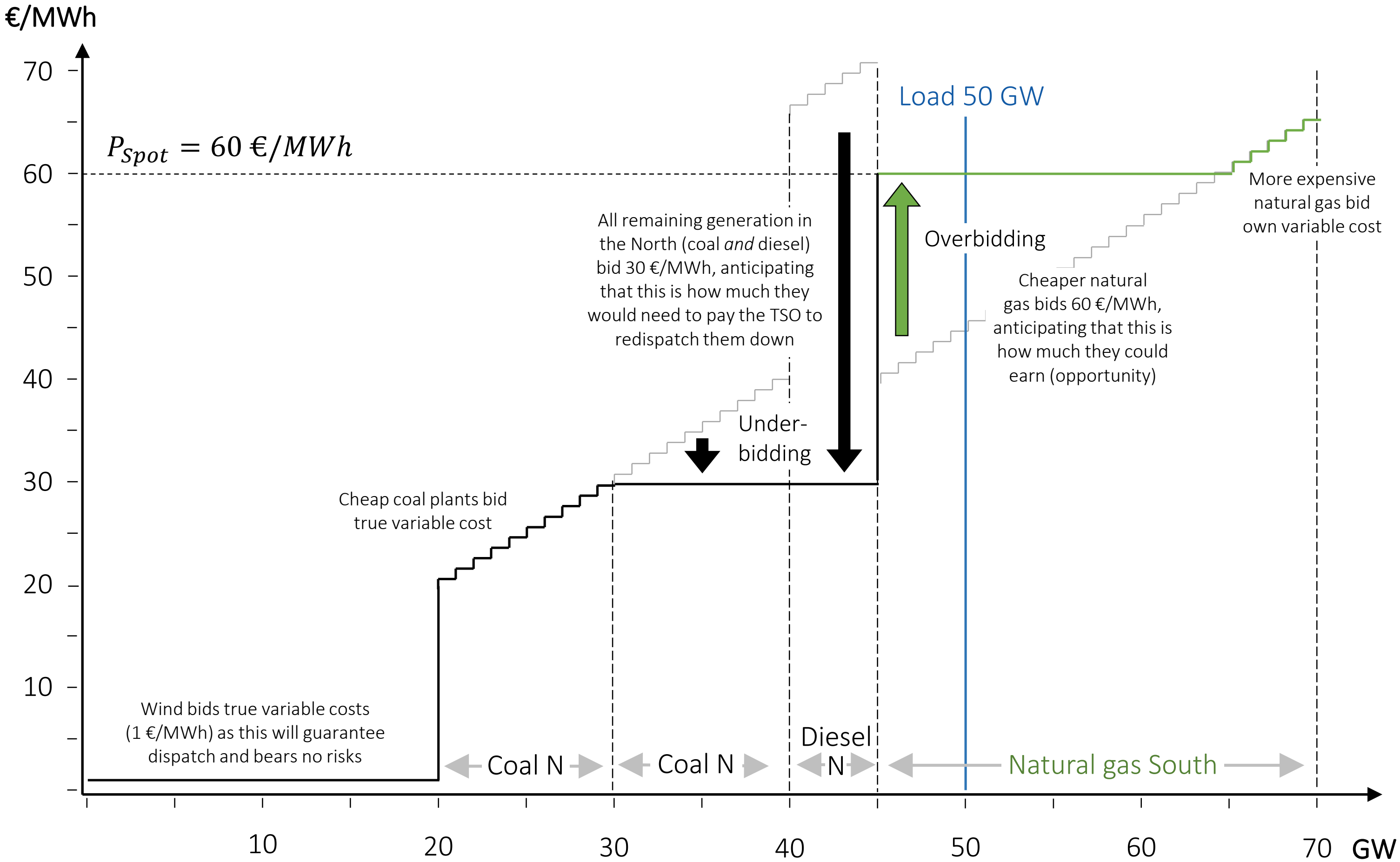
RDM with Anticipation

Spot market (with anticipation)



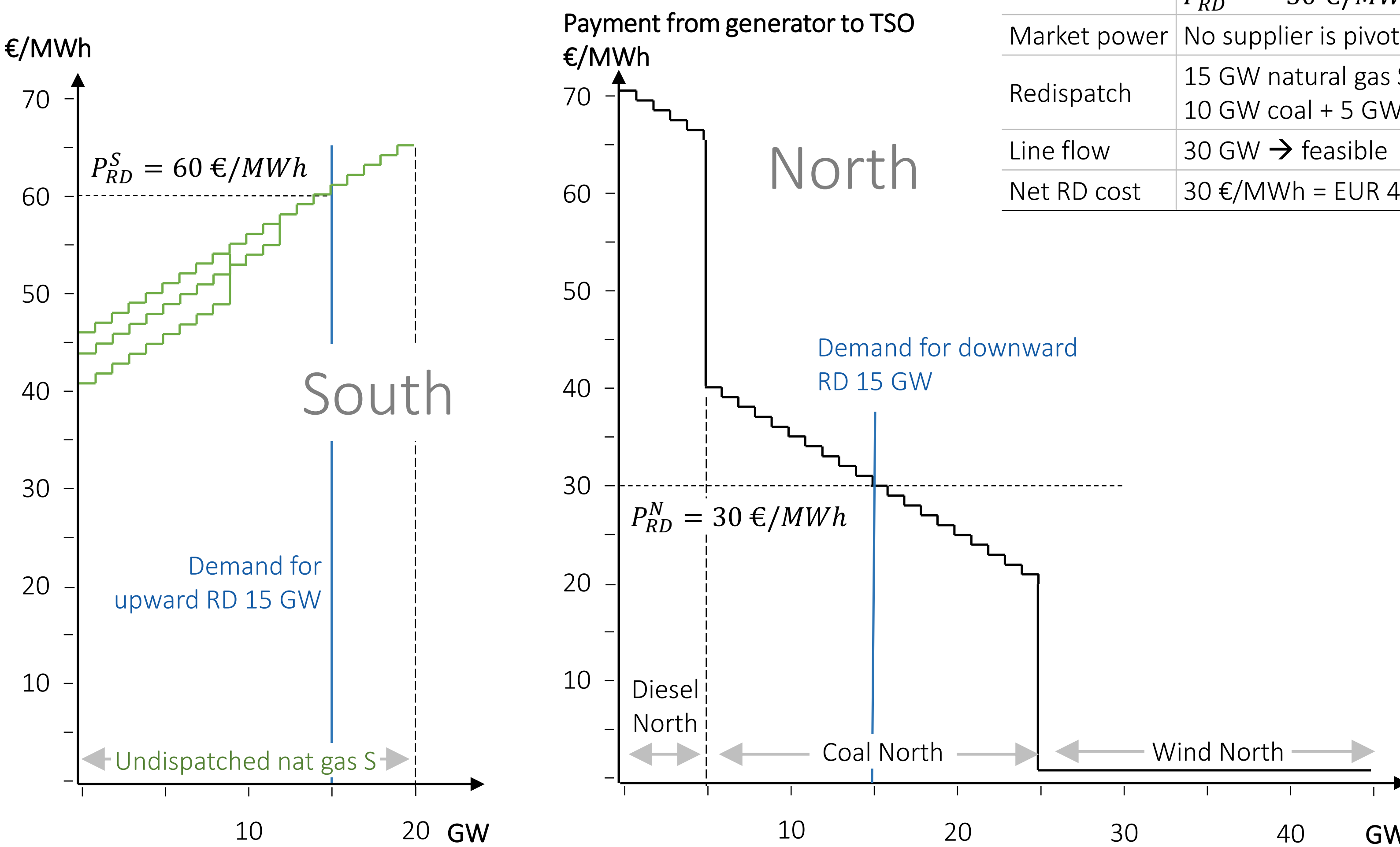
Spot market (with anticipation)

Price	$P_{Spot} = 60\ €/MWh$
Market power	No supplier is pivotal
(Desired) Dispatch	20 GW wind N, 20 GW coal N, 5 GW diesel N 5 GW nat gas S
Line flow	45 GW → Anticipation of RDM has lead to *increase* in line overflow



Redispatch markets (with anticipation)

Price	$P_{RD}^{S} = 60\ €/MWh$ $P_{RD}^{N} = -30\ €/MWh$
Market power	No supplier is pivotal (both nodes)
Redispatch	15 GW natural gas S ↑ 10 GW coal + 5 GW diesel N ↓
Line flow	30 GW → feasible
Net RD cost	30 €/MWh = EUR 450,000



What do we learn?

Requirements for inc-dec gaming

Engaging in inc-dec gaming does not require any market power

- In none of the markets any supplier was pivotal
- Ultimately, everyone bids variable cost
- Attracting more actors will not stop anyone from strategic bidding ("competition is not a solution to inc-dec gaming")

Some foresight required

- We assumed perfect foresight for simplicity
- Some anticipation of constraints is necessary, but it does not need to be perfect

This is a Nash equilibrium

- Ex post, no actor has an incentive to change their bidding strategy

Results

Congestion is aggravated

- Redispatch volumes increase (compared to regulator redispatch or no-anticipation)

Market participants earn windfall profits

- Generators' profits incase (compared to regulatory redispatch or no-anticipation)

	1. Nodal pricing	2. Regulatory redispatch	4. RDM <u>with</u> anticipation
Redispatch volume (GW)	0	10	15
Amount paid by loads for energy (€)	3 000 000	2 500 000	3 000 000
Redispatch cost (€)	-900 000 (CR)	200 000	450 000
Total cost to consumer (€)	2 100 000	2 700 000	3 450 000
Generation cost (€)	1 285 000	1 285 000	1 285 000
Generators' profits (€)	815 000	1 415 000	2 165 000

Implications and generalizations

Financial markets “lose underlying”

- Zonal market becomes meaningless in times of congestion
- Then, not the marginal cost but nodal prices determine the zonal price
- Hedging is no longer possible using financial products that have the spot price as an underlying

Demand can also participate

- Things are getting worse
- Pure financial arbitrage might also be possible

Perverse investment incentives

- “Ghost” plants which are build to never produce

Pay-as-bid pricing does not change the gaming incentives

Conclusions: inc-dec gaming

Installing a nodal (redispatch) market within a zonal market yields an inconsistent market design

- Incentives for strategic bidding

Inc-dec gaming is the result

- Higher redispatch volume
- Windfall profits
- Problematic consequences for financial markets and investment incentives

All this happens without a single actor possessing market power

- If you add market power, things become worse

→ This does not seem like a good way forward. But what are the alternatives?

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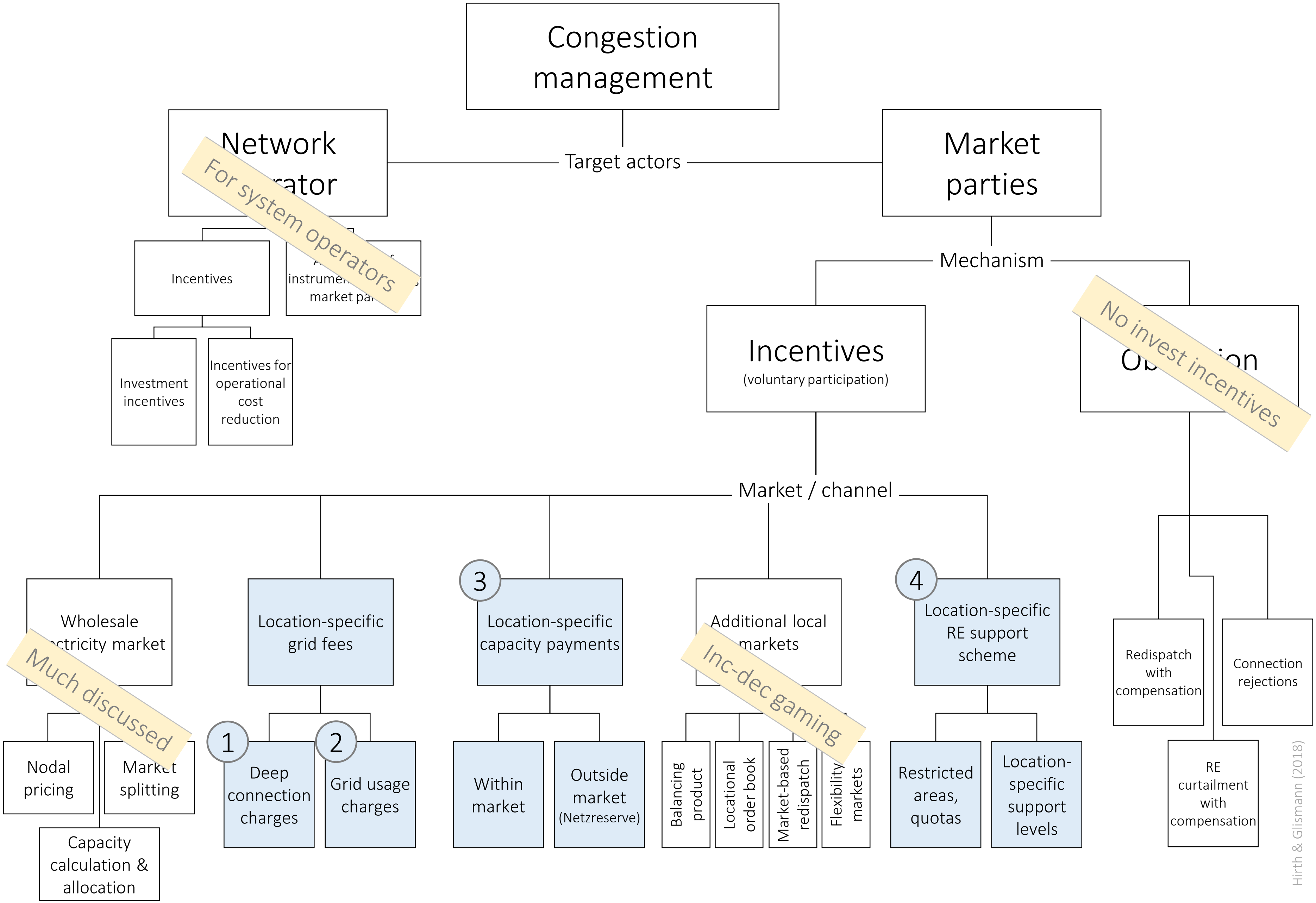
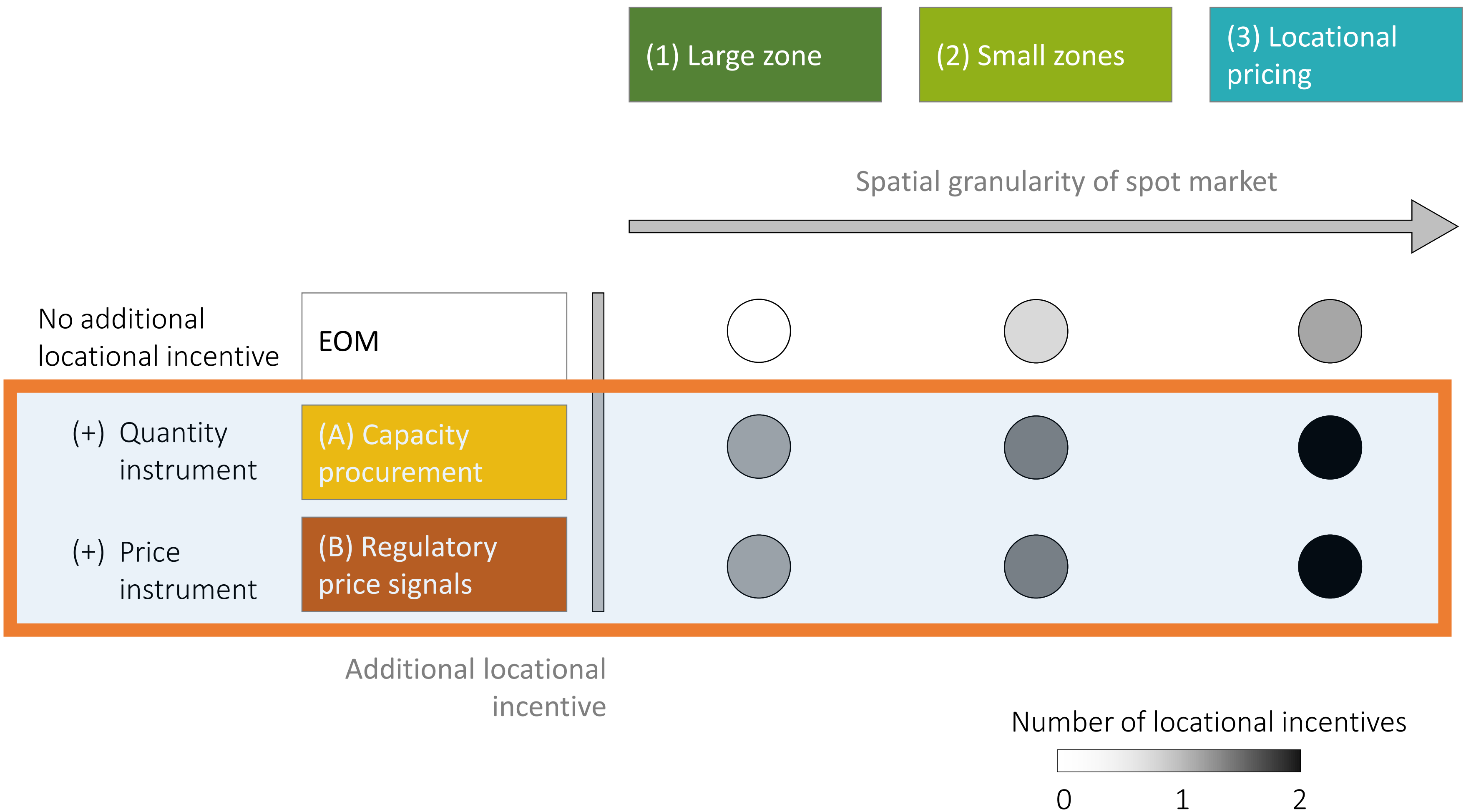


Hirth & Glismann (2018)

Combining spot design with investment incentives

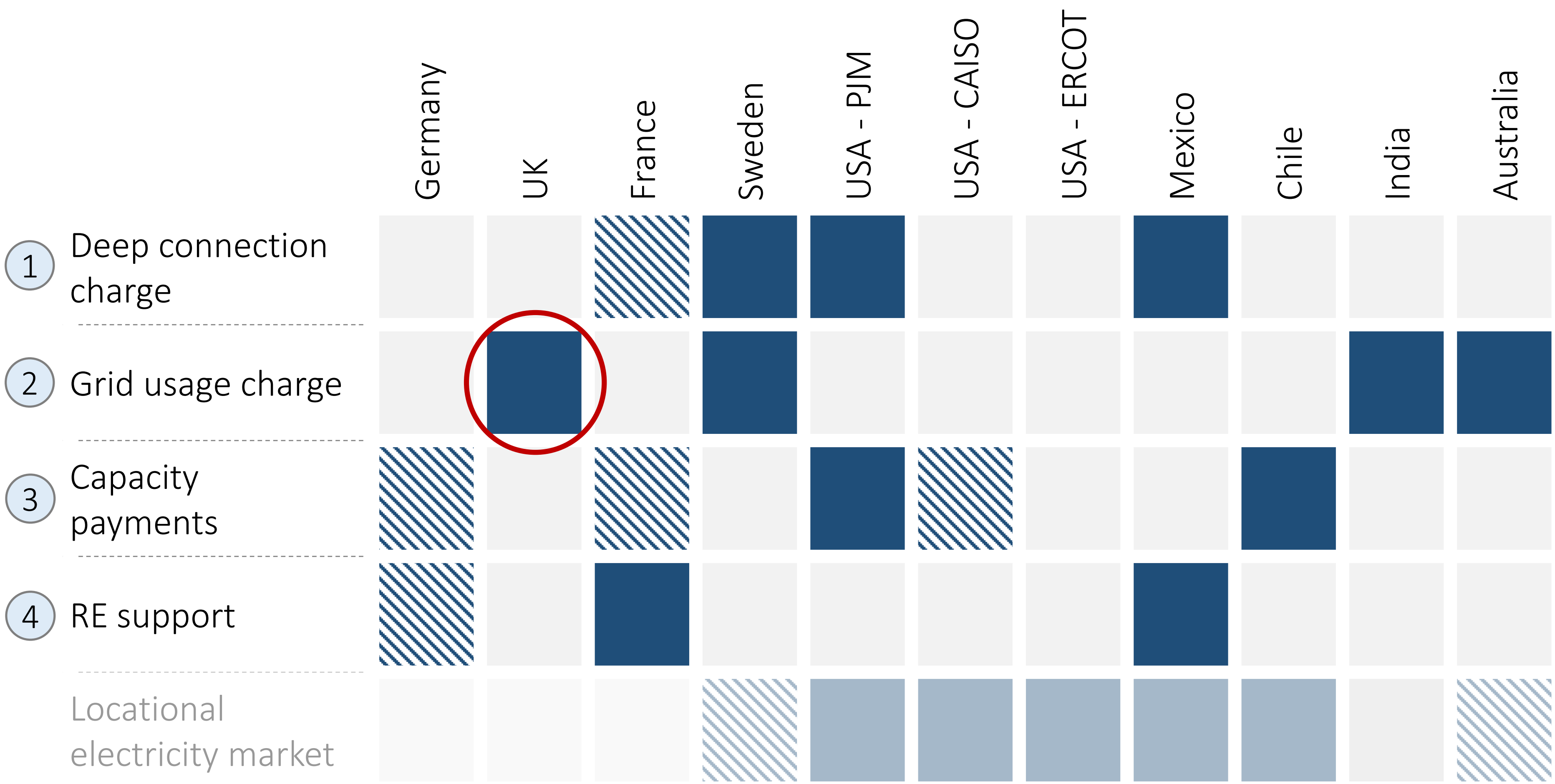


Research question 1

Which locational investments incentives do countries use?

Locational signals for generators

Locational signals
Sometimes
No signals

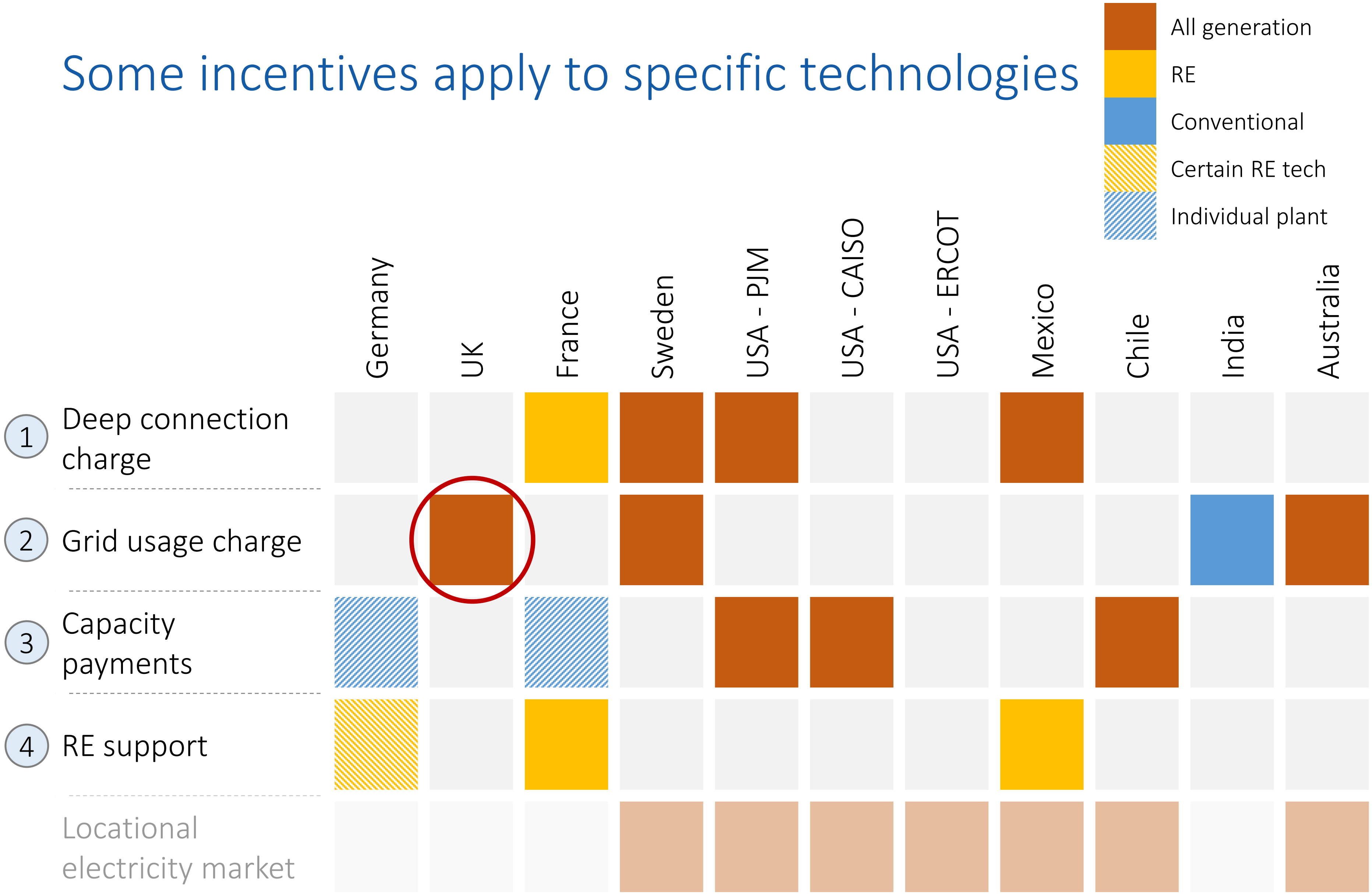


Instrument carry (quite) different names

Locational signals
Sometimes
No signals

	Germany	UK	France	Sweden	USA - PJM	USA - CAISO	USA - ERCOT	Mexico	Chile	India	Australia
1 Deep connection charge			Quote-parts								
2 Grid usage charge		TNUoS								Marginal participation	Marginal loss factors
3 Capacity payments	Netztechnische Betriebsmittel		Landivisiau		Reliability pricing model	Local capacity requirements			Precio Potencia de Punta		
4 RE support	Referenzertrags Modell		SRADDET					RE Auctions			
Locational electricity market											

Some incentives apply to specific technologies



Quantifying instruments: e.g., Great Britain's TNUoS

- We are not interested in overall level of payments, but in quantifying the *strength of the locational signal*
- The maximal cost difference between locations is taken as proxy for the strength of each instrument

Highest difference = most expensive location – cheapest location

Example: Great Britain's transmission tariffs (TNUoS)

The two most extreme TNUoS for renewable generation in 2018/19:

Glenglass in North Scottland:	30 £/kW	
Central London:	-8 £/kW	
Max. difference in TNUoS:	38 £/kW	(≈43 €/kW)

Magnitude of incentives: Max – Min

Difference between locational signals (2018, original units)

Locational signals
Sometimes
No signals

	Germany	UK	France	Sweden	USA - PJM	USA - CAISO	USA - ERCOT	Mexico	Chile	India	Australia
1 Deep connection charge (€/kW)			70	85*	0-1500*			?*			
2 Grid usage charge (€/MWh or €/kWa)		43 €/kWa		3€/MWh 4€/kWa						36 €/kWa	15 €/MWh
3 Capacity payments (€/kWa)	?*		94		33	?*			21		
4 RE support (€/MWh)	32		?*					11			
Locational electricity market (€/MWh)				2	?	?	5	13	7		21

?: No data available
*: Investment signal highly depends on individual case

Converting units into EUR per MWh

- For better comparability, we convert all units into EUR per MWh

Problems and assumptions

- To convert €/kWa into €/MWh, we need to assume full load hours – we use two cases
  - Wind power: 3000 FLH
  - Combined cycle gas turbine: 5000 FLH
- To convert €/kW (one-off) into €/MWh, we need to assume discount rate and life time
  - 5% WACC
  - 25 years
- Some instruments apply only to certain technology

Unit conversion: Great Britain's TNUoS

Converting units into EUR per MWh

- FLH matter (of course)
- Differ by technology (e.g., larger for RE than for conventionals)

→ We look at four exemplary cases

		EUR per kW p.a.	EUR per MWh
Peaker	OCGT @ 500 FLH	16	32
Mid-load	CCGT @ 5000 FLH	34	7
Base	Nuclear @ 8000 FLH	53	7
Renewable	wind power @ 3000 FLH	43	14

1 GBP = 1.13 EUR

Magnitude of incentives: conventional (CCGT@5000 FLH)

€/MWh

Incentive applies to...

- All conventional
- Individual plants

	Germany	UK	France	Sweden	USA - PJM	USA - CAISO	USA - ERCOT	Mexico	Chile	India	Australia
1 Deep connection charge				1*	19*			?*			
2 Grid usage charge		7		4						7	15
3 Capacity payments	?*		19*		7	?*			4		
4 RE support											
Locational electricity market				2	?	?	5	13	7		21

?: No data available
*: Investment signal highly depends on individual case

Magnitude of incentives: RE (wind power@3000 FLH)

€/MWh

Incentive applies to…

All renewables

Certain RE tech

Incentive	Germany	UK	France	Sweden	USA - PJM	USA - CAISO	USA - ERCOT	Mexico	Chile	India	Australia
1 Deep connection charge			2	2*	32*			?*			
2 Grid usage charge		14		4							15
3 Capacity payments					11	?*			7		
4 RE support	32		?*					11			
Locational electricity market				2	?	?	5	13	7		21

?: No data available
*: Investment signal highly depends on individual case

Summary: Findings

- We found a rich variety of locational incentives
  - Grid charge (connection, usage)
  - Capacity payments
  - RE support schemes
  - Locational electricity markets (small zones, nodal pricing)
- <u>All</u> systems studied use some locational signal
  - All zonal markets use instruments to steer investment geographically
  - Most nodal markets have something on top of LMP
- Many jurisdictions use multiple instruments
- Some instruments might not be intended as a locational signal (but serve as one nevertheless)
- Magnitude of the locational signal
  - Extremely heterogenous, sometimes applies to individual plants only
  - Renewables tend to be affected stronger (if expressed per MWh)

Workshop Agenda

1. The Problematic Status Quo
2. Locational Incentives: A Taxonomy
3. Inc-Dec Gaming
4. Findings: What do countries use?
5. **Discussion of Instruments**
6. Annex: detailed results

Research question 2

What are the pro's and con's of different instruments?

Deep grid connection charges: implementation

1

<u>Deep grid connection charge</u>

- Generators pay for grid enhancement necessary to connect plant
- Reflecting costs of connection
- Fee can be zero or positive (at least we are not aware of "connection payments" to generators)

PJM

- Simple deep grid connection charge

France

- Network development costs due to RES integration are mutualized on a regional basis (Quote-parts)
- Grid extension occurs before installation of RE plants

Mexico

- Deep grid connection charge unless grid extension is beneficial for the entire system
- Generators receive FTRs or revenues from sales of FTRs

Sweden

- Plans to reduce charge for offshore wind to a level comparable to onshore wind

CAISO

- Grid enhancement costs are paid by generator but compensated after five years

Deep grid connection charges: features and issues

1

€/kW payment

- Stronger locational impact on peakers, less on base load
- No dispatch incentive

One-off upfront payment

- High financial requirement for investors, increase risk and costs of capital
- Extremely credible as incentive

Distorted incentives across borders

- If implemented only in one country: disadvantage of domestic generation vs. imports (given that charges have always been negative)

Grid investment tends to be lumpy

- Possible problem: wait-and-see

Locational grid usage charge: implementation

2

Locational grid usage charge

- Generators pay a grid fee, which differs by location
- Often meant to reflect (marginal) losses and/or grid expansion costs
- Fees can be negative (payments)

UK (TNUoS)

- Capacity charge: to collect total allowed revenues of TSOs (together with demand charges)
- Complex: differentiated by plant type, full load hours, peak / non-peak
- Generation zones derived from nodal pricing model

Sweden

- Capacity charge: to reflect investment cost
- Energy charge: to reflect losses

Australia (MLF)

- Premium / penalty
- Multiplier with the zonal price
- Reflects losses

India

- Cost allocation per line pro-rata to all users
- No reward for the reduction of flows

Locational grid usage charge: features and issues

2

If €/MWh

- Time invariant – dispatch incentive is sometimes (much) too weak and often too strong
- Strong driver for base load, but weak for peakers
- Impact on storage is non-obvious and possibly perverse, because: cost of charging (hence losses) is affected, little effect on temporal price structure

If €/kW

- No dispatch incentive at all
- Strong locational driver for peakers, but weak for base load

Determining the level of charges (e.g., through modeling)

- Driven by future assumptions (nodal prices 1…5 years into the future)
- Prone to rent-seeking and lobbying

Trade-offs in design

- Capacity vs. energy charge (stronger effect on peaking vs. base load plants)
- Frequent vs. infrequent updating (accuracy vs. credibility as investment signal)

Locational capacity payments: implementation

3

Locational capacity payments

- Generators are compensated for providing capacity at specific location
- Meant to reflect uncompensated fixed costs
- Often specification of existing capacity scheme

Chile

- Nodal capacity prices
- Reflecting availability at 52 hours of highest demand

PJM

- Capacity requirements for LSE
- Market for available generation capacity established

CAISO

- Capacity requirements for LSE
- LSE have to submit resource availability plans

France

- Single plant tendered in grid constrained region (Brittany)

Locational capacity payments: features and issues

3

Consistency with spot market for energy?

- Can be easily implemented in markets with existing (zonal) capacity mechanisms
- Problematic for energy-only markets: undermines investment signals from scarcity pricing

Specification of “capacity” is non-trivial

- Technology-neutrality hard to archive, especially in case of storage, variable renewables and interconnectors
- Bias towards peakers (similar to €/kW grid fee)

Locational RE support: implementation

4

<u>Locational renewable support</u>

- Renewable support is differentiated by location
- Meant to reflect integration costs and system benefits
- Often reduces revenues in high yield sites

France

- Quantity targets for regions (SRADDED Program)
- Individual regional approach

Mexico

- RE auction design with locational bonus/penalty, based on nodal pricing computer model
- Adapting bids in winner selection process

Germany

- Support for wind depends on yield (happens to relief grid constraints)
- Quantity cap in region with grid constraints

RE support: features and issues

4

Addresses only renewable energy (obviously)

- Not conventional generation, batteries, loads
- Does not address market-driven renewables outside support schemes, either

Usually a €/MWh payment

- Because of nature of support schemes
- Same problems as energy based grid usage charge

Long-term and credible

- Usually fixed for around 20 years (the duration of support schemes)

General insights across instruments

Seemingly different instruments can be quite similar in terms of incentives

- Deep connection fee
- €/kW grid usage fee
- Capacity payment

Some instruments set also a locational dispatch incentive, while others do not

- No dispatch signal: deep connection fee, €/kW grid usage fee, capacity payment
- Dispatch signal: €/MWh grid usage fee, RE support scheme

Payments (or quantities) are set administratively

- Prone to lobbying
- Subject to political influence

General insights across instruments

Payments are determined ex ante

- E.g. model-based scenarios

Trade-off: Adjusting payments more or less frequently

- More frequently (such as every year): more accurate, less credible investment signal
- Less frequently (such as once in a lifetime): less accurate, more credible signal

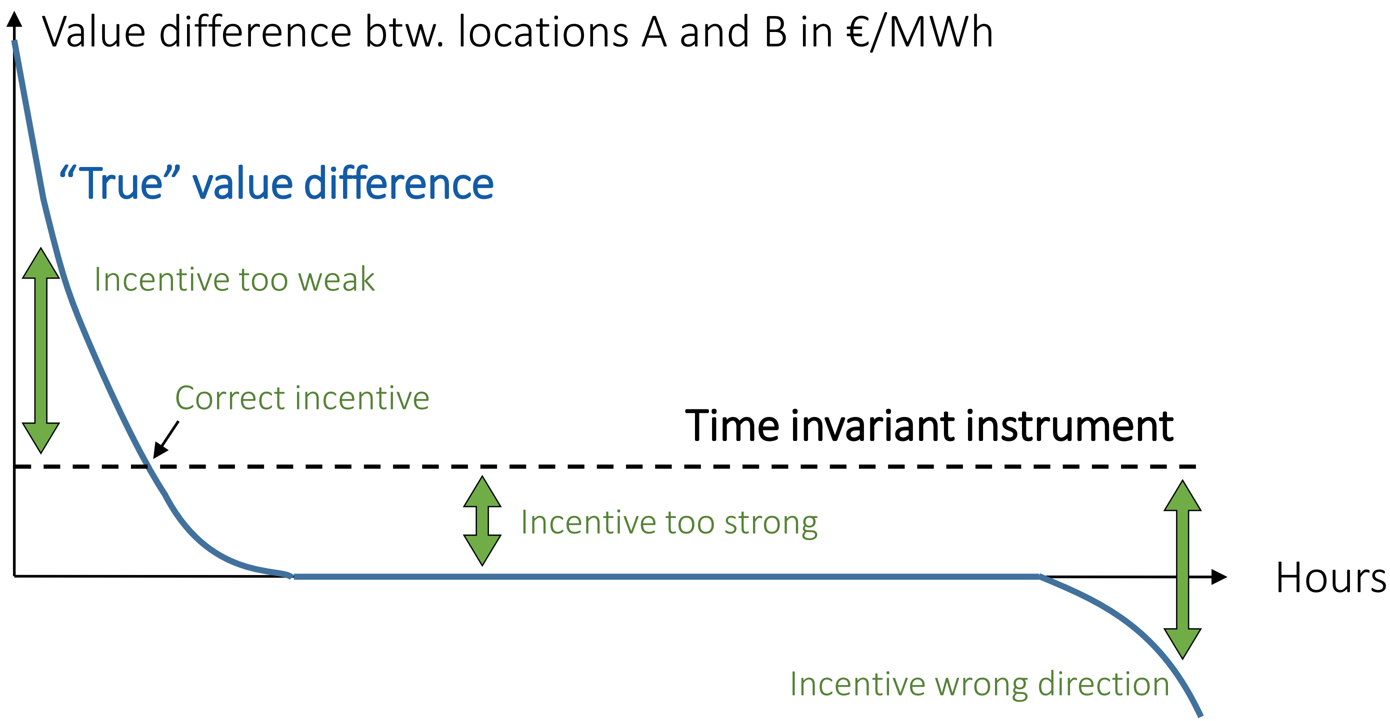
Payments are either specified in €/MWh or €/kW

- €/MWh: stronger signal on base load plants
- €/kW: stronger signal on peakers

General insights across instruments

Payments are usually time-invariant (from hour to hour)

- Only exception (sort of): GB
- Signal is almost always either too weak or too strong
- For high temporal granularity nodal pricing seems the only sensible option



Towards a recommendation

To be discussed!

Grid usage €/kW charge, long duration (10 years?)

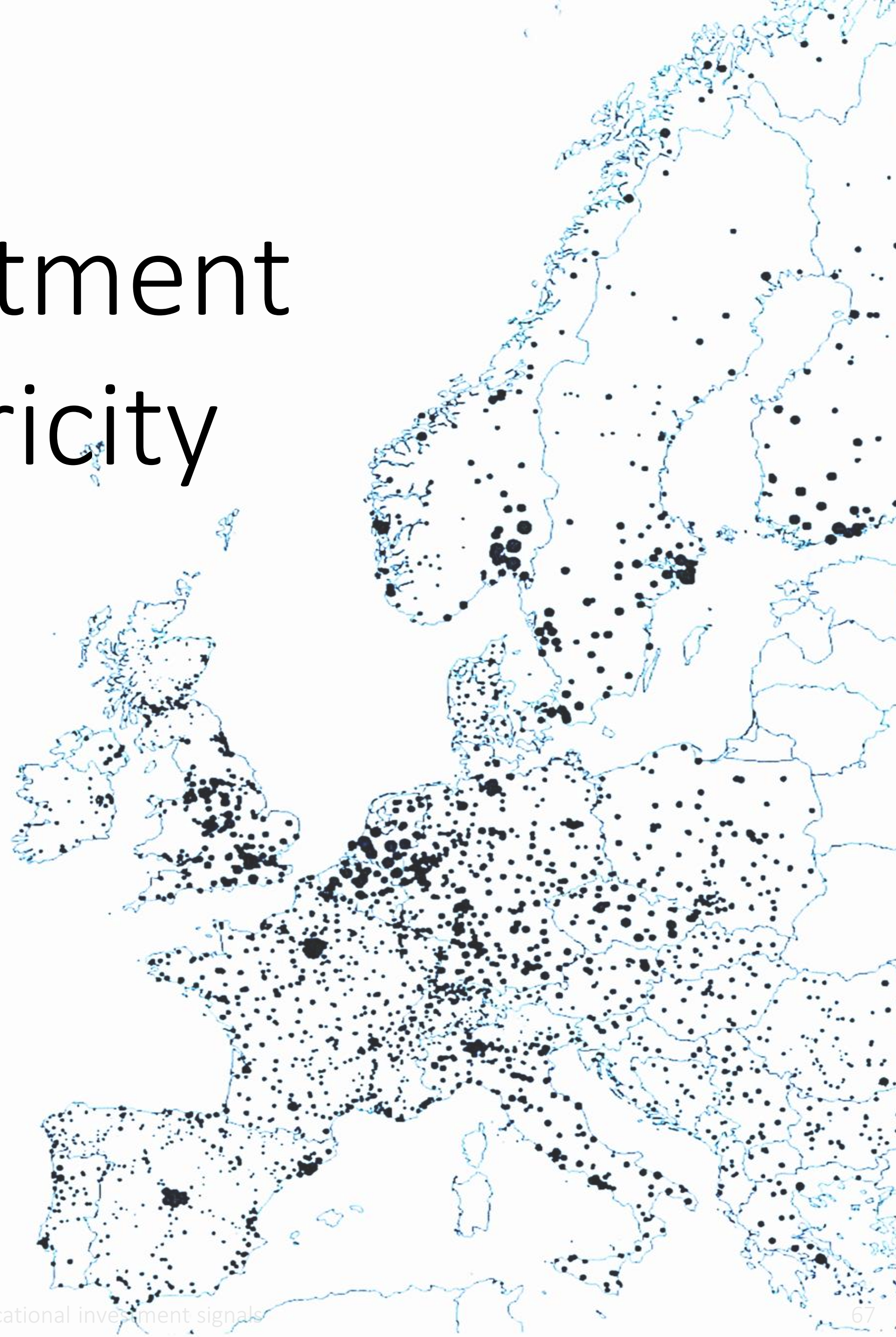
- Base load: little effect on investments → those investment won't happen anyway
- Peak load: strong effect on investment → lack of dispatch signal does not hurt much
- Batteries (counted as generation): strong investment effect, but no dispatch effect – possibly making things worse
- RE: Strong investment effect

Next steps

- Report to be drafted during spring 2019
- START synthesis report summer 2019

Locational investment signals for electricity generation

Lion Hirth
Anselm Eicke
Tarun Khanna



Hertie School of Governance

ENERGY TRANSITION HUB

GEFÖRDERT VOM
Bundesministerium für Bildung und Forschung

Workshop Agenda

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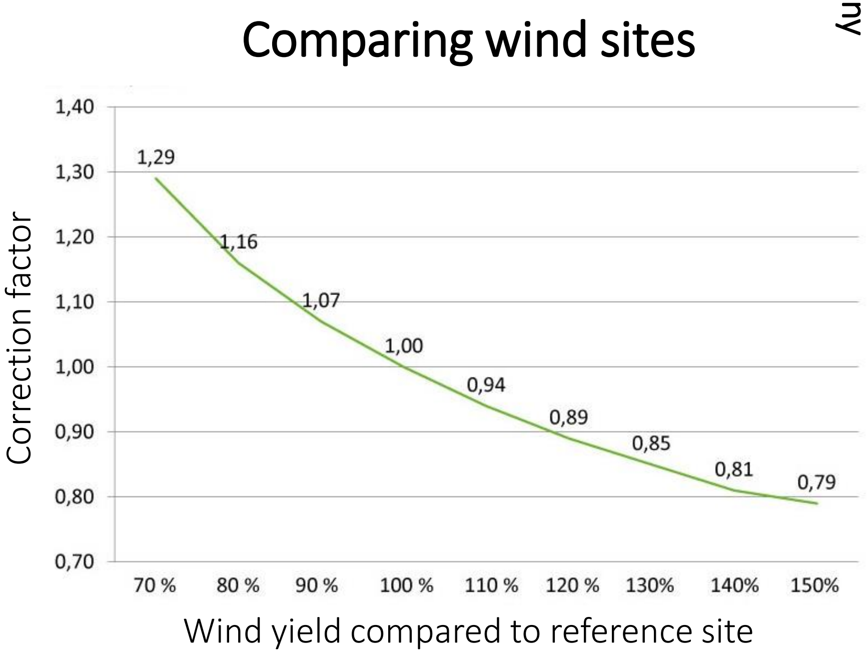
6. **Annex: detailed results**

RE support "Referenzertragsmodell"

- German wind generators receive a higher level of support if they are located at a low-wind site

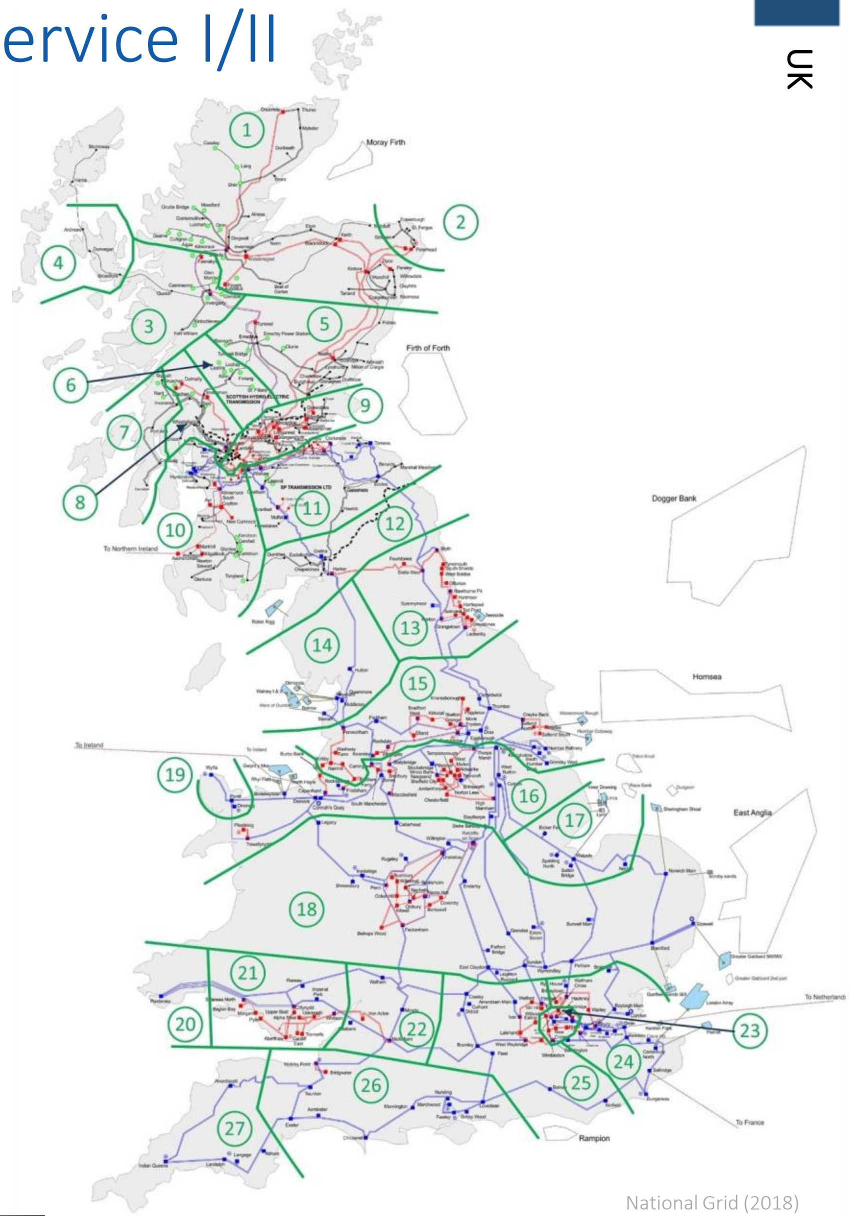
1. capturing rents by reducing the support for higly profitable projects;
2. distributing wind farms more evenly across the country, also to relax grid constraints

- Indirect instrument: does not target system optimal location



Transmission Network Use of Service I/II

- TNUoS* have two purposes
    1. Recover grid costs
    2. Reflect transmission costs
- GB is divided into 27 “generation zones”
- Methodology: model nodal prices, group nodes with average price difference <1 £/MWh
- Average annual generation tariff must remain below €2.5/MWh (EU regulation)
- GB is also divided into 14 demand zones (corresponding to DSOs)



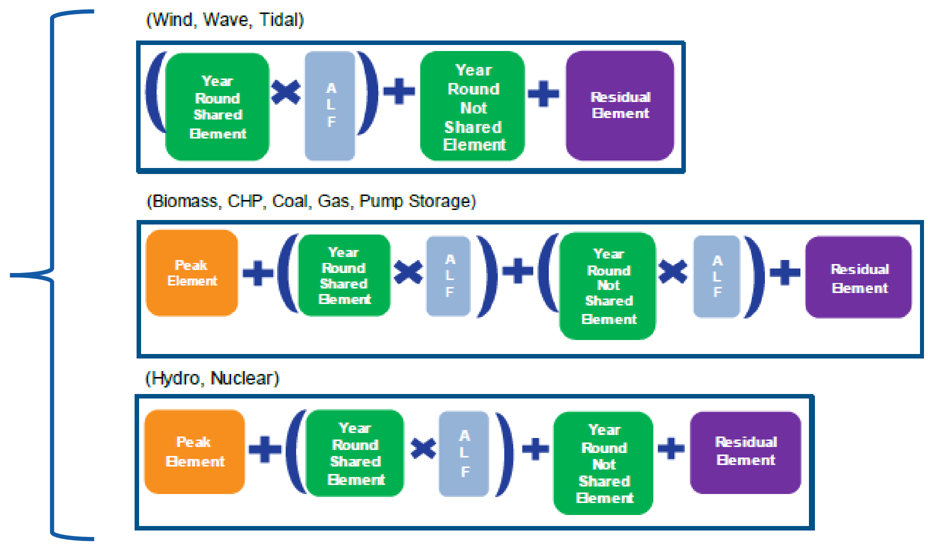
National Grid (2018)

*Transmission Network Use of Service

Transmission charges: GB’s TNUoS II/II

- Tariff is technology specific and depends on 5 elements

TNUoS = local tariff +
(substation)



- Locational differentiation affects technologies to a different degree

Energy	in € / MWh	
FLH	Conv.	RE
500	32	
3000	9	14
8000	7	

Capacity	in € / kW	
FLH	Conv.	RE
500	16	
3000	26	43
8000	53	

1GBP = 1.13€

Grid connection charge: quote-parts

General observation

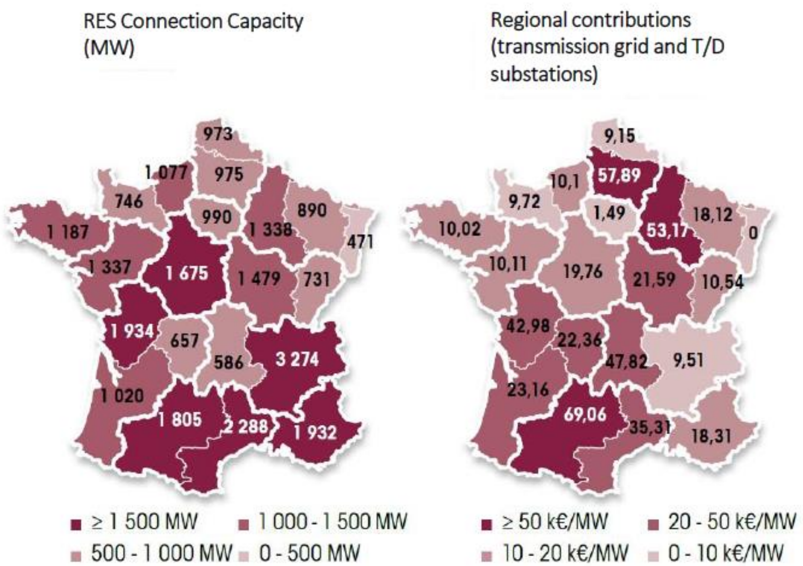
Grid investment tends to be lumpy

Waiting for first-mover impedes investments

- **France's Solution**: S3REnR scheme
  - *1. plan network expansion*
  - *2. share the costs*
  - *3. prioritize RES*

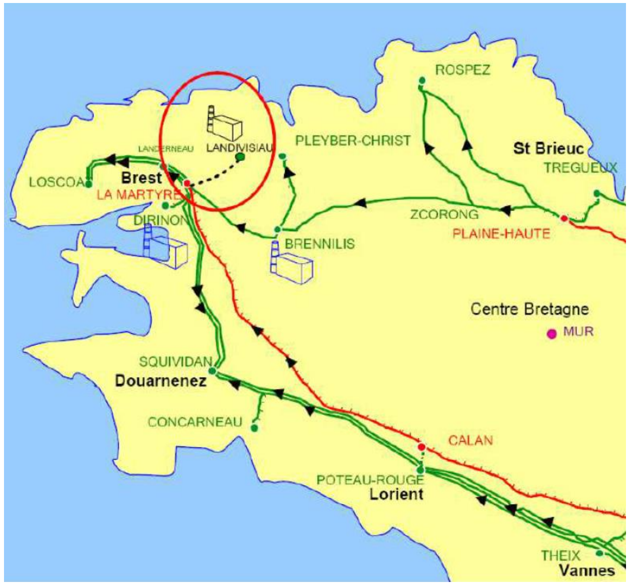
Implementation

- Upfront costs for *regional grid enhancement* are shared (quote-parts)
- Indirect instrument: Highest tariffs correspond to areas where regional grid enhancement is expensive – could still be beneficial from a macro-perspective
- Tariffs vary strongly between regions
  - 0k€/MW – 70k€/MW



Capacity payments in Brittany

- Exceptional tender of CC Gas plant in predefined region (Landivisiau in Brittany) due to:
  - Limited generation capacity in the region
  - Increasing demand and high thermo-sensitivity
  - Limited transmission capacities
- Yearly support of 94.000 EUR/MW for 20 years
- Plant operators ensure electricity generation when required by TSO
- Forbidden to enter long term contracts with suppliers possessing more than 40% of France's capacity (read: EDF)
- EU state aid rules: measure is both proportionate and necessary



SRADDED – Regional renewable support

- SRADDET Programme gives regions powerful tools:
  - tagging land as adequate for wind farms development
  - imposing obligations on new buildings (e.g. RES procurement, energy efficiency…)
  - …
- Support schemes are organized decentrally, hence strong variation between regions exists

The two elements of Sweden‘s grid usage charge

Capacity payment for infrastructure

- Cover costs of operation and maintanance
- The capacity charge is highest in the north, falling linearly towards the south. The reverse applies for consumption.

Energy payment for losses

= Loss coefficient · 0.8 · Loss power price

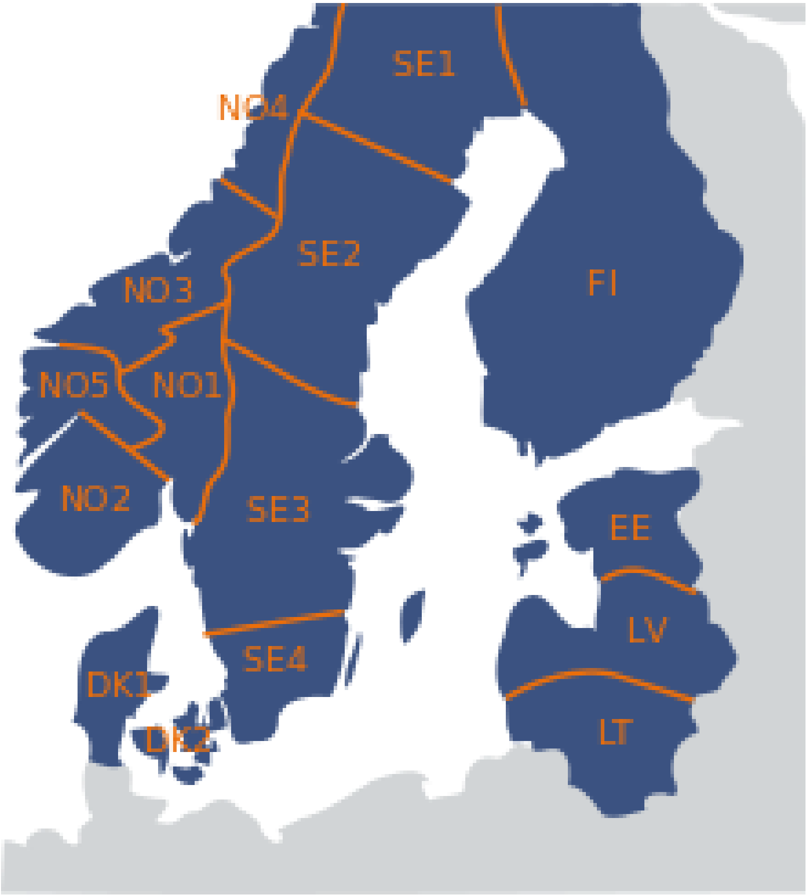
- **Loss coefficient**: Marginal network losses resulting from additional generation at connection point (positive or negative)
- **Correcting coefficient** (0.8) adapts loss coefficient to actual losses
- The **loss power price** is the price the TSO pays to compensate losses. Currently, it is set annually, but will vary with the actual spot price from 2020 onwards

Both charges are…

- Calculated at nodal level (Point of connection charge)
- Determined ex-ante on a yearly basis
- Paid by generators and consumers

Market splitting in Sweden

- The Nordic power market is, since November 2011, split into twelve bidding zones.
- Average spot market prices varied between 441 SEK/MWh in SE1 and 467 SEK/MWh in SE4
- This difference results in an average 2.1€/MWh locational value gap.



Deep grid connection fee Sweden

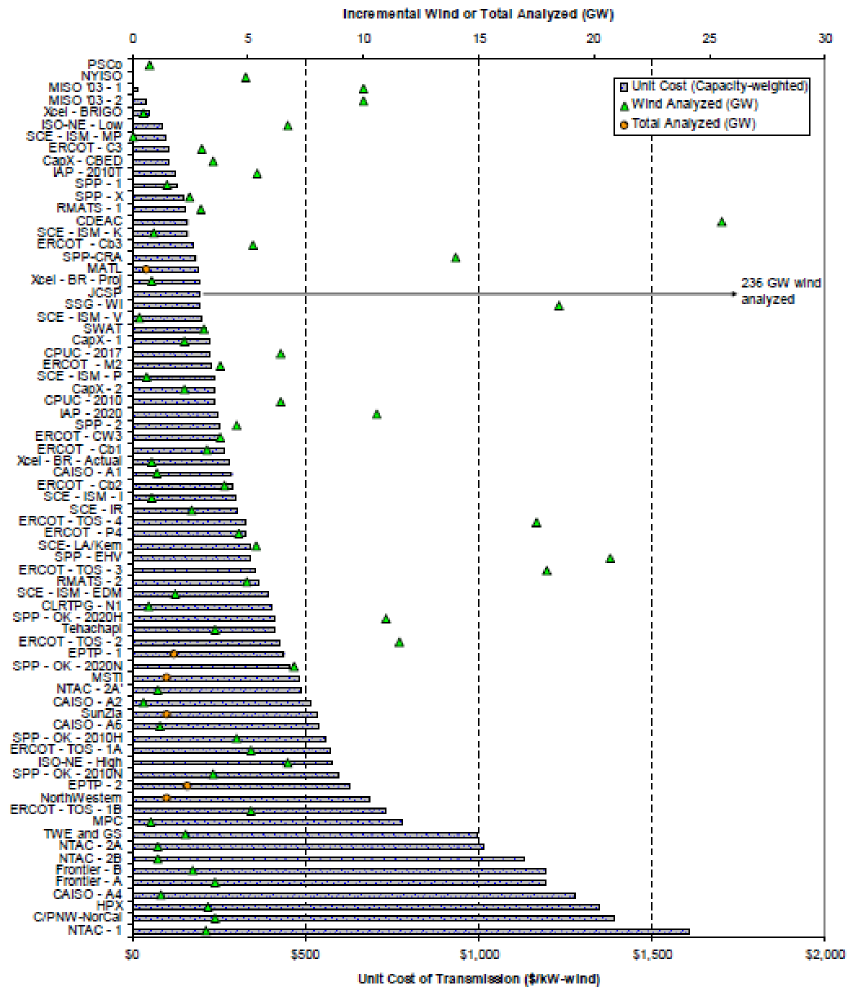
- Svenska kraftnät charges a deep connection fee
- Is meant to recover future and past grid investment
- An estimate whether connection fee will be applied is first determined in the connection agreement

Deep grid connection charge U.S.

CAISO

- April 1st-15th is the only cluster application window each year. A Study Group is a group of electrically related projects usually located in a certain geographic area. Network upgrade costs are shared; interconnection charges are project specific.

- For each proposed generation power project, the ISO studies in two report (Phase I and Phase II) project impacts to the transmission systems



Note: Unit cost of transmission in nominal dollars from various years

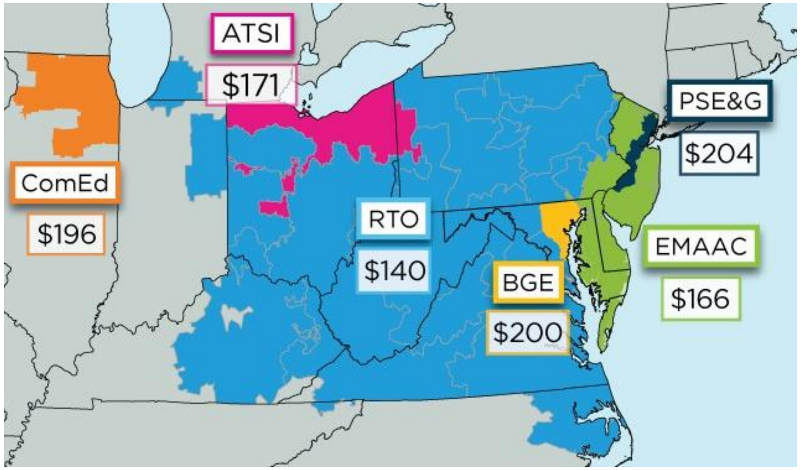
Figure ES-2. Unit Cost of Transmission for Wind in $/kW-wind Terms

Deep grid connection charge PJM

- Each respective generator or transmission project bears the cost required for interconnection.
- For local and network upgrades which are required due to new generation facilities, cost will be allocated according to the order of the New Service Requests and the MW contribution of each individual request for all projects that cause or contribute to the need for the local or network upgrades.

Capacity payments

- The ISO defines capacity requirements which have to be met by Load Serving Entities (LSE) in predetermined sub-regions (i.e., Locational Deliverability Areas).
- Capacity can either be bought bilaterally or from the capacity market.
- Contracted Generators commit to provide energy during PJM emergency under the capped energy price. Capacity revenues are paid independent on whether energy is produced or not.
- Capacity auctions are held three years ahead of delivery. If the fore-cast for demand changes, additional auctions may be held later. Contracts are made for an entire "delivery year".



Capacity payment CAISO

- Quantity based instrument
- The ISO performs annual studies to identify the minimum local resource capacity required to meet the reliability criteria.
- Based on the study results, load serving entities receive a proportional allocation of the minimum required local resource capacity, and submit resource adequacy plans to show that they have procured the necessary capacity.

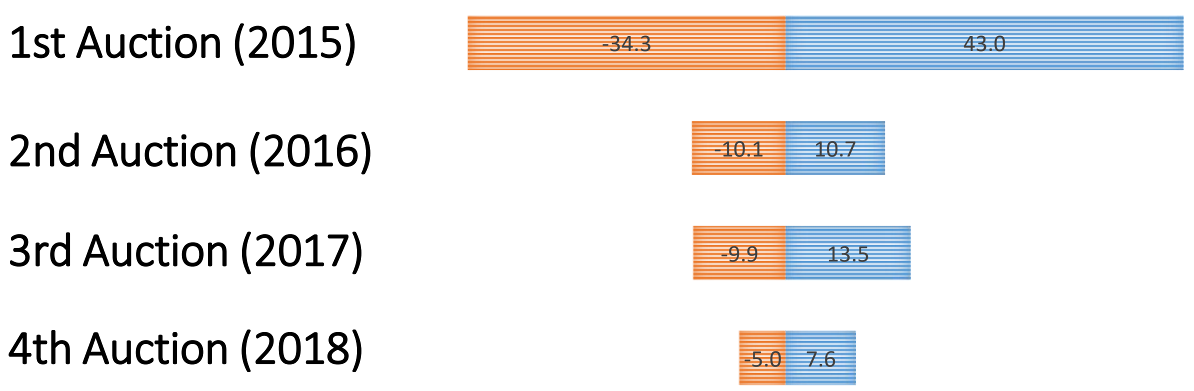
Nodal pricing ERCOT

- ERCOT implemented a nodal market structure in late 2010 with a ‘congestion only’ Locational Marginal Pricing (LMP) structure.
- ERCOT conciders including marginal losses in its LMP.
- An ICF study on the effects of marginal loss pricing in 2020 found there may be no significant shift in the dispatch of renewable generation. Yet, reduced pricing in ERCOT West may affect the economic viability of renewables.
- All other nodal markets use an LMP market structure that accounts for both congestion and marginal losses. With the focus on reducing congestion in the market, ERCOT introduced a ‘congestion only’ LMP structure. This means difference in power prices at different pricing points in the system differed only by their impact on transmission congestion and not due to transmission losses. The inclusion of marginal losses may affect cost-benefit assessments of recently approved or future transmission projects.

Location specific renewable auctions

- Technology neutral auctions for RE development
- Adjustment factors in RES long-term auctions (15 year contract for energy and capacity, 20 years for clean energy certificates)
- Bids are modified in two ways:
  - (i) location bonus / penalty based on projections of future nodal prices
  - (ii) limits for generation is set for zones with insufficient transmission capacities
- Optimization model maximizes the economic surplus of the buyer
- Locational boni / penalties are published before the auction

Range of locational price adjustment (in USD / MWh)



Deep grid connection charge Mexico

- Deep grid connection charge if generation is not necessary (= not part of the national grid expansion plan)
- If generator pays for the construction of a new line, it receives FTR or corresponding revenues

Nodal pricing Mexico

- Wholesale market is implemented as nodal pricing market comprising of 2417 nodes
- The country is divided into three zones which are not interconnect among each other. The largest share of nodes (2284) is on the mainland power system
- Average nodal prices in the central system vary between 48 and 62 USD/MWh. Converted maximum value difference is approx. 13 €/MWh.

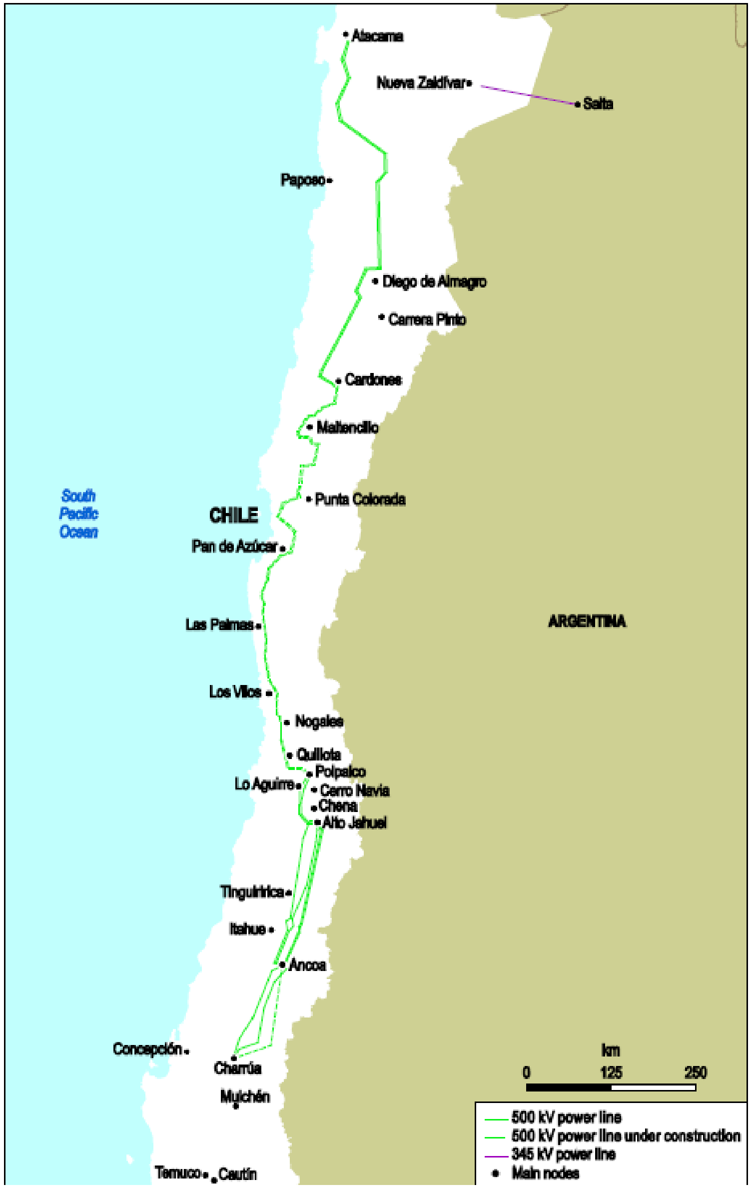
Precio Básico de la Potencia de Punta

- Capacity payments reflect the costs of the cheapest technology to supply electricity at a specific location.
- Each generator's firm capacity is estimated using historical availability to generate during the 52h of highest demand.
- Generators are awarded for firm capacity on a monthly basis. Prices are adapted every six months.
- In 2018, prices for capacity ranged from 4224 CLP/kW/month in Rahue to 5544 CLP/kW/month in Parinacota
- That translates into a maximal value difference of 21 €/kW/year.

Nodal pricing Chile

- Chile's national electric system (SEN) consists of 50 220kV substations which have individual energy and capacity prices
- Average energy prices range from 33.6 to 28.0 CLP / kWh, implying a location specific difference of 7.3 €/MWh (data for second semester 2018)

Figure 5.8 Map of the interconnected high-voltage electricity grid, end 2017



Grid usage charge Chile

- Before 2016, grid usage charges depended on the distance between generator and consumers. Generators used to pay up to 80% of these costs.
- Owners of a power plant that wanted to provide electricity to customers outside the Area of Common Influence of this plant had to pay tolls.
- An Area of Common Influence is defined as the minimal set of assets that connect the power plant with the nearest basic energy substation
- Under the 2016 law, tolls are entirely shifted to consumers. This regulatory change shall enable renewable energy projects at remote but resource rich sites.

Marginal participation in India

- Grid usage costs are allocated to users based on their utilization of each line.
- To do so, the marginal participation is calculated for each line:
  - change in electricity flows when production or consumption are marginally increased.
- Only positive participation in the direction of the power flow is considered
  - increments which reduce burden on lines are neither given any credit nor charged for use of the system
- The cost of each line is allocated pro-rata to all agents according to their participation in the corresponding line

Marginal loss factors (MLF)

- MLF are locational marker for premium / penalty of prices that generators get on the wholesale market (same is applied to consumers using different factors)
- Estimation of marginal network losses resulting from power flow from connection point to reference node.
  - MLF < 1: generation increases system losses
  - MLF > 1: generation reduces system losses
- Local value of electricity
  = regional reference price · MLF of location
- MLF are determined ex-ante for one year using a load flow model.

Locational electricity market Australia

- Australia's electricity market is organized in 5 zones
- Annual average prices differ strongly between zones (2017-18 data):
  - South Australia: 109 AU$/MWh
  - Queensland: 75 AU$/MWh
  - Victoria: 99 AU$/MWh
- Prices within zones are adjusted by marginal loss factors