Reconsidering the design of electricity market in the light of increasing shares of renewables: still fit for purpose?

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Outline

1. Conclusions ‘position paper’TenneT
2. Giving incentives to grid users to provide flexibility
3. Energy-only market and capacity mechanisms
4. Market-zone review
5. Investing in grid capacity
6. Conclusions

Conclusions TenneT

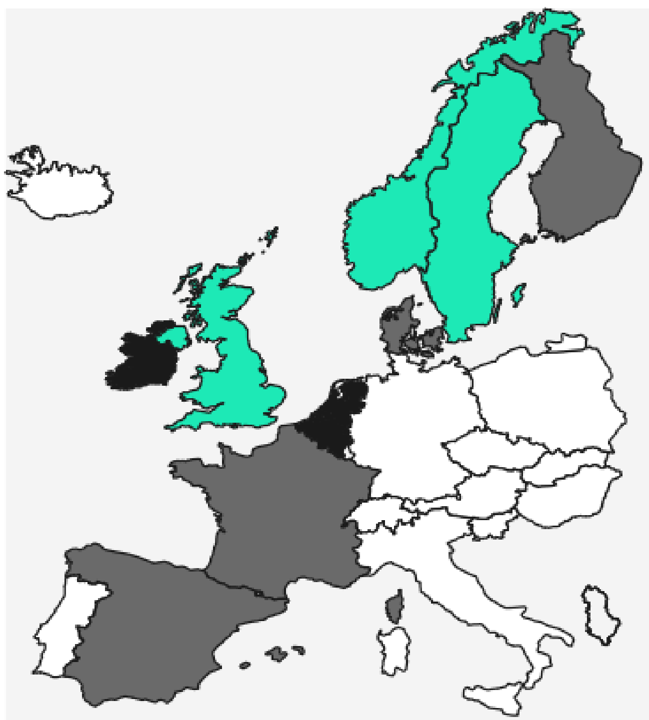
1. So far, market mechanism has resulted in reliable electricity system
2. Because of the energy transition, the market model is under pressure
3. High-voltage grid will not be extended to meet future peak usage
4. Therefore, grid users should receive incentives to provide more flexibility, for instance through the introduction of time-varying transport tariffs
5. In addition: bidding zones need to be reviewed
6. Support schemes for renewables should be abolished and/or combined with scheme with capacity remunerations

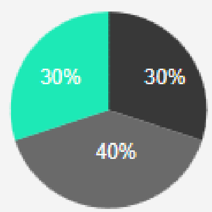
2. Giving incentives to grid users to provide flexibility

Dynamic tariffs based on underlying market prices can be observed in Great-Britain, Norway and Sweden

Dynamic tariffs that are **based on underlying market prices** can be observed in 3 countries: **Sweden, Norway and Great-Britain. Four** countries **(Spain, France, Denmark & Finland)** use (or will be using) **multiple tariff periods. Belgium** is **investigating a potential dynamic tariff** for the tariff period 2024-2027. In **Ireland and the Netherlands** there are **no indications that a dynamic component will be implemented** in future tariff periods.

Dynamic tariffs implemented/to be implemented





Legend

- Based on underlying market price
- Tariff periods
- No dynamic tariffs
- Out of Benchmark scope

… but these dynamic tariffs are not related to grid scarcity

Highlighted countries

In **Great-Britain**, the **Balancing Service Use of System (BSUoS)** charges are **dynamic** as the tariff is directly related to the actual costs the TSO incurs for balancing the system on a given day. The tariff is **determined on a half hourly basis**.

In **Norway** is the **energy component**, which covers the costs for grid losses, **dynamic**. The tariff component is directly **related to the hourly Day-Ahead electricity price**. The tariff is calculated based on the loss rate of the concerned tariff period and on the DA-price.

In Sweden is the **energy charge**, which covers the costs of losses on the grid, **dynamic**. The tariff component is directly **related to the Day-Ahead price on an hourly basis**. The tariff is calculated by multiplying the DA-price, increased with a risk premium, with the loss rates (variable between connection points).

The new tariff methodology allows the introduction of a dynamic component in the tariffs.. The tariff would **partly be linked to an underlying market price**. The share of the dynamic component is not specified in the tariff methodology.

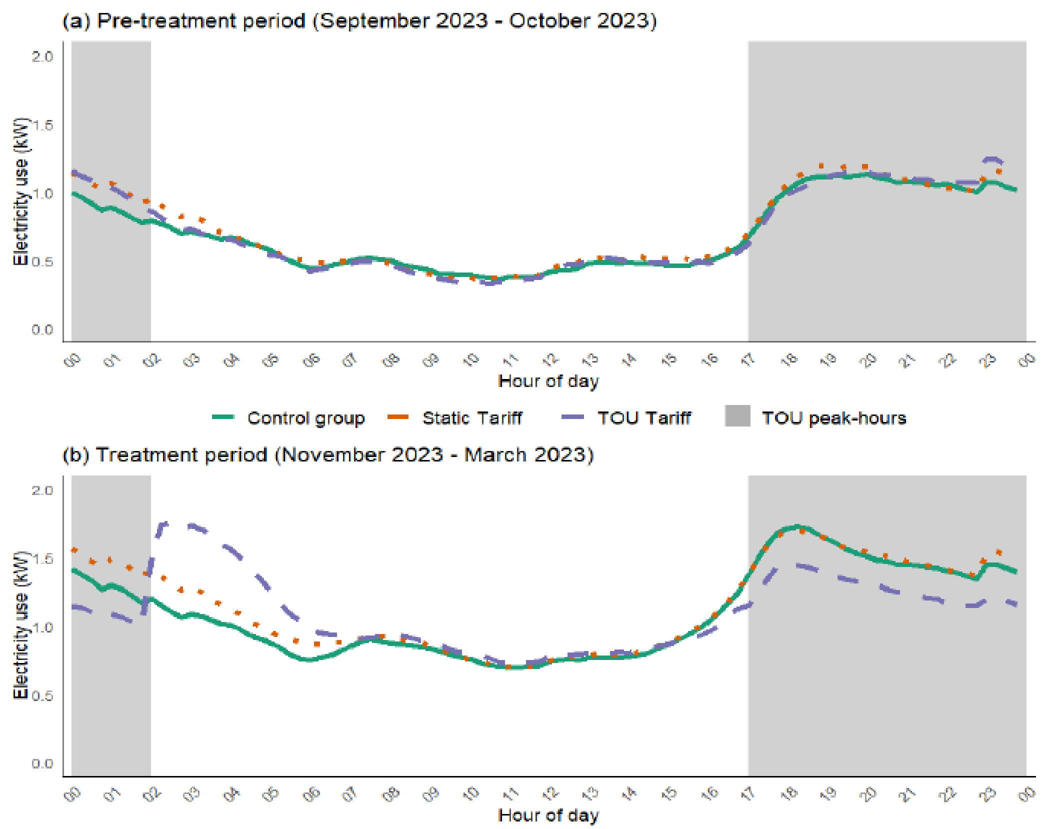
In **Denmark** there is a will to **include 2 tariff periods** (day- and nightime) in order to spread the consumption and grid use during the day. The changes should be implemented in the tariff period starting in 2024 (decisions are expected in quarter 3 of 2023).

2. Giving incentives to grid users to provide flexibility

Current allocation of grid capacity (within zone) is not based on economic principles

Dynamic grid tariffs does give incentive to change timing of grid usage

Figure 3. The average 15-minute electricity consumption by control and treatment groups during the pre-treatment period and treatment period



Draft results of field experiment with phd student on dynamic grid tariffs for households with e-car and own charging facility

3. Energy-only market and capacity mechanisms

Do we need to add capacity mechanism because high shares of renewables in order to realize reliable supply?

“Restructured wholesale electricity markets have a spot market in which consumers pay producers for the electricity they deliver. In energy-only markets, such as Denmark, the Netherlands and Norway, this is the only payment producers earn in the wholesale market.

In many other markets, producers receive an additional upfront payment for making capacity available to the power system. In Belgium, Finland, Germany, Sweden and Texas, such capacity payments are limited to generation units within a designated strategic reserve, which is activated when the market capacity has been exhausted.

In Great Britain and in most restructured electricity markets in the U.S., nearly all generation units on the market receive capacity payments. We refer to such a market-wide capacity mechanism as a capacity market.”

Source: Holmberg and Tangeras, A survey of capacity mechanisms: lessons for the Swedish electricity market, The Energy Journal, 44 (6), 2023

3. Energy-only market and capacity mechanisms

Conclusions Holmberg and Tangeras:

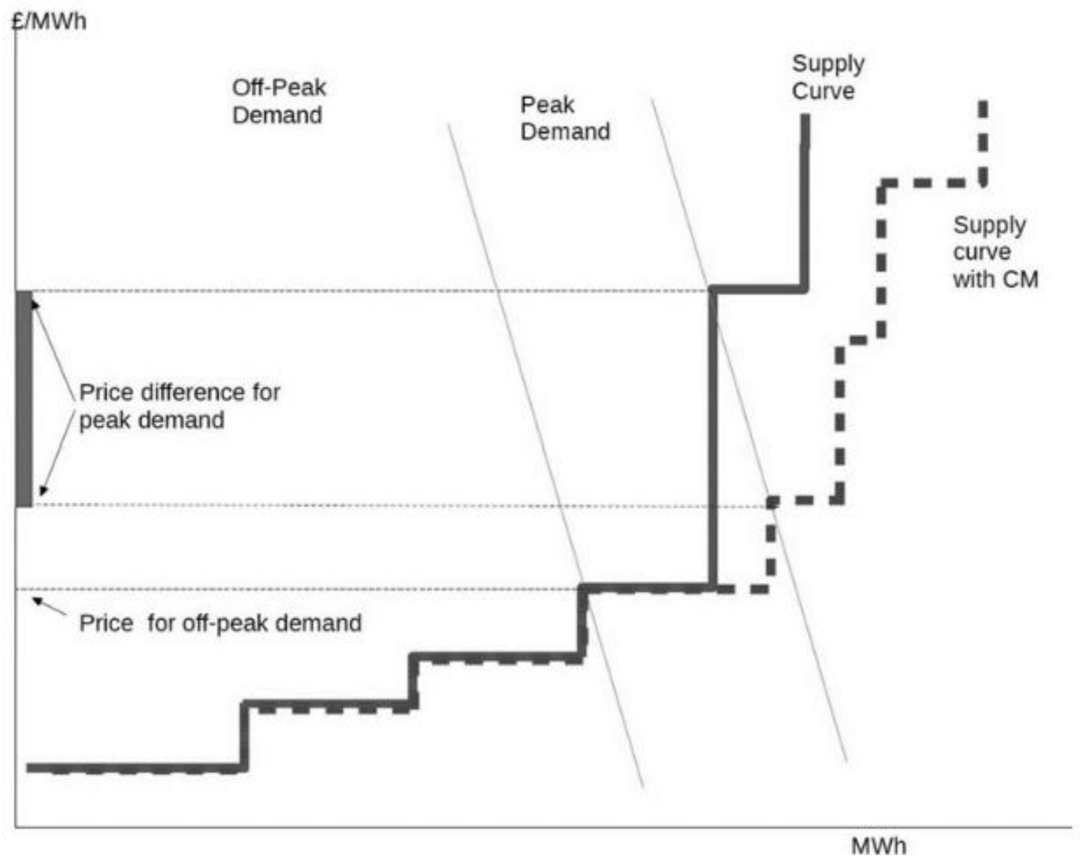
1. Energy-only market is most efficient market design
2. A reason to introduce capacity mechanisms is that building of new capacity takes time, and new regulations can result in temporary scarcity (e.g. coal, nuclear phase out)
3. Capacity mechanisms introduce distortions: it is hard to define firm capacities per plant, bureaucratic process of verifying and approving capacity
4. Strategic reserves based on capacity payments for a limited group of plants do not have these caveats
5. Another issue with capacity mechanisms is problem of imperfect competition when procuring capacity
6. When more consumers will more strongly respond to prices, there is less need for price caps and capacity mechanisms

7. Recommendation: price cap in spot market should be as high as possible in order to stimulate demand response and reduce the need for capacity mechanisms

3. Energy-only market and capacity mechanisms

One of the concerns with capacity mechanisms is market power

Figure 1: Demand (peak and off-peak) and supply (with and without a Capacity Market)



Introduction of capacity market reduces wholesale market prices: transfer of value from the EOM to the capacity market

Moraiz and Scott, The impact of capacity market auctions on wholesale electricity prices, The Energy Journal, 43(1), 2022

Table 3: Increase in total buyer costs in the capacity market due to strategic behaviour: (with 1 GW entry, varying procured capacity and competitiveness of electricity market).

Forward contracts	100%	80%	60%	0%
5000 MW	15 [5%]	11 [4%]	–11 [–4%]	0 [0%]
6000 MW	224 [62%]	227 [64%]	151 [44%]	9 [3%]
7000 MW	301 [44%]	560 [133%]	561 [134%]	564 [136%]
8000 MW	304 [37%]	48 [4%]	46 [4%]	46 [4%]

In sum, for plausible scenarios with around 6000 MW procured capacity, 60–80% forward contracting, and up to 1 GW new entry, our simulations suggest that strategic behaviour raises buyer costs in the capacity auction by around 150–400 mEUR (40–100%) above the competitive least-cost solution. This translates into an increase of around 10–25% in buyer costs across the electricity and capacity markets, and suggests that policymakers' concerns about market power are well-founded.

Moraiz and Scott, The impact of capacity market auctions on wholesale electricity prices, The Energy Journal, 43(1), 2022

Table 2: Outcomes under different "market designs" (electricity market with 80% forward contracting, capacity market with 6000 MW procured capacity).

Market design	Energy-only	CM	CM0	CM1	CM2
Total buyer costs, electricity market (mEUR)	1406.5	1285.7	1285.7	1161.8	1138.4
Total buyer costs, capacity market (mEUR)	—	351.9	831.7	575.0	527.6
Weighted average electricity price (EUR/MWh)	66.1	60.2	60.2	54.0	52.8
Maximum electricity price (EUR/MWh)	1632.9	361.6	361.6	298.1	274.8
Hours when price > 500 EUR/MWh	21	0	0	0	0
Total variable costs (mEUR)	623.4	626.8	626.8	639.7	628.6
Total fixed costs (mEUR)	248.2	385.0	385.2	416.5	416.5
Capacity auction clearing price	—	59	140	97	89
Number of active generating units	12	32	31	32	32
Active nominal capacity (MW)	3988	5965	5941	5928	5928

Notes: CM = competitive capacity market, CM0 = strategic capacity market without entry, CM1 = strategic capacity market with 1 GW entry, CM2 = strategic capacity market with 2 GW entry

The key finding of this paper is that strategic behaviour in the capacity auction significantly raises total buyer costs. Depending on the amount of entry, the clearing price for procuring 6000 MW rises from 59 EUR to 89–140 EUR and total buyer costs in the capacity market rise by 175–480 mEUR (or 50–136%). Lower buyer costs in the electricity market are outweighed by the direct effect of higher buyer costs in the capacity auction itself: the combined costs to buyers rise by 2–29%.[41]

4. Market-zone review

Table: Alternative configurations to be considered for the bidding zone review:

Identifier	BZRR	Number of BZs per MS	Source (ACER's algorithm/TSOs)	Fallback configuration identifier	Configuration assessed in BZR (Yes/No)
1	CE	DE2	k-means	14	No
2	CE	DE2	Modified version of Spectral P1 following remarks provided by German TSOs		Yes
3	CE	DE3	Spectral P1	12	No
4	CE	DE4	Modified version of Spectral P1 following remarks provided by German TSOs	13	No
5	CE	FR3	Spectral P1		Yes
6	CE	IT2	k-means		Yes
7	CE	NL2	Spectral DIRC		Yes
8	Nordic	SE3	Spectral P1		Yes
9	Nordic	SE3	Modified version of Spectral P1 following remarks provided by Svenska Kraftnat		Yes
10	Nordic	SE4	Spectral P1		Yes
11	Nordic	SE4	Modified version of Spectral P1 following remarks provided by Svenska Kraftnat		Yes
12	CE	DE3	Modified version of configuration 3 to align with Amprion's control area borders		Yes
13	CE	DE4	Modified version of configuration 4 to align with Amprion's control area borders		Yes
14	CE	DE5	Modified version of configuration 13, including a new bidding zone in Schleswig-Holstein		Yes
15 onward	CE	Combinations as derived during the bidding zone review study			

4. Market-zone review

Criteria for the review by ENTSOe

Network security

1. Operational security
2. Security of supply
3. Uncertainty in cross-zonal capacity calculation

Market efficiency

4. Economic efficiency
5. Firmness costs
6. Market liquidity & transaction costs
7. Market concentration & market power
8. Effective competition
9. Price signals for building infrastructure
10. Accuracy & robustness of price signals
11. Transition costs
12. Infrastructure costs
13. Market outcomes in comparison to corrective measures
14. Adverse effects of internal transactions on other BZs
15. Impact on operation and efficiency of balancing

Stability & robustness of BZs

16. Stability & robustness of price signals over time
17. Consistency across capacity calculation time frames
18. Assignment of generation and load units to BZs
19. Location and frequency of congestion, market and grid

Energy transition

20. Short-term effects on carbon emissions
21. Short-term effects on RES integration
22. Long-term effects on low-carbon investments

4. Market-zone review

Criteria for the review by Ofgem

EFFICIENT USE OF THE NETWORK	▪ The costs of re-dispatch ▪ Dispatch restrictions in the spot market ▪ Aggregated and disaggregated price levels
LIQUIDITY	▪ The levels of liquidity in the short-term (day-ahead and intraday) markets ▪ The levels of liquidity in the forwards market ▪ The ability of market players to hedge against uncertainty
INVESTMENT	▪ The degree to which locational signals are sharpened by a change in the configuration of bidding zones ▪ The relative influence of price signals compared with other factors ▪ The distributional effect on new investment in generation ▪ The wider investment climate
MARKET POWER	▪ The number of market players and degree of market power in markets of different timeframes ▪ Incentives for investment and bidding behaviour resulting from network constraints ▪ Market power in re-dispatch
CROSS-BORDER FLOWS	▪ The effect on price signals for efficient use of existing interconnection capacity ▪ The effect of the configuration of bidding zones on incentives for new interconnector investment

Ofgem, Bidding zones literature review, 2014

4. Market-zone review

Conclusions on impact on liquidity

We have assessed the likely effect on liquidity metrics for the alternative configurations based on identified historic relationship between market characteristics and liquidity metrics.

Countries	ACER identifier	Market concentration	Price correlation	Market size	Assessment of liquidity metrics of short-term markets	Assessment of liquidity metrics of long-term markets
Sweden	8	Mostly decreasing	Decreasing, but only to a small extent	Mostly increasing	Tendency to **improvement**	Tendency to **improvement**
Sweden	9	Mostly decreasing	Decreasing, but only to a small extent	Mostly increasing	Tendency to **improvement**	Tendency to **improvement**
Sweden	10	Mostly decreasing	Mostly decreasing, but only to small extent	Decreasing	Tendency to **impairment**	Tendency to **impairment**
Sweden	11	Limited change	Decreasing, but only to small extent	Two-sided	**Inconclusive** due to limited changes in market characteristics	**Inconclusive** due to limited changes in market characteristic
Germany; Luxembourg	2	Mostly decreasing	Mostly increasing, but only to a small extent	Decreasing	Tendency to **impairment**	Tendency to **impairment**
Germany; Luxembourg	12	Mostly decreasing	Mostly increasing, but partially to a small extent	Decreasing	Tendency to **impairment**, with potential exceptions for a subset of BZs due to potentially offsetting changes	Tendency to **impairment**
Germany; Luxembourg	13	Mostly decreasing	Mostly increasing	Decreasing	Tendency to **impairment**, with potential exceptions for a subset of BZs due to potentially offsetting changes	Tendency to **impairment**
Germany; Luxembourg	14	Mostly decreasing	Mostly increasing	Decreasing	Tendency to **impairment**, with potential exceptions for a subset of BZs due to potentially offsetting changes	Tendency to **impairment**
France	5	Mostly decreasing	Increasing	Decreasing	**Inconclusive** due to potentially offsetting changes	Tendency to **impairment** in line with market size changes
Northern Italy	6	Mostly decreasing	Two-sided	Decreasing	Tendency to **impairment**	Tendency to **impairment**
Netherlands	7	Decreasing	Increasing, but only to a small extent	Decreasing	Tendency to **impairment**	Tendency to **impairment**

Note: The BZ liquidity and its metrics materialising after a BZ reconfigurations may significantly differ from the expectations formed in a "ceteris paribus" analysis such as this one.

- Market size **decreases** for most BZs reconfigurations.
- Market concentration as measured by the simulated HHI and RSI is **decreasing** in most cases or at least remains below critical levels such as RSI values below 1.
- Price correlation tends to **increase** for the reconfigured BZs.

COMPASS LEXECON entsoe

5. Investing in grid capacity

Burgholzer and Auer (2016) estimated the costs and benefits of grid extension in Austria to support the further integration of renewables

B. Burgholzer, H. Auer / Renewable Energy 97 (2016) 189–196

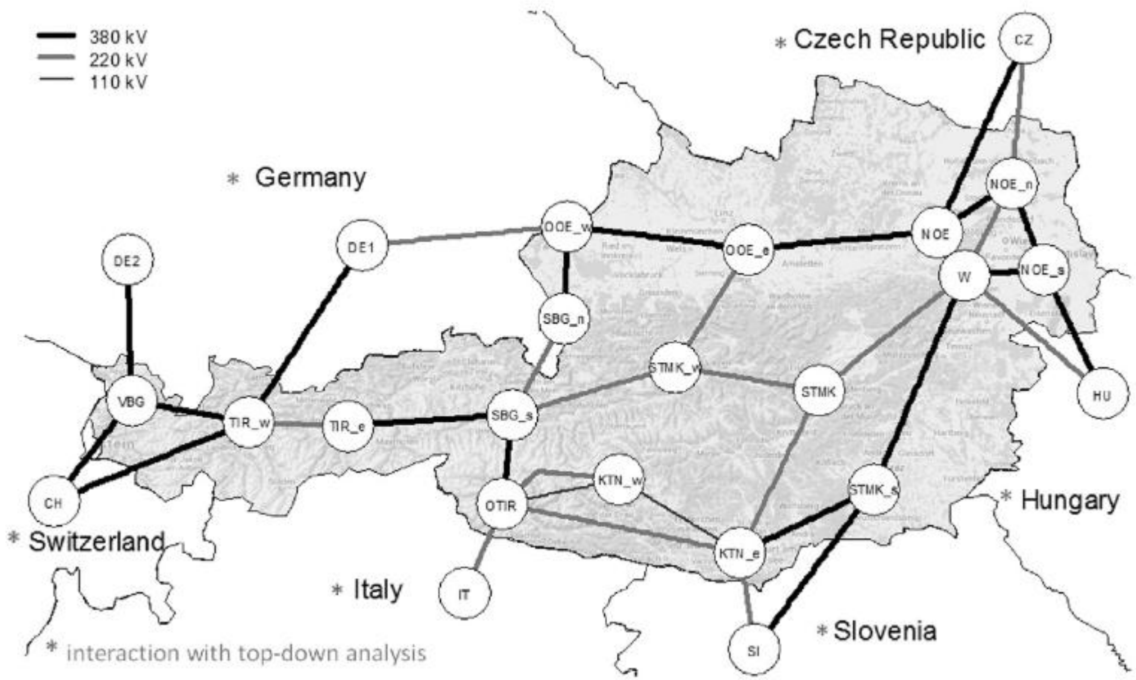


Fig. 1. Austrian transmission grid model for the year 2020.

Source: Burgholzer and Auer, Cost-benefit analysis of transmission grid expansion to enable further integration of renewable electricity generation in Austria, Renewable Energy 97 (2016)

5. Investing in grid capacity

194 B. Burgholzer, H. Auer / Renewable Energy 97 (2016) 189–196

Table 1
Key indicators.

Benefit/Aspect	Explanation of the key indicators	Parameters
Social welfare increase	Ability of a power system to reduce congestion as a basis for an efficient market	Welfare, producer and consumer surplus, congestion rents
System reliability	Adequate and secure supply of electricity	NSE, load factors of power lines and generation capacity margins
CO_2 emissions reduction	CO_2 emissions in the power system	CO_2 emissions
RES-E spillage reduction	Reduce RES-E curtailed energy	$Spill^{Hy}$,$Spill^{WindPV}$
Controllability & flexibility	Possibility to control power flows and different possible future development paths or scenarios	Type of grid technology
Socio-environmental impact	Public acceptance and environmental impact	Type of expanded power line

5. Investing in grid capacity

Conclusions:

- expansions of the transmission power lines (from 220 kV to 380 kV) in Salzurg and Carinthia are important to guarantee transmission adequacy in Austria up to 2030
- the future 380 kV circuit is crucial for both the national and European integration of RES
- innovative transmission technologies can reduce RES curtailment

Table 5
Key indicators for 2050 cases.

Benefit/aspect	Social welfare increase	System reliability	CO_2 emissions reduction	RES-E spillage reduction	Controllability &flexibility	Socio-environmental impact
(2050 A) Base	0	0	0	0	0	0
(2050 D) FACTS & DLR	++	+	+	++	++	0
(2050 F) High PHS, FACTS & DLR	++	+	+	++	++	−
(2050 r) −33.3% RoR	0	0	0	0	0	0
(2050 SK) HVDC SK-AT	0	0	++	+	+	−

Scenarios for grid expansion

Conclusions

1. Treating grid capacity more as an economic good, i.e. pricing scarcity, improves efficiency of electricity system

2. Capacity mechanisms have several caveats compared to energy-only markets… if implemented a concise one is preferred

3. Market-zone review has many consequences which are not easy to oversee

4. Societal benefits of extending the grid strongly likely exceed the costs