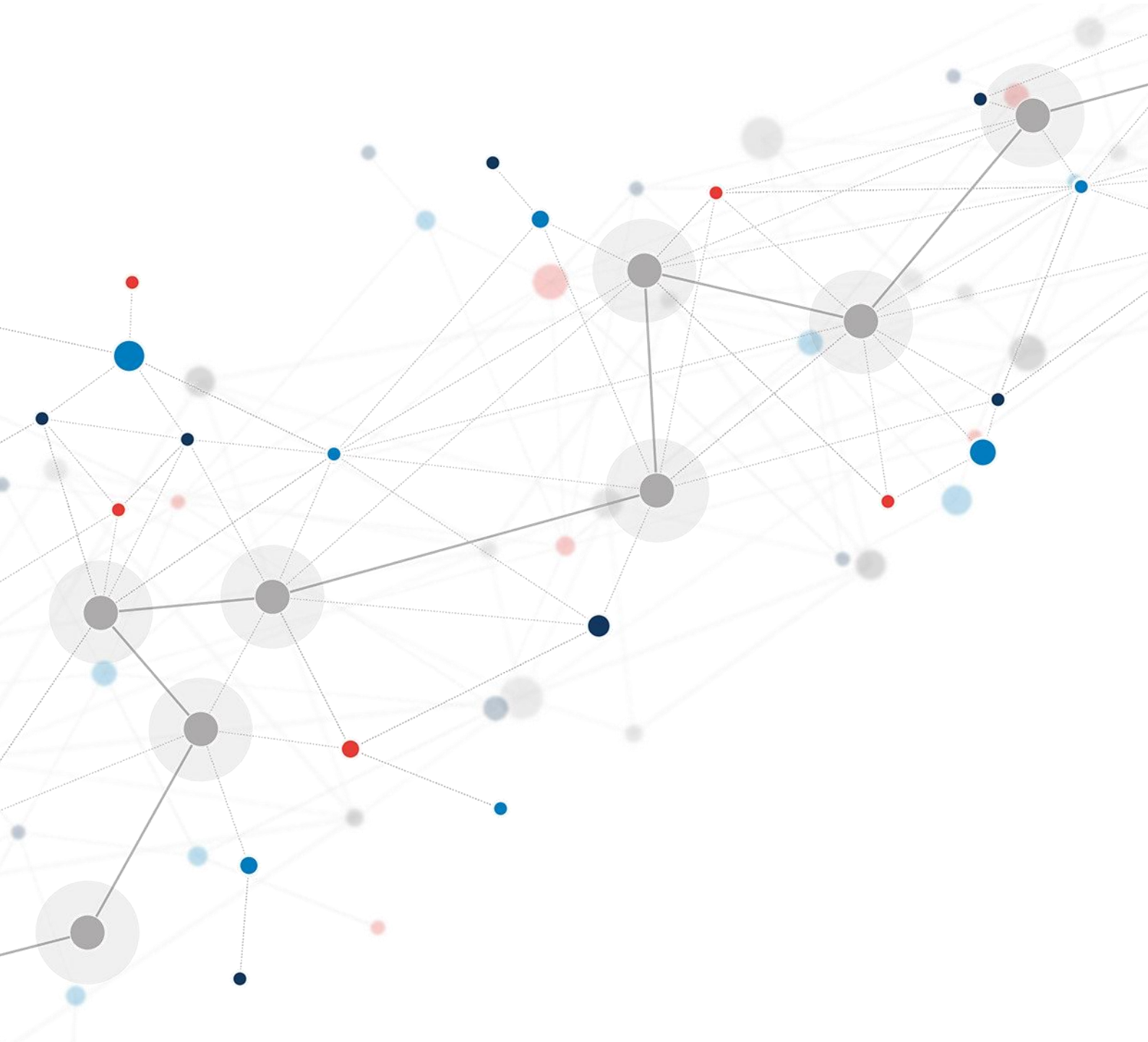
COMPASS LEXECON

Electricity costs of energy intensive industries in Norway: a comparison with selected countries

Final report

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14 October 2026



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1 Executive summary

1 Norway has historically benefitted from one of the most competitive industrial electricity price in Europe. But the energy crises in 2022 triggered by Russia's invasion of Ukraine, and the ongoing conflict in the Middle East caused electricity prices to rise above pre-COVID-19 levels across Europe and EEA countries. Combined with Chinese industrial overcapacity and US border tariffs, this has raised concerns about the international competitiveness of Norwegian and EU and EEA manufacturing industries.

2 In parallel, the EU and Norway have in recent years substantially stepped-up decarbonisation and renewable deployment targets, such that their electricity sectors are undergoing deep structural changes, with increased penetration of variable renewable electricity sources (RES-E). In 2021 and 2022, Norway has been further integrated in the European electricity market through the implementation of the third energy market package and commissioning of two new interconnectors to the UK and Germany.

3 This report assesses the competitiveness of electricity costs for electricity-intensive industries in Norway relative to a selected group of relevant international benchmark jurisdictions (France, Germany, Texas/ERCOT, the United Arab Emirates, South Korea and the province of Shandong in China). Those regions are important for energy intensive industries, and they present a range of electricity market designs, industrial structures, generation mixes and positions in global industrial value chains. The report considers how electricity markets are organised, the drivers currently shaping electricity prices in each jurisdiction, their competitiveness in terms of industrial retail rates and how this may evolve through to 2035.

4 Industrial electricity retail rates are analysed in this report as the sum of three key components: energy purchase cost, network and system costs, and taxes and levies. Additional support schemes that may limit electricity retail costs for some industrial consumers (e.g., Indirect Carbon Cost Compensation) are treated separately as sensitivity analyses, acknowledging that not all industrial sectors may be eligible.

5 To enable cross-regional comparison, a standardised industrial consumer consumption profile is used for our analysis: a manufacturing industry plant connected to the high voltage transmission grid (typically 63–350 kV, most commonly 110 kV), not owning its own generation assets, with annual consumption exceeding 10 GWh/year and a utilisation rate of 80% (baseload consumption profile). The findings presented in this report are thus specific to the assumptions made and could be different for another type of consumer consumption profile.

Norway’s retail electricity rates benefit from some decisive competitive advantages associated with the structural features of its power system

6 Norway is part of the broader European integrated electricity market. Norway has 17 transmission lines or subsea interconnectors to neighbouring countries with a total exchange capacity of approximately 9,000MW, representing 23% of installed generation capacity in 2024.

7 Currently, Norway ranks among the most competitive jurisdictions globally for electricity-intensive industries. Industrial electricity costs for a benchmark baseload consumer are approximately €42/MWh in 2025, compared to an average of ~€66/MWh across the benchmarked jurisdictions.

Norwegian retail rates for the benchmarked industrial consumer profile rank second most competitive among all selected regions, behind only ERCOT/Texas at ~€36/MWh.

8 This advantage has been consistent over time: the key findings from a 2016 Fraunhofer benchmark report[1] remain valid in 2025, confirming Norway's structural, long-term cost competitiveness relying on structural features of its electricity system including:

- Hydropower dominance: Hydropower accounted for 89% of total generation in 2024 (140 TWh), with wind at 9% and conventional fossil fuels at just 2%.
- Reservoir flexibility: Norway holds 87 TWh in reservoir storage capacity, providing a significant buffer against supply scarcity and supporting price stability.
- Net export position: Norway has been a net exporter every year since 2010 (except 2019), exporting a net 18.4 TWh in 2024 and reaching a historically high power surplus of ~23 TWh in 2025.
- Low network costs: Structural drivers include high hydropower availability reducing balancing costs, large reservoir storage, high congestion revenues offsetting some of the network costs, and a market framework comprising five bidding zones limiting internal congestion.

9 At the same time, Norway implemented an Indirect CO2 cost compensation scheme compensating electricity-intensive industries for carbon costs embedded in electricity price. Further, Norway increased its level of integration in the European electricity market through the implementation of the third energy market package and the commissioning of two new interconnectors, to Germany in 2021 and to the United-Kingdom in 2022.

10 In Norway, long-term contracts and hedging opportunities for industrial customers primarily comprise futures/forward products and PPAs (*Kraftavtaler*) alongside the Energy Purchase Guarantee Scheme — a public guarantee complementary to PPAs that reduces counterparty risk.

11 In our cross-country analysis, average day-ahead market prices are used as a proxy for electricity procurement costs embedded in large power consumers' bills, to enable the comparative analysis of selected benchmark areas.

12 The benchmark highlights the role of both domestic low-cost resources and policy choices in providing competitive industrial electricity rates over the 2015-25 period. Regions benefiting from abundant domestic energy resources tend to exhibit the lowest electricity procurement costs, although regions with less favourable resource endowments can also feature competitive retail rates through specific policies and market designs choices:

- Norway and ERCOT/Texas are the two jurisdictions combining low-cost energy resources with competitive procurement costs — hydropower in Norway, domestic gas in Texas. Norway's increased European market integration does not seem to have weakened the competitiveness of its power rates for electricity-intensive industries.
- France benefits from a predominantly low-carbon generation mix, dominated by nuclear power, complemented by a range of measures supporting electricity-intensive industries, such as network costs and taxes exemptions as well as a state aid for indirect CO2 cost compensation.

[1] Fraunhofer Institute for Systems and Innovation Research (2016). Electricity Costs of Energy Intensive Industries An International Comparison.

- Germany features higher costs as wholesale electricity prices remain influenced by substantial investment needs and a dependence on imported fossil fuels, that network cost rebates, tax exemptions and state aid for indirect CO2 cost compensations cannot fully offset.
- In Asia, South Korea and Shandong province in China illustrate alternative power sector organisation models leveraging domestic generation resources and relying on regulated pricing arrangements and industrial policy measures to ensure competitive rates for industrial consumers.
- The United Arab Emirates boast relatively competitive industrial tariffs thanks to abundant domestic gas resources and a vertically integrated, state-dominated electricity sector that maintains relatively low end-user tariffs.

Flexible power demand valuation opportunities can complement competitive electricity rates with additional revenues streams for industrials with flexibility capabilities

13 In addition to competitive industrial power retail rates, Norway's electricity markets provide a framework for industrial demand-side flexibility monetisation, which can reduce the total energy bill.

14 Where an industrial plant has the technical and economic capability to curtail or shift part of its load, it may derive additional value through participation in power markets, reserve products, demand-response programmes or local flexibility mechanisms. These revenues, where available, partially offset electricity procurement costs. The size of the opportunity varies significantly across jurisdictions

15 In Norway, industrial consumers can access four market routes to earn revenues associated with the electricity consumption flexibility: wholesale market optimisation, reserve and balancing products (FCR, aFRR, mFRR, FFR), and local flexibility markets. Indicative annual revenue ranges for 1 MW of flexible industrial load are: FCR €10k–50k/MW/year, aFRR €15k–80k/MW/year, mFRR €5k–40k/MW/year, and reserve capacity/local flexibility up to €10k–120k/MW/year for the period 2015-25.

16 Demand-side flexibility opportunities differ significantly across the benchmarked regions. Norway, France and Texas appear to provide the clearest monetisation routes for industrial users, supported by relatively mature wholesale, reserve, capacity or demand-response mechanisms. Germany and South Korea provide moderate opportunities, although access is more product-specific or programme-led. The United Arab Emirates and Shandong in China remain lower-maturity markets from a monetisation perspective, with evidence of policy development, pilots or demand-response programmes, but more limited public price transparency.

By 2035, Norway's industrial power rates could remain competitive with continued development of low-carbon generation

17 Looking ahead, Norway could remain among the most competitive jurisdictions assessed in 2035. Under the assumptions adopted in this study based on reference third party sources[2], industrial retail electricity prices in Norway are projected to remain within a range of approximately €41-50/MWh. Norway's prices would remain lower than in France (€47–57/MWh), Germany (€56–68/MWh), the UAE (€68–83/MWh), and Shandong (€73–89/MWh), and broadly comparable to those in ERCOT (€50–62/MWh).

[2] These include NVE projections and Stattnet's 2025 long term market analysis.

18 This outlook depends on some critical assumptions, and our analysis identifies some the uncertainties and risks associated with the ongoing changes in Norway's electricity sector:

- Norway's onshore wind development has stalled in recent years due to permitting issues, and public opposition.
- Offshore wind development has been slower than onshore wind, complicated by cross-border coordination and permitting procedures.
- Hydroelectricity generation faces increasing unavailability risks and higher water values due to more frequent drought and low rainfall periods. The potential due to environmental concerns is very limited.
- Statnett's System Development Plan 2025 foresees transmission grid investments of NOK 150–200 billion by 2035, substantially higher than the approximately NOK 92 billion invested during 2014–2024, potentially creating upward pressure on future network tariffs.
- The indirect CO_2 cost compensation State Aid is set to stop in 2030, with uncertainty regarding its renewal.

19 In particular, the projection assumes electricity demand and generation capacity development broadly in line with the *NVE Langsiktig kraftmarkedsanalyse 2025* (Basis/B2035 scenario) and Statnett's Long-term Market Analysis 2025 (Medium scenario). Under these assumptions, total Norwegian electricity demand will reach approximately 181 TWh in 2035 and installed generation capacity grow from ~41 GW to ~55 GW, driven primarily by 4.7 GW solar and 3.9 GW wind additions between 2026 and 2035, well above recent historical deployment rates.

Key take aways from the international benchmark to maintain competitive retail electricity rates

20 Across Europe and globally, policymakers are facing similar questions regarding the interaction between growing electricity demand, industrial competitiveness, generation development and network expansion. International experience therefore provides useful insights into a number of potential policies that may help address these challenges.

1: Address barriers to the timely development of a generation mix and network adapted to the expected growth in demand

21 One of the key risks faced by the Norwegian power system is that electricity demand growth is not matched by timely additions in generation capacity and flexibility assets, creating scarcity and thereby increasingly importing power prices volatility from interconnected countries:

- Given the uncertainty surrounding the pace of industrial electrification and data-centre developments, continued monitoring of demand growth and regular long-term system planning exercises may help ensure that network and generation investments develop in line with evolving needs.
- International experience suggests that streamlined permitting and connection processes can help facilitate the timely deployment of generation, storage and network infrastructure where these become necessary to meet demand growth.
- Onshore wind has a large potential in Norway and offshore wind may play an increasing role if projects develop as planned. Should merchant revenues prove insufficient to support the investment levels required to maintain adequacy, international experience provides examples of mechanisms that can reduce investment risks and support the deployment of additional

capacity. Whether such mechanisms are needed and desirable in Norway would depend on future market developments and investment outcomes, as of today, the biggest hurdle remains permitting procedures.

2: Foster efficient network development and utilisation

22 Given the projected increase in electricity demand and network utilisation requirements in Norway, international experience highlights several technical and regulatory approaches that can improve the use of existing assets and support efficient network development. Some international practices derived from the benchmark include:

- Harnessing innovative grid-enhancing technologies can increase the utilisation of existing network assets and defer or reduce the need for network reinforcement. For instance, Italy has introduced output-based regulation for the TSO Terna that contributed to the adoption of Dynamic Line Rating increasing internal transfer capacity between bidding zones.
- Making better use of flexibility resources can help accommodate growing demand while limiting the need for network expansion. For instance, in the UK, commercial flexibility is explicitly included in the cost-benefit analysis used by NESO to identify the most advantageous network development solutions.
- Some countries have implemented industrial policies involving targeted subsidies for transmission system operators transferring costs borne by electricity consumers to taxpayers. For instance, Germany has introduced State aid for the four TSOs to partially cover their transmission-network costs, reducing network tariffs by circa 50% for 2026.

3: Specific mechanisms targeted at electricity-intensive industrials potentially involving state aid

23 Finally, the benchmark provides examples of specific mechanisms which have been introduced in different European countries to limit electricity rates for electricity-intensive industrials such as:

- The continuation of the indirect CO2 cost compensation mechanisms post-2030 has been and remains a powerful tool to compensate industrial sectors at risk of indirect carbon leakage from carbon costs embedded in electricity prices. A clarification of its application towards 2035 remains essential for predictability.
- State aid for industrial electricity rates akin to the Clean Industrial Deal State Aid Framework (CISAF) of the European Union that could allow for temporary price relief for selected sectors and under strict conditions of eligibility, price impact and duration.

24 To conclude, Norway has structural competitive advantages in its power system, but the evolution of electricity retail costs will depend on the timely development of new generation capacity, flexibility assets, and network infrastructure alongside growing electricity demand, as well as policy and costs allocation choices that can support the competitiveness of industrial electricity rates. The continuation of a CO2-compensation mechanism remains essential for predictability for the industry.

2 Introduction

2.1 Context

With the Green Deal, the EU has pledged to become climate-neutral by 2050. This pledge was formalised in 2021 by the European Climate Law (Regulation 2021/1119) which sets Greenhouse Gas (GHG) emission reduction targets for 2030 and 2050. Similarly, Norway has entrenched in its Climate Law, a reduction of 55% of GHG emissions by 2030 compared to 1990 levels[3], as well as a transition to a low-carbon economy by 2050 with a 90-95% reduction in emissions.

The energy crisis in 2022 triggered by Russia's invasion of Ukraine, and the ongoing conflict in the Middle East caused electricity prices to rise above pre-COVID-19 levels across Europe and EEA countries. In parallel, the EU and Norway have in recent years substantially stepped-up decarbonisation and renewable deployment targets, such that their electricity sectors are undergoing deep structural changes, with increased penetration of variable renewable electricity sources (RES-E). Consequently, the power systems also saw a gradual phasing out of fossil-fuelled thermal power plants.

Nevertheless, thermal power plants remain crucial to the current electricity system and are setting electricity prices directly or indirectly a significant portion of the time (e.g. through storage units bidding based on opportunity costs). This is expected to continue with a gradual decoupling in some EU countries over the next decade, affecting price formation in Norway as the country is highly interconnected with other European countries. As a result of the series of energy crises in recent years, first with the invasion of Ukraine by Russia and second, with the conflict in Iran, electricity prices have increased compared to pre-COVID-19 levels almost everywhere in Europe and EEA countries.

Combined with broader economic and geopolitical issues, rising energy prices have raised concerns about the international competitiveness of EU and EEA manufacturing industries. As a result, industrial competitiveness has become a major focal point for policy making. In particular, recent European Commission initiatives comprised the Draghi report on the Future of European Competitiveness (European Commission, 2024), the EU's Competitiveness Compass (European Commission, 2025a), the first Omnibus simplification package (European Commission, 2025b), and the Action Plan on Steel and Metals (European Commission, 2025c) amongst others.

The regulatory framework both at EU and national level to enhance the competitiveness of electricity for industrial users has been relying on a range of measures to moderate electricity costs for large industries considered as highly electro-intensive. Measures to decrease electricity costs for industrials include contractual mechanisms to purchase electricity for long periods of time, rebates on network charges and/or levies funding RES-E support mechanisms, tax credits or compensation for indirect carbon costs. In addition to such policy measures, structural features of national power systems can also play an important role in determining wholesale electricity price levels. Norway has historically had comparatively low electricity prices, reflecting in part its

[3] Norway's target of reducing GHG emissions by at least 55% by 2030 compared to 1990 levels is intended to be achieved in cooperation with the European Union under the framework for joint fulfilment of climate commitments, aligning Norway's climate policy with the EU's climate and energy legislation.

abundant hydropower resources and generation mix, making electricity prices more affordable to both households and power intensive industries.

2.2 Objectives and mandate

This report follows a previous report by the Fraunhofer Institute for Systems and Innovation Research and Ecofys GmbH Germany published in 2016.[4] The 2016 report compared electricity costs of energy-intensive industries in Norway with a selection of countries including Germany, the Netherlands, the United-Kingdom, France, Italy, Denmark, South Korea, Japan, the USA with Texas, Pennsylvania and California, and China.

Fornybar Norge mandated Compass Lexecon to assess large energy user power prices in Norway and how they compare to selected jurisdictions. The objective is to provide Fornybar Norge with an understanding of current levels and drivers of industrial retail rates for power in the EU, North America, Asia and the Middle East, and their changes since 2016, as well as a projection of the same in 2035.

More precisely, we analyse the evolution of retail electricity costs for industrials since 2016 in a range of jurisdictions, and assess how they have developed up until 2025, based on the latest publicly available data. In addition, this report explores flexibility opportunities and provides a projection of electricity retail costs in 2035. Through this benchmarking exercise, the report aims to assess Norway's competitive position relative to a selected group of strategically relevant international comparators occupying important positions in global industrial value chains.

The selection of benchmark jurisdictions for this report was developed in consultation with Fornybar Norge and seeks to balance continuity with the 2016 Fraunhofer study with the objective of reflecting the competitive landscape currently faced by electricity-intensive industries. Several jurisdictions included in the previous study were therefore retained as they continue to represent important reference points for industrial electricity costs and industrial competitiveness. This report analyses retail electricity costs for energy-intensive industries as of today in Norway, Germany, France, South Korea, the USA – Texas, the United Arab Emirates, and the Chinese province of Shandong. Together, these jurisdictions represent a range of electricity market designs, generation mixes, industrial structures and policy frameworks, and include several important competitors for energy-intensive industries operating in Europe.

2.3 Limitations

The benchmarking exercise is not intended to provide a comprehensive assessment of retail energy prices for energy-intensive consumers across all global industrial locations. Rather, it focuses on a selected group of jurisdictions considered particularly relevant for understanding Norway's competitive position and the broader competitiveness challenges facing European energy-intensive industries. The selected jurisdictions provide a useful basis for assessing Norway's competitiveness relative to a set of strategically relevant international comparators and for placing Norwegian electricity costs within a broader international competitiveness context.

This report focuses only on electricity procurement costs for industrial energy intensive consumers, including wholesale power prices, grid tariffs and support measures. Measures that aim to support the decarbonisation or electrification of industrial processes, such as for example Enova grants in Norway, are not considered in this analysis. While such measures may increase

[4] Fraunhofer Institute for Systems and Innovation Research (2016). Electricity Costs of Energy Intensive Industries An International Comparison.

electricity consumption, and total power expenditure, they can improve energy efficiency and reduce power procurement costs per unit of industrial output. They do not directly reduce electricity prices and may, in some cases, contribute to higher system-wide electricity demand. Although their impact can be significant, it has not been included in our analysis.

Finally, the analysis presented in this report relies on a range of data and sources. We have not independently verified these data. Similarly, the prospective analysis of the evolution of power prices is based on a series of assumptions, and different assumptions would lead to different projections of prices.

2.4 Structure of the report

This report comprises six chapters: this introduction (**Section 1**), a description of the Norwegian electricity market (**Section 2**), a description of the electricity markets in the six other chosen regions (**Section 3**), a comparison of retail price components between Norway and the other studied regions (**Section 4**), a high-level review of flexibility opportunities for energy-intensive industries (**Section 5**), a projection of electricity retail prices up to 2035 (**Section 6**), and conclusions (**Section 7**).

3 Electricity sector and industrial power prices in Norway

This section presents some aspects of the power sector in Norway that are relevant to understand the drivers of electricity costs for electro-intensive industries. In particular, we detail successively the organisation of the sector and the sequence of markets for trading electricity in Norway, the country's historical generation mix and power demand, the structure of its power network, and the regulatory framework and main energy policies in place.

3.1 Sector and market organisation

3.1.1 Sectoral organisation and main stakeholders

Like in most EU Member states, the electricity sector in Norway went through a period of liberalisation and unbundling in the 1990s – 2000s. Both generation and retail activities were liberalised through the Energy Act, which introduced market-based power trading in 1991 and opened the retail the retail market to competition.[5]

Despite considerable public ownership of hydropower plants,[6] generation and retail supply tend to be competitive, while the transmission and distribution systems infrastructure operates under a regulated regime of natural monopoly, as in most other economies in EU and abroad.

The main electricity sector stakeholders include:

- The **Ministry of Energy**, which is responsible for the overall management of the country's energy resources, including electricity, hydropower, and petroleum. It is supported by several key public bodies as the Norwegian Water Resources and Energy Directorate (NVE), the Ministry of Climate and Environment, and Enova (which provides support with investment subsidies).[7] The Ministry is also the owner of Statnett, Norway's transmission system operator.
- ***Reguleringsmyndigheten for energi*** (RME), the regulator for energy, which is responsible for regulating and supervising the electricity and gas markets. RME operates as part of the Norwegian Water Resources and Energy Directorate (NVE) and oversees network regulation market access, transmission and distribution tariff methodologies, transparency and market oversight, metering issues, settlement of energy related disputes.[8]
- **Publicly owned power producers**, including companies owned by municipalities, counties and the Norwegian State, which collectively own around 80% of Norway's electricity production capacity. Public ownership is strong in hydropower, where around 88% of production is

5 Ministry of Energy (1990) Energy Act (link)

6 Energy Facts Norway (2026) Ownership in the energy sector (link)

7 NVE, About NVE (link)

8 RME, The Norwegian Energy Regulatory Authority (link)

publicly owned. Private and foreign ownership is more significant in wind power, where only around 42% of capacity is publicly owned and around half is owned by foreign investors;[9]

- **Statnett**, the state-owned transmission system operator (TSO), which owns and operates the Norwegian transmission grid, manages system operation and security of supply, and is responsible for the country's interconnections with neighbouring power systems;
- The state-owned company **Statkraft SF**, which owns around 35% of generation capacity and is Norway's largest power producer and Europe's largest producer of renewable energy.[10]

3.1.2 Market organisation

The Norwegian wholesale electricity market is divided into five bidding zones organised within the wider Nordic power market and is an integral part of the interconnected European power system and coupled markets. Producers, suppliers and large consumers trade electricity through organised exchanges as well as through bilateral contracts.[11]

Integrated in the broader interconnected European power system since 2014, Norway is coupled with other European markets through the Single Day-Ahead Coupling (SDAC) and the Single Intraday-Coupling (SIDC), which relies on the Price Coupling of Regions (a single pan European cross zonal electricity market).[12,13,14]

The Norwegian wholesale electricity market comprises the sequence of forward, day-ahead, intraday, balancing markets and imbalance settlement mechanism found in other European countries:

- Ahead of physical delivery, market participants can hedge their exposure to spot price volatility through financial forward and futures markets. Nordic power derivatives are traded on platforms such as EEX and Euronext Nord Pool Power Futures.
- The day-ahead market is the reference market for physical electricity trading.[15] In the Nordic region, day-ahead trading is operated by power exchanges such as Nord Pool and EPEX SPOT.
- After the day-ahead auction, participants can adjust their positions in the intraday market.[16]
- In real time, Statnett, as the Norwegian TSO, is responsible for maintaining system balance and operational security.[17]

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9 NVE, Ownership of Power Plants (link)

10 Energy Facts Norway (2026) Ownership in the energy sector (link)

11 Nord Pool, Bidding areas (link)

12 Nord Pool, Single Day-Ahead Coupling (SDAC) (link)

13 Nord Pool, Single intraday Coupling (SIDC) (link)

14 Nord Pool, Price Coupling of Regions (PCR) (link)

15 Day-ahead trading closes at 12:00 CET for delivery during the following day. Market participants submit hourly purchase and sale bids, and prices are calculated through an implicit auction that takes into account available cross-zonal transmission capacity and physical grid constraints.

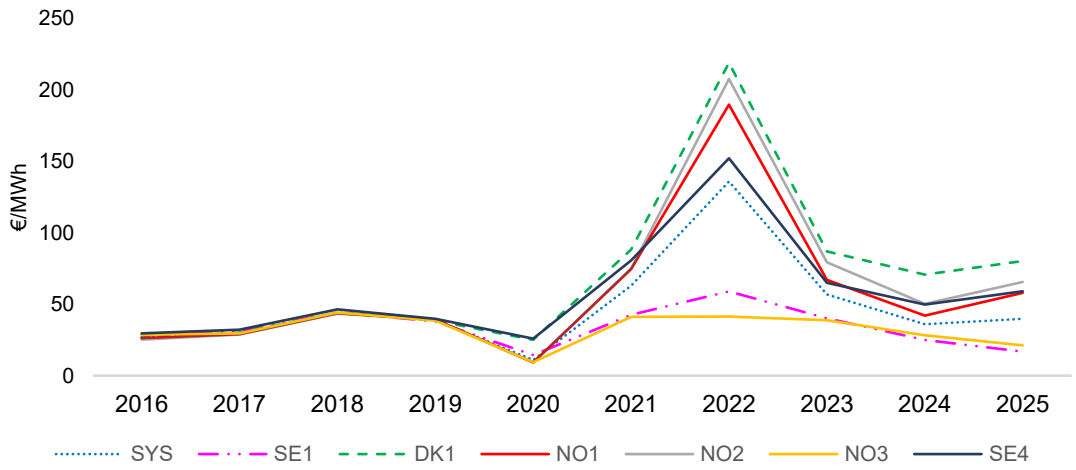
16 Intraday market functions as a correction market that enables participants to trade closer to physical delivery in order to help maintain the balance between supply and demand.

17 Balancing is coordinated within the Nordic balancing framework and relies on automatic and manual reserves, including aFRR and mFRR, which are activated by the Nordic TSOs when deviations arise between scheduled and actual generation or consumption (a transition to a 15-minute imbalance settlement and market time units has been led to improve the ability of the Nordic system to balance a more renewable and variable power mix).

- Finally, deviations after delivery are financially settled through the Nordic Imbalance Settlement system, operated by eSett.[18,19]

Price differences between the 5 bidding zones occur when transmission capacity between the areas is insufficient to equalise prices through the market coupling algorithm. Over the last 10 years, spot prices remained relatively stable across the region until 2019 but increased since 2020 in some bidding zones. The commissioning of new interconnectors increased export capacity and contributed to the convergence of spot price formation with other European markets.[20] Figure 1 below provides an overview of the developments of average spot prices for three Norwegian bidding zones (NO1, NO2 and NO3), two Swedish ones (SE1, SE4), a Danish (DK1) and the Nordic System Price (SYS)[21] over the 2016-2025 period.

Figure 1: El spot prices on NordPool, from 2016 to 2025 (€/MWh, nominal prices)



Notes: Three bidding zones are selected among five to keep the figure clearly readable.
Source: Compass Lexecon analysis based on data from Nord Pool (2026).

Norway is interconnected with neighbouring Nordic countries and with continental Europe and the UK. Norway currently has 17 transmission lines or subsea interconnectors to other countries. The total exchange capacity with foreign countries is now approximately 9,000 MW. This capacity is distributed mainly between Sweden (around 4 GW), Denmark (around 1.6 GW), Germany (1.4 GW), the United Kingdom (1.4 GW), and the Netherlands (0.7 GW). Norway also has a connection to Finland in the North, while the former connection between Kirkenes and the Boris Gleb power plant in Russia is currently inactive. There are currently no firm plans for new conventional Norwegian interconnectors. Instead, Statnett is evaluating potential hybrid interconnector projects linked to North Sea offshore wind with partners in Belgium, Germany and Denmark, but these remain at the feasibility stage and would only materialise in the 2030s if approved.[22]

18 Each balance responsible party is financially liable for the difference between its market trades, bilateral contracts, realised generation and consumption. The purpose of imbalance settlement is therefore to restore financial balance after the operating hour and to allocate the cost of balancing actions to the parties responsible for imbalances.

19 eSett, About eSett (link)

20 Bjørndal, E., Bjørndal, M., Hovdahl, I., & Tselika, K. (2026), « European market integration and price convergence: A panel quantile regression analysis of NordLink », Energy Economics. (link)

21 The Nordic system price is a reference price for trading and clearing most financial contracts and is used for electricity supply as well.

22 Statnett (2025) Interconnectors (link)

In 2024, Norway exported 33.1 TWh of electricity and imported 14.7 TWh, resulting in a net export of 18.4 TWh. The country has been a net exporter of electricity every year since 2010 (except for 2019), although imports remain important in dry years or periods of low reservoir levels because Norway's power system is heavily hydropower-based.[23] Norway reached a historically high power surplus of around 23 TWh in 2025. The share of interconnection capacity over total installed generation capacity was 23 % in Norway in 2024.[24]

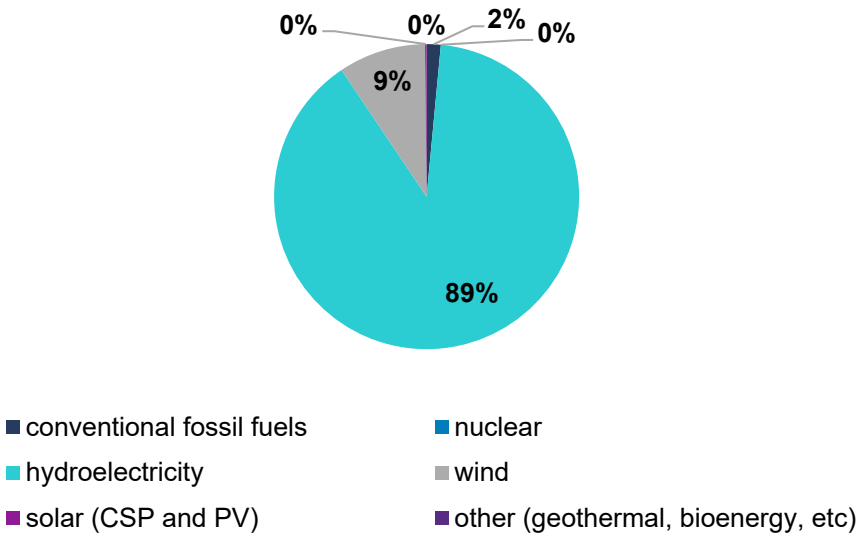
Norway's adequacy outlook does not identify major issues, supported by substantial hydropower reservoir storage, flexible generation capacity and access to cross-border electricity trade. [25] Norway does not operate a dedicated capacity remuneration mechanism (CRM), relying instead on market-based arrangements to attract new investment.

3.2 Generation mix and power consumption

The electricity mix of Norway is almost fully decarbonised. In 2024, 140 TWh were produced by hydropower – by far the largest source of electricity in Norway, 14.5 TWh by wind, 2.3 TWh by conventional fossil fuels and 0.3 TWh by solar. Generation has been relatively stable in Norway between 2016 and 2024, fluctuating between 134.6 TWh (2019) and 157.2 TWh (2024). In 2024, total gross electricity generation in Norway was 157.2 TWh and the country has 87 TW in reservoir capacity,[26] representing a valuable buffer in scarcity situations. However, the generation mix of Norway is strongly dependent on weather conditions, with dry years threatening hydropower generation and requiring larger shares of conventional fossil-fuelled generation.

Figure 2 shows generation shares for each source in Norway in 2024. Hydroelectricity dominates the generation mix with an 89 % share of the total electricity generation in 2024.

Figure 2: Norwegian generation mix in 2024 (%)



Source: Compass Lexecon analysis based on data from Statistics Norway (2026).

23 EnergiFaktaNorge, The Power Market (link)

24 We consider goals set by the European Commission to analyse interconnectivity with neighbouring countries. European Commission has set a 10% electricity interconnection target for 2020 (interconnection capacity/total installed generation capacity) and extended this figure up to 15% by 2030.

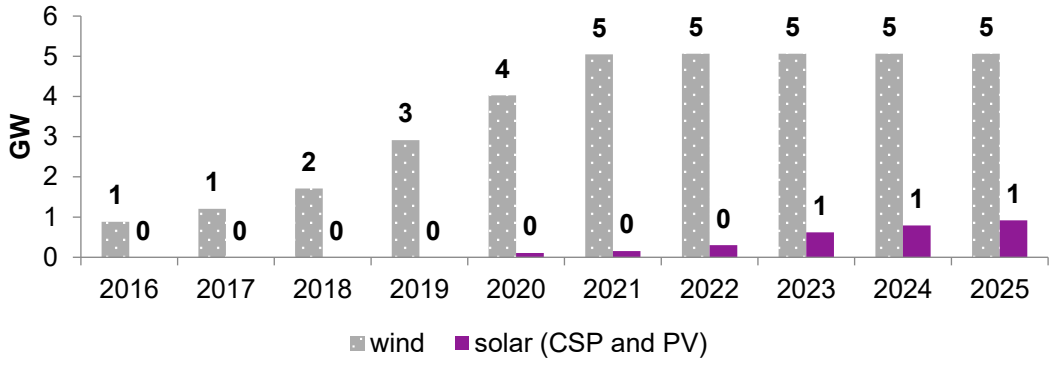
25 Energy Facts Norway; Security of Electricity Supply (link)

26 Energy facts Norway, Electricity Production (link)

Norway has been supporting the development of renewable electricity sources through dedicated regulatory mechanisms. Due to its high wind resources, NVE projected reaching 25 TWh of onshore wind production by 2030.[27] However, wind development has stalled due to public opposition.[28] Almost no additional capacity was connected to the grid since 2021. Additional capacity development is hampered by strict permitting rules and procedures, whereby municipalities can refuse the construction of wind turbines on their territory. Additionally, public opposition to onshore wind (also known as Not In My Backyard - NIMBY effect) is amongst the highest in Europe – a 2025 survey highlights that 60 % of the population is mostly against onshore wind development at a local level.[29]

Figure 3 below shows installed wind and solar capacities in Norway between 2016 and 2025. Wind capacity increased by 4,180 MW over the period, almost only offshore wind. Solar capacity increased by 918 MW over the same period.

Figure 3: Cumulated installed onshore wind and solar capacity in Norway since 2016 (GW)



Source: Compass Lexecon analysis based on data from Statistics Norway (2026).

Over the same period, conventional fossil fuels capacity decreased by 508 MW (2025: 600 MW) and hydroelectricity capacity increased by 2,849 MW (2025: 34,666 MW).

On the demand side, gross electricity consumption has been relatively stable over the past 9 years ranging between 133.1 TWh (2016) and 139.5 TWh (2024). The increase of consumption driven by higher economic growth, population growth and electrification of new uses has been compensated by energy efficiency progress in households and buildings and a slight decline of energy-intensive industries.[30] Figure 4shows electricity consumption and breakdown of generation by energy source in Norway between 2016 and 2024. In 2024, industry (secondary) amounted to 47 % of total net consumption, households to 31 % and construction and other services sector to 22 %.

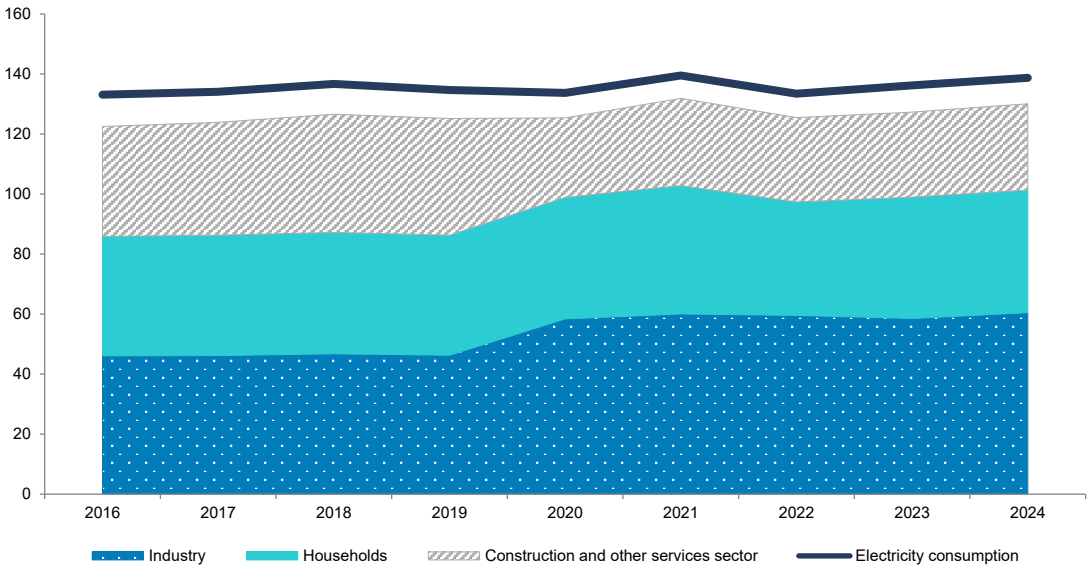
27 Noting that production stood at 4 TWh 2022 (latest information available). Source is Compass Lexecon analysis based on NVE (2018), Kraftmarkedsanalyse 2018 – 2030 (link)

28 Compass Lexecon analysis based on NVE (2026), Status og utvikling i kraftsystemet 2025-2030 (link)

29 Kraft, P., & Kraft, B. (2025), "Public attitudes and the socio-political divide surrounding onshore wind power in Norway," Frontiers in Sustainable Energy Policy (link)

30 European Environment Agency (2025), Final energy consumption (link)

Figure 4: Gross electricity consumption and net consumption breakdown by sector in Norway between 2016 and 2024 (TWh)



Note: The change observed in the consumption breakdown by sector can be explained by the change of dataset. Indeed, the Eurostat dataset includes in industry the construction sector, whereas Statistics Norway only include secondary industry in the category "industry" (the construction sector is included in the "construction and other services sector" category)
Source: Compass Lexecon analysis based on data from Statistics Norway (2026) for the 2020-2024 period, and Eurostat (2026) for the 2016-2019 period.

3.3 Network structure

The Norwegian electricity network is organised into three voltage levels: the transmission grid, the regional distribution grid and the local distribution grid. This network structure is essential in Norway because hydropower resources are often located far from consumption centres, while the system must also manage regional imbalances, weather-dependent production and cross-border electricity exchanges:

- The transmission grid is owned and operated by Statnett (a State-owned company) between 300 and 420 kV, with 83 % of the 14,000 km network made up by overhead lines. It connects large power producers, major consumers, regional grids and international interconnectors.[31,32]
- Below this level, the regional distribution is operated at 33–132 kV and covers around 19,000 km. It links the transmission grid to local distribution networks and may also connect large generators and energy-intensive consumers.[33]
- The local distribution grid supplies households, services and smaller industrial customers. It operates up to 22 kV and covers over around 101,000 km. Around 80 DSOs and grid companies own and operate Norway's regional and local distribution grids. Most regional and

31 Statnett (2026), Investor presentation (link)
32 Energy Facts Norway, The electricity grid (link)
33 Ibid.

distribution grids are owned by municipalities and county authorities, although some private ownership also exists.[34]

Importantly, the Norwegian networks benefit from a high quality of supply (99.98 % delivery rate even in challenging weather years), consistent with levels observed in central and western Europe. In 2024, the Energy Not Supplied (ENS) was 4,336.4 MWh while the System Average Interruption Frequency Index (SAIFI) was of 1.7 interruptions a year.[35,36]

Figure 5: Grid map of Norway (as of 2024)



Source: ENTSOE (2024).

Further grid reinforcements and developments are planned to accommodate increasing electricity demand, including from industrial users. Statnett has invested a total of 92 billion NOK (around 8.3 billon €) in grid (and digital projects) during the period 2014-2024. Over the next decade, Statnett plans to double these investments. In its System Development Plan 2025, Statnett has announced investments of NOK 150 bn - 200 bn (13 - 17 billion €) in the country's power grid by 2035.[37]

3.4 Regulatory framework and public policies

Over the past decade, the Norwegian energy sector has undergone a significant policy evolution, driven by increasingly ambitious climate commitments, global industrial competition and the need

34 Ibid.
35 ENTSO-E (2025), HVAC Nordic and Baltic grid disturbance statistics 2024 (link)
36 RME (2025), Operation of the Power System 2024 (link)
37 Statnett (2025), System Development Plan (link)

to reconcile the country's dual identity as both a renewable energy leader and Europe's largest hydrocarbon exporter.

First, the Climate Change Act (*Lov om klimamål*) of 2017 sets the central target for reducing greenhouse gas emissions for horizons 2030 and 2050: at least -55 % by 2030 compared to 1990 levels, followed by a long-term trajectory aimed at making Norway a "low-emission society" by 2050, with a reduction of 90 to 95 % in emissions.[38] This trajectory was reinforced by the Storing in June 2025, with the introduction of a new interim target of -70 to -75 % by 2035 compared to 1990 levels.[39] Norway intends to pursue these targets in cooperation with the European Union under the EEA framework, making use of the flexibilities available under the EU climate policy architecture. While the climate targets provide an important strategic direction for policymaking, they are not translated directly into specific power-sector targets.[40] Nevertheless, they influence a range of supply-side and demand-side energy policies aimed at decarbonisation and electrification.

On the supply side:

- The white paper *Energi til arbeid (Meld. St. 36 of 2020–2021)* does not set an overall electricity generation target in TWh, but identifies renewable electricity as the cornerstone of decarbonisation: modernisation of hydropower, grid reinforcement, development of offshore wind power and support for new low-carbon industries;[41]
- This strategy is confirmed and amplified through the Roadmap *The Green Industrial Initiative* of 2022, which sets the ambition to allocate areas for 30 GW of offshore wind by 2040;[42]
- Finally, the Roadmap 2.0 published in 2023 adds a target of 8 TWh of new solar generation by 2030.[43]

On the demand side, the Norwegian government fosters an electrification of energy uses in transport, industry and certain offshore energy applications, and the development of demand-response. For instance, in the transport sector, the National Charging Strategy of 2023 reiterates and expands upon the objectives of the National Transport Plan 2018-2029: 100 % of new passenger cars and light commercial vehicles to be zero-emission by 2025, 100 % of new heavy commercial vehicles to be zero-emission by 2030, zero-emission or biogas-powered city buses from 2025, and by 2030 75 % of new coaches as well as 50 % of new lorries using zero-emission technology.[44,45] The National Transport Plan 2025-2036, Meld. St. 14 (2023–2024), extends this approach by focusing on charging infrastructure, heavy goods vehicles, maritime transport, aviation and construction sites.[46]

Finally, the Norwegian government's strategy for the oil sector is published in the white paper *Klimamelding 2035 - Meld. St. 25 (2024–2025)*. It sets a target for emissions reduction from petroleum extraction activities (i.e. scope 1 emissions for the industry, representing currently circa 25 % of total national domestic emissions) of 50 % by 2030, primarily through electrification.[47]

38 Ministry of Climate and Environment (2018), Climate Change Act (link)
39 Ministry of Climate and Environment (2025), Norway submits its new NDC under the Paris Agreement (link)
40 Ministry of Climate and Environment (2025), link
41 Ministry of Petroleum and Energy (2021), White Paper No. 36 (2020-2021) (link)
42 Ministry of Trade, Industry and Fisheries (2022), Roadmap: The Green industrial Initiative (link)
43 Ministry of Trade, Industry and Fisheries (2022), Roadmap: The Green industrial Initiative (link)
44 Ministry of Transport (2023), National charging strategy (link)
45 Ministry of transport (2017), National Transport Plan 2018–2029 (link)
46 Ministry of Transport (2024), National Transport plan 2025-2036 (link)
47 Ministry of Climate and Environment (2025), Climate Report 2035 – Towards a Low-Emission Society (link)

4 Electricity sectors of jurisdictions selected for comparison

This section presents an overview of some aspects of the power sector that are relevant to understand the drivers on electricity retail costs for electro-intensive industries in each of the markets selected as comparables for this study. The selected jurisdictions for the comparison of industrial electricity retail rates include France, Germany, The Unites Arab Emirates, Texas in the Unites States of America, Shandong in China and South Korea. For each of those, the section provides an overview of the organisation of the sector, the country's historical generation mix and power demand, the structure and quality of its power network, and the regulatory framework and main energy policies in place.

4.1 France

4.1.1 Sector and market organisation

In France, both generation and retail activities have been liberalised since 2004. However, the electricity market is still dominated by the national company *Electricité de France* (EDF). Law 2004-803 introduced the regulatory framework defined by the European Union and, in 2010, the NOME law implemented the unbundling of production, transport, distribution and retail activities.[48,49]

Main stakeholders in the French power sector include:

- The **Ministry of Ecological Transition through the Directorate General for Energy and Climate** (DGEC), and the Ministry of Economy and Finance, jointly developing energy policies;[50]
- The French energy regulator is the ***Commission de Régulation de l'Energie*** (CRE), responsible for tariff regulation, market oversight, network access, monitoring and reporting, renewable energy promotion, compliance and enforcement;[51]
- ***Électricité de France*** (EDF), 100% publicly owned by the French state, produces more than 75% of electricity production in France (2024).[52] Alternative energy producers include Engie, TotalEnergies and Eni;[53]
- The French TSO is **RTE** and operates as regulated monopoly and public utility operator;[54]

48 Légifrance (2004), Law No. 2004-803 on the public electricity and gas service and on electricity and gas companies (link)
49 Légifrance (2010), Law No. 2010-1488 on the new organisation of the electricity market (link)
50 DGEC, Ministry of Ecological Transition, Directorate General for Energy and Climate (link)
51 CRE, Who are we? (link)
52 EDF, Power production (link)
53 In 2019, EDF's electricity generation in France stood at ~432 TWh, out of a national total of ~536 TWh, a production share of approximately 79%. In 2025, EDF's generation stood at ~434 TWh, out of a national total of ~ 547 TWh, a production share essentially equivalent to that of 2019.Compass Lexecon analysis based on data from EDF (link) and RTE (link).
54 RTE, About RTE (link)

- **Enedis** is the main operator of the distribution grid.[55]

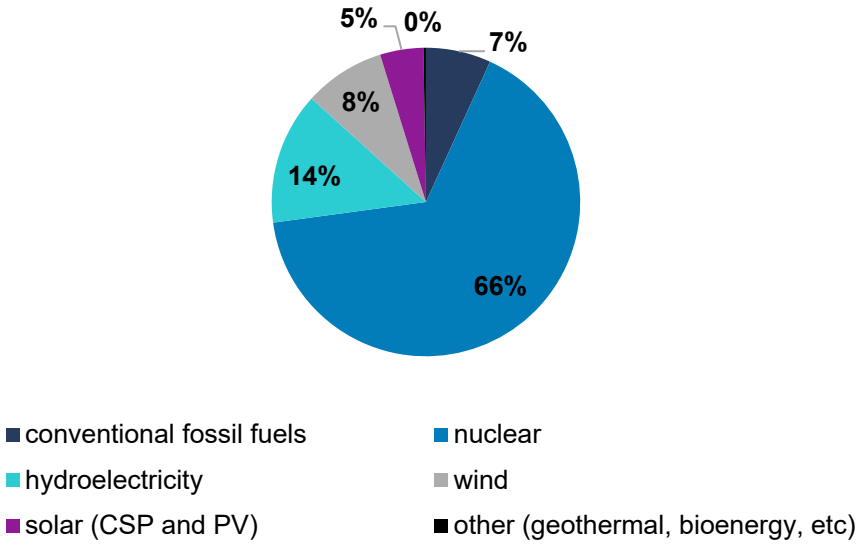
As for Norway, the French power system is an integral part of the European interconnected power grid, and its markets for trading electricity are coupled with the rest of European countries. Thus, electricity markets in France also comprise the forward / futures market, a day-ahead market (which is the reference for prices), an intraday market, balancing markets and an imbalance settlement mechanism (for more details, please refer to Section 3.1.2 on Norway).

France is largely interconnected all six neighbouring countries and is a net exporter of electricity. Interconnected countries include Belgium, Germany, the UK, Spain, Italy and Switzerland. The total French interconnection capacity amounted to 19.7 GW in 2024, i.e. 9.80 % of installed generation capacity.[56] In 2024, France exported 101.3 TWh of electricity and imported 12.3 TWh, resulting in a net export of 89 TWh. The country has been a net exporter of electricity every year since 2010, except for 2022 when of the production of some nuclear and hydropower plants was limited due to, respectively, stress corrosion cracking on cooling systems and low rain levels.[57]

4.1.2 Generation mix and consumption

The French electricity mix is dominated by nuclear power generation and hydroelectricity, resulting in a 93% low-carbon power production in 2024. The same year, total gross electricity generation in France was 547.8 TWh, with 361.7 TWh produced by nuclear power, 148.7 TWh by renewables (mainly hydro, wind and solar) and 37.4 TWh by conventional fossil fuels. Figure 6Figure 6 shows generation shares by source in France in 2024.

Figure 6: French generation mix in 2024 (%)



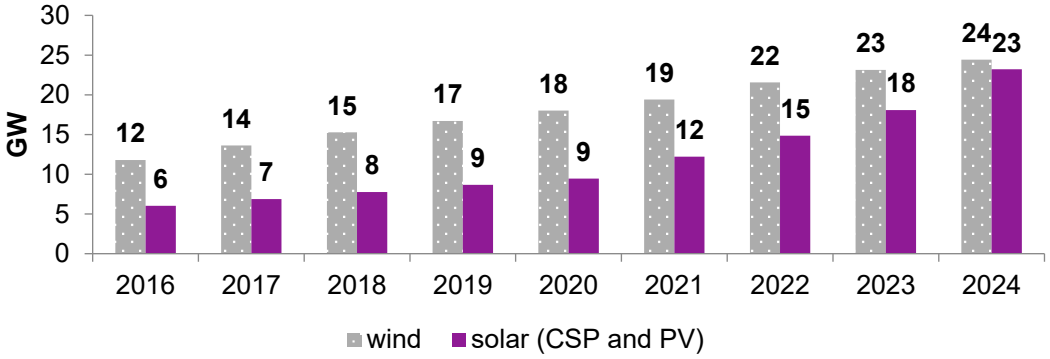
Source: Compass Lexecon analysis based on data from SDES (2026).

Moreover, total production has been relatively stable in France between 2016 and 2024 except for 2022 (446.3 TWh), fluctuating between 494.7 TWh (2023) and 547.5 TWh (2018).[58]

55 Enedis, Our role in the French power market (link)
56 Direction générale du Trésor (2026), Electricity Interconnections and their Contribution to the Energy Transition (link)
57 RTE, Annual Electricity Review 2024 (link)
58 RTE, Annual national electricity production (link)

Recent years have witnessed a steady development of renewable energy sources, implemented through dedicated support mechanisms. Figure 7 below shows installed wind and solar capacities in France between 2016 and 2024. Wind capacity increased by 12,646 MW over the period. Solar capacity increased by 17,174 MW over the same period. Over the same period, conventional fossil fuels capacity increased by 1,431 MW (2024: 17,506 MW) and hydroelectricity capacity slightly increased by 319 MW (2024: 25,336 MW).

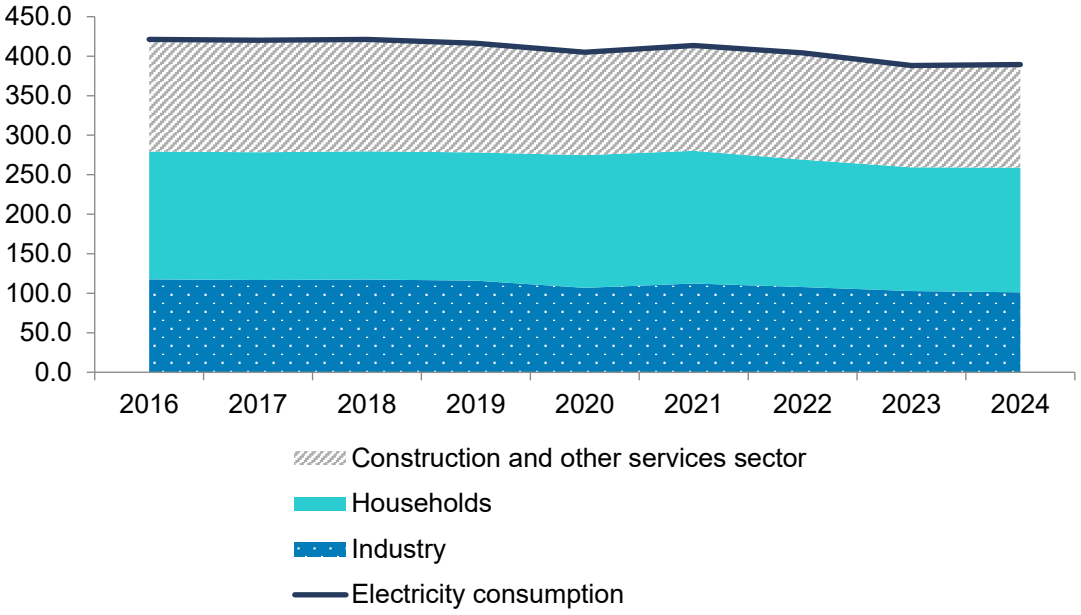
Figure 7: Cumulated installed wind and solar capacity in France since 2016 (GW)



Source: Compass Lexecon analysis based on data from Rte (2026).

On the demand side, power consumption has been relatively constant (even slightly decreasing) over the 2016-2024 period, ranging between 449.2 TWh (2024) and 479.5 TWh (2017). Figure 8 below shows electricity consumption and breakdown of generation by energy source in France between 2016 and 2024. Gross electricity consumption in France has been relatively stable.

Figure 8: Net electricity consumption (breakdown by sector) in France between 2016 and 2024 (TWh)



Source: Compass Lexecon analysis based on data from Rte (2026) and SDES (2026).

In 2024, industry (secondary) amounted to 26 % of total net consumption, households to 41 % and construction and other services sector to 33 %.

4.1.3 Network structure

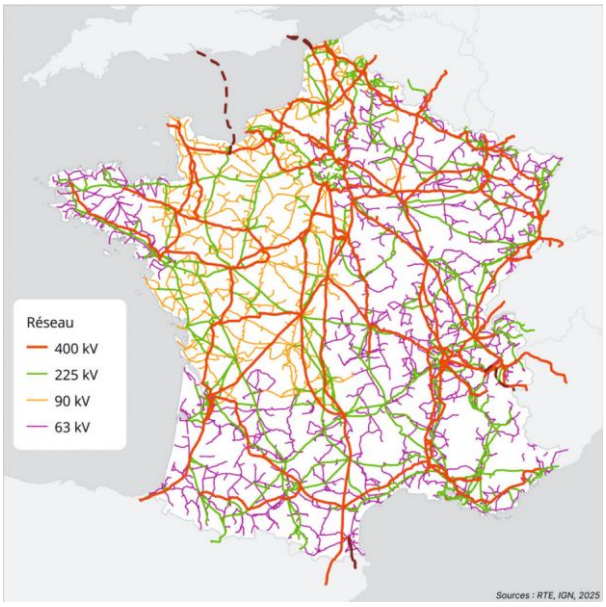
The French transmission network is operated by RTE, a publicly owned regulated monopoly. The distribution network is mainly operated by Enedis. The French electricity transmission network is operated at 63 to 400 kV and 92 % of the around 107,000 km of lines are overhead.[59] Below this level, the distribution grid is operated at 20 kV and covers around 1,390,000 km.[60]

- RTE owns and operates the French public electricity transmission network. The French electricity transmission network is made up of 106,874 km of power lines, making it the largest network in Europe. These lines can be divided into two types: Ultra-high-voltage lines (*ligne à Très Haute Tension*),[61] and High-voltage lines (*ligne à Haute Tension*).[62] The average age of the transmission network stands at 50 years.[63] Of the more than 100,000 km of transport lines, 92 % are overhead;
- The distribution grid is mainly operated by Enedis on 95 % of the grid in continental metropolitan France. 160 other DSOs also operate the grid. The distribution network is made of 658,800 km of medium-voltage lines, operating at 20 kV and of 732,900 km of low-voltage lines serving directly end-users (domestic, tertiary and small industrial customers) evenly distributed between underground and overhead lines.[64]

At a transmission level, where the bulk of electro-intensive industries is connected, the System Average Interruption Duration Index (SAIDI) in France has fluctuated between 2 and 7 minutes without exceptional events over 2000 – 2024, with 2 minutes and 32 seconds in 2024.[65]

59 RTE, Transmission grid (link)
60 Enedis, Network development plan (link)
61 Directly connected to large power stations (hydroelectric dams, nuclear power stations), they use extremely high voltages, between 225 and 400 kV, which minimise losses and allow long distances to be covered. They play a crucial role in interconnecting power grids across regions and countries.
62 Operating between 63 and 90 kV, these lines are designed for medium to long distances. They may be connected directly to medium-voltage power plants, or they may be extended from primary substations, where transformers are used to lower the initial voltage level. They either deliver electricity directly to large consumers or are connected to the distribution network via secondary substations.
63 CRE, Deliberation of the French Energy Regulatory Commission on the tariff for the use of public electricity transmission networks (link)
64 Enedis, Network development plan (link)
65 RTE, Annual Report on Electricity Quality (link)

Figure 9: Grid map of France (as of 2025)



Source: Rte (2025), Strategic development plan for the French transmission grid (SDDR).

RTE released in 2025 a 15-year transmission network development plan (SDDR), which foresees € 94bn of investments until 2040.[66] RTE plans to invest three times more annually over the 2025-2040 period as compared to historical levels to accommodate electrification of uses including in industry and improve network quality.

4.1.4 Regulatory framework and public policies

Over the past decade, the French power sector has been subject to significant policy and regulatory reforms. Following debates that started in 2012, the French energy transition bill (*Loi sur la Transition Energétique pour la Croissance Verte*, LTECV) was passed in 2015 and set a range of objectives and targets on climate change mitigation, environmental protection, energy mix diversification and energy security and guide their implementation.[67] Those targets were updated several times in recent years, reflecting increased ambitions at European level and shifts in French public orientations. Two major instruments were created by the LTECV: the National Low-Carbon Strategy (*Stratégie nationale bas-carbone*) and the Multi-year Energy Programme (*Programmation pluriannuelle de l'énergie*).[68]

The current policy framework is structured around the French Energy and Climate Strategy presented in 2023, within which the third National Low-Carbon Strategy ("SNBC 3") sets the long-term decarbonisation pathway and the 3rd Multi-year Energy Programme ("PPE 3") sets the main operational priorities for the period 2026-2035.[69,70]

- SNBC 3 provides the long-term climate strategy to reach carbon neutrality by 2050. The main targets are to reduce greenhouse gas emissions (GHG) from the energy production and transformation sector by 69% in 2030 and 96 % in 2050 compared with the 1990 level. To do so, the coal-fired power stations should be closed by 2027, phase out from oil should happen

66 RTE (2025) – Ten-year development plan of the network – Executive Summary (link)
67 Légifrance, Law No. 2015-992 on Energy Transition for Green Growth (link)
68 Article 176 of the law (codified as Article L. 141-1 of the Energy Code) (link)
69 Ministry of Ecological transition, National Low-Carbon Strategy (link)
70 French government, Decree on the third Multi-year Energy Programme (PPE3) (link)

by 2045 and from fossil gas by 2050. The annual production of decarbonized electricity should reach 585 TWh by 2030. By 2050, electricity production is expected to be fully decarbonised, with a 100 % decarbonised power mix and around 800 TWh of electricity production. SNBC 3 was adopted in July 2026.

- PPE 3 translates climate and electricity objectives fixed by SNBC 3 into operational power-sector targets. It presents the power sector as a central pillar of the decarbonisation strategy, both through the expansion of low-carbon electricity supply and through the electrification of end uses. It sets a target of 585 TWh of decarbonised electricity production by 2030 and between 650 and 693 TWh by 2035. It also sets technology-specific capacity targets for RES: solar PV (48 GW by 2030 and 55 to 80 GW by 2035), onshore wind (31 GW of by 2030 and 35 to 40 GW by 2035), offshore wind (3.6 GW of by 2030 and 15 GW by 2035), hydropower capacity (26.3 GW of by 2030 rising to 28.7 GW by 2035, including pumped-storage hydropower). Moreover, nuclear power remains a key component of French electricity policy as presented in the PPE3.[71] PPE 3 also highlights the need to preserve adequacy throughout the transition and therefore gives an important role to flexibility resources, including batteries, pumped-storage hydropower, demand-side response, interconnections.

In parallel, the French government aims to stimulate electricity demand and electrification. Announcements made in April 2026 placed increased emphasis on end-use electrification. The French government indeed announced a series of measures aimed at accelerating the shift in energy consumption from oil and gas towards electricity. In buildings, this includes the end of gas boilers in new housing and stronger public support for replacing gas- and oil-fired heating systems with heat pumps. In transport, the stated objective is for two-thirds of new cars sold in 2030 to be electric, together with industrial targets of 400,000 electric vehicles produced per year by 2027 and 1 million by 2030.[72]

4.2 Germany

4.2.1 Sector and market organisation

In Germany, both generation and retail activities have been liberalised since 1998. Distribution and transmission network operation remains a local monopoly and thus is regulated.

Main stakeholders in the German power sector include:

- The **Federal Ministry for Economic Affairs and Energy** (Bundesministerium für Wirtschaft und Energie), which is in charge of developing energy policies;[73]
- The German energy regulator, called ***Bundesnetzagentur*** **(BNetzA)**, which is the federal agency in charge of regulating Germany's electricity and gas markets and implementing energy policies developed;[74]
- The **four TSOs** (TenneT, 50Hertz, Amprion, TransnetBW), each operating as a regulated monopoly on their respective zone (*Regelzone*).[75]

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71 The existing nuclear fleet is to continue operating subject to safety requirements, with the objective of maintaining reactors in service for up to 60 years and potentially beyond where conditions allow. The construction of six new EPR2 reactors and the continuation of studies relating to an additional tranche of new nuclear capacity are also included in the text. For 2030, PPE3 indicates 57 reactors in service and nuclear output of around 380 TWh. The policy framework also includes specific measures on system security.

72 Ministry of Economy and Finance, Presentation of the End-Use Electrification Plan (link)

73 Federal Ministry for Economic Affairs and Energy, Home (link)

74 Bundesnetzagentur, Role and structure (link)

75 Bundesnetzagentur, Transmission system operator (link)

- **More than 860 DSOs** (in 2025) operate the distribution grid in Germany, and they are regulated monopolies as well on their zone (mainly municipalities, *Stadtwerke*).[76]

The German market is integrated in a broader bidding zone with Luxembourg. As for Norway and France, the German power system is an integral part of the European interconnected power grid, and its markets for trading electricity are coupled with the rest of European countries. Thus, electricity markets in Germany also comprise the forward / futures market, a day-ahead market (which is the reference for prices), an intraday market, balancing markets and an imbalance settlement mechanism (for more details, please refer to Section 3.1.2 on Norway).

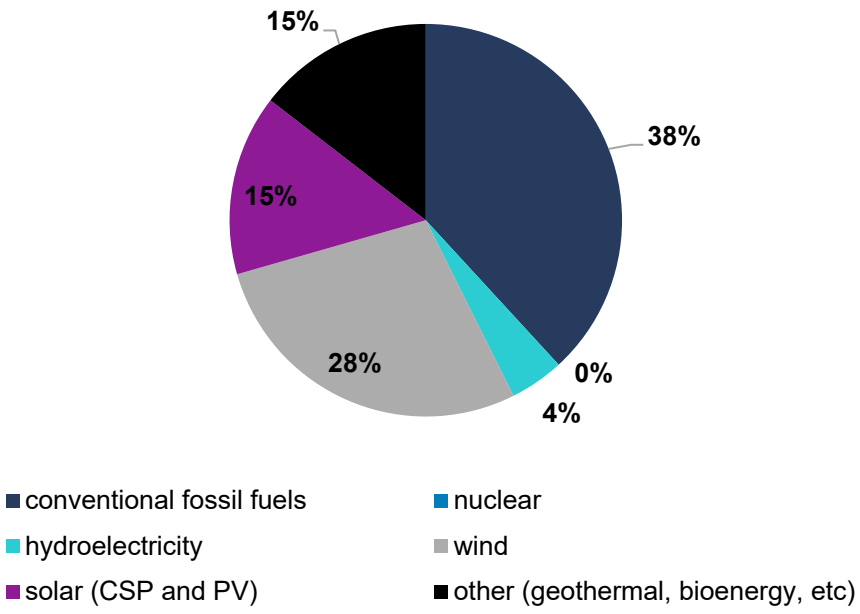
Germany is interconnected with all eleven neighbouring countries. The main ones are France, Denmark, Norway, the Netherlands, Switzerland and Austria.[77] The total German interconnection capacity amounted to 31,315 MW in 2024, i.e. 12.5 % of installed generation capacity. Germany thus ranks amongst the medium interconnected countries in Europe. In 2024, Germany exported 55.4 TWh of electricity and imported 81.7 TWh, resulting in a net import of 26.3 TWh. The country has been a net exporter of electricity until 2022 and a net importer since (*Atomausstieg* of 2023).[78]

4.2.2 Generation mix and consumption

The generation mix of Germany is still largely dependent on conventional fossil fuels, although the share of electricity generated by renewable energy sources now dominates the mix with a share of circa 60%. In 2024, total gross electricity generation in Germany was 547.8 TWh. Generation has been relatively stable in Germany between 2016 and 2024 except for 2022 (454.3 TWh), fluctuating between 502.4 TWh (2023) and 558.0 TWh (2018). In 2024, 189.8 TWh were produced by conventional fossil fuels, 138.9 TWh by wind, 74.1 TWh by solar and 94.5 TWh by other renewable energy sources. Figure 10 below shows generation shares for each source in Germany in 2024. Germany phased out nuclear power generation as of 2023 (*Atomausstieg*).

[76] Eurelectric, Distribution grids in Europe (link)
[77] Bundesnetzagentur, Cross-border electricity trading (link)
[78] ENTSOE-E, Power statistics (link)

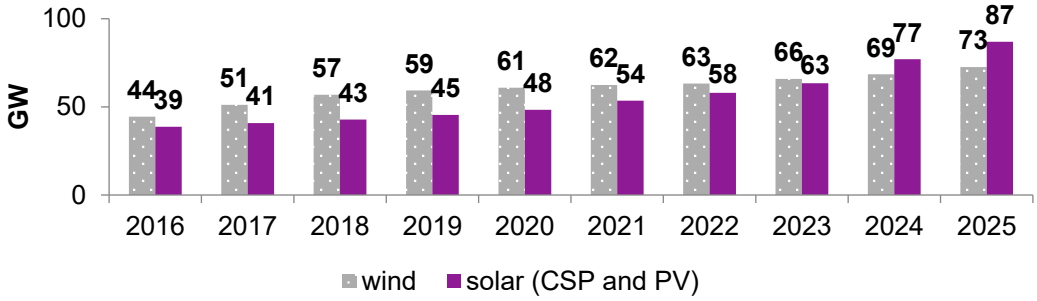
Figure 10: German generation mix in 2024 (%)



Source: Compass Lexecon analysis based on data from AG Energiebilanzen (2025).

The installed capacity of renewable power generation has grown in recent years, pushed by dedicated support mechanisms. Figure 11 below shows installed wind and solar capacities in Germany between 2016 and 2024. Wind capacity increased by 24,054 MW between 2016 and 2024. Solar capacity increased by 38,330 MW over the same period. Over the 2019-2024 period, conventional fossil fuels capacity decreased by 3,336 MW (2024: 80,108 MW) and hydroelectricity capacity slightly increased by 340 MW (2024: 14,767 MW).

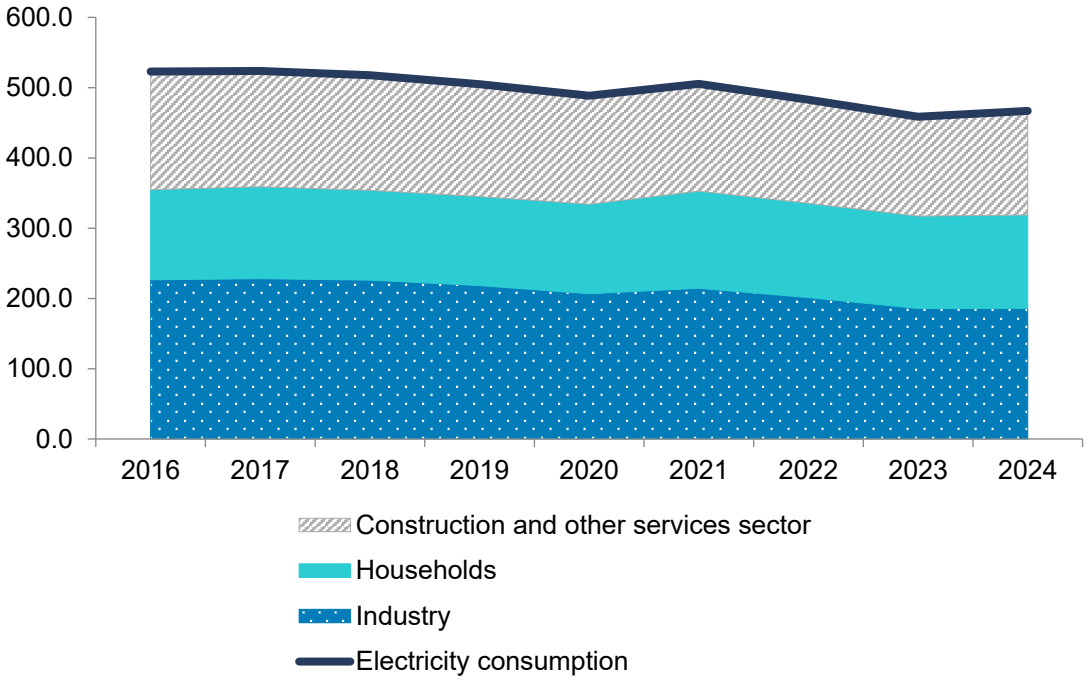
Figure 11: Cumulated installed wind and solar capacity in Germany since 2016 (GW)



Source: Compass Lexecon analysis based on data from ENTSO-E (2026).

Consumption has been slightly decreasing over the last ten years in Germany. Figure 12 below shows electricity consumption and breakdown of generation by energy source in Germany between 2016 and 2024. It can be seen that net electricity consumption in Germany has been decreasing over the 2016-2024 period, ranging between 458.6 TWh (2023) and 523.7 TWh (2017). In 2024, industry (secondary) amounted to 40 % of total net consumption, households to 28 % and construction and other services sector to 32 %.

Figure 12: Net electricity consumption (breakdown by sector) in Germany between 2016 and 2024 (TWh)



Source: Compass Lexecon analysis based on data from AG Energiebilanzen (2025).

4.2.3 Network structure

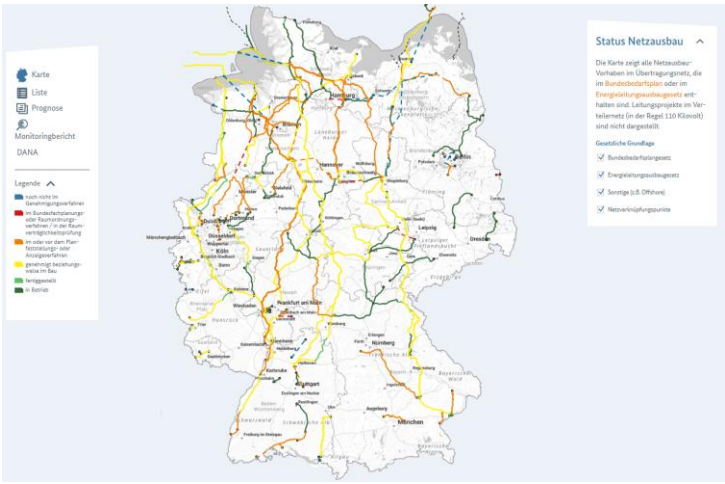
The German transmission and distribution networks are operated by actors who are regulated monopolies on their respective geographical area. The German electricity transmission network is operated at 220 to 380 kV and almost all of the around 35,000 km of lines are overhead. Below this level, the regional distribution grid is operated at 6-220 kV and covers around 1,114,000 km.[79]

- The German transmission network is operated by four TSOs: Amprion, TenneT, TransnetBW und 50Hertz. Each TSO operates as a regulated monopoly on its geographical area. The transmission network is operated at 220-380 kilovolts (new lines are planned up to 525 kV) in alternating current. 37,000 kilometres is the total length of the main transmission grids in Germany, almost all overhead lines. 1.2 million kilometres is the length of the low-voltage grid in Germany via which the electricity is distributed to end-users (around 1,190,000 km at 230-400 kV; around 94,000 km at 60-220 kV; around 520,000 km at 6-60 kV). [80]
- The distribution network is operated by more than 860 DSOs, each operates as TSOs as regulated monopolies on their respective zone (the majority of DSOs is municipalities, called *Stadtwerke*). At distribution grid level, underground powerlines are the norm in Germany. By contrast, the transport of electricity across large distances at high-voltage level, via the transmission grids, has generally taken place using overhead powerlines.[81]

79 Federal Ministry for Economic Affairs and Energy, An electricity grid for the energy transition (link)
80 Ibid.
81 Ibid.

Germany shows a high quality of supply of the transmission network: its SAIDI amounts to 11.6 minutes in 2024 (9.2 minutes in medium voltage and 2.4 minutes in low voltage), placing Germany among the world's highest-performing electricity systems. The transmission level, where the bulk of electro-intensive industries are connected, only contributes to a very low part of this SAIDI, which means that the quality of supply on the transmission network is very high.[82]

Figure 13: Grid map of Germany (as of 2025)



Source: Netzausbau (2026).

Future network development needs are currently set by law at around 16,800 kilometres.[83] The *Netzentwicklungsplan* (Grid Development Plan) is the key planning tool for the German transmission grid. The investment costs in the development pathways for the year 2045 amount to between 360 and 390 billion euros (as estimated by the last *Netzentwicklungsplan*).[84] In December 2025, a federal subsidy of €6.5 billion towards transmission grid costs in 2026 was approved.[85] This subsidy will be taken into account by the transmission system operators when calculating grid tariffs and will help to reduce the prices charged to consumers by electricity suppliers.

4.2.4 Regulatory framework and public policies

The Federal Climate Change Act (*Bundes-Klimaschutzgesetz*) is the 2019 law (revised in 2021) which sets targets for greenhouse gas emissions reduction in Germany in order to comply with European targets. The German Renewable Energy Act (*Erneuerbare Energien Gesetz*)[86] of 2023 seeks to help ensure that both electricity supply and electricity consumption become carbon-neutral before 2050. To this end, the law specifies the pace at which sustainable energy such as wind and photovoltaics are to be expanded over the next few years. *Windenergie auf See Gesetz* is the law that specifies the same targets but for offshore wind.

- The *Bundes-Klimaschutzgesetz* set targets for reduction in greenhouse gas emissions. The basis of the Act is the obligation according to the Paris Agreement, under the United Nations Framework Convention on Climate Change, to limit the increase in the global average

82 Bundesnetzagentur, Key figures on electricity supply disruptions (link)
83 Energy Line Extension Act of 21 August 2009, as last amended by Article 4 of the Act of 8 May 2024 (link); Federal Requirements Plan Act of 23 July 2013, as last amended by Article 1 of the Act of 16 July 2024 (link).
84 Netzentwicklungsplan, Grid Development Plan 2037/2045 (link)
85 Bundesregierung, Relief on energy costs (link)
86 Federal Ministry of Justice and Consumer Protection, Renewable Energies Act – EEG 2023 (link)

temperature to well below 2°C and, if possible, to 1.5°C, above the pre-industrial level so as to minimise the effects of worldwide climate change. The *Bundes-Klimaschutzgesetz* set the following targets: a reduction in greenhouse gas emissions of at least 65 % by 2030 (compared with 1990), and the achievement of net-zero greenhouse gas emissions by 2045. By 2025, Germany had reduced its greenhouse gas emissions by 48 % compared with 1990;

- *Erneuerbare Energien Gesetz* (EEG) of 2023 specifies targets for renewable energy sources capacity until 2040. The targets set in the EEG are to be achieved through an increase in the installed capacity of onshore wind turbines, as well as maintaining this installed capacity after 2040 (69 GW in 2024, 84 GW in 2026, 99 GW in 2028, 115 GW in 2030, 157 GW in 2035 and 160 GW in 2040), an increase in the installed capacity of offshore wind turbines in accordance with the Offshore Wind Energy Act, an increase in the installed capacity of solar power plants, as well as the maintenance of this capacity beyond 2040 (88 GW in 2024, 128 GW in 2026, 172 GW in 2028, 215 GW in 2030, 309 GW in 2035 and 400 GW in 2040), an installed capacity of 8,400 MW for biomass plants by 2030;
- *Windenergie auf See Gesetz* set goals for offshore wind until 2045. The aim of this law is to increase the installed capacity of offshore wind turbines connected to the grid to a total of at least 30 GW by 2030, to a total of at least 40 GW by 2035, and to a total of at least 70 GW by 2045.

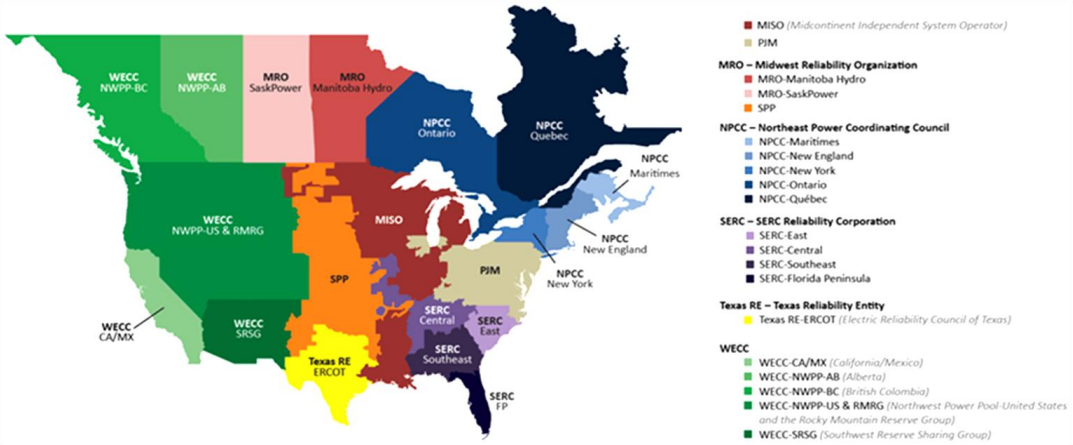
4.3 Texas

4.3.1 Sector and market organisation

Prior to the 1990s in the United States, electricity was mostly supplied by regulated and vertically integrated utilities that owned both the generation, distribution and transmission networks.[87] However, beginning in the 1990s, many states began to deregulate their electricity generation. In these deregulated markets, utilities are only responsible for delivering electricity that they purchase from other generating entities to the end customer. The utilities and generators buy and sell electricity through competitive wholesale power markets operated by independent system operators ("ISOs") and regional transmission organisations ("RTOs"). There are seven RTOs across the United States, including ISO New England, New York ISO, the PJM Interconnection, the Midcontinent ISO, the Southwest Power Pool, the Electric Reliability Council of Texas ("ERCOT"), and the California ISO ("CAISO"). These organisations, illustrated in Figure 14, serve as grid operators and operate wholesale markets for electricity within their territories.[88]

87 Resources for the Future, US Electricity Markets 101 (link)
88 EPA, Power Market Structure (link)

Figure 14: North American Electricity System Regions



Source: NERC (link)

Main stakeholders in the Texan power sector include:

- The **Electric Reliability Council of Texas** ("ERCOT"), a non-profit Independent System Operator (ISO) for more than 24 million customers and 90 % of Texas' electrical load. ERCOT market participants include buyers and sellers of wholesale power like investor-owned electric utilities, municipal electric utilities, electric cooperatives, independent generators, power marketers, retail electric service providers, and large electric consumers.[89]
- The **Public Utility Commission of Texas** (PUCT), a state agency which has complete statutory authority to oversee ERCOT[90], a role significantly reinforced in the aftermath of Winter Storm Uri (2021) through Senate Bills 2 and 3, and subsequently HB 1500 (2023).[91,92]
- The **Transmission and Distribution Service Providers** (TDSPs) are the regulated utility monopolies that own and operate the transmission assets, with rates set by the PUCT. The four main investor-owned TDSPs serving the deregulated portion of ERCOT are: Oncor Electric Delivery, CenterPoint Energy Houston Electric, AEP Texas and Texas-New Mexico Power.[93] In areas not subject to retail competition, distribution is handled by vertically integrated municipal utilities (e.g. Austin Energy, CPS Energy in San Antonio) and electric cooperatives.

ERCOT operates an energy-only wholesale electricity market that includes real-time, day-ahead, and ancillary service products. The market design is different from the ISO-administered markets in that it does not feature an explicit capacity market. Instead, ERCOT relies on scarcity pricing in the wholesale energy market to incentivise new generation entry.

The scarcity pricing mechanism fully incorporates ancillary services. Following the go-live of Real-Time Co-Optimization plus Batteries (RTC+B) in December 2025, energy and ancillary services are co-optimized in real time every five minutes, with scarcity priced directly through Ancillary Service Demand Curves (ASDCs) that produce real-time ancillary service clearing prices for each specific reserve product (e.g. regulating reserves).[94] Previously, ancillary services were procured

89 Federal Energy Regulatory Commission, Electric Reliability Council of Texas Overview (link)
90 Ibid.
91 Senate Bill 3, Enrolled Bill Summary (link)
92 House Bill 1500, Bill Analysis (link)
93 Texas Electric Utility Companies (link)
94 ERCOT, Real-Time Co-Optimization Overview (link)

separately in the day-ahead market and could not be adjusted in real-time to reflect supply and demand conditions.

Finally, ERCOT's transmission system is entirely located within Texas and is not synchronously interconnected with neighbouring regions in any significant capacity, although the state does maintain limited asynchronous DC connections to neighbouring power systems.[95,96]

4.3.2 Generation mix and consumption

Texas is one of the fastest growing state economies in the U.S. Business-friendly regulation, a skilled workforce, and oil and gas industry activity have led to growth in commercial and industrial demand for electricity in the state. These factors in turn have led to a high rate of population growth, the fourth highest in the nation in 2025.[97] Finally, the growth of data centres and the electrification of heating, cooling, and transportation technology are also boosting electricity demand in the state.

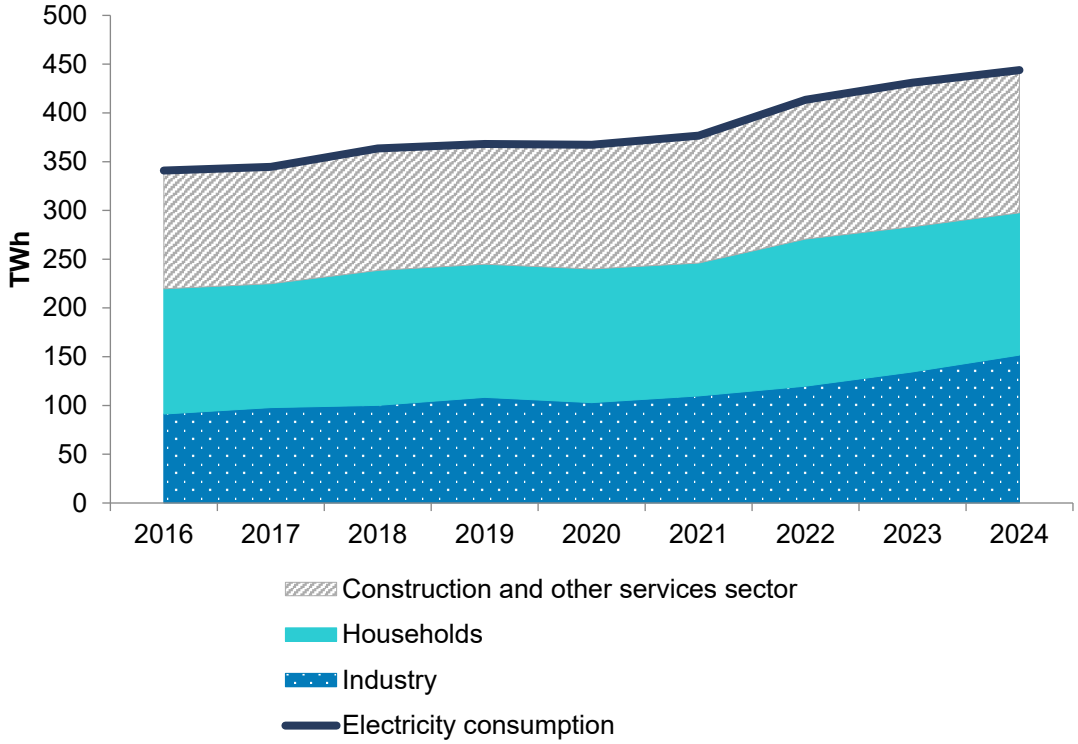
The demand for electricity in ERCOT has grown steadily since 2016. All in all, electricity demand in the state has increased from 341 TWh in 2016 to 444 TWh in 2024, an increase of more than 30%. 2020 was the exception to this trend, with electricity demand declining year over year by 0.2% due to the COVID-19 pandemic. However, since 2020 demand for electricity has rebounded. Demand in 2022, for example, grew by 10% relative to the prior year, as illustrated in Figure 15.

95 Federal Energy Regulatory Commission, An Introductory Guide to Electricity Markets regulated by the Federal Energy Regulatory Commission (link)

96 ERCOT, ERCOT Grid Insights (link)

97 US Census Bureau, U.S. Population Growth Slows Due to Historic Decline in Net International Migration (link)

Figure 15: ERCOT historic annual sales (breakdown by sector) between 2016 and 2024 (TWh)

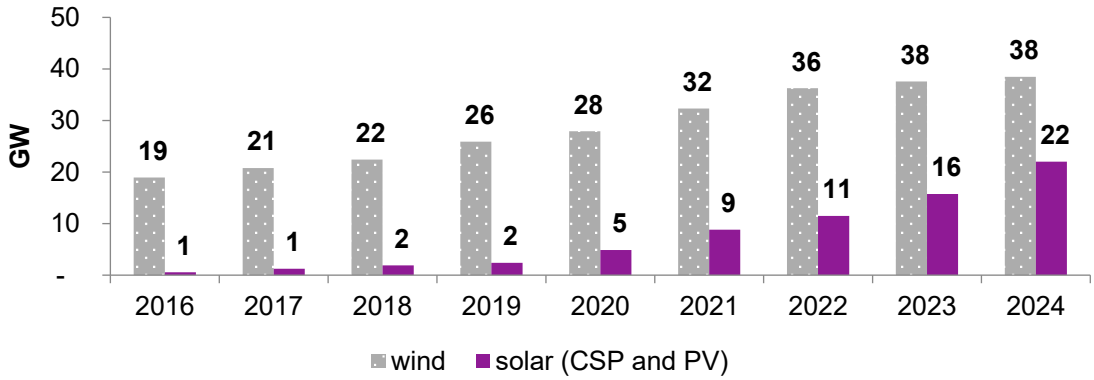


Source: Compass Lexecon analysis based on data from EIA-861 (link)

ERCOT benefits from Texas' large fossil fuel and renewable resources. In 2024, ERCOT had 155 GW of total installed nameplate capacity. 52% of that capacity was powered by fossil sources, and 24% and 14% of that capacity was made up of wind and solar resources, respectively.

Over the period from 2016 to 2024, the ERCOT power market has undergone several changes. The capacity of fossil-fuel powered resources as a percentage of total ERCOT nameplate capacity has dropped from 75% in 2016 to 52% in 2024, being offset mainly by renewable resources. As seen in Figure 16, wind capacity has increased from 19GW to 38GW over this period, and solar capacity has increased from 0.5 GW to 22GW in just the period from 2016 to 2024.

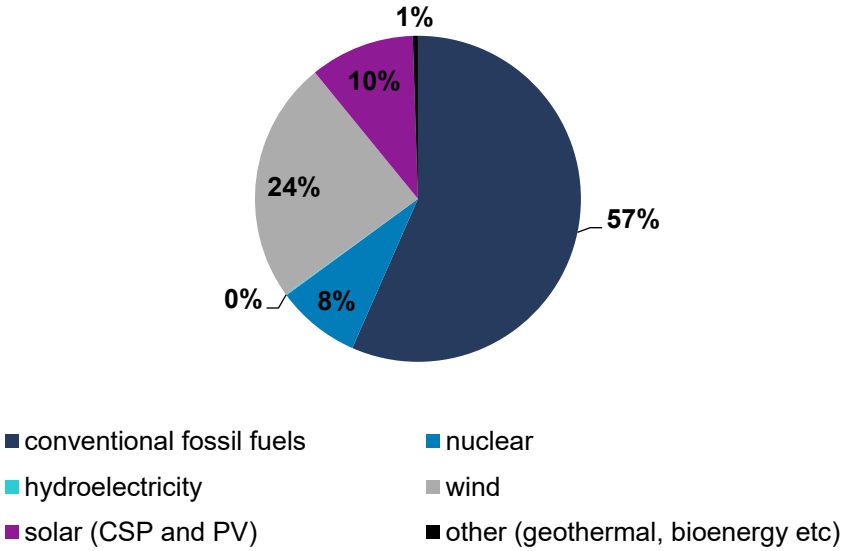
Figure 16: Cumulated installed capacity of wind and solar capacity in ERCOT since 2016 (GW)



Source: Compass Lexecon analysis based on data from EIA-860 (link)

Renewable generation in ERCOT has grown as new renewable capacity has been added to the system. Generation from solar increased from 0.7 TWh in 2016 to 48.2 TWh in 2024, and wind generation increased from 53 TWh in 2016 to 112 TWh over the same period. As intermittent resources, renewable generators generally have lower capacity factors than base load fossil units. As a result, renewable's share of total capacity is greater than its share of total generation. For example, renewable resources made up roughly 44% of total nameplate capacity in 2024 but contributed to 35% of total generation, as illustrated in Figure 17.

Figure 17: Generation mix of ERCOT in 2024 (%)



Source: Compass Lexecon analysis based on data from EIA-923 (link)

Coal generation has also decreased rapidly in recent years declining from 99 TWh in 2016 to 58 TWh in 2024. This decline is the result of several factors including environmental regulation, an ageing generator fleet, cheap natural gas, and increased demand for rapidly ramping resources to balance higher levels of renewables.

4.3.3 Network structure

The Texas Interconnection, of which ERCOT is the sole manager, operates at a synchronous frequency of 60 Hz. The ERCOT system includes approximately 1,250 generators and over 54,000 miles of high-voltage transmission lines.[98] The backbone is built primarily at 345 kV (Extra-High Voltage), with extensive underlying networks at 138 kV, 69 kV and some 161 kV.[99]

In recent years, the installation of wind and solar has far outstripped state targets which combined with extreme weather, thermal outages, and higher-than-expected loads has increased network congestion, price spikes, and reliability events. The 2024 SAIDI (excl. exceptional events) in Texas was 153.7 minutes, which is higher than the 48 U.S. state average of 120.4 minutes. The 2024 SAIFI (excl. exceptional events) in Texas was 1.398 interruptions, which is higher than the lower 48 U.S. state average of 1.061 interruptions.[100]

As a result, large investments are planned to adapt ERCOT's grid. The DOE's National Transmission Planning (NTP), assessing the US electric grid's investment needs, forecasts an almost 2-to-3-fold extension of the US grid by 2050 compared to its size in 2020.[101] Because ERCOT's limited interconnection capacity leaves it largely unable to import power from neighbouring grids, ERCOT must accommodate projected load growth internally by expanding its own transmission capacity, at substantial cost. Between 2011 and 2020, the average annual capital cost of maintaining and upgrading the Texas grid was approximately $970 million, reflecting the significant investment required to enhance the grid's capabilities.[102] To expand its backbone, ERCOT is evaluating two plans that are estimated to require approximately $5 billion per year of transmission project investment over the six-year planning horizon.[103] Specific projects include:

- Three 765-kV import paths recommended in the Permian Basin Reliability Plan approved by the PUCT in April 2025. These first-ever ERCOT 765-kV voltage class paths deliver power into the Permian Basin to meet load growth projected to rise to 24 GW by 2030.[104]
- The Western Loop and Eastern Backbone, two 765-kV projects endorsed by ERCOT's Board in December 2025 (pending PUCT approval) that interconnect the import paths into a meshed statewide backbone, improving reliability and transfer capability.[105]

4.3.4 Regulatory framework and public policies

Energy and climate policies relevant to the evolution of the power system in the USA are developed both at federal and state-level.

At Federal level, the main energy policies governing changes in the power system include:

- The *Inflation Reduction Act* ("IRA", 2022) which supports the power sector primarily through tax credits for new generation projects. The Production Tax Credit ("PTC") provides a per-MWh credit over a project's first ten years of operation, while the Investment Tax Credit ("ITC") provides a credit based on a percentage of total build cost. Bonus credits add up to 10% for meeting domestic-content requirements (iron and steel fully US-sourced, and manufactured

98 ERCOT Fact Sheet (link)
99 ERCOT, ERCOT System Planning (link)
100 EIA, Form 861 (link)
101 US DoE, National Transmission Planning Study (link)
102 The Electric Reliability Council of Texas Report on Existing and Potential Electric System Constraints and Needs (link)
103 PUCT, 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison (link)
104 ERCOT, ERCOT Permian Basin Reliability Plan Study (link)
105 ERCOT, Recommendation Regarding AEP Texas, CPS Energy, Oncor and CNP Texas 765-kV STEP Eastern Backbone Regional Planning Group (RPG) Project (link)

products on a sliding scale from 40% in 2024 to 55% by 2027) and a further 10% for siting in an energy community, for a potential 20% uplift. The IRA also modified Section 45Q, which provides up to $85/ton of CO_2 permanently stored and $60/ton for enhanced oil recovery, rising to $180 and $130/ton respectively for direct air capture, with construction required to begin by January 2033.[106]

- The *One Big Beautiful Bill Act* ("OBBBA", July 2025) substantially amends the IRA. To remain eligible for the PTC and ITC, wind and solar projects must now have commenced construction by July 2026 or be commissioned by December 2027, and the "start of construction" test has been tightened (Notice 2025-42 requires significant physical work, such as pouring foundations or installing solar racking). New restrictions also deny credits to specified foreign or foreign-influenced entities.[107] OBBBA further broadened eligibility to the DOE's loan-guarantee to include non-renewable generation projects, with around $250 billion of guaranteed capacity answering to the "Energy Dominance Financing" framework that runs through September 2028.

Federal environmental regulation of power plants has meanwhile moved in the same direction. Standards under the *Clean Air Act* (the NSPS greenhouse-gas standards and the Mercury and Air Toxics Standards) and under the *Clean Water Act* (the Effluent Limitation Guidelines for steam-electric plants) were tightened in 2023–2024[108], but EPA proposed to repeal the power-plant greenhouse-gas standards in 2025, reinstated the 2012 mercury standards in February 2026.

At state-level, Texas has encouraged investment in new electricity supply through a combination of mandates and public funding:

- The *Renewable Portfolio Standard*, adopted in 1999, targeted 5,000 MW of renewable capacity by 2015 and 10,000 MW by 2025; both were met far ahead of schedule (the 2025 goal by 2009), and no more stringent standard is expected. The state now favours grants and low-interest loans to support generation and grid reliability.[109]

- The *Texas Energy Fund* ("TEF"), created in 2023 and administered by the PUCT, is the principal current instrument, with total authorized funding of about $10 billion to support dispatchable generation, backup power and reliability inside and outside ERCOT.[110] Its In-ERCOT Generation Loan Program offers low-interest loans (up to 60% of eligible cost at 3% over 20 years) for at least 100 MW of new dispatchable capacity; the Completion Bonus Grant Program pays performance-based grants to dispatchable units interconnecting before June 2029; and the $1.8 billion Backup Power Package Program supports backup power at critical facilities.[111]

- The recent *House Bill 14* (2025) created the Texas Advanced Nuclear Development Fund, a $350 million fund administered by the Texas Advanced Nuclear Energy Office to reduce early-stage risk and accelerate advanced nuclear projects through feasibility studies, permitting support, site preparation and development.[112] Smaller programmes also remain in place, including the State Energy Conservation Office's LoanSTAR low-interest loans for efficiency

106 Inflation Reduction Act (link)
107 One Big Beautiful Bill Act, Pub. L. No. 119-21 (link)
108 EPA, Greenhouse Gas Standards for Fossil Fuel-Fired Power Plants, Final Rule (link)
109 Texas's Renewable Portfolio Standard (link)
110 Utility Dive, Texas voters approve $10B energy fund, with most going to build gas-fired power plants (link)
111 PUCT, The Texas Energy Fund (link)
112 Office of the Texas Governor, Texas Advanced Nuclear Development Fund (link)

retrofits and the Texas Emissions Reduction Plan's grants for vehicle and charging-infrastructure electrification.[113,114]

4.4 United Arab Emirates

4.4.1 Sector and market organisation

The UAE electricity sector is organised around a federal policy layer and emirate-level utility systems. Unlike European markets and ERCOT, the UAE does not operate a liberalised national wholesale electricity market. Electricity regulation, procurement, network operation and retail supply are largely structured by emirate, with public or government-linked utilities remaining central across the value chain. For large industrial users, this means that power costs are driven mainly by regulated tariffs, utility-specific charging structures and targeted industrial incentive programmes, rather than direct exposure to wholesale spot prices.[115]

Main stakeholders in the UAE power sector include:

- The **Ministry of Energy and Infrastructure** (MoEI), which sets national energy direction, covering energy policy, energy security, sustainability, competitiveness and infrastructure planning.[116]
- The **Abu Dhabi Department of Energy** (DoE), which acts as Abu Dhabi's emirate-level energy regulator and policy authority, including for licensing, technical standards, compliance, customer-care standards and tariff or fee proposals.[117]
- **Emirates Water and Electricity Company** (EWEC), which acts as Abu Dhabi's sole procurer of power and water and is responsible for planning, forecasting, purchasing and system despatch.[118]
- **Abu Dhabi National Energy Company** (TAQA), the main state-backed utility platform in Abu Dhabi, with TAQA Transmission / TRANSCO operating the high-voltage transmission network and TAQA Distribution supplying customers through the merged ADDC and AADC platform.[119]
- **Dubai Electricity and Water Authority** (DEWA), which remains Dubai's dominant vertically integrated electricity and water utility across generation, transmission, distribution and customer supply.[120]
- **Sharjah Electricity, Water and Gas Authority** (SEWA), which is responsible for electricity, water and gas services in Sharjah.[121]
- **Etihad Water and Electricity** (EtihadWE), which is the main public electricity and water utility in Ajman, Umm Al Quwain, Ras Al Khaimah and Fujairah.[122]

In the UAE, electricity activities are not liberalised in the same way as in Norway, France or Germany. Generation is increasingly open to private participation through Independent Power Producer (IPP) and Independent Water and Power Producer (IWPP) structures, but procurement,

113 SECO, LoanSTAR Revolving Loan Program (link)
114 Texas Commission on Environmental Quality, Texas Emissions Reduction Plan (link)
115 Abu Dhabi Department of Energy, Economic Regulations: Tariffs and charges (link)
116 Ministry of Energy and Infrastructure, About the Ministry (link)
117 Abu Dhabi Department of Energy, Legislation and Compliance (link); Law No. 11 of 2018 establishing the Department of Energy (link)
118 Emirates Water and Electricity Company, corporate overview (link)
119 TAQA Transmission, Who We Are (link); TAQA Distribution, ADDC and AADC merger (link)
120 DEWA, Consolidated Financial Statements 2025 (link)
121 Sharjah Electricity, Water and Gas Authority, Electricity services (link)
122 Etihad Water and Electricity, official website (link)

transmission, distribution and retail supply remain strongly public-led. The market structure can be summarised as follows:

- Abu Dhabi follows a single-buyer and unbundled model, where EWEC procures capacity and energy under long-term offtake agreements, while separate entities handle transmission and distribution.[123]
- Dubai follows a bundled and vertically integrated utility model, with DEWA controlling most of the electricity value chain and procuring selected generation projects through IPP structures.[124]
- Sharjah follows a public utility-led model, with SEWA operating across electricity generation, transmission, distribution and customer supply.[125]
- The Northern Emirates follow a public utility-led model through EtihadWE, with limited evidence of retail supplier switching or wholesale market access for industrial customers.[126]

The UAE does not have day-ahead, intraday, balancing or imbalance electricity markets comparable to European markets or ERCOT. For this reason, there is no wholesale spot-price reference that can be used for large industrial users in the same way as in liberalised markets. Industrial power costs are instead based on public regulated tariffs, customer category, connection characteristics, load profile and eligibility for emirate-level incentive schemes.[127]

For large industrial users, the UAE market structure means electricity costs are primarily shaped by emirate-level regulated tariffs, customer category, connection characteristics and targeted incentive schemes, rather than direct participation in wholesale electricity markets.

The UAE is connected to the regional GCC grid through the Gulf Cooperation Council Interconnection Authority (GCCIA), which links the power systems of the UAE, Saudi Arabia, Oman, Qatar, Bahrain and Kuwait. The interconnection supports reliability, emergency support and cross-border electricity exchange, but it does not create a domestic UAE wholesale electricity market. In 2024, the UAE exported 2.66 TWh and imported 2.15 TWh, resulting in a small net export position of around 0.51 TWh. Based on a 2,400 MW interconnection capacity and estimated national peak demand of around 34 GW in 2024, interconnection capacity represented approximately 7 % of peak demand. GCCIA is expanding UAE interconnection capacity from 2,400 MW to 3,500 MW, which should improve regional resilience but is not expected to transform the UAE into a liberalised trading market.[128,129]

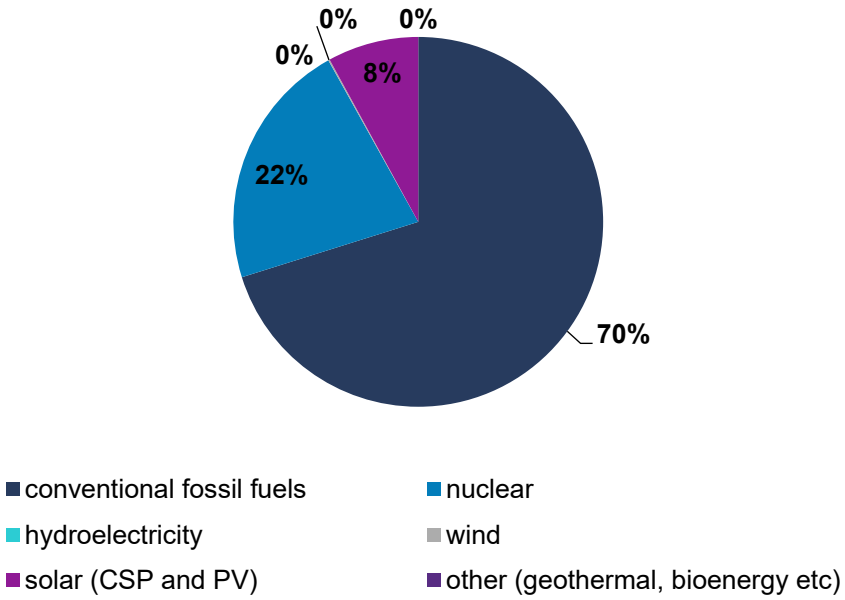
4.4.2 Generation mix and consumption

The UAE generation mix remains dominated by conventional fossil fuels, mainly gas-fired generation, although the mix has changed significantly since 2016 as nuclear and solar capacity started to be developed. In 2024, total gross electricity production was around 179.3 TWh, compared with 129.6 TWh in 2016, representing an increase of around 38 %. Conventional fossil fuels still accounted for the largest share of generation, with 125.8 TWh in 2024 (approx. 70 % of total generation). Nuclear power accounted for 39.0 TWh (approx. 22%), while renewables accounted for 14.5 TWh (approx. 8%). Figure 18 shows the UAE generation mix in 2024, highlighting that clean generation is growing but that fossil-based generation remains the core

123 Abu Dhabi Department of Energy, Economic Regulations: Tariffs and charges (link)
124 DEWA, Consolidated Financial Statements 2025 (link)
125 Sharjah Electricity, Water and Gas Authority, Electricity services (link)
126 Etihad Water and Electricity, official website (link)
127 Abu Dhabi Department of Energy, Economic Regulations: Tariffs and charges (link)
128 GCC Interconnection Authority, UAE interconnection expansion (link)
129 Federal Competitiveness and Statistics Centre, UAE.Stat electricity statistics (link); Ember, yearly electricity data (link)

source of supply.[130] The UAE have considerable natural reserves of gas (ranked 4th in domestic natural gas production around the world in 2023) and oil (ranked 3rd in crude oil production around the world in 2023), which inevitably influences the composition of the generation mix.[131]

Figure 18: Generation mix of the UAE in 2024 (%)

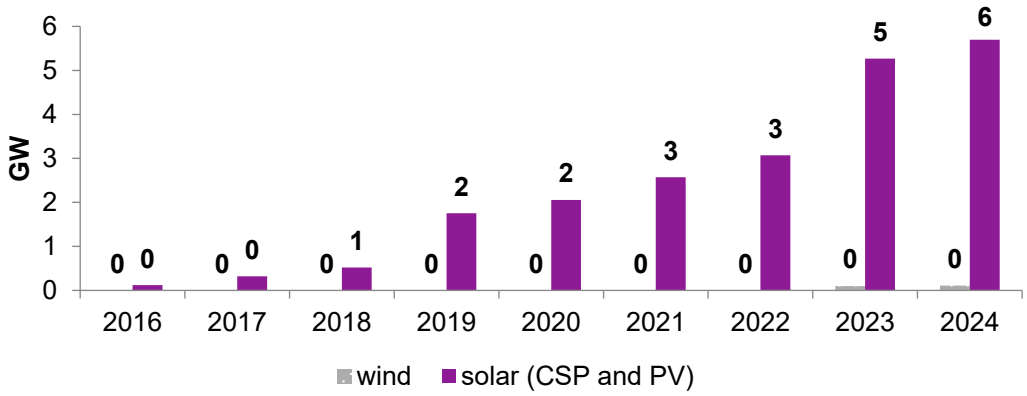


Source: Compass Lexecon analysis based on data from Ember (consulted in 2026) and FCSC Statistical Report 2024 (2025).

Installed generation capacity has expanded rapidly since 2016. Total installed capacity increased from around 29.0 GW in 2016 to around 47.1 GW in 2024, an increase of around 18.0 GW. Conventional fossil-fuel capacity increased from around 28.9 GW to 35.5 GW over the same period, but its share of total installed capacity declined as nuclear and renewable capacity was added. Nuclear capacity increased from zero in 2016 to 5.6 GW in 2024, while renewable capacity increased from 0.1 GW to 6.0 GW. Figure 19 shows that renewable capacity growth has been almost entirely solar led, with solar capacity increasing from around 0.1 GW in 2016 to around 5.7 GW in 2024, while wind capacity remained marginal at around 0.1 GW in 2024.[132]

130 Ibid.
131 IEA (2026), Overview of the energy system of United Arab Emirates
132 Federal Competitiveness and Statistics Centre, UAE.Stat electricity statistics (link); Ember, yearly electricity data (link)

Figure 19: Cumulated installed capacity of wind and solar capacity in the UAE since 2016 (GW)

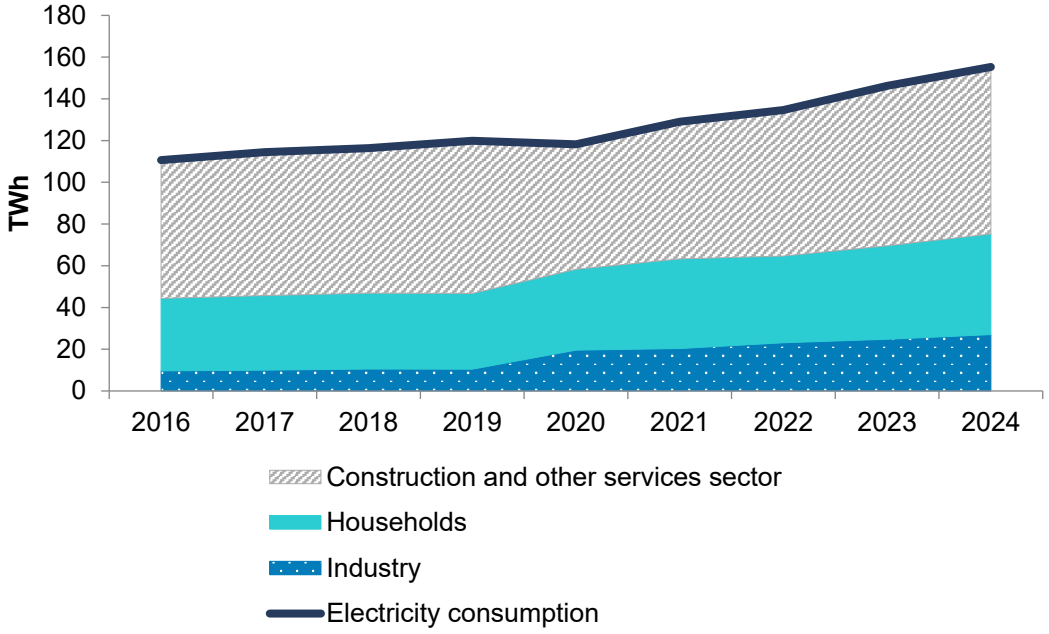


Source: Compass Lexecon analysis based on data from FCSC Statistical Report 2016-2020 and FCSC Statistical Report 2024 (2025).

On the demand side, electricity consumption has grown materially over the last decade. Net electricity consumption increased from around 110.6 TWh in 2016 to 155.3 TWh in 2024, an increase of around 40 %. Figure 20 shows net electricity consumption by sector in the UAE between 2016 and 2024. In 2024, industry accounted for around 27.0 TWh, or 17 % of total net consumption. Households accounted for around 48.2 TWh, or 31 %, while construction and other services accounted for around 80.0 TWh, or 52 %. Industrial consumption has increased significantly since 2016, but industry's share of total demand remains lower than in more electro-intensive count such as Norway or South Korea.[133]

[133] Ibid.

Figure 20: Net electricity consumption (breakdown by sector) in the UAE between 2016 and 2024 (TWh)



Source: Compass Lexecon analysis based on data from FCSC Statistical Report 2024 (2025).

4.4.3 Network structure

The UAE does not have one centralised national transmission system operator. Transmission is organised mainly by emirate and utility system, with regional interconnection provided through GCCIA and domestic interconnection supported by the Emirates National Grid. The structure is therefore different from countries with a single TSO or an integrated wholesale electricity market.

Network responsibilities are organised as follows:

- In Abu Dhabi, TAQA Transmission / TRANSCO owns and operates the high-voltage transmission network, connecting generation plants to distribution companies and large customers. EWEC handles procurement, planning and despatch, while TAQA Distribution supplies customers across the former ADDC and AADC service areas.[134,135]
- In Dubai, DEWA owns and operates the transmission and distribution networks as part of its vertically integrated utility model.[136]
- In Sharjah, SEWA provides electricity generation, transmission and distribution across the emirate.[137]
- In the Northern Emirates, EtihadWE provides electricity and water services across Ajman, Umm Al Quwain, Ras Al Khaimah and Fujairah.[138]

134 TAQA Transmission, Who We Are (link); TAQA Distribution, ADDC and AADC merger (link)
135 Emirates Water and Electricity Company, corporate overview (link)
136 DEWA, Consolidated Financial Statements 2025 (link)
137 Sharjah Electricity, Water and Gas Authority, Electricity services (link)
138 Etihad Water and Electricity, official website (link)

Public network data is mainly available at emirate or utility level rather than as a consolidated national dataset. In Abu Dhabi, the transmission network operates at 132 kV, 220 kV and 400 kV, while distribution operates mainly at 33 kV, 22 kV and 11 kV. In 2023, Abu Dhabi reported 166 transmission grid substations, 9,501 km of overhead transmission lines, 1,259 km of underground transmission cables and 72,095 MVA of transmission capacity. Based on reported line and cable length, Abu Dhabi's transmission network was around 88% overhead and 12% underground.[139]

In Dubai, the transmission network operates at 400 kV and 132 kV, while distribution operates mainly at 33 kV and 11 / 6.6 kV. In 2023, DEWA reported 27 substations at 400 kV and 348 substations at 132 kV, as well as 75 substations at 33 kV and more than 44,000 substations at 11 / 6.6 kV. Based on reported line and cable lengths, Dubai's network was approximately 94% underground and 6% overhead across reported voltage levels.[140]

Network quality appears strong in the main industrial and urban centres, although indicators are not published in a single UAE-wide format. In Abu Dhabi, 2023 SAIDI was approximately 42 minutes per customer for ADDC and 64 minutes per customer for AADC, while SAIFI was approximately 0.52 and 0.70 interruptions per customer respectively. Industrial-zone reliability was materially stronger, with average annual outages just above 10 minutes in Khalifa A and B Industrial Areas and below 4 minutes in the Industrial City of Abu Dhabi. Dubai reported Customer Minutes Lost of 1.06 minutes per customer in 2023, 0.94 minutes in 2024 and 0.82 minutes in 2025, alongside electricity transmission and distribution losses of around 2%.[141]

Finally, the Energy Strategy 2050 sets out plans to develop renewable energy sources, driving investment in the grid. Abu Dhabi National Energy Company (TAQA) plans to invest USD 10.9 billion for the expansion of its transmission and distribution network, including to accommodate further industrial electricity needs.[142]

4.4.4 Regulatory framework and public policies

UAE electricity policy follows a federal strategy and emirate-level implementation model. Federal policies set national targets on clean energy, demand management and net zero, while emirate-level policies define how each local utility system contributes. Over the past decade, the direction of policy has shifted from a gas-dominated power system toward a more diversified system based on gas, nuclear, solar and demand-side management.

At federal level, the main policy frameworks include:

- The UAE Energy Strategy 2050, originally launched in 2017 and updated in 2023, which targets higher clean-energy capacity, improved energy efficiency and energy security. The updated 2030 direction includes increasing clean-energy capacity from 14.2 GW to 19.8 GW, raising the share of installed clean-energy capacity to 30%, increasing the clean-energy contribution to electricity generation to 32%, tripling the renewable-energy contribution and mobilising AED 150-200 billion of investment by 2030.[143]
- The UAE Net Zero 2050 Strategic Initiative, which provides the broader economy-wide decarbonisation framework and implies continued diversification of the electricity mix toward nuclear, solar and other clean-energy sources.[144]

139 Abu Dhabi Department of Energy, 2023 Technical Report (link); DEWA, Statistics Booklet 2023 (link); DEWA, World-class results (link)
140 DEWA, Consolidated Financial Statements 2025 (link)
141 Ibid.
142 ReGlobal (2021), UAE's Power Sector: Transitioning to a clean and smart grid
143 UAE Government, UAE Energy Strategy 2050 (link); UAE Government, Net Zero 2050 Strategy (link); UAE Legislation, National Energy and Water Demand Management Programme 2050 (link)
144 Ibid.

- The National Energy and Water Demand Management Programme 2050, which targets a 40% reduction in total energy demand and a 21% reduction in total water demand by 2050, with a focus on high-consumption sectors including transport, industry and buildings.[145]
- Federal Decree-Law No. 17 of 2022 on distributed renewable energy, which provides a framework for connecting distributed renewable energy units to distribution networks.[146]

At emirate level, the most relevant policies include:

- Abu Dhabi's Clean Energy Strategic Target 2035, which requires 60% of Abu Dhabi electricity production to come from clean and renewable sources by 2035 and targets up to a 75% reduction in power-sector carbon intensity per MWh.[147]
- Abu Dhabi's Energy Outlook 2050 and Demand Response Policy, which reinforce clean-power expansion, demand management, clean-energy certificates, hydrogen, waste-to-energy and demand-side flexibility.[148]
- Dubai's Clean Energy Strategy 2050 and Net Zero Carbon Emissions Strategy 2050, which target 100% of Dubai's energy production capacity from clean energy sources by 2050.[149]
- Dubai's Demand Side Management Strategy 2050, which targets savings of at least 30% by 2030 and 50% by 2050 compared with business-as-usual across electricity, water and transport fuel consumption.[150]
- Ras Al Khaimah's Energy Efficiency and Renewables Strategy 2040, which targets at least 30% electricity savings, 20% water savings and a 20% renewable energy contribution by 2040 compared with business-as-usual.[151]

For large industrial users, the main implication is that UAE electricity policy combines three drivers: regulated tariffs and targeted incentives to support industrial competitiveness, clean-energy expansion to reduce reliance on gas-fired generation, and demand-side management to contain peak-demand growth.

4.5 South Korea

4.5.1 Sector and market organisation

The electricity sector in South Korea is formally unbundled in 2001 and generation opened to competition, however the historical national power company retains a major share of activities within the sector. The main sector stakeholders are:

- The **Ministry of Trade, Industry and Energy** (MOTIE), responsible for overseeing comprehensive policies for demand and supply of electricity, including renewable energy policies, a master plan revised every two years setting forth a national plan of electricity supply and demand for the next 15 years;[152]

145 Ibid.
146 Ibid.
147 Ibid.
148 Ibid.
149 Ibid.
150 Ibid.
151 UAE Government, Ras Al Khaimah Energy Efficiency and Renewable Energy Strategy 2040 (link)
152 Chambers and Partners, South Korea (link)

- The **Korea Power Exchange** (KPX) and the **Korea Energy Agency** (KEA). KPX, established in April 2001 as a non-profit entity commissioned by MOTIE, manage the electricity market's operational functions;[153]
- The Korean electricity regulator **Electricity Regulatory Commission** (ERC), an affiliated body within MOTIE;[154]
- **KEPCO**, the historical power producer which owns the entire share capital of each of its generation subsidiaries (GENCOs) (one nuclear-hydro company, KHNP, and five thermal GenCos).[155]

The South Korean electricity market is a centralised, single-buyer cost-based pool. South Korea runs a centralised, mandatory power pool. It rests on a strict functional separation of roles: the Korea Power Exchange (KPX) acts as the independent system and market operator (ISO/MO), while the state-owned KEPCO holds a monopoly over transmission, distribution and retail. Competition is limited to generation, where KEPCO's six subsidiary generation companies (GENCOs) compete with independent power producers (IPPs) though the GENCOs remain dominant, with around 70 % of the nation's electric power generation. Although the generation, transmission, distribution and supply segments of the Korean power industry are formally unbundled, KEPCO retains a monopoly over the transmission, distribution and sales markets.[156]

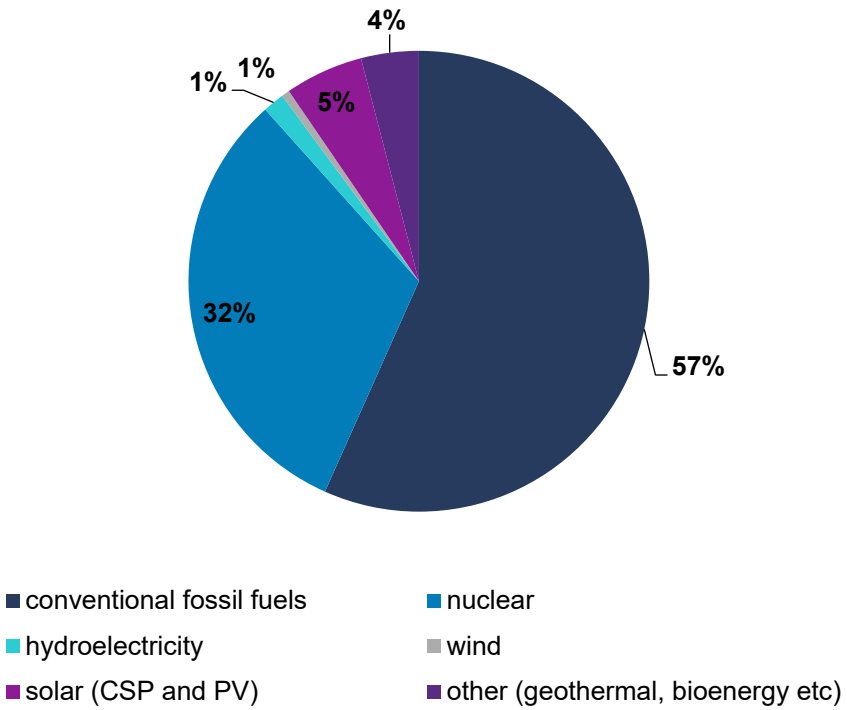
All electricity must be traded through the KPX-administered wholesale market, in which KEPCO is the single buyer; the only exceptions from this mandatory pool concern certain renewable transactions. The resulting wholesale price, the System Marginal Price (SMP), departs from conventional gross pool design: rather than resulting from competitive bids submitted by generators, it is derived from cost parameters that KPX itself evaluates on a recurring basis through a dedicated commission, the Cost Evaluation Committee. KPX then uses these assessed costs to solve a Day-Ahead Unit Commitment (DAUC) problem, dispatching plants in the sequence that minimises total system cost while satisfying forecast demand and grid stability requirements. Whichever plant proves marginal in this schedule determines the SMP.[157]

4.5.2 Generation mix and consumption

In 2024, total gross electricity generation in South Korea was 595.6 TWh. In 2024, 335.6 TWh were produced by conventional fossil fuels, 188.8 TWh by nuclear power and 71.3 TWh by renewable energy sources. Figure 21 below shows generation shares for each source in South Korea in 2024. Electricity generated by conventional fossil fuels (gas and coal) largely dominates the mix, followed by nuclear power. Very few electricity was generated by renewable energy sources.

153 Lexology, Renewable Energy in South Korea (link)
154 Chambers and Partners, South Korea (link)
155 IAEA, Country Nuclear Power Profiles — Republic of Korea (link)
156 US Government, Korea – Energy New and Renewable (link)
157 Lee, R., Yoon, M., & Shin, H. (2026), "Price Distortions in Korea's Electricity Market: Barriers to Renewable Integration and Reform Pathways," arXiv:2605.09318 (link)

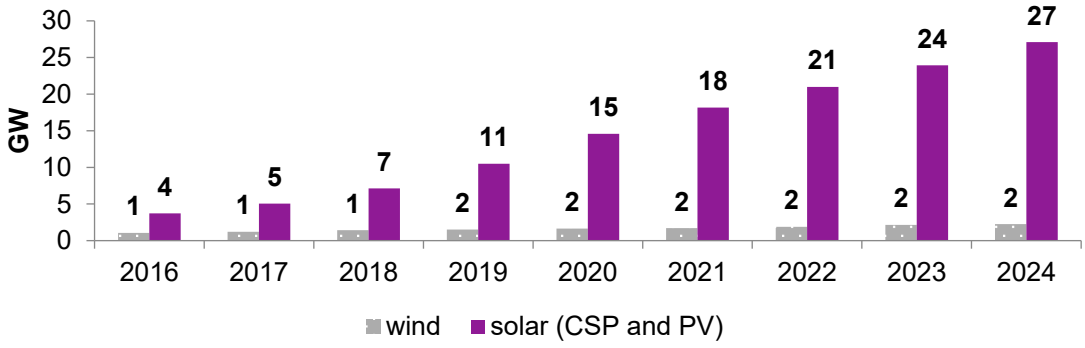
Figure 21: South Korean generation mix in 2024 (%)



Source: Compass Lexecon analysis based on data from EPSIS (consulted in 2026).

South Korea is developing new capacity of RES, especially solar one. Figure 22 shows installed wind and solar capacities in South Korea between 2016 and 2024. Wind capacity increased by 1,197 MW over the period. Solar capacity increased by 23,379 MW over the same period. Solar capacity has been growing over the ten last years, whereas wind capacity remained quite stable.

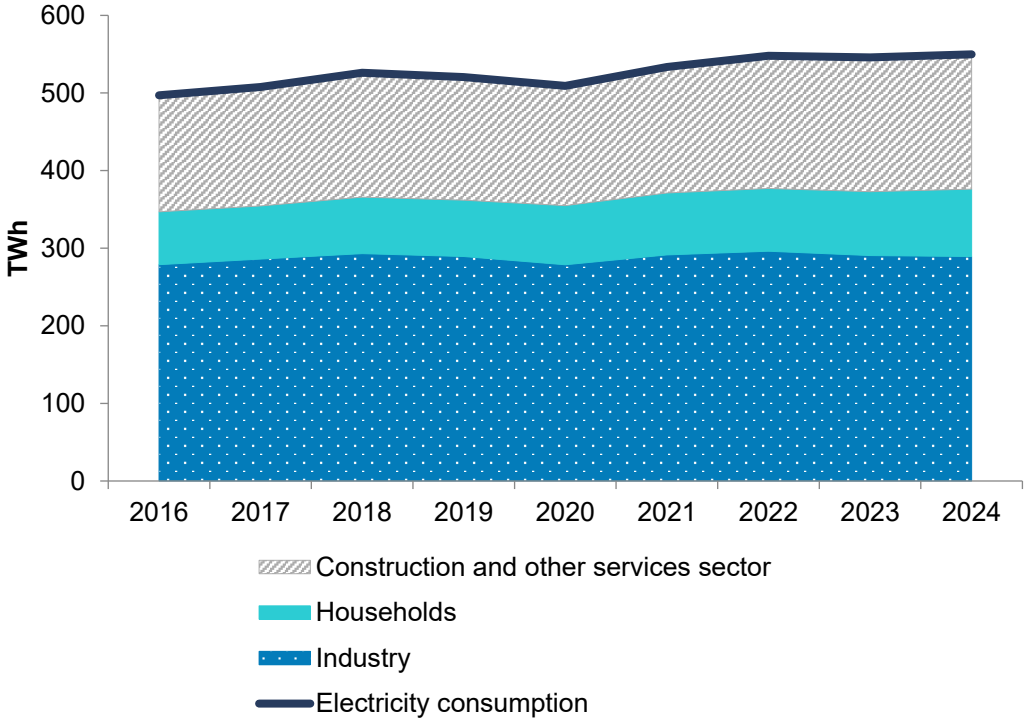
Figure 22: Cumulated installed capacity of wind and solar capacity in South Korea since 2016 (GW)



Source: Compass Lexecon analysis based on data from EPSIS (consulted in 2026).

Over the 2016-2024 period, conventional fossil fuels capacity increased by 18,413 MW (2024: 87,179 MW) and hydroelectricity capacity has been almost stable, increasing by 18 MW (2024: 6,503 MW).

Figure 23: Net electricity consumption (breakdown by sector) in South Korea between 2016 and 2024 (TWh)



Source: Compass Lexecon analysis based on data from EPSIS (consulted in 2026).

In 2024, industry (secondary) amounted to 53 % of total net consumption, households to 16 % and construction and other services sector to 32 %. Figure 23 above shows electricity consumption and breakdown by sector in South Korea between 2016 and 2024. Net electricity consumption in South Korea has been slightly increasing over the 2016-2024 period, ranging between 497 TWh (2016) and 550 TWh (2024).

4.5.3 Network structure

KEPCO operates both transmission and distribution networks and is a monopoly.

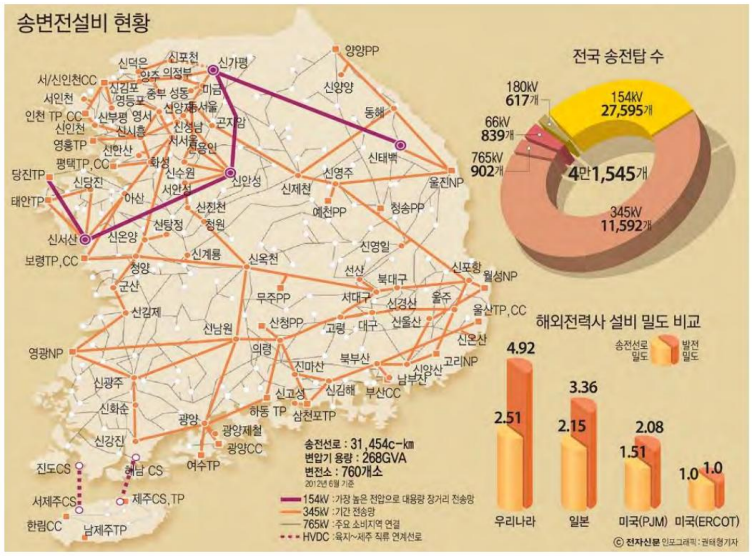
- As of 2025, KEPCO operated about 16,302 km of transmission lines at voltages from 154 kV to 765 kV. 13,753 km were overhead lines (~84 %), 2,451 km underground cables (~15 %) and 98 km undersea cables (less than 1 %). Transmission length has been broadly flat over the past five years (~0.34 % CAGR);[158]
- Below the transmission grid, distribution is delivered at 22.9 kV (medium voltage) down to 220 V for end users.[159]

At a transmission level, where the bulk of electro-intensive industries is connected, South Korea boasts one of the most reliable power supplies in the world. The total System Average Interruption

158 REGlobal, South Korea's Power Plans: Ambitious expansion strategy for a sustainable future (link)
159 Ibid.

Duration Index (SAIDI) in South Korea was of 9.05 minutes in 2022, the contribution of the transmission level to this number is almost zero.[160]

Figure 24: Grid map of South Korea (as of 2012)



[Statistics and Map of Korea Electric Power grid]

Source: *ESMAP (2022).*

To address potential congestion, the government announced in the 11th Long-Term Transmission and Substation Facility Plan that by 2038, the total length of transmission lines to be constructed is expected to reach 25,587 circuit-km (representing an approximately 1.72-fold increase compared to 2023). The total capacity of substation facilities to be constructed by 2038 is projected to be 187,560 MVA, which about 1.52 times higher than in 2023.[161]

4.5.4 Regulatory framework and public policies

The current policy framework is structured around the Framework Act on Carbon Neutrality and Green Growth, which set the goal of carbon neutrality by 2050, and the Plan for Electricity Supply and Demand, which set operational goals for the electric sector:

- The Carbon Neutrality Act stipulates legal procedures and policy instruments to achieve the country's 2050 carbon neutral vision. This Framework Act on Carbon Neutrality and Green Growth for coping with climate crisis is a 2021 law which set the goal of carbon neutrality by 2050.[162] A mid-term goal of a 40 % reduction of GHG emissions by 2030 compared to 2018 level has also been set. South Korea also plans to phase out from coal;
- The 11th Basic Plan for Electricity Supply and Demand (2024–2038) is the operational instrument of the MOTIE which set goals for the electric sector until 2038. The 10th Basic Plan set the renewable target to 22 % by 2030 and 31 % by 2036. The 11th Basic Plan increases the goal of renewables to reach 33 % by 2038.[163] The generation mixed to be reached by 2038 is the following: 248.3 TWh of nuclear (35.2 %), 70.9 TWh of coal (10.1 %), 74.3 TWh of gas

160 KEPCO, Outage time per household (link)
161 REGlobal (2024), South Korea's Power Plans: Ambitious expansion strategy for a sustainable future (link)
162 Korea Legislation Research Institute, Act on Carbon Neutrality and Green Growth for Coping with Climate Crisis (link)
163 Climate Action Tracker, South Korea target overview (link)

(10.6 %), 205.7 TWh of RES (29.2 %) and 105.2 of others (15 %). New installed RES capacity is aimed to be 125.9 GW by 2038 (mainly solar and wind).

4.6 China - Shandong

4.6.1 Sector and market organisation

In Shandong, both generation and retail activities have been progressively opened to competition since 2015. However, State ownership remains significant with central/provincial State-owned enterprises (SOE) acting as producers alongside private / listed renewables developers. Industrial users can procure through grid proxy purchase, retailers or direct market participation if qualified. Distribution and transmission networks operations are monopolies.[164]

Main stakeholders in the power sector of Shandong include:

- The National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) oversee the national energy market. Energy policy is nationally determined but implemented through provincial notices and market rules;[165]
- The NEA Shandong Regulatory Office (provincial office of NEA) supervises market order, grid access and regional implementation;[166]
- Shandong Development and Reform Commission (DRC) and Shandong Energy Bureau set provincial energy policy and pricing implementation within national rules;
- State Grid Corporation of China, through its provincial branch State Grid Shandong, is the state-owned TSO operating in Shandong. The distribution grid is mainly operated by State Grid Shandong,[167] but some other public and private local distribution networks operators exist;[168]
- Main generation companies in Shandong are the provincial branches of Huaneng, Huadian, Datang, State Power Investment and China Energy Investment group. All are central State-owned enterprises, fully owned by the Chinese State through the State-owned Asset Supervision and Administration Commission (SASAC). Only a marginal part of the generation is owned by private actors.[169]

The core framework is set at a national level, in a transition started in the early 2000s moving from regulated coal-fired tariffs to a market-based pricing system. Shandong is a forerunner in this liberalisation process, showing also some initial steps towards the unbundling of power network operators (previously owning the generation and supply segments of the energy value chain)[170] .The level of competition in the market, however, remains limited as assets are mostly

164 Oxford Institute for Energy Studies, Guide to Chinese climate policy 2022 (link)
165 Ibid.
166 Shandong Energy Regulatory Office of NEA, Overview of the institution (link)
167 State Grid Corporation of China, Organizational structure (link)
168 Jining Development and Reform Commission, Comprehensive Pilot Plan for Electricity Sector Reform in Shandong Province (link)
169 Feng, X. (2016), "Smart Grids in China: Industry Regulation and Foreign Direct Investment," Energy Law Journal (link)
170 Unbundling of generation and transmission activities have been launched in 2002. A further step in unbundling has been done in 2015 when retail and network operation activities have been separated. Distribution operations have been also opened to new entrants, but only on new areas (DSOs operate as monopoly on their respective areas). However, State ownership remains significant with central/provincial State-owned enterprises (SOE) acting as producers alongside private / listed renewables developers. State Council (2002), Notice of the State Council on the Issuance of the Plan for Electricity Sector Reform (link) ; Central Committee of the Communist Party of China (2015), Several Opinions on Further Deepening the Reform of the Electricity Sector (link) ; NDRC and NEA (2015), Notice on the Issuance of Supporting Documents for Electricity Sector Reform (link)

state owned, with private ownership starting to be present at the supply level - although only marginally.

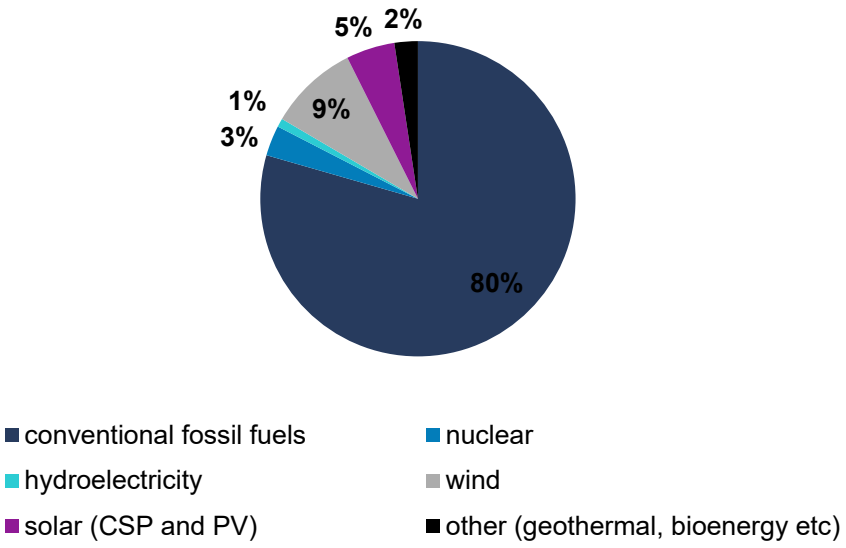
Structure-wise, there are a fully-fledged forward market (where contracts of different lengths are traded), a day-ahead spot market, an intraday market, a market for ancillary services and a system that allows the trading of green electricity certificates (GEC).

In Shandong, interconnection is domestic and interprovincial rather than cross-border. Shandong is a receiving-end province with ultra-high voltage (UHV) import corridors. In 2024, imports from neighbouring provinces exceeded 150 TWh, equal to 18.6 % of provincial electricity consumption. During summer peak, external power reached 28.07 GW, equal to 25.8 % of load.[171]

4.6.2 Generation mix and consumption

In 2024, total gross electricity generation in Shandong was 613.3 TWh. 487.3 TWh were produced by conventional fossil fuels, 19.1 TWh by nuclear power and 106.9 TWh by renewable energy sources (mainly wind and solar). Figure 295 below shows generation shares for each source in Shandong in 2025. Electricity generated by conventional fossil fuels (gas and coal) largely dominates the mix.

Figure 25: Generation mix of Shandong in 2024 (%)

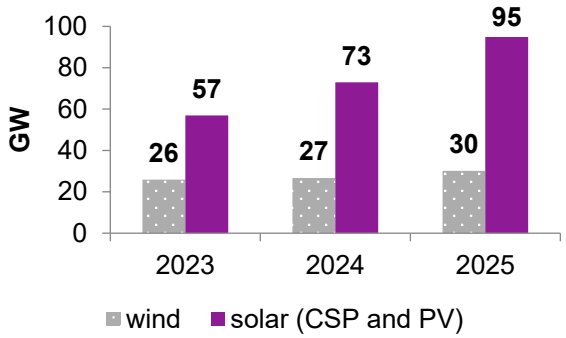


Source: Compass Lexecon analysis based on data from National Bureau of Statistics of China (2026)

Shandong is developing new RES-E capacity, especially solar power with circa 20 GW of annual additions in both 2024 and 2025. Figure 26 below shows installed wind and solar capacities in Shandong between 2023 and 2025. Solar capacity increased by 37,923 MW over the period. Wind capacity increased by 4,219 MW over the same period.

171 Dazhong News, "External Electricity Entering Shandong" - 20 Years Supporting a Leading Economic Province: State Grid Shandong Electric Power's Twenty-Year Retrospective on the "External Electricity into Shandong" Strategy (link)

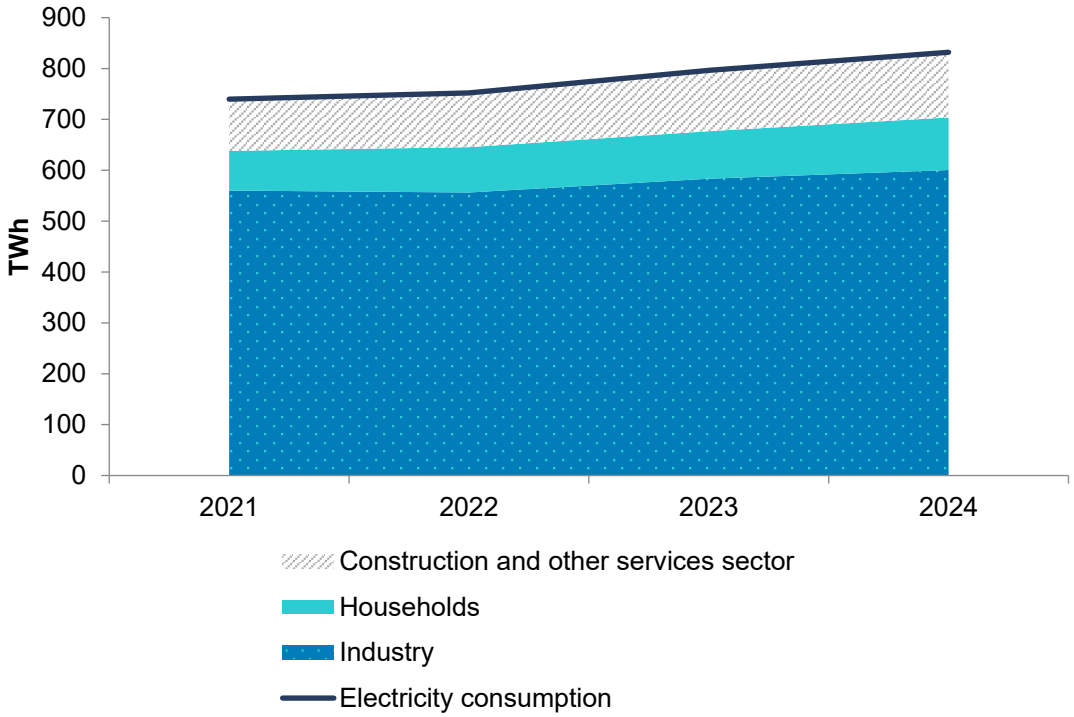
Figure 26: Cumulated installed capacity of wind and solar capacity in Shandong since 2023 (GW)



Source: Compass Lexecon analysis based on data from xxx

Over the 2023-2025 period, conventional fossil fuels capacity increased by 436 MW (2025: 117,956 MW). The fossil fuels capacity installed in Shandong is predominantly coal-fired.

Figure 27: Net electricity consumption (breakdown by sector) in Shandong between 2021 and 2024 (TWh)



Source: Compass Lexecon analysis based on data from China Electricity Consumption (2026); Shandong Provincial Bureau of Statistics (2025), *Energy analysis 2024*; State Grid Shandong *via* CPEM (2025), 2024 electricity consumption.

In 2024, industry (secondary) amounted to 74 % of total net consumption, households to 13 % and construction and other services sector to 13 %. Figure 27 above shows electricity consumption and breakdown by sector in Shandong between 2021 and 2024. Net electricity consumption in Shandong has been slightly increasing over the 2021-2024 period, ranging between 740 TWh (2021) and 832 TWh (2024).

4.6.3 Network structure

State Grid Shandong operates both transmission and distribution networks:

- Transmission and system operation are within the State Grid Corporation of China (SGCC) area, with State Grid Shandong operating the provincial grid and connecting Shandong to UHV/interprovincial import corridors. The SGCC provincial grid is dense with major 35-500 kV reinforcement and UHV import links. In 2024, State Grid Shandong reportedly commissioned 134 projects at 35-500 kV, added 1,997 km of lines and 14.64 million kVA of transformer capacity.[172]
- Distribution remains primarily grid-company led through State Grid Shandong and local distribution networks. Incremental reform allows some local distribution or industrial park arrangements, but public evidence points to SGCC as the dominant grid actor.

At transmission and distribution level, where the bulk of electro-intensive industries is connected, Shandong has a reliable power supply. Reliability indicators for 2024 confirm this: SAIFI stood below 1 interruption per year for rural network customers and below 0.25 for urban network customers, while SAIDI for urban network customers was below 1 hour per household (no comparable rural-network data being available).[173] On both counts, Shandong ranks among the best-performing provinces nationally. This is corroborated by SGCC's grid-reinforcement reporting, peak-load management, and the absence of demand-response activation in 2024 despite 61 days with load above 100 GW, together pointing towards a high level of security and continuity of supply.[174]

Figure 28: Grid map of Shandong (as of 2026)



Source: Open Infrastructure Map *(2026)*.

The "Shandong Province Power Development 14th Five-Year Plan" (for the 2021-2025 period) aims at the implementation of 68,500 kV electricity network projects, which will add a transformer capacity of approximately 59 million kVA and approximately 5,200 km of power lines.[175] The 15th plan has not yet been published, but State grid (the national TSO) plans to invest 4,000 billion Yuan (around 480 billion €) under the 15th five year plan. This represents a 40 % increase

172 China Power, "In 2024, Shandong's total electricity consumption reached 831.972 billion kWh" (link)
173 NEA & China Electricity Council (2024), National Power reliability Annual Report (link)
174 Ibid.
175 Energy Administration of Shandong Province (2022), Building a New-Type Power System to Support the "Dual Carbon" Goals: Shandong's 14th Five-Year Plan (link)

compared to the previous plan. Therefore, an increase in the grid investment plan of Shandong could be awaited.[176]

4.6.4 Regulatory framework and public policies

China has planned in 2021 in its 14th Five-year Plan at a national level to reach peak carbon emissions by 2030 and carbon neutrality by 2060. The Plan had set the objective to reduce energy consumption and carbon dioxide emissions per unit of GDP by 13.5 % and 18 % in 2025 respectively compared to 2021.[177]

The "Shandong Province Power Development 14th Five-Year Plan" (for the 2021-2025 period) set objectives in term of development of new capacities for the 2025 horizon. Directions given by the 14th plan are, on the one hand, the development of renewable energy, nuclear power, natural gas and imports, and on the other hand, the reduction of the share of electricity generated from coal, along with the reduction of low-efficiency generation capacity. For 2025, this would result in a generation mix comprised of 60 % conventional fossil fuels, 20 % RES-E and 20 % imports.[178]

Furthermore, the Chinese government has historically supported the development of energy-intensive industries through a combination of regulated electricity pricing arrangements, support for coal-fired generation and, in some cases, and access to captive power plants. In the aluminium sector, captive generation remains an important feature of the cost structure of some industrial facilities, particularly in provinces with a strong heavy-industrial base. Historically, Shandong hosted one of the largest concentrations of captive coal-fired power plants associated with aluminium production. [179] However, since 2020, a significant share of Chinese aluminium smelting capacity has been relocated towards provinces with greater access to low-cost electricity, including Yunnan and Inner Mongolia, as the industry adapts to China's 45 Mt/year primary aluminium production cap and decarbonisation objectives.[180] While access to relatively low-cost power continues to be an important determinant of competitiveness for aluminium producers, recent increases in electricity prices in some recipient provinces, including Yunnan, illustrate that these advantages may evolve over time. Overall, regional differences in electricity costs continue to influence the geographic distribution of energy-intensive industrial activity within China.

176 State-owned Assets Supervision and Administration Commission (2026), State Grid Plans 4 Trillion Yuan Fixed Assets Investment in Next 5 Years (link)

177 NDRC (2021), *Outline of the People's Republic of China 14th Five-Year Plan for National Economic and Social Development and Long-Range Objectives for 2035*, translated by CEST (2021) (link)

178 Energy administration of Shandong Province (2022), Shandong Province 14th Five-Year Plan for Energy Development (link)

179 Ember (2021), *As aluminium surges in China, so do carbon emissions* (link)

180 On the aluminium smelting relocation: China Strategy, "China's heavy industry starts long march from rust belt to sunshine", Feb 2026, link, and on the cap: Recycling today, "China's aluminum capacity hits the ceiling", May 2026, link

5 Comparative analysis of industrial electricity rates as of 2025

This section analyses industrial electricity retail rates in Norway compared to selected regions presented in Section 4. This section is structured as follows:

- In subsection 5.1, we present the methodology used for benchmarking industrial electricity rates amongst selected regions. In particular, we explain the assumptions regarding the type of consumers considered for the benchmark and how we assess each of the electricity price components;
- In subsection 5.2, we present the key results of our analysis comparing Norwegian electricity prices with the other regions included in this study;[181] As part of this exercise, we provide a projection of the evolution of prices over the last 10 years and compare our results with the key findings presented in the 2016 Fraunhofer report.[182]
- In subsections 5.3 to 5.6, we focus on the three key components of the retail electricity price paid by industrials (procurement costs, system and network costs and taxes and levies) and the relevant additional support schemes analysing in detail the differences across the benchmarked regions. For each component, we will comment on the evolution of the presented figures over the past 10 years and compare our results with the key findings presented in the 2016 Fraunhofer report.[183]

5.1 Methodology

Retail electricity rates usually aim at covering the costs of the full electricity value chain, including:

- Generation: the costs of investing in and fuelling electricity production plants recouped from consumers through wholesale electricity prices;[184]
- Commercialisation: the costs of managing client relationships, contracts and marketing electricity;

181 Our figures excluding additional support schemes (such as Indirect Carbon Cost Compensation)

182 Fraunhofer Institute for Systems and Innovation Research (2016), *Electricity Costs of Energy Intensive Industries An International Comparison.* (link)

183 Ibid.

184 Typically, in Europe, those costs are recouped through the sale of electricity on the series of wholesale markets. The pricing of electricity is based on the principle of marginal pricing whereby plants bid their short-run marginal costs (SRMCs). The market operator ranks these bids in merit order, from the lowest to the highest cost, and dispatches plants accordingly. The last plant required to meet demand sets the clearing price. All dispatched generators are then paid at this clearing price. Overtime, the revenues earned from wholesale markets should cover variable operating costs but also contribute to the recovery of the fixed costs and of the investment. A notable exception is hydropower. Bids of hydroelectric plant are indeed generally based on the water value, which is the opportunity cost of using water today rather than storing it for future periods when electricity prices may be higher. Moreover, gas prices drive EU wholesale electricity prices since they are marginal during a large share of the time (European Energy Agency, 2026). Main components of the gas price are the supply (price of natural gas imports) and the CO_2 price.

- Transmission (and where relevant distribution) and grid balancing: the costs of investing and maintaining electrical lines and transformers to supply consumption sites, as well as the costs of ensuring the balance between production and consumption at all times;[185]
- National and local taxes on electricity consumption, and levies that may include charges to fund public interventions in support of policy objectives that the market itself would not deliver – typically, renewables support mechanisms such as Feed-in-Tariffs.

In this section, generation and commercialisation costs will be referred to as "**electricity purchase costs**" (the cost for a unit of power), transmission and grid balancing costs will be referred to as "**network and system costs**", and national and local taxes and levies will be referred to as "**taxes and levies**",[186] representing the three key components of the electricity retail price paid by industrials.

Importantly, the total costs of the power system are diversely spread over each unit of power demand, or every consumer class, depending on the structure of power rates (based on connected power, or energy consumed), the hourly shape of the consumption of a given site, the voltage level of its grid connection and other characteristics. Thus, to allow comparing data between world regions, we define a profile of consumer for which we will identify procurement conditions, network charges and levies applied and potential rebates available. Our typical consumer is:

- a manufacturing industry plant,[187] connected to the high voltage transmission grid – but not the highest voltage level (this would typically correspond to a voltage level between 63 and 350 kV, in most cases to 110 kV) and that does not own the power plants supplying it with electricity;[188]
- with an annual consumption higher than 10 GWh a year, a threshold used by regulators in Europe to define electro-intensity – and in practice closer to several TWh;
- a utilisation rate of 80 %, i.e. 80 % of the hours of the year, it consumes at a power equivalent to the level of power with which it is connected to the network, in other words, the site has a "baseload" consumption profile.

Large electricity users may also include installations that do not belong to the manufacturing industries, such as data centres. Where relevant, we analyse changes to tariffs and electricity costs for these categories of users.

We analyse three main components of the electricity retail price paid by industrial applying the following assumptions:

- **Electricity purchase costs**: industrials buying electricity have a range of de-risking / hedging mechanisms and markets available to buy from, typically through PPAs (long-term power

185 Network and system charges are used to finance the extension of the network, as well as maintaining it and ensuring grid stability These costs cover the following types of costs: fixed components (€/year), which cover management and metering costs; a withdrawal component; an injection component, which reflects the costs of losses generated on the network as well as the cost of losses under the ITC cross-border mechanism; components specific to certain ancillary services.

186 Taxes and levies cover various taxes (excluding VAT), some allocated directly to the state budget. Taxes and levies are for example renewable taxes, capacity taxes, environmental taxes, and nuclear taxes.

187 Our mandate also includes an analysis of the electricity retail rates for large power consumers that are not manufacturing industries – such as data centres. Where retail rates of data centres would differ from retail rates of electro-intensive manufacturing industries, we include qualitative comments in boxes throughout the report.

188 Ownership of generation assets can result in significantly lower electricity procurement costs than those experienced by consumers who rely exclusively on the grid. This is particularly true for certain large integrated industrial companies, such as RioTinto in Canada (link). However, in the absence of sufficiently detailed and comparable public data, these scenarios cannot be robustly modelled within the scope of this study.

purchase agreements). Thus, the actual purchasing strategy of a company or if widely adopted, a given sector, may result in a diversity of outcomes as compared to the average market prices. A widespread hedging strategy, for instance, is to buy electricity using the available range of futures/forward products from 3 years prior to the year in which the consumption occurs. However, statistical data on whether those strategies lead to an outcome that is different than the average electricity day-ahead price for the year of delivery is lacking, especially in some regions studied (South Korea, China, etc). As such, we assume that the costs of procuring electricity that is embedded in large power consumers' bills is best reflected by average market/generation prices for electricity in each zone for the year of delivery.

- **Network and system costs**: network and system costs are usually (for Europe at least) spread over consumers classes based on a principle of cost-reflectivity, permitted by the regulation of network operators. Therefore, large electricity consumers connected to the high voltage grid tend to bear the lowest share of the total system costs than consumers further down the grid levels. As such, we use the actual network and system tariffs according to the latest data published by regulators, in each of the selected countries, for our consumer profile. We include available rebates and discount for our benchmark consumer profile.
- **Taxes and levies**: as for network costs, the latest data published by regulators is used and we include available rebates and discounts for our benchmarked consumer profile.

Other mechanisms affecting industrial retail electricity costs, such as the Temporary Price Relief under CISAF, Indirect CO_2 cost compensation, and similar schemes are analysed in a dedicated section where their impact on total retail costs is presented as a sensitivity analysis, acknowledging that not all industrial sectors may benefit from them.[189]

To the extent possible, we comment on evolutions of each segment of the retail rates since 2016 according to the analysis of the report "Electricity Costs of Energy Intensive Industries. An International Comparison" published by Fraunhofer Institute for Systems and Innovation Research and dated 2016 (see 2.1). In doing so, we distinguish between, methodological discrepancies, and drivers of change associated with fundamentals of the electricity sector.

5.2 Norwegian retail rates for our benchmarked consumer profile rank 2nd most competitive amongst selected regions

5.2.1 Comparison of retail prices in 2025 across selected regions

For our benchmarked consumer profile defined in Section 5.1, and according to available public data, Norway currently has amongst the lowest industrial electricity prices across benchmarked regions. Table 1 below presents industrial electricity retail prices for the benchmarked consumer profile including rebates in Norway and selected regions in 2025.

Table 1: Retail industrial prices (€/MWh) with rebates in Norway and selected regions in 2025 – baseload consumption

Region	NO	FR	DE	ERCOT (Texas-USA)	UAE	Shandong (CN)	KR

189 Investment support schemes (such as Enova grants in Norway) that may indirectly influence the cost of electricity, notably through energy efficiency gains, are excluded from the scope of this analysis as far as they do not act directly on the price paid per unit of energy consumed.

Table 1: Retail industrial prices (€/MWh) with rebates in Norway and selected regions in 2025 – baseload consumption

Energy procurement cost (€/MWh)	**39.88**	61.14	89.61	29.64	n.a.	43.63	77.27
Network and system cost (€/MWh)	**1.89**	1.37	7.00	5.91	n.a.	18.10	21.44
Taxes and levies (€/MWh)	**0.51**	18.34	2.14	0.01	n.a.	10.47	8.77
Total price (€/MWh)	**42.28**	80.85	98.74	35.57	45.81	72.20	107.49

Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT)).
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

We note that, for the UAE, there is no public breakdown of electricity costs by component. Abu Dhabi serves as the primary benchmark, as it publishes a dedicated tariff category for industrial customers with connected load above 1 MW. Under the 2025 tariff schedule, the standard industrial tariff ranges from 6.5 to 8.8 c€/kWh (incl. VAT), depending on the time of use.

However, large industrial consumers may benefit from preferential tariff schemes administered by local utilities. In Abu Dhabi, the Electricity Tariff Incentive Program (ETIP) provides eligible industrial users with reduced tariffs of 4.8 to 6.0 c€/kWh, while the Northern Emirates offer preferential rates for very large industrial and technology-sector consumers. As the benchmark aims to reflect the effective electricity costs faced by electro-intensive industry, the ETIP tariff has been used, resulting in an indicative retail price of 45.81 €/MWh for the benchmark consumer profile.[190]

Norway achieves industrial electricity rates for the benchmarked consumer profile around 43 €/MWh through a combination of low energy production and purchase costs, mostly reflective of a high penetration of hydropower sources,[191] and targeted rebates on network costs and levies. Meanwhile, the average industrial electricity rate across selected regions stands at 66 €/MWh.

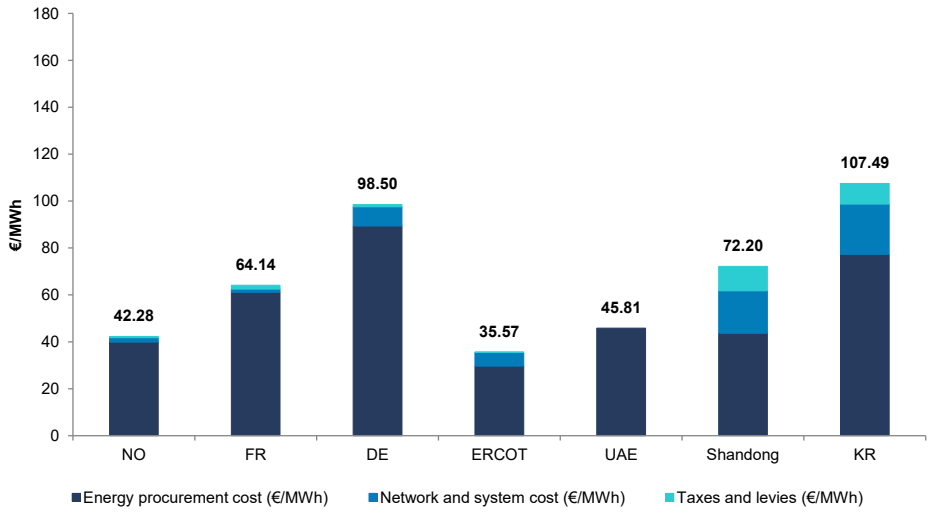
Germany and South Korea have the highest retail prices in the benchmark, driven primarily by high energy procurement costs. In both markets, wholesale electricity prices remain significantly influenced by fossil-fuelled generation. In Germany, this reflects continued exposure to imported gas and other fossil fuels despite a high share of renewable generation, while in South Korea the generation mix remains largely dependent on conventional thermal generation and a high dependency to fossil-fuelled power plants. By comparison, although gas represents a large share of the generation mix in Texas (ERCOT) and UAE, these two regions' own gas resources allow electricity generators to access lower costs commodities. Figure 29 presents the breakdown by component (procurement cost, network and system costs, taxes and levies). Energy procurement cost represents between 72% and 92 % of the total retail industrial price in the selected regions. Norway has the highest share with 92 %.[192]

190 This is above Norway's benchmarked industrial retail rate but remains below the highest-cost regions in the sample. The UAE figure is not directly comparable on a component-by-component basis, because it reflects a regulated bundled tariff, while Norway's benchmark is built from separately identifiable procurement, network, and tax components in a liberalised market structure. Targeted emirate-level industrial incentives may reduce electricity costs for eligible users and are discussed separately in Section 5.6.

191 This corresponds to the electricity market price (in 2025) as explained in Section 5.1(Methodology).

192 This does not reflect unusually high procurement costs in Norway. Rather, it is driven by the comparatively low level of non-energy charges, including network and system costs and taxes and levies, which are among the lowest in the benchmark for the consumer profile defined in Section 4.1. For the benchmarked consumer profile, network and system costs amount to 1.9 €/MWh and taxes and levies to 0.5 €/MWh in Norway, compared with averages of approximately 8 €/MWh and 7 €/MWh respectively across the benchmarked regions. See Table 1 and Sections 4.4 and 4.5.

Figure 29: Retail industrial prices (€/MWh) with rebates in Norway and selected regions in 2025



Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT)), all components were therefore included in the procurement costs component.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

Figure 29 also shows that network and system costs represent between 2 and 20 % of the industrial electricity rates. In Europe, low network and system charges are achieved through rebates for energy intensive industrials. Comparatively, ERCOT does not provide industrial rebates although the network tariff's structure acknowledges large industrial consumers as a specific category. In South Korea, network costs increased in 2024 only for industrial customers, while domestic clients were not affected by tariff updates.

Similarly, taxes and levies represent between less than 1 % and 23 % of the bill for industrial customers across studied regions. Both France and Germany exempt industrial consumers from the bulk of renewables support charges. South Korea applies no rebates on taxes and levies to industrial consumers.

5.2.2 Evolution of retail electricity prices paid by industrials since 2016

The comparative analysis of electricity procurement cost between selected regions reveals a similar ranking between 2016 and 2026. Key conclusions of the 2016 report remain mostly valid. Energy procurement costs have increased in nominal terms in virtually all countries studied. Particularly acute in Europe, the increase masks an even higher variation during the 2021 energy crisis. Spot prices increased in all studied regions, except for the UAE with regulated prices and no open market (for which the retail industrial price remained the same since 2018).

Network and system costs increased in 2025 compared to 2016. This increase has been driven by the increase in investment needs in transmission and distribution networks, including both the reinforcement and renewal of ageing infrastructure and the integration of growing share of RES.

Two kinds of evolutions of taxes and levies were observed over the ten last years: an increase in taxes and levies mainly due to the impact of the energy crisis and the cost of financing RES capacity, and a decrease in taxes mainly as a support measure during the energy crisis. The effect of this evolution varies across the countries studied.

5.2.3 Comparison of our findings with the 2016 Fraunhofer report

The analysis of electricity prices presented in the 2016 Fraunhofer report shows figures up until 2013 and is based on a different methodology: perimeter (consumption band) and data sources are different between the two reports for procurement and network and system costs. In addition, taxes and levies in the 2016 Fraunhofer report are presented without exemptions, while we include them in our analysis.

Due to the methodological difference, a detailed comparison of the results across the two reports is not meaningful. We therefore provide a high-level comparison of the main findings of the two reports.

Both reports find that Norway has amongst the lowest electricity procurement costs for energy intensive consumers. One key driver is the favourable availability of resources, especially hydropower. Similarly, Network system costs in Norway tend to be lower than most of the benchmarked regions, as they were in the 2016 report. This is in part driven by the high availability of hydropower that tends to reduce balancing costs. The level of taxes and levies, and the ranking of Norway within the selected regions are also aligned in the two reports.

5.3 Norway has amongst the lowest electricity purchase costs across the benchmarked areas

Norway has amongst the lowest electricity purchase costs in 2025, driven by the availability of resources (especially hydropower) and high penetration of renewables. In addition, the flexibility provided by Norway's large reservoir hydro fleet helps mitigate scarcity risks and is reflected in wholesale market prices through reservoir water values, which influence bidding behaviour and price formation in the Nordic market. These features significantly decrease the cost of producing electricity locally and provide Norway with a valuable buffer in situations of scarcity, although procurement costs remain exposed to weather conditions and reservoir inflows.

5.3.1 Procurement costs

The price paid by companies depends on the size and procurement strategy of each company. Small companies and residential customers are mostly tied to retail tariffs that reflect their suppliers' costs and hedging strategies. Energy-intensive and big companies, instead, have the power to negotiate procurement prices individually with generators and have a range of de-risking / hedging mechanisms and markets available to buy from. Thus, the resulting price they pay might differ from the average market price.

Transparency on the actual procurement costs borne by large industrial consumers is limited in most of the regions covered by this study. As a result, and in order to ensure a consistent comparison across jurisdictions, we use average market prices, generation prices or regulated industrial tariffs, depending on the market design of each region, as proxies for procurement costs. While these proxies may not fully reflect the procurement outcomes achieved by individual industrial consumers, they provide the most robust and comparable publicly available benchmark across the selected regions.

Under that assumption, Norway has lower procurement costs than France, Germany, Shandong and South Korea and higher than Texas (ERCOT). Energy procurement costs in Norway and Texas are in the same order of magnitude (around 35 €/MWh), followed by Shandong (with around 50 €/MWh), France (with around 60 €/MWh), South Korea (around 75 €/MWh) and finally Germany (with around 90 €/MWh). Table 2 below presents energy costs (€/MWh) without rebates

of large energy users in 2025 in the selected regions and Norway. Low procurement costs in Norway and Texas are driven by the same factors: a high penetration of renewable energy sources and resources availability (hydro in Norway and fossil fuels such as gas) in Texas. High procurement costs in Germany and South Korea can be explained by the large share of power plants fuelled by (imported) gas in the generation mix, setting prices in the day-ahead market.

Table 2: Energy procurement costs (€/MWh) of large energy users in Norway and selected regions in 2025

Region	NO	FR	DE	ERCOT (Texas-USA)	UAE	Shandong (CN)	KR
Energy procurement cost (€/MWh)	39.88	61.14	89.61	29.64	n.a.	43.63	77.27

Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT)), all components were therefore included in the procurement costs component.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

5.3.2 Procurement strategies

Procurement strategies for industrial consumers vary between selected regions, although some are common to most. Large energy users can rely on forward markets, which allow to cover a share of the consumption up to 3 years in advance.

An alternative for industrials willing to hedge part of the volatility in procurement costs are Power Purchase Agreements (PPA), which are also long-term contracts stipulated with the power producer. In most developed energy markets, several types of PPAs are available including *as-produced PPAs*, where the power supplied depends on the site's generation, and *baseload PPAs* where the quantity of power supplied is fixed. In regions where the retail market is not opened to competition such as the UAE, the utility company passes on the procurement costs to consumers.

In Norway, long-term contracts and hedging opportunities mostly comprise PPAs (*Kraftavtaler*) and the Energy Purchase Guarantee Scheme, a complementary scheme to PPAs which is a public guarantee, reducing counterparty risk.[193] A significant proportion of the electricity consumption of energy-intensive industries is covered by long-term electricity contracts.[194] The high number of agreements in the Norwegian market indicates its good functioning.[195]

In France, electro-intensive consumers can benefit since 2026 from long-term allocation contracts based on nuclear production (Co*ntrats d'allocation de long-terme de la production nucléaire*, CAPN), in addition to PPAs. The CAPN guarantees physical delivery of electricity produced by the nuclear fleet for a price that is based on the nuclear fleet's availabilities and costs.[196] The PPA market in France in 2023 amounted to approximatively 3,500 GWh/year (cumulating new

193 Norwegian Ministry of Trade and Industry, Amendments to the Creditors' Recovery Act (link)
194 NVE, Energibruksrapporten 2023 (link)
195 Ministry of Petroleum and Energy, Energy and Power Balance towards 2020 (link) ; S&P Global, Continued success: European PPA market experiences strong growth in H1 2023 (link) ; Copenhagen Economics, Changed trading behaviour in long-term power trading an analysis of the recent development in power purchase agreements in Norway (link).
196 Characteristics of CAPN: a volume (the contract would not relate to a strict volume of electricity, but to a share of the nuclear fleet's output), a share of nuclear fleet of around 50% of electro-intensives' consumption (~50 TWh, i.e., contractual volume ~25 TWh), a duration of 10-15 years on average, a price based on total nuclear generation costs (the full cost of existing nuclear power calculated by CRE is 60.7 €$_{2022}$/MWh over the period 2026-2030, 59.1 €$_{2022}$/MWh over 2031-2035, and 57.3 €$_{2022}$/MWh over 2036-2040 respectively).

and existing contracts) with around 85 % of Greenfield PPAs (newly built renewables installations). This is equivalent to a cumulative volume of around 2,3 GW until 2023.[197]

In Germany, hedging opportunities revolve around bilaterally traded contracts such as forward / futures contracts and PPAs. PPAs development in Germany is very strong compared to other European countries: Germany was ranked 2nd of the European countries in 2024 and 4th in 2025 after Spain, Italy and Poland. The total (cumulative) volume of PPAs signed between 2019 and 2015 amounts to 10,5 GW (187 contracts signed).[198] There are no specific industrial long-term contracts comparable to, for instance, France's CAPN.

In ERCOT, the electricity system has the most developed power purchase agreement (PPA) market in the United States, offering extensive opportunities for long-term energy contracts. PPAs are the only direct low-carbon power purchase contracts available in Texas. The state of Texas has specific characteristics that facilitate the development of its PPA market.[199] Texas leads the USA in hosting clean power projects contracted to commercial and industrial (C&I) buyers. The state represented 27.6 % of contracted capacity in 2025 and 20 % of projects in 2022.[200] Corporate buyers have contracted with more than 100 clean power projects in Texas, totalling 33 GW. Over the past five years, PPA prices in Texas have ranged from $15 to $45/MWh for wind power and from $25 to $45/MWh for solar power, which makes it one of the most competitive PPA market in the United States.[201] Recent PPA deals in Texas also highlight significant commitments from a variety of industries to secure renewable energy.[202]

In the UAE, there is no liberalised electricity market where end-users choose retail suppliers or buy directly from wholesale markets. As such, industrial consumers are supplied by the utility responsible for their emirate or service area under regulated tariffs.

In South Korea, three kind of PPAs are offered as long term contracts: Direct PPAs (the energy-intensive industry contracts with the generator *via* a renewable power supplier), Third-Party PPAs (KEPCO is involved as an intermediary) and Virtual PPAs (these involve the financial settlement of a PPA price against the KPX pool price in return for Renewable Energy Certificates). In 2025, estimated cumulative PPA capacity amounted to 2,053 MW.[203] The PPA market in South Korea is, however, still in its early phase of development.

In China's Shandong Province, large users can access annual and monthly medium- and long-term transactions, retailer contracts, green power contracts and price-linked retail packages.[204] These long term contracts are available for all industrial and commercial (I&C) consumers, there

197 Capgemini, Green Energy Procurement Barometer in France (link). Load factor used by Capgemini: 17 %, which allows to compute the cumulative capacity as 3,500 GWh/an / (17 % * 8,760 hours).

198 DENA, PPA-Marktanalyse 2025 (link)

199 Its unique electricity market design incentivizes the use of PPA by industrials to mitigate supply risks. In addition, while Texas is the largest state in the US after Alaska, its grid coverage is quite extensive (ERCOT covers +75 % of the state's land area). As such, it tends to have larger-scale renewable projects due to its vast land area and large transmission infrastructure. For instance, Western Texas benefits from greater land availability in a state where permitting is already fairly easy, and lower demand also places downward pressure on PPA prices there.

200 Corporate buyers are selecting Texas-based power purchase agreement (PPA) projects at a faster rate than developers are completing renewable energy projects in the state (only 21 % of all clean power capacity contracted had come online or were under development in 2022).

201 However, these PPA prices are for as-produced contracts, which means that power is delivered when the RES capacity generates power. The competitivity of these contracts can be discussed for baseload consumers which need to buy power on the market when the PPA installation does not generate power.

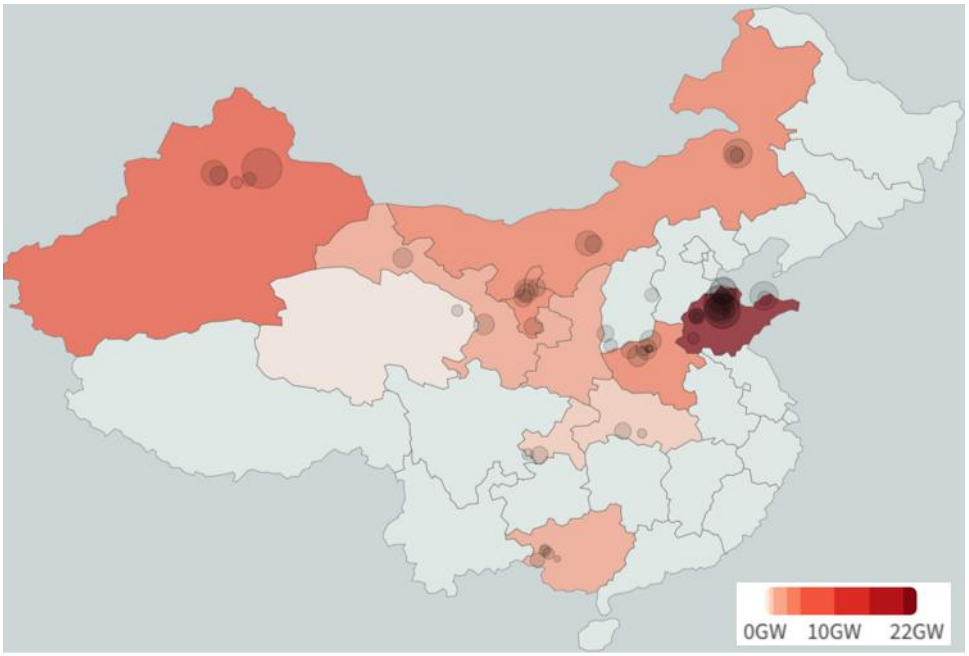
202 Graphic Packaging signed a PPA with NextEra Energy Resources for 250 MW of solar power from the Selenite Springs solar farm, aimed at supporting its sustainability goals. Rio Tinto signed a 15-year PPA with TerraGen for 78.5 MW of wind energy from a 238 MW Texas project, adding to its renewable energy portfolio in the US. Meta secured 600 MW of solar power through a PPA with Engie to reduce its carbon emissions and support its data centre operations in the US. Within a year, the company has signed PPAs totalling more than 1 GW in the state of Texas.

203 Baringa, As South Korean PPAs close in on grid parity, what does it mean for offtakers? (link)

204 National Energy Administration, China Power Market Annual Report 2024 (link), and RMI, 2024 China Power Market Outlook (link)

is no condition of electro-intensity but there is a minimum of contracted capacity of connection to the network (10 kV).[205] Shandong's spot market provides a reference price and settlement mechanism for these contracts and retail offers. Industrial consumers can sign bilateral contracts directly with a producer (mostly a coal plant, but also with wind and solar energy generators) and negotiate the volume and price (similar to PPAs) within a range determined by the government for coal.[206] In addition to purchasing electricity through market-based contracts, some energy-intensive industries in Shandong have historically benefited from access to captive generation assets, particularly in the aluminium sector. These industry-owned power plants, often coal-fired, supply electricity directly to industrial facilities and have been associated with lower electricity costs than grid procurement. Shandong hosts one of China's largest concentrations of captive power capacity, reflecting the province's sizeable aluminium and heavy industrial base. Figure 30 below is a map of China showing the distribution of subcritical captive power stations used for aluminium production in Mainland China. Shandong hosts the highest concentration of such coal assets.

Figure 30: Geographical distribution of subcritical captive coal power stations used for aluminium production in Mainland China



Source: Compass Lexecon analysis based Ember (2021), *As aluminium surges in China, so do carbon emissions*.

5.3.3 Evolution of procurement costs paid by industrials since 2016

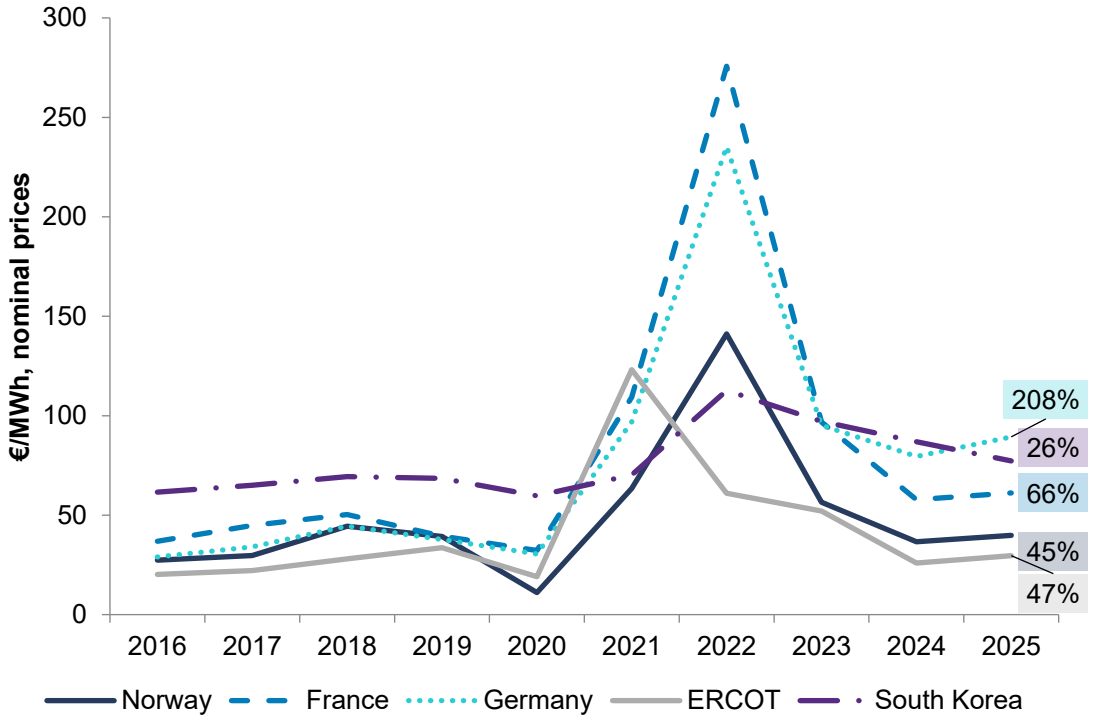
The comparative analysis of electricity procurement cost between selected regions reveals a similar ranking between 2016 and 2026 and therefore the key conclusions reached in the 2016 report about the drivers of procurement costs tend to remain valid. Texas had and still has lower procurement costs than all benchmarked regions, followed by Norway. This result is driven by renewables penetration and availability of resources. Over the 2026-2025 period, the lower price in Texas was driven by the availability of relatively low-cost domestic gas resources, while Norway also experienced a significant increase in procurement costs during the 2021-2022 energy crisis,

205 NDRC, Notice on Further Strengthening the Work of Grid Enterprise Power Purchase on Behalf of Users (link)
206 S&P Global, "Negative electricity prices in Shandong put spotlight on China's energy transition challenges" (link)

although the magnitude of the increase remained lower than in several Continental European markets.

Energy procurement costs have increased in nominal terms in all countries studied since 2016, especially in Europe where they did not return to levels observed before the 2021 energy crisis. Figure 31 below shows spot prices from 2016 to 2025 in all selected regions (€/MWh, nominal prices). In 2025, Germany had the highest procurement costs, whereas it was ranked 3rd in 2016. South Korean costs were the highest in 2016 and remained high in 2025. Spot prices increased the most in 2022, due to a combination of energy crisis, stress corrosion cracking affecting the French nuclear fleet availability and low hydropower production because of the 2022 drought.

Figure 31: Spot prices from 2016 to 2025 in all selected regions (€/MWh, nominal prices) except for the UAE and Shandong, and change (%) in spot prices in 2025 compared to 2016



Notes: The Norwegian spot price is computed as the arithmetic average of all five bidding zones (NP Spot NO1 Base, NP Spot NO2 Base, NP Spot NO3 Base, NP Spot NO4 Base, NP Spot NO5 Base). For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT), all components were therefore included in the procurement costs component. For Shandong, no public data is available on spot prices since 2016. Change has been computed as follows: (price in 2025 – price in 2016) / price in 2016.
Source: Compass Lexecon analysis based on data from Energy Market Price (2026).

Spot prices increased in all studied regions, except for the UAE with regulated prices and no open market (for which the retail industrial price remained the same since 2018). Figure 31 above also shows that the increase in spot prices between 2016 and 2025 range between 26 and 209 %. Compound annual growth rate (in nominal prices) range between 3 and 13 %.[207] The increase in South Korea has been the most limited, where the market is largely state controlled. The increase was the largest in Germany, where generation mix still partly relies on gas and other conventional fossil fuels. The increase in Norway was limited compared to other studied regions because the

[207] Compound annual growth rate was computed as follows: (value in 2025 – value in 2016) ^ (1/9) – 1.

country has been less impacted by high gas prices during the energy crisis, electricity being mostly generated by hydropower and other RES.

Finally, it is important to note that power prices in Norway and most European countries are mainly set by market prices: these are reflective of procurement cost dynamics but can also be influenced by other market factors such as market coupling. Procurement costs are therefore a reliable proxy for electricity prices, but the two might not match exactly.

5.3.4 Comparison of our findings with the 2016 Fraunhofer report

The 2016 Fraunhofer report concluded that Energy procurement costs increased in all studied regions. Comparing these 2013 figures with 2025 ones we note an increase. This increase might be however underestimated by the methodological differences between this report and the 2016 Fraunhofer one. For procurement costs, the main differences are to be attributed to different data sources and a different definition of the representative (industrial) consumer. Table 3 below shows energy procurement costs of large energy users in Norway and in the selected regions in 2013 (Fraunhofer report) and 2025 (this report).

Table 3: Energy procurement costs (€/MWh) of large energy users in Norway and selected regions

Region	NO	FR	DE	ERCOT	UAE	Shandong	KR
Energy procurement cost (€/MWh) in 2013 (methodology of the 2016 report)	35.7	42.0[208]	46.9	29.4	n.a.	n.a.	58.2
Energy procurement cost (€/MWh) in 2025	39.9	61.1	89.6	29.6	n.a.	43.63	77.3

Notes: The UAE and Shandong were not selected in the 2016 report.
Source: Compass Lexecon analysis based on data from Appendix 9.3 and the 2016 Fraunhofer report.

5.4 Norway stands in the middle of benchmarked regions in terms of level of network and system costs for electro-intensive industries

Network system costs in Norway tend to be lower than most of the benchmarked regions, as they were in 2016. This is mostly driven by the high availability of hydropower that tends to reduce balancing costs, considerable storage availability from reservoirs, a high electricity production relative to population, high congestion revenues offsetting the network costs and an historically limited need for large scale grid reinforcement features of the networks (bidding zones send price signals to large consumers to install as well as to generators, limiting the investment needed in the grid).

[208] This price reflects the tariff guaranteed by ARENH until 2025. The 2016 Fraunhofer report mentions that “a law guarantees that alternative energy suppliers can buy nuclear electricity at a price of 42 €/MWh. This value was used in the calculations as a wholesale price, even though bilateral contracts could provide electricity at lower prices”.

5.4.1 Network and system costs without rebates

In a given power system, companies pay different network costs depending on technical characteristics of their connections and consumption profiles (e.g. voltage level of the grid connection, need for network expansion and reinforcement, size of the grid). Network and system costs without rebates are in Norway among the lowest compared to other countries. Table 3 below presents network and system costs without rebates in Norway and selected regions. The full set of sources used to reconstruct the network and system costs component for each of the benchmarked countries is provided in Appendix 9.3. Norway has the lowest network and system costs among all studied regions.

Table 3: Network and system costs (€/MWh) without rebates of large energy users in Norway and selected regions in 2025

Region	NO	FR	DE	ERCOT (Texas-USA)	UAE	Shandong (CN)	KR
Network and system cost (€/MWh)	2.71	7.21	47.00	5.91	n.a.	18.10	21.44

Notes: In Norway, Texas, Shandong and South Korea, there is no rebate on a base tariff (tariff depend directly on a category) so the tariff without rebates is the same as with rebates. For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT)), all components were therefore included in the procurement costs component.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

5.4.2 Rebates and reductions

Energy-intensive companies may be eligible to rebates and State aids in several of the benchmarked regions. Criteria to benefit from network costs rebates vary depending on the region. The full set of sources used to document the eligibility criteria and rebate mechanisms for each of the benchmarked countries is provided in Appendix 9.3. In most cases, rebates on network and system charges are available on criteria of connected power and energy consumption, not sector or electro-intensity.

In Norway, power intensive industries were eligible to rebates in 2025 depending on their connected power subscription and level of annual consumption. The criterium for the rebate for industries in Norway is individual companies with a power subscription of over 15 MW and an annual consumption of over 100 GWh.

In France, a reduction is applied to the tariffs for use of the public electricity transmission network paid by sites that are heavy consumers of electricity and have a predictable and stable or counter-cyclical consumption profile. Provided that the annual electricity drawn from the transmission grid exceeds 10 GWh and the grid usage time is 7,000 hours or more, the industry is eligible for an 81 % reduction on the standard rate in force.

In Germany, companies may obtain a reduction in *Netzentgelte* (grid usage charges).[209] The mechanism targets two distinct consumption profiles: on the one hand, atypical grid users, whose peak load occurs predictably outside periods of high grid load; and on the other, so-called *stromintensiv* or *Bandlast* consumers, who use the grid in a particularly stable and intensive

[209] This comprises both the Leistungspreis (capacity charge) and the Arbeitspreis (energy charge) through the individual grid charge arrangements (individuelle Netzentgelte) provided for under Section 19(2) of the Electricity Grid Charges Ordinance (StromNEV).

manner. For the latter category, the site must achieve at least 7,000 annual utilisation hours and consume 10 GWh per year at a single point of supply (*Abnahmestelle*).[210]

In Shandong, the tariff for industrial is for a 110 kV power subscription and within the tariff, two levels are available. The client can choose between a tariff depending on the demand (yuan/kW/month) or on the capacity subscribed. For this study, the cheapest tariff between the two was chosen, when computed with assumptions made in this study).

Other regions (ERCOT, the UAE and South Korea) do not apply specific rebates although the structure of the network tariffs results in electricity intensive industrials paying less than residential consumers per unit of consumption.[211]

Table 4: Network and system costs (€/MWh) with rebates of large energy users in Norway and selected regions in 2025

Region	NO	FR	DE	ERCOT (Texas-USA)	UAE	Shandong (CN)	KR
Network and system cost (€/MWh)	1.89	1.37	8.22	5.91	n.a.	18.10	21.44

Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT)), all components were therefore included in the procurement costs component.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

Overall, including rebates available for the benchmarked consumer profile defined in Section 5.1, Norway has lower network and system costs after rebates than all studied regions except France, as explained in Section 4.4.3. Shandong and South Korea have the highest network and system costs for energy-intensive industries, with an order of magnitude of around 25 €/MWh. Table 4 above presents network and system costs including rebates for electro-intensive industries in Norway and selected regions. France has the lowest network costs for industrials because of a structure of tariffs which lighten these costs for energy-intensive industries.

On the contrary, ERCOT has a structure of tariffs which does not lighten network costs for industrials. High network and system costs in Germany are due to investment needs in the grid to integrate new renewables capacity and congestion costs. South Korea has the highest network and system costs as a consequence of the 2022 energy crisis when it chose not to increase end-users tariffs (see Section 4.5), while buying energy to generators at a higher price and therefore making operational losses of around 31 billion USD.[212] The government chose to transfer these losses to industrial customers through network and system costs, and taxes and levies (and spared household consumers).[213] In Shandong, network and system costs are quite high, which could be explained by the investment need in the grid and capacity charges (system costs include

210 The level of the reduction is then a function of the number of utilisation hours: from 7,000 h/year, the customer pays a minimum of 20 % of the published grid tariff; from 7,500 h/year, 15 %; and from 8,000 h/year, 10 %. The cost of these reductions is not absorbed by grid operators free of charge: the revenue shortfalls arising from the reduced tariffs are socialised through the §19 StromNEV surcharge (§19 StromNEV-Umlage), which, as of 2025, has been incorporated as a component of the new Aufschlag für besondere Netznutzung (surcharge for special grid usage).

211 It was the case until recently in South Korea where the rate structure has historically been designed to support industrial development through industrial rates set below cost, while other users paid a higher price (link)

212 S&P Global, “South Korea raises electricity rates for industrial use, while freezing bills for households” (link); The Korea Times, “KEPCO hikes industrial electricity rates, keeps residential fees steady” (link)

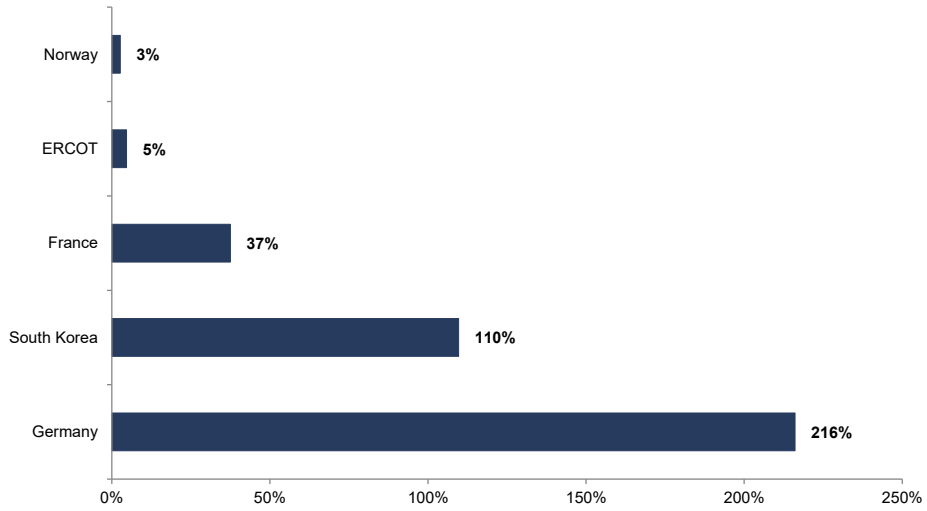
213 Korea Herald, “KEPCO keeps electricity rate frozen for Q1” (link)

capacity compensation, coal-power capacity payment, proxy line loss, pumped-storage capacity cost and allocation adjustments).

5.4.3 Evolution of network and system costs paid by industrials since 2016

In nominal prices, network and system costs have increased in 2025 compared to 2016 in all studied regions. Figure 32 below shows the change (in percentage) of network and system costs of large energy users between 2016 and 2025 in Norway and the selected regions (in nominal prices). Compound annual growth rates range between less than 1 % and 13 % over the 2016-2025 period.

Figure 32: Change (%) in network and system costs with reductions for large energy users between 2016 and 2025 (nominal prices)



Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT)). For Shandong, no public data with a similar breakdown is available for 2016.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

Network and system costs increased in all the reported regions by 3 to 216 %. The most limited increases are in Norway and in ERCOT.

Norway started from a system with abundant domestic hydropower, limited renewable integration costs, and relatively low grid congestion. As a result, there was less need for major network expansion or cost recovery through tariffs than in countries undergoing large-scale energy transition investments.

ERCOT experienced only a modest increase because many grid expansion costs are recovered differently than in Europe, and network charges for large users have historically represented a relatively small share of total electricity costs. The period also saw fewer policy-driven surcharges being passed through network tariffs compared with countries such as Germany and France.

France faced rising investment needs to modernize its electricity network and integrate new renewable generation. However, the scale of network expansion and associated cost recovery was more limited than in Germany or South Korea, resulting in a more moderate increase in tariffs.

South Korea started from relatively low network charges and invested heavily in transmission and distribution infrastructure to support growing demand and evolving generation patterns. As a

result, network and system costs increased significantly as utilities sought to recover these investments through tariffs.

Germany underwent a large-scale energy transition requiring substantial investment in transmission and distribution networks to integrate renewable generation and accommodate changing power flows. As a result, a larger share of network costs had to be recovered through tariffs, leading to a sharp increase despite exemptions for energy-intensive industries. [214]

5.4.4 Comparison of our findings with the 2016 Fraunhofer report

Comparing findings with the 2016 report, we note that network and system costs decreased in all studied regions in 2025 compared to 2013. While this shows an opposite trend compared to the one observed comparing 2016 and 2025 numbers, its justification relies in a methodological difference between the two numbers, as it can be observed in Table 6 below: the Fraunhofer report bases its 2013 figures on different data sources and a different representative (industrial) consumer. This difference explains a higher level of system costs observed in 2013 compared to 2025.

Table 5: Network and system costs (€/MWh) with rebates of large energy users in Norway and selected regions

Region	NO	FR	DE	ERCOT	UAE	Shandong	KR
Network and system cost (€/MWh) in 2013 (methodology of the 2016 report)	6.0	9.0	15.3	n.a.	n.a.	n.a.	n.a.
Network and system cost (€/MWh) in 2025	1.9	1.4	7.0	5.9	n.a.	18.10	21.4

Notes: The UAE and Shandong were not selected in the 2016 report. Network and system costs in ERCOT and South Korea were not computed in the 2016 report.
Source: Compass Lexecon analysis based on data from Appendix 9.3 and the 2016 Fraunhofer report.

5.5 Norway has among the lowest taxes and levies

Norway has amongst the lowest levels of taxes and levies in 2025. The level of taxes and levies, and the rank of Norway within the selected regions are similar to the 2016 ones. The level remained the same in Norway, whereas it increased or decreased in other countries.

5.5.1 Norway has amongst the lowest levels of taxes and levies in 2025 (the level and the rank are similar to 2016).

Companies pay taxes and levies on electricity. National and local taxes and levies include charges that fund the State's budget and public interventions aimed at supporting policy objectives that the market itself would not deliver. Taxes and levies may include an electricity tax, a social tax (social electricity tariffs or contribution to pensions), a local tax (other taxes used by a state or a community for specific purposes), support for energy intensive industries, support for renewable energy sources (such as a RES levy, the cost of certificates, an energy efficiency levy, public

[214] SMARD, Congestion management in the second quarter of 2024 (link)

service obligations, a carbon tax and a smart meter levy) or various other taxes and levies (such as nuclear and capacity taxes).

Table 6 below presents the total of taxes and levies (€/MWh) paid without rebates for large energy users in Norway and selected regions in 2025. The full set of sources used to reconstruct the taxes and levies component for each of the benchmarked countries is provided in Appendix 9.3.

Table 6: Taxes and levies (€/MWh) without rebates of large energy users in Norway and selected regions in 2025

Region	NO	FR	DE	ERCOT (Texas-USA)	UAE	Shandong (CN)	KR
Taxes and levies (€/MWh)	12.05	23.66	24.37	2.93	n.a.	10.47	8.77

Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT), all components were therefore included in the procurement costs component.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

Among European jurisdictions selected, Norway has the lowest level of taxes and levies (all taxes and levies included), while France and Germany present a markedly higher level, at around 25 €/MWh. At the global level, ERCOT recorded the lowest level of taxes and levies of all benchmarked jurisdictions in 2025, with South Korea and Shandong showing a broadly similar level of around 10 €/MWh.

- In Norway, large energy users are generally liable for an electricity consumption tax (called energy tax) on their electricity use. They are also indirectly exposed, through their electricity supplier's cost pass-through, to the cost of the *"elsertifikater"* (green certificates) quota obligation, a market-based renewable energy support mechanism.
- In France, large energy users have to pay an excise tax (ex-TICFE, called "*Accise sur l'électricité*"), a fixed tax on electricity and gas bills used to fund the pensions of former employees of the power industry (*CTA*), and a capacity charge (covering for the costs of the capacity remuneration mechanism);
- In Germany, large energy users must pay the following taxes: RES levies (a KWKG levy for CHP, an offshore grid levy and until 2022 an EEG-Levy for all other RES), an electricity tax and a tax to be allowed to use the public domain (*Konzessionsabgabe*);
- In ERCOT, large energy users are subject to the Texas sales tax (6.25 % of the total bill);
- In the UAE, electricity bills do not include any dedicated tax or levy on electricity consumption;
- In Shandong (China), industrial customers are subject to taxes and charges to the Government. Two government funds are financed: the National Fund for Major Hydraulic Works, financing flagship water infrastructure, and the Fund to Support People Displaced by Medium- and Large-Scale Dams, funding resettlement programs. Capacity charges (generic Capacity Compensation Tariff, pumped-storage capacity charge and coal capacity charge) are passed through to remunerate dispatchable and flexibility assets. The Renewable Energy Electricity Price Surcharge funds historical feed-in tariff subsidies granted to pre-2021 wind and solar projects.

5.5.2 Rebates and reductions

Energy-intensive companies are eligible to rebates and state aid in many studied regions, depending on varying criteria. All the sources used to reconstruct the taxes and levies component including rebates and exemptions for each of the benchmarked countries are provided in Appendix 9.3.

In Norway, eligible energy-intensive users can benefit from a reduced rate of, or exemption from, the energy tax, as well as an exemption from the green certificate quota obligation:

- A rebate or exemption is applied on the energy tax based on the sector (there is no condition of electro-intensity). The reduced energy tax rate is applied to industry, mining, district heating production and sheltered workshops carrying out industrial production. The exemption applies to electricity used in chemical reduction, electrolysis, metallurgical and mineralogical processes, greenhouse industry, direct production of electricity, rail transport;
- Sectors exempted from the electricity tax are also exempted from the green certificate quota obligation.

In France, the excise tax is the only tax reduced for industrial customers:

- In 2025, all reduced electricity rates were replaced by a rate of 0.50 €/MWh under the tax component of the tariff shield (which was introduced in 2022 and until the end of 2025);
- In 2026, industries need to meet criteria to benefit from a reduced excise tax rate. For mining, manufacturing industries, energy, water and waste industries, the activity must be higher than a minimum electro-intensity ratio fixed at 0.5 %, 2.25 %, 6.75 % or 13.5 % to benefit from a reduced rate, ranging between 7.5 €/MWh and 0.5 €/MWh. For example, an aluminium smelter in France would stand in the “hyper electro-intensive” category and therefore benefit to a reduced rate amounting to 0.5 €/MWh.

In Germany, the reductions applied to the regulated components of the electricity bill are based on several distinct schemes.

- First, the *Konzessionsabgabe* is capped at a rate of 0.11 ct€/kWh for industrial customers on special contracts (*Sondervertragskunden*), compared to higher rates for customers billed based on the size of the municipality. Customers of special contracts are all customers with an annual consumption of over 30 MWh per year and a power of over 30 kW during at least two months over a year. Therefore, there is no condition on the sector or on electro-intensity;[215]
- Next, the *KWKG-Umlage* and the offshore grid surcharge fall under the Special Compensation Scheme (*Besondere Ausgleichsregelung*) provided for by the Energy Financing Act (*Energiefinanzierungsgesetz*). The company must meet criteria to be eligible, which are an annual consumption of minimum 1 GWh and the belonging to a sector (sectors of high risk of

[215] It can even be reduced to 0 when the average net price actually paid by the customer is lower than the reference threshold (*Grenzpreis*) published by Destatis. For the 2025 delivery year, this reference threshold is 24.27 ct€/kWh; it corresponds to the 2023 average price for customers under special contracts, excluding VAT and electricity tax refunds, but including network charges, the *Stromsteuer*, and certain surcharges.

offshoring such as heavy manufacturing industries, and sectors with less risk of offshoring based on CISAF criteria);[216]

- Finally, the surcharge for special grid usage (*StromNEV-Umlage*)[217] and the federal tax (*Stromsteuer*, of 20.50 €/MWh) can both be reduced on eligibility criteria.[218] The industry must be a *Produzierendes Gewerbe or Landwirtschaft* (manufacturing industry or agriculture), which is an activity criterium (the eligible sectors are the following: mining, manufacturing industry, energy and water, construction). The industry must also have an annual consumption of over 12.5 MWh, which is a volume criterium.

In ERCOT, if the electricity is used for some type of activities, the site's electricity consumption may become tax exempt. This applies in particular to electricity used for lighting, cooling, and heating within the manufacturing area during the actual manufacturing or processing of tangible personal property for sale; to electricity used directly in processing, or transporting materials extracted from the earth; and to electricity used directly in electrical processes such as electroplating and electrolysis.

Other regions (the UAE, Shandong and South Korea) do not apply electricity taxes rebates for energy-intensive industries.

Considering the impact of the above-mentioned rebates, in 2025 for the benchmarked consumer profile defined in Section 5.1, Norway boasts the second lowest level of taxes and levies for industrial consumers, only topped by ERCOT's almost nil level of taxes. Table 7 below presents taxes and levies (€/MWh) with rebates of large energy users in Norway and selected regions in 2025. Germany and Shandong stand in the middle of the benchmarked regions. France has the highest taxes for industrials customers.

Table 7: Taxes and levies (€/MWh) including rebates of large energy users in Norway and selected regions in 2025

Region	NO	FR	DE	ERCOT (Texas-USA)	UAE	Shandong (CN)	KR
Taxes and levies (€/MWh)	0.51	6.63	0.92	0.01	n.a.	10.47	8.77

Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT), all components were therefore included in the procurement costs component.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

216 The company must belong to an industry listed in Annex 2 of the EnFG, with a distinction between List 1 (sectors exposed to a significant risk of relocation) and List 2 (sectors exposed to a risk of relocation), submit an application to the BAFA, and meet the "green conditionality" requirements, that is, demonstrate efforts toward energy efficiency, green electricity procurement, or investment in decarbonization. The first 1 GWh/year per metering point remains subject to the standard rate; beyond that, companies on List 1 pay only 15 % of the standard rate, companies on List 2 pay 25 %, and companies on List 2 may also be reduced to 15 % if their consumption is covered in a specific manner by renewable electricity. In 2025, the standard rates were 0.277 ct€/kWh for the KWKG surcharge and 0.816 ct€/kWh for the offshore grid surcharge; the reduction therefore lowers their combined total from 1.093 ct€/kWh to approximately 0.164 ct€/kWh at a 15 % rate, or 0.273 ct€/kWh at a 25 % rate, on volumes exceeding the first GWh.

217 *StromNEV-Umlage* offsets revenue losses resulting from individual grid tariffs and exemptions; in 2025, it amounts to 1.558 ct€/kWh for the first GWh, but consumers exceeding 1 GWh/year pay only 0.050 ct€/kWh on the excess volume, and manufacturing companies whose electricity costs exceeded 4 % of revenue pay only 0.025 ct€/kWh on these volumes.

218 Since 2024, companies in the manufacturing sector can obtain, upon request, a reduction of 20 €/MWh under §9b of the StromStG, which reduces the residual charge to 0.50 €/MWh, the minimum allowed under European law.

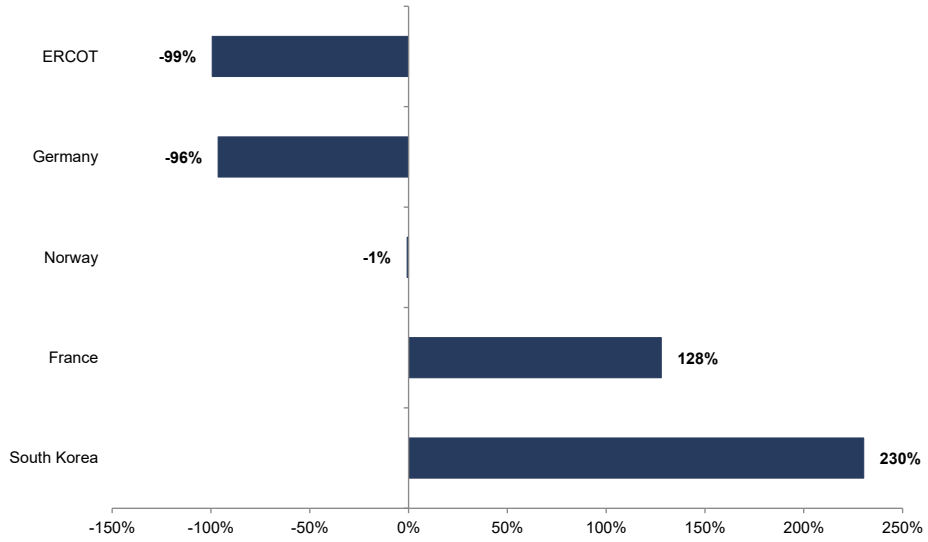
Finally, outside of traditional manufacturing industries, other large electricity users can be exempt of parts of the taxes and levies applied to electricity bills:

- In Germany, the criteria of electro-intensity have been removed in 2023. Since then, the criteria are based on the sector of activity and on a minimum annual level of consumption. Based on these criteria, data centres in Germany are not eligible to tax rebates on *Stromsteuer* and *KWKG-Umlage* because data centres are not on the list of sectors eligible. However, they are eligible to a tax rebate on *Konzessionsabgabe*, if the operate under a special contract (*Sondervertragskunden* – as described in p.72).
- In France, there is a dedicated legislation (L.312-70) that allows data centres to benefit from a rebate on the excise tax. The rebate applies to electricity consumption exceeding 1 GWh per year, provided the data centre meets the following criteria: ability to physically store digital data, securing the data access, owning a management system for environment checks, participating in a best practices sharing programme, recovering waste heat, and fixing a quantified target for water and electro-intensity of at least 2.25 %.
- In ERCOT, a tax rebate is applied to electricity used directly by a data center or large data center project that is certified by the Texas Comptroller as a qualifying data center under Section 151.359, or as a qualifying large data center project under Section 151.3595, for use in the processing, storage, and distribution of data.

5.5.3 Evolution of taxes and levies paid by industrials since 2016

In nominal prices, taxes and levies have decreased in 2025 in ERCOT, Germany and Norway compared to 2016, whereas taxes and levies have increased in France and South Korea over the period. Figure 33 below presents taxes and levies including reductions and rebates of large energy users in 2016 and in 2025.

Figure 33: Change (%) in taxes and levies including reductions for large energy users between 2016 and 2025 (nominal prices)



Notes: For the UAE, there is no similar breakdown (only peak energy consumption, off-peak energy consumption and federal taxes (VAT), all components were therefore included in the procurement costs component. For Shandong, no public data with a similar breakdown is available for 2016.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

South Korea experienced the largest increase in the taxes and levies component of the retail cost. This increase is explained by two distinct factors. First, although the rate of the Power Industry Infrastructure Fund contribution, calculated as a percentage of the pre-tax electricity bill, was reduced over the period, from 3.7% in 2016 to 3.2% in 2025, the increase in the tax base more than offset the lower rate. Second, and more significantly, the Climate and Environment Charge, a levy introduced in 2021 to fund the cost of emission allowances purchased under the Korean Emissions Trading Scheme (K-ETS) and to support the development of renewable energy sources adds 5.61 €/MWh to the electricity bill, accounting for a substantial share of the overall increase in this component.[219]

France saw a substantial increase driven primarily by the capacity mechanism, whose costs rose significantly following tight supply conditions and concerns over nuclear fleet availability.[220] This led to a marked increase in taxes and levies recovered from consumers.

Norway started from a relatively low level of taxes and levies, which remained broadly stable over the period. As a result, the overall tax burden for large energy users changed little between 2016 and 2025.

Germany reduced taxes and levies substantially by shifting the financing of renewable energy support from electricity consumers to the federal budget.[221] As a result, a large share of costs previously recovered through electricity bills was removed from end-user charges.

ERCOT experienced the largest reduction as several electricity-sector charges were eliminated over the period.[222] As a result, taxes and levies became a relatively minor component of electricity costs for large industrial consumers.

Overall, developments in taxes and levies were primarily driven by policy decisions regarding the allocation of energy transition and energy crisis costs. Jurisdictions that continued to recover these costs through electricity bills saw significant increases, while those that shifted funding to public budgets or removed charges experienced declines.

5.5.4 Comparison of our findings with the 2016 Fraunhofer report

Taxes and levies in 2013 are higher than in 2025. Table 8 below shows taxes and levies of large energy users in Norway and in the selected regions in 2013 according to the methodology of the 2016 report, and in 2025 according to the methodology of this report. The values are not comparable because the Fraunhofer report shows values without accounting for exemptions, which brings them at a considerable higher level.

Table 8: Taxes and levies (€/MWh) with rebates of large energy users in Norway and selected regions

Region	NO	FR	DE	ERCOT (Texas - USA)	UAE	Shandong (CN)	KR

219 Barlaup, A., & Biedenkopf, K. (2024), « Carbon pricing under electricity market constraints: analyzing rent management dynamics in the Republic of Korea », Climate Policy (link)

220 CRE, Deliberation of the French Energy Regulatory Commission of 27 September 2018 on the draft decree relating to the capacity obligation mechanism in the electricity sector (link)

221 Bundesfinanzministerium, EEG-Umlage (link)

222 Several charges, including Nuclear Decommissioning Collections, System Benefit Fund and Transition Charges, were removed over the period.

Table 8: Taxes and levies (€/MWh) with rebates of large energy users in Norway and selected regions

Taxes and levies (€/MWh) in 2013 (methodology of the 2016 report, without exemptions)	16.4	22.3	77.1	6.1	n.a.	n.a.	4.4
Taxes and levies (€/MWh) in 2025	0.5	8.6	0.92	0.0	n.a.	10.47	8.8

Notes: The UAE and Shandong were not selected in the 2016 report.
Source: Compass Lexecon analysis based on data from Appendix 9.3 and the 2016 Fraunhofer report.

5.6 Additional mechanisms can affect industrial retail electricity costs

Industrial retail electricity costs are affected by additional mechanisms, available to specific industries. On top of rebates applied directly to components of the industrial retail tariffs, some countries use ex-post grants and direct aid schemes that offset part of the electricity costs borne by eligible industrial consumers.

These mechanisms differ from retail tariff rebates on three aspects:

- First, they are not automatic. Eligibility is generally restricted by sector classification (for example NACE in EU), exposure to carbon leakage risk or minimum electro-intensity thresholds.
- Second, they are typically granted ex-post, commonly in year t+1 based on actual electricity consumption in year t.
- Third, they can – although not always - require an active annual reporting by the beneficiary, with documented consumption and compliance with conditionality requirements (energy audits, reinvestment commitments).

This section identifies three families of ex-post mechanisms in the benchmarked regions, quantifies their effect on industrial retail costs for the reference consumer profile defined in Section 5.1, and presents the sensitivity of Section 5.2 results when these additional schemes are considered.

The mechanisms identified across the benchmarked regions fall into two distinct categories, summarised in Table 9.

Table 9: Typology of ex-post support mechanisms across the benchmark

Categories	Principle	Benchmarked regions concerned
Indirect Carbon Cost Compensation	Compensation of the ETS carbon cost passed through wholesale electricity prices for electro-intensive sectors at risk of carbon leakage	France, Germany, Norway
Direct wholesale electricity price relief	Subsidies a portion of the wholesale electricity price for electro-intensive industries	Germany

Texas, Shandong and South Korea do not operate similar mechanisms. Nevertheless, transparency regarding the effective electricity procurement costs borne by energy-intensive industries varies across jurisdictions, particularly outside Europe. In some cases, publicly available information does not allow a full assessment of contractual arrangements, captive generation, or other factors that may affect realised electricity costs. As such, the comparison presented in this report should be interpreted as reflecting the best available public information rather than the exact procurement costs incurred by all industrial consumers.

The Indirect Carbon Cost Compensation (ICCC) is the most established mechanism of this nature. It compensates electro-intensive industries exposed to a genuine risk of carbon leakage associated with the pass-through of carbon prices in electricity prices (so called indirect CO_2 costs). The aim is to compensate these electro-intensive industries for a cost that competitors in other regions do not have. Eligibility in 2025 was restricted to 15 sectors satisfying combined criteria of trade intensity and indirect emission intensity, as listed in Annex I of the Guidelines, including primary aluminium, basic chemicals, ferro-alloys, electrolytic chlorine, copper, lead and zinc, pulp and paper, and certain plastics.[223]

The scheme is governed by a single legal framework across the EU and EEA: the ETS State Aid Guidelines and transposed in each Member State (and in Norway via the EFTA Surveillance Authority under the EEA Agreement). The ETS State Aid Guidelines define the maximum level of compensation that may be granted ex-post in year t+1 based on actual production in year t according to the following formula. Individual Member States (and Norway under the EEA framework) may choose to provide compensation below this ceiling:

$$A_{max,t} = A_i \times C_t \times P_{t-1} \times E \times BO_t$$

Where A_i is the aid intensity (75% over 2021-2025, raised to 80% from 2026), C_t is the regional CO_2 emission factor fixed in Annex III, P_{t-1} is the average EUA forward price for delivery in December of the support year observed during the preceding calendar year, E is the product-specific electricity consumption benchmark[224], and BO_t is the baseline production.

Beneficiaries are subject to a three-option conditionality requiring satisfaction of at least one of the following: implementation of energy audit recommendations with payback under three years, coverage of at least 30 % of consumption from carbon-free sources, or reinvestment of at least 50 % of the aid in significant decarbonisation projects.

The three benchmarked schemes (*Compensation des coûts indirects (CCI)* in France, *Strompreiskompensation* (SPK) in Germany and *CO_2-kompensasjonsordningen* in Norway) apply the same formula but differ on the regional CO_2 emission factor C_t parameters that drive material variation in realised compensation per MWh of eligible consumption.[225,226]

Consistent with the flexibility allowed under the ETS State Aid Guidelines, the Norwegian scheme is also distinct in two respects: an annual budget ceiling of 7.252 billion NOK for support year

223 The 23 December 2025 revision of the ETS State Aid Guidelines extends the eligible sectoral scope by adding 20 new sectors and 2 new sub-sectors from 2026 onwards. The revision also introduces a strengthened conditionality requirement for large beneficiaries to invest a share of the aid in projects contributing to electricity system cost reductions. Updated CO_2 emission factors and geographic reference areas applicable to the 2026–2030 period are set in the revised Annex III, with a gradual transition mechanism permitted between 2026 and 2030 where the change in regional C_t is particularly large.

224 For products listed in Annex I of the Guidelines that do not have a product-specific electricity consumption benchmark, a fallback efficiency benchmark applies. In this case, the formula uses EF × EC in place of E × BO_t, where EF is a dimensionless fallback coefficient (set at 0.80 in 2021 and reduced by 1.09% annually thereafter, reaching approximately 0.77 in 2025) and EC is the installation's actual electricity consumption in MWh.

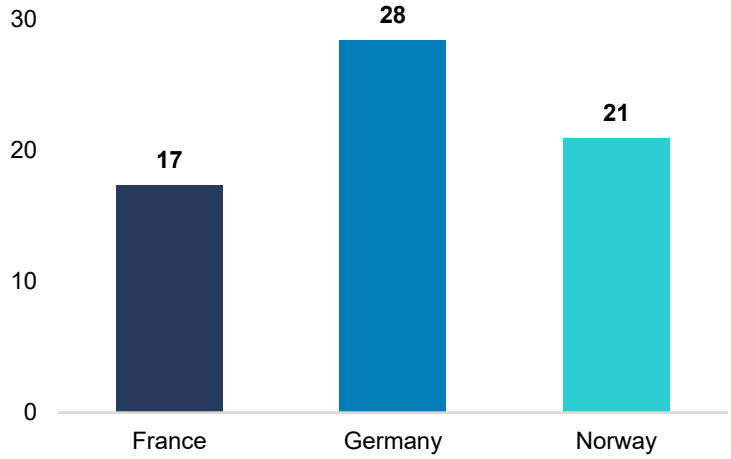
225 Norwegian Ministry of Climate and Environment, Regulation on CO2 compensation for industry for the period 2021-2030 (link)

226 European Commission, Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post-2021 (link)

2025 triggers a pro rata curtailment across beneficiaries when the gross compensation exceeds the cap, and the conditionality is reinforced through a mandatory 40% reinvestment requirement over the period 2024–2030.[227] For 2024, this annual budget ceiling reduces the effective compensation rate from 75 % to around 43 % because of the total compensation demands exceeding this ceiling.[228]

For a reference electro-intensive industry with an annual consumption of 3 TWh and no product-specific electricity consumption benchmark, Figure 34 summarises the resulting compensation across the three jurisdictions.

Figure 34: Illustrative ICCC compensation rate under the standard ETS State Aid Guidelines framework, support year 2025 (€/MWh)



Notes: The figure is illustrative and based on a simplified reference electro-intensive consumer. Actual compensation levels may differ by sector, product benchmark, eligibility conditions and national implementation of the ETS State Aid Guidelines.
Source: Compass Lexecon analysis based on local data sources cited in Appendix 9.3.

The compensation gap between Germany and France reflects the difference in the regulatory C_t. By design, this factor captures the carbon intensity of the marginal generation units in each bidding zone. The higher C_t set for Central Western Europe is a direct translation of Germany's more carbon-intensive generation mix compared to the predominantly nuclear-based French mix. The Norwegian C_t of 0.53 tCO_2/MWh for the period 2020-2025,[229] materially higher than the actual carbon intensity of Norway's hydro-dominated mix, reflects Norway's integration into the broader NordPool-European market via cross-border interconnectors with the continent.

At EU level, since 2025, a new category of ex-post support scheme has been developed, with a different logic than the ICCC. The Section 4.5 of the Clean Industrial Deal State Aid Framework (CISAF) authorises Member States until 2030 to grant relief on the wholesale electricity price for sectors where the combination of electricity intensity and exposure to international trade creates a documented risk of relocation outside the EU.[230] The relief covers at most 50 % of annual consumption and is capped at 70 %[231] of the average wholesale market price. In addition, the

227 The impact of this requirement is not included in the scope of this report, as explained Section 2.1 for any investment subsidy (such as for example Enova grants).
228 Norwegian Environment Agency, Payment of CO2 compensation to industry for 2024 (link)
229 For the 2026-2030 period, the Norwegian C_t is of 0.36 tCO_2/MWh.
230 Eligibility is restricted to the energy-intensive and trade-exposed sectors listed in Annex 1 of the CEEAG 2022 (approximately 91 sectors)
231 Under the draft METSAF framework, Member States may grant relief covering up to 70% of eligible electricity consumption, compared with the 50% limit under CISAF. As of September 2026, implementation details remain subject to approval and national transposition. [European Commission (2026), Middle East Crisis Temporary State Aid Framework (METSAF), adopted on 29 April 2026]

subsidised price cannot fall below 50 €/MWh, and at least 50 % of the aid must be reinvested in decarbonisation, energy efficiency or demand flexibility. As of mid-2026, among the European jurisdictions covered in this benchmark, only Germany has activated this support scheme. The *Industriestrompreis* (industrial electricity price) set to run from 2026 to 2028 with a maximum budget of 3.8 billion euros.[232]

Beyond these two categories, several benchmarked jurisdictions also operate investment support schemes that can indirectly reduce the industrial electricity bill when the funded projects deliver energy savings, on-site generation or process electrification at improved efficiency.[233] These mechanisms differ from the recurring tariff relief schemes discussed above as they target capital costs rather than the electricity bill. They are not quantified in the per-MWh comparative framework underlying Figure 35 but contribute to overall industrial competitiveness in the jurisdictions concerned. These kinds of subsidies are not studied in detail because they are out of the scope of this report, although they indirectly affect industrial power procurement costs.

In South Korea, the K-Steel Act adopted to support the domestic steel industry through five-year master plans and annual action plans explicitly excludes electricity subsidies from its scope,[234] confirming that no sector-specific ex-post electricity cost relief exists.

In China, publicly available information does not allow to identify any such ex-post or additional mechanism that would top-up rebates applied to retail rates components.

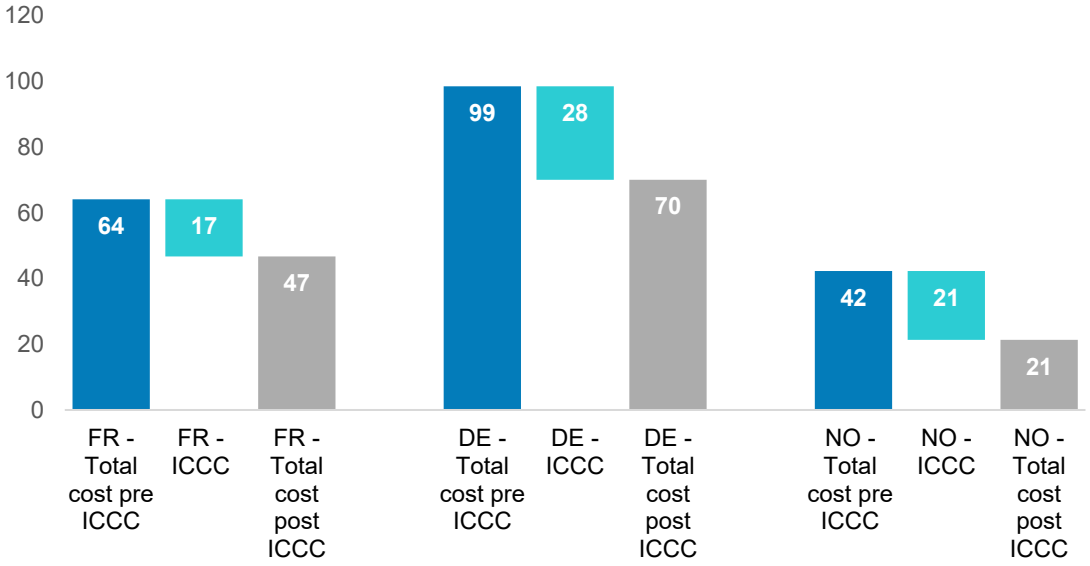
Including these additional ex-post mechanisms, assuming that the benchmarked consumer profile defined in Section 5.1 is eligible, Norway's electricity costs for large industrials remain in the lowest range of the benchmarked regions. Figure 35 below presents industrial electricity retail rates including additional mechanisms in the three benchmarked regions that implemented an ICCC scheme.

232 Federal Ministry for Economic Affairs and Energy (BMWE), Press Paper on the *Industriestrompreis* (link)

233 In Norway, Enova grants finance industrial decarbonisation and energy efficiency projects (including biogas, heat recovery, breakthrough climate technologies) through competitive calls administered by the Enova public agency.
Similar mechanisms exist in France and Germany, respectively through the Fonds Décarbonation de l'Industrie administered by ADEME, and the Bundesförderung für Energie- und Ressourceneffizienz in der Wirtschaft (EEW) administered by BAFA.
In Texas, the federal §48C Qualifying Advanced Energy Project Credit (Inflation Reduction Act) provides an investment tax credit up to 30 % of qualifying CAPEX for industrial decarbonisation and clean manufacturing projects.

234 BusinessKorea, K-Steel Passes, Boosting steel industry competitiveness (link)

Figure 35: Power price net of ICC compensation, 2025 (€/MWh)



Notes: The total cost pre–Indirect Carbon Cost Compensation (ICCC) includes rebates and exemptions on network costs and on other taxes and levies.
Source: Compass Lexecon analysis based on data sources cited in Appendix 9.3.

However, ICCC is planned to expire in 2030. Extension beyond 2030 is not decided yet at EU level, but it might be part of the ETS review to be proposed soon. For the incoming review, Business Europe acknowledges that the situation for EU competitiveness is alarming. Businesses are indeed facing increased costs and fierce global competition while the enabling conditions to create a business case for decarbonisation are largely missing. The ETS should therefore be adjusted to the current challenges and post-2030 context.[235]

[235] Business Europe, Priorities for the EU ETS review (link)

6 Opportunities for monetisation of power consumption flexibility for energy-intensive industries

Actual electricity rates are an important element of cost competitiveness for power-intensive industries. However, they may not provide the full picture of electricity procurement conditions as power systems decarbonise. Demand-side flexibility is increasingly valued in systems with higher shares of variable renewable generation, as large consumers may be able to reduce, shift or optimise consumption in response to system needs.

Where an industrial plant has the technical and economic capability to curtail or shift part of its load, it may derive additional value through participation in power markets, reserve products, demand-response programmes or local flexibility mechanisms. These revenues, where available, partially offset electricity procurement costs. The size of the opportunity varies significantly across jurisdictions depending on market design, access rules, technical requirements and price transparency. For example, in some industries such as pulp and paper, when the paper mill is equipped with thermal storage, revenues derived from flexibility provision bridge a significant share of the additional costs of electrifying the process.[236]

However, providing flexibility with an industrial plant can increase risks of production disturbances that might result from temporarily reducing demand, higher wear and tear of the equipment, extra administrative procedures to ensure security and business continuity or increased electricity consumption when ramping up again after a curtailment event.[237]

This section describes industrial demand-side flexibility valuation opportunities in Norway, before comparing the availability and value of similar mechanisms across the benchmarked regions.

6.1 Industrial demand side flexibility valuation in Norway

In Norway, demand-side flexibility can be offered across several of the markets used to trade power and operate the grid, as presented in Section 3.1.2.

Notably, the whole range of Statnett-operated balancing markets are opened to industrial demand-response participation, with technical requirements that can be adapted to several types of industrial flexibility. These markets include Frequency Containment Reserve (FCR), automated Frequency Restoration Reserve (aFRR), and manual Frequency Restoration Reserve (mFRR) as well as reserve capacity / seasonal reserve-type arrangements. Industrial sites can participate as single installations or aggregated through 3rd party flexibility providers (aggregators). However, information about actual involvement of DSR in these markets is not available in the public domain and therefore the impact of these revenues has not been accounted for in the presented price figures.

236 Compass Lexecon (2025), The business case for flexibility provision in energy intensive industries (link)

237 Compass Lexecon (2025), The business case for flexibility provision in energy intensive industries (link);L. Scharnhorst et al. (2024), Barriers to demand response in the commercial and industrial sectors – An empirical investigation, Renewable and Sustainable Energy Reviews (link); S. Siddiquee et al. (2021) Progress in Demand Response and It's Industrial Applications. Front. Energy Res. (link)

Wholesale markets (both day-ahead and intraday) can provide further opportunities to optimise electricity consumption by arbitraging between time periods to place consumption (load-shifting) or by curtailing at times of high-prices (load shedding). Although, in Norway, third-party aggregators have to obtain prior agreements by the site's supplier to operate.[238]

In addition, local flexibility markets for industrial sites connected at distribution system operator (DSO) level (such as NODES in Norway) may be available depending on the industrial site's location and the relevant market access route.

Revenues from those markets are stackable. A single site may operate alternatively on all those markets during the year, optimising among them, provided it meets the technical requirements to participate. The value derived from the markets will depend on actual market conditions (prices tend to be higher in years with tight supply of flexibility) and the site's actual flexibility capabilities (notably in terms of ramping, i.e. speed of consumption adjustments, and frequency and durations of demand response activations). At a high level, the review below highlights that 1 MW of flexible load can derive between tens of thousands to hundreds of thousands of Euros of revenues from flexible load management per year.

Table 10 summarises the available flexibility valuation opportunities in Norway, highlighting selected technical requirements needed to participate as well as the indicative revenue ranges that can be derived from those markets based on current prices.

Table 10: Industrial load flexibility valuation opportunities in Norway

Valuation avenue	Description	Technical requirements	Revenue band (1MW)
Wholesale: day-ahead and intraday markets	Load shifting or curtailment to reduce consumption during high-price periods in day-ahead and intraday markets. This can be a cost-avoidance / optimisation value or explicit demand response offered on the market obtaining a separate flexibility payment	Min 100 kW, subject to market access route / aggregation model	Site-dependant
Ancillary services and balancing reserves: FCR, aFRR, mFRR	Flexible load may provide reserve or balancing services to Statnett, subject to product-specific requirements. These products remunerate availability and / or activation depending on the market	Min 1 MW Activation ramp-up: under 30s for FCR-D, 5 min for aFRR, 12.5 min for mFRR Minimum activation time: 15 min	FCR: 10,000 – 50,000 €/MW/y aFRR: 15,000 – 80,000 €/MW/y mFRR: 5,000-40,000 €/MW/y
Reserve capacity / seasonal reserve-type arrangements (RKOM-H, RKOM-B)	Secures enough available capacity is offered in mFRR during winter month. Payments are made to available capacities over specific periods against an obligation to submit mFRR bids in energy activation markets	Min 5 MW Minimum activation time (mFRR): 15 min	10,000 – 120,000 €/MW/y

238 SmartEn, Market Monitoring Report 2025 (link)

Table 10: Industrial load flexibility valuation opportunities in Norway

Local flexibility markets (NODES)	Location-specific flexibility procurement where flexible loads can help manage local grid constraints through capacity availability and / or energy activations	Typically aggregated; depends on local grid needs, metering and platform / DSO requirements	Site-dependant

Notes: FCR = Frequency Containment Reserve; aFRR = automatic Frequency Restoration Reserve; mFRR = manual Frequency Restoration Reserve; RKOM = Regulerkraftopsjonsmarkedet, Norway's seasonal regulating-power options market; DSO = distribution system operator; NODES = local flexibility market platform. Revenue bands are indicative and should not be interpreted as guaranteed revenues.
Source: Compass Lexecon analysis based on data sources cited in Appendix 9.4.

6.2 Comparative analysis of power consumption flexibility monetisation possibilities in selected jurisdictions

Demand-side flexibility opportunities differ significantly across the benchmarked regions. Norway, France and Texas appear to provide the clearest monetisation routes for industrial users, supported by relatively mature wholesale, reserve, capacity or demand-response mechanisms. Germany and South Korea provide moderate opportunities, although access is more product-specific or programme-led. The UAE and Shandong remain lower-maturity markets from a monetisation perspective, with evidence of policy development, pilots or demand-response programmes, but more limited public price transparency.

Norway is retained as the detailed reference case in Section 6 and is also included in the comparative table below (Table 11) to allow a consistent cross-region comparison. It provides one of the clearest examples of industrial demand-side flexibility monetisation, with value available through wholesale optimisation, reserve and balancing products, reserve capacity arrangements and local flexibility markets. Overall, the net income from providing flexibility has not, and will not, contribute substantially to the competitiveness of a power-intensive industry. While flexibility services can create an additional revenue stream, the value captured is, in the current status of energy markets is, except for some specific sectors and processes, insufficient to materially influence long-term operating or investment decisions.[239]

France also represents a mature flexibility market, supported by explicit demand-response participation, balancing services, a capacity mechanism, flexibility tenders and interruptibility contract opportunities for large industrial sites. This creates multiple routes for industrial loads to monetise flexibility, although the actual value depends on certification, availability, activation and product eligibility.

Germany has established balancing markets and price-optimisation opportunities, but the monetisation route for industrial demand-side flexibility is more constrained. Participation is generally product-specific, technically demanding and dependent on prequalification, aggregation and eligibility for narrower interruptible-load arrangements.

In Texas, the Electric Reliability Council of Texas (ERCOT) market provides high upside for flexible industrial loads, particularly through ancillary services, Emergency Response Service, scarcity-price response and peak-related bill avoidance. However, the revenue opportunity is

[239] Compass Lexecon and SmartEn (2025), The business case for flexibility provision in energy-intensive industries. Technical and economic assessment for the EU in 2030. (link)

more volatile than in European reserve markets, as value depends heavily on market conditions, scarcity events and performance during system stress.

South Korea has an established demand-response framework, with participation generally structured through Korea Power Exchange (KPX) programmes and aggregators. The opportunity is meaningful but more programme-led, with value depending on contracted capacity, baseline measurement, event performance and the specific demand-response product used.

The UAE remains at an earlier stage of flexibility market development. Abu Dhabi has introduced demand-response policy, regulations and pilots, while Dubai's mechanisms are more focused on demand-side management (DSM), bill optimisation and solar-related compensation. As a result, the current monetisation opportunity for industrial demand-side response (DSR) remains limited, with no public monetary range identified.

In Shandong, flexibility emerges as a topic for grid optimisation. The province notably implements a demand-response program and allows the participation and contracting of virtual power plants, i.e. several generation assets including demand response aggregated and operated by an independent third-party. However, the market remains policy-led and public price transparency is limited, data allowing to estimate direct industrial revenue potential is not available.

Table 11 below summarises the findings with regards to the openness of markets, technical requirements to participate and revenues estimates in each of the benchmarked areas.

Table 11: Demand-side flexibility opportunities across benchmarked regions

Country / region	Flexibility markets available for industrial DSR	Technical requirements to provide	Range of revenues based on current prices
Norway	4 market routes are available: ▪ Wholesale optimisation: load shifting / curtailment in response to day-ahead and intraday prices. ▪ Reserve and balancing products: FCR, aFRR, mFRR and FFR procured by Statnett. ▪ Reserve capacity arrangements: availability-based remuneration where additional reserves are procured. ▪ Local flexibility: location-specific procurement where grid constraints create value.	Requirements vary by markets: ▪ Prequalification for reserve products. ▪ Metering, communication and dispatch capability are a must-have ▪ Response capability from seconds for FCR / FFR to minutes for aFRR / mFRR. ▪ Product-specific minimum bid sizes, with aggregation possible in some routes.	Overall value can range from c. €10k-120k/MW/year across reserve-type products: ▪ Wholesale optimisation: site dependent. ▪ FCR: c. €10k-50k/MW/year. ▪ aFRR: c. €15k-80k/MW/year. ▪ mFRR: c. €5k-40k/MW/year. ▪ Reserve capacity / local flexibility: site-dependent to c. €10k-120k/MW/year where applicable.
France	5 market routes are available, making France a strong industrial DSR market: ▪ NEBCO / explicit demand response: load reductions monetised through the French DSR framework. ▪ Balancing and ancillary services: flexible load supports system balancing. ▪ Capacity mechanism: certified DSR can receive capacity payments.	Participation is structured, but requirements vary by mechanism: ▪ NEBCO / wholesale markets: minimum bid size of 100 kW; direct participation or participation through an aggregator / demand-response operator. ▪ Ancillary services: minimum bid size of 1 MW; activation ramp-up under 30s for FCR, 5 min for aFRR and 12.5 min for mFRR; minimum activation time of 15 min ▪ Capacity mechanism: minimum bid size of 1	Revenue potential is high and stackable across markets: ▪ NEBCO / wholesale optimisation: value depends on activation volumes and wholesale prices. ▪ Ancillary services: 2025 reservation-price indicators include FCR at c. €10/MW/hour, aFRR at c. €30-60/MW/hour and mFRR at c. €1-5/MW/hour, before availability and activation assumptions. ▪ Capacity mechanism: c. €5k/MW for Delivery

Table 11: Demand-side flexibility opportunities across benchmarked regions

	▪ Carbon-free flexibility tender: long-term support for eligible DSR and storage, with up to 2,900 MW in 2025. ▪ Interruptibility: large sites, generally above 10 MW, can provide interruptible capacity.	MW; certification required, with derating factor applied to demand-response units. ▪ Low-carbon flexibility tender: minimum bid size of 1 MW; tender-specific availability and performance commitments apply. ▪ Interruptibility: minimum 10 MW and maximum 1,200 MW; activation under 5s; minimum activation time of 15 min; maximum 10 activations per year.	Year 2026, with actual value depending on certified capacity, availability and penalties. ▪ Low-carbon flexibility tender: c. €30k/MW indicator, subject to tender award and terms. ▪ Interruptibility: price not publicly available; tender merit-order selection with price cap of c. €85k/MW, mainly relevant for very large eligible sites.
Germany	3 market routes available, more constrained than in Norway or France: ▪ Balancing reserve markets: participation in FCR, aFRR and mFRR where prequalified. ▪ Wholesale / retail optimisation: load shifting where contracts provide price exposure; third-party access depends on supplier, aggregator or market-access arrangements ▪ Interruptible-load arrangements: SEAL provides a route for eligible fast-response loads after the expiry of Germany's former AbLaV framework.	Participation is technically demanding and product-specific: ▪ BSP / TSO prequalification. ▪ Metering, telemetry and communication capability. ▪ Product-specific response and availability requirements. ▪ Minimum bid sizes, with aggregation possible where allowed.	Revenue potential is medium and stackable across markets: ▪ Balancing reserves: aFRR capacity-price indicators around €10-13/MW/hour in 2024, before availability and bidding assumptions. ▪ Wholesale / retail optimisation: value depends on contract exposure. ▪ Interruptible-load route: potentially valuable for eligible loads, but narrower than the former AbLaV regime.
Texas / ERCOT	4 market routes are available, with high upside but significant volatility: ▪ Load Resource / Aggregate Load	Participation depends on ERCOT qualification and market access: ▪ Access through a Qualified Scheduling	Revenue potential is high but volatile, combining market revenues and costs avoidance:

Table 11: Demand-side flexibility opportunities across benchmarked regions

	Resource: participation in ancillary services. ▪ Emergency Response Service: availability and deployment during grid emergencies. ▪ Scarcity / wholesale price response: curtailment during high-price periods. ▪ 4CP management: demand reduction during system peaks to reduce transmission charges.	Entity or market participant. ▪ ERCOT registration, telemetry and metering. ▪ Product-specific response and performance capability. ▪ Contractual exposure for scarcity-price or 4CP value.	▪ Ancillary services: value depends on awards, prices and performance. ▪ Emergency Response Service: offer cap of US$80/MW/hour, with realised value depending on contracts and events. ▪ Scarcity response: potentially material but event driven. ▪ 4CP: bill-avoidance value can be material but is not direct market revenue.
South Korea	3 market routes are available, generally through KPX and aggregators: ▪ KPX demand response market: load reductions from industrial and commercial users. ▪ Peak / reliability DR: demand reductions for system reliability and peak management. ▪ Demand-up / Plus DR: flexible demand used to absorb surplus generation.	Participation is programme-led and often aggregator-led: ▪ Registration through a DR operator / aggregator, with possible direct routes for some large users. ▪ Baseline calculation and interval metering. ▪ Ability to respond to event calls. ▪ Product-specific performance and settlement rules.	Revenue potential is medium, with limited current public pricing: ▪ KPX DR: case-study evidence suggests value can be material for large loads, but not as a market-wide benchmark. ▪ Reliability / peak DR: value depends on contracted capacity and event performance. ▪ Plus DR: value depends on renewable-curtailment and programme design.
UAE	2 flexibility-related routes are visible, but the UAE does not yet have a mature open industrial DSR market: ▪ Abu Dhabi demand response: policy, regulations and pilots covering capacity, balancing and system-stability applications.	Participation is emerging and programme-led: ▪ Measurable and verifiable load reduction in Abu Dhabi. ▪ Participation through regulator / utility-led programs or aggregators. ▪ Abu Dhabi targets 80 MW of contracted DR	Revenue potential is low and emerging: ▪ Abu Dhabi DR: no standard public AED/MW/year or AED/MWh payment identified. ▪ Dubai DSM / solar: supports bill optimisation, not direct flexibility revenue.

Table 11: Demand-side flexibility opportunities across benchmarked regions

	▪ Dubai DSM / solar optimisation: bill reduction and solar-related compensation, rather than paid flexibility markets.	capacity by 2027 and 200 MW by 2030. ▪ Pilot activity has demonstrated 137 MW, with further pilot targets at more than 250 MW	▪ Overall: value is not publicly quantifiable from available sources.
Shandong	3 flexibility-related routes are visible, but the market remains policy-led and emerging: ▪ Provincial demand response: peak shaving and valley filling under provincial rules. ▪ Virtual power plants / aggregation: flexible load, storage and distributed resources aggregated for system flexibility. ▪ TOU / spot-market optimisation: load shifting in response to time-varying prices.	Participation depends on provincial rules and market access: ▪ Registration and qualification under Shandong market rules. ▪ Time-of-use metering and data connection. ▪ Measurable response capability. ▪ Aggregator / VPP participation where relevant.	Revenue potential is low / emerging: ▪ Demand response: reported compensation parameters include RMB 2/kW/month & RMB 0.4 /kWh in certain schemes. ▪ VPP participation: value expected to develop as rules mature. ▪ TOU/spot optimisation: mainly bill optimisation. ▪ Planning targets: >2 GW by 2027 and >4 GW by 2030 are system-level targets, not revenue indicators.

Note 1: Revenue indicators are not directly comparable across regions. Some are annual capacity payments, some are hourly reserve or emergency-response prices, some are tender-based, and some are bill-avoidance values rather than direct market revenues.
Note 2: DSR = demand-side response; DR = demand response; FCR = Frequency Containment Reserve; aFRR = automatic Frequency Restoration Reserve; mFRR = manual Frequency Restoration Reserve; NEBCO = Notification d'Échange de Blocs de Consommation; RTE = Réseau de Transport d'Électricité; BSP = balancing service provider; TSO = transmission system operator; ERCOT = Electric Reliability Council of Texas; ERS = Emergency Response Service; 4CP = four coincident peak; KPX = Korea Power Exchange; DSM = demand-side management; VPP = virtual power plant; TOU = time-of-use; SEAL = Germany's real-time system-service product from interruptible loads; AbLaV = Germany's former Interruptible Loads Ordinance.
Note 3: Revenue indicators are not directly comparable across regions. Some are annual capacity payments, some are hourly reserve or emergency-response prices, some are tender-based, and some are bill-avoidance values rather than direct market revenues.
Source: Compass Lexecon analysis based on data from public market operator and regulatory information. Detailed source mapping by region, mechanism and revenue indicator is provided in Section 9.4.

Overall, Norway, France and Texas provide the strongest flexibility upside for energy-intensive users, although the nature of the value differs. Norway offers clearer annual reserve-product benchmarks, France provides multiple formal demand-response and capacity routes, and Texas can provide high but volatile value.

Germany and South Korea offer more moderate opportunities, as participation is dependent on specific products, aggregators or program rules. The UAE and Shandong show emerging flexibility policy and pilot activity, but they currently provide less transparent monetization routes for industrial demand-side flexibility.

7 Projections of electricity retail prices for energy intensive consumers to 2035

The comparison of current industrial electricity prices presented in Section 4 provides a snapshot of the competitiveness of Norway and selected benchmarked regions today. However, investment decisions by energy-intensive industries are typically based on long-term expectations regarding electricity costs. Assessing the potential evolution of electricity prices over the coming decade therefore provides a useful complement to the analysis of current retail rates.

The purpose of this section is not to provide detailed forecasts future electricity prices in each benchmark area, but rather to provide a high-level indication of the relative competitiveness of electricity prices in Norway compared with other selected regions in 2035. Section 7.1 presents the methodology adopted for the projection exercise. Section 7.2 discusses the outlook for electricity procurement costs and presents the resulting 2035 retail electricity price projections. Finally, Section 7.2.3 discusses possible developments affecting network and system costs, as well as taxes and levies.

7.1 Methodology of the high-level 2035 projection

Our methodology produces indicative projections of the electricity price paid by industrials as the sum of two key components:

- The cost of producing electricity, considered a good proxy for the procurement costs and is estimated by projected spot prices in the relevant countries;
- RES Taxes & levies (inclusive of rebates and exemptions industrials might be eligible for) and capacity charges (when they apply);
- Other taxes/levies and system and network costs. These are assumed constant at the current 2025 levels, as the evidence around how they might develop over the next 10 years is relatively controversial and risks to make our estimates unreliable.

We use three key steps to calculate our projections:

- Step 1: Estimate the 2035 electricity system production costs by projecting the generation mix and calculating the system levelized cost of electricity (LCOE) for each benchmarked region.
- Step 2: Derive net system costs by comparing annualized production costs with projected wholesale electricity market revenues and accounting for RES support needs.
- Step 3: Estimate the 2035 energy procurement costs for an industrial consumption profile by incorporating energy purchase costs and policy rebates to benchmark industrial electricity costs across regions.

We provide more details on these three steps below.

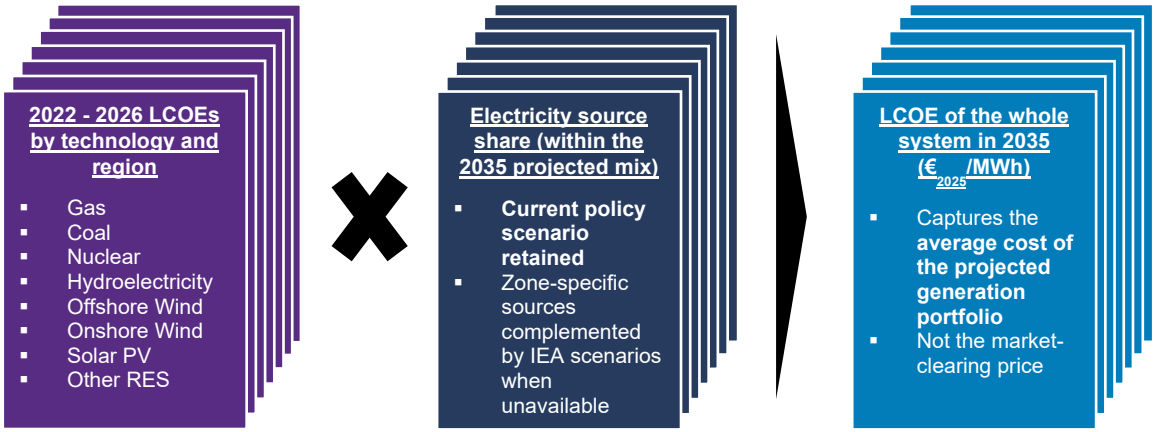
Step 1: Electricity system production costs

In step 1, we estimate electricity system generation costs by multiplying the LCOEs of the different technologies in the projected generation mix in 2035 of each country with their expected generation. The result is an estimate of the total costs for the system to generate the amount of electricity it produces nationally in 2035, in EUR/MWh.

The assumptions used in step 1 are the following:

- LCOEs are based on a range of external sources (see. Appendix 9.5) over the period 2022-2026 and we assume they are reflective of the costs of assets that will be running in 2035;
- We use projected 2035 generation mixes based on local sources (see Appendix 9.6). To ensure comparability across regions, we use projections developed under assumptions reflective of the current (2025) policy framework in every area, whenever possible.[240]

Figure 36: Estimation of a LCOE of the whole system running in 2035



Note: All results are expressed in €2025/MWh. LCOEs and electricity mix data collected in other currencies (USD/CNY/KRW/AED/NOK) are converted using an exchange rate corresponding to the annual average published by the ECB. LCOEs published in constant currencies from a previous year are updated to €2025 using the euro area updated to €2025 using the euro area HICP index.

Step 2: Split between market prices and the cost of additional support mechanisms

In step 2, we take the projected day-ahead electricity market prices (spot prices, when available) of the countries included in this study and deduct from them the costs of generation obtained in step 1 in order to identify any remaining need for support. The difference between the total electricity generation costs calculated in step 1 and the day-ahead market prices projected (when available), is akin to the concept of *missing money* and can be used to provide a high level estimate of the need for additional remuneration for supported generation such as RES-E plants.[241] Indeed, the missing money problem in European and North American electricity markets has contributed to the implementation of range of mechanisms providing additional remuneration

240 Those scenarios, when locally developed, would be close to the logic of the Stated Policy (STEPS) of the World Energy Outlook published by the IEA

241 *Missing money* refers to the gap between the total costs of electricity generation assets (including capital recovery and operating costs) and the revenues they earn from electricity markets. It arises when market prices are insufficient to allow generators to fully recover their costs, either temporarily or structurally, which can create a need for additional support mechanisms or revenue streams.

to generators (including capacity remuneration mechanisms and RES-E support schemes), whose impact on retail costs needs to be accounted for in our retail price projections.

The assumptions used in step 2 are the following:

- For **ERCOT and the European countries**, we rely on Compass Lexecon's proprietary market model to project day-ahead spot prices in 2035. These projections are based on a set of assumptions based on third party reference sources described in Appendix 8.6.

  For the **UAE**, we rely on externally sourced gas price projections for 2035. These projections are derived from historical production costs of domestic gas fields, projected domestic gas demand and production, and expected import and export volumes. Combining these elements allows us to estimate the future supply-demand balance of the Emirati gas market and derive an indicative gas price for 2035. Natural gas is the dominant fuel used for electricity generation in the UAE, accounting for around 70% of total power production. Under the Power and Water Purchase Agreements (PWPAs), fuel costs are passed through to electricity producers, as EWEC is responsible for procuring and supplying gas to generating units. Consequently, there is a strong relationship between gas prices and electricity prices in the UAE.[242] We assume that this relationship remains unchanged through 2035 and therefore derive projected electricity prices projections from the projected gas price.

- For the Shandong province in **China**, no publicly available projections of day-ahead spot prices were identified. To obtain a projection of the purchase costs at the 2035 horizon for Shandong, we rely on publicly available electricity retail price projections and apply a correction factor to account for differences in horizon and types of consumers.[243] In parallel, we calculate the share that the purchase costs represent within the industrial retail price for 2025. We assume that this ratio remains stable through 2035, and we apply this share to the considered projected retail price to obtain the projected procurement price for Shandong in 2035.

- For **South Korea**, no public projections of wholesale or spot electricity prices are available for 2035 to our knowledge. As a result, it was not possible to develop a robust estimate of future procurement costs under a methodology consistent with the one applied to the other benchmarked regions. Consequently, no 2035 retail electricity price projection is provided for South Korea.

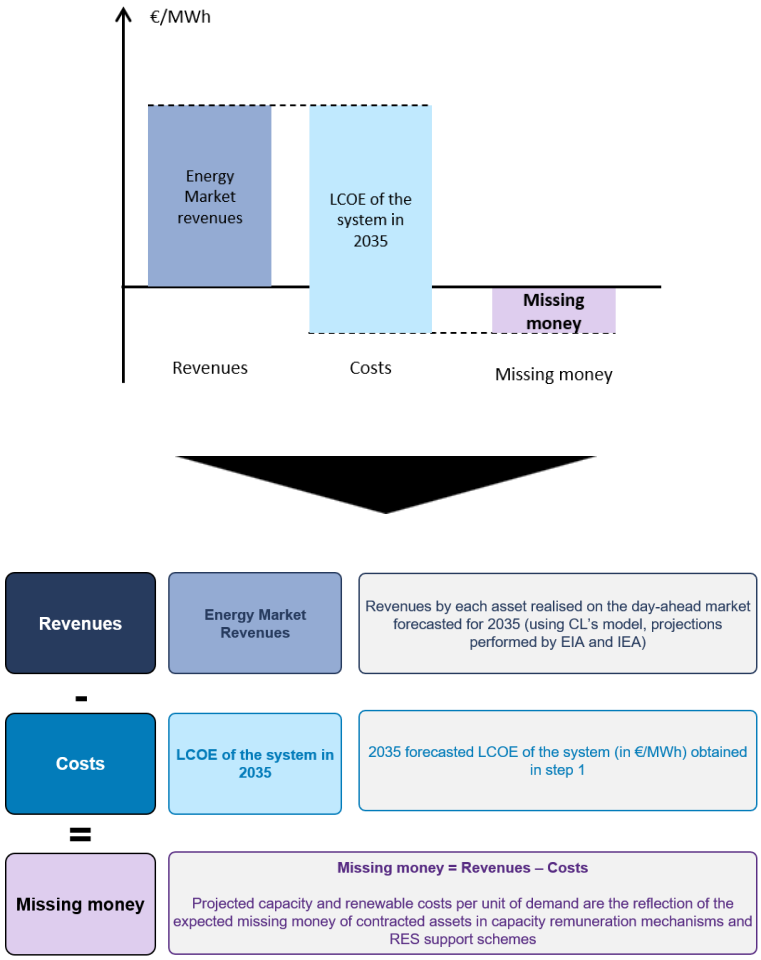
- Finally, we assume that system costs and taxes and levies not directly related to RES support remain constant at their 2025 levels. We note the significant uncertainty surrounding the future evolution of these components, for which available evidence remains limited and often points to divergent outcomes depending on the pace of electrification, network expansion needs and future market design choices. Nevertheless, we provide qualitative insights into the possible evolution of these components by 2035.

Step 2 is illustrated on Figure 37 below.

242 Lexology, Spotlight: the energy markets in United Arab Emirates (link)

243 IDDRI-Agora, EU industrial competitiveness: measures to address power sourcing costs whilst fostering decarbonisation (link)

Figure 37: illustration of methodology - relationship between market price and missing money driving additional support mechanisms costs



Note: All results are expressed in €$_{2025}$/MWh.

Step 3: 2035 projection of electricity procurement cost borne by the benchmarked industrial consumer

In step 3, we estimate the electricity procurement cost borne by our benchmarked industrial consumer by combining two components: (i) the projected day-ahead market electricity price (where available), and (ii) the share of *missing money* that could be attributed to our benchmarked consumer as a proxy for the additional support costs associated with support mechanisms for generators.

We estimate the share of missing based on existing levels of rebates on RES-E support levies and capacity remuneration charges. In other words, we assume that the current relative levels of rebates on those charges are maintained through to 2035.

Following this three-step approach, we obtain indicative power generation procurement costs for each benchmarked region.

We then add to this generation cost the cost of network and system charges, taxes and levies with the assumption that they remain constant at the 2025 level. We note the significant uncertainty surrounding the future evolution of these retail-price components, which are assumed to remain unchanged in real terms and are discussed further in Section 6.3.

7.2 By 2035, Norway power purchasing costs are projected to remain lower than the average across the selected world regions

This section presents a high-level comparison of projected industrial electricity costs across the benchmarked regions in 2035. Building on the methodology described in Section 6.1, the analysis compares projected retail electricity prices for the benchmarked consumer profile defined in Section 5.1, before examining the evolution of power procurement costs and the drivers underpinning regional differences. Finally, we discuss the outlook for the remaining retail price components, including network and system costs, taxes and levies, and RES-related charges. Given the significant uncertainty surrounding future regulatory frameworks, tariff methodologies and cost allocation mechanisms, only procurement costs and RES-related funding requirements are explicitly projected, while other components are assumed to remain at their 2025 levels.

7.2.1 Under our assumptions, Norway could remain among the most competitive locations for industrial power retail rates in 2035

Our projections suggest that Norway's industrial power retail rates continue to rank alongside ERCOT among the most competitive benchmarked regions in 2035. However, we note that this finding is dependent on the assumptions underpinning the scenarios used in this study, including:

- The development of additional clean generation in line with the TSO scenario projections, such as Statnett[244] and NVE. [245] Our model assumes combined onshore/offshore wind capacity growing from 5.1 GW (2025) to 8.5 GW (2035, ~5.3% CAGR), down from a ~21.5% CAGR over 2016-2025. Solar is assumed to grow from 0.9 GW to 4.9 GW (~18.3% CAGR, roughly 4 times the prior decade's pace). These assumptions are slightly more conservative than Statnett's Medium scenario (9.0 GW wind, 5.5 GW solar by 2035),[246] a pattern also observed for hydro (37.2 GW) and total capacity (51.5 GW), which sit roughly 3% below both Statnett's Medium scenario and NVE's Basis scenario (38.4 GW and 54 GW respectively).[247, 248]
- Battery capacity grows modestly from 74 MW to 574 MW and demand response from 2.6GW to 4GW; in line with assumptions in ENTSOE's Ten-Year Network Development Plan 2025.
- The growth of electricity demand as a result of increased electrification, data-centre development, and electricity-intensive industries. Our model assumes total Norwegian demand growing to 181 TWh by 2035, matching NVE's Basis scenario projection (161 TWh in

244 Statnett (2025), Langsiktig Markedsanalyse Norge, Norden og Europa 2024-2050 (link)
Statnett's Medium scenario represents an intermediate trajectory for Norwegian generation and consumption growth, bounded by Low and High scenarios. Unlike Statnett's Basis scenario for market prices, which reflects the company's central expectation, Low/Medium/High are not forecasts but define a range of uncertainty used for grid planning purposes.

245 Norsk og nordisk effektbalanse mot 2035 (link)
NVE's Basis scenario is its central reference case, built on adopted policy measures and instruments rather than announced political targets. NVE (2024), Norsk og nordisk effektbalanse mot 2035 (link)

246 Statnett (2025), Langsiktig Markedsanalyse Norge, Norden og Europa 2024-2050 (link)
Statnett's Medium scenario represents an intermediate trajectory for Norwegian generation and consumption growth, bounded by Low and High scenarios. Unlike Statnett's Basis scenario for market prices, which reflects the company's central expectation, Low/Medium/High are not forecasts but define a range of uncertainty used for grid planning purposes.

247 Ibid.

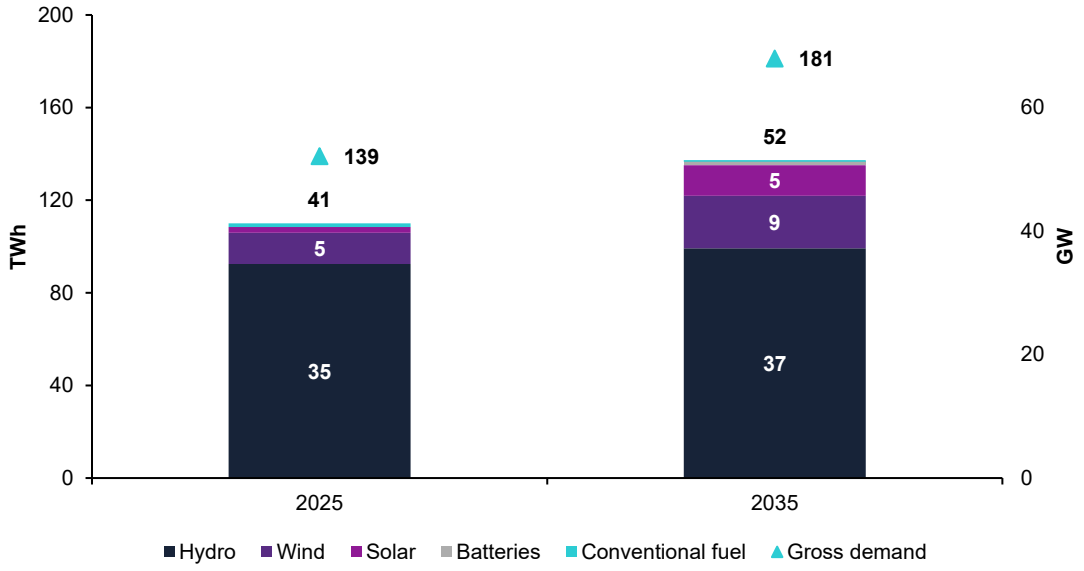
248 Norsk og nordisk effektbalanse mot 2035 (link)
NVE's Basis scenario is its central reference case, built on adopted policy measures and instruments rather than announced political targets. NVE (2024), Norsk og nordisk effektbalanse mot 2035 (link)

2025 and 181 TWh in 2035, ~1.2% CAGR)[249] and closely aligned with Statnett's Medium scenario (180 TWh).[250]

- Assumptions for the evolution of commodity prices (gas and CO2 prices) are taken from the World Energy Outlook 2024 of the International Energy Agency (see Appendix 9.6).

Should demand grow materially faster than projected or if the development of new generation capacity were to stay below projected levels, Norway could experience a tighter power system balance and higher electricity prices than those projected here. Figure 38 below shows the annual power demand and installed production capacity in Norway in 2025 and in our 2035 projection.

Figure 38: Demand (TWh) and generation capacity (GW) in 2025 and 2035 in Norway



Source: Compass Lexecon analysis based on data sources cited in Appendix 9.6.

More broadly, the comparison with other benchmarked regions suggests that jurisdictions endowed with large volumes of established low marginal cost low-carbon generation (such as hydropower in Norway) are likely to retain a structural advantage in industrial power procurement costs through 2035. [251]

As shown in Table 12 and Figure 39, Norway's projected power purchasing costs in 2035 are estimated at 41-50 €/MWh. Within Europe, this places Norway below both France and Germany, whose procurement costs are projected at 47-57 €/MWh and 56-68 €/MWh, respectively. These values should be interpreted as indicative system-level procurement costs under the assumptions of the underlying scenario rather than as the cost of electricity from a specific new generation technology. Norway continues to benefit from a large fleet of existing hydropower assets with lower operating costs than thermal plants, which contributes materially to moderate projected procurement costs. However, we note that the results remain sensitive to assumptions regarding future generation development and demand growth, and commodity prices. In particular, a slower

249 Ibid.
250 Statnett (2025), Langsiktig Markedsanalyse Norge, Norden og Europa 2024-2050 (link)
251 Norwegian Energy Facts, Electricity production (link); IEA, World Energy Outlook 2025 (link)

deployment of new generation capacity, including onshore wind, could tighten the Norwegian power system balance, increase reservoir water values and result in higher electricity prices than those presented in the central scenario. While increasing shares of low-marginal-cost renewable generation are expected to put downward pressure on wholesale electricity prices compared with recent years, Norway as well as other countries will continue to face substantial investment requirements in generation assets, flexibility resources and supporting infrastructure. France must combine renewable deployment with investments in its existing and future nuclear fleet, while Germany's transition remains heavily reliant on continued large-scale deployment of wind and solar generation. [252]

Outside Europe, ERCOT is projected to continue to have low power purchasing costs ranging from 50-62 €/MWh. By contrast, the UAE and Shandong are projected to record the highest procurement costs in the benchmark, at 68-83 €/MWh and 73-89 €/MWh respectively. In both regions, rapidly growing electricity demand is expected to require significant investment in generation and network infrastructure, while thermal generation technologies continue to play an important role in the power mix. We note, however, that a different assumption on the evolution of commodity prices could modify substantially these findings.

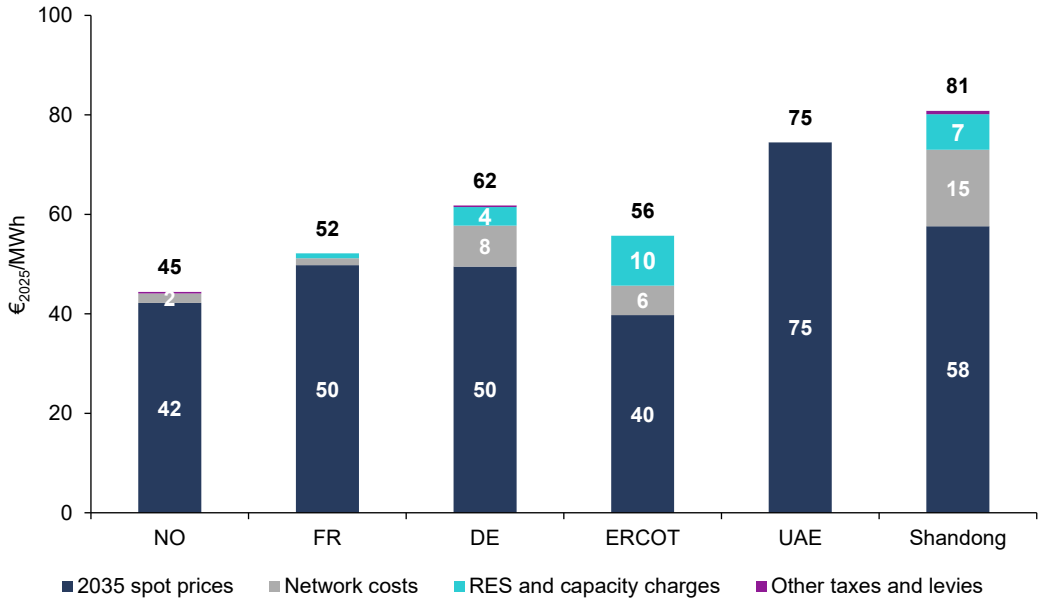
Table 12: Range of 2035 projected retail electricity prices paid by industrials by region, €2025/MWh

Country	Retail price range, €2025/MWh
Norway	41 – 50
France	47 – 57
Germany	56 – 68
ERCOT	50 – 62
United Arab Emirates	68 - 83
Shandong	73 – 89

Notes: Public data for spot prices in South Korea in 2035 is not available. Projected prices reflect system-wide electricity market fundamentals, and the generation mix of each jurisdiction. They should not be interpreted as the cost of electricity from a specific generation technology or procurement arrangement available to individual industrial consumers.
Source: Compass Lexecon analysis based on data sources cited in Appendix 9.5 and 9.6.

252 IEA, World Energy Outlook 2025 (link)

Figure 39: Comparison of projected retail electricity prices (€/MWh) of large industrial users in Norway and selected regions in 2035



Note: Public data for spot prices in South Korea in 2035 is not available, therefore South Korea could not be included in the scope of selected regions.
Source: Compass Lexecon analysis based on data sources cited in Appendix 9.5 and 9.6.

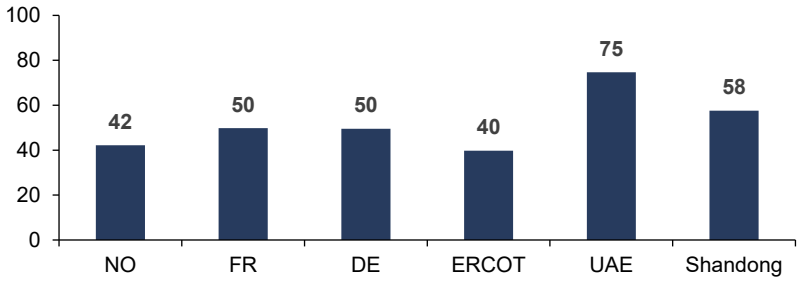
7.2.2 Norway's competitive electricity generation cost advantage is expected to persist in 2035

Under our assumptions, Norway is projected to maintain a meaningful electricity procurement cost advantage over most benchmarked regions in 2035. While the gap with some jurisdictions narrows compared to today, Norway remains among the most competitive locations, benefiting from its large fleet of established hydropower assets and the availability of low-cost electricity generation. As a result, access to abundant low-cost energy resources is expected to remain an important determinant of industrial competitiveness through the coming decade.

As illustrated in Figure 40, projected procurement costs in Norway remain below those in France, Germany, the UAE and Shandong, and broadly comparable to those in ERCOT. Norway's projected procurement costs reach around €42/MWh, compared with approximately €50/MWh in France, €50/MWh in Germany, €58/MWh in Shandong and €75/MWh in the UAE. ERCOT is projected to remain the most competitive benchmark, at around €40/MWh.[253]

[253] Sources for all these numbers are provided in Table 17 of the Appendix.

Figure 40: Energy procurement costs (€/MWh) of large energy users in Norway and selected regions in 2035



Notes: South Korea is not included in the analysis due to a lack of public data through 2035.
Source: Compass Lexecon analysis based on data sources cited in Appendix 9.5 and 9.6.

The narrowing of procurement cost differentials across regions is driven primarily by improvements in competing regions rather than by a deterioration of Norway's position. Compared to 2025, the largest reductions in procurement costs are projected in Germany (-45%) and France (-19%), reflecting the continued expansion of renewable generation and the gradual reduction in fossil-fuel generation. Norway is also projected to benefit from a favourable outlook, although procurement costs increase only modestly (+6%), given that its power system is already dominated by low-cost renewable generation today. By contrast, procurement costs are projected to increase more significantly in ERCOT (+34%), Shandong (+32%) and the UAE (+26%). In ERCOT, higher costs are driven by rapid demand growth and the need for continued investment in new generation resources, while in the UAE and Shandong increasing electricity demand and the continuing role of thermal generation contribute to upward pressure on costs. [254]

FP_TX_NotesPrefixOverall, the results suggest that procurement costs in 2035 will continue to reflect differences in power system fundamentals, including the generation mix, the availability of low-cost domestic energy resources, the need for investment in generation and network infrastructure, and the pace of electricity demand growth. Although other regions are projected to partially close the gap with Norway, jurisdictions benefiting from large volumes of established low-cost generation, such as Norwegian hydropower, are expected to retain a structural advantage and remain among the most competitive locations for electro-intensive industries under our assumptions.

7.2.3 Evolutions of non-energy costs in industrial electricity bills are subject to diverse drivers

The evolution of non-energy electricity costs remains considerably more uncertain than the outlook for procurement costs. In particular, future network and system charges will depend on the interaction between investment requirements, demand growth and regulatory decisions regarding cost allocation.

For network and system charges, most benchmarks jurisdictions are expected to require substantial investment in transmission and distribution infrastructure to accommodate the development of RES-E installations, additional power demand, and in some cases modernise an ageing grid infrastructure. In Norway, for example, Statnett's System Development Plan 2025

254 IEA, World Energy Outlook 2025 (link)

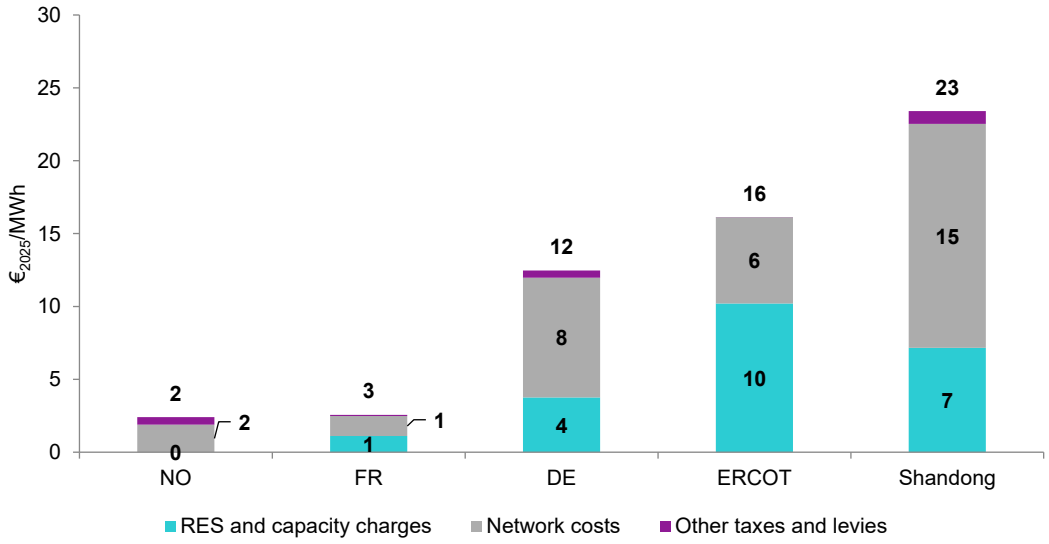
foresees transmission grid investments of NOK 150-200 billion by 2035, compared with approximately NOK 92 billion invested during the period 2014-2024. Such investment requirements create upward pressure on future network tariffs.

At the same time, those investments are required to, among others, alleviate congestions costs, and accommodate increasing electricity demand. This would respectively lower system charges and broaden the consumption base over which network costs are recovered, resulting in downward impacts on unitary network cand system charges.

For network and system charges, RES-E support levies, or capacity remuneration mechanisms, benchmarked jurisdictions have made choices in terms of allocation of those costs between end-user categories, reflected in targeted rebates, exemptions or compensation mechanisms. The extent to which such arrangements remain in place, are expanded or are reformed over time materially influences future industrial electricity costs.

As a result, the net impact of those drivers on non-energy components of industrial power bills is largely uncertain. As mentioned in section 7.1, we include network and system charges and taxes and levies at their 2025 levels for our benchmark consumer. This approach provides a transparent and consistent basis for the comparative analysis while avoiding the need to make country-specific assumptions regarding future tariff allocation frameworks. Considering this approach, Figure 41 shows Norwegian non energycosts at around €2/MWh. France exhibits a similarly low level of non-energy costs, at approximately €3/MWh. By contrast, non-energy charges reach around €12/MWh in Germany, €16/MWh in ERCOT and €23/MWh in Shandong.

Figure 41: Network and system costs, and other taxes and levies (€/MWh) of large energy users in Norway and selected regions in 2035



Notes: South Korea is not included in the analysis due to a lack of public data through 2035.
Source: Compass Lexecon analysis based on data sources cited in Appendix 9.5 and 9.6.

8 Conclusions

This report has assessed the competitiveness of electricity costs for electricity-intensive industries in Norway relative to a range of benchmark jurisdictions and considered how it may evolve over time. The analysis indicates that Norway currently benefits from a number of structural advantages with regards to retail industrial electricity costs relative to benchmarked jurisdictions. Looking ahead, several uncertainties may affect retail industrial electricity prices amongst jurisdictions benchmarked. Under assumptions of a continued development of RES-E capacity to respond to demand growth as well as a continuation of key policies like CO2-compensation, Norway can maintain low retail industrial power prices. However, it will increasingly rely on policy choices regarding the allocation of power system costs between end-users. Against this backdrop, international experience provides useful insights into measures and mechanisms that can keep retail industrial electricity prices in check.

8.1 Norway’s retail electricity rates benefit from some competitive advantages associated with the structural features of its power system

Norway's competitive industrial power prices reflect a combination of structural characteristics of its power system and the broader framework applicable to electricity-intensive industries. As shown in the benchmarking analysis presented in Section 3, Norway ranks among the most competitive jurisdictions assessed, with industrial electricity costs for the benchmark consumer of approximately €42/MWh in 2025, compared with an average of around €66/MWh across the benchmarked regions.

Indeed, Norway benefits from a generation mix dominated by hydropower, which accounted for approximately 89% of total generation in 2024, as well as substantial reservoir flexibility that supports system balancing and security of supply. Norway has also historically benefited from a favourable power balance and remained a net exporter of electricity, reaching a power surplus of around 23 TWh in 2025. Together, these characteristics have contributed to comparatively low electricity procurement costs while limiting exposure to fossil fuel and carbon costs relative to many European jurisdictions. Importantly, Norway’s increased level of integration with the European electricity market has not materially affected the competitiveness of its power rates for industrials as of 2025.

Norway's position is further supported by comparatively low non-energy electricity costs for electricity-intensive industries. The analysis shows that network charges, taxes and levies remain among the lowest observed across the benchmarked regions as a result of the flexibility of the power system provided by large hydro reservoirs as well as rebates and exemptions applicable to electricity-intensive industries.

Taken together, these characteristics explain Norway's favourable competitive position today and continue to provide an important foundation for future industrial competitiveness.

8.2 Several risks and uncertainties can affect Norway’s industrial power prices going forward

Looking ahead, Norway’s electricity rates for electricity-intensive industrials will depend on drivers affecting the evolution of electricity procurement costs such as the demand / supply balance in

the power system, and the generation and capacity mix supplying electricity to consumers, as well as network and system charges and policy choices affecting the allocation of those as reflected in rebates and exemptions.

Several uncertainties and risks can adversely affect Norway's power prices for electricity-intensive industrials.

On the power demand and supply balance:

- Norway's energy transition relies on the electrification of end-uses, the pace at which industry, transport and heating sectors will electrify can increase domestic electricity demand, which would push power prices up unless the supply side can respond;
- Similarly, the actual level of data centres development in Norway can create accelerated power demand growth;
- Norway's onshore wind development has stalled for the past 4 years, under both permitting issues, and a greater public opposition than in comparable EU countries;
- Offshore wind development is markedly slower than onshore wind with complex cross-border coordination and permitting procedures;
- Hydroelectricity generation, currently the backbone of the Norwegian power system, faces increasing unavailability risks and higher water values due to more frequent drought and low-rain periods; the potential is limited due to environmental concerns.
- High growth in electricity consumption and a surge in intermittent power production will make it more challenging to balance the system during hours with little solar and wind power increasing the likelihood of high price peaks.

On network and system costs:

- Statnett's long-term investment plans for 2025-2035 plans to double annual investment amounts compared to the previous decade, mostly to replace ageing grids and accommodate new electricity demand and generation. In 2025, Statnett reported a 40% increase in investment spending compared to the previous year. Should expected increases in demand not materialise, this result in higher unitary retail grid charges for current end-users in the long run.

On rebates and exemptions for electricity intensive industrials:

- Electricity-intensive industrials will likely continue to benefit from exemptions of power consumption taxes and green certificates levies, however, for eligible sectors, the current indirect CO2 cost compensation State Aid will stop in 2030, with uncertainties on its renewal and if so, based on what mechanism details. This is essential for predictability.

8.3 By 2035, Norway's industrial power rates could remain competitive with continued development of low-carbon generation

While Norway's structural advantages remain significant, policy choices may increasingly shape the extent to which these advantages translate into competitive electricity prices for electricity-intensive industries. Future retail power prices' competitiveness will depend on the ability of the power system to respond to growing demand through the timely development of generation capacity, network infrastructure and the continuation of exemptions regimes for large industrials.

The analysis presented in Section 5 indicates that Norway can remain among the most competitive jurisdictions assessed through 2035. Under the assumptions adopted in this study, projected industrial electricity costs remain within a range of approximately €41-50/MWh, placing Norway among the lowest-cost jurisdictions considered in the analysis. This result is conditional on a demand level of approximately 181 TWh in 2035 and a substantial growth in electricity supply. Installed generation capacity is projected to increase from approximately 41 GW in 2025 to around 55 GW in 2035, mainly due to additional solar and wind capacity development (+4.7 GW and +3.9 GW respectively from 2025 levels).[255]

Future competitiveness may also be influenced by regulatory developments. In particular, the future allocation of network costs, evolving approaches to industrial support measures, and the treatment of mechanisms such as indirect carbon cost compensation beyond 2030 are key to maintaining industrial power prices in check.

Across Europe, policymakers are facing similar questions regarding the interaction between growing electricity demand, industrial competitiveness, generation development and network expansion. International experience therefore provides useful insights into a number of policies that may help address these challenges.

1: Address barriers to the timely development of a generation mix and network adapted to the expected growth in demand

25 One of the key risks faced by the Norwegian power system is that electricity demand growth is not matched by timely additions in generation capacity and flexibility assets, creating scarcity and importing power prices volatility from interconnected countries:

- Given the uncertainty surrounding the pace of industrial electrification and data-centre developments, continued monitoring of demand growth and regular long-term system planning exercises may help ensure that network and generation investments develop in line with evolving needs.
- International experience suggests that streamlined permitting and connection processes can help facilitate the timely deployment of generation, storage and network infrastructure where these become necessary to meet demand growth.
- Should merchant revenues not prove sufficient to support the investment levels required to maintain adequacy, international experience provides examples of mechanisms that can reduce investment risks and support the deployment of additional capacity. Whether such mechanisms are needed in Norway would depend on future market developments and investment outcomes. To date, the biggest hurdle remains permitting procedures.

2: Foster efficient network development and utilisation

26 Given the projected increase in electricity demand and network utilisation requirements in Norway, international experience highlights several technical and regulatory approaches that can improve the use of existing assets and support efficient network development. Some international practices derived from the benchmark include:

- Harnessing innovative grid-enhancing technologies can increase the utilisation of existing network assets and defer or reduce the need for network reinforcement. For instance, Italy

255 Statnett (2025), Langsiktig Markedsanalyse Norge, Norden og Europa 2024-2050 (link)

has introduced output-based regulation for the TSO Terna that contributed to the adoption of Dynamic Line Rating increasing internal transfer capacity between bidding zones.

- Making better use of flexibility resources can help accommodate growing demand while limiting the need for network expansion. For instance, in the UK, commercial flexibility is explicitly included in the cost-benefit analysis used by NESO to identify the most advantageous network development solutions.
- Some countries have implemented industrial policies involving targeted subsidies for transmission system operators transferring costs borne by electricity consumers to taxpayers, although this approach is less efficient from an economic theory perspective as it contravenes cost-reflectivity principles. For instance, Germany has introduced State aid for the four TSOs to partially cover their transmission-network costs, reducing network tariffs by circa 50% for 2026.

3: Specific mechanisms targeted at electricity-intensive industrials potentially involving state aid

27 Finally, the benchmark provides examples of specific mechanisms which have been introduced in different European countries to limit electricity rates for electricity-intensive industrials such as:

- The continuation of the indirect CO2 cost compensation mechanisms post-2030 could be a powerful tool to exempt industrial sectors at risk of indirect carbon leakage from carbon costs embedded in electricity prices.
- State aid for industrial electricity rates akin to the Clean Industrial Deal State Aid Framework (CISAF) of the European Union that could allow for temporary price relief for selected sectors and under strict conditions of eligibility, price impact and duration.

To conclude, the analysis suggests that Norway can remain among the most competitive jurisdictions assessed through 2035 under the assumptions adopted in this study. However, achieving this outcome depends on maintaining an adequate balance between electricity supply and demand through the timely development of new generation capacity, flexibility assets and network infrastructure. Clarifying conditions for the continuation of the state aid for indirect CO2 cost compensation after 2030 would provide additional predictability to eligible consumers. International experience suggests potential policy and regulatory choices that can further support the competitiveness of Norwegian electricity rates for large industries.

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9.3 Sources for tariffs components by country

This annex provides the structured source mapping supporting Section 0.

Table 13: Sources for 2016

Region	Energy procurement component	Network and system component	Taxes and levies component
Norway	▪ Energy Market Price (2026)	▪ ENTSOE (2024) ▪ Stattnett (2026) ▪ Kraftnytt (2016)	▪ Regjeringen (2015) ▪ The Norwegian-Swedish Electricity Certificate Market. Annual report 2016. (2016) ▪ Regjeringen (2011)
France	▪ Energy Market Price (2026)	▪ CRE (2013)	▪ Ministère des finances et des comptes publics (2016) ▪ Legifrance (2016) ▪ Legifrance (2013) ▪ Legifrance (2016)
Germany	▪ Energy Market Price (2026)	▪ Westnetz (2016)	▪ Netztransparenz (2017) ▪ Destatis (2017)
ERCOT	▪ Energy Market Price (2026) ▪ Potomac economics (2026)	▪ Oncor (2011)	▪ Oncor (2011) ▪ Tax Code chapter 151 (1981) ▪ GA Group
UAE	▪ n.a.	▪ n.a.	▪ n.a.
South Korea	▪ EPSIS (2026)	▪ 한전ON | 2010년대	▪ 한전ON | 2010년대 ▪ Energy platform news (2023) ▪ Elec times (2024)

Table 13: Sources for 2016

Shandong	▪ Jinan Municipality (2017)	▪ Jinan Municipality (2017)	▪ Jinan Municipality (2017)

Table 14: Sources for 2025

Region	Energy procurement component	Network and system component	Taxes and levies component
Norway	▪ Energy Market Price (2026)	▪ ENTSOE (2024) ▪ Stattnett (2026) ▪ Kraftnytt (2016)	▪ Regjeringen (2026) ▪ NVE (2025), 26/2025 report: Utredning av muligheten for å avslutte elsertifikatsystemet tidligere enn 2035
France	▪ Energy Market Price (2026)	▪ CRE (2025) ▪ CRE (2021)	▪ Legifrance (2025) ▪ Légifrance (2025) ▪ Impots.gouv.fr (2025) ▪ Ministère de l'Economie (2025)
Germany	▪ Energy Market Price (2026)	▪ Westnetz (2025) ▪ Gesetze im Internet (1992) ▪ Stückmann (2025)	▪ Netztransparenz (2025) ▪ Netztransparenz (2025) ▪ BDEW (2017) ▪ Netztransparenz (2025) ▪ Zoll (2025) ▪ Netztransparenz (2025)
ERCOT	▪ Energy Market Price (2026)	▪ Oncor (2023)	▪ Oncor (2023) ▪ Tax Code chapter 151 (1981) ▪ GA Group ▪ Comptroller.Texas.gov (2025)
UAE	▪ n.a.	▪ n.a.	▪ n.a.
South Korea	▪ EPSIS (2026)	▪ 한전ON | 과거 전기요금표	▪ 전기요금 결정구조와 요금 조정 추이 | 에너지종합 | 연구·발간물 : 국가에너지통계종합정보시스템

Table 14: Sources for 2025

		▪ 한전ON | 과거 전기요금표 ▪ KEPCO	▪ 전기요금 결정구조와 요금 조정 추이 | 에너지종합 | 연구·발간물 : 국가에너지통계종합정보시스템 ▪ 전기요금 결정구조와 요금 조정 추이 | 에너지종합 | 연구·발간물 : 국가에너지통계종합정보시스템 ▪ Etoday (2024)
Shandong	▪ Municpal government of Yantai (March 2025)	▪ Shandong development and reform Commission (2023) ▪ State grid Shandong electric power company (2025)	▪ State grid Shandong electric power company (2025)

9.4 Sources for Table 10 and Table 11: Demand Side Flexibility Opportunities

This annex provides the structured source mapping supporting Table 10. It links the main market routes, technical requirements and revenue indicators in the table to public market operator, regulator and industry sources. Revenue indicators should be interpreted with the caveats shown, as they are not directly comparable across regions.

Table 15: Source mapping for demand-side flexibility opportunities

Region	Table 10 item supported	Evidence / caveat	Source links
Norway	Reserve and balancing products: FCR, aFRR, mFRR and FFR	Supports the reserve-product route in Table 9. Revenue bands should remain labelled as indicative Compass Lexecon analysis based on TSO data, not guaranteed revenues.	Statnett reserve markets
Norway	Reserve-market technical requirements	Supports activation and market-access framing for Norwegian reserve products, including mFRR timing and minimum bid-size context.	Energy Facts Norway power market
Norway	Local flexibility markets	Supports local flexibility procurement and	NODES NorFlex

Table 15: Source mapping for demand-side flexibility opportunities

		aggregation routes, including NorFlex / NODES integration with Statnett's mFRR market.	
France	NEBCO / explicit demand response	Supports explicit demand-response participation through consumption reduction monetised on French energy markets.	RTE NEBCO
France	Carbon-free flexibility tender	Supports the tender route and the 2025 volume indicator of up to 2,900 MW for demand-response capacity.	RTE support mechanism
France	Interruptibility for large loads	Supports the interruptible-load route for large sites, including the >10 MW eligibility indicator and fast-response requirement.	RTE interruptible load tender
Germany	Balancing reserve markets	Supports FCR, aFRR and mFRR access route and TSO prequalification. Revenue indicators should be caveated because realised value depends on bids, availability and product access.	Regelleistung prequalification
Germany	Balancing-market price indicators	Supports public balancing-market price data as a revenue indicator, but not as a guaranteed 1 MW annual revenue benchmark.	Regelleistung data center
Germany	Interruptible-load successor route	Supports FSV SEAL as a narrower successor-type route for eligible interruptible loads after the expiry of the former AbLaV regime.	Entelios FSV SEAL (link)
Texas / ERCOT	Load Resource and ancillary-service participation	Supports Load Resource / Aggregate Load Resource participation in ERCOT ancillary services and demand response.	ERCOT Load Resource
Texas / ERCOT	Emergency Response Service	Supports ERS as an availability / deployment route for qualified loads and aggregations during grid emergencies.	ERCOT ERS
Texas / ERCOT	4CP and price-response value	Supports broader demand-response framing, including 4CP load reduction and	ERCOT DR summary

Table 15: Source mapping for demand-side flexibility opportunities

		price-responsive demand response.	
South Korea	KPX demand response and case-study revenue evidence	Supports South Korea DR participation and case-study evidence of KRW 854.9m benefit over two years for a 10 MW customer; treat as case-study evidence, not a market-wide benchmark.	MDPI South Korea DR case study
UAE	Abu Dhabi demand-response framework and targets	Supports Abu Dhabi DR policy targets of 80 MW by 2027 and 200 MW by 2030, backing the emerging but programme-led classification.	Abu Dhabi DoE DR Policy
UAE	Abu Dhabi DR pilots and aggregator route	Supports the pilot / aggregator route and phase-two scale-up. Use pilot figures as programme evidence, not as revenue indicators.	Energy Pool UAE DR
UAE	Dubai DSM / solar optimisation	Supports Dubai D33 as solar / bill optimisation rather than direct DSR revenue, including 10.5 fils/kWh feed-in compensation.	DEWA D33 certificates
Shandong	National flexibility context	Supports the broader China flexibility context, including the role of demand response in meeting short-term flexibility needs by 2030.	IEA China flexibility report

9.5 Sources for 2035 projection – step 1 (electricity production costs)

This table present sources used for the projected mix of each selected region, as well as sources for the LCOEs of each technology by country.

Table 16: Sources for the 2035 projection by country – step 1

Region	Projected mix	LCOEs
Norway	NVE (2025), Langsiktig kraftmarkedsanalyse 2025. B2035 scenario.	WEO 2025, NVE LCOE, IRENA Renewable Power Generation Costs in 2025
France	RTE (2025), bilan prévisionnel – période 2025-2035. Scenario « décarbonation lente » and « R2 ».	WEO 2025, ADEME Renewable Power Generation Costs 2024, IRENA Renewable Power Generation Costs in 2025
Germany	UBA (2025), Treibhausgas-Projektionen 2025 für Deutschland (Projektionsbericht 2025). MMS scenario.	WEO 2025, IRENA Renewable Power Generation Costs in 2025
ERCOT	EIA (2026), Annual Energy Outlook. "Counterfactual baseline case" scenario.	WEO 2025, IRENA Renewable Power Generation Costs in 2025
UAE	UAE.gov. UAE Energy Strategy 2050—the Official Portal of the UAE Government. Linear interpolation (between 2025 data and generation mix of the strategy for 2050) done to get a 2035 mix.	LCOE in MENA region, LCOE in UAE, IRENA Renewable Power Generation Costs in 2025
Shandong	IEA (2025), mix for whole China used in the projection	WEO 2025, IRENA Renewable Power Generation Costs in 2025
South Korea	MOTIE (2024). Projections from MOTIE are for 2030 and 2038, we therefore interpolated values. All RES (wind, solar, hydrogen…) are included in "Other RES".	LCOE in South Korea, IRENA Renewable Power Generation Costs in 2025

9.6 Sources for 2035 projection – step 2 (forecast of spot prices to split between market prices and RES support)

This appendix presents CL's models along with a table showing sources used for the assumptions made along with Fornybar to perform the projections of spot prices for the 3 European countries and ERCOT.

FTI-CL's power market model covers the EU-27 countries as well as the UK, Switzerland, Norway, the Balkans. The model is run on a commercial modelling platform Plexos® and is recently fitted

with PECD and PEMMDB inputs. It is calibrated to be consistent with other reference modelling exercises, including ENTSO-E's ERAA and TYNDP scenarios.[256]

FTI-CL's European power market model

- constructs supply in each price zone based on aggregated plants and simulates the market with hourly resolution. The model outputs are obtained using a European power and hydrogen plants database containing technical parameters of all thermal European plants (PEMMDB).
- uses ENTSOE Pan-European Climate Database (PECD) for hourly time series for wind and solar production, hydro inflows and power (and H2 demand pattern).
- considers cross-border transmission and interconnectors and unit-commitment plant constraints both in Power (and H2 grids).

The model outputs include market and zonal prices, with the latter estimated as the marginal value of energy accounting for generators' bidding strategies (and H2 import cost).

FTI-CL's ERCOT power market model is built following the same methodology as the European model, run on Plexos® with hourly resolution. It relies on NERC's Long-Term Reliability Assessment (LTRA) as its primary input for demand growth, planned capacity additions and retirements, and resource adequacy assumptions.[257]

Those models have been widely used by regulators, TSOs, and power market participants for high-profile projects and valuation or benchmarking exercises.

Moreover, the table below presents key assumptions made for each of the four regions to create the ad hoc model we used to forecast DA prices in 2035: the total installed capacity, the total demand, the level of interconnections and the price of carbon.

Table 17: Assumptions used in step 2 for the 3 European countries and ERCOT to create the ad hoc model

Country	Installed capacity in 2035 (GW)	Total demand (TWh)	Level of interconnections	Price of carbon
Norway	55 (thermal 0.3; solar 5; wind onshore 5.5; wind offshore 3; hydro 37; other RES 4)	181	Aligned with ERAA 2026	CO_2 prices are expected to increase in the long run. Standing at c.74 EUR/tonne in 2025, the scenario price reaches c.113 EUR/tonne real 2025 by 2035

256 Acronyms:
- ERAA: European Resource Adequacy Assessment, this is ENTSO-E's assessment of whether Europe will have sufficient generation and flexibility resources to meet future electricity demand.
- PECD: Pan-European Climate Database, a harmonised weather and climate dataset used to model renewable generation and electricity system conditions across Europe.
- PEMMDB: Pan-European Market Modelling Database, a common European database containing assumptions on generation, demand, interconnection and system developments used for power market modelling.
- TYNDP: Ten-Year Network Development Plan, ENTSO-E's long-term plan outlining expected transmission network developments and system needs across Europe.

257 Acronyms:
- NERC: North American Electric Reliability Corporation. Regulatory body responsible for ensuring the reliability of the bulk power system across the United States, Canada, and part of Mexico.
- LTRA: Long-Term Reliability Assessment. NERC's annual report assessing resource adequacy and reliability risks across North American power regions over a 10-year horizon

Table 17: Assumptions used in step 2 for the 3 European countries and ERCOT to create the ad hoc model

France	213 (nuclear 63; thermal 11; solar 57; wind onshore 33; wind offshore 6; hydro 8; other RES 14)	525	Aligned with ERAA 2026	CO_2 prices are expected to increase in the long run driven by increased decarbonisation ambitions of the EU. Standing at c.74 EUR/tonne in 2025, the scenario price reaches c.113 EUR/tonne real 2025 by 2035
Germany	521 (thermal 47; solar 228; wind onshore 130; wind offshore 33; hydro 13; other RES 70)	640	Aligned with ERAA 2026	CO_2 prices are expected to increase in the long run driven by increased decarbonisation ambitions of the EU. Standing at c.74 EUR/tonne in 2025, the scenario price reaches c.113 EUR/tonne real 2025 by 2035
ERCOT	225 (thermal 81; solar 66; wind onshore 54; hydro 0.5; nuclear 5; other RES 18)	630	Aligned with NERC's LTRA 2023	n.a

Locations

Europe

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Brussels
Copenhagen
Düsseldorf
Helsinki
Lisbon
London
Madrid
Milan
Paris

North America

Boston
Chicago
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Los Angeles
Miami
New York
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Singapore

Latin America

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