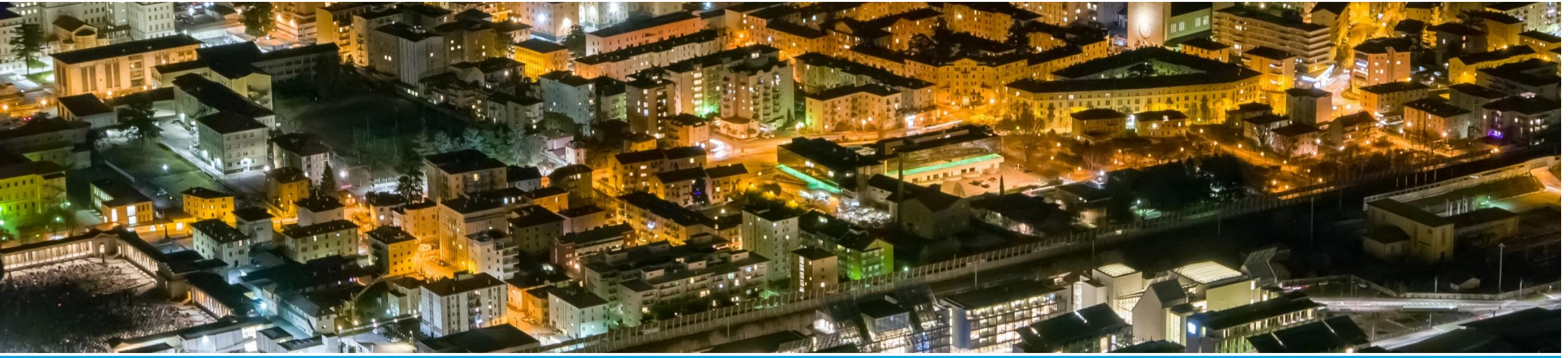


ENERGY

A state of the art review of demand side flexibility

Report to the Swedish Energy Markets Inspectorate

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Objective:

The aim of the project is to produce a state of art review in the form of a discussion paper of demand side flexibility resources in different types of markets. The review will be used and presented in an IEA conference on power system flexibility in February 2020.

This report is compiled over a few hectic weeks between December 2019 and January 2020.

We are indebted to the experts within the Swedish Energy Markets Inspectorate and the IEA secretariat, as well as to internal colleagues in various DNV GL offices around the world.

A particular thank you goes to the following, for swift replies to our tedious questions:

- Wesley Woo-Duk Hwang-Chung, the Korean Power Exchange
- Julia Matevosjana, ERCOT

The responsibility for remaining errors and inaccuracies remain with the project manager.

Introduction

- The Swedish Energy Markets Inspectorate commissioned this study in November 2019
- The objective is to provide a review of the state of art for demand side flexibility (DSF) resources in different countries around the world. The review will be used and presented at an IEA conference on power system flexibility in February 2020
- Historically, power generation was designed to follow consumption (load). The energy transition has brought down the costs of electricity supply from intermittent or less flexible sources, while the flexible power plants based on fossil fuels are being phased out. While this leads to an important decarbonisation, it also implies increased cost for the generation to follow the load. A key question is then to which extent demand side resources can provide flexibility to the power systems
- A parallel trend is caused by new technology and reduced costs for communication and load management, making non-wire alternatives to traditional network investments viable. This increases the business case for demand side management
- The key part of the report is 9 country analyses, which aims to highlight how far DSF is currently mobilised and offer some relevant motivations and drivers for the development behind those numbers
  - In addition, there is a section explaining the key market and market design parameters that may have an impact on participation from the demand side in meeting the challenges of the energy systems
- A key feature of the report is the focus on comparing the 9 cases with an aim to draw conclusions on what drives demand side participation, at the expense of full explanation of all national details
  - Therefore, the report only provides a birds eye perspective on each of the 9 countries
  - However, it is our strong belief that this is in fact sufficient to draw some relevant policy conclusions
  - The conclusions are presented first
    - The report then continues with explanation of the market parameters before presenting the 9 cases

Overview of this report

- This report consists of three parts
  - Part 1 presents an overview of the selected countries and the findings
  - Part 2 briefly explains key market and market design parameters, focusing on such parameters that are likely to have significant impact on flexibility and demand side participation
  - Part 3 presents nine examples of how demand-side flexibility is implemented in practice
- An underlying assumption for the description and analysis is that some basic economic mechanisms are at work also in the electricity sector and applies to all kinds of demand for electrical energy
  - One of these is that consumption or use of electricity partly depends on the costs of using electricity. The elasticity of price in the electricity demand can be low, particularly in the short term, but there is no reason to believe prices play no role at all in how demand develops and varies over time
  - This also implies that prices do have an impact on the flexibility of the electricity demand, and the willingness of demand-side actors to participate in solving issues related to a lack of flexibility on the supply side
  - Demand side participation also depend on other factors, such as costs and other potential burdens of participation, the inconvenience of not being able to consume as initially planned, etc.
  - Experience suggest such inconvenience factors are less important the larger the size of the end user, such that for industrial end users, it is largely the economic factors that are at play, including impact on their production costs and ability to satisfy their customers
  - Prices may also play an important role as information signal to e.g. automated energy management systems, and to coordinate the behavior of a large number of entities

Table of content, list of (some) abbreviations

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Abbreviations frequently used in this report

DSF – Demand Side Flexibility

DS – Demand Side

DSO – Distribution System Operator

DNO – Distribution Network Operator

TSO – Transmission System Operator

BRP – Balance Responsible Party

BSP – Balancing Service Provider

CMSP – Constraint Management Service Provider

BM – Balancing Mechanism

Part 1
Executive summary
– General observations
– Key findings for nine selected cases

General observations for demand side flexibility (1/2)

- There are a few key drivers that seem to explain high activity or participation of demand side flexibility
  - For most countries, there is a combination of factors that motivates the actual participation
  - Which driver is the most important varies between countries; country-specific concerns or issues are important
- The drivers generally fall within one of two categories
  - Economic and/or technical system characteristics, like
    - Energy adequacy & energy mix (Japan, Texas, South Korea, California), or
    - High growth in demand (e.g. related to economic growth) (South Korea, Australia), or
    - Grid stability or adequacy, or (Chile, Japan, Australia)
    - Measure to increase competition (France)
  - Decarbonisation and climate policy
    - Challenges originating from deep decarbonisation policies (e.g. resulting in high growth in electricity demand) (France, Great Britain, Norway)
    - 'Traditional' energy conservation policies aimed at reducing energy or electricity demand, frequently motivated by environmental concerns (and/or recognition of failure of the existing market or pricing arrangements to provide sufficient or correct incentives to energy end users) (Texas, California)

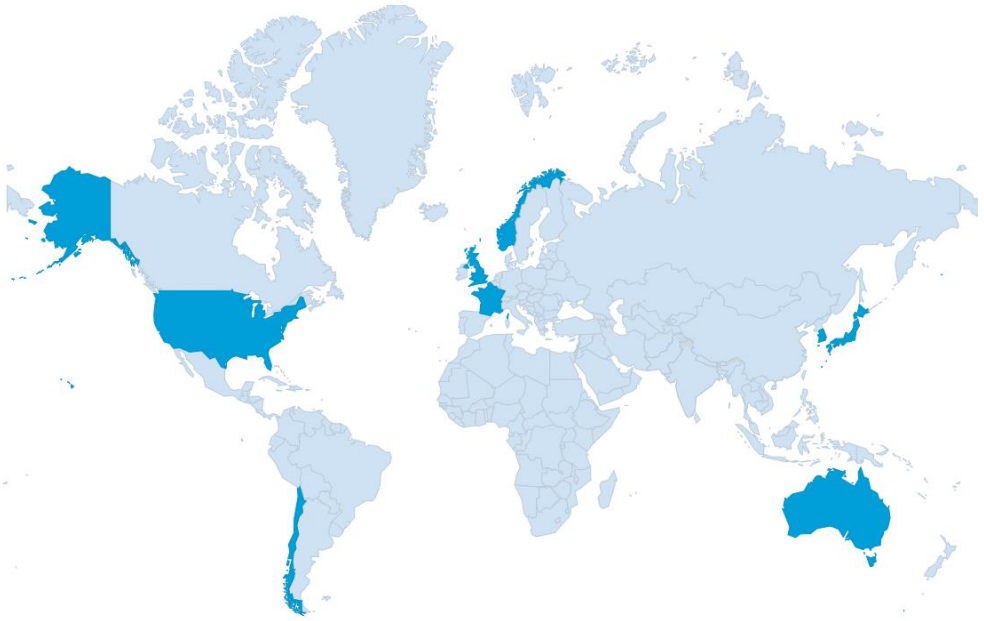
General observations for demand side flexibility (2/2)

- Complex relation between 'classical' market design parameters and DS participation (see next slide)
  - DS participation can be high in both 'perfectly' designed and competitive markets and in monopolistic systems with weak incentives, such as
    - No or low energy price volatility,
    - Grid charges largely independent of capacity (kW) such as pure or mostly volumetric charges
      - With a purely volumetric charge, the time of consumption does not matter for the final bill. Such tariffs provide no incentive to shift load from peak to off-peak periods
    - Combined energy and network charges, eventually including taxes, where the total payment per period to a low extent depend on capacity or time of consumption
  - In some countries, producers generally face competitive prices that vary according to the state of the system (e.g. peak and off-peak) whereas end users are facing a constant price regardless of the actual production costs at the time
- What matters for DSF participation are the specific incentives for specific customers or customer groups, which may be 'good' for targeted customers even if the general market design and features provide no or little incentive to flexibility
- This does not indicate that market design does not matter; it does. But when we observe high DS participation, we cannot know if it is because of or despite the actual market design unless we go further into the details
  - Also, the total cost of attracting and mobilising demand side flexibility is likely to be lower per kW or kWh if the market design is efficient as compared to compensating for inefficient market design by means of tailored programs

Market design parameters and demand side activity

The analysis include 9 examples of how demand-side flexibility works in practice. The examples represent different regions worldwide, as well as different market design and different fundamental features and challenges in the electricity sectors. The table below outlines our impression about the demand side activity and some key market design parameters per case.

	Demand side activity*	Wholesale market	Dispatch	Transmission constraint management
Norway	Low	Contestable	Decentralised	Zonal prices
Japan	Medium	Contestable	Centralised	Zonal prices
South Korea	High	Monopolistic	Centralised	Zonal prices
Australia	Medium	Contestable	Centralised	Zonal prices
Great Britain	High	Contestable	Decentralised	Zonal price
France	High	Contestable	Decentralised	Zonal price
California	High	Contestable	Centralised	Nodal prices
Texas	Medium	Contestable	Centralised	Nodal prices
Chile	Low	Contestable	Centralised	Nodal prices



*Note: This is a subjective comment, based on our general impression of the level of participation of demand side resources, as compared to our impression of the potential.

Electricity system indicators and demand side activity

The analysis include 9 examples of how demand-side flexibility works in practice. The examples represent different regions worldwide, as well as different market design and different fundamental features and challenges in the electricity sectors. The table below outlines our impression about the demand side activity and some key electricity system parameters per case.

	Demand side activity*	Price volatility	Capacity issues	Retail tariffs	Energy sources
Norway	Low	Low	No	Volumetric	Hydropower
Japan	Medium	Low	Yes (Fukushima)	Volumetric	Coal and gas
South Korea	High	Low	Yes	Volumetric	Coal, gas and nuclear
Australia	Medium	High	Yes (peaks)	Volumetric	Coal and gas
Great Britain	High	High	No	Volumetric	Gas, nuclear, wind and PV
France	High	Low	Yes (peaks)	Volumetric	Nuclear, hydro
California	High	High	Yes (peaks)	Volumetric	Gas, hydro, wind and PV
Texas	Medium	High	Yes (peaks)	Volumetric	Gas, coal and wind
Chile	Low	Low	Yes (grid)	Volumetric	Coal, hydro and gas

- The characteristics in the table to the left are rough summaries of key observations per country

*Note: This is a subjective comment, based on our general impression of the level of participation of demand side resources, as compared to our impression of the potential.

Norway – key findings

- Demand side flexibility activity in Norway is currently low, except for the major energy intensive industry selling flexibility to the TSO
- There are few legal barriers to demand side flexibility, but the incentives are weak
- The price volatility is low
- The grid tariffs are volumetric, but capacity tariffs are being discussed
- There are pilot projects on DSF for DSO congestion management
- The market design is contestable, unbundled and decentralised
- Increasing share of distributed generation and increasing peak demand challenge the existing distribution grid. In addition to an expected change towards capacity based grid tariffs, these are key drivers for future DSF participation. Smart meters in all households and the fast increasing share of electric cars are enablers for residential DSF

Japan – key findings

- The demand side flexibility activity is still in an early implementation phase, and the participation is approximately 1 GW
- After the Fukushima accident in 2011, voluntary reduction in electricity use was highly promoted by the government to avoid blackouts, and started the utilization of demand response
- The NegaWatt Demand Response market was launched in 2017, mainly to ensure grid stability
- Demand side flexibility can participate in the JPEX wholesale market through negawatt trading contracts between an aggregator and the regional electricity network operator
- Price volatility is relatively low
- The grid tariffs mostly rely on volume (energy)
- Liberalization of the electricity markets, leading to an active and rapidly growing wholesale market, as well as willingness to increase resilience, are major drivers for demand response in Japan. Increasing share of distributed generation and smart meter rollouts are key enablers for DSF

South Korea – key findings

- South Korea has high demand side flexibility activity; 4.3 GW is currently participating in the wholesale market through 28 aggregators. The participants are mostly commercial and industrial consumers
- There are several demand response programs in preparation, aiming to reduce barriers and increase DSF activity
- The price volatility of the day-ahead market is low due to a cost evaluation scheme instead of price bidding, combined with a high share of thermal generation
- The grid tariffs mostly rely on volume (energy)
- The electricity system is monopolistic, and transmission, distribution, sales and most of the generation are provided by a single entity (KEPCO). Despite of central dispatch and no retail competition, DSF activity is high
- South Korea is facing high growth in electricity demand, and especially high system peak demand caused mostly by energy intensive industry. There is a low potential for new generation sites, and South Korea rely on fuel imports for electricity generation. There is increased public concern about nuclear generation and rising apprehension to power line construction. Thus, the government has shifted the focus to demand management to balance supply and demand, reduce the need for building new generators and power lines and running expensive peak generators. Ambitious plans for electric vehicles and smart meter rollouts are key enablers for residential DSF.

Australia – key findings

- Demand side flexibility activity has grown significantly in the last couple of years
- Through recent changes, DSF can now participate in both adequacy, wholesale, balancing and constraint management services. The participation in the Frequency Control Ancillary services has grown rapidly since it opened up for DSF in 2017
- Price volatility is relatively high
- The grid tariffs are volumetric (energy) based, but include an extra charge for peak periods
- The market design is contestable, decentralized and advanced
- There is an increasing energy demand in Australia due to growing population, and there are especially high demand peaks during heat waves. At the same time there is a rapid increase in Distributed Energy Resources (DERs), including both generation (solar), storage and loads (EVs). These factors place pressure on the grid and are, combined with strong incentives from price volatility and peak period charge in both network and energy tariffs, key drivers for DSF participation

Great Britain – key findings

- Great Britain has high demand side flexibility activity especially in the adequacy services and balancing markets (2.3 GW for FCR in 2018 and ~10GW across 3 tenders for STOR in 2018)
- DSF does not participate in wholesale markets yet and only recently Independent Aggregators can enter the Balancing Mechanism. In the future we expect additional DSF in DSO constraint management and wider access for DSF to more routes to the market (NG ESO initiative and DNO/DSO transition)
- The price volatility in wholesale market is high but not sufficient for DSR providers
- Grid tariffs rely on volume and not capacity. Avoidance of network charges (i.e. Triad and DSoUs), however, incentivise consumers to shift their demand aways from high peaks. Time-of-use energy tariffs are in use for C&I customers, and at early stages of use for residential customers
- The market design is contestable, unbundled and encourages high DSF activity. Despite being a mature market (especially at Transmission level), there are still barriers and market uncertainties which hinder wider DS participation
- Key enablers for DSF participation in GB are regulation and support from Ofgem and BEIS as well as market signals. The policy has led network companies to create emerging opportunities for DSF such as the wider access to the Balancing Mechanism (BM), weekly low frequency response auctions (in 2018-19) and participation of DSF in DSO constraint management. Innovation is also supporting this direction toward DSF

France – key findings

- France has relatively high demand response participation (~5GW)
- Flexibility can be offered in balancing and capacity services. Since 2018, there is an annual tender to procure demand response
- Since 2014, flexibility can be traded in the wholesale market through a mechanism called NEBEF. The participation is mostly during the cold months, when the generation is tighter and prices are higher
- Price volatility is relatively low in France
- Network tariffs are mostly volumetric. There are various supply tariffs available for industrial, commercial and residential customers, allowing for implicit DSR. In 2018, it was estimated that the capacity made available by these tariffs was around 700MW
- The market is contestable, unbundled and decentralised, but EDF has a 80 % market share. Enabling demand response participation is a way of enhancing competition
- High demand during the winter months causing adequacy problems and the need for an increase in competition in the various markets have driven the participation of demand side response in France. This has been enabled by targeted policies and regulations.

California – key findings

- California is one of the leading markets when it comes to implementation of demand response programs and demand side flexibility
- DSF can participate in the wholesale market, ancillary services (spinning reserve, non-spinning reserve) and adequacy services (capacity procurement). There is no DSF participation in constraint management services yet. In California there is a wide range of Demand Response programmes that are offered to the consumers by the utility companies
- Price volatility is generally high, seeing spikes during summer months and afternoons/evenings. This price volatility is a driver for DR programmes mainly and for the ToU tariffs
- Grid tariffs rely on volume and not capacity, but CAISO is considering possible changes to this approach to better reflect cost causation, utilization, and benefits for the existing transmission system
- The power market is centered around the California ISO in a mandatory centralized pool model. The electricity system in California is currently a mix of regulated and deregulated. Despite the lack of a fully liberalised system, DSF activity is high
- The main drivers for demand flexibility in California are management of peak capacity during hot summer days, affordability of electricity, grid reliability and supporting more renewables on the grid. Management of renewable integration will call for demand response that can compensate for the uncontrollability of this new generation. CAISO created the “duck curve” to show the impact of grid-connected PV on the electric grid’s operation which indicated balancing variability in electricity demand

Texas – key findings

- In Texas, demand response participation is relatively high, with 2–3 GW of demand response capacity in 2018
- Demand response can participate in the wholesale market and balancing services. However, participation is limited to controllable loads (can vary electric usage immediately based on a signal) and have high technical requirements for most of the services. The services with significant demand response participation are the responsive reserve and the emergency response service
- Price volatility is relatively high, especially during the summer months and highly influenced by residential demand. This has caused emergency situations and demand response activations
- Grid tariffs are purely volumetric. There is a range of demand response programmes offered to customers by utilities, to avoid high energy and network prices (costs)
- The market is unbundled, centralised and quite open to competition
- The key enablers for demand side flexibility in Texas are peak management during summer months, grid stability and reliability, especially in emergency situations. Due to increasing renewable intermittent generation, ERCOT is discussing a possible change in balancing services to allow for faster response times and more demand response participation

Chile – key findings

- Demand response in Chile has been highly used for peak management through network and supply tariffs
- There are no explicit demand response products open yet. From 2020, however, the provision of balancing services will open to competition, allowing demand response participation
- There is an increasing need for flexibility in Chile's electricity grid due to intermittent renewable generation
- The market is centralized, soft contestable and unbundled. The fact that Chile is not fully liberalized does not strengthen the case for demand response
- Grid tariffs are largely volumetric
- Grid adequacy problems (due to decentralized renewable generation) and generation adequacy problems (in the past) are the key enablers for demand side flexibility in Chile. With the increase of renewable generation and the opening of balancing services to competition, an increase of demand response participation is expected in the coming years

Part 2
Market and market design parameters

Electricity markets are organised in different ways across the globe. Also, the electricity systems differ between countries. In this part, we describe the features that typically differ between countries and are likely to have an impact on demand side participation and the use of distributed resources with respect to flexibility in the electricity systems.

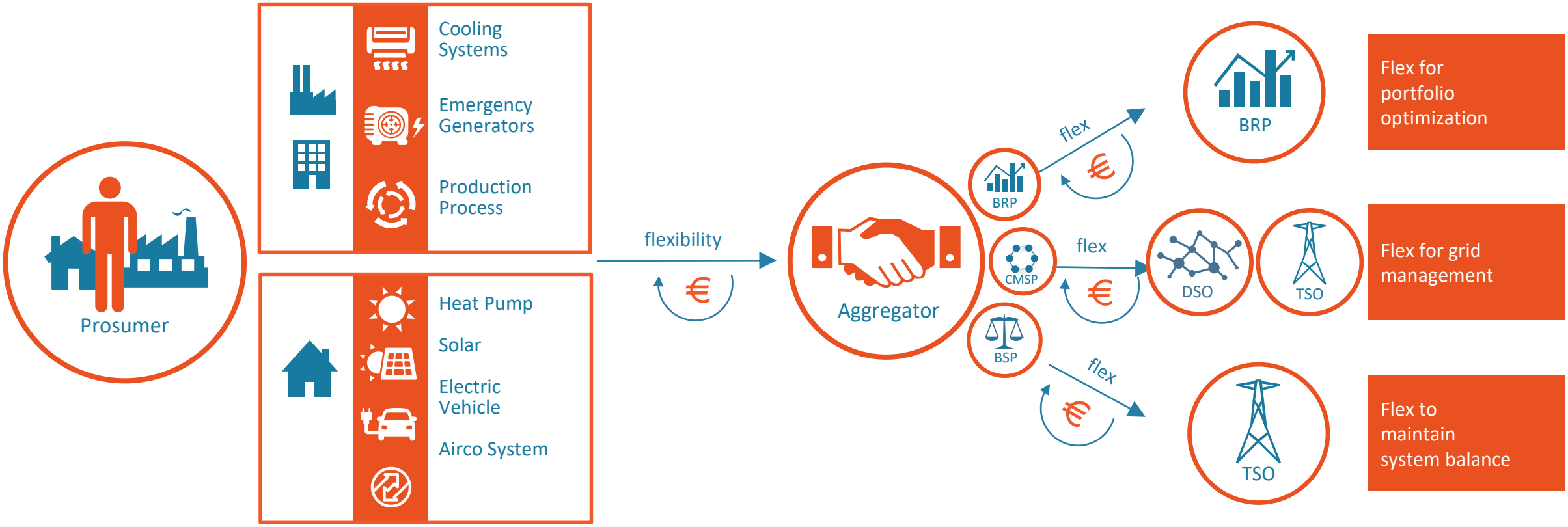
We distinguish between parameters that describe regulatory choices or decisions, and parameters less dependent on regulatory decisions, such as energy mix and market structure.

Items described in this part

- In this section, we briefly explain
  - The terms listed to the right,
  - How they are related to demand side flexibility, and
  - How the choices or features for each term impact the incentives for the demand side to offer their flexibility
- Before going into details, the next page provide an illustration of how resources at the demand side may participate in different markets or for different purposes, and how this may be organised

- Transmission congestion management methods
- Dispatch
- Market organisation
- Market structure
- Adequacy organisation
- Other key indicators
  - Generation mix
  - Volatility of day-ahead prices (or similar)
  - Degree of electrification: electricity consumption per household
  - Capacity: generation or network adequacy concerns
  - Retail tariff structure
  - Composition of the energy bill: energy and taxes share
  - Design of the network tariff: primarily capacity or volumetric based
  - Load curve

USEF's flexibility value chain shows how demand side flexibility can be sold on different markets and products through explicit mechanisms



Market design parameters – transmission constraint management

- This parameter describes the method with which grid capacity limitations are dealt with, and thus to some extent how wholesale electricity prices are determined and differ geographically
  - Wholesale prices and price formation is relevant also for residential end-users, even though the relation between wholesale prices and the cost of using electricity can be blurred and vary between countries
  - The distinctions made below mostly refer to congestion management some time before time of delivery (real time). In the real time operation, there are less, or other, differences between TSOs in how network constraints are managed
  - This dimension is more important for very large end-users, like aluminium plants, than for the residential load. Still, it may have some impact also for the smaller customers; if not directly, so for the suppliers to such customers
- **Nodal pricing** considers all the transmission constraints in the physical short-term market (day-ahead or later). Each generator is paid in accordance with the local price at the node where it is located. This method is used e.g. in several US markets and in New Zealand. With a nodal pricing approach, market participants are consistently encouraged to adapt demand (or supply) plans so as to avoid or minimise congestion issues in the transmission network
- **Zonal pricing** ignores the constraints within a zone, such that there are uniform prices within the zone. This implies market participants are essentially encouraged to ignore physical constraints, which the TSO must then resolve at a later stage. The zones can be smaller (e.g. Sweden) or bigger (e.g. Germany), can also be different for demand and supply side (Italy).

Market design parameters – dispatch

- This (binary) parameter describes how the dispatch of power production is organised
- **Central dispatch** means that the system operator instructs and plan dispatch, some time before delivery, e.g. day-ahead or hour(s) ahead. Many nodal systems have central dispatch, only a few minutes before real-time.
  - The central dispatch will normally apply only for power plants above a minimum size, or only for plants connected at some specific voltage levels (the higher ones)
- **Decentralised dispatch** means that producers are supposed to self-dispatch, based on commitments made in e.g. a day-ahead or an intraday market
- Central dispatch does not preclude end-users from self-dispatch; most end-users will anyway have full discretion over their consumption, in particular in the short-term. However, for the very large consumers (heavy industry), there may be some sort of central 'control' of load in centrally dispatched power systems
  - With central dispatch, prices may be less relevant as motivation or explanation of actual behaviour for those market participants that are subject to a central dispatch arrangement

Market design parameters – market organisation

- This parameter describes how and to what degree the market is regulated. Market organisation is a non-binary parameter, and can sit between two extreme sides
- **Regulated** is normally associated with monopolies with regulated revenue or prices, often within a defined geographical delimitation
- **Contestable** means that market participants compete for resources and customers, and prices determined by the balance between supply and demand
- Different approach for wholesale and retail is feasible; historically, a combination of contestable wholesale markets and regulated monopolies responsible for retail distribution and sale has been quite common
- Innovation and creativity with respect to how demand side flexibility is organised and remunerated may be expected to depend on the extent to which supply to residential end-users is exposed to competition
- In well-designed contestable markets, the prices and the price structure will tend to reflect the value of electricity and capacity as well as flexibility, in a more precise manner than in monopolistic systems
  - However, it is not impossible to design regulation such that prices reflect these values, but the complexity of the real world tends to be so high that regulatory flaws seem inevitable

Market design parameters – market structure

- This parameter describes the degree of unbundling of generation, distribution and retail. This parameter is non-binary, and can sit between two extreme sides
- **Bundled** companies used to be the standard approach in several countries, in the form of vertically integrated utilities active in both power generation, ownership and operation of electricity networks and sales of electricity to end users
- **Unbundled** with complete separation of generation, distribution and retail. In the 'extreme' version there is full unbundling not only in terms of separation in different companies, but also separation of ownership such that e.g. someone enjoying control over generation cannot also enjoy control over networks.
- There is an inherent risk that bundled companies get their price setting wrong, particularly for utilities comprising network activities as well as power generation and/or retail sales
  - The tendency to transfer costs from commercial activities to monopoly activities, and transfer revenues the opposite direction is everywhere, and may result in blurred or wrong price signals to customers
  - With unbundling, the incentives for companies to distort prices is weaker and less cause of concern

Market design parameters – adequacy organisation

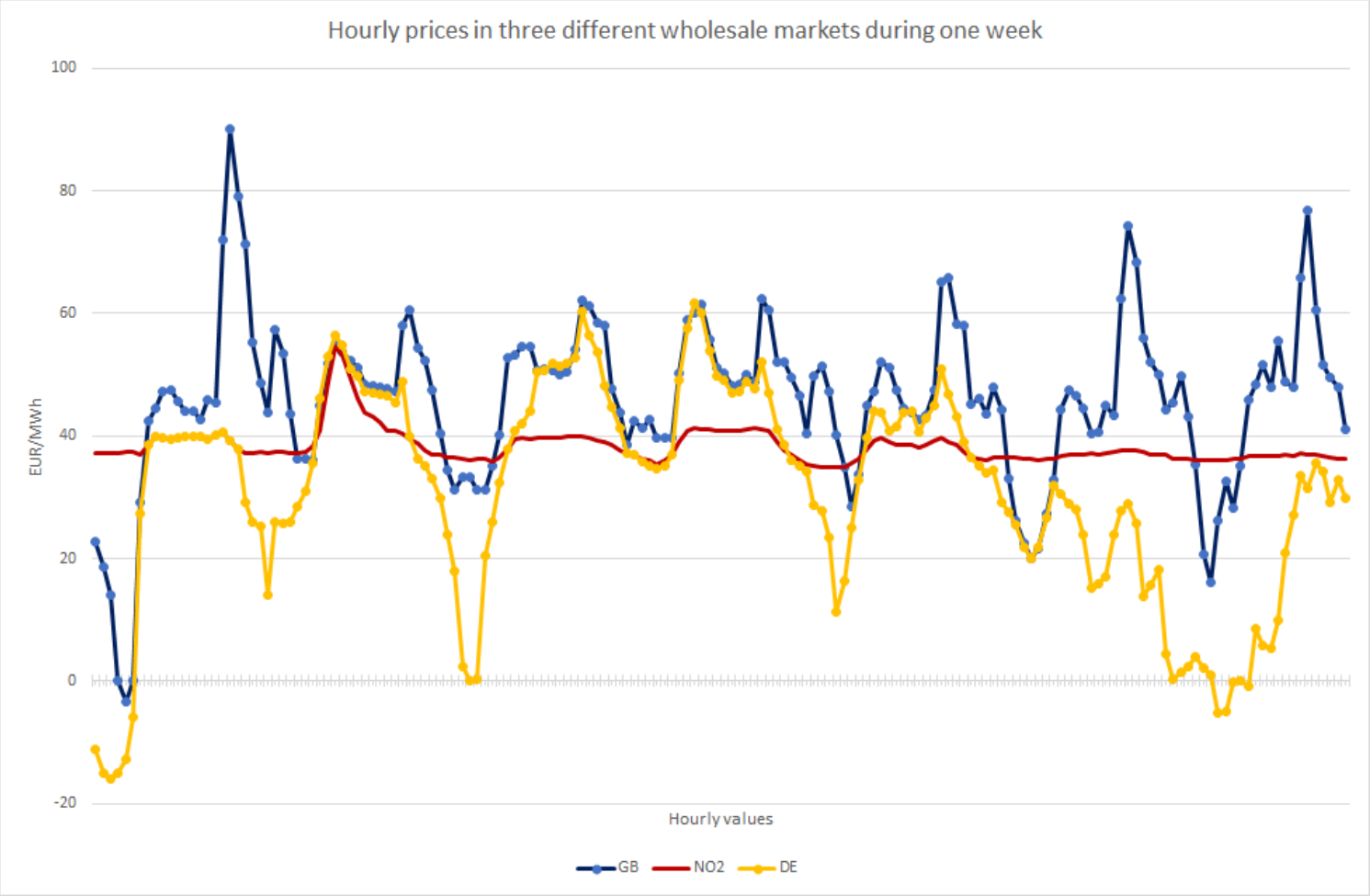
- This parameter describes whether a responsibility for generation adequacy is defined, and if so, how it is organised. This is a non-binary parameter, with some typical alternatives when adequacy is defined by the regulation
- A key distinction is between market wide arrangements, with an ambition of contracting capacity corresponding to the total peak load, and narrow arrangements, which are less 'ambitious', aiming at contracting resources that otherwise would not remain in the market. The key difference is that in capacity markets, 'all' capacity is remunerated for holding capacity, while in strategic reserves arrangement, only some of the capacity is contracted.
- **Capacity markets** are such wide arrangements, and normally refer to cases where explicit contracts are made with all capacity owners that are expected to be required for covering peak demand. The objective of such contracts is normally to ensure a revenue for owning capacity for successful participants. There are different detailed designs of capacity markets. Differentiating features include, but are not limited to, duration of contracts, type of remuneration, which technologies can participate, whether demand side is eligible for participation, and mechanism for determining prices or remuneration.
- **Strategic reserves** is the term used for narrow arrangements, in which only a limited volume of capacity is contracted, typically meant as a supplement to what the competitive (wholesale) market is expected to mobilise anyway. As with capacity markets, there are different designs of strategic reserve markets or mechanisms
- **Energy only** (or mostly) refers to markets without any particular arrangement for ensuring capacity. Implicitly, the regulation of energy only markets rest on an assumption that competitive market participants will make sure to cover demand, on commercial terms
- For countries applying capacity market or strategic reserves, the actual organisation of responsibilities and tasks can vary; typically it is a regulatory body defining criteria and other rules, while a TSO or a separate body organise auctions or other procurement procedure and contracts with winning tenders
- Capacity markets are frequently designed such that demand can also participate, by committing to reduce consumption when requested by the responsible body
  - Such arrangements may improve the business case for aggregators and others working with demand response

Other key indicators – market indicators

The economic situation for demand side flexibility can also depend on the (existing) market characteristics, as suggested by the descriptive parameters below. The parameters provide information relevant for the value of demand side flexibility

1. Generation mix
   - The value of demand side flexibility is generally larger the less flexible the generation portfolio is
2. Volatility of day-ahead prices (or similar)
   - The price volatility normally reflects the generation mix and represent an important revenue sources for all flexibility
3. Degree of electrification: electricity consumption per household
   - The larger the consumption per capita or per household, the more important is it also for private consumers to explore revenue opportunities in flexibility markets. Also, the 'required' price impact is smaller if there is a large number of kWh's
4. Capacity
   - Is there a perception of generation adequacy problems in the country?
   - Is there a perception of network adequacy problems in the country?
5. Retail tariff structure
   - Composition of the energy bill: energy and taxes share
   - Design of the network tariff: primarily capacity or volumetric based
   - Retail prices matter for retail customers. If energy only represents a minor part of the energy bills, it will normally be less important to get the prices and incentive right. Also, volumetric grid charges tend to offer few incentives for demand side participation
   - See also https://www.dnvgl.com/publications/effective-and-cost-reflective-distribution-tariffs-162913
6. Load curve
   - The shape of the load curve gives some indication about how flexible the demand side can be; i.e. how much 'supply' there might be.

Example illustration and discussion about price volatility



- The three curves to the left shows hourly wholesale electricity prices for one week in 2019 for three markets
  - Germany – yellow
  - Great Britain – blue
  - Norway – red
- The lack of price volatility in the Norwegian example suggests a low value of flexibility in this market, as compared to it's German and British peers
  - There are more value in moving demand in time when looking at the blue or the yellow curve, than the red
  - To which extent the revenue would be sufficient to cover costs is separate matter and not showed in the diagram
- Note that the prices in the diagram are not including network charges, connection charges or taxes

Part 3
Analyses of the selected cases

The cases are presented over 5-10 slides using the same structure for each case study
The first slide gives an overview of demand side flexibility in the country
Next follows an overview of explicit products are available for demand side flexibility in this country, with regards to

- Adequacy
- Wholesale
- Balancing
- Constraint management
- For each product, we describe
  - Possibilities of value stacking
  - Remuneration mechanism (energy or capacity or both)
  - Market participation (quantify size in GW)

If there are implicit products/mechanisms available, such as within network tariffs or standard supply tariffs, these are explained
Finally, the market is described with regards to the parameters explained in part 2

Norway

- Demand side flexibility activity in Norway is currently low, except for the major energy intensive industry selling flexibility to the TSO
- There are few legal barriers to demand side flexibility, but the incentives are weak
- The price volatility is low
- The grid tariffs are volumetric, but capacity tariffs are being discussed
- There are pilot projects on DSF for DSO congestion management
- The market design is contestable, unbundled and decentralised
- Increasing share of distributed generation and increasing peak demand challenge the existing distribution grid. In addition to an expected change towards capacity based grid tariffs, these are key drivers for future DSF participation. Smart meters in all households and the fast increasing share of electric cars are enablers for residential DSF

Overview of demand side flexibility

- Demand response and aggregation can participate in both wholesale markets and all balancing markets
- Aggregators have to be a Balance Responsible Party (BRP) or have an agreement with the consumer's BRP to participate in the markets, meaning that independent aggregation (without being or having an agreement with a BRP) is not permitted
- For an aggregator to participate in the day ahead or intraday market, the bidding zones applies; the TSO procure energy per bidding zone. Hence, it is impossible to aggregate load from different bidding zones.
- Congestion management (TSO)
  - The TSO manage congestions in the transmission and regional distribution grid using mFRR-bids/offers ("spesialregulering").
- Congestion management (DSO)
  - Currently, the DSOs manage grid capacity shortage by grid investments. Today there are only a few serious capacity constraints at DSO level, which are either managed by switching substations or through pilot projects for load management
  - Active network management based on voluntary agreements with grids customers are legal, but only implemented in tests/pilots - explicit products are expected
  - There are ongoing pilot projects on demand side flexibility for DSO congestion management

Explicit products for demand side flexibility

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Energy options	Yes	Capacity and energy	Yes	0-2000 MW, depending on precipitation etc.	
Balancing	Primary reserves FCR (FCR-N and FCR-D)	Yes, through a BRP	Capacity and energy based	Yes	Very little participation from demand	Minimum bid size 1 MW, notification time 2-3 min (FCR-N), 5s and 30s (FRC-D).
	Secondary reserves aFRR	Yes, through a BRP.	Capacity and energy based	Yes	Very little participation from demand	Minimum bid size 5 MW, notification time 2 min. Participation is practically unfeasible due to unlimited activation time.
	Tertiary reserves mFRR (RK for energy and RKOM for capacity)	Yes, through a BRP	Capacity and energy based	Yes	1000-2000 MW from industrial consumers. There are capacity contracts on weekly and monthly basis in the winter time, depending on TSO evaluation of their need to contract capacity.	Minimum bid size of 10 MW (manually operated). 15 minutes notification time. Statnett eFleks is a pilot in the regulating power market, testing to go from 10 to 1 MW bid size.
Wholesale	Day-ahead (Elspot)	Yes, trough a BRP	Energy based	Yes	Mainly large industrial consumers	A significant share of electricity is traded in the wholesale market. Demand response and generation can not be aggregated within the same bid. Minimum bid size of 0.1 MW
	Intraday (Elbas)	Yes, through a BRP	Energy based	Yes	Mainly large industrial consumers	Minimum bid size 0.1 MW
Constraint management	TSO congestion management: mFRR is used for TSO congestion management in Norway (see above).					TSO congestion management is largely based on manual calls
	DSO congestion management: DSO congestion management is currently grid investments, but there are pilot projects on demand side flexibility for DSO congestion management.	Yes				NODES is a pilot flexibility marketplace for DSO congestion management

Implicit products for demand side flexibility

- **Network tariffs**
  - Capacity-based residential tariffs, but with very high volumetric share for households and other small customers. The regulator has an objective of introducing tariff designs for DSOs that to a larger extent than the current to incentivize DSF, with a relatively high share of the grid charge depending on capacity and a quite low volumetric charge. This has become a political process with some delays
  - Flexible tariffs are in use today, and it is voluntary for the DSOs to offer this mechanism to its customers. The DSO can disconnect customers with flexible tariffs on short notice when needed. When some network customers have cheaper flexible tariffs, all other network customers have to pay more. The regulator has recognized that this may be changed in order to support flexibility markets, and this is being discussed
- **Supply tariffs (energy)**
  - The energy suppliers offer three main types of electricity contracts: fixed-price, standard variable price and spot price. In a spot price contract, the price is based on the market price and includes a mark-up. Most consumers have dynamic pricing based on day-ahead prices. All Norwegian households now have AMS installed, which meter electricity consumption every hour. This means that they can have electricity contracts effectively based on hourly prices, which can incentivise consumptions adjustments to hours with low demand and low prices

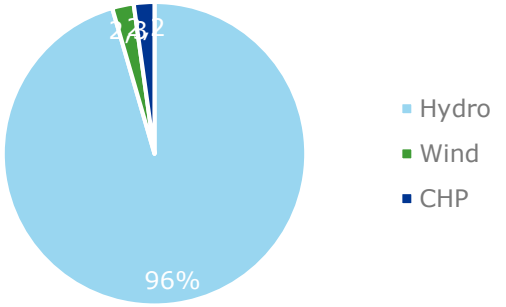
Market design parameters

1. **Transmission congestion management methods**
   - Zonal pricing. Norway is divided into 5 price zones.
2. **Dispatch**
   - Decentralized. Producers are supposed to self-dispatch, based on commitments made in the day-ahead market
3. **Market organisation**
   - Contestable. All end users are free to choose their power supplier
4. **Market structure**
   - Grid companies with more than 100 000 customers (7 companies) have to be legally unbundled, meaning that they can not control both grid operations and generation in one legal entity. By 2021 all grid companies are required to implement legal unbundling, and companies with more than 10 000 customers must also undertake functional unbundling. Legal unbundling means that grid operations and production and/or trading activities are performed by separate legal entities (but these can have the same owner), while functional unbundling means that the management of a grid company can not be involved in the management of other company structures in an integrated company, but it is allowed to influence the financing of the network company.
5. **Adequacy organisation**
   - Energy only: Forward markets, day-ahead and intraday market and reserve markets
   - In critical hydrological situations the TSO can buy "Energy Options" from industrial consumers committing to reduce consumption. The notice time is at least one week and the reduction must be available for at least two weeks
   - The Norwegian TSO runs a capacity market to ensure sufficient liquidity in the market for tertiary reserves (mFRR) for all Norwegian bidding zones during the winter season (RKOM – acronym for "Regulerkraftsopsjonsmarkedet"; Tertiary reserves options market). RKOM has similar features as a limited capacity mechanism, but is not designed to ensure there is always an equilibrium in the day-ahead market. RKOM is run with seasonal and weekly auctions and is open to all eligible suppliers (i.e. large suppliers) in the mFRR market. Successful bidders get paid an amount in advance to guarantee they submit offers in the mFRR market, regardless of whether theirs resources are activated or not. Participants in RKOM commit to deliver bids on upward regulation, and are allowed to receive payments from other sources/markets as well
   - The TSO also has some bilateral agreements with demand resources which requires them to bid in the mFRR-market during the winter season

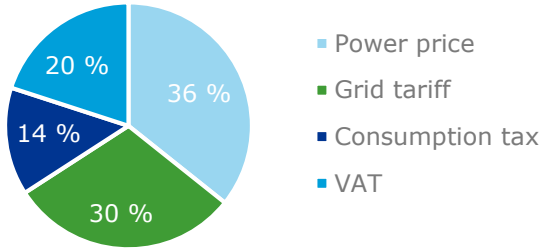
Other key indicators

1. **Generation mix**
   - 2.3% wind, 2.2% CHP, 95.5% hydro (2018).
2. **Volatility of day-ahead prices**
   - Low price volatility.
3. **Degree of electrification**
   - Most of the residential heating is electric. Total electricity use in households: 38,8 TWh (2018) (Energy use in households 47.2 TWh, total electricity use in Norway 125 TWh).
   - Electric vehicle share of 7.2% (2018), and 44% of new care sales (so far in 2019).
4. **Capacity**
   1. Is there a perception of generation adequacy problems in the country?
      - No.
   2. Is there a perception of network adequacy problems in the country?
      - The transmission network is in general strong, but most DSOs have to upgrade parts of their network in order to connect new large loads like ferries and wind power production.
5. **Retail tariff structure**
   - Composition of the energy bill: 1/3 is electricity price.
   - Design of the network tariff: Mainly volumetric based in the distribution network.
     - Fixed component (NOK/year): Customer specific costs, capital and maintenance costs
     - Energy component (øre/kWh): Greater or equal to marginal cost of losses in the grid when used by the customer. Large customers (>100 000 kWh/year) can have a capacity charge (NOK/kW)

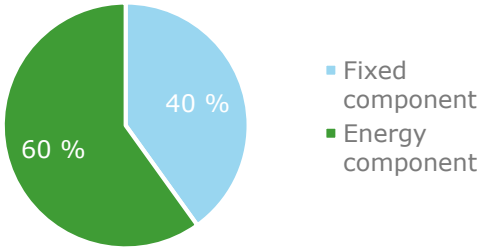
Generation mix 2018



Energy bill

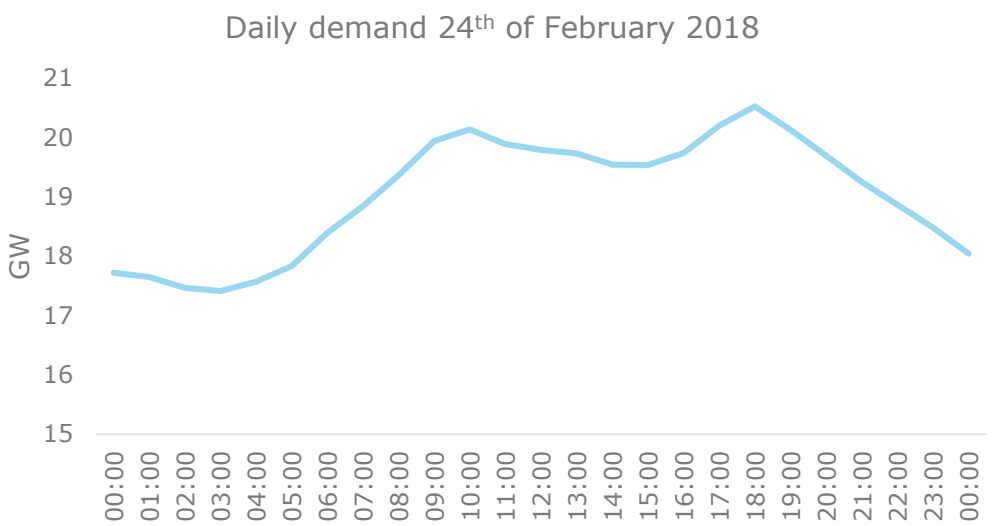


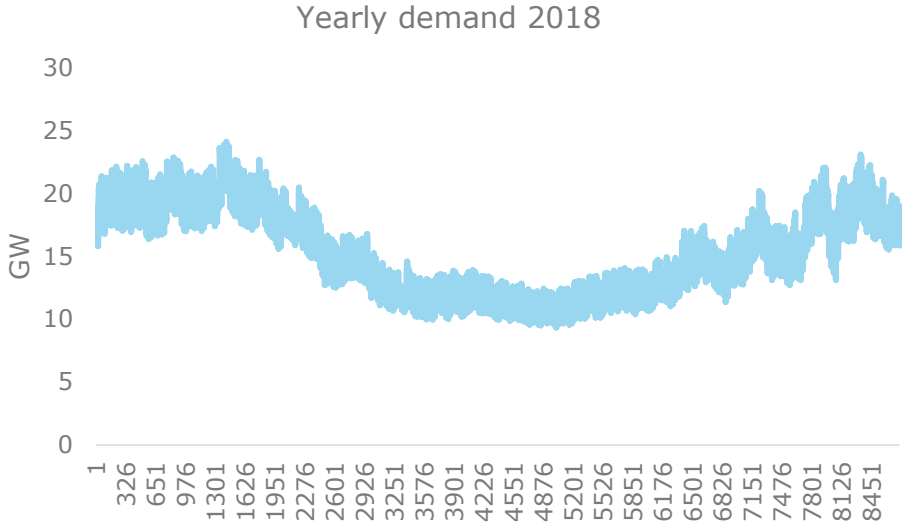
Network tariff

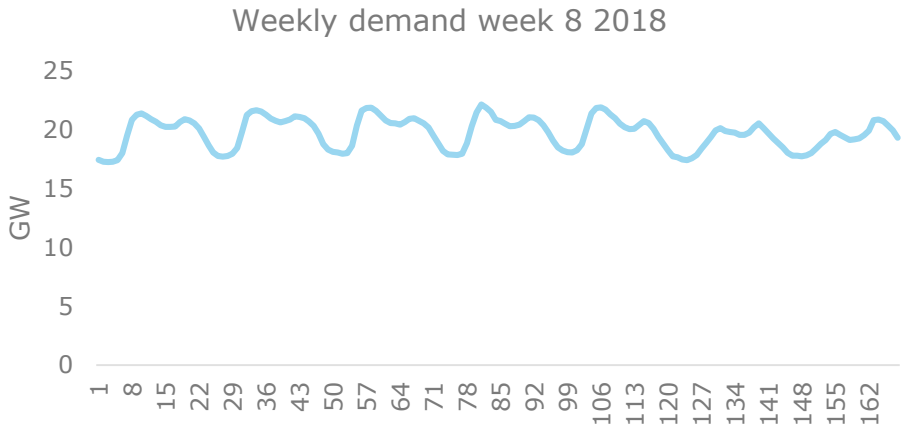


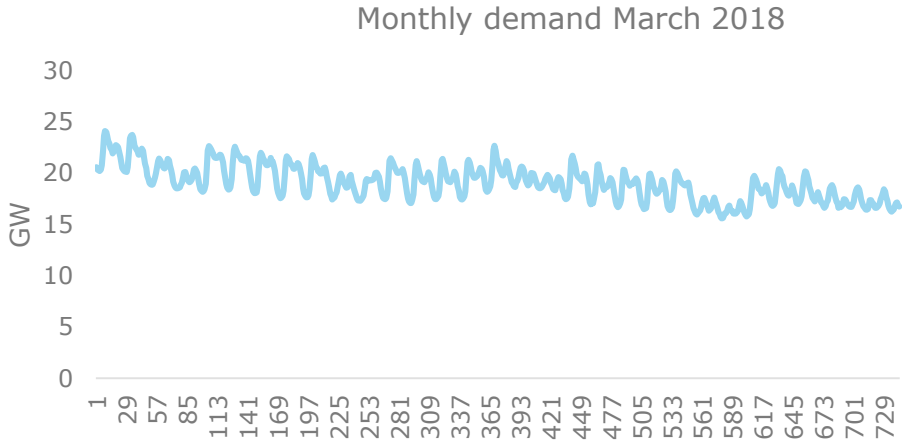
Source: SSB (2018)

Other key indicators: Load curves









Source: NordPool

Japan

- The demand side flexibility activity is still in an early implementation phase, and the participation is approximately 1 GW
- After the Fukushima accident in 2011, voluntary reduction in electricity use was highly promoted by the government to avoid blackouts, and started the utilization of demand response
- The NegaWatt Demand Response market was launched in 2017, mainly to ensure grid stability
- Demand side flexibility can participate in the JPEX wholesale market through negawatt trading contracts between an aggregator and the regional electricity network operator
- Price volatility is relatively low
- The grid tariffs mostly rely on volume (energy)
- Liberalization of the electricity markets, leading to an active and rapidly growing wholesale market, as well as willingness to increase resilience, are major drivers for demand response in Japan. Increasing share of distributed generation and smart meter rollouts are key enablers for DSF

Overview of demand side flexibility

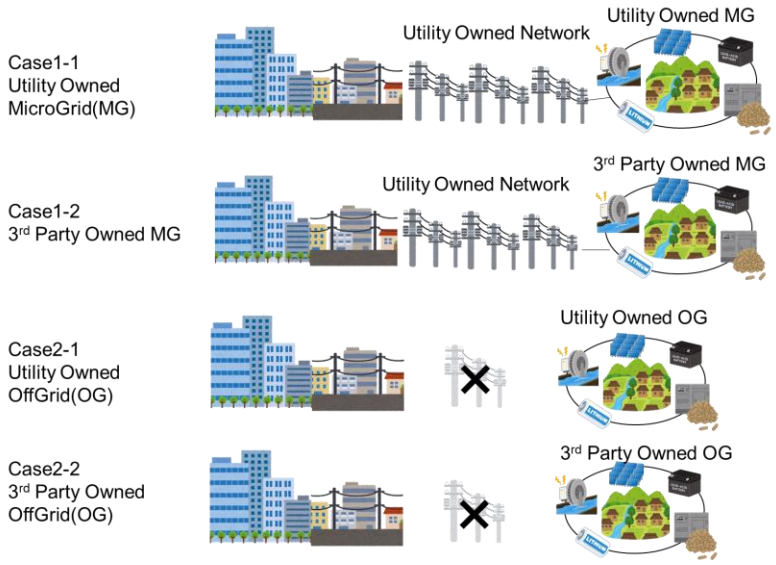
- After the 2011 Fukushima accident and the shutdown of reactors, the Japanese government has implemented several measures to reduce electricity use, requesting voluntary reduction in electricity use from both large and small consumers to avoid blackouts. Article 27 of Electricity Business Act obliges consumers to make their power saving plans and submit power saving implementation results to the Minister (Restriction on Use of Electricity). The Minister of Economy, Trade and Industry can order or recommend a consumer to restrict their use of electricity. This is voluntary and without financial incentives. If demand reduction is not enough after these plans are implemented, forced rotating disconnection (as in UK) will be activated by the order of the Minister of Economy, Trade and Industry (METI).
- The NegaWatt market was launched in 2017, where Tokyo Electric Power Company (TEPCO) is partnering with several DR providers to ensure grid reliability.
  - A negawatt is a negative megawatt, which is a hypothetical unit of power measuring the amount of power saved compared to a baseline based on previous electricity demand.
  - The negawatt contracts differ from one region to another.
  - The price of this service is relatively high in comparison to procurement of capacity, with average at JPY 3,661 per kW, ie. 30 euro per kW.
- Demand response aggregators can participate in the wholesale market JEPX through negawatt trading contracts.
- Balancing is performed by the TSOs in each area. A cross-regional balancing market is planned to launch in 2021.
- There are several pilot projects on Virtual Power Plants (VPP). VPPs aggregate several resources (generation, demand, storage) using IoT technologies. Many aggregators are involved in Trial VPP projects, with Enel being the largest.

Explicit products for demand side flexibility

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Capacity mechanism	There are plans to open a capacity market in 2020/2021	Capacity	N/A	N/A	
Wholesale	NegaWatt Demand Response market	Yes, since 2017	Both capacity and energy	No	Total DR Offer is 1,112 MW, Total DR Contract is 958 MW (2018). The largest aggregator is ENEL through its subsidiary EnerNOC Japan, currently offering 165 MW. Current participation is mostly limited to large consumers in commercial and industrial sectors, but households can participate as well. Technologies participating include air conditioning, lighting, generators, storage, production facility equipment and heat storage tanks.	Electric power consumers get a financial incentive as a reward for Negawatts. A negawatt is a unit of power saved as a direct result of energy conservation measures, measured against a baseline. The are different methods to estimate the baseline, and standard baseline calculation methods have been stipulated by METI. The baseline for longer duration DR is based on historical demand and short duration DR is based on demand immediately previous to the implementation of DR. Dispatch of DR by the utility is currently all manual, with the utility informing the aggregator by phone or email. The aggregator uses a mix of manual and remote control. There are two types of demand response in the market: - Auto demand response is priced higher, and initiated without notifying the customer. - Best effort demand response is initiated by the customer and load is shed as a best effort basis.
	JEPX spot market	Yes, since March 2017, through negawatt trading contracts between aggregator and regional electricity network operator.	Energy	Yes	The volume on the JEPX market is increasing rapidly after the market was liberalized, from <100 GWh/day in 2017 to 400 GWh/day in 2018.	
Balancing	"Open Procurement" of Balancing Power	Yes, by tenders conducted by regional electricity network operators	Energy	Yes	Approximately 350 MW as shortage imbalance Approximately 1.46 GW as surplus imbalance (Generators and retailers)	Japan plan to launch joint balancing markets in 2020-2024.
Constraint management	Not available	No				

Implicit products for demand side flexibility

- **Network tariffs**
  - The network tariff consist of an energy charge (approximately 73%) and a capacity charge (approximately 27%), and there are currently discussions about increasing the capacity charge.
- **Supply tariffs (energy)**
  - A time-of-use tariff was first launched by the energy retailer Looop Inc in 2018, following the implementation of smart meters. The pricing is higher in daytime and lower in evening and night than the common pricing.
- **Microgrid and OffGrid suggestions**
  - In recent years, damage from typhoons and earthquakes has continued in Japan, and Agency for Natural Resources and Energy has been promoting the introduction of microgrids (MG) to increase resilience.
  - The implementation of an off-grid (OG) that is completely separate from the grid is also being considered due to the reduction of operating costs from lower costs of renewable energy and the difficulty of maintaining the distribution network in depopulated areas due to population decline. The figure shows different suggested cases, where case 2-1 (Utility Owned OffGrid) is currently favoured by the Japanese regulator EGC (The Electricity and Gas Market Surveillance Commission).

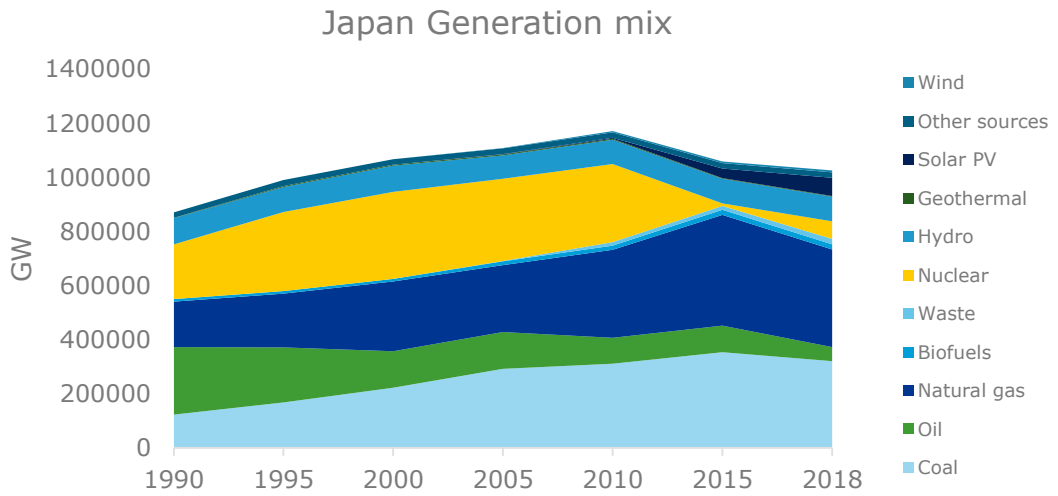


Market design parameters

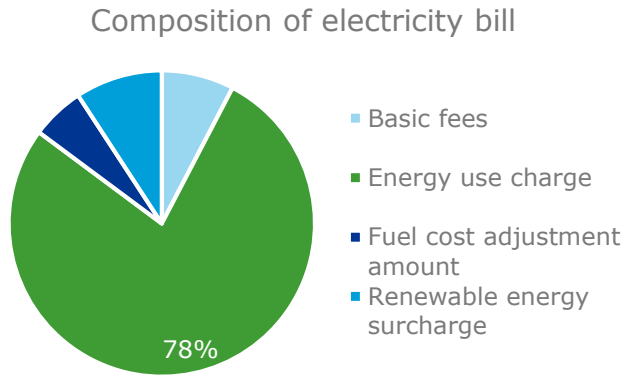
1. **Transmission congestion management methods**
   - Zonal pricing, 10 zones and two different frequencies (50 Hz in Eastern Japan and 60 Hz in western Japan)
2. **Dispatch**
   - Centralised dispatch performed by TDSOs in the different provinces
3. **Market organisation**
   - The wholesale market was liberalized in 1995.
   - There was full liberalization of the retail market in April 2016 (partly and gradually liberalised on higher voltage levels since 2000), and the consumers can select their own electricity supplier. Consumers on low voltage levels can continue to purchase electricity at regulated rates until April 2020, when regulated tariffs will be abolished.
4. **Market structure**
   - The market has been dominated by 10 utilities with regional monopolies controlling most of the generation, distribution and retail.
   - Japan is currently undergoing an electricity market reform, which began after the Fukushima accident in 2011. The goal of the reform is to secure a stable power supply, suppress increase in electricity rate, and expand consumer choice and business opportunities new market participants.
     - Phase 1: Establishment of the Organization of Cross-regional Coordination of Transmission Operators (OCCTO) in April 2015
     - Phase 2: Liberalization of retail market in April 2016. As of September 2018 507 registered retail suppliers and 6 million retail customers have changed supplier.
     - Phase 3: Legal unbundling of utilities by April 2020. TEPCO is currently the only utility with a separate entity for the power grid.
5. **Adequacy organisation**
   - There is a forward market at JEPX with energy products on specific periods and times.
   - There are plans to open a capacity market in 2020/2021 to ensure higher investment predictability

Other key indicators

1. **Generation mix**
   - 77% thermal, 9 % hydro, 6% nuclear, 8 % VRES.
   - Japan is reducing dependence on nuclear power.
2. **Volatility of day-ahead prices**
   - Relatively low
3. **Degree of electrification**
   - Yearly electricity consumption per capita: 8.1 MWh (2018)
4. **Capacity**
   1. Is there a perception of generation adequacy problems in the country?
      - The Fukushima accident in 2011 lead to temporary shutdown of all nuclear plants, causing generation adequacy problems. Creation of a stable power supply system resistant to natural disasters is a challenge. After 2011 the Japanese government has launched several power saving campaigns to avoid blackouts.
   2. Is there a perception of network adequacy problems in the country?
      - There are grid challenges from market reform and deployment of RES, and large needs for replacement investments of infrastructure.
5. **Retail tariff structure**
   - Composition of the energy bill: Example in figure
   - Design of the network tariff: On average 73% is energy charge and 27% is capacity charge (2017).

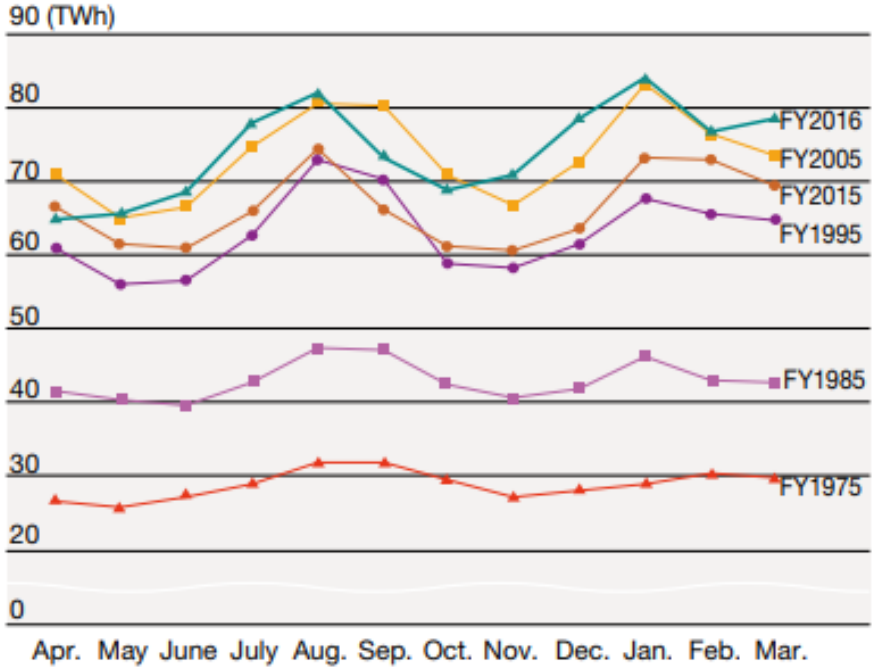


Source: IEA



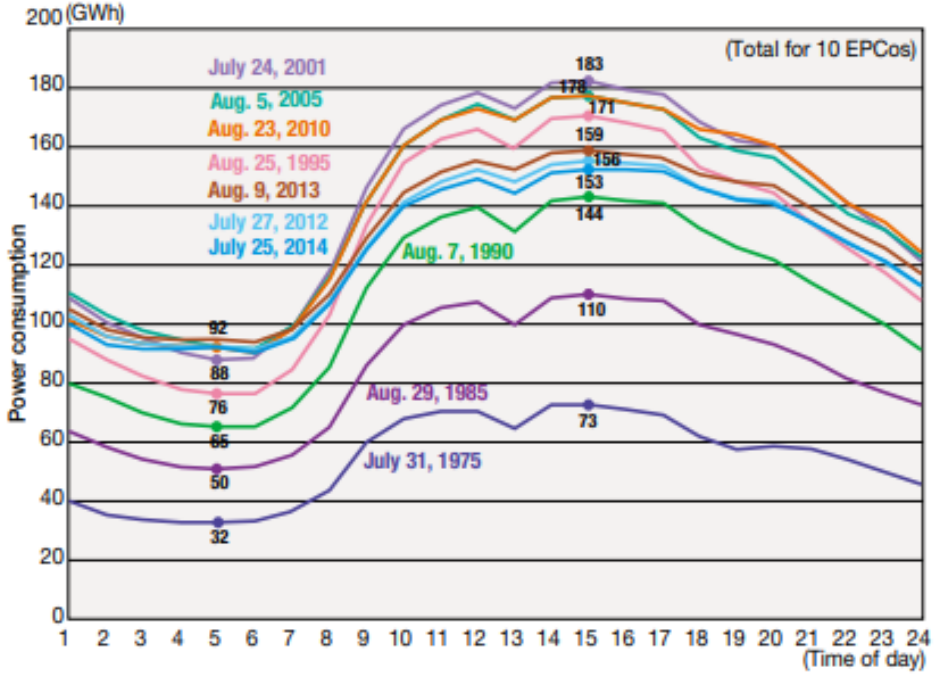
Other key indicators: Load curves

Figure 3.5 Electric Power Consumption over the Course of a Year



Note 1: Figures for fiscal 1975 and 1985 exclude Okinawa EPCo.
Note 2: Figures are totals for 10 EPCos through fiscal 2015, and for 10 areas in fiscal 2016.
Source: Compiled based on Agency for Natural Resources and Energy, *Energy White Paper 2018*.

Figure 3.6 Power Consumption over the Course of Days on Which Peak Loads Occurred



Note: Figures for fiscal 1975 exclude Okinawa EPCo.
Source: Agency for Natural Resources and Energy, *Energy White Paper 2018*

Reference: https://www.jepic.or.jp/pub/pdf/epijJepic2019.pdf

South Korea

- South Korea has high demand side flexibility activity; 4.3 GW is currently participating in the wholesale market through 28 aggregators. The participants are mostly commercial and industrial consumers
- There are several demand response programs in preparation, aiming to reduce barriers and increase DSF activity
- The price volatility of the day-ahead market is low due to a cost evaluation scheme instead of price bidding, combined with a high share of thermal generation
- The grid tariffs mostly rely on volume (energy)
- The electricity system is monopolistic, and transmission, distribution, sales and most of the generation are provided by a single entity (KEPCO). Despite of central dispatch and no retail competition, DSF activity is high
- South Korea is facing high growth in electricity demand, and especially high system peak demand caused mostly by energy intensive industry. There is a low potential for new generation sites, and South Korea rely on fuel imports for electricity generation. There is increased public concern about nuclear generation and rising apprehension to power line construction. Thus, the government has shifted the focus to demand management to balance supply and demand, reduce the need for building new generators and power lines and running expensive peak generators. Ambitious plans for electric vehicles and smart meter rollouts are key enablers for residential DSF.

Overview of demand side flexibility

- Demand response was allowed access to the wholesale capacity market in 2014 and is actively promoted, playing an important role in balancing supply and demand
- There are three new demand response programs
  - "Citizen DR" program (in preparation)
    - Enables small-scale household customer participation
    - Encourages voluntary consumption curtailing during specific periods (e.g. peak load, fine dust alerts). If the curtailment of a DR resource unit (i.e. the group of the participants) is 1MWh or higher, the aggregator is paid according to its amount (which in 2019 was KRW 1,300/kWh, calculated based on residential basic payment, maximum reduction time and maximum generating unit price). The aggregators can decide how to incentivize the customers to reduce their consumption (e.g. cash, points, discounts, donations, etc.).
  - Voluntary "Peak Demand DR" program (from January 2020)
    - This program is for peak shaving during summer/winter peak demand periods ("supply emergency alertness period"), to reduce constraint costs. This period is 1pm to 8pm in the summer and 9am-12pm and 1pm-8pm in the winter.
    - DR resources participate in the Operational Scheduling by placing bids on available capacity the day before (before 4 pm D-1). When demand is forecasted to exceed a nominal level, the participants are notified the amount of hourly load curtailment they shall provide the next day.
  - Voluntary "Fine Dust DR" program (from January 2020)
    - This program is for load curtailment when coal-fired generation is reduced due to fine dust reduction measures being issued. This is activated when forecasted average levels of PM2.5 are above certain criteria.
    - Participants bid before 4 pm the day before, and the maximum amount activated is the coal-powered generation curtailment. Eligible bid slots are between 6am and 9pm.
  - Through these programs, the availability and access to flexibility is expected to be greatly expanded while the barriers to entry are significantly lowered

Explicit products for demand side flexibility

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Adequacy is organised with a capacity payment scheme.	No	N/A	N/A	N/A	The adequacy is considered in planning of the future demand outlook. Every two years, the capacity expansion plan for the next 15 years is established by KPX with consideration for both the peak and total demand. The size of the expected demand response market is derived from this plan. It is however not a firm value, and the market treats it as the manifestation of governmental policy and intent.
Wholesale	Day-ahead economic DR and hour-ahead reliability-based DR.	Yes, since 2014.	Energy	N/A	4.3 GW demand response is currently participating in the marked, through 28 aggregators. The participants are mainly large C&I customers, but the number of small and medium size companies are increasing. 3580 customers was participating as of November 2018. The market takes the shape of a "Negawatt" market directly tied to the wholesale market, where aggregators place bids and are dispatched similarly to regular generators. The demand side flexibility providers are compensated by KPX for saving electricity. As of April 2018, approximately 899 GWh of electricity was saved through demand side participation in the market.	In order to participate in the market, the demand response resource must fulfill the DR Resource Registration Criteria: • One registration per one DR resource, by principle • Classified by region • Mandatory curtailment amount for each DR resource is: Standard DR: 10-500MW Mid-to-Small DR: 2-50MW • One DR resource must comprise at least 10 DR customers Economic DR: Aggregators participating in the Price-Setting Scheduling bid demand curtailment amount and price (Net Benefit Threshold Price or above) before 10am D-1, bid results are posted at 3pm D-1, and are settled by the System Marginal Price of the actual curtailment time and amount. The load curtailment is measured against the Customer Baseline Load (CBL). The method for CBL assessment in standard DR and mid-to-small DR: - Max: Average of 4 max days out of the 5 past days - Mid: Average of 6 days out of 10 past days, excluding 2 max and 2 min days. Reliability DR: The criteria for activating reliability DR is when demand and supply alert levels are at (or are expected to be) "preparation" (reserve < 5GW) or "Concern" (reserve <4 GW).
Balancing	There is no balancing market. KPX is responsible for balancing through real-time dispatch.	No	N/A	N/A	N/A	KPX adjusts the output of generators in real-time to balance supply and demand. However, the Reliability DR program (see above), can support balancing efforts during supply emergencies. There are plans to introduce market changes, including opening of a real-time market by 2024.
Constraint management	Not available	No				KPX monitors and controls the power flow of the transmission lines to keep stable voltage levels. KPX establishes contingency plans using Energy Management System (EMS) Network Analysis. Voltage increase and congestion occurring in real-time are resolved through EMS, and participants are ordered to increase or decrease output.

Implicit products for demand side flexibility

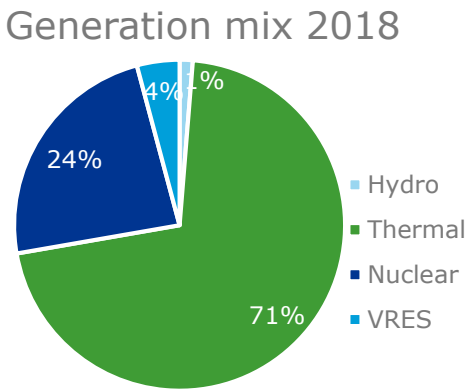
- **Network tariffs**
  - The network tariffs consists of base charge (KRW/kW/month) and usage charge (KRW/kWh). An example of a network charge is 921,9 KRW/kW/month base charge, and different usage charge in the Capital area (2.84 KRW/kWh), Non-Capital area (1.70 KRW/kWh) and the Jeju Island (8.42 KRW/kWh).
- **Supply tariffs (energy)**
  - Time-of-use energy pricing is in effect for commercial and industrial customers, and a pilot program of the same for residential customers will start this year.
  - There is an R&D project in progress for introducing Fast Demand Response. Fast DR is a mechanism where customers proactively reduce their electricity consumption to maintain grid stability, mainly automatic through an algorithm, and are rewarded with financial incentives. The aim of the project is to promote Fast DR resources for ancillary services to cope with the increasing variable renewable generation.

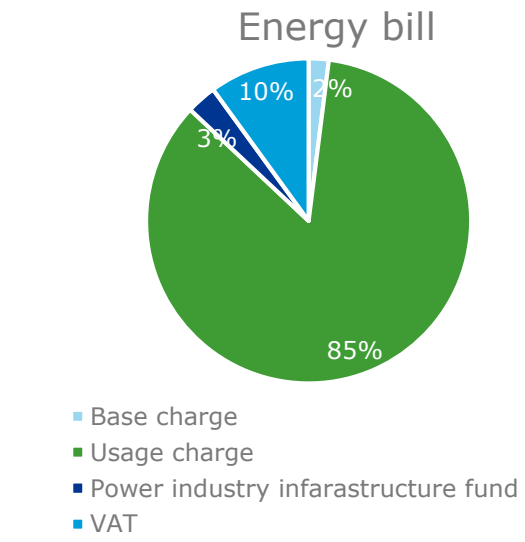
Market design parameters

1. **Transmission congestion management methods**
   - The wholesale market is split in two zones, using a zonal pricing approach between the mainland and Jeju Island that takes HVDC congestion into account. There are transmission constraints in the mainland, but they are not taken into account when the generation amount and the market price are determined in the day-ahead market. The difference between this and the real-time operation results are reconciled via an uplift.
2. **Dispatch**
   - Central - all generators that meet the central dispatch requirements (e.g. conventional generator with at least 20MW output) must be registered at and dispatched by KPX (Korean Power Exchange)
3. **Market organisation**
   - The wholesale market has a pool-based approach. The market is operational, but generators cannot freely bid on price. Instead, energy price is determined based on the generators' pre-evaluated fuel costs under the Cost-Based Pool (CBP) market. This system is deemed to provide more competition than the PPA model, but is more regulated than the Price-Based Pool (PBP) market. Wholesale market prices (i.e. the pool prices) are set by KPX, retail prices are regulated by the government.
   - The retail market is a KEPCO (Korean Electric Power Corporation) monopoly with a heavy government regulation. The retail tariff is determined based on the principles of principal cost, fair compensation, and equity with the government making the final approval.
4. **Market structure**
   - It is considered to be about half way between the two extremes (bundled and unbundled). The Electricity Utility Act separates the roles of generation, transmission, distribution, and sales. But transmission (ownership), distribution, and sales are effectively handled by a single entity (KEPCO) and about 3/4 of the total generation are provided by the six KEPCO subsidiaries.
5. **Adequacy organisation**
   - A capacity payment scheme is in use. Its price is based on the fixed costs of the marginal generators (gas turbines), with automatic yearly adjustments made by looking at how much deviation from the adequate reserve levels occurred. Securing of adequate reserve levels is being managed and maintained by the regulator. It establishes a long-term supply/demand plan separate from the market, which encourages new entrants that would help maintain adequate reserve levels.

Other key indicators

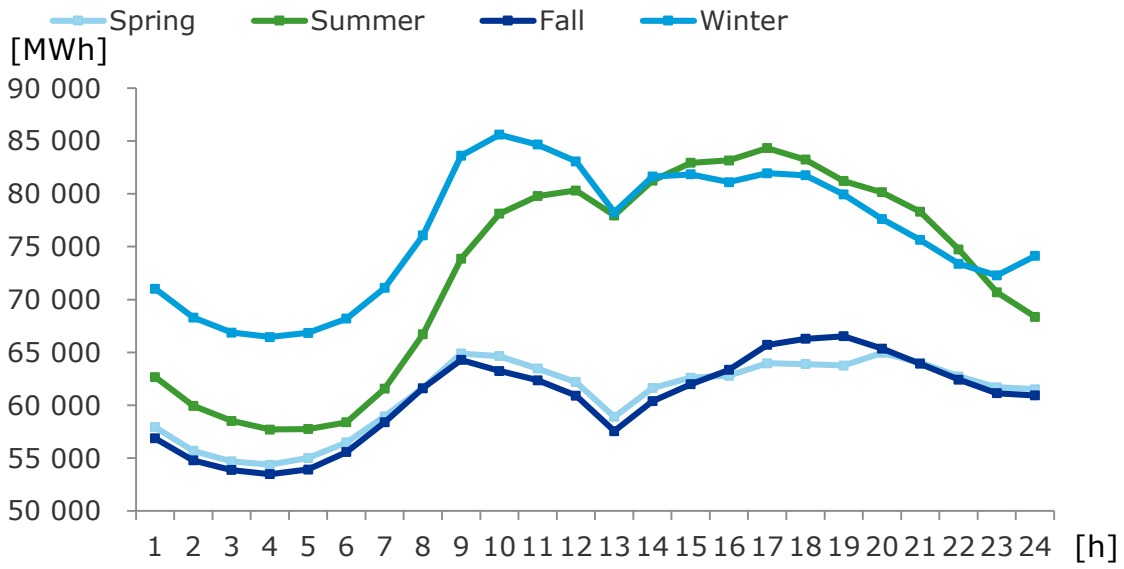
1. **Generation mix**
   - 71% thermal, 24% nuclear, 5% renewable (2018)
2. **Volatility of day-ahead prices**
   - The energy market is using cost evaluation scheme instead of price bidding. Together with the generation mix, this ensures the price volatility of the day-ahead market is low.
3. **Degree of electrification**
   - Yearly electricity consumption per capita: 10 MWh (2018)
   - Yearly electricity consumption per residential household: 4.76 MWh (2018). (80% of consumption is from C&I users).
4. **Capacity**
   1. Is there a perception of generation adequacy problems in the country?
      - Adequate levels of generation reserves are being maintained. However, a re-evaluation of what amount of reserves is adequate is needed due to the increasing number of renewable generation.
   2. Is there a perception of network adequacy problems in the country?
      - There are some delays in construction of transmission lines connecting large-scale generation zones to load centres. Also, adequacy of the distribution grid is being re-evaluated due to the rise of small-scale renewable generators.
5. **Retail tariff structure:**
   - Composition of the energy bill (example):
     - Base charge (2%), usage charge (won/kWh, 85%), power industry infrastructure fund (3%) and VAT (10%)
   - Design of the network tariff:
     - The network tariff is a two-part tariff consisting of base charge (Won/kW/month) and usage charge (Won/kWh). The network tariff is not reflected in the energy bill because of the government policy



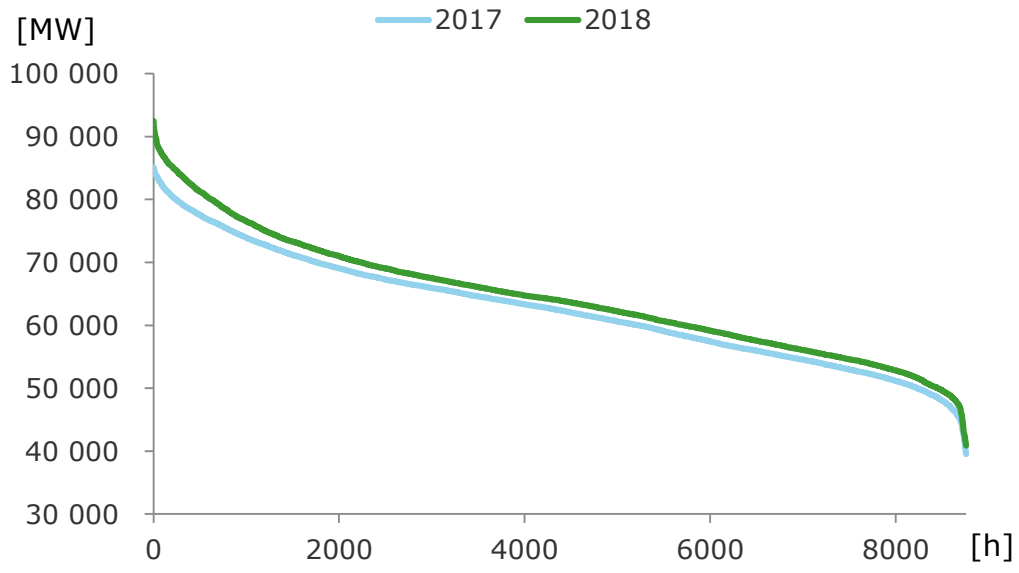


Other key indicators: Load curves

- Characteristics of power demand in Korea is described in the graph below. In spring and fall, peak demand normally appears at 7 PM because of street lighting, residential, and commercial loads. In summer, peak demand appears at 3 PM because of air conditioning. In winter, at around 10 to 11 PM, people use electricity the most because of heating.



- Load duration curve:



Australia (NEM)

- Demand side flexibility activity has grown significantly in the last couple of years
- Through recent changes, DSF can now participate in both adequacy, wholesale, balancing and constraint management services. The participation in the Frequency Control Ancillary services has grown rapidly since it opened up for DSF in 2017
- Price volatility is relatively high
- The grid tariffs are volumetric (energy) based, but include an extra charge for peak periods
- The market design is contestable, decentralized and advanced
- There is an increasing energy demand in Australia due to growing population, and there are especially high demand peaks during heat waves. At the same time there is a rapid increase in Distributed Energy Resources (DERs), including both generation (solar), storage and loads (EVs). These factors place pressure on the grid and are, combined with strong incentives from price volatility and peak period charge in both network and energy tariffs, key drivers for DSF participation

Overview of demand side flexibility

- The Australian Renewable Energy Agency (ARENA) and AEMO are funding ten demand response pilot projects to manage electricity supply during extreme peaks such as heat waves. The initiative will deliver 200 MW by 2020, covering residential, commercial and industrial energy users.
- In October 2017 EnerNOC was awarded a 50 MW Demand Response Contract with ARENA and the NSW government. EnerNOC operates a 50 MW dispatchable demand response resource, utilizing aggregated load curtailment from voluntary commercial and industrial consumers, to support system reliability in the NEM. The response time is 10 minutes, and the consumers receive financial incentives.
- Since July 2017, independent DR aggregators have been allowed to bid into the NEM's Frequency Control Ancillary Services (FCAS) markets. This FCAS is divided in different functions (positive/negative power, frequency regulation, 6sec response, 60sec response, or delayed 5min response). As of 2019, this market represent 180/170 MW raise/Lower up volumes.
- Demand response service providers (DRSP) was recently (2019) introduced as a new type of registered participant in the network energy market. DRSPs are able to bid demand response into the wholesale market. Before this was only open to energy retailers.
- The number of Distributed Energy Resources in the Australian electricity grid is increasing rapidly. AEMO has launched a DER program, which includes a set-up for a uniformed communication protocol where DER (Rooftop solar, EVs, batteries) can participate directly into the market.

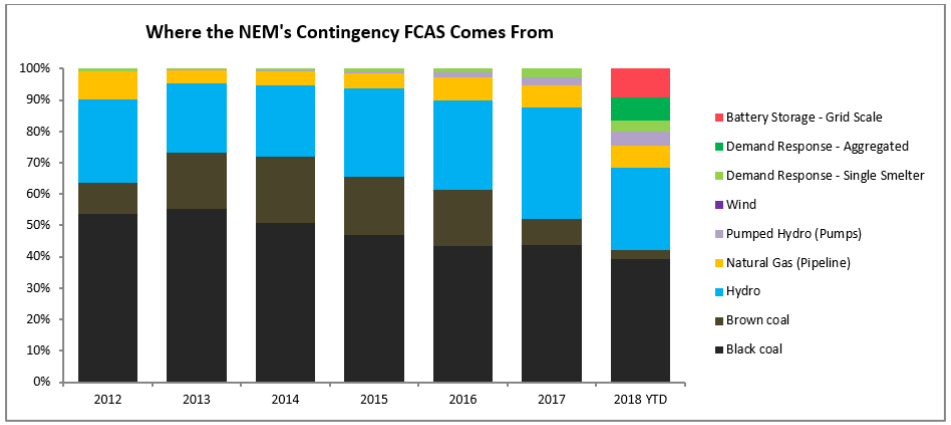


Chart data: *Sum of R6, R60, R5 FCAS |Enabled MWh (NB: not 'energy supplied') by technology type*
Calendar years | 2017 to 30 Sep (pre EnerNOC + Hornsdale PR) | 2018 to 31 May

Source: https://energysmart.enelxnorthamerica.com/demand-response-disrupting-australias-ancillary-services-markets



Explicit products for demand side flexibility

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Reliability and emergency reserve (RERT)	Technically yes, through bilateral contracts, but not expected to be used for DSF.	Capacity based	No	Usually aluminum smelters, steelworks and paper mills.	To be eligible, reserves provided under a reserve contract must not be available to the market through any other arrangements. In addition there are a number of criteria that AEMO will use to assess the reserve, these include: • What is the availability of the reserve over the summer period • Whether the reserve can be activated as a block of not less than 10MW • Whether the reserve can be activated continuously for at least 30 minutes Using these emergency contracts are not compatible with the other energy contacts. These contracts were only used two days in 2019.
Wholesale	NEM wholesale market	Yes, it has been open to smaller loads since 2019 through a DRSP (has been open to large loads as "scheduled loads" before that)	Energy based	Yes	So far only pilot projects	From 1 July 2021 the settlement period for the wholesale electricity spot market will be changed from 30 to 5 minutes, to align with the dispatch period.
Balancing	NEM Frequency Control Ancillary Services (FCAS) (Eight different markets)	Yes, since July 2017.	Capacity based	Yes	180/170 MW raise/Lower up is the total FCAS volumes as of 2019. See figure on previous slide for demand response participation.	A multitude of subservices are proposed in the this FCAS services, 6 sec, 60 sec and 5 min delay (on addition to the regulation service)
Constraint management	Contracts	Yes, but on a contractual basis	Capacity based	No	N/A	The operators use mechanisms for demand response on a contractual basis (introduced a year ago for network security). Tell generators/loads to reduce/increase output/consumption.



Implicit products for demand side flexibility

- **Network tariffs**
  - These tariffs are a combination of:
    - **System access charges** (SAC) ($ per National Metering Identifier (NMI) per day) (fixed charges)
    - Anytime **energy charges** ($/kWh) (energy consumption charges)
    - **Demand charges ($ per month per kVA) in peak periods** (only available for Smart meters). This is to encourage a reduction in peak consumption. While the peak period is 12pm to 9pm weekdays, which includes public holidays for all customers with a smart meter, there are some differences across tariffs, regarding which season AEMO apply demand charges. Specifically:
      - For customers assigned to the LV Smart Meter the demand charge applies between 1 October and 31 March with the rest of the year being off-peak (i.e. 6 months)
      - For customers assigned to the LV Majors, HV Majors Tariffs or HV Minors Tariffs, the demand charge applies across the year (i.e. 12 months).
- **Supply tariffs (energy)**
  - In most places in Australia there are basically two types of tariffs; flat rate tariffs or time of use (TOU) tariffs. Flat rate tariffs have a fixed cost for each kWh, while TOU tariffs have different rates at different times of the day (off peak, shoulder and peak), financially incentivizing consumers to shift their demand to off-peak hours.
- **Other implicit products**
  - Electricity Transformation Roadmap 2017: Australia is pushing towards active network management, flexible connections with pro-consumers (consumers bidding directly on the market), by 2025-2030.



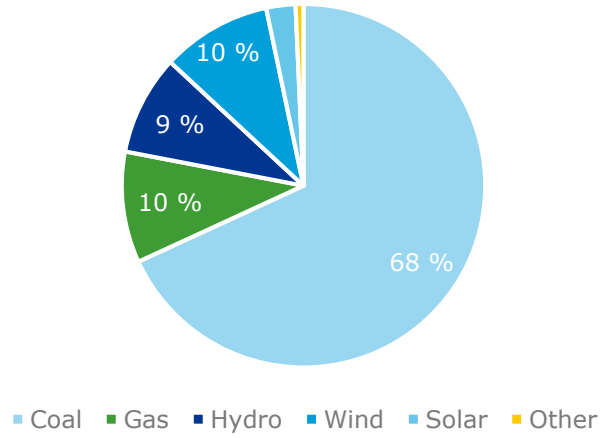
Market design parameters

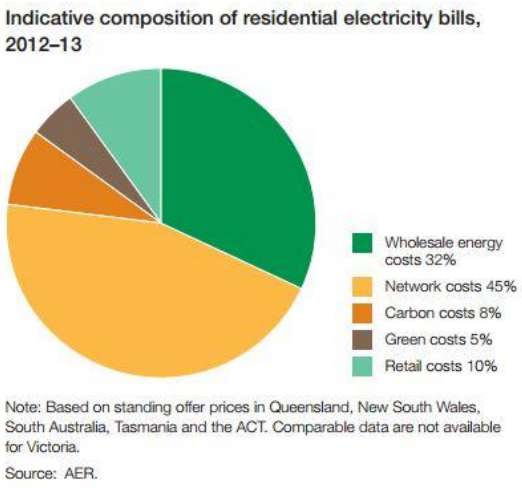
1. **Transmission congestion management methods**
   - Zonal pricing, five zones in the National Electricity Market (NEM). (NEM covers six states in the eastern Australia and is the focus of this study. Western Australia and the Northern Territory are not connected to the to the NEM, but to the Wholesale Electricity Market (WEM). Australian Energy Market Operator (AEMO) is responsible for operating both the NEM and the WEM markets.)
2. **Dispatch**
   - Centralised market based dispatch (with a five minute interval) by AEMO. The dispatch process carries out a constrained linear optimisation, subject to physical limits of the transmission network (grid constraints that are continuously updated), where the output is output target and consumption target for every scheduled generator and load. Five spot prices are produced (one for each NEM zone), every 5 min dispatch interval. At the end of every half hour the six preceding spot prices are averaged to find the settlement price.
3. **Market organisation**
   - Contestable. End users are free to choose their power supplier.
4. **Market structure**
   - Unbundled (vertical separation). Generation and retailing are separated from transmission and distribution.
   - One transmission company in each state.
5. **Adequacy organisation**
   - Strategic reserves of demand and generation resources of >1000 MW (2017/2018).

Other key indicators

1. **Generation mix (NEM)**
   - 78 % fossil fuels (coal, natural gas), 10 % wind, 9 % hydro, 3 % solar
2. **Volatility of day-ahead prices**
   - Relatively high
3. **Degree of electrification**
   - Yearly electricity consumption per capita: 9.2 MWh
4. **Capacity**
   1. Is there a perception of generation adequacy problems in the country?
      - In general no problem, but can happen due to extreme weather events. Intense heat waves has lead to several power outages due to high demand peaks and low generation despite having sufficient installed capacity (unexpected outages of coal and gas generators due to extreme heat and low wind generation).
   2. Is there a perception of network adequacy problems in the country?
      - Not for the current network system, but it is not strong enough for the large increase expected in renewable generation. There is pressure on the grid during heat waves, where electricity demand increase significantly.
5. **Retail tariff structure**
   - Composition of the energy bill: Approximately 30 % is wholesale retail price, 45 % is the network costs.
   - Design of the network tariff: There is a demand charge for peak period, which represent around 15-30% of the tariff (based on the actual consumption).

NEM Generation mix 2019





Other key indicators: Load curves

Figure 2 Summer workday average demand profiles

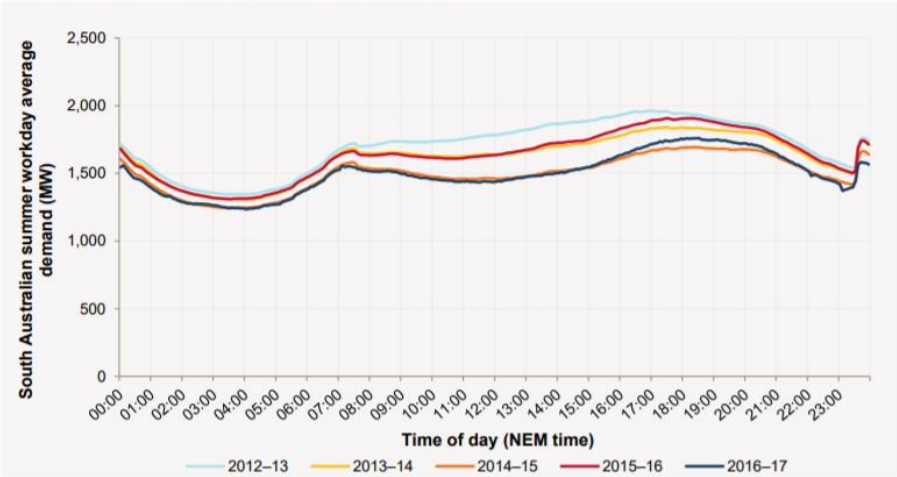
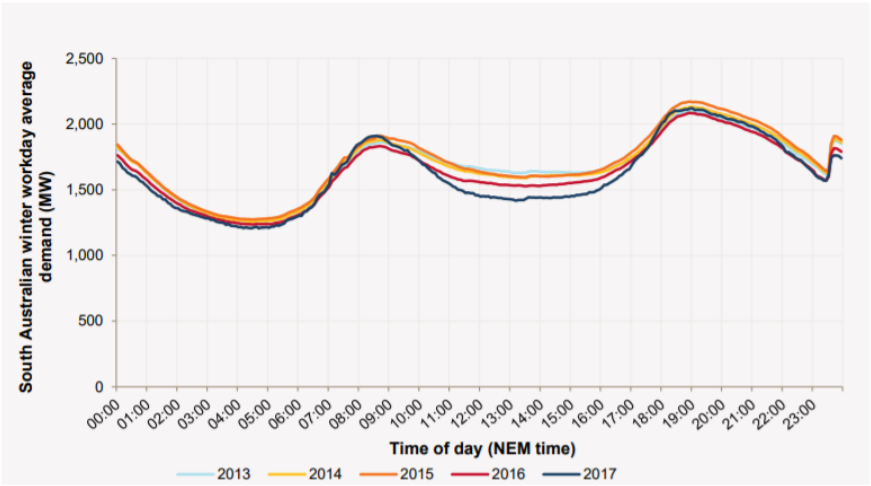
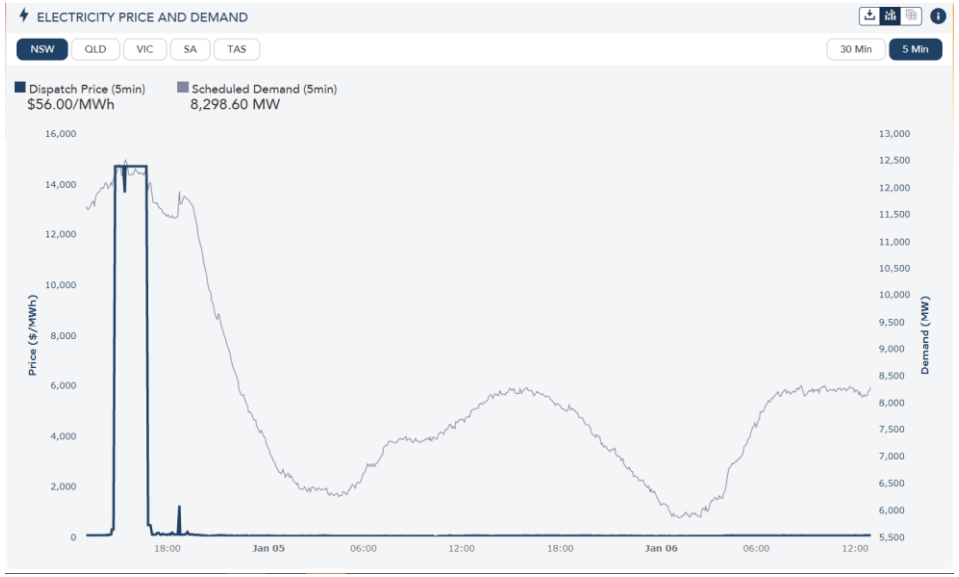


Figure 3 Winter workday average demand profiles



- The figure below shows the price curve of the extreme case of the 5th of January 2020. During summer, demand is high and the price variation is often high, especially during heat waves. The ongoing fires have also caused some network disruption. The electricity price reached the market price cap of $14,500/MWh.



Source: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2017/South-Australian-Electricity-Report-2017.pdf

Great Britain

- Great Britain has high demand side flexibility activity especially in the adequacy services and balancing markets (2.3 GW for FCR in 2018 and ~10GW across 3 tenders for STOR in 2018)
- DSF does not participate in wholesale markets yet and only recently Independent Aggregators can enter the Balancing Mechanism. In the future we expect additional DSF in DSO constraint management and wider access for DSF to more routes to the market (NG ESO (electricity system operator) initiative and DNO/DSO transition)
- The price volatility in wholesale market is high but not sufficient for DSR providers
- Grid tariffs rely on volume and not capacity. Avoidance of network charges (i.e. Triad and DSoUs), however, incentivise consumers to shift their demand away from high peaks. Time-of-use energy tariffs are in use for C&I customers, and at early stages of use for residential customers
- The market design is contestable, unbundled and encourages high DSF activity. Despite being a mature market (especially at Transmission level), there are still barriers and market uncertainties which hinder wider DS participation
- Key enablers for DSF participation in GB are regulation and support from Ofgem and BEIS as well as market signals. The policy has led network companies to create emerging opportunities for DSF such as the wider access to the Balancing Mechanism (BM), weekly low frequency response auctions (in 2018-19) and participation of DSF in DSO constraint management. Innovation is also supporting this direction toward DSF

Overview of demand side flexibility

- Demand response and aggregation can participate in balancing markets, in the Balancing Mechanism (BM), in adequacy markets and in constraint management services through DSO congestion management. The GB market is highly competitive with a high number and broad mix of stakeholders active in DSF.
- Independent aggregation is generally allowed for balancing services, adequacy markets and congestion management but it is not allowed in wholesale energy markets. Independent aggregation arrangements in GB do not account for open supply and imbalance position of the supplier (or its balance responsible party, BRP) yet.
- Flexibility value stacking and portfolio aggregation is in generally possible.
- Key enabler for DSF participation in GB is regulation/policy and support from Ofgem as well as price signals. The policy has led network companies to create emerging opportunities for DSF such as the wider access to the Balancing Mechanism and weekly low frequency response auctions (in 2018-19). For DSR service providers (e.g. retailers) a tangible business opportunity should be presented to encourage the development of products and services.
- GB DNOs have started designing and developing the flexibility services for distribution networks open to DSF as well as commenced actively using flexibility (outside of innovation projects). So far, DSO flexibility is insufficient to incentivise new investment in flexibility. This is unlikely to change – unless clear price signals for flexibility emerge from Ofgem's network charging and access reviews.
- Innovation projects and trials around DSF are key for the successful implementation of flexibility markets in GB.
- Despite being a mature market (especially at Transmission level), there are still barriers and market uncertainties around flexibility.

Explicit products for demand side flexibility (1/2)

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Capacity Market	Yes	Capacity based	Yes	T-4 2016 auction: 1367 MW of unproven DSR and 44 MW of prover DSR for £22.50 per kW T-4 2017 auction, 1160MW of unproven DSR and 46 MW of proven DSR were contracted for £8.40 per kW/year for delivery in 2020/21 – a record low clearing price. T-1 2017 auction also delivered a record low clearing price of £6 per kW, contracting 521 MW of unproven DSR and 93 MW of proven DSR.	Different auctions have been held . T-1 auctions are held for delivery in the next year. T-4 auctions are held for deliver in 4 years ahead/
Wholesale	Day-ahead	Yes, through suppliers	Energy based	N/A	N/A	
	Intra-day	Yes, through suppliers	Energy based	N/A	N/A	
Balancing	Firm frequency response (or FCR)	Yes	Capacity based and Energy based	Yes across different windows. Yes across same availability windows, but subject to the product and further agreements.	2341 MW (in 2018) and 773 MW (in 2017) across all tenders.	During 2018, National Grid ESO introduced tenders for long-term FFR contracts. This resulted in the increased number of tenders received and in the capacity accepted in 2018. Tender rounds for longer-term contracts occur every three months, and reflect how National Grid ESO has responded to stakeholder requirements for short and long-term contracts.
	Fast Reserve (or FRR)	Yes	Energy and Capacity based	Yes (excluding Response products)	Limited participation (3 DSF providers) due to the 50MW threshold to participate) - data for 2018	
	STOR (Replacement Reserve)	Yes	Energy and Capacity based	Yes (excluding Response products)	10192 MW (accepted tenders) – data for 2018. This number reflects all the tenders for STOR during 2018, across 3 tenders. The average DSF accepted capacity pre tender is around 3GW.	DSF includes: - Dist Gen (for export) - Dist Gen (for onsite) - Load response - Storage (for export) - Multiple fuel tem
	Balancing Mechanism (Replacement Reserve)	Yes (recently open for DSF and Aggregators acting as Virtual Lead Parties - VLPs)	Energy based, according to the contracted volumes during Bids and Offers processes.	Yes	Not on operation yet for DSF	
	Demand Turn-Up (DTU - replacement reserve, currently discontinued by the ESO)	Yes	Energy and Capacity based	Yes (excluding Response products)	114 MW	Market participation include generation, generation for balancing support and load response.
Constraint management	TSO level	Not open	N/A	N/A	N/A	

Explicit products for demand side flexibility (2/2)

- **Constraint management → Congestion management (DSO)**
  - With funding from BEIS, Piclo has developed and trialled the first GB-wide flexibility marketplace. This allows DSOs in the UK to source flexibility from the rapidly growing number of flexibility providers (including demand response aggregators, electricity suppliers, generation operators, battery operators, I&C customers, local authorities, community groups and electric vehicle charging operators). All six UK DNO's were involved in the trial along with 175 smart and flexible energy providers; over 4GW worth of flexibility (or 2.8 million household's worth) was uploaded to the Piclo Flex platform. The table below refers to product development and flex. services outside the Piclo Trial.
  - GB DNOs have started designing and developing the flexibility services for distribution networks open to DSF as well as commenced actively using flexibility (outside of innovation projects).
  - For example, Scottish and Southern Electricity Networks (SSEN) has also agreed to procure flexibility and demand-side response services across its entire network rather than just the constrained areas. SSEN has already procured flexibility for 6 sites in their licence areas.
  - UK Power Networks launched their second tender for flexibility services competition in February 2019 and they recently announced that their second flexibility tender offered contracts for a total of 18.2MW of power from six companies across eight different locations.

	Remuneration type	Open to DSF	Value stacking available
UKPN	The flexibility provider (FP) receives a utilisation payment for the delivered energy and an availability payment for all period available.	All DSO congestion management products will be open to DSF.	Yes for different availability windows. Yes for the same availability windows and subject to furtrher arrangements.
WPD	Remuneration will be based on: - arming and utilisation for Secure product. Arming is only paid for the duration of expected utilisation. - availability and utilisation for Dynamic product. Availability is paid in this case, instead of arming, due to reduced expectation of utilisation. Availability reflects a payment for readiness. - availability only for Restore.		
ENW	Depending on the product, availability and utilisation remuneration will take place.		
NPG	Information not available		
SPEN	Information not available		
SSEN	Depending on the product; availability and utilisation payments will be available		

Extra clarifications on DSF

1. Currently, there are 19 commercial aggregator companies in GB listed by National Grid, of which only 9 are registered as independent aggregators, whereas the others are registered as suppliers or in partnership with a supplier. Wider participation of Aggregators and DSR in GB energy markets is one of the priorities in Ofgem's and BEIS plans. However, there are still elements that need to be defined and designed such as balancing responsibility and delivery risk. Under current arrangements, suppliers can be exposed to delivery/imbalance risks due to the independent aggregator's activity. Ofgem has already raised these concerns in an Open Letter and in the Smart Systems and Flexibility Plan, and has suggested that the balancing' costs and delivery risks must be borne by the parties that created them, meaning in this case, the aggregator.
2. **Balancing Mechanism vs FRR:** The Balancing Mechanism is one of NG ESO's (the electricity system operator) main tools to balance electricity and supply close to real time. The Balancing Mechanism is considered as Replacement Reserve product. It is inherently more flexible than the Reserve Products in continental Europe, since it allows a wider range of price, MW capability and dynamic/performance-related parameters than the specific Replacement Reserve products require. Where NG ESO predicts that there will be a discrepancy between electricity production and demand during a time period, they accept a 'bid' or 'offer' under the Balancing Mechanism from a market participant to either increase or decrease generation or consumption. Balancing Mechanism and FRR have different market requirements, set up and response time.
3. **Is congestion management (on TSO level) handled with the same bids that is used in the Balancing Mechanism?** TSO Congestion management is not open to demand side flexibility. The Balancing Mechanism is not part of the congestion management services. It is considered as a Replacement Reserve product.



Implicit products for demand side flexibility (1/3)

- **Network tariffs**
  - **Triad avoidance**: National Grid uses Triad to determine Transmission Network Use of Systems (TNUoS) charges for customers with half-hour metering. The Triad refers to the three half-hour settlement periods with the highest system demand from November to February, separated by at least ten clear days. Large industry costumers with half-hour (HH) metered consumption are only charged for the average demand that they consume during these three settlement periods. In this way, they are incentivised to reduce their load at times of high transmission demand. Aggregators can assist customers in Triad Management by forecasting high demand periods, and managing their large customers' load during these periods, to realise lower TNUoS charges.
  - **Distribution Use of System (DUoS) Charge Avoidance**: DUoS charges can vary during the day and across different regions to encourage customers to spread their network usage throughout the day and avoid network usage at peak demand times in certain areas. Half-hourly metered customers are subject to a mechanism known as "traffic light system," or "time banding," which varies DUoS rates for specified time periods during the day. This is an implicit flexibility mechanism where consumers benefit from lower energy bills when they use the distribution network at off peak times. DNOs do not pay customers explicitly for this service, but customers that avoid higher rates incur lower overall network charges in their energy bill.
  - Each DNO applies their own DUoS to recover the cost of installing and maintaining local distribution networks. The charge is based on the volume of electricity which has passed through the Distribution Network. Rates vary depending on the region as well as the time of day. The charges for the demand tariffs, Time of Day (Green, Amber and Red) are set to mirror the impact on the distribution network. These time bands are set by each DNO independently but tend to be set to similar periods. The bands only apply to Half Hourly metered customers who can then monitor their demand to avoid consumption during Red and/or Amber time bands which include high charges.
  - Settlement of DUoS: DUoS charges are invoiced to the Customer's Supplier, and not directly to the Customer. Suppliers generally incorporate DUoS charges in the regular bills sent to their Customers. As such, DUoS are paid with the same frequency as the common electricity bill.



Implicit products for demand side flexibility (2/3)

- **Supply tariffs (energy)**
  - Time of Use Tariffs: ToU Tariffs have been introduced in GB, allowing consumers to adjust their consumption patterns in a way that they benefit from lower tariffs during certain off-peak periods in a day. ToU Tariffs are available for large consumers with HH metering. In the residential sector, ToU Tariffs have been introduced, but not all suppliers offer them. Green Energy's TIDE tariff and Octopus Energy's Agile tariff are examples of ToU tariffs in the GB market. Different companies have different ToU Tariffs. ToU Tariffs are still relatively uncommon. However, the ongoing smart meter rollout means that momentum is beginning to build around this new pricing structure, which has the potential to lower consumers' energy bills and reduce the strain on Britain's energy network.

Implicit products for demand side flexibility (3/3)

- **Flexible Connection (DNOs):** This is not exactly an implicit product for DSF but it is related to constraint management at distribution networks. DNOs offer flexible connections into their connecting options for both existing and potential customers and for both demand and generation. Flexible connections are made available in constrained areas so that reinforcement can be avoided or deferred. DNOs allow new customers to connect to the network, without reinforcing the network, even if customer's required capacity exceeds the peak network limits. Network companies allow these connections on the basis that the customer agrees to being constrained off when the network is reaching its capacity limits, usually through Active Network Management (ANM) or Timed Connections. This approach can reduce the cost and time of connecting to the network, as no extra works are required. Therefore, the customer pays lower connection fees than the costs that would have occurred in case of a conventional connection type, which would require network reinforcement to ensure additional capacity.
- Flexible connections were introduced in 2015/16. The table below shows the current scale of Flexible Connection solution on the distribution networks in GB:

	ANM/Flexible Connections (MW)	Inter-tripped Generation/Operational Tripping Schemes (MW)
Industry Total – End of 2018	2495.1	4763.9
Industry total – projections for 2019	1813.1	1290
Contracted July 2019	702	385.9
Industry total – Contracted to date	3197.1	5149.8

- All DNOs hold historic data on curtailment and curtailment estimated in each connection. This information becomes available to potential flexible connection customers. This information is not publicly available. More information is available here: http://www.energynetworks.org/assets/files/ON-WS1-P7%20Good%20Practice%20Guide%20v1.1%20republished.pdf

Market design parameters

1. **Transmission congestion management methods**
   - One single price zone, No locational (zonal or nodal bidding in GB). Congestion costs are currently incurred by National Grid through the balancing mechanism (BM) and are averaged over all producers and consumers on a pro rata per MWh basis and included in Balancing Services Use of System (BSUoS) charges
2. **Dispatch**
   - Decentralised: During the Balancing Mechanism (BM) the System Operator (SO) can instruct parties to increase or decrease their generation or consumption in order to achieve a balance between supply and demand throughout the settlement period. The SO instructs the participants based on the Bids and Offers that the SO has accepted during the BM, When accepting these instructions, Participants must then act to ensure that their BM Units produce the required level of output.
3. **Market organisation**
   - Contestable. End users are free to choose their power supplier.
4. **Market structure**
   - Unbundled: complete separation of generation, distribution and retail
5. **Adequacy organisation**
   - Capacity Market (CM) operates in GB. Ofgem govern the CM rules. National Grid (ESO) is the EMR (Electricity Market Reform) delivery body and administers key elements of the CM, including the prequalification and auction processes. The EMR Settlement Ltd. is a subsidiary of ELEXON which manages settlement for CM.

Other key indicators

1. **Generation mix**

Coal	Oil	Gas	Nuclear	Hydro	Wind & Solar	Bioenergy	Pumped	Other	Net imports
4.79%	0.46%	38.71%	17.72%	1.62%	21.00%	9.10%	-0.27%	1.14%	5.73%

Positive values represent supplies to the GB system. This includes electricity produced by GB power stations and imports via interconnectors. Negative values represent supplies from the GB system (excluding end consumer demand).

2. **Volatility of day-ahead prices (or similar)** The volatility of day-ahead gas and power prices has been generally decreasing in recent years. Volatility for both gas and power remained low over the course of 2015 and the first half of 2016, but increased during winter 2016/17. A sharp increase in the average of volatility for GB gas occurred in March 2018, with record high gas prices due to both high demand and supply issues: gas demand reached the highest level in seven years and there was a series of unplanned outages across GB supply infrastructure that increased the gas price further. Since May 2018 volatility for both gas and electricity has remained low and relatively stable, hovering between 24% to 50% for gas, and 10% and 29% for electricity. However, the volatility for gas increased in Q2 2019.

3. **Degree of electrification** Typical domestic electricity consumption is:

   - Low 1900 kWh/year, medium 3100 kWh/ year, High 4600 kWh/year (Ofgem's values).
   - Gas heating is the most common source with around 80% of households using gas boilers.
   - Electricity heating (including electric storage, and heat pumps) accounts for around 10% according to NG ESO Future Energy Scenarios. 2013 data from BEIS report around 8% of households using electricity for heating.
   - New registrations of plug-in cars increased from 3,500 in 2013 to more than 246,000 by the end of October 2019. There has also been a huge increase in the number of pure-electric and plug-in hybrid models available in the UK

Source: SSB

Other key indicators

4. Capacity

1. Is there a perception of generation adequacy problems in the country? No – winter outlook 2018/19 and winter outlook 2019/20 show large margins on the electricity system and forecasts are well within the national Reliability Standard.
2. Is there a perception of network adequacy problems in the country? Yes. The transmission network is in general strong but constraints are noticed in some boundaries of the network. The primary challenge is in Scotland, which is experiencing large growth in renewable generation capacity, often in areas where the electricity network is limited. In addition the connection of large amounts of new generation in Scotland and the north, most of which is intermittent renewables, will cause overloading in the northern transmission network unless appropriate reinforcements are in place. Future power transfer requirements could be more than double compared to what they are today.

Some DNOs are also planning ahead to face network adequacy problems especially due to electrification of heat and transport. These DNOs mainly serve high populated areas such as London or towns in Midlands.

5. Retail tariff structure

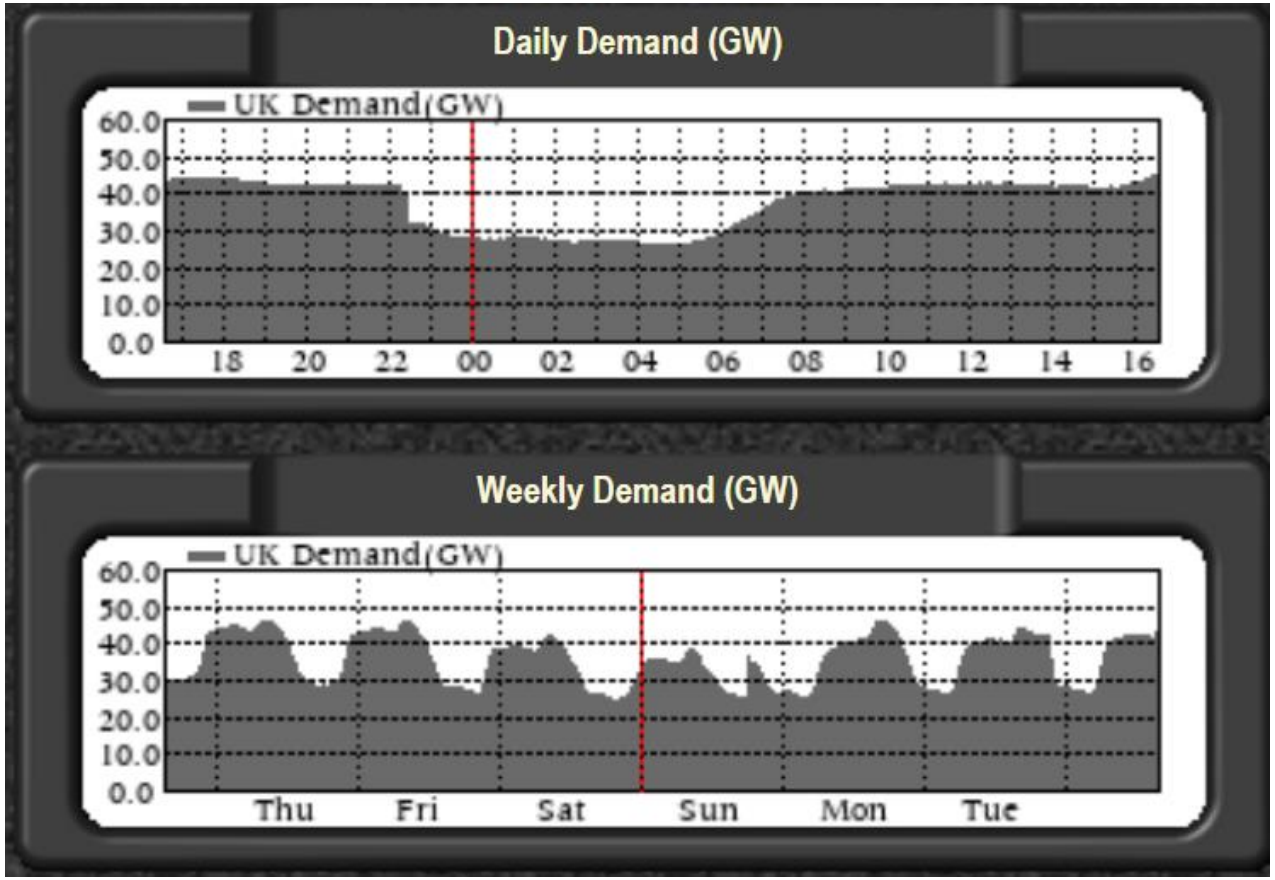
- Composition of the energy bill

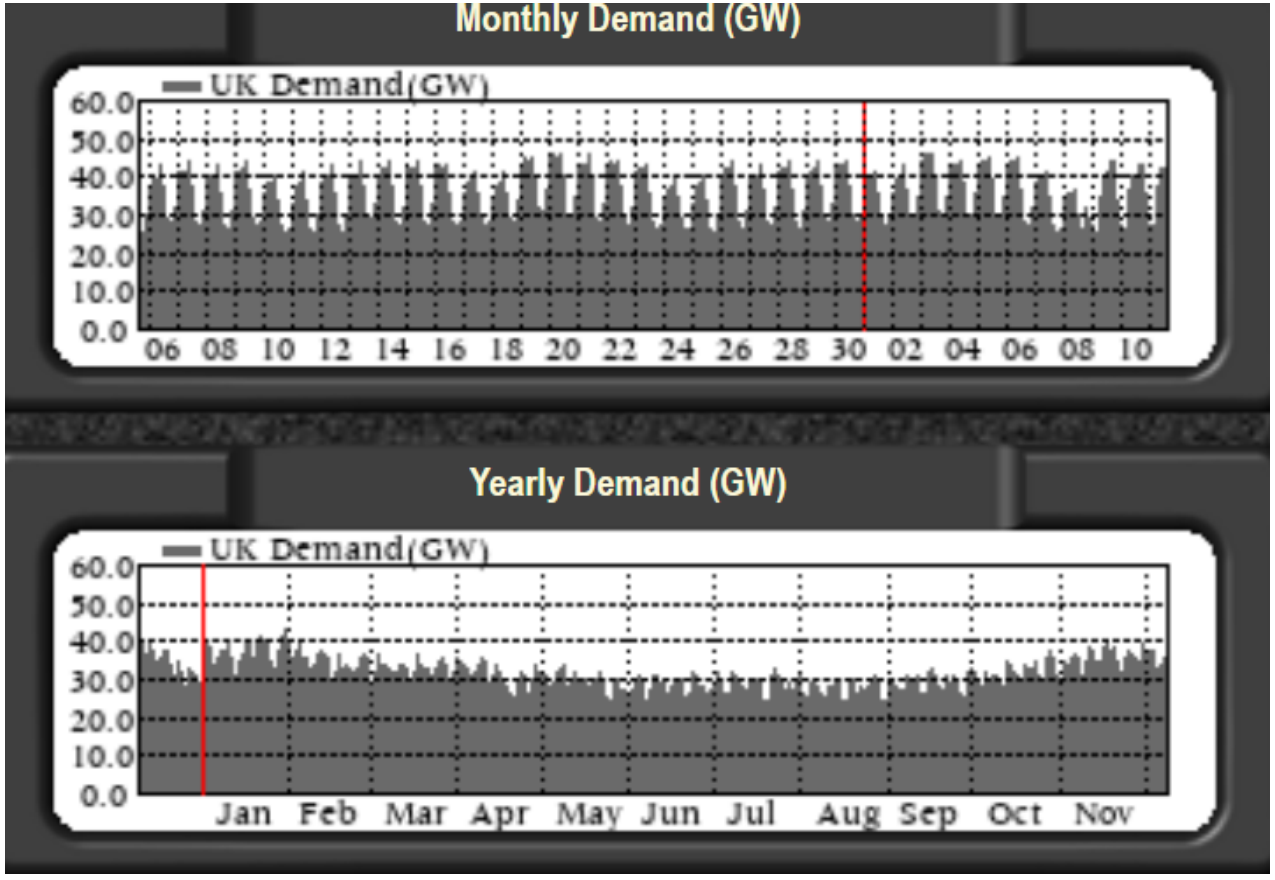
Wholesale costs	32.32%
Network costs	23.15%
Operating costs	17.34%
Environmental and social obligation costs	20.44%
VAT	4.76%
Supplier pre-tax margin	0.73%
Other direct costs	1.25%

- Design of the network tariff
  - Transmission: volumetric, based on actual demand of the suppliers
  - Distribution: Volumetric

Source: SSB

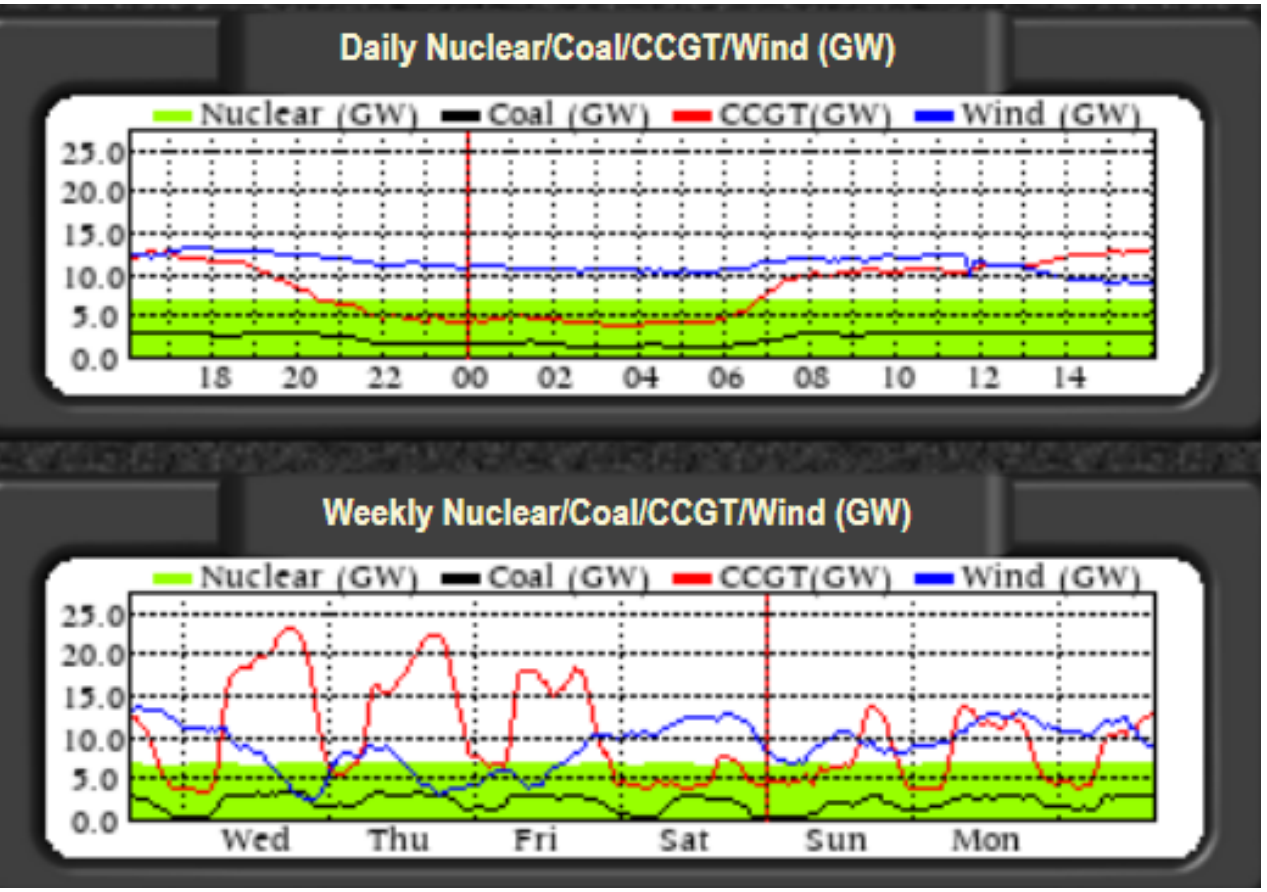
Other key indicators: Load curve

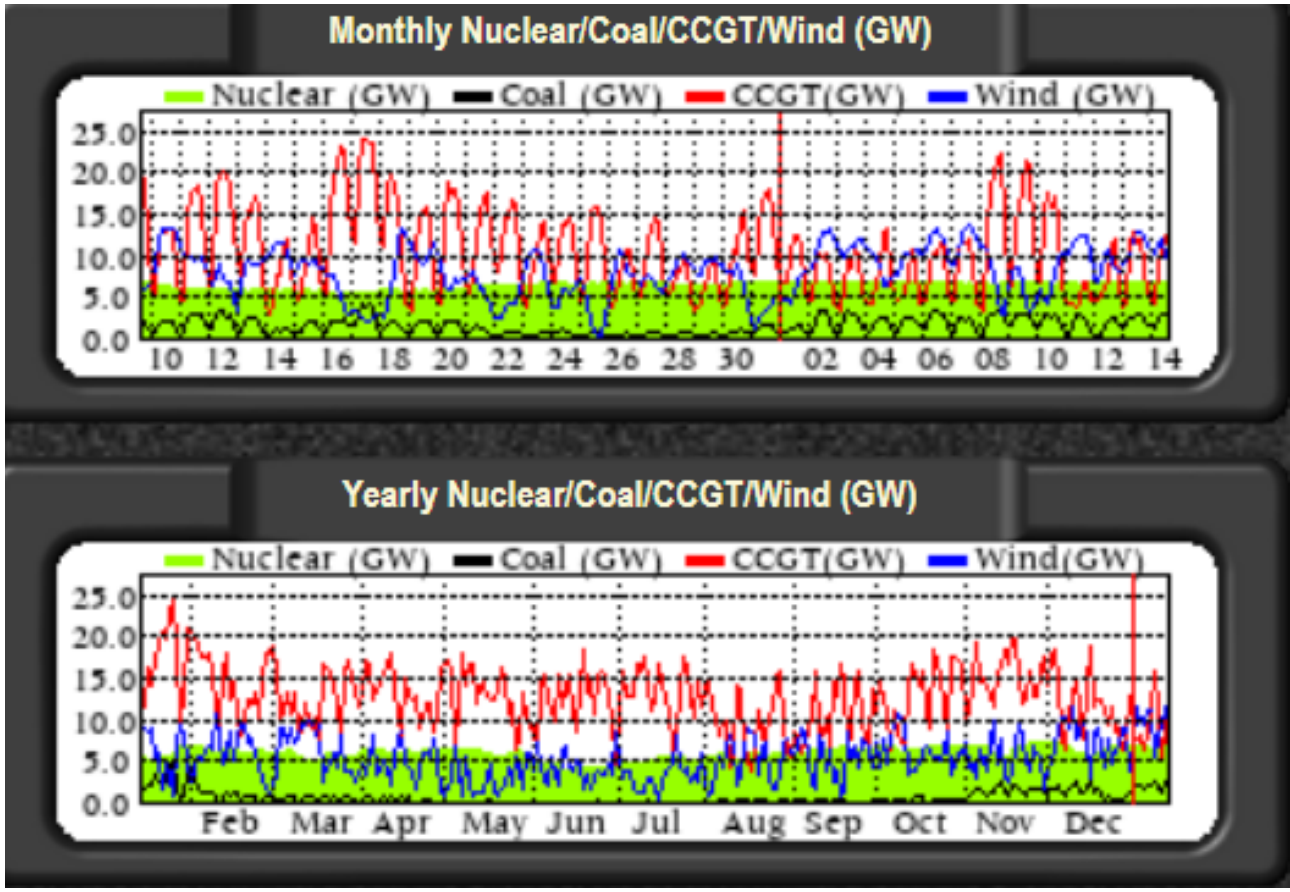




Source: SSB

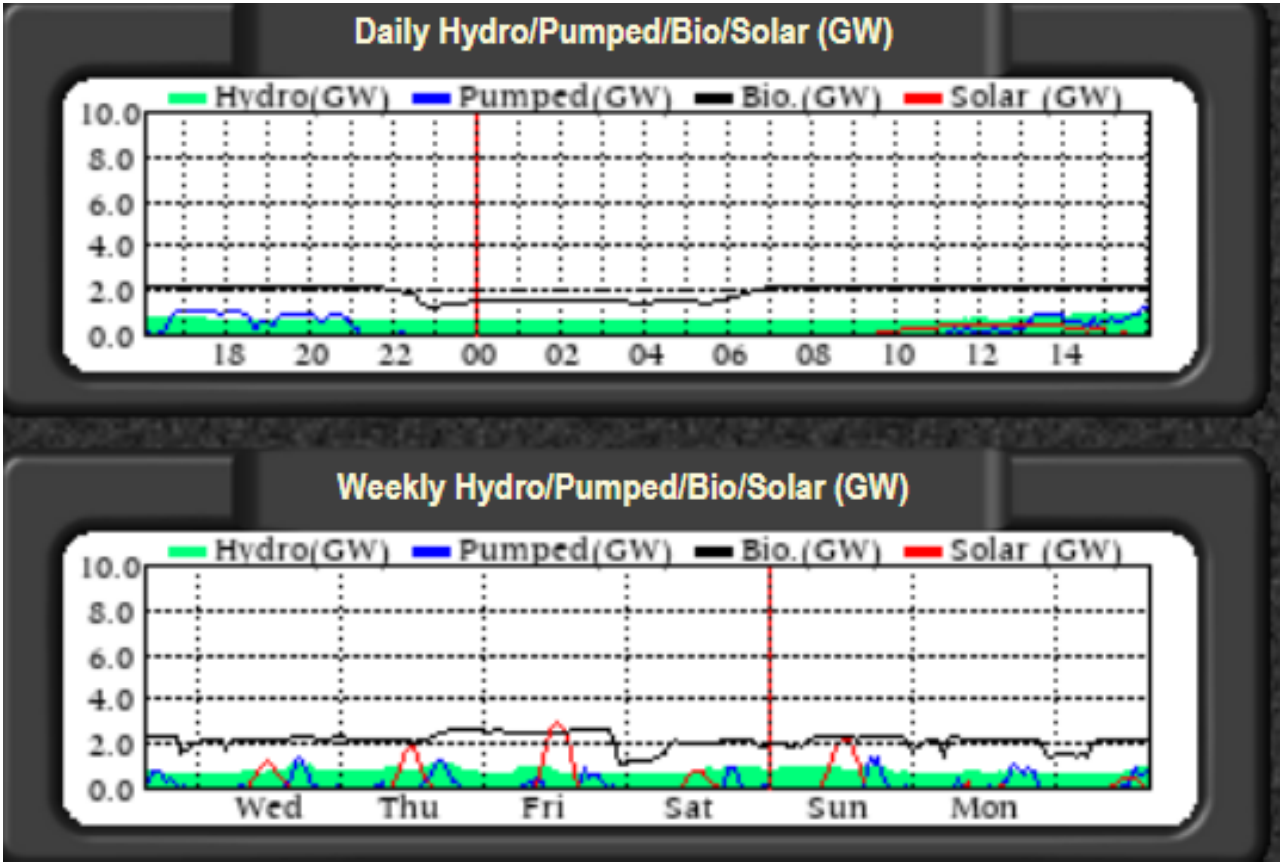
Other key indicators: Production Curves (Nuclear, Coal, CCGT, Wind)

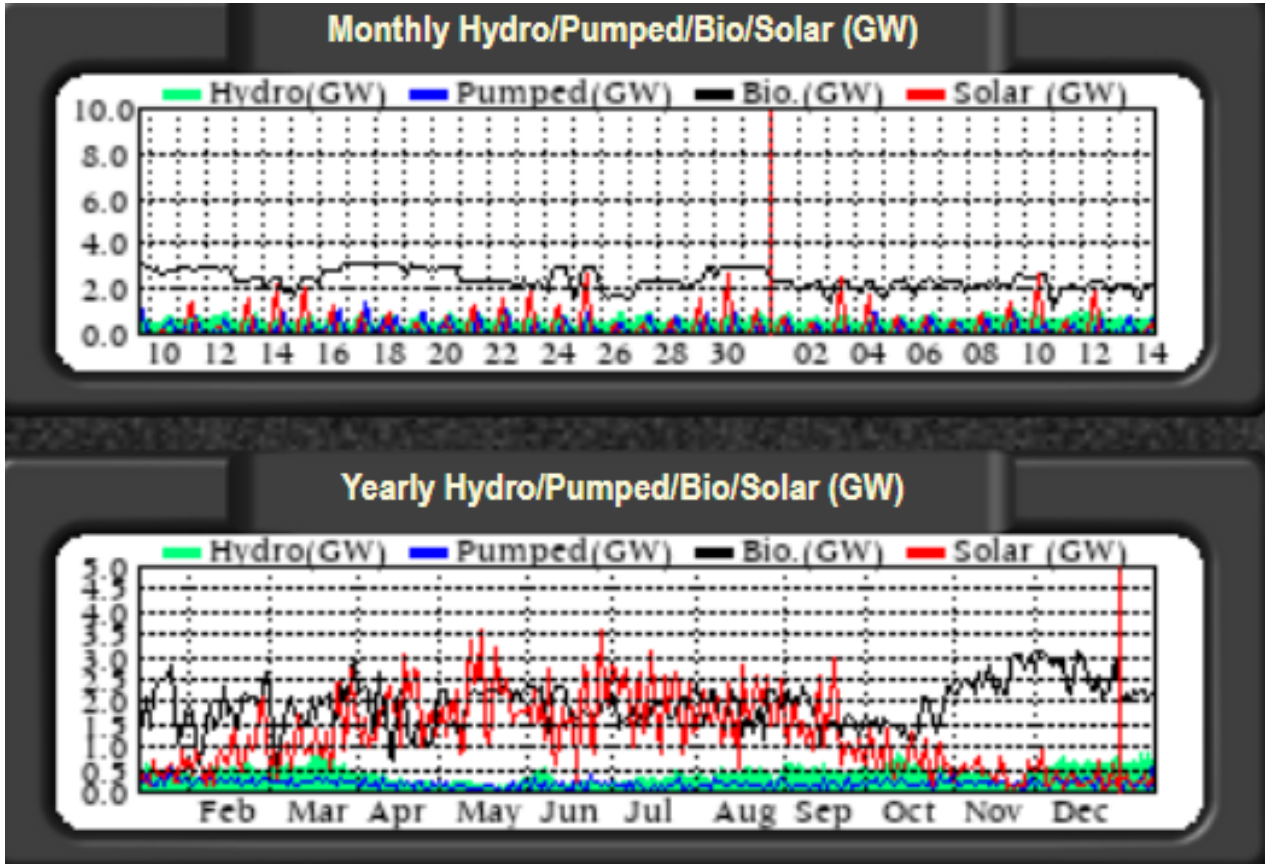




Source: SSB

Other key indicators: Production Curves (Hydro, Pumped, Bio, Solar)





Source: SSB

France

- France has relatively high demand response participation (~5GW)
- Flexibility can be offered in balancing and capacity services
- Since 2014, flexibility can be traded in the wholesale market through a mechanism called NEBEF. The participation is mostly during the cold months, when the generation is tighter and prices are higher
- Price volatility is relatively low in France
- Network tariffs are mostly volumetric. There are various supply tariffs available for industrial, commercial and residential customers, allowing for implicit DSR. In 2018, it was estimated that the capacity made available by these tariffs was around 700MW
- The market is contestable, unbundled and decentralised, but EDF has a 80 % market share. Enabling demand response participation is a way of enhancing competition
- High demand during the winter months causing adequacy problems and the need for an increase in competition in the various markets have driven the participation of demand side response in France. This has been enabled by targeted policies and regulations.



Key findings

- France has relatively high demand response participation (~5GW)
  - The market is dominated by large commercial and industrial loads that participate in ancillary services and capacity market
  - Residential loads account for ~1GW of flexibility where electric heating is the key asset
- Flexibility can be offered in balancing and capacity services. Since 2018, there is a annual tender to procure demand response
- In addition, since 2014, flexibility can be aggregated and traded in the wholesale market through a mechanism called NEBEF. There are 23 aggregators active in this mechanism
  - There is a transfer of energy (ToE) mechanism in place so independent aggregators compensate the supplier for the energy sourced
- Price volatility is relatively low in France. However, the electricity demand doubles from summer to winter months.
- Network tariffs are mostly volumetric. There are various supply tariffs available for industrial, commercial and residential customers, allowing for implicit DSR. In 2018, it was estimated that the capacity made available by these tariffs was around 700MW.
- High demand during the winter months causing adequacy problems and a need of an increase in competition in the various markets have driven the participation of demand side response in France. This has been enabled by targetted policies and regulations



Explicit products for demand side flexibility (1/2)

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Capacity Mechanism	Yes	Capacity based	Yes	1,7 GW	
Wholesale	Day-ahead	Yes. Either in supplier/BRP portfolio or through NEBEF for aggregators	Energy based	Yes, out of the committed activation windows	27GWh activated through the NEBEF mechanism	Through bidding in the DA/ID wholesale market by offering reduction blocks. Minimum load reduction capacity of 100 kW
	Intra-day	Yes. Either in supplier/BRP portfolio or through NEBEF for aggregators	Energy based	Yes, out of the committed activation windows	27GWh activated through the NEBEF mechanism	Through bidding in the DA/ID wholesale market by offering reduction blocks. Minimum load reduction capacity of 100 kW
Balancing	Firm Frequency Response (FCR)	Yes, also open to independent aggregation	Capacity and energy based (spot price)	Yes, out of the committed activation windows	70 MW (out of 570 MW in total) in 2018	Weekly auctions. Minimum bid size 1 MW
	Automatic Frequency Restoration Reserve (aFRR)	Yes. Aggregation is allowed in generation. Aggregated load, through a secondary market, is also allowed but never used in practice	Capacity based (regulated price) and activation based	Allowed to do value stacking with other services	No DSR participation	Obligatory bids from generators. Minimum bid size 1 MW. In practice this mechanism is not viable for aggregators since the service is obligatory for generators and the bid selection is pro-rata. This is going to change during the development of the PICASSO project
	Manual Frequency Restoration Reserve (mFRR)	Yes. Either in BRP portfolio or through load aggregator	Availability and activation payment	Yes, out of the committed activation windows	More than a third of the reserves procured, come from DSR providers. 727MW were offered in average, in 2018.	Yearly tender. Minimum bid size 10 MW or 5MW (for electronic activation)
	Replacement Reserve (RR)	Yes. Either in BRP portfolio or through load aggregator	Availability and activation payment	Yes, out of the committed activation windows		Yearly tender. Minimum bid size 10 MW or 5MW (for electronic activation)
Constraint management	For TSO	Yes			Low participation from DSR due to low revenue for aggregators	

Explicit products for demand side flexibility (2/2)

Congestion management (DSO)

Enedis (DSO covering 95% of French connections) has been involved in multiple flexibility implementation in the medium and low voltage grid since 2012. Now they wish to make it business as usual.

Enedis released a roadmap to use local flexibilities to optimise planning and operation on the distribution network, based on market-based approach:

- Flexibility as alternative to resupply resources before or following an accident
- Flexibility to support planned maintenance
- Flexibility to defer investments





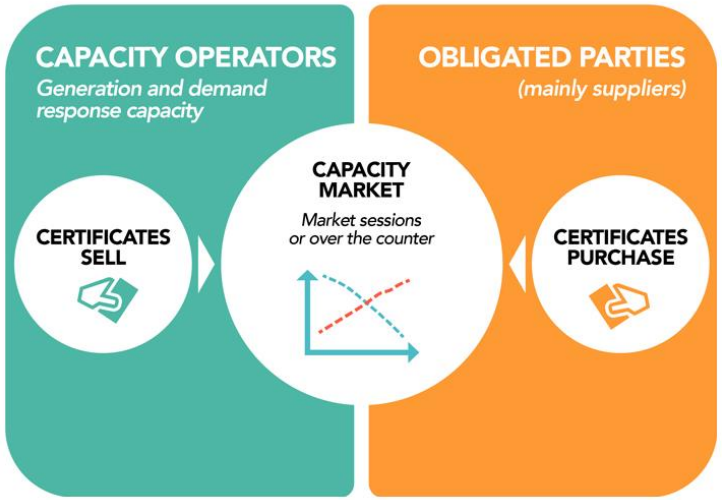
Implicit products for demand side flexibility

- **Network tariffs**
  - **For high voltage:** Differentiated in 5 time periods for energy and capacity charge. There is the option of having the tariff with "fixed peak hours" and the option of "mobile peak hours". For the latter, RTE communicates them one day ahead.
  - **For low voltage:** All residential customers have the choice between a network tariff with a single price or a night/day tariff. Residential customers with smart meters have 4 different time periods combining seasonal and peak and off-peak components. The latter applies also for customers above 36 kVA.
- **Supply tariffs (energy):** Currently, there are several contracts available for customers, including time-of-use energy pricing and critical peak pricing. Suppliers have estimated the demand response capacity made available through different tariff-based mechanisms at close to 700 MW, in 2018.

- **Smart connection offers (DSOs) – Trial**
  - This mechanism consist of a special contract between producers/consumers and DSO in Medium Voltage connections. The DSO offers a faster and less expensive contract in exchange for controlling the flexibility directly. This is at a trial stage, with 7 experiments spread in the whole country. Regulatory changes are required for this mechanism to become a real option.

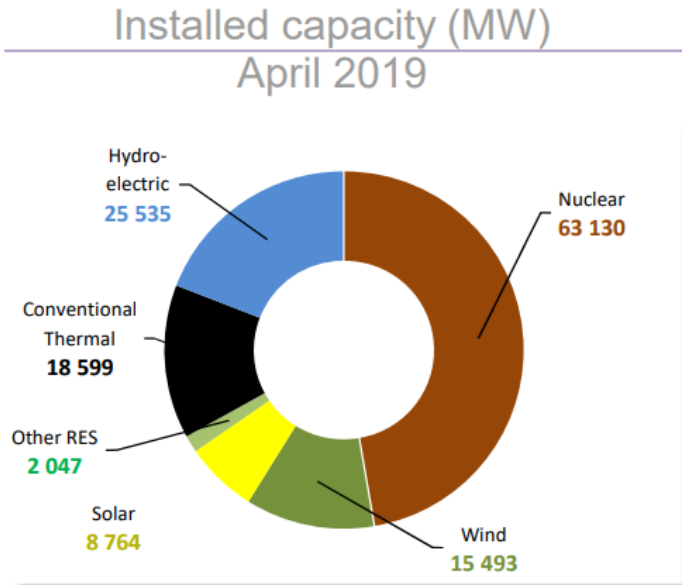
Market design parameters

1. **Transmission congestion management methods:** Zonal pricing, France is one bidding zone.
2. **Dispatch:** De-centralised. The electricity market model is based on the "standard European model" (self-dispatch, net power exchange, balance responsibility towards the TSO). Contracts traded at EPEX Spot (Paris) and EEX (Leipzig) plus bilateral contracts.
3. **Market organisation:** Contestable, consumers can choose supplier. However EDF still dominates the market, it has more than 80% of the market for residential customers and 65% of the business and local authority segments.
4. **Market structure:** Unbundled. RTE (TSO) and ENEDIS (DSO for 95% of the territory) are independent and regulated entities but still subsidiaries of EDF group. Distribution system operators of less than 100 000 customers are not obliged to be legally unbundled.
5. **Adequacy organisation:** A capacity mechanism is intended to safeguard the security of electricity supply in France during peak winter periods. It is based on an obligation for obligated parties to cover consumption during peak periods by means of certificates based on generation and demand response capacities.
   - Capacity operators (generation and demand response capacity) undertake to ensure availability during peak winter periods. In exchange, RTE gives them certificates that they can then sell to obligated parties
   - Obligated parties demonstrate on an annual basis that they are able to cover customer consumption during peak winter periods. To meet this obligation, they must hold certificates. Obligated parties are suppliers, as well as end consumers and system operators for their losses, which, for all or part of their consumption, are not supplied by a provider.



Other key indicators

1. **Generation mix:** Largely dominated by nuclear and hydro



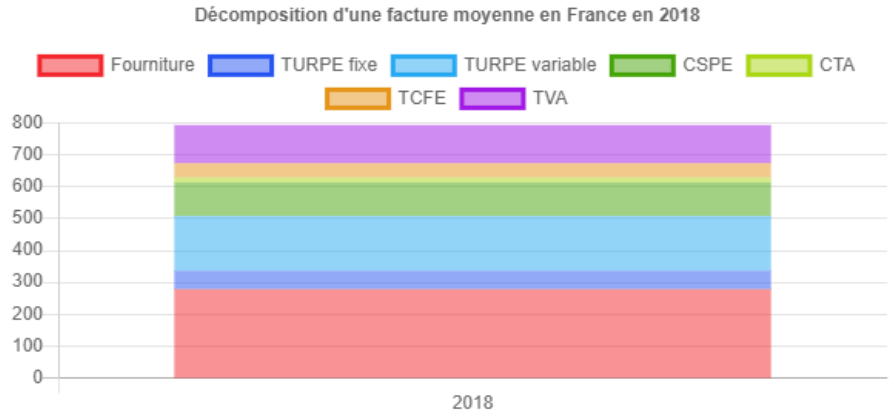
Source	%
Nuclear	47.3
Hydro	19.1
Thermal	13.9
Wind	11.6
Solar	6.6
Other RES	1.5

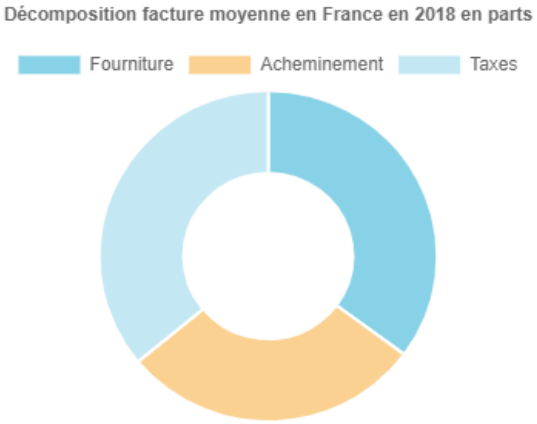
Total installed capacity 2019: 133,568 MW

Reference: https://www.rte-france.com/sites/default/files/apercu_energie_elec_2019_04_an.pdf

Other key indicators

2. **Volatility of day-ahead prices (or similar):** Relatively low price volatility
3. **Degree of electrification**: Typical domestic electricity consumption per household is 4 770 kWh/year
4. **Capacity**
   - **Is there a perception of generation adequacy problems in the country?:** Yes, for peak consumption during winter, thus the capacity mechanism
   - **Is there a perception of network adequacy problems in the country?:** Not in the short term but foreseen in the future with the increasing intermittent renewable generation
5. **Retail tariff structure**
   - **Composition of the energy bill:** The weight of all network tariffs is around 30% of the whole bill, the energy component is 34 % and the other 36% are taxes and charges.
   - **Design of the network tariff:** Distribution network tariffs for households comprise on average comprises 10% on fixed term, 20% on the capacity term and 70% on the volumetric term, however, this can vary depending on the consumption patterns of the client.

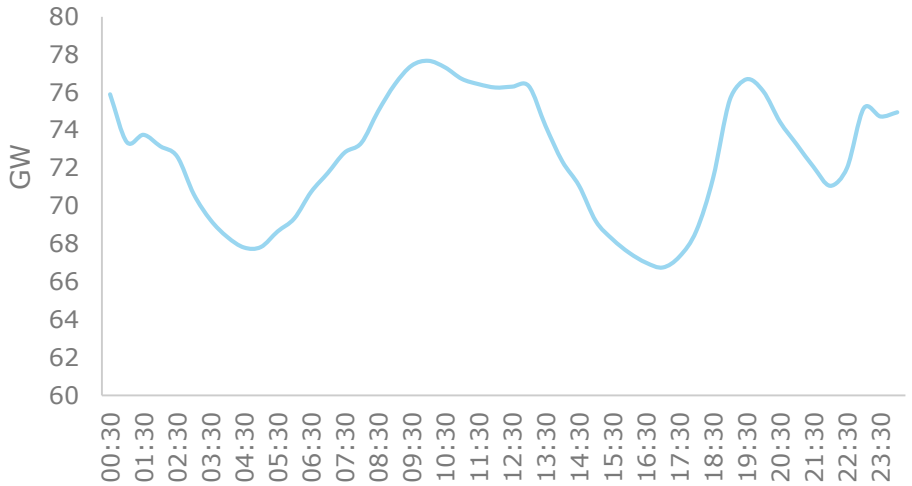




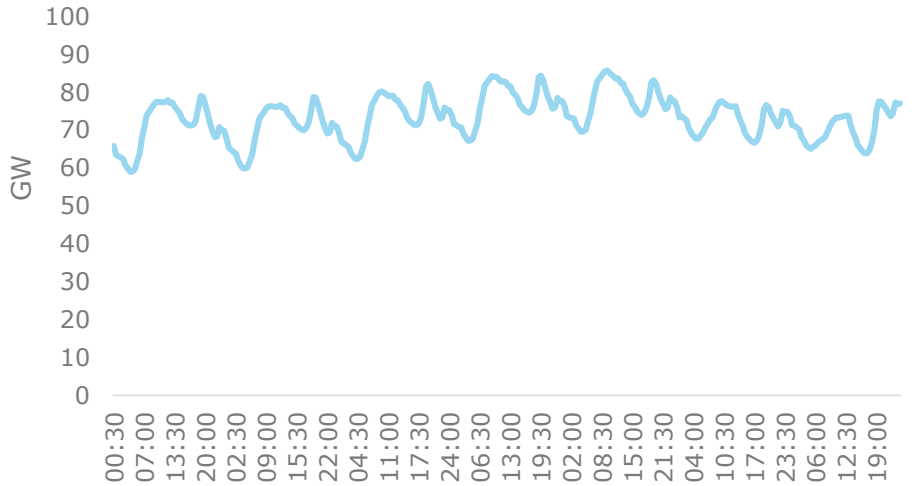
Source: SSB

Other key indicators: Load curve

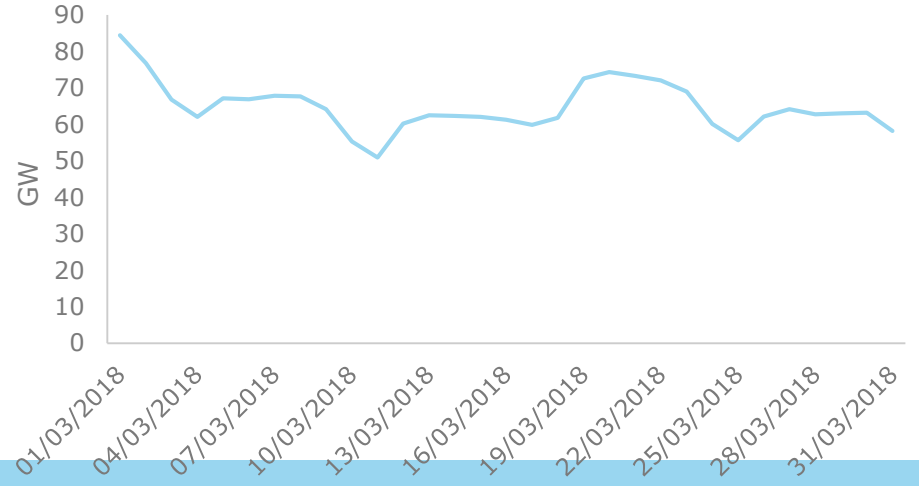
Daily demand 24th of February 2018



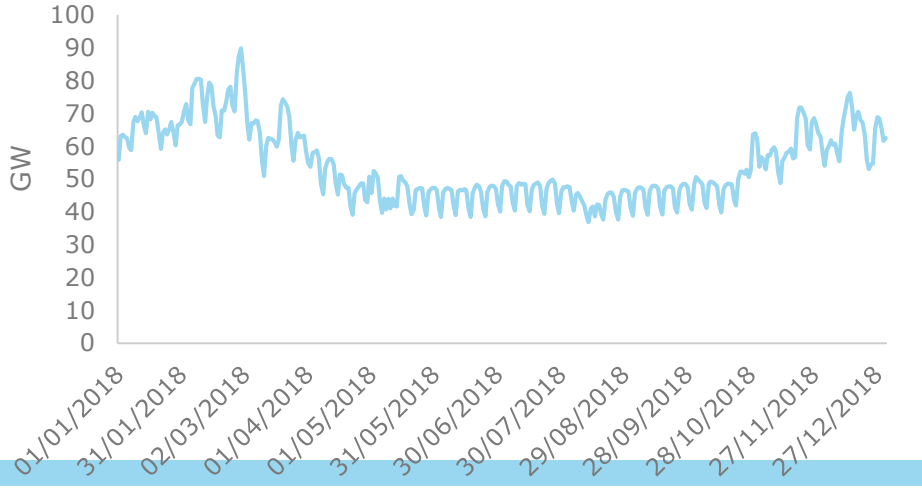
Weekly demand week 8 2018



Monthly demand March 2018 (daily average)



Annual demand 2018



California

- California is one of the leading markets when it comes to implementation of demand response programs and demand side flexibility
- DSF can participate in the wholesale market, ancillary services (spinning reserve, non-spinning reserve) and adequacy services (capacity procurement). There is no DSF participation in constraint management services yet. In California there is a wide range of Demand Response programmes that are offered to the consumers by the utility companies
- Price volatility is generally high, seeing spikes during summer months and afternoons/evenings. This price volatility is a driver for DR programmes mainly and for the ToU tariffs
- Grid tariffs rely on volume and not capacity, but CAISO is considering possible changes to this approach to better reflect cost causation, utilization, and benefits for the existing transmission system
- The power market is centered around the California ISO in a mandatory centralized pool model. The electricity system in California is currently a mix of regulated and deregulated. Despite the lack of a fully liberalised system, DSF activity is high
- The main drivers for demand flexibility in California are management of peak capacity during hot summer days, affordability of electricity, grid reliability and supporting more renewables on the grid. Management of renewable integration will call for demand response that can compensate for the uncontrollability of this new generation. CAISO created the “duck curve” to show the impact of grid-connected PV on the electric grid’s operation which indicated balancing variability in electricity demand



Overview of demand side flexibility in California

- California is one of the leading markets when it comes to implementation of demand response programs.
- The main drivers for demand flexibility in California are management of peak capacity during hot summer days, affordability of electricity, grid reliability and supporting more renewables on the grid. Management of renewable integration will call for demand response that can compensate for the uncontrollability of this new generation. CAISO created the "duck curve" to show the impact of grid-connected PV on the electric grid's operation which indicated balancing variability in electricity demand.
- DSF can participate in wholesale market, ancillary services and adequacy services. There is no DSF participation in constraint management services yet.
- In California there is a wide range of Demand Response programmed that are offered to the consumers by the utility companies. Each program contains some form of incentive for the customer to reduce their electricity consumption during certain hours, called "events". During these events customers are asked, or are remotely signalled. These DR programmes are mainly driven by volatility in energy prices (i.e. very high prices during the afternoon) and system reliability. In the future, customers may also be asked to increase their electricity consumption during certain events.
- Price volatility is generally high, seeing spikes during summer months and afternoons/evenings. This price volatility is a driver for DR programmes mainly and for the ToU tariffs.



Demand side flexibility - models

- In California there are several demand side flexibility models:
  - **Distributed energy resource provider** is a market participation model that allows for an aggregation of Distributed Energy Resources (DERs) allowed within limitations to meet minimum capacity requirements and act as one 'virtual' resource
  - **Proxy Demand Resource** (PDR) is a market participation model that enables 3rd parties to bid demand response into the CAISO market independent of the Load Serving Entity for load curtailment in wholesale Energy and Ancillary Services markets
    - Currently 818 active proxy demand resources
  - **PDR Load Shift Resource** (PDR-LSR) is a market participation model recently developed; allows for a bidirectional dispatch product that rewards PDRs for increasing consumption during negative pricing (i.e., oversupply events). Available Fall 2019.
  - **Reliability Demand Response Resource** (RDRR) is a market participation model for reliability based load curtailment, triggered only under emergency conditions. RDRRs have different requirements and limitations, as participation is limited to CPU C jurisdictional DR program integration, with a cap on the amount of MWs that count for Resource Adequacy based on a CPUC settlement agreement
    - Currently 148 participating reliability demand response resources
  - **Non-Generating Resource** (NGR) is a resource-type market participation model (i.e., such as a conventional generator), created to account for the positive/negative range of a storage resource. It may either act as a storage resource—or, if providing generation-only, as a conventional generator.
  - **Participating load:** This model includes Pumped Hydro Storage. These resources act as load while using energy to pump water to higher elevation reservoirs; then act like generators by creating energy when releasing water back to lower reservoirs
- These models have been developed so that they provide different routes to flexibility provision for market participants (e.g. one model might be more suitable aggregated portfolio while another model might be more suitable for storage technologies). They also have different telemetry and metering requirements, different operating and bidding characteristics.



Explicit products for demand side flexibility - California

Service	Product	Open to DSF	Market Participation	Comments
Balancing	Regulation up	Only open for non-generating resource	Not available information	
	Regulation down	Only open for non-generating resource	Not available information	
	Spinning reserve	Yes to all DSF models	0 MW IN 2018	
	Non-spinning reserve	Yes to all DSF models	Total awarded in 2018: 281,384MW Total self-provided: 56190MW	Market participants can choose to bid ancillay services or to self-provide them
Wholesale	Convergence bidding	Yes	Not available information	This market feature allows a scheduling coordinator representing a registered convergence bidding entity to submit bids in the day-ahead market. Financial positions are taken in the day-ahead market and liquidated in the real-time market. For demand, the participant bids to buy at day-ahead price and sell at real-time price. For supply, the participant bids to sell at day-ahead prices and buys at real-time price. It allows market participants, including electricity suppliers, consumers and virtual traders, to arbitrage price differences between the day-ahead (DA) market and the real-time (RT) market without physically consuming or producing energy.
	Day-ahead	Yes to all DSF models	Not available information	
	Real-time	Yes to all DSF models	No. of dispatches: 19423 MW instructed: 16202 MW delivered: 7779	
Adequacy	Capacity procurement through the resource adequacy framework	Applicable to Load Serving Entities and Community Choice Aggreagtors (CCAs)		
	Capacity procurement mechanism		For utility run demand response programs, more than 1,700 MWs of capacity have been procured to meet 2018 system RA requirements	



Implicit products for demand side flexibility - California

- The **Flex Alert program** is a voluntary energy conservation program that alerts and advises consumers about how and when to conserve energy. The Flex Alert program continues to be a vital tool for the CAISO during periods of high peak demand or other stressed grid conditions to maintain system reliability. The alerts also serves as a signal that both non-event and event-based demand responses are needed. A Flex Alert is issued by the ISO when the electricity grid is under stress because of generation or transmission outages, or from persistent hot temperatures. No financial incentives are involved, other than the impact of the conservation of energy on the utility bill.
- **Time of Use Tariffs:** Utilities companies plan to fully roll out ToU Tariffs for all types of customers by the end of 2020. Currently, all commercial, industrial and agricultural customers in California are required to be on a time-of-use plan. Residential customers can choose to be on to time of use plans, by contacting their utility.
- **Critical Peak Pricing** is the default rate for large customers.
- **Implicit products for DSF** (Demand response programs as they are called in California) are administered by California's three regulated investor-owned utilities: Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric. Each utility company offers different types of DR programmes to it customers. Independent commercial entities known as 'aggregators' or 'Demand Response Providers' may also approach customers to offer DR services. Residential, commercial, agricultural and industrial customers can all participate in demand response programs and receive incentives for doing so. Examples can be found on the links below:
  - https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/energy-incentives.page
  - https://www.sce.com/business/demand-response
  - https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response
- Demand response programs can be categorized as event based and non-event based. **Non-event based** demand response programs include real-time pricing and load shifting (implicit demand response). **Event based** or dispatchable demand response programs are supply side resources that have triggering conditions. These include base interruptible programs, aggregator managed portfolios, capacity bidding programs, demand bidding programs, smart AC, summer discount plans, and demand response contracts. The Reliability Demand Response Resources (RDRR) programs in the CAISO market are event based programs that require the CAISO to declare a system warning before they can be utilized

Market design parameters - California

1. **Transmission congestion management methods:** Nodal pricing
2. **Dispatch:** Centralised, producers submit detailed cost data to the day-ahead market, and the market operator decides how much should be produced in each plant
3. **Market organisation**
    1. The retail market is not fully open for competition
        1. Investor-owned utilities (IOUs): private electricity providers, which are overseen by the Public Utilities Commission (CPUC). There are 3 major IOUs which comprise approximately three quarters of electricity supply in California. Customer rates are set and regulated by CPUC through public process that includes some customer participation.
        2. Publicly owned utilities (POUs): subject to local public control and regulation. POUs are organized in various forms including municipal districts, city departments, irrigation districts, or rural cooperatives. Municipal districts may include territories outside city limits or may not even serve the entire city. Cooperatives are owned by the customers they serve usually in rural areas. There are more than 40 POUs in the state that account for approximately a quarter of electricity supply in California. Most POUs are smaller than IOUs in the electricity sales and the number of customer accounts. Customer rates are set by each utility's governing body (board or city council) in a public forum.
        3. Community choice aggregation (CCA), also known as municipal aggregation, are programs that allow local governments to procure power on behalf of their residents, businesses, and municipal accounts from an alternative supplier while still receiving transmission and distribution service from their existing utility provider. Participation in CCAs is always voluntary. Residential customers are by default registered in the CCA programmes but the can opt-out if they want to. Commercial/Industrial customers choose at the beginning whether they register with the CCA.
    2. Wholesale market: Open for competition (day ahead and real time market), Power Purchase Agreement.

Market design parameters - California

4. Market structure

- The power market is centered around the California ISO in a mandatory centralized pool model (US style), which also administers procurement of ancillary services and capacity reserves.
- The electricity system is California is currently a mix of regulated and deregulated. In the wholesale market, utilities purchase power primarily from independent electricity producers at a competitive wholesale price that is set using an auction process administrated by CAISO. CAISOs markets include day-ahead market, real-time market, ancillary services and congestion revenue rights. CAISO also operates an Energy Imbalance Market (EIM). In the retail market, electricity utilities sell power to end-use consumers at prices that are regulated by the California Public Utilities Commission

5. Adequacy Organisation

- The California Public Utilities Commission (CPUC) adopted a **Resource Adequacy (RA)** policy framework in 2004 in order to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs). Under the RA program, each LSE must commit its own generators – or contract with generators owned by other entities – to ensure reliability of the electric system. Over the last ten years, California has maintained adequate reserves under the RA program to ensure reliable grid operation.
  - LSE: Any company that (a) sells or provides electricity to end users located in California, or (b) generates electricity at one site and consumes electricity at another site in California (both sites owned or controlled by the company). LSE does not include the owner or operator of a co-generator.
- The **capacity procurement mechanism** is the tool that CAISO uses to backstop the RA program. Specifically, when there is insufficient capacity shown in the RA process to reliably operate the grid, CAISO may make CPM designations to procure resources that have not been shown in the RA process so that enough capacity is available to reliably operate the system. Resource owners with additional capacity can participate in the competitive solicitation process for their bids to be considered when and if CAISO makes a CPM designation. Generally, in any timeframe CAISO makes a designation, all options for procurement are reviewed and the least cost option that meets the reliability need is selected.

Other key indicators - California

1. Generation mix

2018 Total System Electric Generation in Gigawatt Hours						
Fuel Type	California In-State Generation (GWh)	% of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Energy Mix (GWh)	California Power Mix
Coal	294	0.15%	399	8,740	9,433	3.30%
Large Hydro	22,096	11.34%	7,418	985	30,499	10.68%
Natural Gas	90,691	46.54%	49	8,904	99,644	34.91%
Nuclear	18,268	9.38%	0	7,573	25,841	9.05%
Oil	35	0.02%	0	0	35	0.01%
Other (Petroleum Coke/Waste Heat)	430	0.22%	0	9	439	0.15%
Renewables	63,028	32.35%	14,074	12,400	89,502	31.36%
Biomass	5,909	3.03%	772	26	6,707	2.35%
Geothermal	11,528	5.92%	171	1,269	12,968	4.54%
Small Hydro	4,248	2.18%	334	1	4,583	1.61%
Solar	27,265	13.99%	174	5,094	32,533	11.40%
Wind	14,078	7.23%	12,623	6,010	32,711	11.46%
Unspecified Sources of Power	N/A	N/A	17,576	12,519	30,095	10.54%
Total	194,842	100.00%	39,517	51,130	285,488	100.00%

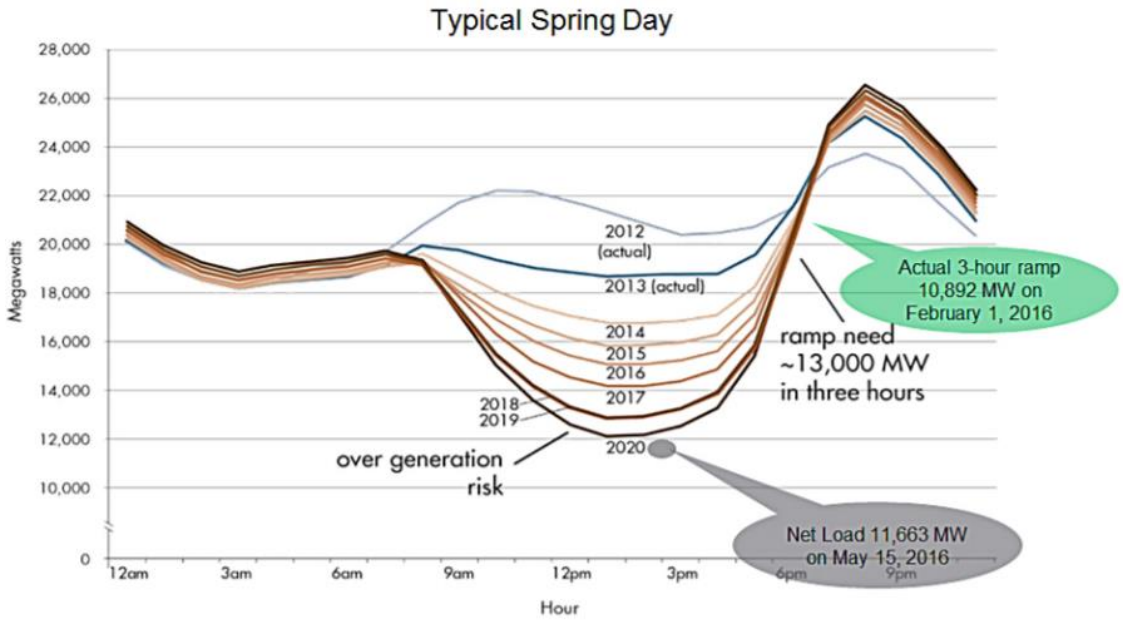
Source: SSB

Other key indicators - California

2. Load profile

- Because of its success in deploying clean energy California came across a unique load profile that was firstly observed in 2012. The CAISO has named this profile as the "duck curve". The graph here is produced by CAISO and the curves show the oversupply risk from 2012 to 2020, expressed as the difference in electricity demand and the amount of available solar energy throughout the day (total load minus solar energy (and eventually also wind power)). When net load decreases, the risk of having too much power generation increases.
- Since the curve was identified, the CAISO has taken many steps to mitigate the oversupply risk and avoid the continuation of the "duck curve".

Figure 2: The duck curve shows steep ramping needs and overgeneration risk



Source: SSB

Other key indicators - California

3. **Volatility of day-ahead prices (or similar)**
   - Prices vary depending on the day of the week, the month or the hour of the day. The yearly range of wholesale electricity prices in the CAISO area is from 0 to ~150 $/MWh. Day-ahead and real-time market prices increased in 2018. This was attributed primarily to an increase in natural gas prices and tight system conditions, especially in the third and fourth quarters of the year.
   - Volatility has been increasing in the recent years (e.g. from 2017 to 2018), seeing spikes during summer months.
   - Based on the CAISO market design for the Day-Ahead Market (DAM) and the Real-Time Market (RTM), prices in these markets are expected to converge to a reasonable degree, due to changes in system conditions. The level of price convergence across markets, and the degree to which prices reflect actual system conditions are natural indicators of efficient price formation in the CAISO markets.
4. **Degree of electrification**: California has a strong zero carbon policy; the greenhouse gas goals will require abandoning fossil fuels entirely. Electrification of energy use is also accompanied by "greener" electricity due to high penetration of RES. Electrification of transport is leading California's electrification. In summer 2019 California regulators updated the decades-old energy policy to allow the state's $1 billion annual budget for energy efficiency to be directed towards building electrification efforts, giving a boost to the state's move away from natural gas.
5. **Capacity**
   1. **Is there a perception of generation adequacy problems in the country?** No. California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the California Public Utilities Commission (CPUC) to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities. In 2018 The total amount of local resource adequacy capacity available to bid into the day-ahead and real-time markets exceeded the total local capacity requirement; some individual areas did not meet the requirement, relying on resources from within the greater transmission access charge area. California had generation problems in the 2000's, but not any more.
   2. **Is there a perception of network adequacy problems in the country?** Yes. Network adequacy problems are more related to the ramping capability to account for uncertainty due to intermittent generation (e.g. high solar generation while demand is low). In additions, network issues are encountered at the federal connections zones due to the power flows from one zone to the other (e.g. Arizona – California, excessive solar generation in Arizona, power flows from the dessert to California). In addition California experiences network problems with regard to its liability, upgrades and aged networks that cannot cope with the weather conditions in California (e.g. wind). For example , in October 2019 Pacific Gas and Electric shut down power to millions of Californians due to problems on the distribution network. Fire risks are also an issue for network operation.

Source: SSB

Other key indicators - California

5. Retail tariff structure:

– Composition of the energy bill (Online example; this customer ca. pays $79 for network services and $36 for the energy, including fees etc.)

Details of your new charges

Your rate: DOMESTIC (SCE)

Billing period: Feb 28 '17 to Mar 29 '17 (29 days)

Delivery charges		
Basic charge	29 days x $0.03100	$0.90
Energy-Winter		
Tier 1 (100% of baseline)	305 kWh x $0.08291	$25.29
Tier 2 (101% to 400%)	263 kWh x $0.16838	$44.28
CCA cost responsibility surcharge		
PCIA	568 kWh x $0.00920	$5.23
DWR Bond Charge	568 kWh x $0.00549	$3.12
CTC	568 kWh x -$0.00034	-$0.19
Other charges or credits		
Generation Municipal Surcharge		$0.39
Subtotal of your new charges		$79.02
Your new charges		**$79.02**

Your Delivery charges include:

- *$9.15 transmission charges*
- *$47.32 distribution charges*
- *$0.01 nuclear decommissioning charges*
- *-$0.69 conservation incentive adjustment*
- *$8.66 public purpose programs charge*
- *$5.78 new system generation charge*

Your overall energy charges include:

- *$0.72 franchise fees*

(Continued on next page)

Generation Charges		
13% MARKET DEMAND ADJ - ALL		-$0.20
10% MARKET DEMAND ADJ		-$3.88
GENERATION	547.18 KWH @ 0.07082	$38.75
GENERATION	20.59 KWH @ 0.07454	$1.53
ENERGY SURCHARGE		$0.16
Sub-Total of LCE Generation Charges		$36.36
Your New Charges		**$36.36**

- **Design of the network tariff:** The Transmission Access Charges are currently volumetric-only. The ISO in 2018 questioned if the current volumetric approach best reflect the cost causation, utilization, and benefits of the existing transmission system, and has proposed changing the current system. Possible changes to the ISO's current volumetric Transmission Access Charge (TAC) structure for recovering participating transmission owners' costs of owning, operating and maintaining transmission facilities under ISO operational control will be considered. The ISO will consider stakeholder input on the initiative scope, which will include possible changes to reflect the benefits of distributed energy resources in reducing future transmission needs.

Source: SSB

Texas

- In Texas, demand response participation is relatively high, with 2329MW of demand response capacity in 2018
- Demand response can participate in the wholesale market and balancing services. However, participation is limited to controllable loads (can vary electric usage immediately based on a signal) and have high technical requirements for most of the services. The services with significant demand response participation are the responsive reserve and the emergency response service
- Price volatility is relatively high, especially during the summer months and highly influenced by residential demand. This has caused emergency situations and demand response activations
- Grid tariffs are purely volumetric. There is a range of demand response programmes offered to customers by utilities, to avoid high energy and network prices (costs)
- The market is unbundled, centralised and quite open to competition
- The key enablers for demand side flexibility in Texas are peak management during summer months, grid stability and reliability, especially in emergency situations. Due to increasing renewable intermittent generation, ERCOT is discussing a possible change in balancing services to allow for faster response times and more demand response participation



Overview of demand side flexibility in Texas

- In Texas, demand response participation is relatively high, with 2329MW of demand response capacity in 2018.
- Demand response can participate in the wholesale market and balancing services.
- Participation of DSR in wholesale and most of balancing products (regulation up, down and spinning reserve) is limited because of qualification technical barriers. Only controllable loads, which are the ones able to vary their electric usage immediately based on a signal, are allowed to participate on these services.
- There is high DSR participation on other balancing products, namely, responsive reserve and emergency response services. These products are open to participation for both, controllable and non-controllable loads, allowing large industrial loads to offer DSR.
- Due to high demand during summer period, among other reasons, Texas' Transmission/Distribution Service Providers (TDSPs) and suppliers offer a variety of demand response programmes to their customers, most of which have been increasingly successful over the years.
- Overall, the key enablers for demand side flexibility in Texas are peak management during summer months, grid stability and reliability, specially in emergency situations. Due to increasing renewable intermittent generation, ERCOT is discussing a possible change in balancing services to allow for faster response times and more demand response participation



Explicit products for demand side flexibility - Texas

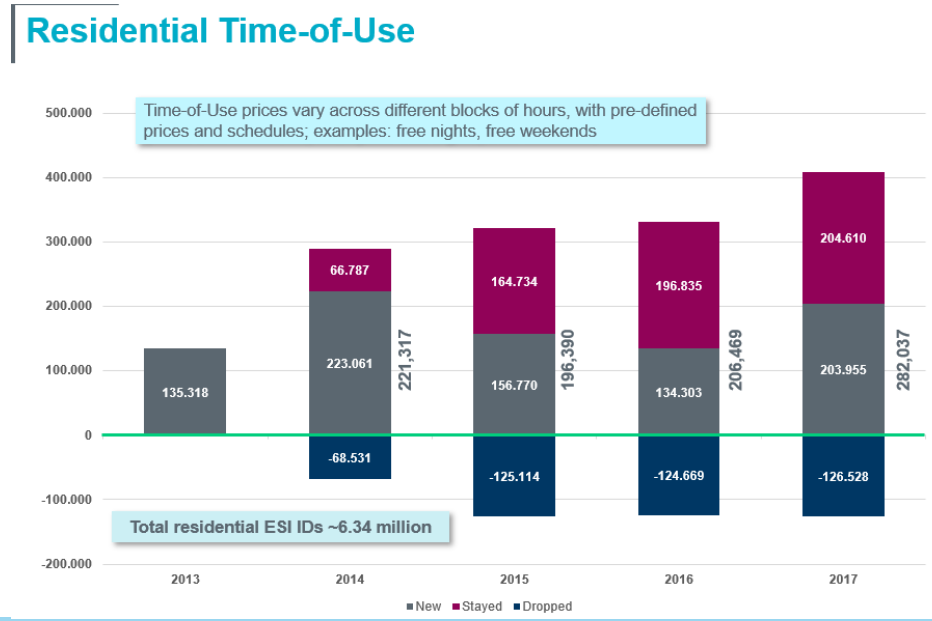
Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation	Comments
Balancing services	Regulation Service Up (Down for demand side response)	Yes	Capacity and avoided energy cost	No	Only controllable loads* can participate. Batteries are successfully providing the service. Fast responding regulation service provided by controllable loads is limited to 65MW/h.	There is the provision for controllable loads*. However, there are high barriers in telemetry requirements and Primary Frequency Response provision requirements
	Regulation Service Down (Up for demand side response)	Yes	Remuneration is based on capacity, but they incur on additional cost for energy consumption	No	Only controllable loads* can participate. 6 controllable loads have successfully registered in the system during 2018, with the intention of providing the service. Fast responding regulation service provided by controllable loads is limited to 35 MW/h.	There is the provision for controllable loads*. However, there are high barriers in telemetry requirements and Primary Frequency Response provision requirements
	Responsive Reserve Service	Yes, but no aggregation	Capacity based (cleared in the day-ahead)	No	Currently over 300 Load Resources registered with total capacity of about 4200MW Participation rates are 1600-1700 MW of offers and about 1400 MW of awards every day	Controllable and non-controllable loads* can provide this service. Used to ensure sufficient capacity is available to respond to frequency excursions due to unit trips. Up to 60% of Responsive requirement can be provided by Loads with underfrequency relays that trip at 59.7 Hz
	Non-Spinning Reserve	Yes	Capacity based (cleared in the day-ahead)	No	In 2018, there were no Load Resources that were qualified to be dispatched for this service	There is the provision for controllable loads*. However, there are high barriers in telemetry requirements and Primary Frequency Response provision requirements
	Emergency Response Service	Yes, also from aggregated loads	Capacity based	No	Any load can participate: controllable and non-controllable*. 100-200MW were procured in 2018 auctions for 10min response emergency service. 600-800MW were procured for 30min response service. Auctions are 3 per year.	Any load, controllable and uncontrollable, aggregated or not, can participate.
Wholesale	Day-ahead market	Yes.	Energy	No	The volumes of energy provided are trivial in normal periods, since energy prices will usually be below the willingness-to-pay of almost all loads	There is the provision for controllable loads*. However, there are high barriers in telemetry requirements and Primary Frequency Response (PFR) provision requirements
	Real-time market	Yes	Energy	No	No active demand response participation in the Real-Time Market	There is the provision for controllable loads*. However, there are high barriers in telemetry requirements and Primary Frequency Response provision requirements

*Controllable loads: A Load Resource capable of controllably reducing or increasing consumption under dispatch control and provides Primary Frequency Response.

Non-controllable loads: Loads that don't qualify as "controllable loads"

Implicit products for demand side flexibility - Texas

- **TDSP Load Management Programs**
  - Any program under which end-use customers agree to receive payment from a Transmission/Distribution Service Provider (TDSP) in exchange for reducing peak demand for a specified duration upon request by the TDSP. This service was created to tackle energy scarcity issues.
- **4CP Load Reduction**
  - The four coincident peaks (4CP) in ERCOT are the four 15-minute settlement intervals corresponding with the highest ERCOT load in each of the four summer months. The average of the 4CP load establishes the share of T&D cost responsibility.
- **Price-Responsive Demand Response Products from Retail**
  - Block & Index (BI)
  - Critical Peak pricing (CPP)
  - Peak Rebates (PR)
  - Real-Time pricing (RTP)
  - Time of Use (TOU) pricing
  - Other Load Control (OLC)
  - Other Voluntary DR Product (OTH)





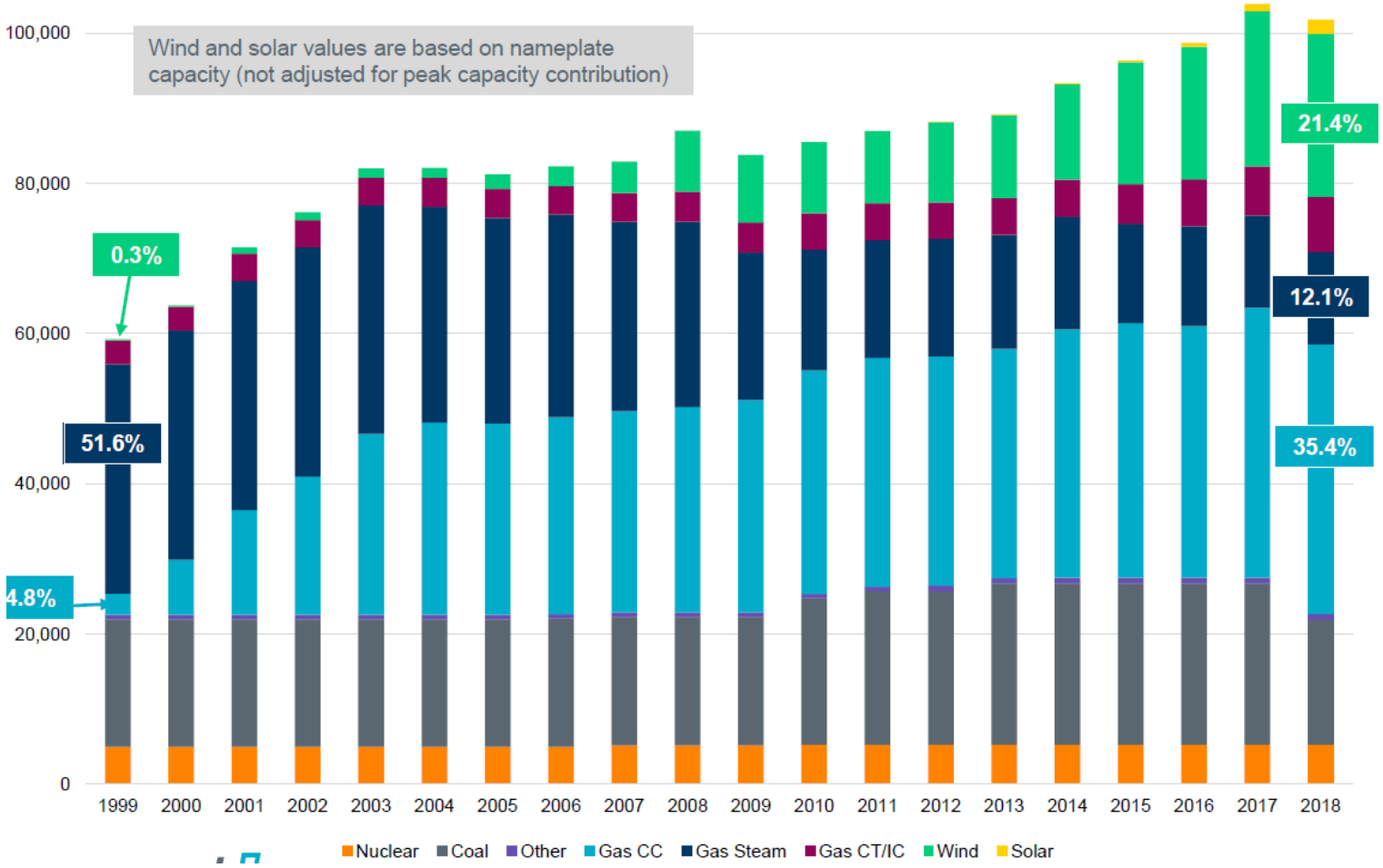
Market design parameters - Texas

1. **Transmission congestion management methods**
   - Texas applies nodal pricing at transmission level
2. **Dispatch**
   - Texas apply centralised dispatch, such that Producers submit detailed offers to the market operator Electric Reliability Council of Texas (ERCOT), which then dispatches the units according to demand. The real-time market clears every five minutes, using the cheapest generation to serve the load, subject to transmission constraints.
3. **Market organisation**
   - Generation: Generating units compete in ERCOT market to serve load. They are owned by privately owned companies. Except for municipal and cooperative units
   - Transmission and distribution lines and related facilities are owned and operated by regulated utilities. They are regulated by Public Utility Commission of Texas (PUCT)
   - Retailers: Consumer's electric load is served by competitive retailers, except in municipal and cooperative utility areas. Approved by Texas Senate Bill 7 on January 1, 2002, electricity deregulation allows 85% of Texas power consumers (those served by a company not owned by a municipality or utility cooperative) to choose their own providers.
4. **Market structure**
   - Legally unbundled
5. **Adequacy organisation**
   - Texas has an energy only market and operating reserves. There is no capacity market.

Other key indicators - Texas

1. **Generation mix**

ERCOT Installed Capacity (1999-2018)



Source: SSB

Other key indicators - Texas

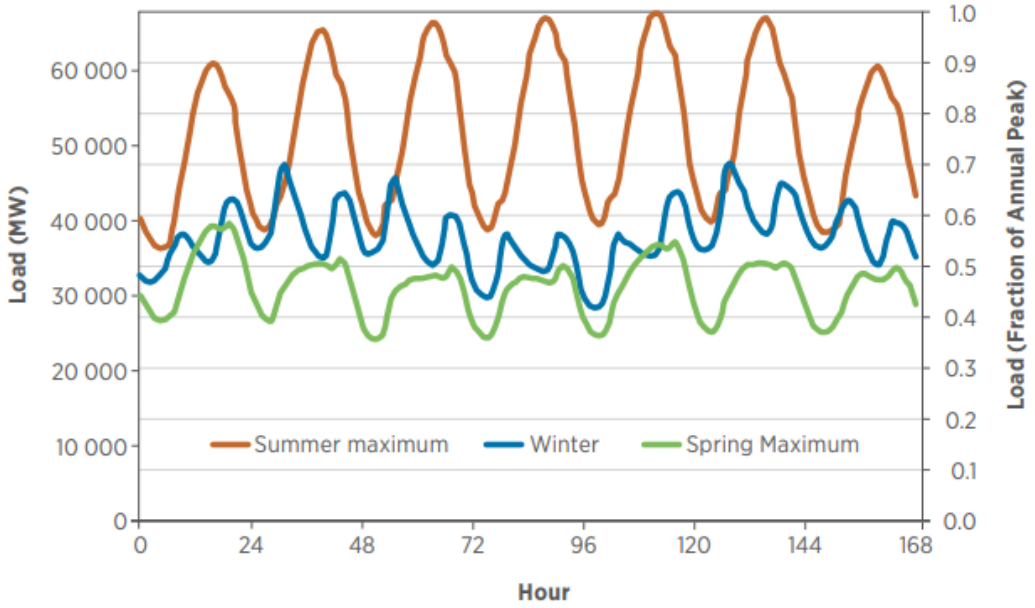
2. **Volatility of day-ahead prices (or similar):** Relatively high volatility. Prices exceeded $75/MWh in 1,6% of the intervals over 3 years.
3. **Degree of electrification**: Residential customers use an average of about 1,000 kWh of electricity per month, with usage higher during hot summer months and lower in the winter. Residential demand is half of the total demand during summer months
4. **Capacity**
   - Is there a perception of generation adequacy problems in the country? - Yes, during peak times in summer. In August 2019, ERCOT called an energy emergency alert twice in one week as capacity reserves dipped below ERCOT's set reserve margin.
   - Is there a perception of network adequacy problems in the country? – Currently, congestion on transmission is localised in renewable energy, oil&gas and mining areas. ERCOT experienced wind curtailment levels of 17 % in 2009 due mainly to transmission constraints. Curtailment levels were reduced in 2014 by 0.5 % following a restructuring in the regulatory framework and encouraging transmission investments to reduce wind curtailments. As part of the measures, Texas abolished a rule where transmission lines had to be used above a certain level, by a rule where curtailment had to be kept under 3%.
5. **Retail tariff structure**
   - Retail price for energy includes delivery (network), and a typical energy bill will have a volumetric payment corresponding some 80 - 90 % of the total energy bill
   - Tariffs for larger end users depend to a larger degree on capacity (30 – 70 %), based on 4 coincidental peaks (July-Sept).

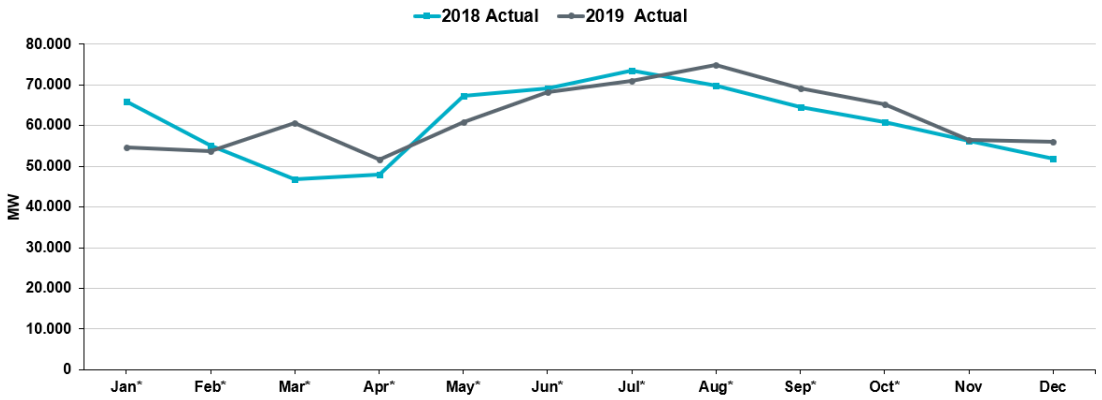
Projection of reserves based in the data from summer 2019



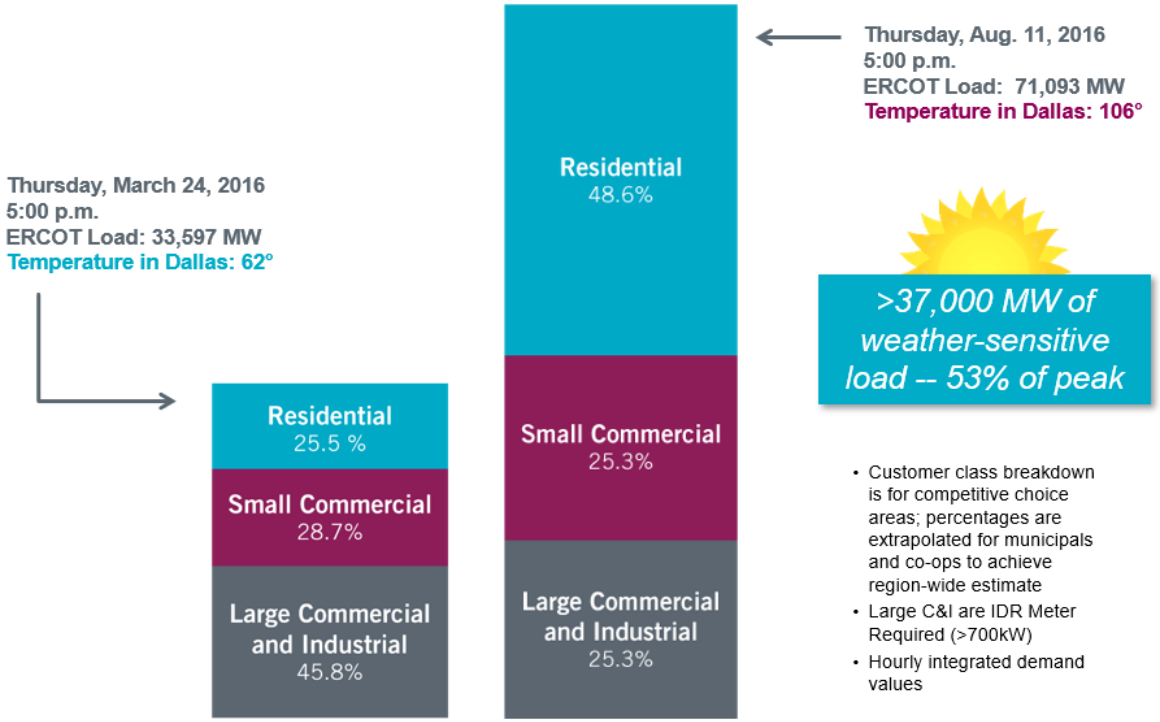
Source: SSB

Other key indicators: Load curves





Summer Weather Impacts on Load by Customer Type



- Customer class breakdown is for competitive choice areas; percentages are extrapolated for municipals and co-ops to achieve region-wide estimate
- Large C&I are IDR Meter Required (>700kW)
- Hourly integrated demand values

Source: SSB

Chile

- Demand response in Chile has been highly used for peak management through network and supply tariffs
- There are no explicit demand response products open yet. From 2020, however, the provision of balancing services will open to competition, allowing demand response participation
- There is an increasing need for flexibility in Chile's electricity grid due to intermittent renewable generation
- The market is centralized, soft contestable and unbundled. The fact that Chile is not fully liberalized does not strengthen the case for demand response
- Grid tariffs are largely volumetric
- Grid adequacy problems (due to decentralized renewable generation) and generation adequacy problems (in the past) are the key enablers for demand side flexibility in Chile. With the increase of renewable generation and the opening of balancing services to competition, an increase of demand response participation is expected in the coming years

Overview of demand side flexibility in Chile

- Demand response in Chile has been highly used for peak management through network and supply tariffs
- There are no explicit demand response products open yet. From 2020, however, the provision of balancing services will open to competition, allowing demand response participation
- There is an increasing need for flexibility in Chile's electricity grid due to intermittent renewable generation.
- Due to the geography of the country the transmission system is suffering from de-localised demand and generation, causing low (0) nodal prices or curtailment instructed by the ISO.
- Ancillary services have just opened (Jan 2020) to competition, previously they were part of the technical requirements of de-regulated power stations
- The Energy Ministry launched a flexibility strategy in November 2019, focusing on
  - Market design for the development of a flexible system
  - Regulatory framework for storage systems
  - Flexible system operation



- The work plan from the Energy Minister ends in May of 2022 and considers changes in the Grid Code with respect to technical standards for power transfer, safety and quality of service, marginal costs, operation scheduling, and real-time operation

Explicit products for demand side flexibility

Service	Product	Open to DSF*	Remuneration type	Value stacking available	Market Participation	Comments
Adequacy	Capacity payments ("pagos por potencia de suficiencia")	No			-	Capacity payments are only available for generators
Balancing services	Primary frequency response	-	Capacity and energy	Yes	-	Opening to competition in 2020
	Secondary frequency response	-	Capacity and energy	Yes	-	Opening to competition in 2020
	Terciary frequency response	-	Capacity and energy	Yes	-	Opening to competition in 2020
	Interruptible loads	Yes	Capacity and energy	Yes	-	Opening to competition in 2020
	Voltage control services	-	Investment, operation and maintenance per the offered service	Yes	-	Opening to competition in 2020
	Contingency services: demand and generation disconnection	Yes	Energy	Yes	-	Opening to competition in 2020
	Black start services	-	Investment, operation and maintenance per the offered service	Yes	-	Opening to competition in 2020

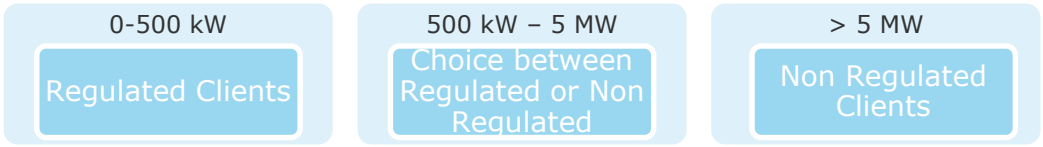
* The National Regulatory Agency (CNE) provided a set of rules for the auctions where it is stated that services related to load reduction (e.g. interruptible loads and demand disconnection) can be managed by the customer, an association of customers or a third party (i.e. Aggregator). Load reduction is only explicitly mentioned in interruptible and contingency services. Whether other services will be open for DSR will be specified when the auction is released by the ISO

Implicit products for demand side flexibility

- **Network tariffs**
  - **For high voltage:** It has an energy and a maximum power component (kWmax)
  - **For medium-low voltage:** The distribution charge is split in a fixed component, a capacity charge (kW) and a volumetric component for energy. The network charge thus varies with the maximum power consumed during peak hours per month
- **Supply tariffs (energy)**
  - **Fixed tariff:** For regulated customers, fixed power and energy price with a charge for additional energy consumed during winter. Most residential customers choose this tariff.
  - **Flexible tariffs:** For regulated customers, there are day/night/peak-hour tariffs that can be combined with a seasonal component.

Market design parameters

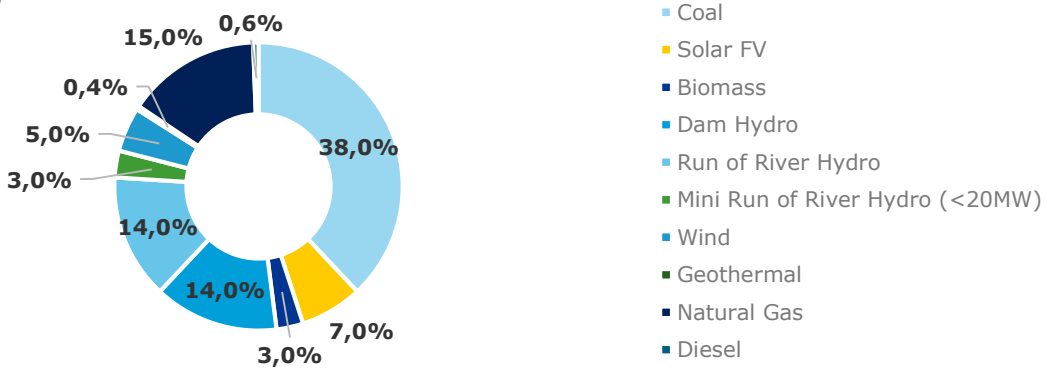
1. **Transmission congestion management methods**
   - Nodal Pricing
   - The National Commission of Energy (CNE), subscribed by a law that the transmission plan should be enough to minimize the congestion. In Chile the curtailment because of transmission congestion it's given in wind zones as Region de Coquimbo and in the northern part of Chile because of solar farms. The major demand it's in the centre of the country (Santiago de Chile).
2. **Dispatch**
   - Centralized. Producers submit detailed costs to the ISO (Coordinador Eléctrico Nacional) and the ISO decides who inject to comply with the demand. This is regulated by the marginal cost of energy, so the renewables energies are self-dispatched since they have zero marginal cost. If they are network constraints, renewables can be curtailed by the ISO.
3. **Market organisation**
   - "Soft contestable", there are regulated clients and non-regulated clients according to their power level. Regulated clients are those that have regulated energy prices.



5. **Market Structure**
   - Unbundled: Complete separation of generation, transmission and distribution.
6. **Adequacy organisation**
   - There is a capacity payment available only for generation units in order to be available when the ISO requires.

Other key indicators

1. **Generation mix: 76,175 GWh (2018)**



2. **Volatility of day-ahead prices (or similar)**
   - Low price volatility within the year (Depends of Hydrology – wet or dry years).
3. **Degree of electrification: Total electricity use in households**
   - 13.7 TWh (2018) out of 28.16 TWh.
4. **Capacity**
   - Is there a perception of generation adequacy problems in the country? No.
   - Is there a perception of network adequacy problems in the country? Yes. Due to the geography of the country, the generation and demand are delocalised in different parts of the country, generally leading renewable energy curtailment. The CNE has a plan for expanding the transmission network to solve this problem. Next to that, they are also working on a flexibility strategy

Other key indicators

5. Retail tariff structure

- **Composition of the energy bill:**

Energy	65.2%
Capacity	15.5%
Transmission	2.8%
Sub – Transmission	5.5%
Distribution Added Value (If you are in a Distribution Area)	11.0%

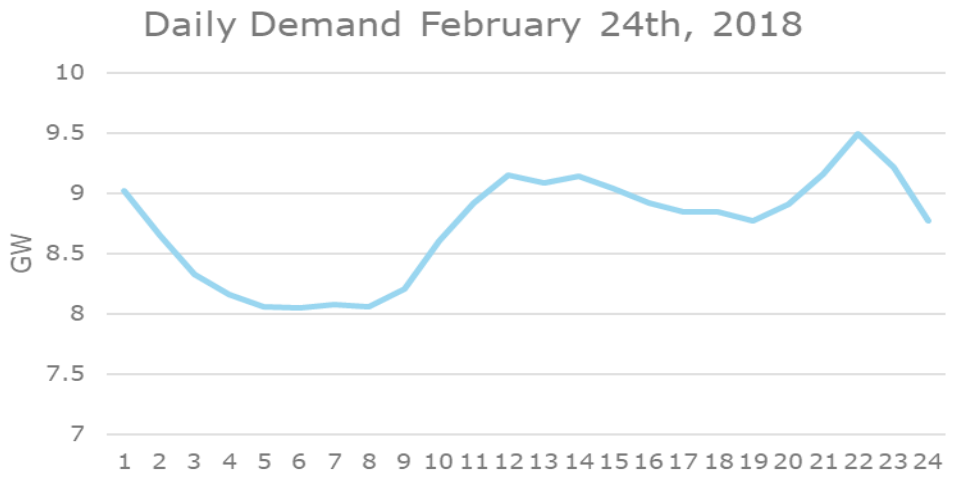
Regulated Client*

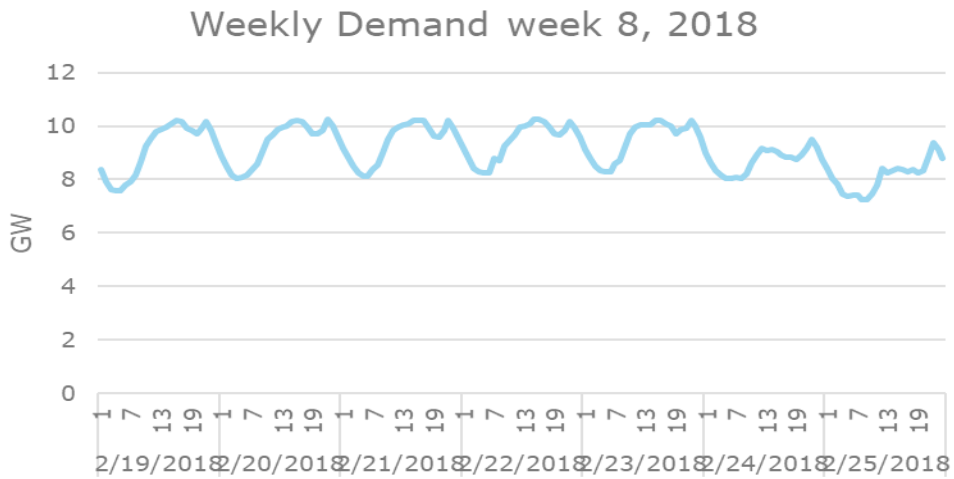
* Regulated client: For connections below 500kW, energy prices are regulated.

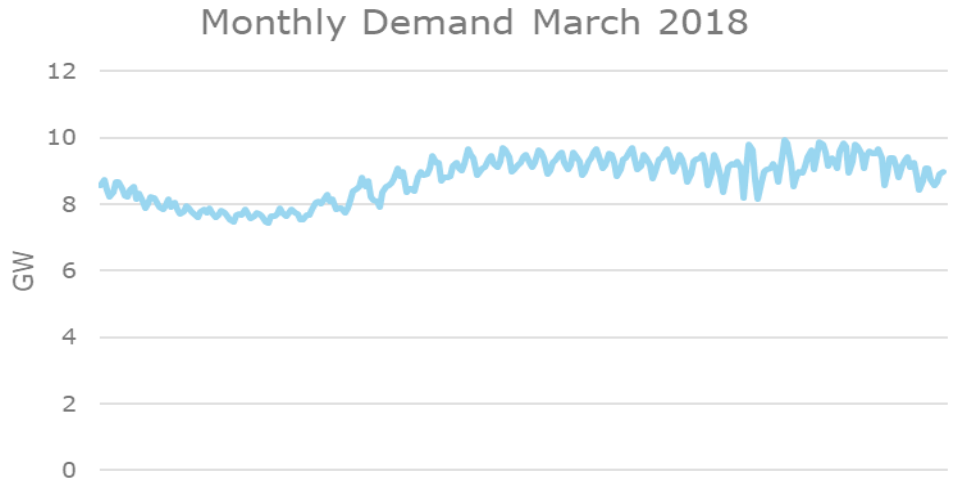
For Non regulated Client, the percentage depends of the Price of the PPA

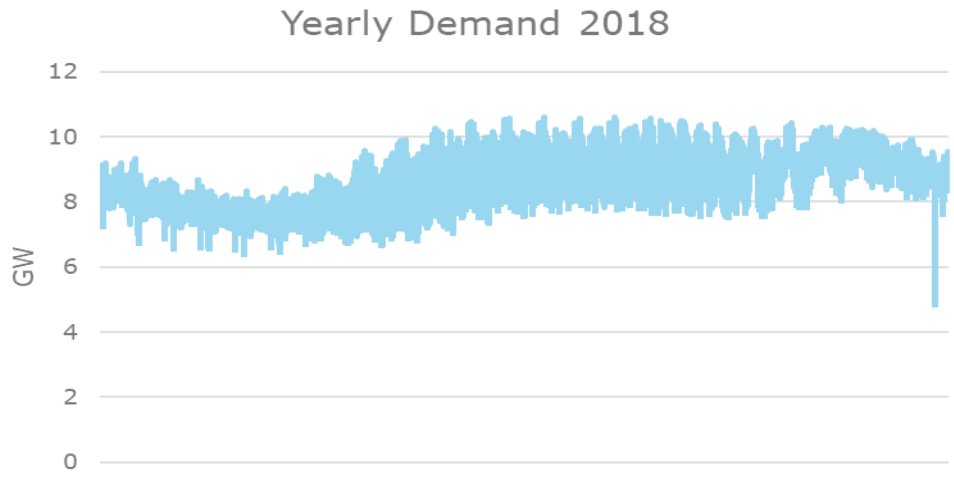
- **Design of the network tariff:**
  - The tariff design is largely volumetric.
  - The transmission charge is calculated on the energy consumption whereas the distribution charge is based on energy or capacity, depending on the type of tariff.
  - Most tariffs have a distribution charge component of peak hour demand that is based on capacity.

Other key indicators: Load Curve









Source: Demanda Real – Coordinador Eléctrico Nacional

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Please get in touch with us for further questions about demand side flexibility and how it can be mobilised and activated!

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