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IWEA Energy Vision 2030

Analysis of costs and benefits to Irish consumers

Irish Wind Energy Association (IWEA)
20 March 2018

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Objectives of this project

We have carried out analysis of IWEA's 2030 Energy Vision and studied the wider costs and benefits to consumers in the Republic of Ireland under two new scenarios

How we approached the analysis

- First, we looked to produce a Fossil Fuel scenario, to provide a baseline against which to compare other scenarios
- Second, we modelled a new scenario with assumptions provided by IWEA – this is the Renewable Energy scenario with 70% renewable penetration in the electricity sector across Ireland and Northern Ireland, including additional flexibility measures such as:
  - Battery energy storage
  - Electric vehicles able to shift demand to lower price hours
  - Heat pumps able to shift demand to lower price hours
  - An increase in the SNSP limit to 90% and a decrease in the min gen (system stability) constraint to 700 MW by 2030
- The analysis utilised our sophisticated and fully optimised pan-EU market model, and our constrained model for I-SEM to project wind curtailment levels
- We also extended the scope of the analysis to cover CRM costs, constraints, network, and the impact on heat / transport sectors

Key outputs

- Quantification of the cost implications to consumers driven by RES-E deployment, including:
  - Wholesale energy savings
  - RES support costs
  - CRM, EV, HP and constraint / network costs
- Quantification of curtailment levels under the two modelled scenarios

Description of scenarios

For IWEA renewables vision 2030 we looked at two scenarios, named as Fossil Fuel scenario and Renewable Energy scenario respectively

Fossil Fuel scenario

- This scenario describes a possible future state of the Ireland where decarbonisation of the power, heat and transport sectors stop post 2020, with no further deployment of low-carbon/renewable technologies
- Under this scenario, conventional thermal plants continue to play a major part in the generation mix, whilst renewable generation technologies, energy storage technologies and flexible demand sources remain at their status quo
- This scenario is used as a benchmark

Renewable Energy scenario

- This scenario describes a possible future state of Ireland where significant decarbonisation in the power sector leads to 70% of demand being met by renewable generation by 2030 in the Republic of Ireland and Northern Ireland
- Decarbonisation of the heat and transport sectors also takes place, with the adoption of electric vehicles (EVs) and heat pumps (HPs) by consumers making demand more flexible
- Battery storage projects and increased interconnection with GB and France also improves flexibility on the supply side

Scenario assumptions

The key differences between the two scenarios are demand and capacity mix

	Fossil Fuel scenario	Renewable Energy scenario
Demand	▲ Business as usual demand trajectory, with annual demand reaching 36.3 and 9.6 TWh by 2030 in the Republic and Northern Ireland respectively	▲ Additional demand from EVs and HPs contribute to higher demand, reaching 38.8 and 10.6 TWh by 2030 in the Republic and Northern Ireland respectively
Conventional thermal plants	▲ 2.3 GW of additional combined cycle and open cycle gas turbines (CCGTs and OCGTs) built by 2030, to meet increasing peak demand and replace existing thermal plants that retire	▲ 0.2 GW of OCGTs built to provide capacity to meet peak demand only, as most of the demand is met with renewable generation
Wind	▲ No further development post 2020, with overall capacity at 3.7 and 1.1 GW in the Republic and Northern Ireland respectively	▲ 8.0 and 2.2 GW in the Republic and Northern Ireland respectively by 2030, including 1.0 GW of offshore wind in the Republic
Solar	▲ No further development post 2020, with overall capacity at 50 and 270 MW in the Republic and Northern Ireland respectively	▲ 2.5 and 0.4 GW in the Republic and Northern Ireland respectively by 2030
System constraints	▲ SNSP limit remains at 70% ▲ Min gen (system stability) constraint decreases to 1000 MW by 2030	▲ SNSP limit increases to 90% by 2030 ▲ Min gen (system stability) constraint decreases to 700 MW by 2030

Technology cost assumptions

We have used technology cost assumptions from PB Power as a starting point for the analysis – consistent with the assumptions used in the DCCAE / CEPA RESS analysis

- The 'baseline' technology cost assumptions for all three scenarios were taken from the PB Power report published alongside DCCAE's RESS consultation paper, as used in the CEPA analysis
- These are widely viewed as being extremely high, given the cost reductions reflected in recent European renewables auctions
- The likelihood that renewable projects will require significantly lower support levels than these cost assumptions suggest adds further weight to the end consumer cost findings of the study

Technology cost assumptions for onshore wind and solar (real 2017)

Onshore wind - large		**2020**	**2025**	**2030**
Capex	*€/kW*	1529	1473	1434
Fixed Opex	*€/kW/year*	52.8	50.8	49.7
WACC (real, pre-tax)		10%	10%	10%
Total constr time	*years*	2	2	2
Economic life	*years*	20	20	20
Load factor pre-curtailment		35%	35%	35%
Load factor post-curtailment		34%	33%	33%
LCOE	*€/MWh*	**81.6**	**78.6**	**76.7**

Solar - large		**2020**	**2025**	**2030**
Capex	*€/kW*	882	787	732
Fixed Opex	*€/kW/year*	12.2	11.2	10.2
WACC (real, pre-tax)		10%	10%	10%
Total constr time	*years*	1.75	1.75	1.75
Economic life	*years*	25	25	25
Load factor pre-curtailment		11%	11%	11%
Load factor post-curtailment		11%	10%	11%
LCOE	*€/MWh*	**121.0**	**108.2**	**100.4**

Model approach: day-ahead power

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We project spot wholesale electricity prices using our industry-leading pan-European hourly dispatch model, based on economic fundamentals and calibrated for the RAs

What questions does it answer?

- What will be the level and volatility of future day-ahead and intra-day power prices, and their sensitivity to different scenarios and outcomes?
- How will assets be dispatched in these timeframes on an hourly basis?
- What energy gross margins will be earned by different generation assets and technologies?
- What will the level of 'uplift' be, above short-run marginal costs?
- How will hourly price 'shape' change over time?

Key inputs

- Scenario inputs: fuel and carbon prices, demand (growth and shape), plant build, plant retirement
- Detailed pan-EU plant level database: installed capacity, efficiencies, operating costs, operating constraints
- Cross-border interconnector capacity
- Detailed hourly wind and solar profiles

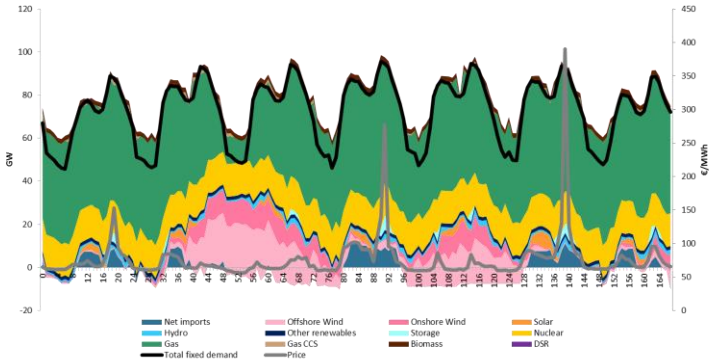
Model engine

- Hourly dispatch, least-cost optimisation framework using the PLEXOS platform
- Optimisation of operational constraints including start costs, ramp rates, heat rates
- Maintenance scheduling and unplanned outages

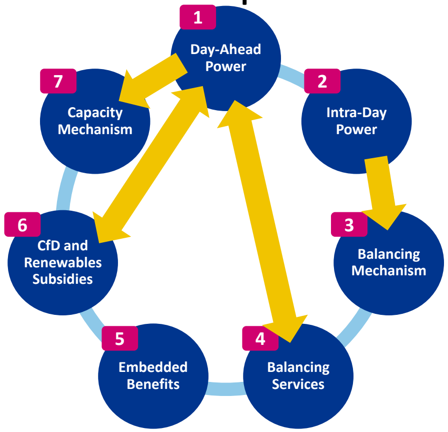
Key outputs

- Wholesale electricity prices
- Generation schedules
- Asset energy revenues and gross margins
- Emissions
- Dispatch costs
- Cross-border flows (imports / exports)

Illustrative schematic



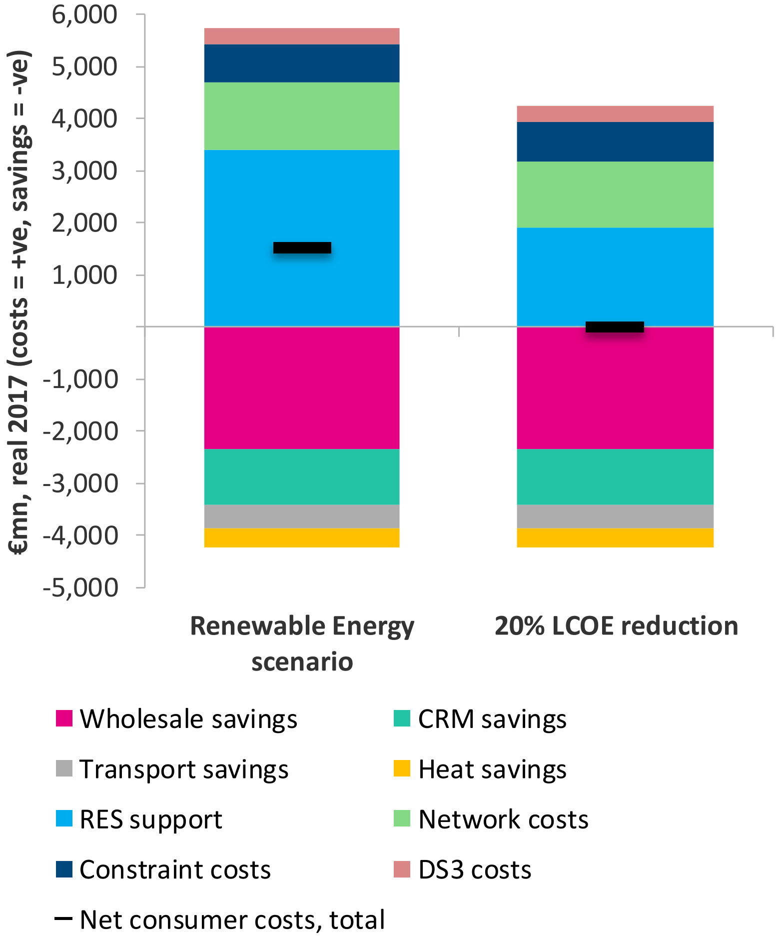
How does it relate to other components?



Headline results

Our analysis indicates that a 2030 70% all-island RES-E scenario is cost neutral for end consumers in the Republic of Ireland with a 20% LCOE reduction

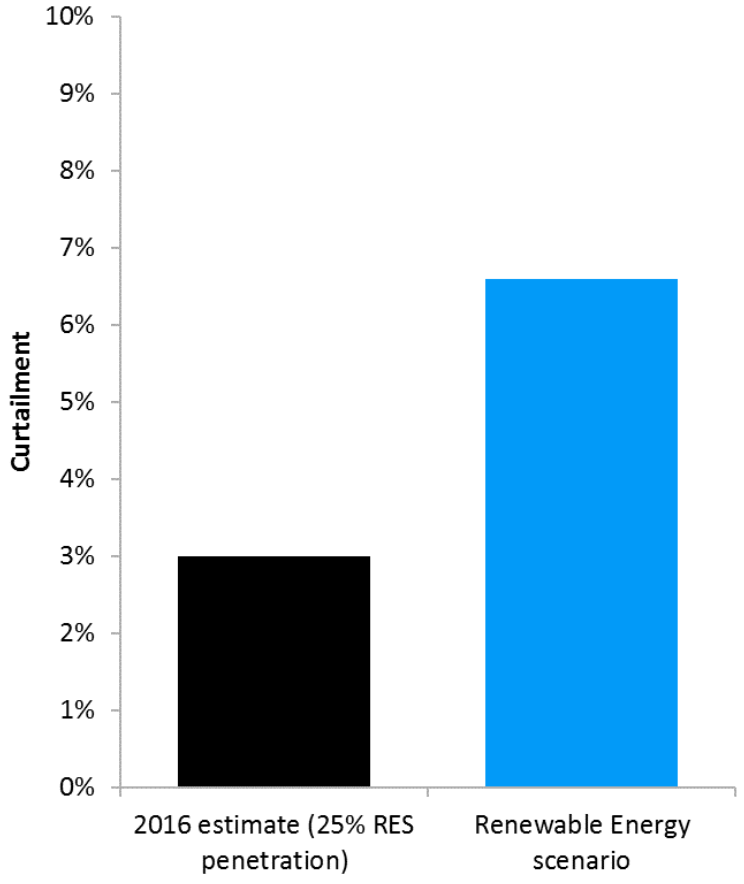
- For the Renewable Energy scenario, our analysis indicates a net consumer cost of around € 1.5 bn, with RES support, constraint costs, network costs and DS3 costs offset by:
  - Lower wholesale electricity prices, driven by the high RES-E deployment, leading to lower end consumer energy costs
  - CRM cost savings, as less conventional thermal new build is required
  - Transport and heat savings
- Our calculations show that a modest 20% reduction in LCOEs, equivalent to reducing the large onshore wind LCOE to €61/MWh, for the Renewable Energy scenario results in breakeven for the Irish consumers



Curtailment

With deployment of flexible technologies and improvement in the SNSP limit, 70% RES-E can be achieved with curtailment levels that rise only incrementally from today's levels

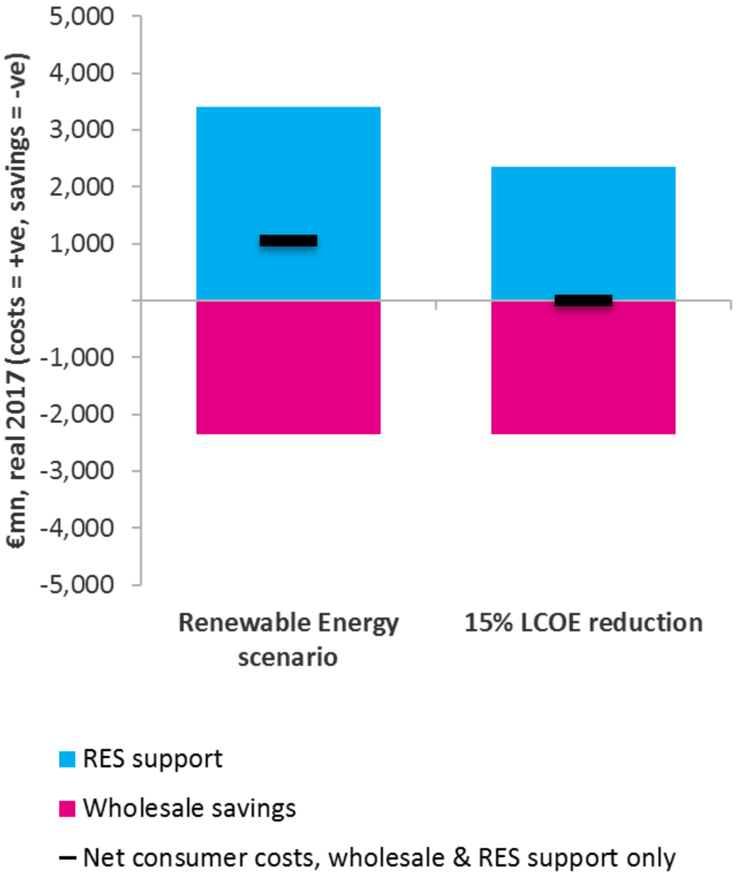
- We model curtailment using our 'constrained' model of I-SEM, which replicates the key system constraints such as the SNSP limit and min gen (system stability) constraints
- Under the Renewable Energy scenario, the resulting curtailment of renewables is around 6.5%, versus the current level of around 3-4%
- The deployment of additional flexible technologies such as battery storage, electric vehicles and heat pumps helps to mitigate against the increased RES-E levels
- The assumed increase in the SNSP limit to % by 2030 is also an important mitigant
- The 'cost' of wind curtailment is reflected in our analysis through (i) increased LCOEs due to reduced generation output, and (ii) constraint costs



Wholesale and RES support costs

Consumer electricity cost savings are significant in the Renewable Energy scenario, and help to substantially offset the cost of RES support

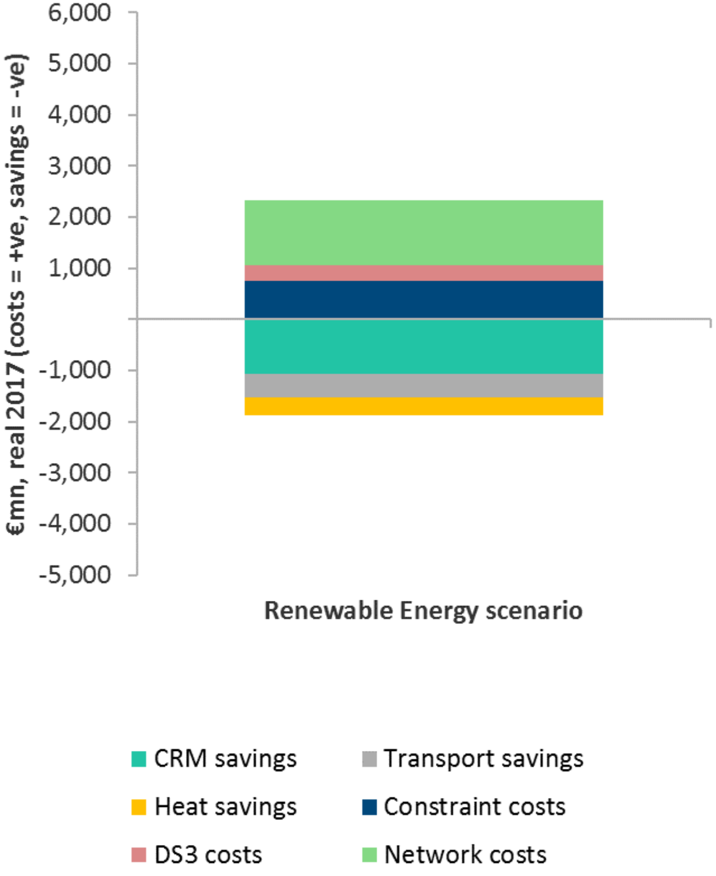
- The reduction in wholesale electricity prices is due to the "merit order effect" of zero marginal cost renewables
- Savings are most significant from 2025 onwards
- The required RES support is a function of both the cost assumptions for renewables, and the 'captured price' achieved for renewable generation in the wholesale market
- Additional flexibility helps to increase captured prices for wind and solar PV in particular, which is an important factor in reducing RES support costs
- Our calculations show that a modest 15% reduction in assumed LCOEs over the baseline assumptions, equivalent to reducing the large onshore wind LCOE to €65/MWh is sufficient to make RES support and savings in the wholesale electricity market cost neutral for end consumers in the Republic of Ireland, but this is before other external costs and savings are taken into account



Other costs and benefits

We have calculated the value of CRM savings, heat and transport savings, and constraint costs for each scenario

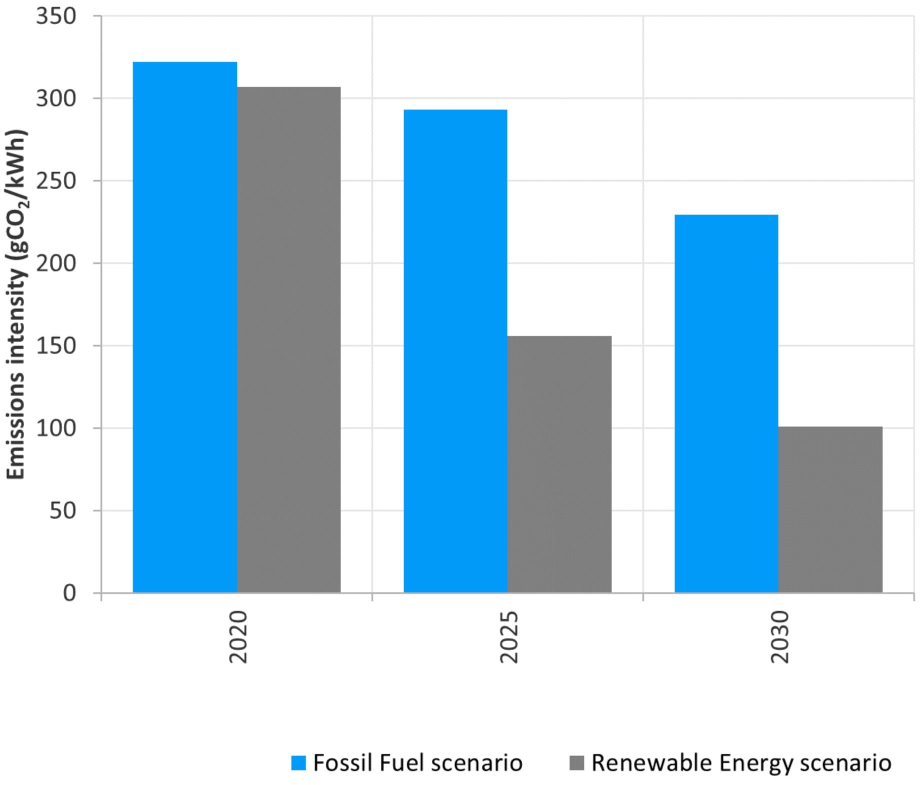
- Constraint costs increase in the Renewable Energy scenario, versus the Fossil Fuel scenario, largely due to greater volumes of wind curtailment, as the SNSP constraint binds more frequently
- There is also an increase in DS3 costs in the Renewable Energy scenario
- CRM cost savings are significant however, as the additional renewable deployment makes a material deployment to the de-rated peak capacity margin and so displaces the need for costly thermal new build
- We have calculated the savings in the heat and transport sectors which are largely driven by avoided fuel costs, offset by higher upfront capital expenditure



Emissions

Power sector emissions intensity declines steeply in the Renewable Energy scenario to around 150 gCO_2/kWh in 2025 and 100 gCO_2/kWh in 2030

Projected emissions intensity for the modelled scenarios



Boundary conditions in our modelling

- We have presented the costs and benefits of each scenario as a simple sum across the time period 2020-30
- This is not strictly correct, but matches the approach used by CEPA in their analysis for DCCAE
- An NPV analysis based on a social discount rate may be more appropriate – this would reduce reported NPVs to some extent
- Although our analysis does not account for the additional cost of the flexibility measures in the 70% RES-E cases, previous analysis suggests that measures such as battery storage and additional interconnection could be self-financing – particularly at higher levels of renewable deployment
- We have not directly modelled network costs within the scope of this study, however, ‘constraint costs’ are a basic proxy for the ‘value’ of system / network constraints

Conclusions

Our analysis indicates that a 2030 70% all-island RES-E scenario, with a plausible 20% LCOE reduction, is cost neutral for consumers in the Republic of Ireland

- For the Renewable Energy scenario, our analysis indicates a net consumer cost of around € 1.5 bn, with RES support, constraint costs, network costs and DS3 costs offset by:
  - Lower wholesale electricity prices, driven by the high RES-E deployment, leading to lower end consumer energy costs
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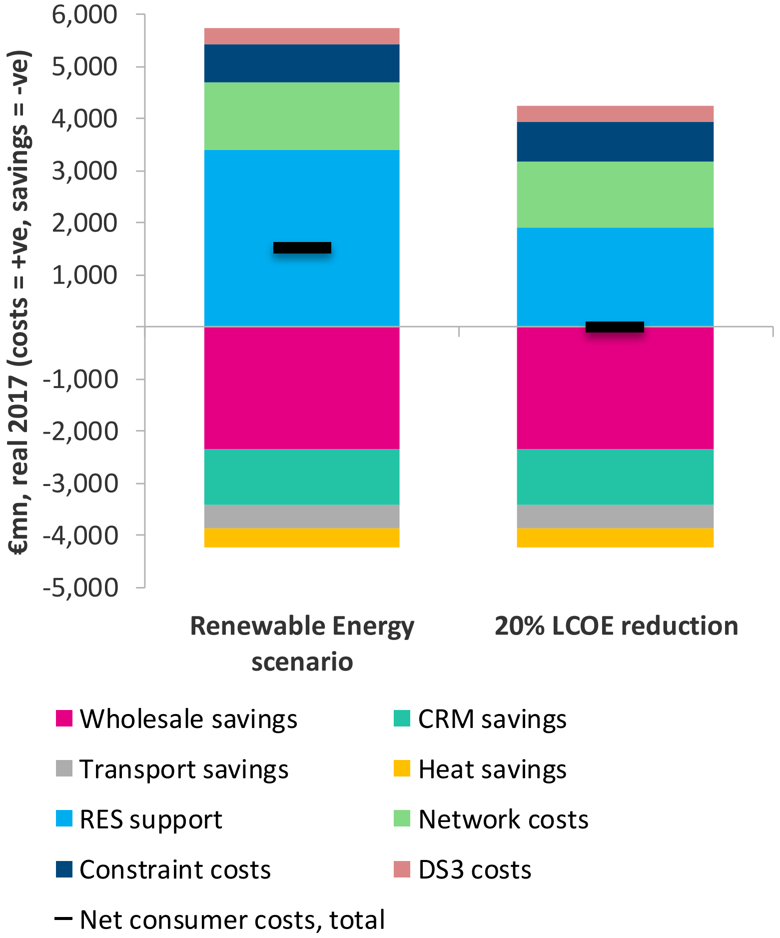


Annex A: Modelling approach

Model approach: power market modelling platform

Our leading-edge platform models energy, capacity, balancing mechanism and balancing services markets holistically – critical as today's assets capture value across multiple markets and timeframes

Background

- We have a deep heritage in modelling energy markets, dating back to the mid-1990s
- We invest continually in our people, models and data to ensure we remaining at the leading edge of energy market analysis
- We are a team of 50 located across Europe servicing clients globally which rely upon our analysis across different asset classes
- Markets are continually transforming – our approach constantly adapts and helps anticipate change

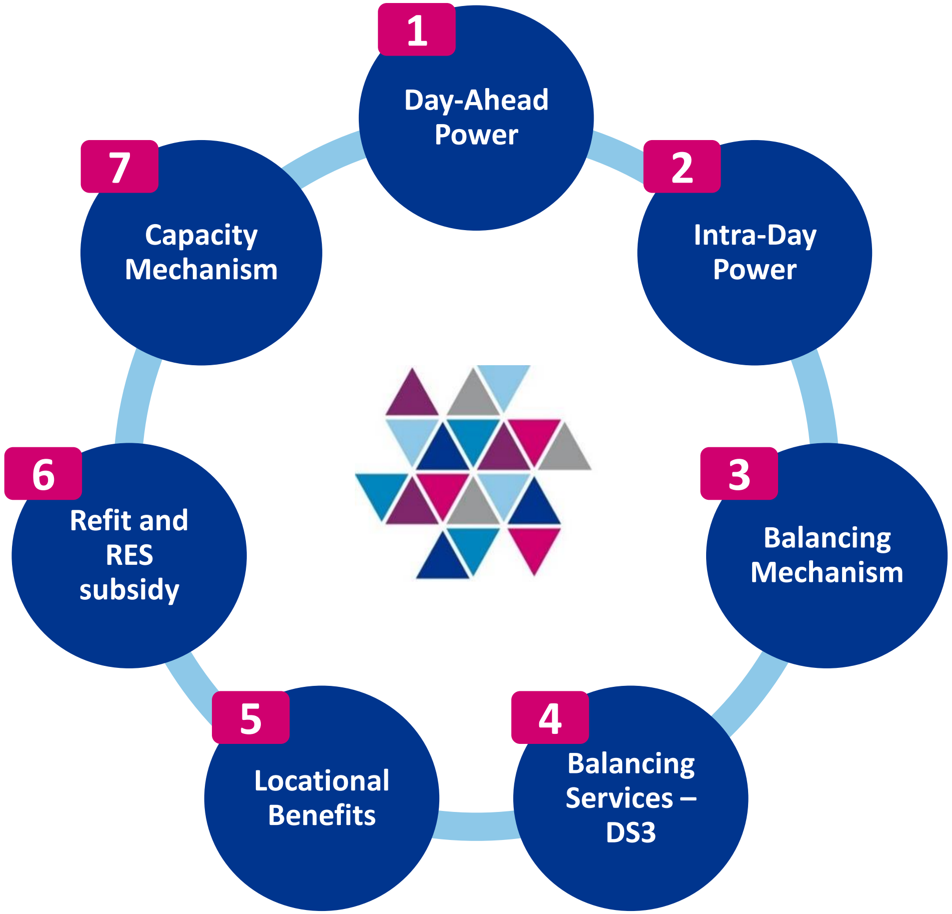
Approach

- Our approach combines insightful and consistent scenarios with probabilistic analysis
- Today's power market is comprised of inter-related products delivering energy, capacity and flexibility across multiple vectors of power, gas, transport and heat, over different time horizons
- We take into account the complex interplay between technology, infrastructure, demand, weather patterns, capital, market design, policy, behaviour and geographies

Core principles

- Transparency – we avoid a 'black box' approach
- Rigorous quality assurance, back-casting and calibration
- Consistent datasets and integrated platforms
- Integrated and internally consistent methodology across multiple different sources of revenue

Baringa power market modelling modules



1 Day-Ahead Power

2 Intra-Day Power

3 Balancing Mechanism

4 Balancing Services – DS3

5 Locational Benefits

6 Refit and RES subsidy

7 Capacity Mechanism

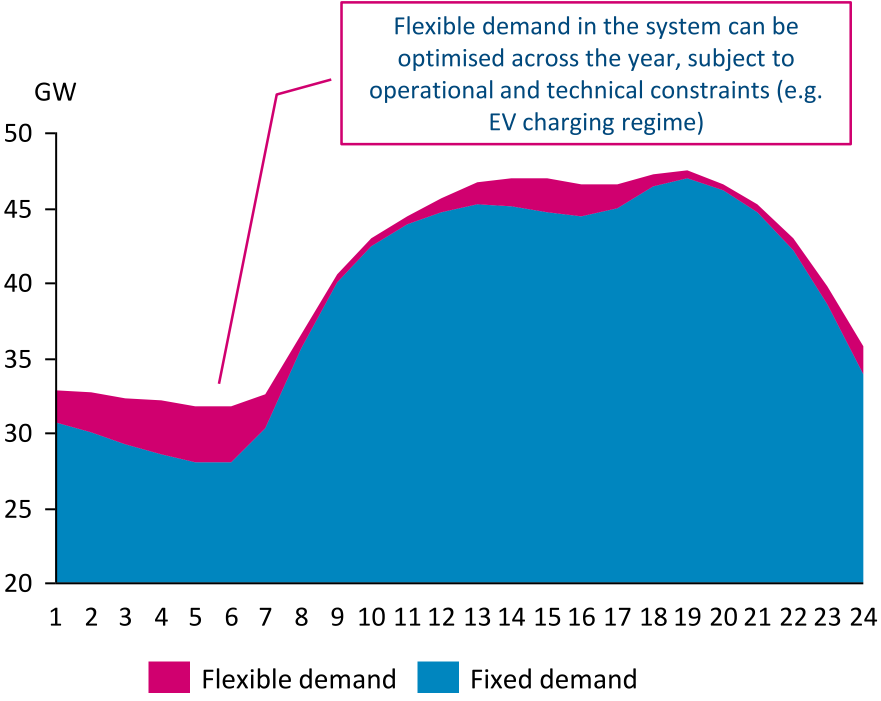
Annex B: Flexible demand modelling

Scenario assumptions: power demand and supply

Time of use tariffs (TOUT), smart home and increased consumer engagement could reduce system peak demand

- The demand in each hour in the PLEXOS market model is a result of the inflexible demand and the flexible demand in the system.
- The basis for the inflexible part of demand varies by type:
  - **BAU Demand**: Historical demand profile, based on the year 2012.
  - **Transport**: Fixed load profiles for unmanaged charging of electric vehicles, based on standard weekday and weekend profiles.
  - **Heating**: Fixed load profiles for inflexible heat demand from heat pumps, based on seasonal standard profiles.
- The basis for the flexible part of demand varies by type:
  - **BAU Demand**: Load shifting (i.e. shifting load from periods with high prices to periods with lower prices) and load curtailment (i.e. curtailing some load if it is more economic to do so) are considered in our modelling. The potential of flexible BAU demand is assumed to increase over time in line with Smart Meter roll-outs in the residential sector and the increasing exploration of demand side flexibility in the industrial and commercial sectors. This refers to applications such as heating, ventilation and air conditioning of commercial buildings, refrigeration, dish washers, laundry driers, washing machines and other residential applications, flexible loads in heavy industry (e.g. electric steel, cement, aluminium, paper recycling, etc.).
  - **Transport**: Electric vehicles (EVs) plugged to the grid may be charged on the basis of prevailing power price signals. The demand side flexibility provided by EVs, however, will be constrained by considerations such as timing, the size of their batteries, the amount of EVs that can be loaded at the same time etc.
  - **Heating**: This refers to flexible heating demand due to heat pump installations and subject to constraints such as storage and heat pump capacity, maximum withdrawal/injection rates, and efficiency losses. The model needs to meet a total amount of heat over a certain period but shifts flexible heating demand to ensure that this is generated in a price optimal manner.

Example



Flexible demand in the system can be optimised across the year, subject to operational and technical constraints (e.g. EV charging regime)

- The chart shows the load for a typical day, split out by flexible and fixed demand.
- The flexible demand is moved to night time hours with low fixed demand and to mid day hours with high solar generation.

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