ENERGY SECURITY BOARD

CAPACITY MECHANISM

SUMMARY OF INTERNATIONAL CASE STUDIES

MARCH 2022

INTRODUCTION

- As part of its detailed design process, the ESB commissioned NERA to undertake case studies of five capacity mechanisms in international jurisdictions to understand, in detail, how they work, and to draw any possible lessons for the NEM
- This pack is designed to summarise NERA's findings to share the important information and lessons from this work
- The jurisdictions studied were: Great Britain, PJM (Pennsylvania – New Jersey – Maryland), Ireland, France and California
- This pack contains a high level summary of each mechanism and a summary of the performance of the regime along with any lessons that might be relevant for Australia
- The appendix contains more detail on each mechanism

CONTENTS

UK – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- The scheme was introduced in 2014 (first auction, with the first delivery year in 2016) alongside a contracts for difference scheme designed explicitly to support renewables
- Renewables that receive subsidies through this separate mechanism are ineligible to participate in the capacity mechanism
- The British capacity mechanism is technology neutral, but emissions limits were introduced in 2020:
  - There are carbon intensity limits (rate of emissions) and also yearly emissions limits
  - These apply to generators commissioned after July 2019 for all auctions beginning in 2021 and all generators from delivery year 2024/25 onwards
  - This will disqualify coal and diesel from receiving capacity payments from the relevant year
- Electricity is procured bilaterally within an integrated zone that covers Great Britain excluding Northern Ireland, with any uncontracted capacity being sold and allocated via the balancing mechanism. The balancing market has a £6,000 per MWh price cap

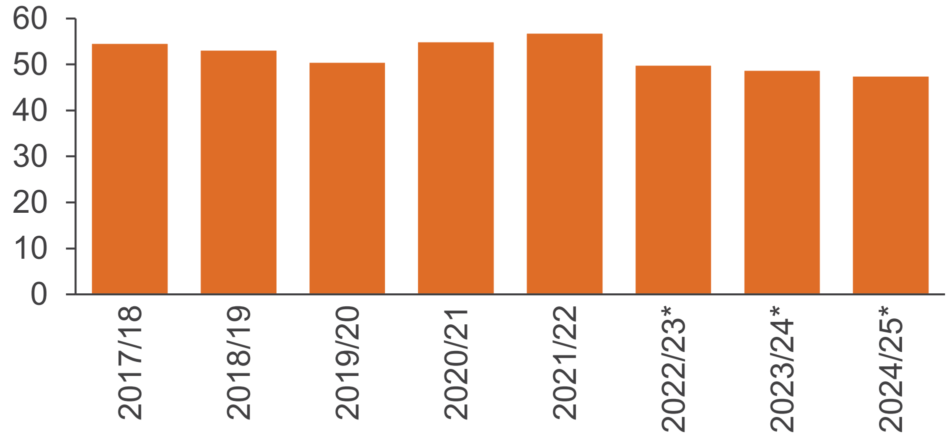
Design aspect	Summary of design choices*
Capacity definition	• Capacity providers make capacity available during "system stress events" (defined by the system operator) with four hours of notice • Derating factors differ by technology type (dispatchable generation, storage, interconnectors, demand response and VRE)
Forecasting methodology and determination of capacity certificate demand	• Centrally determined demand curve, set by the Government on advice of the system operator • The system operator undertakes scenario-based modelling based on publicly available future energy scenarios, each of which specify assumptions around peak demand events, generation capacity and interconnectors • Modelling is a "least worst regrets" analysis of the optimal amount of capacity to procure based on the range of forecast scenarios
Certificate trading and procurement methods	• Centralised auctions run at T-4 and T-1 • The system operator deliberately under-procures in the first auction to leave some residual capacity to be procured at T-1 • Existing capacity contracts are one year, with refurbished plant receiving contracts up to three years in duration, and new plant receiving up to 15 year contracts • Secondary trading permitted but rare in practice
Transmission constraints and interconnection	• The capacity mechanism does not account for transmission constraints within the Great Britain system – all capacity is procured without concern for location • Locational constraints are accounted for using a separate mechanism whereby generators near urban areas pay lower annual charges • Interconnectors can participate in the market, with capacity assessed based on net transfers into Great Britain during system stress events. Their derating factors are highly volatile year-on-year
Market power mitigation	• There are bidding rules depending on type of capacity: new build plants and demand response units are "price makers" and allowed to submit bids up to the price cap of 1.5x net cost of new entry (CONE), existing generators and interconnectors are "price takers" which can only submit bids up to a cap of 0.5x net CONE • Existing generation is required to participate
Penalties, compliance and incentives	• Penalties apply to capacity providers who do not perform during system stress events • Penalties are capped at 2x monthly capacity revenue and 1x annual capacity revenue • Over-delivery during system stress events is awarded at the penalty rate

* More detail in appendix

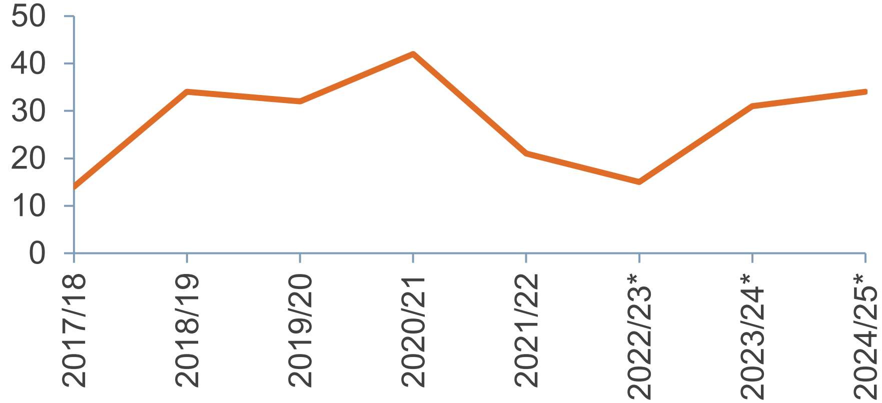
UK – PERFORMANCE OF REGIME

- Despite the investment certainty provided by the longer tenor contracts awarded, new capacity contracted through the auction has not necessarily actually been delivered
  - 1.9GW of capacity (a new CCGT plant) that was secured in the first T-4 auction was never built and the proponent cancelled its capacity contract
- The scheme appears to have achieved its reliability objectives: since the start of operation, there have been seven “notices” but no events in which the system operator would have to disconnect demand
- The scheme has arguably overprocured as loss of load events have been significantly lower than the target amount (under 0.1 hours in 2018-19 to 2020-21 vs a target of 3 hours per year)

Capacity procured in past UK auctions (GW)



Unit price of capacity procured in past UK auctions (A$ per kW)



* T-4 auction results only as T-1 auctions yet to take place

Source: UK Electricity Market Delivery Body (2021), NERA

UK – POINTS OF INTEREST AND LESSONS

- **Sufficient penalties are required in order to guarantee new plant will deliver on contracts:** capacity providers that terminate their contracts have the penalty capped at the capacity revenue – in other words, they are no worse off than if they never had a contract. This is insufficient to guarantee plant actually gets built and as a result, historical projects which have won capacity contracts have not eventuated in the physical market
- **Treatment of demand response is challenging:** the UK system subjects demand response providers to testing requirements which can be difficult to perform (e.g. requiring demand response providers to demonstrate reductions in load when it is not economic for consumers to reduce load), especially for new demand response providers. Derating treatment of demand response has been the subject of successful court challenges
- **Interactions with other government mechanisms can lead to inefficient outcomes:** early capacity mechanism auctions resulted in large amounts of new inefficient diesel-powered generators to enter the market, connected to the distribution system. This happened because the diesel generators benefitted from another government scheme which supported distribution-connected generation. This was remedied in later years
- **The scheme explicitly values dispatchable capacity, with a separate scheme to support renewables, and does not allow any capacity to participate in both schemes:** the British capacity mechanism theoretically includes variable renewable energy generators as eligible participants, but in reality they are virtually all excluded based on their involvement in the separate scheme to underwrite renewables

PJM – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- Pennsylvania – New Jersey – Maryland Interconnection (PJM) serves all or parts of 13 states in the US
- World's largest centrally dispatched electricity grid
- The capacity mechanism is highly complex, with detailed regulations covering virtually every aspect of the scheme
- 27 local delivery areas, but with a different locational price at every delivery point
- Wholesale energy price offers are capped at US$1,000 per MWh, unless the bidder can demonstrate they have a cost-based reason for an offer above that level, up to US$2,000 per MWh (make-whole payments can be above this if needed, but the market price cannot rise above this level)
- Interestingly, the mechanism is a hybrid decentralised and centralised mechanism: retailers can self-fulfil their resource adequacy requirements (for vertically integrated players) or participate in the centralised scheme
- Rule changes are frequent in the PJM capacity mechanism, as are legal challenges to various aspects of its operation

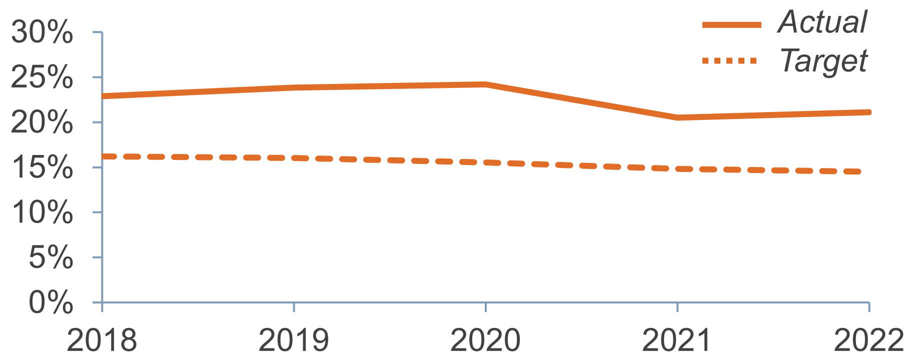
Design aspect	Summary of design choices*
Capacity definition	• Split into two delivery seasons – summer and winter. Capacity can be sold differently for each season • Derated capacity must be available for emergency events between 10am and 10pm in summer and 6am to 9pm in winter • Capacity providers can include: generators, demand response, energy efficiency, aggregated resources (combination of other resources acting as a single bidder) and transmission upgrades • Derating methodology varies for each resource type
Forecasting methodology and determination of capacity certificate demand	• PJM centrally determines reliability requirements • Requirements are determined on a "local delivery area" level and also at a PJM-wide level • Modelling accounts for non-coincident peak load on a day as a function of calendar events (e.g. weekdays, holidays, etc), weather data and other trends • The projected peak plus a specified installed reserve margin (most recently 14.4%) informs the demand curve • If local delivery areas are constrained, they have a separate reliability requirement
Certificate trading and procurement methods	• Vertically integrated retailers can opt out of the mechanism and "procure" their share of the reliability requirement from within their own portfolio. This capacity must still be certified and derated centrally • Other capacity is procured by the system operator in an auction, with auctions at T-3 (which aims to procure all the required capacity) and 20 months, 10 months or 3 months before if required
Transmission constraints and interconnection	• Transmission upgrades can enter into auctions to increase transmission availability into constrained local delivery areas (they may increase connectedness of a "sink area" with a "source area") • If the transmission is successful in an auction, it is paid the difference in price between the sink area and the source area • Existing transmission cannot participate in the auctions – only new projects
Market power mitigation	• There are extensive rules to regulate bids into the capacity mechanism auctions • "Pivotal suppliers"* are subject to market seller offer caps • New generation is subject to other offer caps which are dependent on the average location-adjusted sell offers • A minimum offer price rule applies to a subset of generation – most recently any subsidised generators*
Penalties, compliance and incentives	• Capacity providers with capacity contracts are subject to non-performance charges (including those that are part of a decentralised retailer portfolio and those who bid into the central auction) • The penalties are awarded as revenue to overperforming resources • Other penalties also apply

* More detail in appendix

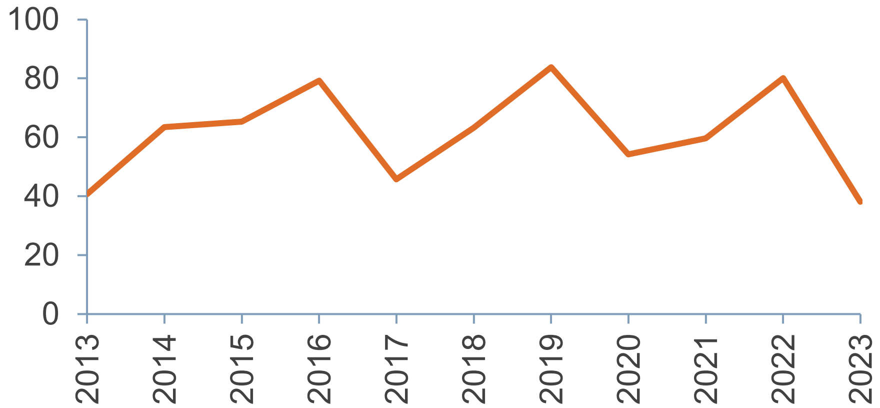
PJM – PERFORMANCE OF REGIME

- The PJM capacity mechanism has successfully procured a large number of new projects over its years of operation (59 GW since 2008), from a variety of capacity sources including: OCGT, CCGT, diesel, hydro, steam, nuclear, solar, wind and fuel cell batteries
- For the 2023 delivery year, almost 9 GW of new capacity has been procured, mostly CCGT
- The capacity mechanism has consistently over-procured relative to the target reserve margin
- Performance assessment intervals have been very rare throughout the operation of the capacity mechanism, suggesting that the level of procurement has been more than sufficient to meet reliability requirements

Actual vs target reserve margin



Unit price of capacity procured in past auctions (A$ per kW)



Source: NERA analysis on publicly available data from PJM

PJM – POINTS OF INTEREST AND LESSONS

- **The hybrid centralised and decentralised system is a point of interest:** it is unusual in a global context as it allows vertically integrated participants to contract for their own needs. This may be an option in Australia, where there are vertically integrated players, however the benefits of such a model are unclear (versus a model that required all generators to participate in the central auction)
- **Transmission upgrades can compete with generation to provide locational capacity:** this is a theoretical point of interest, however no transmission upgrades have actually cleared an auction in PJM
- **Incremental auctions can increase liquidity in capacity contracts:** this may reduce the risk of non-delivery for new capacity by offering an option to “trade out” of their capacity obligations in a delivery year if there are construction delays
- **Permitting a wider range of resources to enter capacity mechanism auctions may be more efficient but also requires much more regulation:** different types of capacity (e.g. energy efficiency and transmission upgrades) need to be derated and monitored differently
- **Competing policy objectives have resulted in issues with operating the mechanism:** tension between competing objectives (e.g. decarbonisation vs undistorted competition) have led to delays in auctions for multiple years, which may undermine the ability of the mechanism to attract long-term investment, particularly if delays continue
- **There are strong incentives to follow through with commitments to build new capacity:** significant penalties for failing to meet targets has incentivised successful delivery of significant amounts of new capacity

FRANCE – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- Mechanism launched in 2016, with first delivery year in 2017
- Market context:
  - The electricity market is highly concentrated
  - Electricite de France (EDF) is the largest retailer (80% of residential customers)
  - EDF owns ~55% of the capacity guarantees traded through the capacity mechanism
  - EDF also owns distribution and transmission assets
- On the generation side, the market is highly dependent on nuclear, which is large and inflexible plant
- The French mechanism is decentralised, with obligations on both retailers to procure capacity guarantees and capacity operators to provide capacity during peak periods
- There are three separate schemes to support different kinds of capacity: the capacity mechanism, which awards one year contracts to capacity based on contribution to reliability, a separate underwriting scheme which supports demand response and batteries (up to 7 year contracts), and a third which underwrites renewables

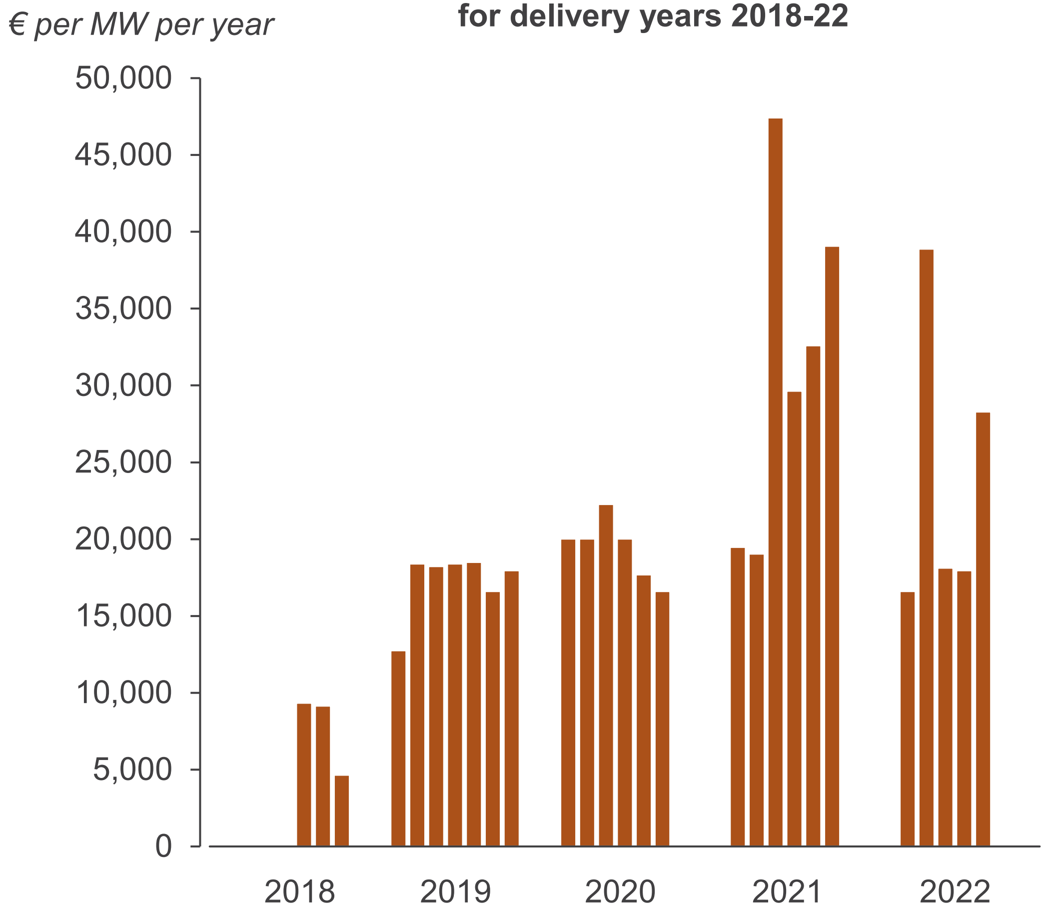
Design aspect	Summary of design choices*
Capacity definition	• Market operator certifies capacity • Must perform during defined peak days – on peak days, all periods between 7am-3pm and 6pm-8pm are peak periods • Notice is given the day before a peak day • There are a fixed number of peak days each year, with additional restrictions around how many can be in each season • De-rating uses a combination of historical data (non-dispatchable), calculation of duration of capacity (dispatchable), and a technology scalar (e.g. solar scalar is 0.25)
Forecasting methodology and determination of capacity certificate demand	• Forecasting is done by retailers • Based on consumer demand during peak periods • Compliance is determined ex post, based on the actual average consumption of the retailers' consumers during peak periods, and a "security coefficient"
Certificate trading and procurement methods	• Auctions and over-the-counter bilateral trades • At least 15 auctions cover every delivery year (across T-4 to T-1) • Can be traded during and after the delivery year
Transmission constraints and interconnection	• Capacity guarantees can come from anywhere in mainland France – there is no adjustment based on location • Interconnectors can be awarded certificates, which are held by the network operator and sold on to obligated parties
Market power mitigation	• Requires internal transfers of capacity guarantees (e.g. from a wholesaler arm to a retailer arm) are made at a price representative of auction prices • Requires all trades to be recorded in the capacity guarantees register
Penalties, compliance and incentives	• Ex-post compliance on obligated parties and capacity providers three years after the delivery year • Assessment made in aggregate over a delivery year (overdelivery on some days can cancel out underdelivery on others) • Penalties for underdelivery in aggregate are up to 1.2 times the capacity price for that delivery year, while overdelivery generally receives 0.8 times the price of capacity for the delivery year

* More detail in appendix

FRANCE – PERFORMANCE OF REGIME

- New capacity is procured through the separate underwriting scheme and awarded multi-year contracts. The scheme is very new and has only awarded contracts to battery and demand response projects
- Prices in capacity mechanism auctions have been volatile and increased on a unit basis in recent years
- Auctions only represent roughly one third of procurement under the scheme (the rest done bilaterally and not transparently), so it is difficult to track the performance of the scheme based on publicly available data
- As the scheme is in very early years of operation, it is arguably too soon to make an assessment of its impact on reliability in the French market

Results of French capacity mechanism auctions for delivery years 2018-22



Source: Flexcity 2021, NERA

FRANCE – POINTS OF INTEREST AND LESSONS

- **Decentralised scheme:** the French scheme places the responsibility and the risk of procuring capacity guarantees on retailers. They are incentivised to procure sufficient guarantees due to a threat of penalties, administered by the market operator
- **Separate mechanisms for long-term and short-term auctions:** the French policy landscape includes a separate mechanism that awards long-term contracts to low-carbon or carbon neutral generation (e.g. batteries). This is similar to the NSW roadmap in that contracts are only awarded to new capacity and take the form of a contract for difference (CfD).
- **Market power mitigation:** During the operation of the French capacity mechanism, market power measures have been introduced, including:
  - Transparency over bilateral over the counter trades to minimise information advantages for incumbents (data is anonymous)
  - Transfer pricing must be based on market prices
  - Regular auctions to promote liquidity
  - Requiring managers of portfolios over 3GW of capacity to offer capacity into the centralised auctions
- **Multiple platforms for procurement:** the mechanism allows both centralised auctions and bilateral procurement

CALIFORNIA – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- California's mechanism is a decentralised system
- There are three types of retailers ("load serving entities"):
  - Investor-owned utilities (three dominant ones with some minor players)
  - Community choice aggregators (not for profit providers which usually serve a specific, small geography)
  - Municipal utility districts (some municipalities directly own electricity companies)
- The wholesale market is quite fragmented – investor-owned utilities have some generation capacity, but not a commanding share
- There are different types of requirements placed on load serving entities, which must procure:
  - System resource adequacy products
  - Local resource adequacy products
  - Flexible resource adequacy products (which are divided into a further three categories)
- The system is decentralised because the obligation is placed on load serving entities to procure the contracts, but has centralised compliance

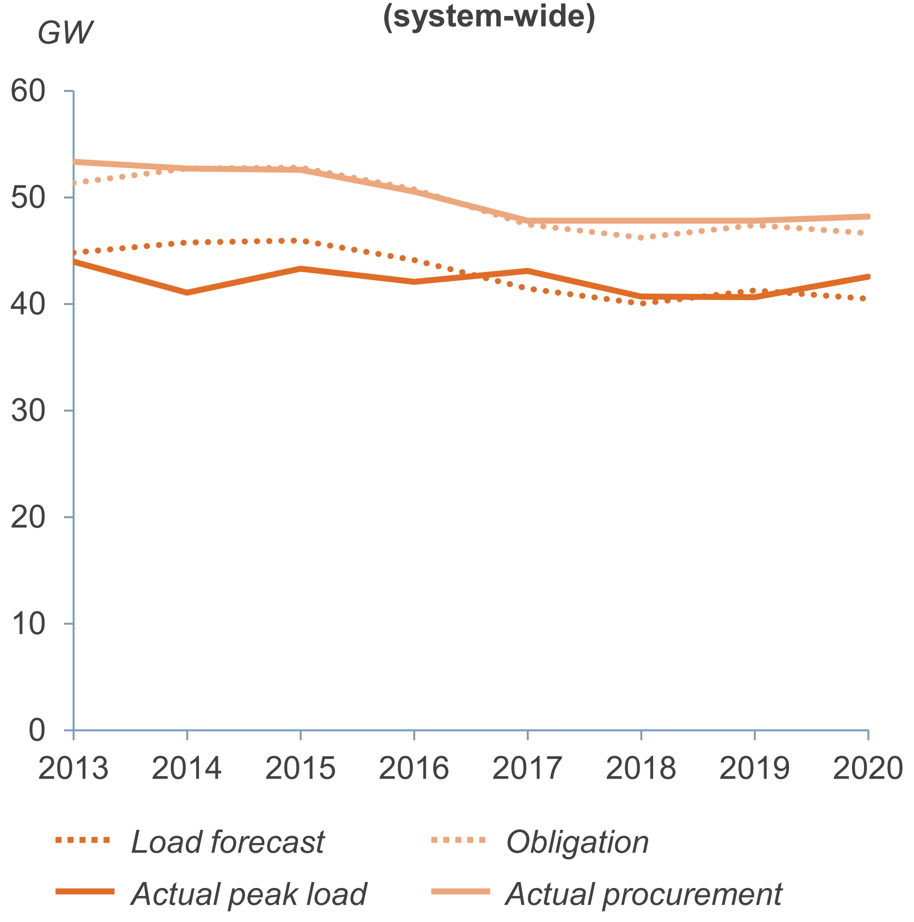
Design aspect	Summary of design choices*
Capacity definition	• Contracts are written and assessed on monthly periods • Three types of contracts: system agreements, local agreements (where load serving entities must show they have enough local capacity to meet the required level) and flexible agreements (where resources must be available within a 3 hour ramp period – this is further separated into three categories which each have their own specific requirements*) • Different methods are used to de-rate different technology types. All technology must be certified and de-rated by the system operator
Forecasting methodology and determination of capacity certificate demand	• Forecasting mostly sits with the market operator, which can assess load serving entities' procurement levels at different times on an ex-ante basis • There is a mandated reserve margin over the peak demand forecast (15%, although this increased to 17.5% for summer months in 2021 and 2022) • There are different requirements for each of the types of required agreements (system, local and flexible)
Certificate trading and procurement methods	• Trading and procurement is totally decentralised and can occur at any point up until load serving entities are assessed • There is an element of forced centralised cost allocation through a "Cost Allocation Mechanism", which can occur if the market operator requires the investor-owned utilities to procure new generation on a case-by-case basis. In this instance, all costs and benefits of the procurement are allocated to the relevant customers. This is a separate, but related mechanism
Transmission constraints and interconnection	• The local procurement requirement addresses the issue of transmission constraints because load serving entities are required to purchase capacity in a way that reflects local transmission constraints • Interconnectors are also accounted for under this system because load serving entities can procure system agreements from resources across an interconnector
Market power mitigation	• A "waiver rule" for local requirements where load serving entities can opt out of some requirements if they can demonstrate they did not receive any reasonable offers • CAISO can act as a backstop to directly procure capacity not otherwise contracted (for a fixed rate)
Penalties, compliance and incentives	• Load serving entities face penalties for non-compliance with each of the three separate requirements • Capacity providers who have sold contracts must offer their capacity at the pre-defined times, but do not actually face a penalty for failing to perform

* More detail in appendix

CALIFORNIA – PERFORMANCE OF REGIME

- In 2020, on a system-wide level, the load serving entities collectively met their system requirements, but there were some shortfalls in respect to local requirements
  - In five of the ten regions, retailers would have had to request a waiver from the scheme or pay a penalty, with the remaining capacity procured by CAISO as a backstop
- Even though forecasts have been a good reflection of actual load in recent years, and retailers have covered their required positions in aggregate, (pictured right) the system has faced reliability events in recent years. These have been attributed to extreme weather events, planning targets that have not accounted for the changing grid requirements in transitioning to renewables, and practices in the day-ahead market that exacerbated supply problems

Procurement in capacity mechanism vs peak load (system-wide)



Source: CPUC, NERA

CALIFORNIA – POINTS OF INTEREST AND LESSONS

- **Difficulty in sending investment signals through a decentralised mechanism:** the mechanism has only recently (in 2020) introduced a requirement for load serving entities to purchase contracts more than a year out from a delivery year. Before this, there was minimal long term capacity contracting (that has been publicly reported). Under the new model, load serving entities must contract 100% of their requirements two years in advance and 50% three years in advance, which is still a shorter investment signal than most centralised mechanisms
- **Clear methodology can mean less technical grounding for decisions:** the methodology for the Californian system is relatively uncomplicated (e.g. penalties for not complying with the system resource agreement requirement are $6.66/kW month, and the local penalties are half that amount), but it is not necessarily based on economic efficient reasoning
- **Different requirements serve different purposes:** the three separate requirements that load serving entities must meet are not co-optimised into one market, but assessed completely separately. This places a compliance burden on load serving entities to procure the minimum amount to meet all three requirements, with no ability to trade-off between them
- **Performance obligations:** the Californian system has no performance obligations for capacity providers. As such, load serving entities can have achieved their required procurement targets, but the system can still face a reliability event. Dispatchable generation is subject to some penalties for not offering into the market, but these do not become steeper in events of actual system need.

IRELAND – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- Irish market covers Northern Ireland and the Republic of Ireland in an integrated system
- This system uses a "reliability option" model where capacity is incentivised by a market-based wholesale price rather than administrative penalties
- The current mechanism was implemented in 2018, but replaced a more administrative, less market-based system that previously existed to hand out explicit capacity payments
- In 2018, alongside the new capacity mechanism, the integrated Irish system also introduced a day ahead market, an intra-day market and a balancing market
- There is a high concentration of market power
- There are three main zones – Dublin, the Republic of Ireland outside Dublin, and Northern Ireland. Significant transmission constraints separate these zones
- There is a high penetration of renewables
- The system is very small (peak demand <10 GW) so exit or entry of one large plant has a huge impact

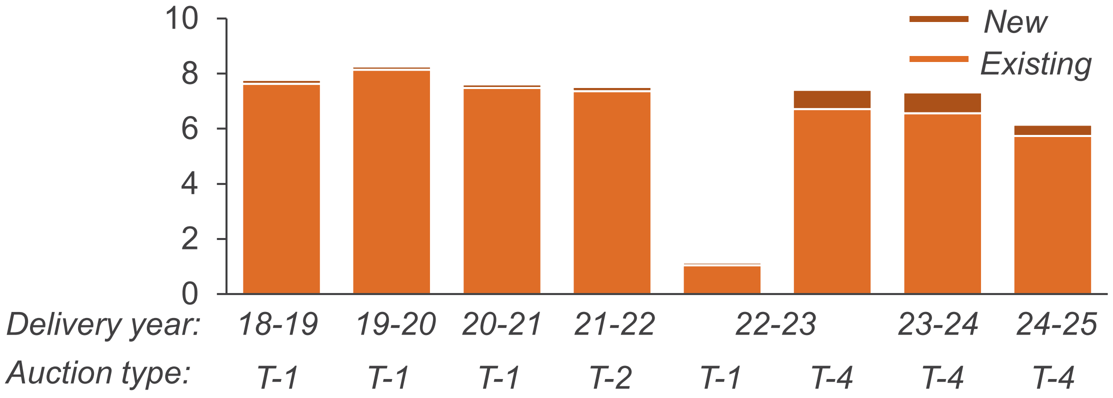
Design aspect	Summary of design choices*
Capacity definition	• Capacity is provided by thermal units, renewables, storage or demand-side units. Interconnectors (i.e. to Great Britain) can also participate in the auctions • Each type of capacity is de-rated using a different methodology
Forecasting methodology and determination of capacity certificate demand	• A central operator sets the demand curve based on modelling of future demand scenarios • The central operator also determines how much capacity is required in each zone (Dublin, Republic of Ireland excluding Dublin and Northern Ireland). If the amount procured in the central auction doesn't meet the requirements, accounting for constraints, in each zone, the central operator will award contracts to additional capacity providers in zones that were short
Certificate trading and procurement methods	• Central auctions at T-4, with additional auctions run in subsequent years if required to fill the capacity demand • Secondary trading is only permitted under certain conditions: if the unit is affected by an outage, if there are fluctuations in the availability of a unit's primary energy source (e.g. hydro, based on water levels), or if otherwise given an exemption to trade
Transmission constraints and interconnection	• The capacity requirements are set by zone as well as overall to account for the transmission constraints between zones • Otherwise, there is one integrated auction, and the marginal value of capacity in different zones is not accounted for • As discussed above, the market operator separately ensures that enough capacity has been procured to meet the requirements for each zone after the auction is complete • Interconnectors (from Great Britain) are included in the auction and de-rated based on technical availability (i.e. accounting for projected outages) as well as the modelled likelihood of availability of capacity to be exported out of Great Britain
Market power mitigation	• Strict bidding price caps for existing generation. The market has typically cleared very close to these price caps • More lenient bidding restrictions on new generation • All capacity required to offer into the auction unless granted an exemption (e.g. if a unit is planning to close)
Penalties, compliance and incentives	• Incentive built into the "reliability option" style capacity contract – similar to the structure of an Australian "$300 cap" – requiring generators to pay out the difference between the (blended) wholesale price and the strike price when wholesale prices are higher than the strike price • Termination charges apply to capacity providers who exit contracts ahead of the delivery year

* More detail in appendix

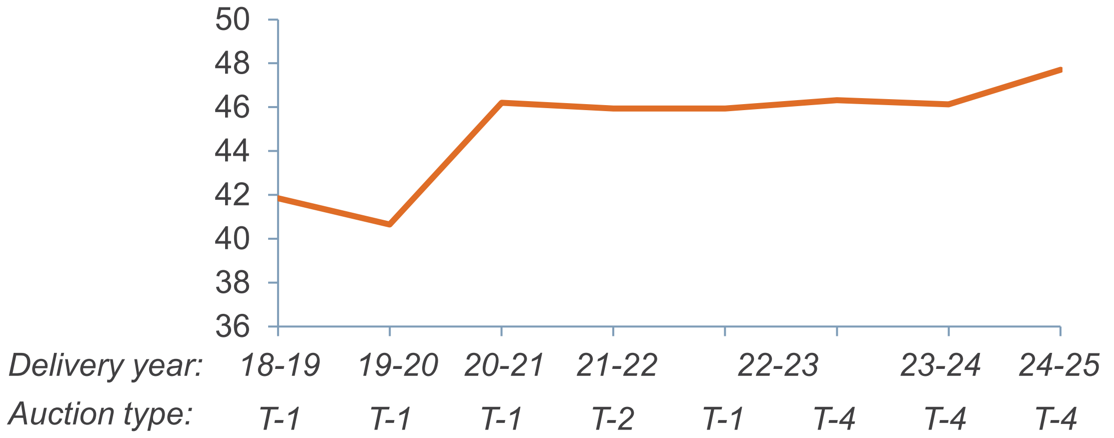
IRELAND – PERFORMANCE OF REGIME

- The scheme was introduced in late 2018 and as such, limited data on performance of the scheme exists
- **Cost:** annual procurement costs are between €300 and €400 million per year, or roughly €40-€50/kW-year.
- **Compliance events:** there have only been two compliance events (where the wholesale price has risen above the strike price) in the operation of the scheme, and neither resulted in a shortfall
- **Overall supply pipeline:** every year since its implementation, the Irish capacity mechanism has overprocured capacity. However, concerns remain about projected resource adequacy, due to:
  - Generation scarcity in Great Britain, and difficulty in accurately de-rating the interconnection capacity four years in advance
  - Closure of fossil fuel plants
  - Growth in electricity demand
  - New capacity failing to deliver (more detail on next slide)

Capacity procured in past Irish auctions (GW)



Unit price of capacity procured in past Irish auctions (€ per kW)



Source: SEM-O data, NERA

IRELAND – POINTS OF INTEREST AND LESSONS

- **Integrating interconnectors has posed a persistent challenge:** interconnector capacity represents a large proportion of the nameplate capacity available to participate in the Irish capacity mechanism, but determining an appropriate de-rating factor is extremely difficult, especially on a T-4 basis. Interconnector owners also do not influence the available flow over an interconnector so cannot respond to the incentives in the capacity contracts, unlike other participants. Additionally, most European interconnectors are subject to revenue caps, so capacity mechanism revenue may not affect investment to promote resource adequacy.
- **If penalties are insufficient, new plant may not actually be delivered:** in the short history of the current capacity mechanism in Ireland, 513 MW of new plant has failed to deliver. While the Irish mechanism has stronger penalties than comparable mechanisms (e.g. UK) within a delivery year and for existing capacity withdrawing from a contract before a delivery year, penalties for non-delivery of new plant appear insufficient. Penalties for early termination for new plants are set at a fixed per-MW fee if the contract is exited more than 13 months in advance of a delivery year.
- **The mechanism was specifically designed to be able to offer a longer-term investment signal:** the committee tasked with the redesign of the Irish capacity mechanism considered it was critical for longer-term contracts to be awarded. The mechanism awards up to ten year contracts for qualifying plant.
- **Locational incentives:** the Irish mechanism attempts to address transmission constraints between zones by procuring additional resources after the auction to meet zone-specific requirements if required. A more ideal design would have separate demand curves to reflect required capacity by zone, even if that resulted in different prices between regions. The current arrangement has resulted in successful litigation by participants that were forced to operate in constrained zones*

* More detail in appendix

APPENDIX 1 - GB

CAPACITY DEFINITION

Product Definition

- Capacity Agreements are a contractual agreement between System Operator and generators, whereby generators will be required to make the contracted amount of capacity available whenever the System Operator gives a Capacity Market Notice of system distress.
- This gives generators 4 hours' notice.
- The generator, in return, receives yearly payments.

De-rating

- Dispatchable: 7-year historical average availability during winter high demand periods.
- Storage units: Equivalent Firm Capacity of storage class (by duration).
  - For every block of extra duration provided to a Base Case (0.5-hour increments), simulations calculate how much firm capacity can be removed while reliability standard is maintained.
- Interconnectors: Stochastic simulations of GB and overseas markets run over 5 'Future Energy Scenarios' (FES) to create a country-specific de-rating factor
- DSR: De-rated on the basis of Average Availability of Non-BSC Balancing Services, measured under assessment of committed availability to provide Short Term Operating Reserves over the previous 3 Winters.
- Units in the same technology class receive the same de-rating factor.

Technology Neutral

- The mechanism is aimed at being technology neutral but is confined to some degree by fossil fuel limits put in place following the EU's Clean Energy Package.
- Emissions of a unit must not exceed 550g of CO_2 per kWh installed or 350kg of CO_2 per kW installed over the year
- This applies for all auctions beginning in 2021 for all generating units commissioned after 4th July 2019.
- For units commissioned before 4th July 2019, these emissions restrictions apply for all auctions for delivery year 2024/25 and onwards.

FORECASTING AND DEMAND

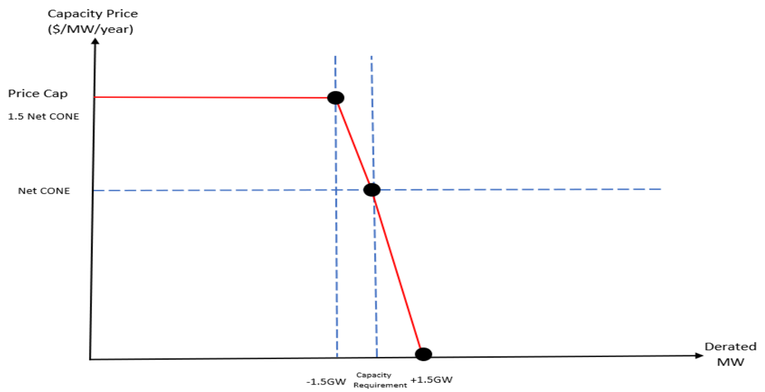
- Forecasting is centralised, the Secretary of State decides the target capacity on advice of the system operator, who publishes a yearly report based on simulated demand scenarios.
- Five Future Energy Scenarios (FESs), generated based on different assumptions about demand conditions.
- Dynamic Dispatch Model (DDM) used to generate de-rating factors and capacity requirements under each scenario
- This method provides i) total de-rated capacity required to meet 3 hours LOLE, ii) de-rated capacity to be secured in the CM auction, iii) de-rated non-eligible capacity expected to be delivered outside the CM, iv) total nameplate capacity split between CM and non-CM, v) de-rated capacity already contracted from previous auctions.
- Least-Worst-Regret analysis used to balance cost of over-procurement against cost of shortfall and select a target capacity requirement that minimises costs, while maintaining 3 hours LOLE standard.

Future Energy Scenario	Energy Demand
Base Case	Demand reduction and decarbonisation continues at a steady pace
Consumer Transformation	2050 net zero target is met, driven by greater consumer engagement in the energy transition. High peak electricity demands managed through flexibility. Low gas demand
System Transformation	Less disruption for consumers, most changes coming from supply-side. High hydrogen demand, produced through natural gas with CCUS
Leading the Way	GB decarbonises rapidly. Assumptions on different areas of decarbonisation pushed to earliest credible dates. Consumers highly engaged. Hydrogen used a lot, produced from electrolysis
Steady Progression	Progress on decarbonisation, however it is slow. Growth in EV means that smart technology is still important

PROCUREMENT AND TRADING

- The operator runs two auctions, one main one at T-4 and a balancing auction at T-1.
- Mandatory participation for existing generators and interconnectors.
    - Can opt out by proving capacity unavailability or failure to meet emission standards
- Price cap for ‘price-setters’ = 1.5 Net CONE
- Price cap for ‘price-takers’ = 0.5 Net CONE
    - Unless 0.5 Net CONE is demonstrably insufficient for a plant to remain operational.
- DSR eligible for multi-year contracts following EU ruling
- Descending clock auction
    - Start at 1.5 Net CONE, descend in £5/kW increments

Demand Curve



Secondary Trading

- There are restrictions on secondary trading, transferees of contracts must qualify in much the same way as participants in the auctions and new build must meet progress milestones before qualifying.

Cost Recovery

- Costs are recovered against retailers based on their contribution to total load in the system.
- Monthly charge levied to retailers: (Total annual payments to capacity provider) * (Monthly weighting factor) * (Ratio of retailer’s gross demand to total gross demand for all retailers)

TRANSMISSION AND INTERCONNECTION

- No locational pricing in the CM
- Interconnectors can participate in the CM, these have country-specific de-rating factors based on ESO modelling of capacity entering GB in system stress periods.
- This is extremely volatile as modelling for interconnectors is based on selected values from a wide range of sensitive assumptions. e.g. Ireland’s interconnector capacity for 2025/26 is between 10-97%.

MARKET POWER

- No locational pricing in the UK means that local market power is not an issue.
- No single firm can exercise significant market power on a national level.
- All generators are obligated to participate in the auction unless they can demonstrate that their capacity will not be available for the delivery year or that they will be in breach of emissions restrictions.
- Price caps of 1.5 x Net CONE and 0.5 x Net CONE for ‘price makers’ and ‘price takers’ respectively.
- Price caps exemptions may be granted if a generator can prove it is not operational at the price cap level.
- Mandatory participation and price caps prevent generators from withholding or driving prices upwards with high bid prices.

PENALTIES AND COMPLIANCE

- System stress event is defined as 15 or more continuous minutes of demand reduction due to a capacity shortage - Distinct from a network failure or demand disconnection.
- The operator must give four hours' notice that a system stress event could occur and will then make an assessment on whether a demand reduction or demand disconnection has occurred, or it is indeed a system stress event.
- It is during system stress events that generators are obligated to provide their contracted capacity.
- Penalty rate = 1/24th the clearing price for that delivery year. Penalty payments capped at twice the monthly revenue for a single month and for the year are capped at the total yearly revenue.
- Termination for failure to meet construction/financial reporting deadlines either £5/kW or £25/kW depending on reasons for termination.
    - Termination not only incurs a penalty fee but foregoes capacity payments, which are not paid until delivery year.

APPENDIX 2 - PJM

CAPACITY DEFINITION

Product Definition

- Capacity Obligation is a contract to provide 'Capacity Performance'
- Under this obligation, contracted capacity must be made available during emergency events between 10:00 and 22:00 during Summer (May to September) and between 06:00 and 22:00 during Winter (October – April)
- Contract can be held for the entire delivery year or on a Summer/Winter basis, though only approx. 0.5% of capacity is procured on this basis

De-rating

- Rated installed capacity adjusted to reflect the previous 15 years' summer peak (ICAP)
- This is de-rated by a unit's forced outage rate over one-year period.
- New capacity is de-rated in the same way but using the forced outage rate of the technology class as a whole.
- Intermittent capacity and batteries de-rated based on Effective Load Carrying Capability (ELCC) – ELCC models displacement of firm capacity by intermittent/batteries while maintaining the reliability standard.
- DR units are de-rated according to their registered capacity multiplied by Forecast Pool Requirement. (*note: FPR > 1)*
- Energy Efficiency resources qualify on the basis of demand reduction during Summer period (provided Winter load reduction is at least equal to this) and de-rated according to FPR.

FORECASTING AND DEMAND

- Forecasting is centralised and performed by PJM, who release an annual report of fifteen-year monthly load forecasts for each local delivery area called the Reliability Requirement.
- PJM set an administered demand curve as described below

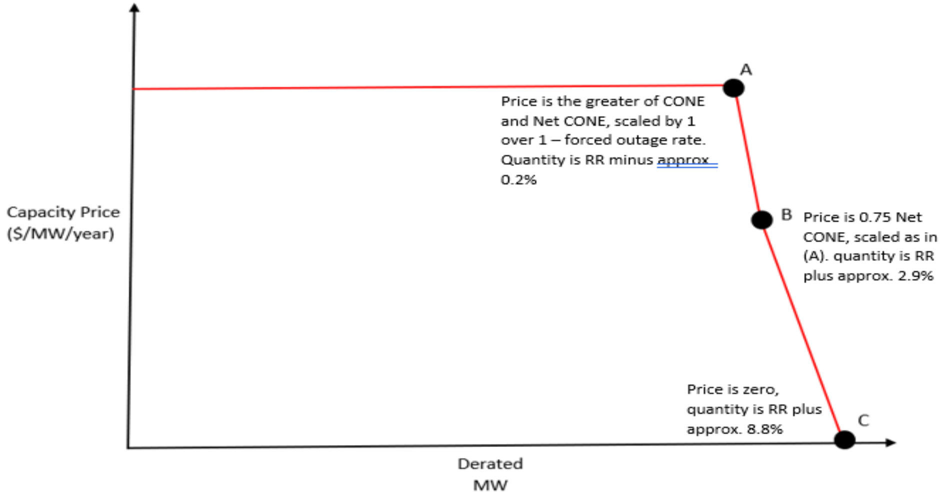
Reliability Requirement

- Econometric model is estimated that can explain non-coincident peak load in terms of calendar effects, weather effects, economic drivers and other related effects.
- Uses these to forecast load using economic drivers and weather simulations based on historical weather data.
- Jurisdiction-wide median load forecasts are allocated across zones in the PJM.
- PJM uses a Probabilistic Reliability Index Study Model (PRISM) to compare peak load forecasts, from which distributions of peak demand are taken for each week of the year, with capacity performance data for existing and new/planned generation.
- LOLE for each week taken and added for the 52 weeks of the year and adjusted to meet the reliability standard (One in ten years/2.4 hours). The difference between total capacity and adjusted demand is the required Installed Reserve Margin (IRM)

LDA-specific Reliability Requirement

- A Local Delivery Area (LDA) is considered constrained if Capacity Emergency Transfer Limit (CETL), the amount of energy the transmission system is capable of importing, is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), the amount of capacity an LDA needs to import to have LOLE of no more than once every 25 years.
- If an LDA has in the past three BRAs had a Locational Price Adder or is the Mid-Atlantic Region, it is also considered constrained.
- Constrained LDAs have a separate Reliability Requirement, equal to local generation capacity plus CETO.

Demand Curve



PROCUREMENT AND TRADING

- Base Residual Auction (BRA) at T-3 and incremental auctions at forward periods of 20 months, 10 months and 3 months.
- Full capacity requirement is procured in the BRA, incremental auctions are for rebalancing purposes.
- All existing generation is required to participate.
- Transmission upgrades are only permitted to participate in the BRA, not in Incremental Auctions.
- Sealed-bid auctions, up to 10 price-quantity pairs can be offered.
- Algorithm used to clear the auction based on demand curve.
- Seasonal bids must be paired, algorithm works this out.

NEPA

- New entrants may be granted a New Entry Price Adjustment, which guarantees a certain price for three years, limited to new generators or upgrades of at least 450 USD/kW.
- If the new entrant capacity is cleared, it must increase the overall capacity for the Local Delivery Area (LDA) from below the LDA Reliability Requirement to approx. 4.9% above it.
- If, subsequently, the capacity, though no longer a new entrant, fails to clear in year 2 or year 3, the participant's bid is replaced with the highest bid that would have cleared and the marginal bidder is replaced. LDA specific clearing price is set on that basis, but the NEPA recipient receives the full price of its bid.

Secondary Trading

- Incremental auctions are used for rebalancing, capacity providers may offer a 'buy bid' to unload some of their obligation.
- Bilateral trading is also permitted

TRANSMISSION AND INTERCONNECTION

- 27 local delivery areas (LDAs), some of which can be designated as constrained LDAs, which may mean those auctions clear with a Locational Price Adder.
- If an LDA receives a Locational Price Adder in two consecutive base (T-3) auctions, a cost-benefit analysis of a transmission upgrade vs. the value of removing the Locational Price Adder. If the transmission upgrade is deemed feasible over ten years, PJM will include the upgrade in the Regional Transmission Expansion Plan.
- Costs of the transmission upgrade will be charged to retailers, prorated to their share of total load.
- External capacity providers may participate but must demonstrate that they have the right and ability to transmit capacity to PJM prior to qualification for the capacity mechanism.
- If an area is expected to have a Capacity Emergency Transfer Limit less than 1.15 times its Capacity Emergency Transfer Objective, PJM can file for that region to be made a new LDA with the Federal Energy Regulatory Commission (FERC).

MARKET POWER

Minimum Offer Price Rule

- Used to prevent state-subsidised generation from depressing the capacity price.
- Until 2018, it only applied to combustion turbines and CCGT but now applies to all state-subsidised capacity except renewable, nuclear technology, DR, Energy Efficiency (EE), or New CCGT.

New Capacity

- New capacity is not subject to MSOC, but if new generation is deemed pivotal, market mitigation measures are used.
- Deemed pivotal if: a) there is only one supplier who submits a sell offer, b) total capacity of new generation offered is less than twice the new entry required to meet reliability requirement, or c) one such sell offer is pivotal.

Market Seller Offer Cap

- Three Pivotal Supplier test is used to determine if capacity from any three generators is required to meet the Reliability Requirement
- Cost-based clearing price – clearing price if all bidders were to bid avoidable costs – is calculated
- PJM works out which bidders could withhold their capacity and in doing so increase the cost-based clearing price by more than 50%
- Pivotal suppliers are then subject to MSOC
- If any two capacity providers are jointly pivotal, then all capacity providers will fail the TPS test.
- MSOC based on Avoidable Cost Rate less projected PJM net market revenues.
- Existing generator bids are replaced with MSOC if a) the bid is above MSOC and b) the bid is either marginal or more expensive than cost-based bid of a marginal unit.
- This mitigation of bids occurs as part of the auction clearing process.
- MSOC previously based on marginal cost of acquiring a capacity obligation, with the assumption of 30 hours of failure to meet capacity obligation - much higher than observed in reality so MSOC was rarely used.

PENALTIES AND COMPLIANCE

- Assessed during Performance Assessment Intervals (PAI), a 5-minute settlement period during which emergency action has been declared.
- Generation and DR resources assessed on the basis of metered output or load reduction plus real-time reserves
- Energy Efficiency resources are assessed on the basis of a post-installation Measurement and Verification Report, submitted prior to the delivery year, thus it is binary, EE is either performing or it isn’t throughout the delivery year.
- Transmission upgrades are assumed to have provided full cleared quantity if in service prior to PAI or zero if not.

Expected Performance

- Generators are expected to provide the full contracted de-rated capacity, scaled down if all generators in PJM underperform.
- DR and EE resources expected to provide full contracted capacity.
- Transmission upgrades expected to provide full committed MW upgrade.
- Shortfalls result in Daily Deficiency Rate payments.
- A resource can buy, bilaterally, replacement capacity if there is an acceptable reason why they cannot provide their committed capacity. Replacement capacity must be bought from within the same LDA.

Penalty and Bonus Rates

- Non-performance charge is such that 30 hours' worth of 5 minute intervals, or 360 PAIs, would cost Net CONE for an LDA.
- Penalty is capped at 1.5 LDA Net CONE (45 hours' worth of PAIs)
- Penalties for non-performance are redistributed as a bonus among resources who overperformed.
- Capacity Resource Deficiency Rate is charged to resources who fail to meet committed capacity requirements.
- CRDR is equal to clearing price plus the higher of 20% and $20/MW-Day.
- For transmission upgrades, CRDR = higher of 1.2 times clearing price in LDA and LDA Net CONE.
- Daily Generation Resource Rating Test Failure Rate (failure to prove it can meet capacity requirement) is calculated in the same way.

APPENDIX 3 - FRANCE

CAPACITY DEFINITION

Product Definition

- Generators are awarded capacity guarantees representing 0.1MW each, which can be sold to obligated parties (mostly retailers) at auctions and bilaterally in over-the-counter trades – these guarantees last for 1 year only
- Capacity operators are obligated to make capacity available during PP2 periods, retailers are required to demonstrate they hold sufficient capacity guarantees to meet customer base during PP1 periods.

De-rating

- Non-dispatchable – Average output for PP2 periods over the last 5 years (10 for RoR Hydro)
- Dispatchable – Certified capacity is scaled down based on duration of capacity it could provide, 10 hours a day for 5 consecutive days being considered full credit.
- C parameter also assigned to each technology class as a further de-rating based on likelihood of delivery.

Peak Definition

- Peak hours on days classified as PP1 or PP2 are always 07:00-15:00 and 18:00-20:00
- Must be 15 PP1 days and between 15 and 25 PP2 days in a year, all PP1 days are automatically PP2 days.
- 11 PP1 days must be in the January to March period, 4 must be in the November to December period
- Only business days, excluding Christmas school holidays.
- PP2 days that are not PP1 days can be distributed across any time of the year, except that the sum of PP2 days in March and November must be less than or equal to 25% of the total PP2 days in a delivery year.
- PP2 days cannot fall on weekends or Christmas school holidays.
- RTE decides if a day is a PP1 or PP2 day by running an algorithm that estimates the following day's demand and decides if it is in the *n* highest demand days, based on how many PP1 days remain in the year.

FORECASTING AND DEMAND

- Obligated parties are responsible for forecasting. The demand curve is formed by retailers' demand and the responsibility is on retailers to forecast demand accurately to avoid penalties as well as to reduce load during peaks to reduce their obligation.
- Ex post analysis by RTE three years after delivery year is based on:
    - ‘Reference power’ – actual consumption each obligated party faced during PP1 periods, adjusted for extreme weather. - Equal to sum of reference powers for remote-reading sites (exact consumption discernible), profiled sites (consumption modelled based on load profile) and ‘network loss buyers’.
    - ‘Security coefficient’ – a factor applied to consumption to cover unforeseen externalities (excluding weather). Based on a target LOLE of 3 hours and derived from adequacy studies carried out by RTE.

PROCUREMENT AND TRADING

- Capacity guarantee of 0.1 MW is awarded by RTE to capacity operators and sold to obligated parties.
- Can be sold bilaterally OTC or through organised auctions.
- At least 15 auctions for each delivery year
    - 1 auction in T-4
    - 4 auctions in T-3
    - 4 auctions in T-2
    - 6 auctions in T-1
- Auctions are run by EPEX Spot who publish auction results and supply and demand curves
- Non-fossil fuel capacity (CO_2 emissions < 200 grams of CO_2 per kWh) is eligible for a scheme with the government which offers a contract for difference (CfD) between a guaranteed price and the MC capacity price for up to 7 years
- Renewable energy sources are not eligible for the CfD scheme if they already benefit from a separate scheme that subsidises renewables.
- Obligated parties can trade capacity guarantees during and after the delivery year, this allows for customer churn during the delivery year.

TRANSMISSION AND INTERCONNECTION

- Obligated parties can buy capacity guarantees from any capacity operator in mainland France.
- Two schemes under which an interconnector can be awarded certificates, which are held by RTE and sold to obligated parties.
  - Simplified
    - Country-wide de-rating based on the country's contribution to the reduction of risk of power failure in France
    - Applies when the other country's System Operator has not signed a Cooperation Agreement with RTE.
  - Advanced
    - Individual Interconnector is de-rated based on its contribution to the overall country contribution.
    - Only applies when the other country's TSO has signed a Cooperation Agreement with RTE.

MARKET POWER

- French Competition Authority highlighted two concerns regarding EDF, who serve more than 80% of customers in France.
    - EDF would internally transfer capacity guarantees from its generation arm to its retail arm.
    - EDF would withhold capacity guarantees from the auctions, raising prices for all other retailers.
- In response, internal transfers must be made at a price representative of the auction for that delivery year.
- All internal transfers must be logged in the Capacity guarantees Register.
- There is a requirement on managers of portfolios of over 3 GW to offer their capacity through centralised auctions.

PENALTIES AND COMPLIANCE

- Compliance is assessed three years after the delivery year
- Retailers are assessed on having sufficient capacity guarantees during all hours PP1 days, capacity operators assessed on making sufficient capacity available during all hours of PP2 days.
- Compliance is aggregated over the full year, i.e. over-procurement during one peak and under-procuring during another would only be penalised if insufficient capacity has been procured on aggregate.
- Penalties generally amount to 1.2 times the price of capacity as cleared in auction the year prior to the delivery year.
- Compensation for capacity produced/procured greater than requirement is typically equal to 0.8 times the price of capacity as cleared at auction in the year prior to the delivery year.
  - Compensation capped at 1 GW above requirement.
  - Penalties increase to 1.6 times capacity price for deficits in procurement/production greater than 1 GW but are capped here.
- If the system has a shortage of 2 GW or more, penalties are replaced by an administrative price set at 60 EUR/kW with no limits.

APPENDIX 4 - CAISO

CAPACITY DEFINITION

Product Definition

- Three types of Resource Adequacy (RA), System RA, Local RA, Flexible RA.
- Calendar delivery year with monthly requirements for each of the three RA types.

System RA

- Monthly requirement on LSEs equal to load forecast plus a 15% margin.
- 90% of system RA requirement for the 5 summer months must be demonstrated to have been procured by LSEs in October prior to delivery year.
- LSEs must demonstrate that they have procured contracts for 100% of the month’s system RA requirement 45 days before each month.

Local RA

- RA required to cover an n-1-1 reliability event while maintaining a LOLE of 1 in ten years.
- An 'n-1-1' reliability event refers to 'n', which means all transmission facilities in service, the first '-1' refers to a forced outage or a single contingency event, and the second '-1' refers to the next worst single contingency event.
- This standard must be met in each of all 10 Local Capacity Areas.
- Waivers on obligation fees can be given if an LSE can demonstrate “every commercially reasonable effort to contract for local RAR resources”
- Fees are $51/kW-year
- Local RA requirements must be contracted for three years in advance. In October prior to a delivery year, LSEs must demonstrate they have contracted for 100% of local RA requirement for the following year, 100% of requirement for the following year and 50% for the third year.
- As of 2023, PG&E and SCE will act as Central Procurement Agency (CPE) for Local RA.
- Other LSEs can still procure Local RA capacity which can; be sold to the CPE, contribute to the LSE’s System RA requirement, or reduce the Local RA requirement for the CPE.
  - This change does not apply to the SDG&E area, where Local RA exceeds System RA for most months of the year.

Flexible RA

- Based on maximum change in load in a 3-hour period and how much production can be ramped up or down in a 3-hour period.
- In October before a delivery year, LSE’s must demonstrate that they have procured 90% of capacity requirement for each month of the delivery year. They must also, 45 days before each month, show that they have procured capacity for 100% of the Flexible RA requirement for that month.

De-Rating

- Dispatchable – Most recent maximum capability test
- Run-of-River or geothermal – average historical production for three years prior to T-1
- Combine Heat and Power (CHP or Biomass – average bid into Day Ahead Market from 16:00 – 21:00
- Wind and Solar – ELCC modelling to simulate how much firm capacity wind/solar can displace and maintain reliability.

FORECASTING AND DEMAND

- Forecasting is performed by retailers who must meet resource adequacy requirements on three different levels.

System RA

- LSEs submit their own forecasts, which the CEC adjusts for plausibility and load migration, as well as a pro-rata adjustment made to the aggregate load forecasts submitted by LSEs in order to achieve a forecast that diverges from the CEC forecast for total demand by less than 1%.
- Forecasts include a 15% reserve margin.

Local RA

- Annual CAISO Local Capacity Technical Study conducted to forecast Local Capacity Requirements (LCRs) for each of the ten LCAs in year 1 and year 5.
- The technical study maps the CEC forecast with CAISO's forecast of transmission constraints and works out how much capacity would be needed locally to cover an n-1-1 event and maintain a 1 in 10 LOLE (same reliability standard as system RA)
- Because the standard is the same, local RA counts towards system RA.
- Data is interpolated between years 1 and 5.

Flexible RA

- Flexible capacity requirement for each month is equal to the maximum 3-hour ramp that would be required 1 in 2 years (50% probability) plus the amount of capacity required to cover a sever, single, system-wide event (assumed for modelling to be an outage of one 1.1 GW reactor at the Diablo Canyon nuclear power plant).
- Flexible RA requirement is met by resources based on resource types.
    - Category 1 - Must be available from 05:00 to 22:00 every day of the year, available for at least 6 hours and able to turn on twice during the day.
        - From May to September, at least 49.6% of Flexible RA must come from Category 1, 39.9% for the rest of the year.
    - Category 2 - Must be available from 07:00 to 12:00 every day from May to September and 15:00 to 22:00 every day for the rest of the year. Must be available for at least three hours and able to turn on at least once every day.
    - Category 3 - Must be available from 07:00 to 12:00 every day from May to September and 15:00 to 22:00 every day for the rest of the year, weekends and holidays excluded. Must be available for at least three hours and able to turn on at least 5 times per month.
        - No more than 5% of Flexible RA.
- Retailers must procure the flexible RA requirement in proportion with their share of peak load.

PROCUREMENT AND TRADING

- Procurement and trading in the CAISO capacity mechanism is entirely de-centralised, there is no central auction.
- Responsibility for procuring Resource Adequacy (RA) is placed on retailers, who must enter bilateral agreements with generators to meet RA requirements.
- RA providers must be accredited and de-rated.
- There is a separate, centralised mechanism called the Cost Allocation Mechanism, which procures a significant amount of new capacity.
- Under this mechanism, CPUC instructs Investor-Owned Utilities (IOUs) to procure new generation, allocating costs and benefits to retailers, while net costs of the contract are paid by the retailers in the IOU service territory.
- This capacity is added to the RA requirement for the IOU and reduces the requirement for non-IOU retailers in the service area.
- Flexible capacity is required to meet RA standards as set out by category in the previous slide and are de-rated based on start-up time and in accordance with how much capacity can be produced within a time frame given their start-up time.
- There is no official mechanism for secondary trading, but it is permitted.

TRANSMISSION AND INTERCONNECTION

- Transmission constraints are built into the RA mechanism by being incorporated into the Local RA requirements.
- The centralisation of Local RA, the designation of two Investor-Owned Utilities (IOUs) (PG&E and SCE) as Central Procurement Entities (CPEs) allows for these two entities to internalise transmission concerns about the trade-off between transmission reinforcement and local capacity.
- This has raised some environmental concerns over these IOUs being able to reinforce transmission rather than opting for potentially greener local capacity,

MARKET POWER

- Waiver rule, which allows retailers to opt out of their Local RA obligations if they can demonstrate that they did not receive any reasonable offers.
- This was put in place to prevent large retailers from dominating the market by effectively capping prices at the waiver rate.
- The rate for waivers was initially $40/kWh but now sits at $51/kWh.
- CAISO can cover shortfalls through its Capacity Procurement Mechanism, the rate for which is $75.68/kW-year, calculated as 20% above marginal costs for a combined cycle resource with duct firing.
- Market power was not much of a concern in the infancy of the RA mechanism due to the lack of retailer-choice that customers had. However, this is becoming an increasing concern as community choice aggregators supply an increasing market share.
- By designating PG&E and SCE as Capacity Procurement Entities CAISO has attempted to address the fragmentation of the consumer base, meaning that in LCAs outside of SDG&E, there is only one buyer of Local RA.
- No entity has a large enough market share state-wide of System and Flexible RA, PG&E is the largest owner with 7 GW to a state-wide peak demand of 40 GW, for market power to be a major concern.

PENALTIES AND COMPLIANCE

- Penalties apply for each of the RA categories
- Dispatchable generators are required through the Resource Adequacy Availability Incentive Mechanism to offer their capacity into CAISO at pre-defined times but have no ‘performance’ requirement that requires availability during system stress events.
- Penalties for retailers who fail to meet System RA requirements are $8.88/kW-month in Summer (May-October) and $4.44/kW-month in Winter. This is a change from the flat rate of $6.66/kW-month that applied prior to 2020.
- Points system, whereby 1% of deficiency in a month accrues 1 point, is in place which dictates that the penalty rate double if 6-10 points have been accrued and triples if 11+ points have been accrued. Points expire after 24 months.
- In 2019, Local RA penalty rate increased from $3.33/kW-month to $4.25/kW-month (1/12th waiver fee)
- Local RA penalties are not additive to System RA penalties. If system RA is deficient, the system RA penalty is paid on the deficiency. If an LSE is deficient by a greater amount in Local RA than System RA, the System RA penalty rate is paid on the system RA deficiency and Local RA penalty rate is paid only on the excess Local RA deficiency.
- Flexible RA penalty rate is $3.33/kW-month (half the average System RA penalty rate) and is likewise with Local RA, not additive to System RA penalties.

APPENDIX 5 - IRELAND

CAPACITY DEFINITION

Product Definition

- Reliability Option – Generator sells a contract to the market operator, under which generators receive a premium but will make difference payments to the market operator equal to any positive difference between the market reference price and the strike price of the option, equal to 500 EUR. This difference payment is owed whether the holder is generating or not.
- If a generator is generating at full de-rated capacity, they receive a net revenue equal to the strike price, large costs can be incurred if a generator is not generating when the market reference price exceeds the strike price.

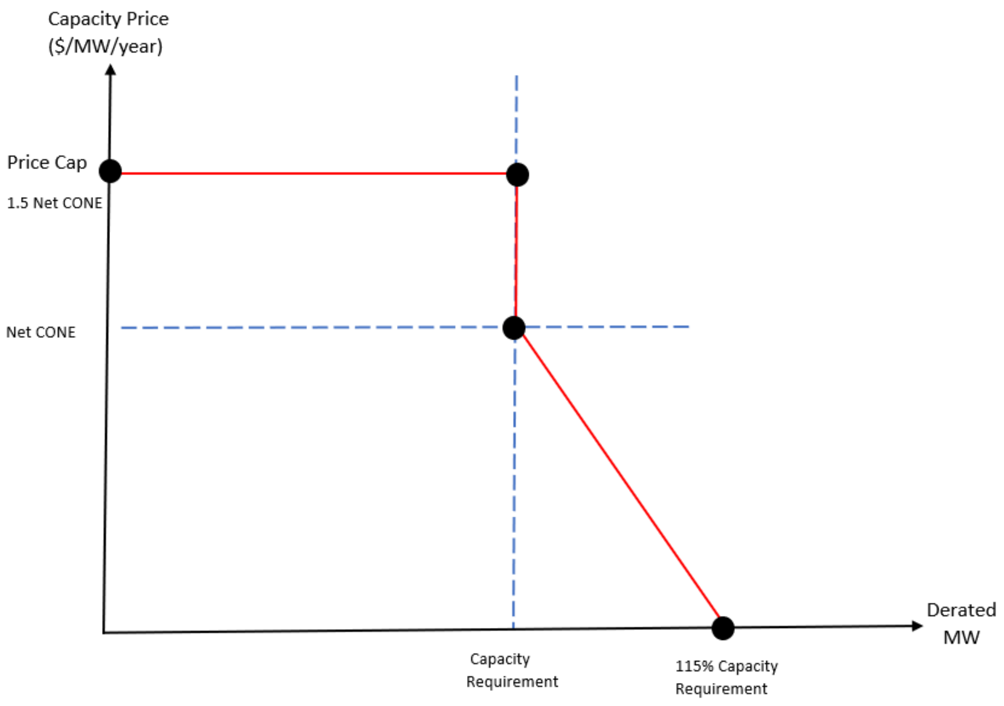
De-rating

- De-rating factors are applied according to technology class
- For non-intermittent generators, de-rating factors are calculated in models that simulate outages in specific technology classes and then calculate how much additional demand the system could manage while maintaining the same reliability standard (LOLE).
- For intermittent generators, de-rating factors are calculated by simulating optimal conditions using thermal generation and calculating surplus to the system when a unit of intermittent generation is added.
- Storage is de-rated by calculating how much firm capacity is required to replace the simulated removal of a storage unit. DR units receive the same de-rating factor as non-hydro storage of the same nameplate capacity and duration.
- Interconnectors are de-rated using the same methodology as thermal capacity, but are then de-rated further using a Monte Carlo simulation of coincident scarcity between GB and Ireland.

FORECASTING AND DEMAND

- Three demand scenarios are forecast by SONI and Eirgrid reflecting different weather effects, economic conditions and energy efficiency uptake.
- Since all capacity is allowed to participate in the capacity auction, there is no mechanism for removing the contribution of intermittent capacity from the forecasted capacity requirement.
- Portfolios of capacity are then randomly generated based on expected capacity and de-rating as outlined in the previous slide.
- Those portfolios that are simulated to meet the reliability standard of 8 hours LOLE are deemed Capacity Adequate Portfolios (CAPs)
- The CAP with the highest capacity requirement for each demand scenario is selected and these portfolios or put through a Least-Worst Regrets analysis, which compares the regret cost of over-procuring (the cost of excess capacity) with the regret cost of under-procuring (a function of VoLL) to determine an optimal demand scenario, which is then used as the forecast.

Demand Curve



PROCUREMENT AND TRADING

- Participation is mandatory in the Capacity Auction, but capacity may apply for exemption
- T-4 auction takes place with the aim of procuring 100% of required capacity, with possible T-3, T-2 and T-1 auctions taking place if the regulator deems them necessary.
- Existing capacity may only win a 1-year contract and has a price cap of 0.5 Net CONE but can apply for a Unit Specific Price Cap which goes up to 110% of estimated net ongoing costs for the unit as determined by the market operator.
- New capacity may win contracts up to ten years in length and have a price cap equal to 1.5 Net CONE.
- All participants bid a flexible or inflexible (whether a partial acceptance of a bid is possible) price-quantity pair.
- Price-quantity pairs are placed in price order by the operator to build the supply curve, the intersection of which with the demand curve sets the clearing price and quantity.
- The operator errs on the side of under-procurement in cases where an inflexible bid crosses the demand curve and the auction is pay-as-clear meaning all winning bidders receive the clearing price.
- Additional ‘out-of-merit’ bidders may receive contracts in order to accommodate transmission constraints into a local area.

Secondary Trading

- May take place for one of the following ‘legitimate reasons’
    - The Unit is affected by outage
    - Fluctuations in availability of primary energy source
    - Any other reason the regulator deems legitimate.

TRANSMISSION AND INTERCONNECTION

- Transmission constraints are incorporated into the forecasting of the capacity requirement.
- Across four jurisdictions (Northern Ireland, Greater Dublin, Rest of RoI, All-Ireland) each has a minimum capacity requirement that is estimated in the forecasting methodology.
- There is no distinction made between generating capacity and transmission capacity, thus it is a sufficient condition that the minimum capacity requirement is met in all four jurisdictions and no consideration is given to the location of a generator.
- The CM acts as a single market with a single clearing price for in-merit bidders (as opposed to out-of-merit bidders which may be awarded contracts to meet local requirements affected by transmission constraints)
- Interconnectors with GB are de-rated using the same methodology as the de-rating of thermal generators, with an additional de-rating based on Monte Carlo simulations of coincident peaks in GB and Ireland.

MARKET POWER

- All generators are required to bid their full de-rated capacity into the T-4 auction unless an application for an exemption is granted by the regulator.
- Price cap of 1.5 Net CONE for new capacity
- Price cap of 0.5 Net CONE for existing capacity, unless they apply for a Unit Specific Price Cap, in which case they may be granted a new price cap equal to 110% of what the regulator estimates are the unit's on-going (forward-looking) costs.

PENALTIES AND COMPLIANCE

- Reliability Options have a built-in compliance measure in that difference payments, which are owed whenever the spot price of energy exceeds the strike price, are owed irrespective of whether the generator is generating.
- Thus, generators have an incentive to cover those costs during high price periods by selling into the energy markets.
- There is a stop-loss in place which caps difference payments a generator can make in a single delivery year to 1.5 times the total revenue of premiums earned by the generator under their reliability option.
- Termination charges on generators which have cancelled or reduced their contracts apply and increase the closer to the delivery year the contract is terminated.
- Only new generation, which is required to deliver 90% of its contracted capacity before receiving premiums, may terminate their contract, existing generation may not terminate and is liable for difference payments.
- The rates for termination charges is not fixed but have so far remained as:

•Termination more than 13 months before delivery year	10 EUR/kW
•Termination between 13 months prior and start of DY	30 EUR/kW
•Termination at start of DY	40 EUR/kW