I-SEM Capacity Remuneration Mechanism

Parameters – Emerging Thinking

Dundalk
2 March 2017

SEM committee

Agenda

Item	Approximate timing
Introduction	**10:00 - 10:15**
Partial ASP Function	10:15 – 10:30
Reliability Option Parameters	10:30 - 10:45
New Capacity, Termination Fees and Performance Bonds	10:45 – 11:15
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Demand curve	12:30 – 12:50
Other issues	12:50 – 13:00

Workshop Overview

- Present SEMC 'emerging thinking' positions on key items of CRM Parameters Consultation and other related issues

- Opportunity for discussion and feedback

- Notes from today's session will be taken

Overall CRM policy development

Decision	Topics	Timing
CRM Decision 1 SEM-15-103	• Capacity Requirement • Eligibility • Product Design • Supplier arrangements • Institutional arrangements	Decision Dec 2015
CRM Decision 2 SEM-16-022	• Interconnector and cross-border capacity • Secondary trading • Detailed Reliability Option design • Level of Administered Scarcity Price • Transitional arrangements	Decision May 2016
CRM Decision 3 SEM-16-039	• Auction Design Framework • Auction Frequency and Volumes • Market Power and Mitigation Measures • Auction parameters • Auction Governance, Roles and Responsibilities	Decision July 2016
CRM 3 Locational Issues Decision SEM-16-081	• Auction format and winner determination • Capacity clearing price determination • Local security of supply issues • Lumpiness issue	Decision Dec 2016
Capacity Requirement and De-rating Decision SEM-16-082	• Capacity Requirement methodology • De-rating methodology • Interconnector De-rating methodology • Tolerance bands	Decision Dec 2016
CRM Parameters Consultation	• ASP parameters • Supplier charging parameters • Reliability Option parameters • New build parameters • Transitional auction parameters • Secondary trading parameters	Published – Nov 2016 Decision – Apr 2017

Future key CRM consultation and decision dates

Consultation	Issued	Responses Due	Decision
CRM Parameters		closed	Early April 2017
Treatment of Transitional Period		closed	Early April 2017 (alongside CRM Parameters decision)
Auction Monitor and CMC Auditor ToR		closed	Early April, appointment by end June
TSC (CRM Settlement Rules)		closed	Early April
Capacity Market Code		closed	Early June
Local capacity constraints methodology	Mid April	Mid May	Early July

- State Aid update

Plans for transitional auctions

- Proposals in CMC consultation in response to ‘stock take’
  - First transitional auctions in December 2017
  - Single auction for:
    - CY 2017/18 (late May 2018 –Sept 2018)
    - CY 2018/19 (Oct 2018 - Sept 2019)
  - CY 2021/2022 a transitional year
  - First T-4 auction for CY2022/23, to take place in Q3 2018

- Implications for CRM Parameters
  - All transitional auctions based on 2021/22 demand forecast, not 2020/21
  - Primary focus on auction parameters for first transitional auction
  - A separate consultation for parameters for first T-4 auction

Key CRM Dates for participants
First transitional auction timetable

• CMC issued:	start June
• Initial Auction Information Pack issued:	start July
• Qualification begins:	start July
• Deadline for Unit Specific Price Cap (USPC):	end July
• Qualification closes:	end July
• Qualification results:	Oct
• Final Auction Parameters issued:	pre Mock Auction
• Mock auction:	early Dec
• First auction:	mid Dec
• Provisional auction results:	December
• Final auction results:	Jan 2018
• Performance bonds lodged:	Feb 2018

See TSOs' Transitional Registration Plan v3.0 (13 Feb 2017) Figure 7 for more detail

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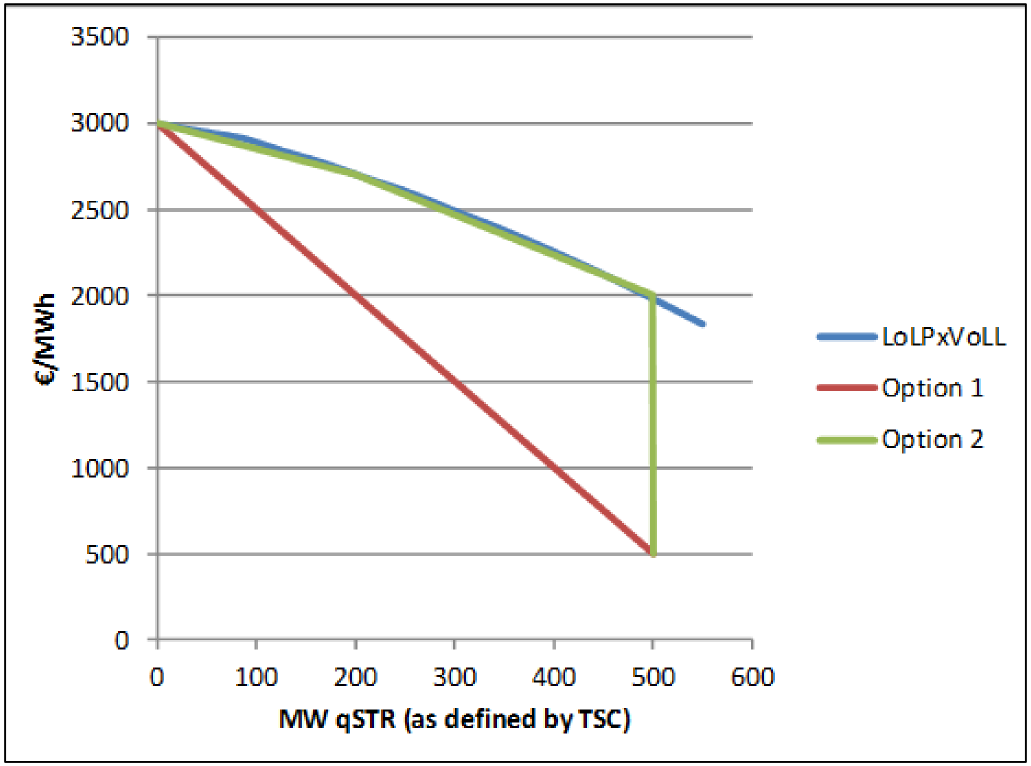
Partial ASP: Options and evaluation



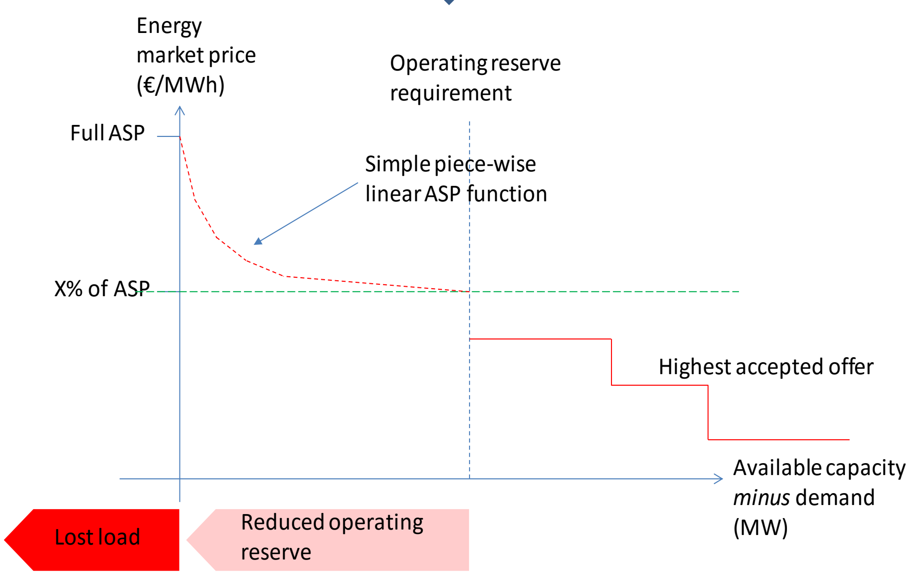
Both curves options are static, to start at 500MW of remaining reserves

Option	Relative Advantages
1	Reduces the risk of volatile administered prices- lower ASP values than Option 2
2	More cost reflective than Option 1- closer to LOLP x VoLL (or strictly LoLP x Full ASP)

Partial ASP: Feedback and Emerging Thinking

Feedback

- Of options offered, stakeholders preferred Option 1
- But some respondents preferred shape used in indicative pictures



Emerging Thinking

- **Option 1** because:
  - Lower price volatility, particularly when Full ASP increases
  - Lower risk initially
  - Sets a floor, so market can still determine higher price outcomes
- Difference between indicative picture and Option 2 reflects true LoLP x VoLL (FASP) curve
- In reality, controlled load shedding may to trigger move to Full ASP before reserves reduced to zero

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DSU Floor Price

- RO Strike Price = Max [fuel and carbon cost of reference peaker, DSU Floor Price]
- DSU Floor Price objectives:
  - System security; maximising the potential contribution of DSUs: favours higher floor; and
  - Limiting generator market power in the energy market; providing a hedge to Supplier price risk: favours a lower floor
- Key complexity is that shutdown period not known
- Not reasonable to ensure that all existing consumers recover shutdown costs under all possible shutdown scenarios
- Short term: Disincentives mitigated as demand side capacity do not pay RO difference payments if deliver demand reduction (can keep more energy value)

RESOURCE_NAME	Cost/MW @ 1 hour shutdown (EUR/MW)	Cost / MW@ max down time (EUR/MW)	Incremental Cost Bid (EUR/MW)	Quantity (MW)	Cumulative MW
DSU_401610	21.14	- 42.69	- 42.75	9.00	9.00
DSU_401400	279.06	279.06	279.06	23.00	32.00
DSU_401490	332.37	321.68	311.00	19.00	51.00
DSU_401590	339.52	234.78	147.49	20.08	71.08
DSU_401850	411.41	362.39	313.37	15.30	86.38
DSU_401620	420.51	354.11	313.37	14.00	100.38
DSU_401330 combined	437.24	408.62	350.00	22.41	122.79
DSU_401800	452.49	382.93	313.37	10.78	133.57
DSU_401530	478.23	404.12	330.00	33.69	167.26
DSU_401270	486.14	411.91	337.68	99.00	266.26
DSU_501380	1,193.00	771.40	307.40	20.00	286.26
DSU_501330	1,521.29	971.84	371.20	18.35	304.60
DSU_401660	2,190.00	1,290.00	390.00	5.00	309.60
DSU_401390	2,602.73	348.94	330.00	11.00	320.60

DSU Floor Price of €500/MWh achieves reasonable balance

Majority of respondents agreed

Billing Period Stop-Loss Limit

- Billing Period = Energy Billing Period of 1 week
- Proposed 50% of Annual Limit, i.e. 0.75x Annual RO fee
- Key objective, to balance:
  - Retain incentives for events in subsequent Billing Periods
  - Sharp incentives in this Billing Period
  - Maintain Supplier hedge and hence consumer protection
- Majority of respondents (Capacity Providers) want lower limit- which limits their risk at lower level
- Minded to stay with 50% of Annual Stop-Loss Limit:
  - Low probability of multiple events across 3 or more Billing Periods initially
  - Applies to uncovered difference payments: Incentive can only be blunted if outage during scarcity in 2 billing periods already, and both hit Billing Period Limit
  - Capacity Provider overall risk capped by Annual Limit

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New Capacity Investment Rate Threshold: Original proposals and feedback

New Capacity Investment Rate Threshold, NCIRT = minimum investment to qualify for multi-year Reliability Option (Substantial Financial Commitment)

Consultation document proposals

- Set at 50% gross BNE investment cost, 2016 = €310/kW
- Rationale:
  - BNE is low cost capacity
  - International benchmarks

Feedback

- Some have argued that the New Capacity Investment Threshold is set too high
  - Do not have a refurbishment category
  - No provision for unavoidable* investment in ECPC / USPC
  - Distortion against upgrades/ refurbishment

*clarification since presentation: unavoidable = unavoidable if capacity to be delivered

New Capacity Investment Rate Threshold Emerging Thinking

NCIRT: **Reduce required investment from proposed 50% of gross BNE investment to 40%:**

- Closer to international benchmarks at latest exchange rates
- We have no refurbishment category, unlike GB. But **propose to allow proportion of unavoidable* future investment in USPC bids, similar to PJM approach- discussed later**

GB 2015 T-4 Auction (in 2014/15 prices for 2019/20 delivery)				
Financial thresholds…	GBP/kW	EUR/kW at Dec 2015 x-rate	EUR/kW at 7 Feb 2017 x-rate	07/02/2017 value as SEM gross BNE %
New build capacity	255	352	295	41%

ISO NE Current (22/07/2016)				
Financial thresholds…	USD/kW	EUR/kW at 22/07/2016 x-rate	EUR/kW at 07/02/2016 x-rate	07/02/2017 value as SEM gross BNE %
Repowering capacity	296	269	277	39%
Incremental capacity	296	269	277	39%

*clarification since presentation: unavoidable = unavoidable if capacity to be delivered

Termination Fees – as per draft CMC

- Prior CRM policy decisions tied application of Termination Fees to termination of Implementation Agreements
- Implementation Agreement applies same Termination Fee schedule in CMC draft for consultation to all uncommissioned capacity, including:
  - All incremental capacity on existing units (whether eligible for multi – year Reliability option or not)
  - All uncommissioned DSUs
- CMC draft for consultation DOES NOT apply Termination Fees to any existing (commissioned) capacity

Termination fees: CRM Parameters consultation

Proposed schedule	Other questions
Termination Fees for new (uncommissioned) capacity: • Any time after the auction but more than 13 months before the start of the Capacity Year: **€10/kW**; • Between 13 months before the start of the Capacity Year and the start of the Capacity Year: **€30/kW**; • After the start of the Capacity Year: **€40/kW**.	Should Termination Fees apply/apply at same rate to: • Incremental uncommissioned capacity • Capacity not eligible for multi-year Reliability Option • DSUs • All existing capacity

Key factors underpinning proposed schedule for new capacity

- Ideally would set at a level which reflects damage to customers if capacity does not deliver (hence function of time to replace)
- Have estimated potential damage at around €135/kW, if a 200MW BNE failed to deliver resulting in additional expected unserved energy* (first year effect only, ignores years 2+)
- But:
  - Termination Fees at this level probably uninvestable (not covered by LDs)
  - Assumes will otherwise be at 8 hour standard
- **So set at same level as revised GB schedule, which appears investable-** GB revised up based on experience

*Unserved energy valued at VoLL, not FASP

Termination Fee: Stakeholder feedback

New Capacity

- Some argued that rate is generally too high and will deter investment- particularly in DSUs
- Some argued initial €10/kW fee too low to deter speculative bids
- Some argued that Termination Fee shouldn't be more than annual option fee. NB:
  - Max termination fee of €40/kW could be more than RO fee
- Also suggested that we express values as percentages of Net CONE so evolves in relation to costs

Existing capacity

- Strong pushback on applying Termination Fees to all existing capacity:
  - Most generators pushed back
  - One participant estimated this could require the industry to lodge €675m in performance bonds, if same schedule applied
  - Argued shouldn't be required to lodge performance bond if have assets in the ground

Latest Emerging Thinking

New capacity	Existing capacity
• Stay with proposed schedule – Do not cap at Annual Option fee, as does not relate to customer damage – Can obtain up to 10 years of Option Fees • But give further consideration to DSU treatment on environmental grounds	• No Termination Fees, because: – Concerned at aggregate size of potential Performance Bonds – Risk lower so not proportionate, although customer damage the same – Less of an issue for T-1 than T-4 (option value) – Difference payment obligation and related collateral support remains

Performance Bond required to cover 100% of Termination Fee exposure

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Bid Controls: Quick recap of parameters

Key bid controls	Proposed parameter values
• **Auction Price Cap** (APC) applies to all bidders	**1.5 x Net CONE**
• **Existing Capacity Price Cap** (ECPC) applies to all existing generators and interconnector without USPC	**0.5 x Net CONE**
• **Unit Specific Price Cap** (USPC) where Net Going Forward Costs (NGFC) > ECPC	**Based on individual costs**

Setting Net CONE and APC- Background

Proposed approach set out in consultation document

General approach	Select BNE reference plant	Calculate Annualised Fixed Cost (AFC)	Calculate Infra-marginal rent (IMR)	Calculate Ancillary Service Revenue (AS)	Calculate Net CONE= AFC – IMR - AS	Set Auction Price Cap = 1.5 x Net CONE
Specific approach to first transitional auction	Use same reference plant as SEM 2017 (and 2016)	• Update SEM 2017 value for inflation to 2018/19 • *Adjust to de-rated kW*	• Update 2017 fuel cost of BNE reference plant to 2018/19 • *Adjust for RO difference payments* • *Adjust for ASP* • *Use 5% FOP* • *Adjust to de-rated kW*	• Adjust for difference between 2017 and 2018/19 ancillary service budget • *Adjust to de-rated kW*	Apply standard process	Apply standard process

Changes to reflect proposed transitional auction approach in red

Auction Bid Parameters
Summary of response and emerging thinking

Key parameter	Consultation proposals	Industry Response	Emerging thinking
Auction Price Cap (APC) applies to all	1.5 x Net CONE	• Mixed, with some preferring higher value • Argued that WACC should be higher in new market	• 1.5 x Net CONE • No change in WACC for first transitional auction. Review before first T-4
Existing Capacity Price Cap (ECPC) applies to all existing generators and interconnector	0.5 x Net CONE	• Strong push back from industry, on exclusion of sunk costs (see later slide) • Argue that denies total cost recovery (in conjunction with energy offer controls) • Less specific than some other markets on allowable costs • Required future investment not provided for • Objections to ex ante scrutiny • Object to any expectation of efficiency savings	• Stay with 0.5 x Net CONE
Unit Specific Price Cap (USPC) where Net Going Forward Costs (NGFC) > ECPC	Based on individual costs, but excludes sunk costs such as depreciation, interest, return on equity		• Sunk costs not included • Allow 10% margin for RA NGFC estimation uncertainty • Allow proportion of unavoidable future investment • No assumption of efficiency savings

Stakeholder feedback and response: APC and Net CONE

Value of Net CONE	Net CONE multiple
1. BNE cost of capital assumptions: – Argued for higher WACC: increased risks under I-SEM trading arrangements – Argued for shorter life: assumes a 20 year period to recover sunk investment costs, whereas new investor now only guaranteed bid price for 10 years 2. Detailed comments about adjustment / assumptions for outages and infra-marginal rent	Argued for APC as higher multiple of Net CONE, at higher end of international range

Our response:

- Premature to review WACC now, and sufficient scope within x1.5 – see next slide
- Economic life beyond 10 year price fix
- Detailed adjustments- will provide detailed respond in decision paper, within scope of x1.5
- Bidders above 1.5 x Net CONE unlikely to be successful in current market conditions

WACC and Net CONE sensitivities

- Respondents argue that SEM BNE uses low WACC, not appropriate to new I-SEM which is riskier than SEM, so Gross / Net CONE too low
- WACC benchmarks (all values pre-tax real)
  - 2016 SEM Annual Capacity Payment Sum = **5.17%** (decision date, Sept 2015)
  - 2013 SEM WACC = **6.6%**
  - GB Net CONE WACC = **7.5%** (from DECC report published July 2013)
- In part WACC difference is due to timing- SEM WACC reduced by 1.4% between 2013 and 2016
- Sensitivities within bounds of 1.5 multiple
- Some also argue that plant life should be reduced to 10 years, but we do not agree
  - Economic value beyond 10 years
- Detailed BNE (including WACC) review before first T-4 auction

WACC sensitivity analysis (2016 Net CONE)

Cost Item (€ms)	Alstom GT13E2 NI Distillate	
Investment Cost (excl Fuel Working Capital	129.2	129.2
Initial Working Capital (including Fuel)	5.6	5.6
minus Residual Value for Land & Fuel	1.6	1.6
Total Capital Costs	**133.2**	**133.2**
WACC	5.17%	7.50%
Plant Life (years)	20	20
Recurring Cost	5.55	5.55
Total Annual Cost	**16.47**	**18.62**
Nameplate Capacity (MW)	195.7	195.7
Annualised Cost per nameplate kW	**83.74**	**95.14**
Annualised Cost per de-rated kW	**88.15**	**100.15**
Latest estimates - €/de-rated kW		
Gross CONE: Annualised Cost per de-rated kW	**88.15**	**100.15**
Net CONE: Inframarginal Rent	4.03	4.03
Ancillary Services	7.73	7.73
BNE Cost per kW	**76.39**	**88.39**
% difference to Gross CONE		**13.6%**
% difference to Net CONE		**15.7%**

Note: numbers do not contain inflation uprating to 2018/19

Approach to setting ECPC and USPC- Background

Proposed approach set out in consultation document

General approach

Use Generator Financial Reporting of Non-Fuel Operating Costs (NFOC) as proxy for unit specific Fixed Operating Costs

Make adjustments to Fixed Operating Costs:
- Variable cost elements of NFOC
- Efficiency gains

Calculate unit specific infra-marginal rent

Calculate unit specific ancillary service income

Calculate unit specific Net Going Forward Costs (NGFC)

Publish ECPC as a multiple of Net CONE which allows majority of plant required to meet Capacity Requirement to Bid at NGFC

Existing Capacity providers review ECPC and furnish evidence of higher NGFC if applying for Unit Specific Price Cap

RAs review evidence and make Unit Specific Price Cap decision

Use latest data available, currently 2015

Adjustments to be determined, none included in indicative values

Update PLEXOS run for fuel curves closer to auction date

Scale unit specific historic net ancillary service revenue to 2018/19 budget

Minded to value of 0.5 x Net CONE

If ECPC is set at low Net CONE multiple then:
- Less scope for plant below ECPC to exercise market power and bid up to cap
- But more USPC applications to be processed

Specific elements for first transitional auction

ECPC and USPC: Stakeholder Feedback and our response

Feedback	Our response
Sunk costs: Strong push back from stakeholders on exclusion of sunk costs	See next slide
Unavoidable forward investment: Not provided for in ECPC/USPC	Allow a proportion of unavoidable* costs in USPC applications (see PJM approach slide)
Projecting costs forwards: Strong push back on inclusion of efficiency savings	Will not assume efficiency savings for now
NGFC/unavoidable* cost formula: Less specific than some other markets (e.g. PJM) on allowable costs in definitions of NGFC	Limited data, but allow 10% tolerance in RA estimates of NGFC in assessing USPC applications

*clarification since presentation: unavoidable = unavoidable if capacity to be delivered

Exclusion of sunk costs: key arguments

Industry argument	Our counter-arguments
ECPC/USPC should include sunk costs: • Breach of statutory duties to allow licensees to finance activities	• Duty to allow a generator to recover its costs is not absolute- no requirement that in an over-supplied market, all capacity should recover its costs • **In a fully competitive market, with excess supply, a bidder would be likely to include only forward looking cost, not sunk cost, and auction would clear at this level**.
• Will result in price clearing below Net CONE, discourages investment and creates distortions	• Winners get at least market clearing price, and price can rise to 1.5 x Net CONE if new capacity required, or higher USPCs
• Other markets (GB) which do not allow CRM bids to recover sunk cost do not regulate energy market bids in the same way, so generators can earn more infra-marginal rent in the energy market than in the I-SEM.	• **We are only regulating non-energy bids in the BM, not other DAM, IDM, BM bids** • US markets regulate energy and capacity market in same way, or more aggressively

We will respond to detailed points in decision paper

PJM treatment of avoidable* forward investment

PJM makes an adjustment to bid caps to allow a proportion of avoidable* investment to be included in the bid cap, defining annual capacity recovery factors

PJM approach

APIR (Avoidable Project Investment Recovery Rate) = PI * CRF

Where:

- PI is the amount of project investment, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.
- CRF is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

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PJM Interconnection - Intra-PJM Tariffs - OPEN ACCESS TRANSMISSION TARIFF - OATT VI. ADMINISTRATION AND STUDY OF NEW SERVICE REQUESTS; R - OATT ATTACHMENT DD - OATT ATTACHMENT DD.6. MARKET POWER MITIGATION

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

*clarification since presentation:
PJM use term avoidable to mean avoidable by closing

We propose to allow a proportion of the avoidable* investment, with proportion assessed on case by case basis, rather than having a standard Levelised CRF schedule

NGFC/USPC approach – Emerging Thinking

Two key changes following consultation:

- Allow appropriate proportion of unavoidable* future investment (on case by case basis)
- Allow 10% tolerance in RA estimates of NGFC in assessing USPC applications

NGFC = Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets + appropriate proportion of unavoidable future investment),0] + Expected Reliability Option difference payments*

Max allowed USPC bid = 110% x RAs' NGFC estimate, updated following review of USPC application

We are developing a USPC application template to help assess bids

*clarification since presentation: unavoidable = unavoidable if capacity to be delivered

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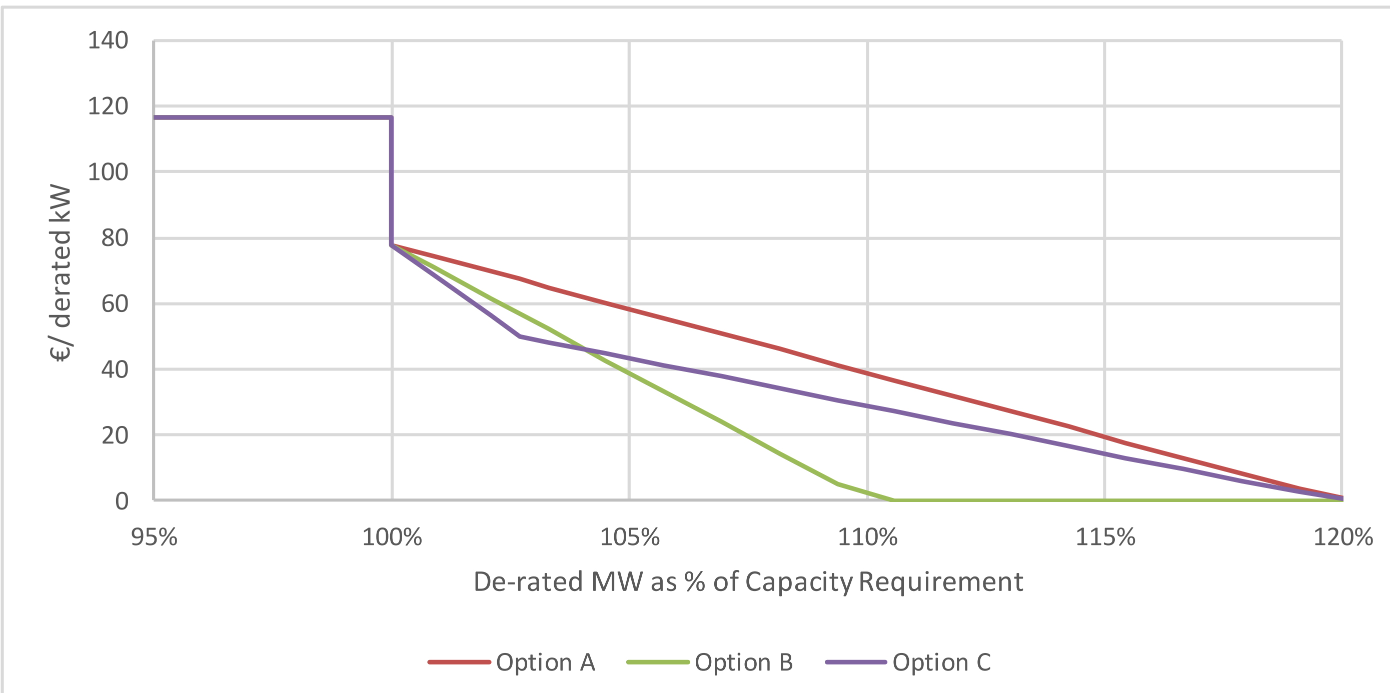
Capacity Requirement (CR)

- Propose to make 2021/22 a transitional year, so CR for first transitional auction based on 2021/22 demand forecast
- Consultation closed, considering feedback
- Changes from CRM Parameters consultation working assumptions (which was 7,498 de-rated MW) :
  - Based on 2021/22 demand forecast, not 2020/21
  - Excludes reserve
  - Based on TSOs’ 2017 GCS forecast, not 2016 GCS
- TSOs will work on Least-Worst Regrets analysis based on 2017 GCS
- Decision in CRM Parameters Decision paper will be expressed as % of CR
- Updated CR and demand curve in MW will be in initial Auction Information Pack in early July
- Demand curve then adjusted for voluntary non-bidders after Qualification, and final demand curve published in final Auction Parameters document before Mock Auction

Auction demand curve: options

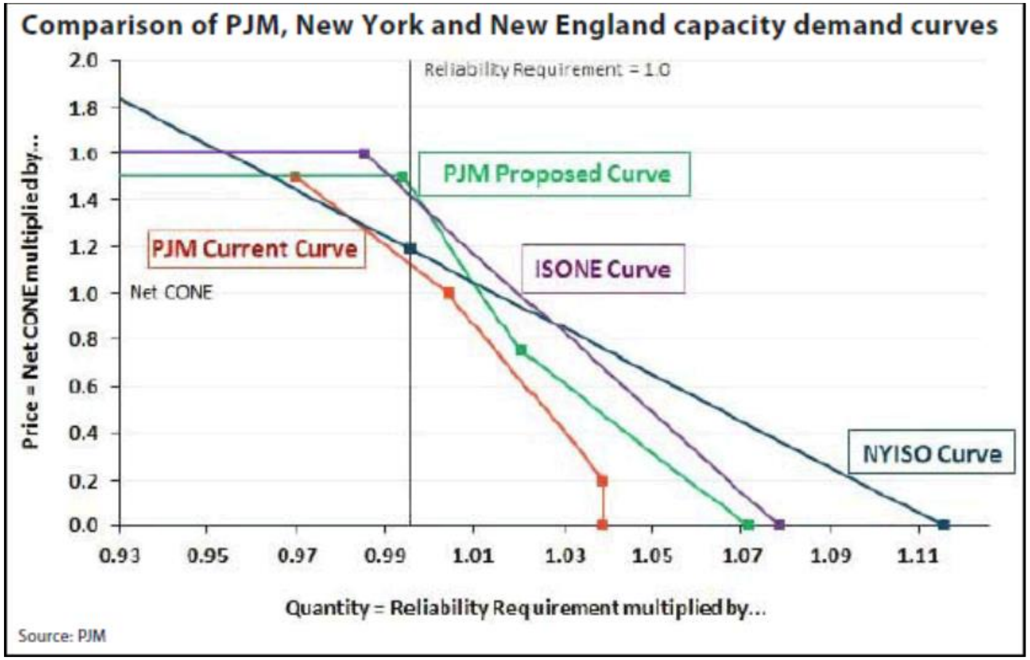
We presented 3 options in the CRM Parameters consultation to guide the debate, variants are possible….

Option	Demand at Net CONE	Zero crossing pt	Inflection pt
A	Capacity Requirement	20%	No
B		10%	No
C		20%	Yes, at pt on EUE/kW curve



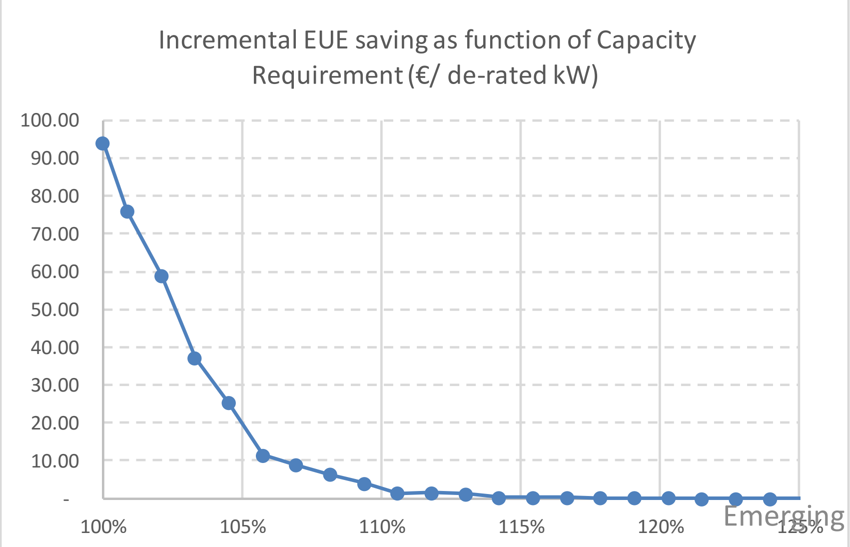
International experience

- We have proposed zero-crossing pt at up to 20% of Capacity Requirement (Options A and C)
- Larger markets tend to have smaller zero-crossing pts
- The New York ISO area as a whole has a zero-crossing point about 12% (4800 MW) above the target capacity level.
- In smaller New York zones (e.g. New York City, still larger than the I-SEM in peak demand), the target is 15% to 18% above the zonal Capacity Requirement



Demand curve options analysis and feedback

Option	Pros	Cons
A	• Security of supply- most capacity procured	• High customer bills • Procures capacity beyond point where minimal unserved energy • Less “competition” than C, within year
B	• Lower customer bills than A	• Less cost reflective than C? • Steep line, less “competition” • Less conservative on security of supply
C	• Lower customer bills than A • Competition- flatter in likely clearing region • Most cost reflective?	• Procures capacity beyond point where minimal unserved energy • Less conservative on security of supply than A



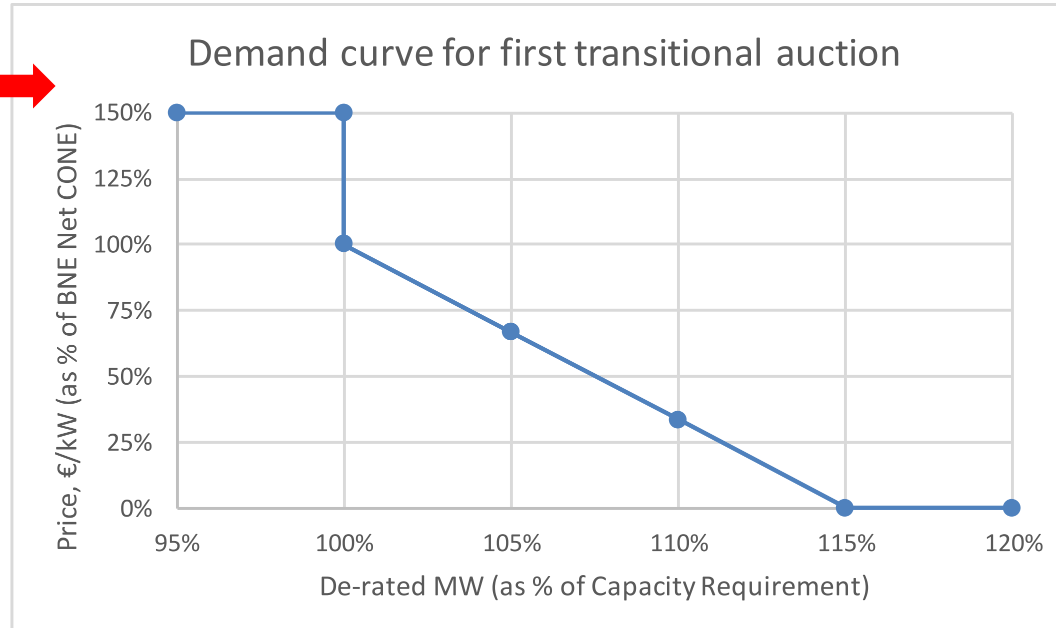
On balance, industry prefer A, which is financial advantageous to Capacity Providers. Argue reduces volatility, and more conservative on security of supply

But limited additional reduction in expected unserved energy above 110% of Capacity Requirement, although may be impacts on energy prices and subsequent year CRM auction

Demand curve
Emerging thinking

Emerging thinking: Hybrid of A and B, with 15% zero-crossing point, no inflection:

- Does not include out-of-merit capacity awarded ROs for constraint reasons
- Limited additional reduction in expected unserved energy above 110% of Capacity Requirement
- Consistent with international precedents
- Reasonable balance between promoting competition and not procuring excessive capacity



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Partial ASP Function	10:15 – 10:30
Reliability Option Parameters	10:30 - 10:45
New Capacity, Termination Fees and Performance Bonds	10:45 – 11:15
Coffee Break	11:15 - 11:30
Bid Control Parameters	11:30 - 12:30
Demand curve	12:30 – 12:50
Other issues	**12:50 – 13:00**

Supplier Charging Base

Options considered

- Option 1: Peak period (5pm to 9pm) in Winter quarters;
- Option 2: Peak period (5pm to 9pm) throughout the year; and
- Option 3: Broader day-time period from 7am to 11pm in all quarters

Stakeholders predominantly in favour of Option 3

Minded to decide on Option 3 because:

- No clear evidence for a more focussed peak
- Similar allocation of charges to residential / I&C classes as now

LoLP as ratio of average LoLP

	Peak (5pm to 9pm)	Mid-merit (7am to 11pm)	Night time (11pm to 7am)	All hours	Peak/ mid-merit	Peak/ Night time
2013						
Qtr1	31.1949	9.2196	0.0046	6.3396	3.4	6,714.5
Qtr2	0.0561	0.0943	0.0001	0.0649	0.6	421.8
Qtr3	1.1152	0.4266	0.0002	0.2933	2.6	5,248.9
Qtr4	2.1031	0.5513	0.0000	0.3790	3.8	71,405.1
2014						
Qtr1	5.7326	1.4456	0.0000	0.9939	4.0	152,163.8
Qtr2	0.0866	0.2477	0.0011	0.1706	0.3	79.2
Qtr3	3.9336	1.5259	0.0040	1.0499	2.6	984.4
Qtr4	0.9655	0.2588	0.0001	0.1780	3.7	14,077.8
2015						
Qtr1	0.1410	0.0363	0.0000	0.0249	3.9	10,085.9
Qtr2	0.0005	0.0012	0.0001	0.0009	0.4	3.6
Qtr3	3.6707	2.1951	0.0271	1.5160	1.7	135.7
Qtr4	13.8366	3.4988	0.0080	2.4077	4.0	1,739.8
2016						
Qtr1	0.0724	0.0231	0.0029	0.0160	3.1	25.3
Qtr2	3.8722	2.1110	0.2724	1.5228	1.8	14.2
All	4.4576	1.4464	0.0219	1.0000	3.1	203.9
All Q1s	9.2852	2.6811	0.0019	1.8436	3.5	4,912.5
All Q2s	1.0038	0.6136	0.0685	0.4398	1.6	14.7
All Q3s	2.2008	1.0520	0.0096	0.7254	2.1	228.6
All Q4s	5.6350	1.4363	0.0027	0.9882	3.9	2,099.7

DECTOL

Background

- Decision allowed a negative tolerance around de-rated capacity for DSU
  - De-rated capacity based on System-wide outage rates
  - Recognises varying compositions of DSUs
  - Value of –ve tolerance (DECTOL) to be set based on historic availability data

- Emerging Thinking
  - Historic availability of DSU does not reflect changes prompted by switch to I-SEM
  - DSU MW Capacity (on which de-rated capacity based) has only limited meaning in context of deliverable capacity
  - No clear benefit to the market of placing an arbitrary limit on DSU composition, as long as awarded capacity is delivered
  - DECTOL to be set to 100% for first Transitional Auction, but will be kept under review