IWEA curtailment study: extended analysis

23 May 2012

Outline

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      b) Pro rata
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Introduction and objectives

Introduction and objectives for this study

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- CER and the Utility Regulator released a Decision Paper on 21 December 2011 relating to the 'Treatment of Price Taking Generation in Tie Breaks in Dispatch in the Single Electricity Market and Associated Issues' (SEM-11-105)
  - Grand-fathering approach to curtailment proposed
  - Hierarchy of curtailment according to:
    1. Fully-firm controllable wind generators
    2. Partially firm (0.1% to 99.9%) controllable wind generators
    3. Non-firm controllable wind generators

  (with priority curtailment of Gate 3 generators in categories 2 and 3 in the Republic of Ireland)

- A consultation paper (SEM-12-028) was subsequently published on 26 April 2012 to re-examine the options for the treatment of curtailment

- The objectives of this study for IWEA are to:
  - Consider the implications of a grand-fathering approach for partially firm and non-firm wind generators in the Single Electricity Market (SEM)
  - Estimate the key economic impacts of different options for allocation of curtailment in 2020

Options considered in this study

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- Two options for prioritising curtailment in the SEM:
  1. Grand-fathering: as per the December 2011 (SEM-11-105) proposed decision
  2. Pro rata: all controllable wind generators curtailed in line with share of availability during periods when curtailment is required

- Three scenarios were considered in this study, with the key scenario variables being the curtailment option, wind capacity build and the relative contribution from non-firm wind projects

Scenario	Curtailment option	2020 SEM wind RES-E	2020 SEM wind capacity
1	Grand-father	~26%	3984 MW (1% non-firm)
2	Pro-rata	~35%	5250 MW (39% non-firm)
3	Grand-father	~35%	5250 MW (1% non-firm)

Grand-fathering of curtailment - categories

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- Curtailment in the Republic of Ireland (ROI) prioritised according to the hierarchy established in the SEM-11-108 decision paper (category E curtailed first, category A curtailed last)
  - Category A: Fully firm
  - Category B: Partially firm pre Gate 3
  - Category C: Partially firm Gate 3
  - Category D: Non-firm pre Gate 3
  - Category E: Non-firm Gate 3

- Curtailment in Northern Ireland (NI) prioritised according to:
  - Category A: Fully firm
  - Category B: Partially firm
  - Category C: Non-firm

Incidence of curtailment

Incidence of curtailment – assumptions

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- Key assumptions sourced as follows:
  - Historic demand and wind profiles taken from the RAs' validated model
  - Projected demand growth based on the Generation Capacity Statement 2012-2021
  - Installed wind capacity projections provided by IWEA
- Interconnector flows are fixed at one average value throughout the year and used to calibrate our curtailment model to aggregate system-wide curtailment estimated from IWEA modelling for 2015 and 2020 and EirGrid's estimate for 2020
  - The calibrated interconnector flow values range from 105 MW imports in 2015 (Scenario 1) to 395 MW exports in 2020 (Scenarios 2 and 3)
  - Results were found to be robust to varying assumptions about pumped storage usage
- In modelling the hourly incidence of curtailment, we have not considered local transmission constraints or the potential for curtailment due to system inertia, minimum generation or reserve constraints
  - However, our model is calibrated on an annual basis to IWEA's estimates of aggregate system-wide curtailment which did factor in minimum generation requirements

Incidence of curtailment – assumptions 2

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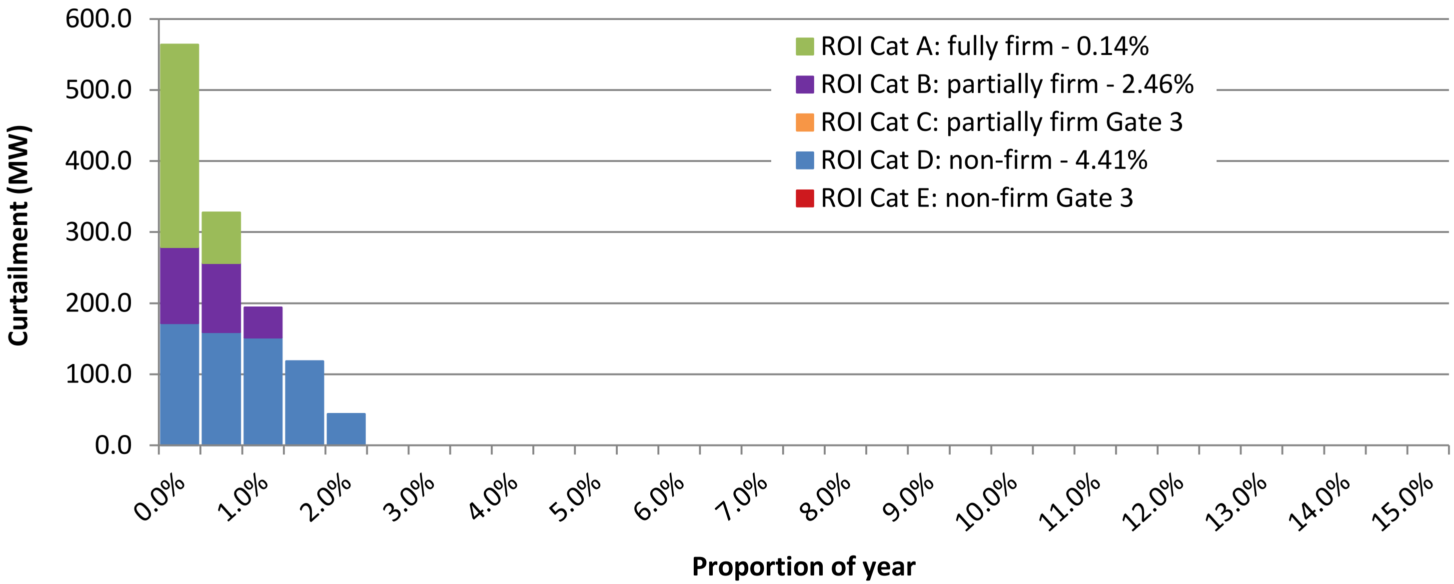
- Instantaneous wind limit and aggregate system-wide curtailment assumptions

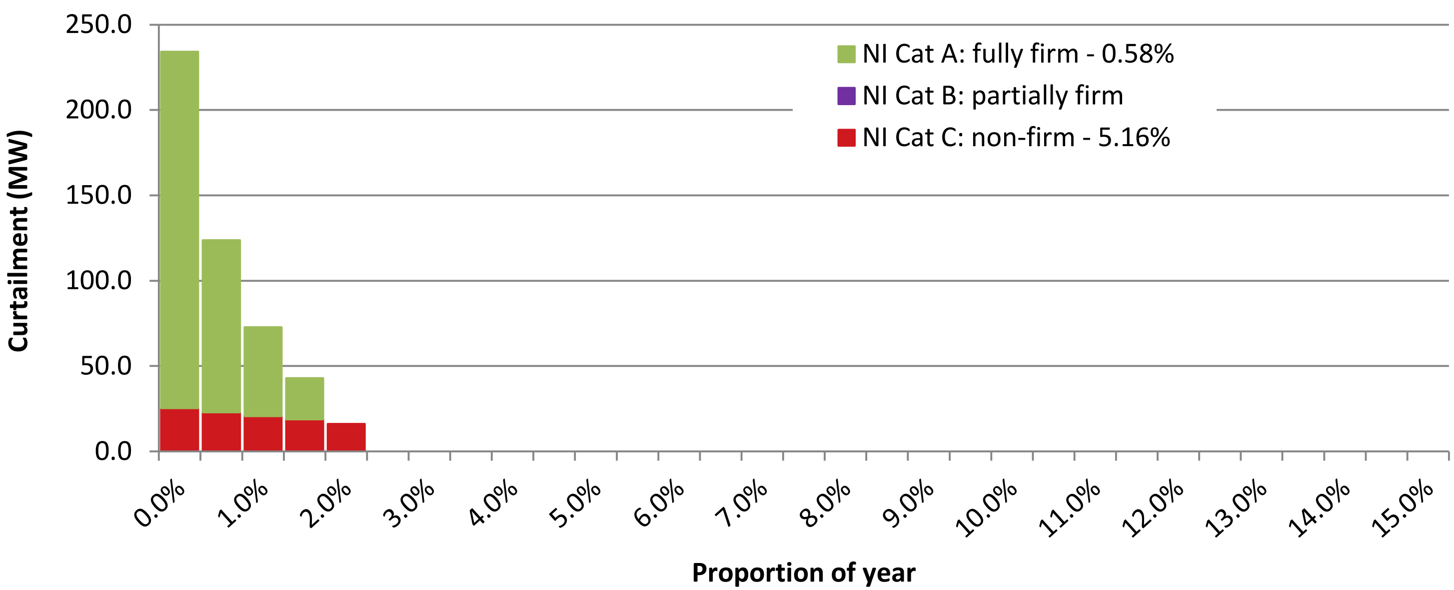
	Instantaneous wind penetration cap (% demand + exports)	IWEA estimates (Scenario 1)	IWEA estimates (Scenarios 2,3)	EirGrid and SONI forecast[1]
2015	65%	0.65%	2.15%	
2020	75%	0.68%	3.77%	5.00%

- The results on the following slides show annual curtailment levels (reported in legend) and duration curve for curtailment by category

[1] Base Case from EirGrid and SONI, *Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment* (June 2011)

Curtailment 2015, Scenario 1





Curtailment 2015, Scenario 2

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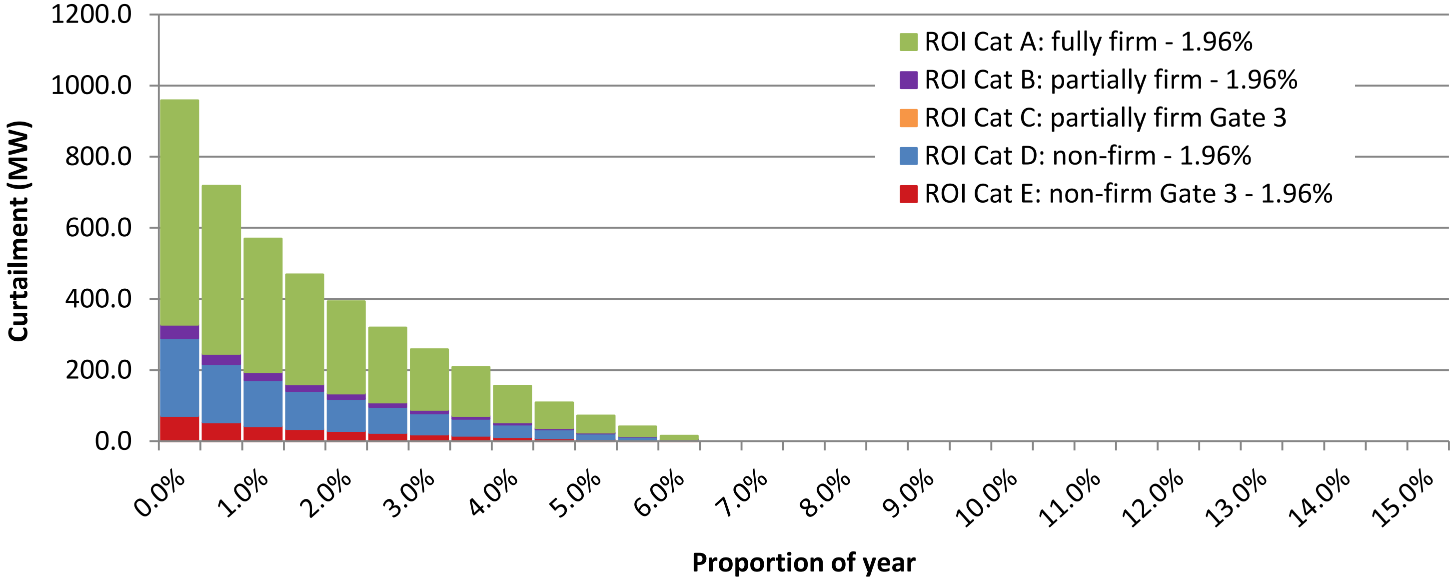
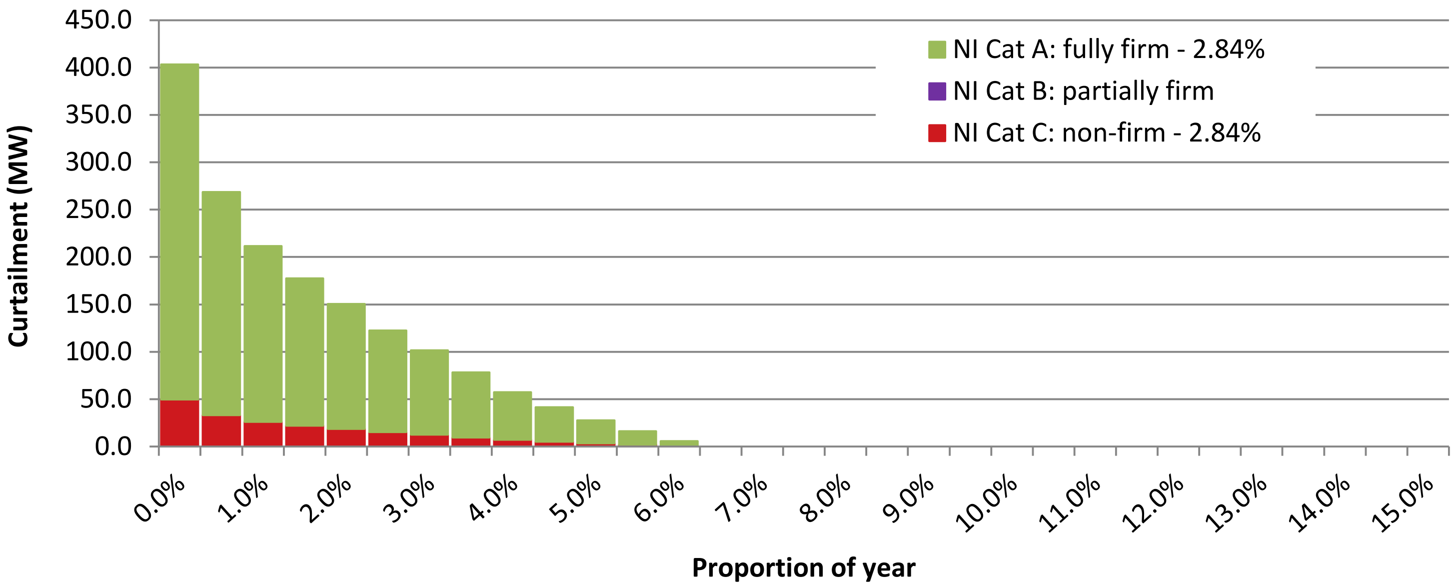
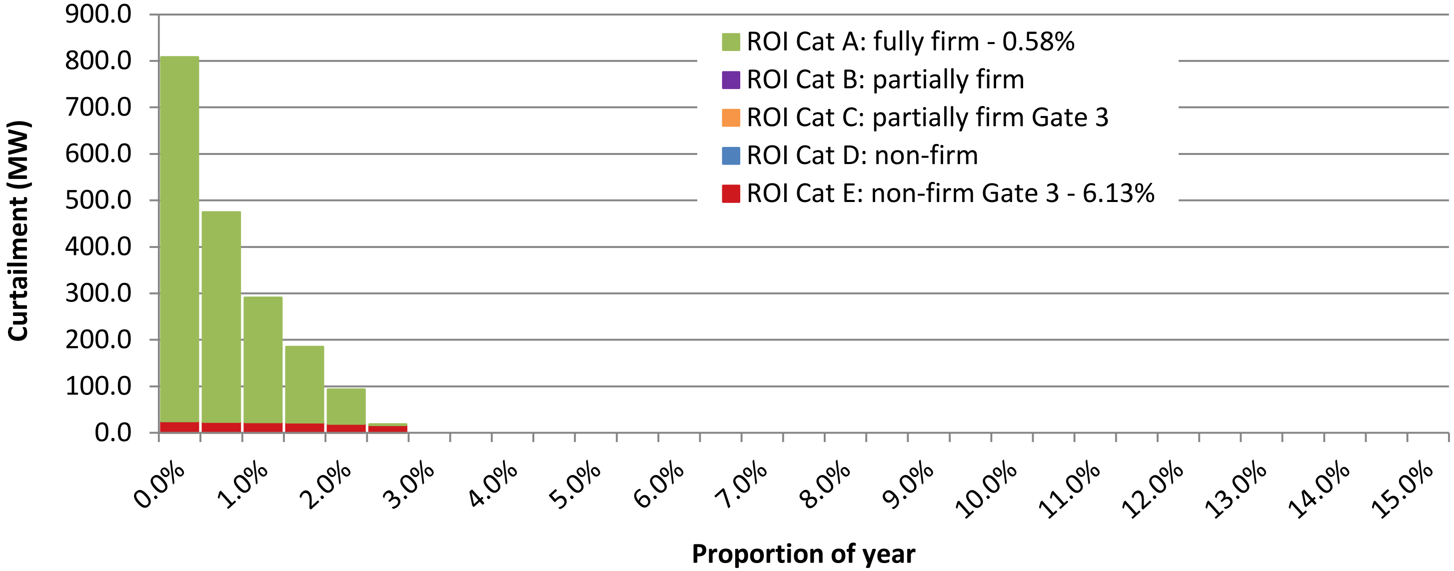
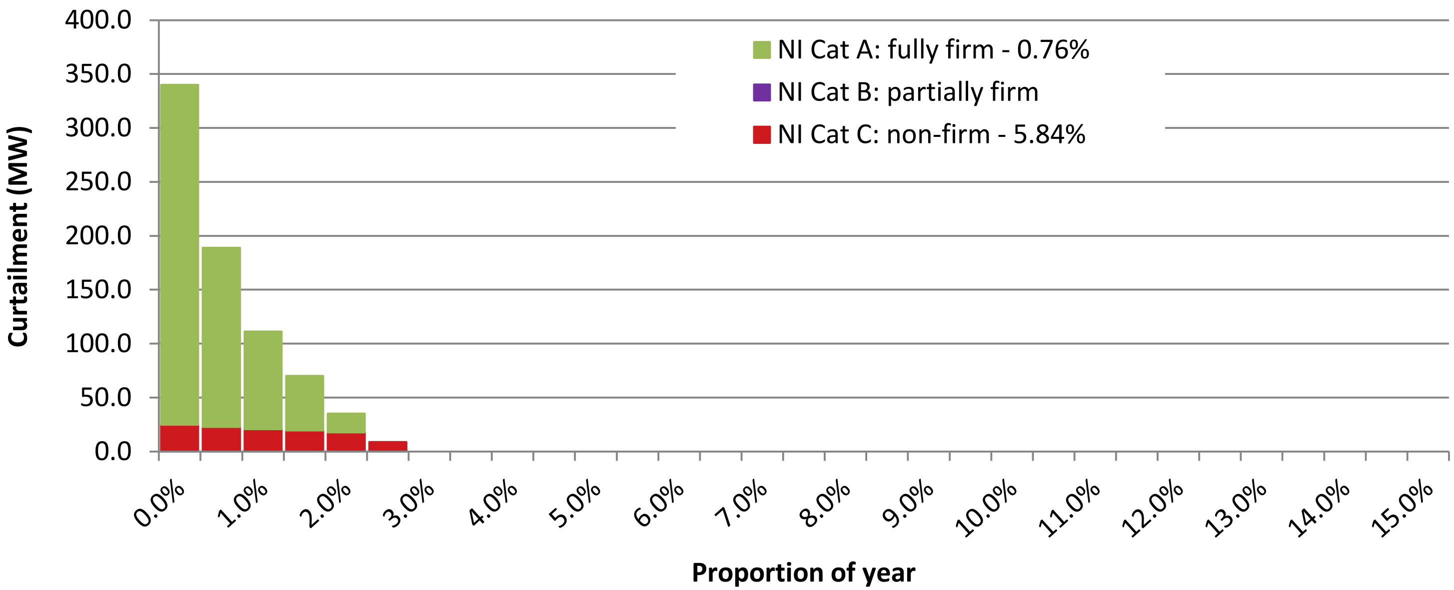




Curtailment 2020, Scenario 1





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Curtailment 2020, Scenario 2 (IWEA:3.77%)

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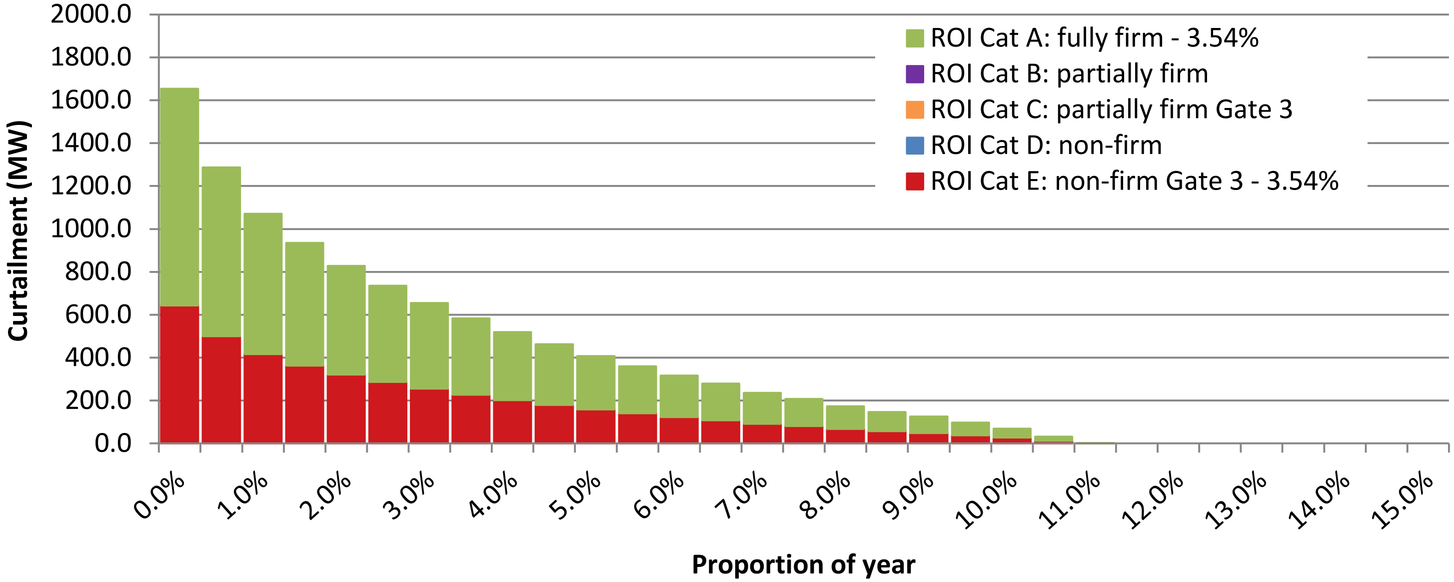
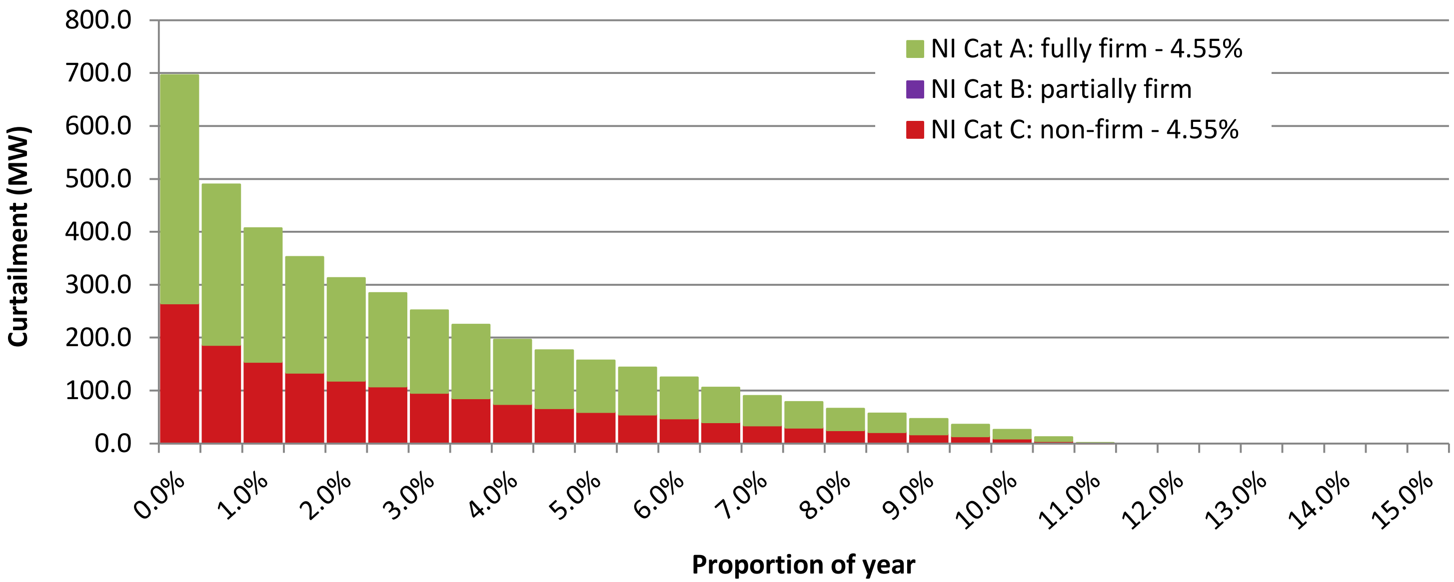
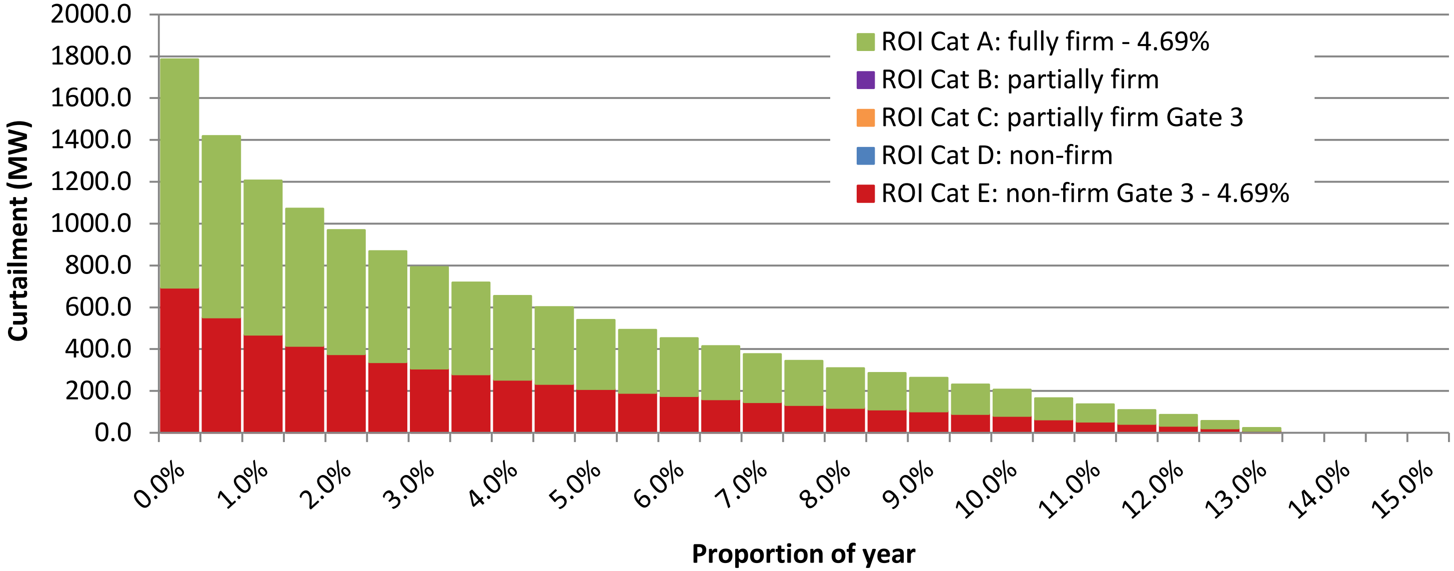
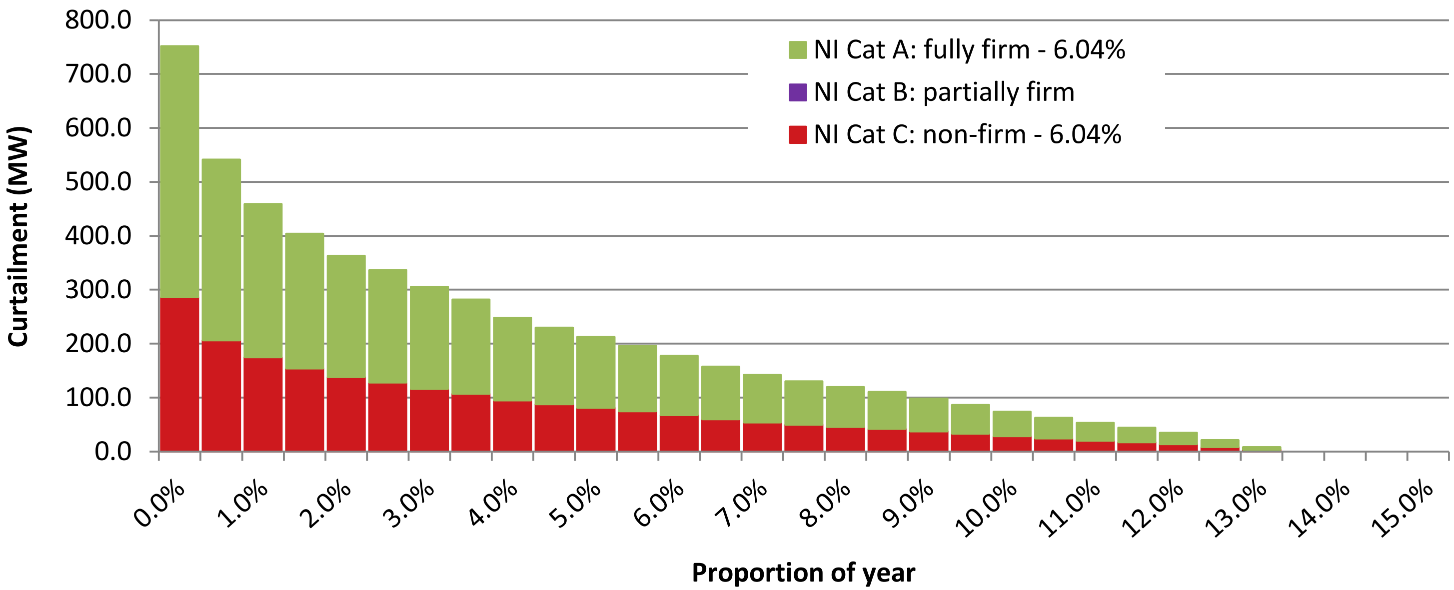




Curtailment 2020, Scenario 2 (EirGrid/SONI: 5%)





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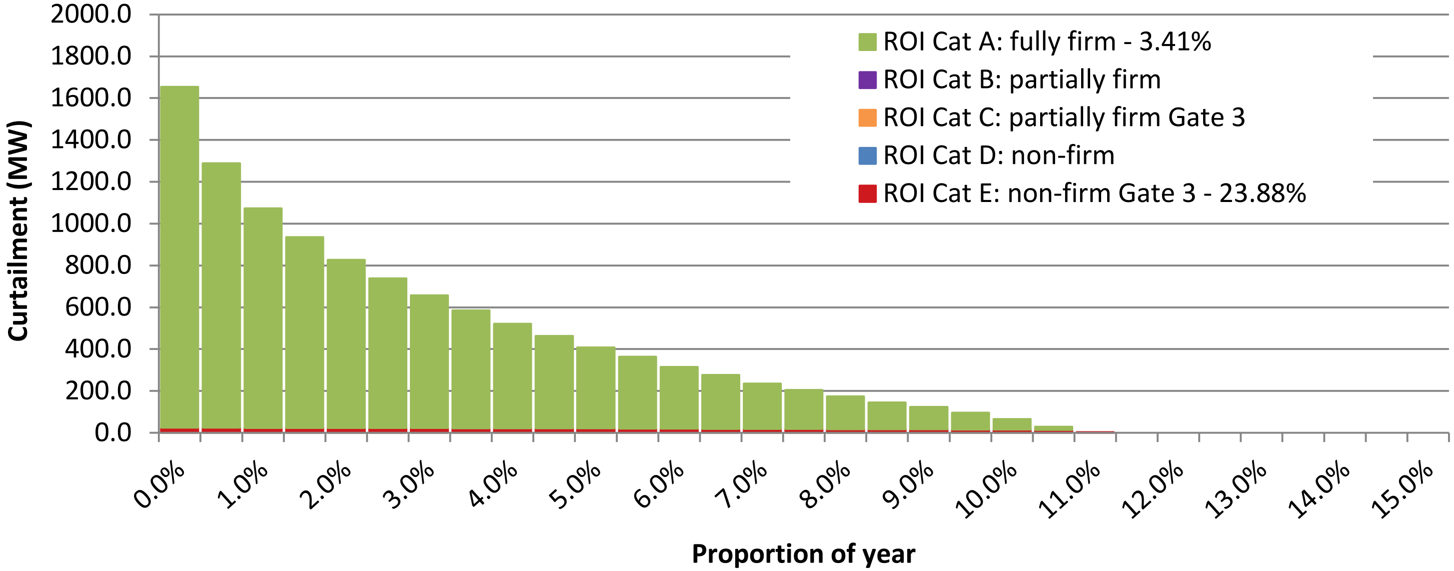
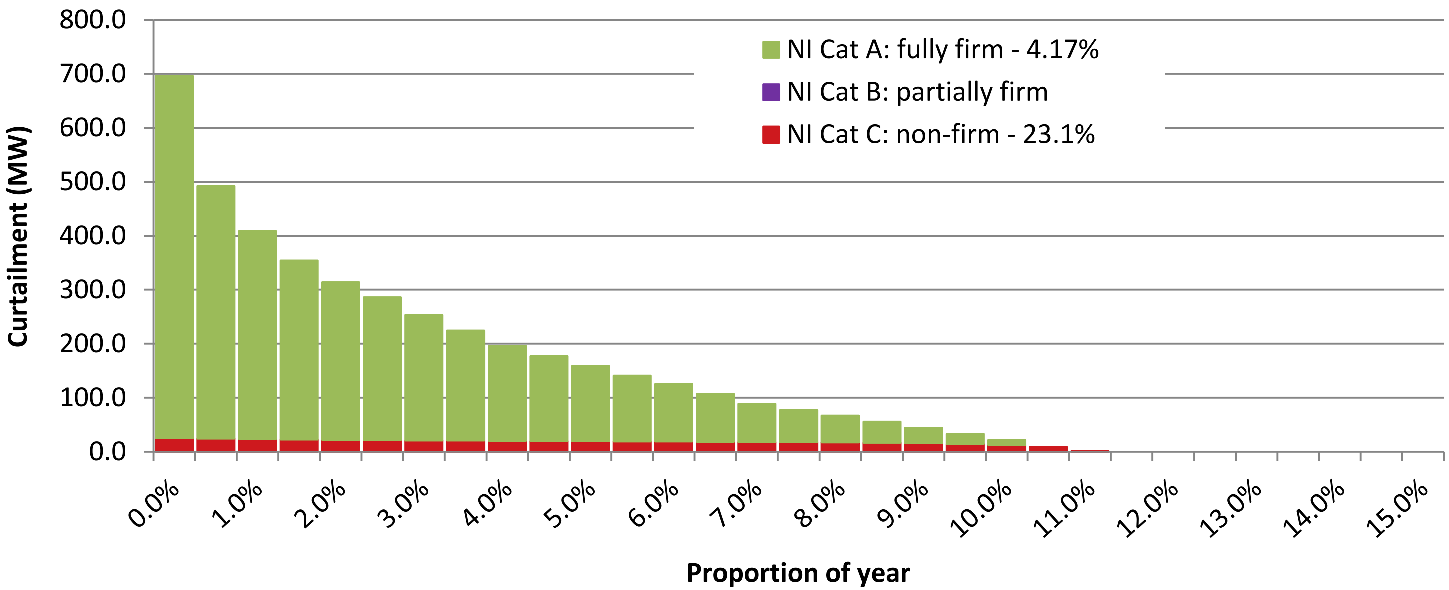
Curtailment 2020, Scenario 3 (IWEA:3.77%)





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Curtailment 2020, Scenario 3 (EirGrid/SONI: 5%)

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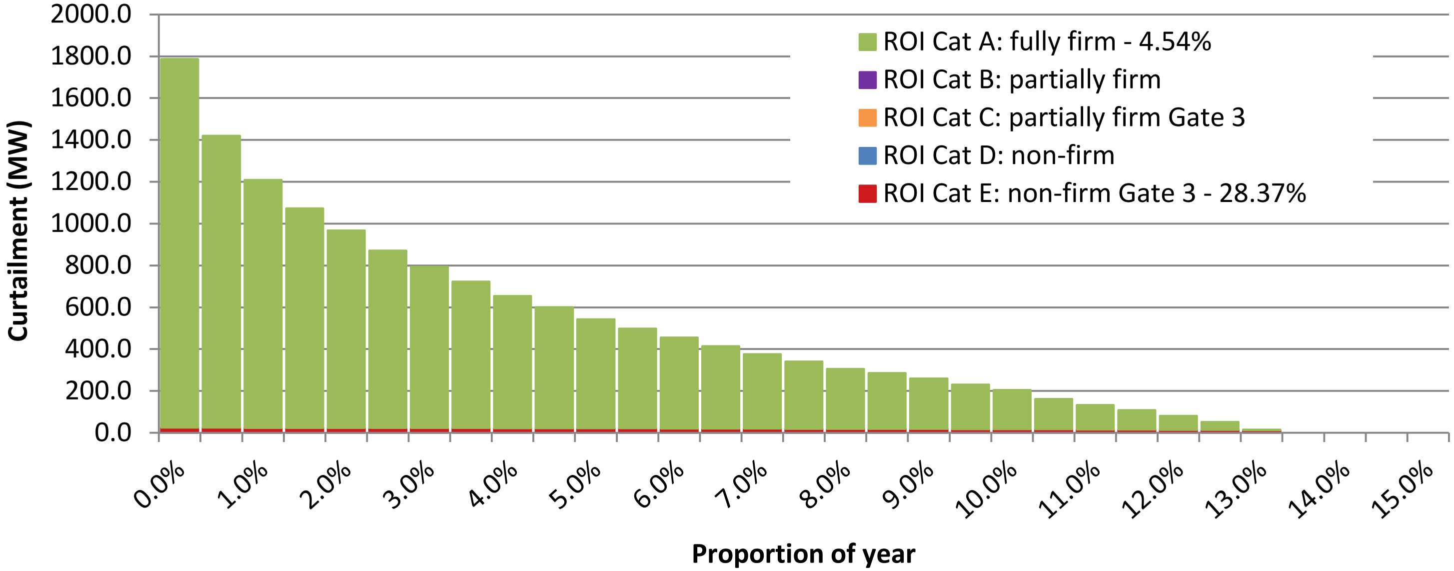
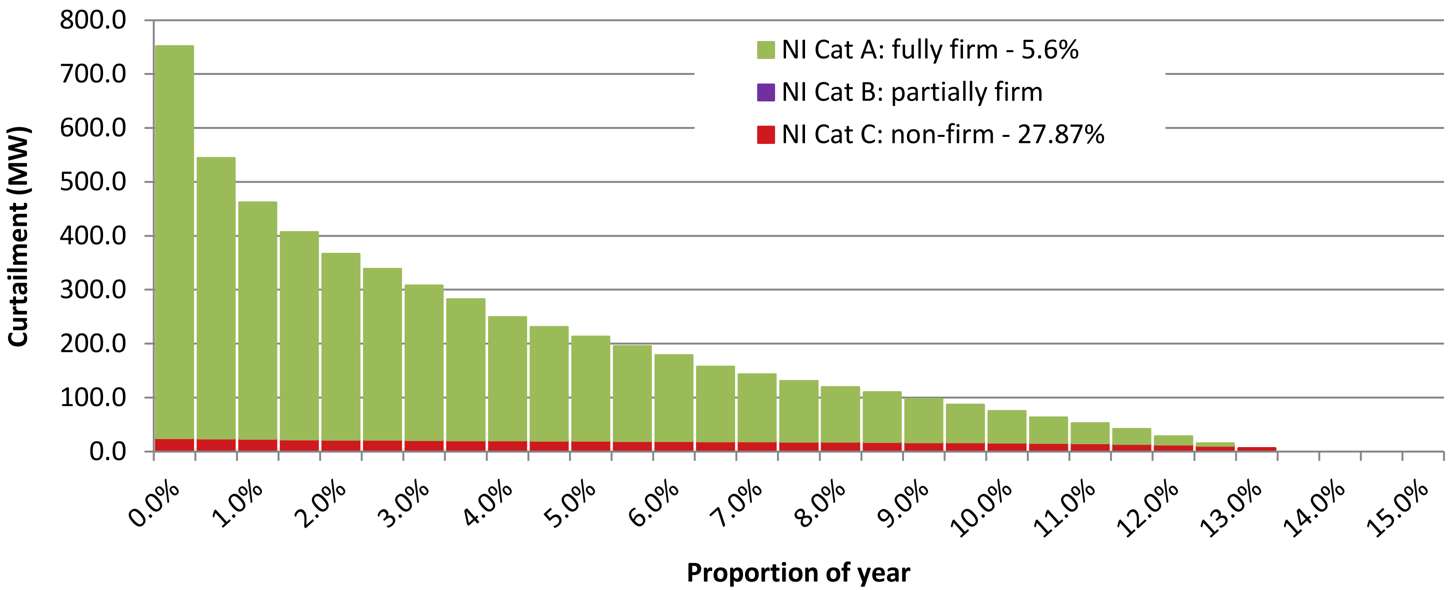
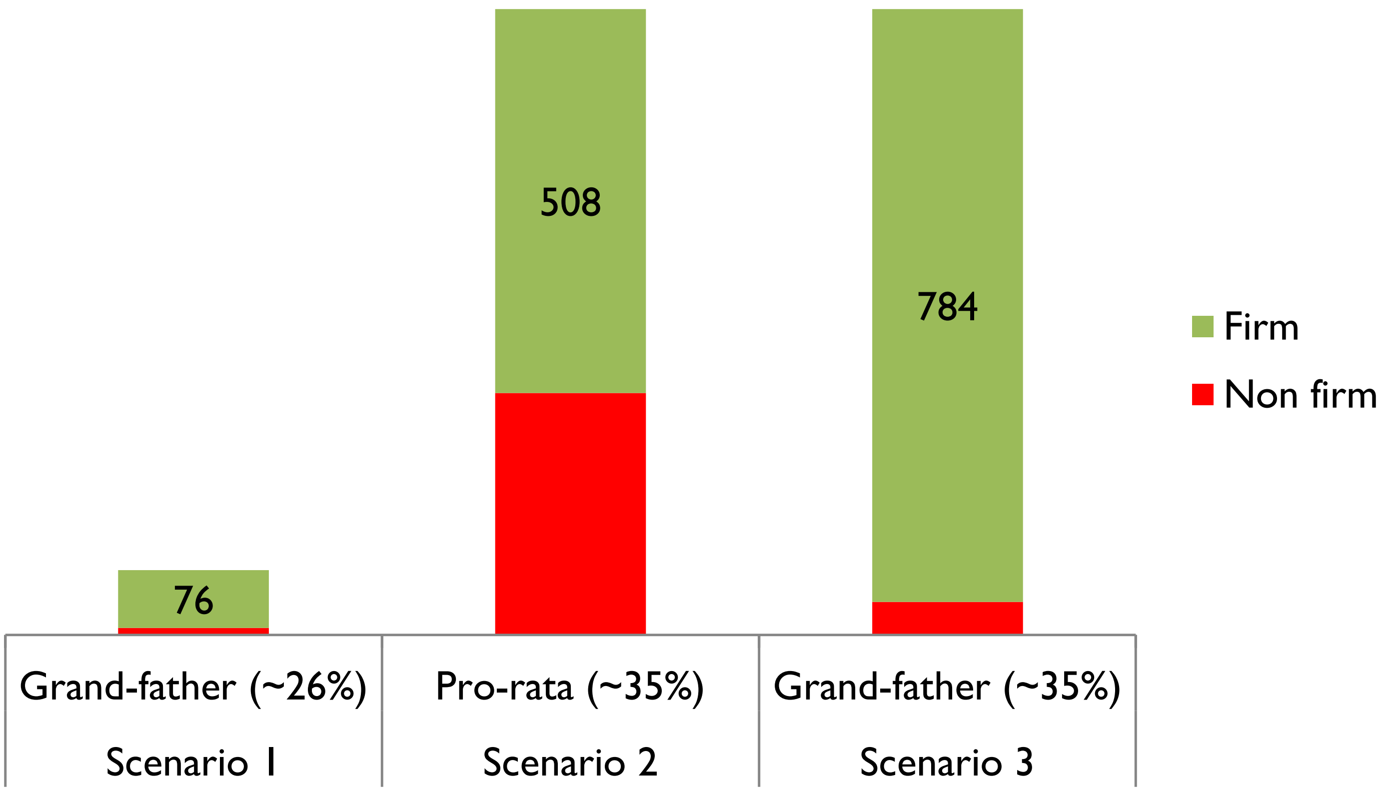




Incidence of curtailment – 2020 summary

- Estimated wind curtailment volumes (GWh) for 2020:
  - Assuming EirGrid/SONI forecasts of 5% aggregate curtailment for Scenarios 2 and 3



Incidence of curtailment – results summary

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- Under grand-fathering, burden of curtailment falls predominantly on non-firm generators
  - Over 25% curtailment projected for incremental non-firm generators in 2020 in Scenario 3 (assuming EirGrid/SONI forecasts of aggregate curtailment and sufficient wind build to meet RES-E targets)
- These results are based on conservative estimates for overall curtailment, as they do not include limitations on the System Operators' ability to re-optimise interconnector flows in order to mitigate the wind penetration constraints (by increasing exports / reducing imports)
- Detailed financial analysis is beyond the scope of this study, but material curtailment of non-firm generators is likely to threaten investment viability
  - How would consumers be affected if non-firm wind generation projects do not proceed?

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Potential consumer impacts

Consumer impacts with no non-firm investment

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- Unlikely to achieve the 40% RES-E targets in ROI and NI (DETI's Strategic Framework) without non-firm wind projects
  - Estimates from IWEA suggest that rather than ~35% of power from wind in 2020, only ~26% would come from wind if only projects with firm connections proceed

- We have sought to quantify multiple consumer impacts in 2020 for the three scenarios modelled:

Market Schedule & wholesale price impacts

- Higher penetration of wind reduces wholesale prices in the SEM where it displaces plant with higher short run marginal cost

Dispatch Balancing Costs

- Increasing the output of conventional generators to replace curtailed wind leads to higher constraint costs

PSO support costs

- REFIT payments to wind generators in ROI are a function of market revenues and post-curtailment output levels

Impact of wind generation on wholesale prices

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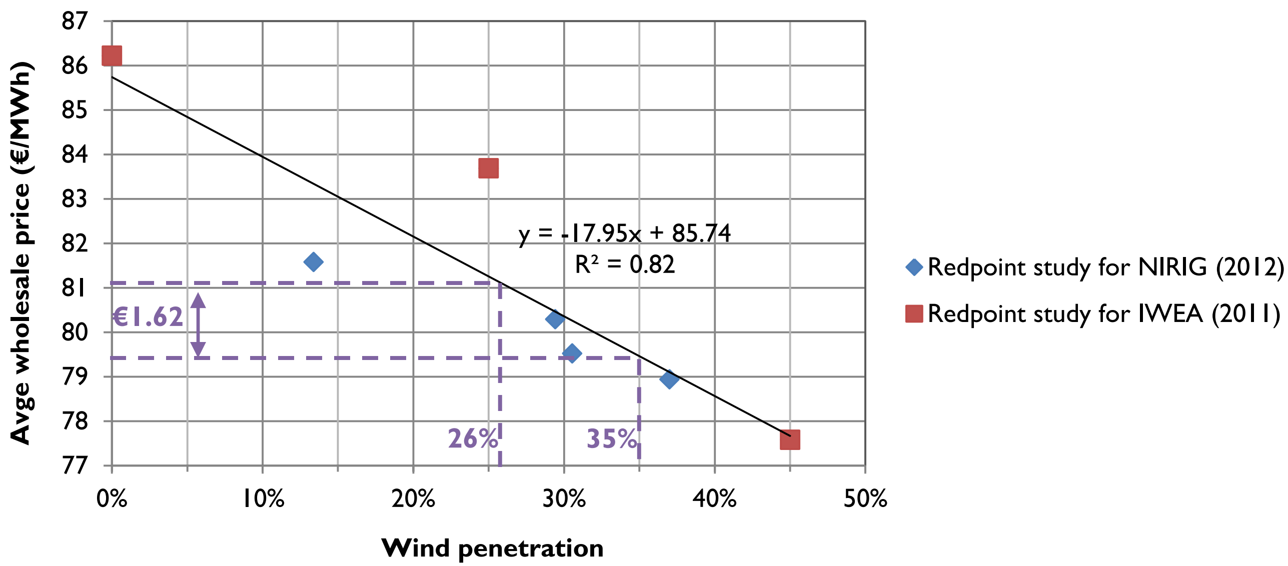
- Relationship between load-weighted wholesale price in the SEM and wind share estimated from previous modelling by Redpoint Energy for IWEA[1] and NIRIG
  - Approximately €0.18/MWh decrease in price for each 1ppt increase in wind penetration
  - Decrease in wind penetration from 35% to 26% could be expected to effect an average price increase of €1.62 /MWh in the SEM
  - Consumer costs of around €69M/year based on 2020 demand of around 42TWh
  - Further modelling would be required to reach more accurate conclusions



[1] Redpoint Energy, *The Impact of Wind on Pricing Within the Single Electricity Market,* Report for IWEA (February 2011)

Non-firm curtailment and wholesale prices

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- Following the implementation of T&SC Mod_43_10, we understand non-firm capacity will be excluded from price-setting in the Market Schedule when curtailed

- We have approximated the wholesale price impact of curtailed non-firm generation by considering the relationship between annual average wholesale prices and wind penetration shown previously (excluding curtailed non-firm wind)
  - Approximately €0.18/MWh decrease in price for each 1ppt increase in wind penetration due to non-firm curtailment
  - This indicates some price impact due to the exclusion of non-firm generators from Market Schedule at 35% wind share, but the larger impact is from not achieving target in Scenario 1

Scenario	Curtailment option	Wind RES-E	Impact on wholesale prices of lower wind capacity (€M/yr)	Impact on wholesale prices of non-firm curtailment (€M/yr)
1	Grand-father	~26%	+68.7	+0.2
2	Pro-rata	~35%	-	+5.7
3	Grand-father	~35%	-	+0.8

Wind replacement costs #1

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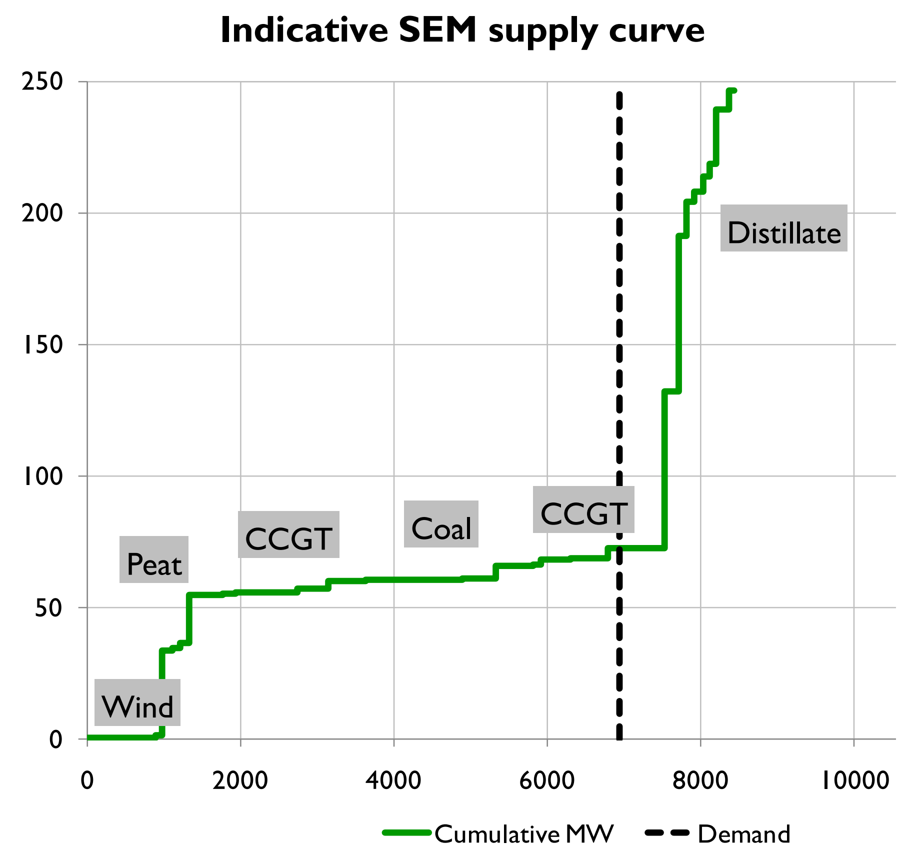
- Curtailed wind generation must be replaced by alternative generation sources (unless available wind generation exceeds demand), and the cost of this replacement energy contributes to Dispatch Balancing Costs (the cost of deviations between the market schedule and actual dispatch)
- Previous modelling by Redpoint Energy for IWEA and NIRIG suggests that the cost of replacement energy is generally close to the prevailing level of SMP
  - As illustrated to the right, the SEM is characterised by a flat supply curve over the typical range of demand, due to the large fleet of gas-fired CCGTs with similar thermal efficiencies
  - Modelling of dispatch profiles with wind curtailment indicates higher incremental costs (fuel, carbon) for gas plant relative to the market schedule, but lower start costs (eg replacing curtailed wind energy during low demand periods overnight may avoid the need to shut down and then restart a CCGT)
  - While the incremental cost of replacement generation would generally be expected to exceed the Shadow Price set by the marginal generator in the market schedule, SMP also includes an Uplift component over and above Shadow Price



Wind replacement costs #2

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- T&SC Mod_43_10 has the effect of excluding non-firm generation capacity from the Market Schedule when curtailed. This implies that the replacement of curtailed non-firm wind generation is already accounted for in the Market Schedule
  - As discussed in a previous slide, replacing curtailed non-firm wind with conventional generation in the Market Schedule may put upward pressure on SMP (we have already estimated this price impact above and so do not consider it here as a component of wind replacement costs)
- The wind replacement component of Dispatch Balancing Costs can therefore be estimated by multiplying the modelled firm wind curtailment volumes by the assumed average price of replacement energy
  - Average SMP weighted by firm wind curtailment estimated using hourly price duration curves for 2020 obtained by recent Redpoint modelling of the SEM under generation backgrounds consistent with meeting RES-E target (as in Scenarios 2 and 3) or under-shooting (Scenario 1)

2020 replacement costs (€/MWh)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
Average SMP (firm curtailed)	58.6	54.4	53.9

  - Curtailment volumes based on EirGrid/SONI estimate of 5% curtailment in 2020 for Scenarios 2 and 3

Wind replacement costs #3

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- Assuming the cost of replacement energy is close to prevailing SMP levels, we obtain the following cost estimates for 2020:

2020 replacement costs (€M)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
@ ~SMP	4.5	27.6	42.3

  - Overall wind curtailment volumes are the same in Scenarios 2 and 3, but replacement costs are higher under Scenario 3 due to the much higher proportion of firm wind capacity
  - Wind penetration, curtailment and hence replacement costs are all lower in Scenario 1

- Sensitivity to the cost of replacement energy assuming a premium above SMP:

2020 replacement costs (€M)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
@ ~SMP + €5/MWh	4.9	30.2	46.2
@ ~SMP + €10/MWh	5.2	32.7	50.1

Wind compensation costs

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- Firm wind capacity is entitled to receive the market price, SMP, in the Market Schedule when available, even if actual output is curtailed
  - ‘Compensation’ for firm curtailed wind is therefore settled directly in the Market Schedule, rather than forming a component of Dispatch Balancing Costs

- ‘Compensation’ payments to firm curtailed wind generators do not directly impact the costs faced by SEM consumers
  - Wind compensation costs are essentially transfers of infra-marginal rent between generators in the Market Schedule, and so do not directly increase costs for consumers (SMP * load)

- As discussed and quantified in previous slides, SEM consumers are exposed to the impact of wind curtailment due to the requirement for replacement energy
  - Replacing non-firm curtailed wind in the Market Schedule may lead to increases in SMP
  - Replacing firm curtailed wind will most likely lead to higher Dispatch Balancing Costs

PSO REFIT assumptions

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- PSO assumptions
  - REFIT 2 balancing payment capped at 9.90 €/MWh (not CPI indexed)
- Market revenues
  - Wind-weighted average SMP * wind output
  - Average capacity payment * wind availability
  - [***Firm only***] Curtailment-weighted average SMP * curtailed wind output
- REFIT 1 pay-out
  - Floor payment: Max (0 , Reference price * wind output - Market revenue)
  - Balancing payment: Reference price * 15% * wind output
- REFIT 2 pay-out
  - Floor payment: Max (0 , Reference price * wind output - Market revenue)
  - Balancing payment: Max (0, Min (9.90, Reference price + 9.90 – Market revenue price)) * wind output

PSO REFIT support costs

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- SMP profiles and capacity payment assumptions sourced from recent Redpoint SEM studies
  - Average capacity payment: 7.29 €/MWh

Wind-weighted average SMP (€/MWh)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
Firm ROI	77.7	75.9	75.9
Non-firm ROI	78.7	75.9	79.5

- Assumed ROI wind capacity under REFIT
  - 741 MW of AER capacity no longer supported by PSO in 2020
  - Maximum REFIT 1 wind capacity: 1450 MW

2020 capacity (MW)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
Firm REFIT 1 capacity	1450	1450	1450
Non-firm REFIT 1 capacity	0	0	0
Firm REFIT 2 capacity	904	253.6	1784
Non-firm REFIT 2 capacity	25	1555.4	25

PSO REFIT support costs

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- The underlying assumptions on commodity prices and SMP levels lead to market revenues exceeding the REFIT floor in 2020
  - Only REFIT 1 balancing payments contribute to PSO costs for ROI consumers in this case:

2020 PSO costs	Scenario 1	Scenario 2	Scenario 3
(€M)	Grand-father (~26%)	Pro-rata (~35%)	Grand-father (~35%)
REFIT	46.9	45.0	45.0

  - All three scenarios assume 1450 MW of firm REFIT 1 wind capacity in 2020
  - This firm REFIT 1 capacity is curtailed less in Scenario 1, leading to marginally higher REFIT 1 balancing payments and PSO costs

PSO REFIT sensitivities

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- PSO REFIT support costs would increase if market prices were lower, as illustrated by the following sensitivities on the SMP assumption
  - PSO REFIT costs have been estimated for sensitivities reducing the wind-weighted average SMP by €10/MWh and €20/MWh below the baseline

2020 PSO costs (€M)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
SMP less €10/MWh	49.7	58.6	46.8
SMP less €20/MWh	91.4	121.9	110.5

  - Reducing average SMP by €10/MWh leads to REFIT 2 balancing payments
  - Reducing average SMP by €20/MWh leads to market revenues below the REFIT Reference price

- PSO REFIT costs are higher for ROI consumers in Scenario 2 due to the higher proportion of non-firm wind capacity, which receives lower annual market revenues due to the lack of compensation when curtailed
  - By contrast, in Scenario 3 wind curtailment is directly compensated in the market (and it is likely that consumers would face higher Dispatch Balancing Costs compared to Scenario 2 due to the costs of replacing firm curtailed wind)

NI RO generator payments

- Renewables in Northern Ireland are currently supported by the Renewables Obligation, although the UK's Electricity Market Reforms may ultimately lead to a new support scheme in NI
- Support payments to NI generators have been estimated assuming all NI wind capacity is eligible to receive Renewables Obligation Certificates (ROCs) in 2020
  - ROC price assumption of £42.6 in 2020 sourced from recent Redpoint UK market studies
  - For simplicity, all NI wind is assumed to receive 1 ROC per unit of output based on the current support levels for large (>250kW) onshore wind

2020 NI ROC payments (€M)	Scenario 1 Grand-father (~26%)	Scenario 2 Pro-rata (~35%)	Scenario 3 Grand-father (~35%)
ROC payments	136.5	187.2	187.2

- ROC payments to NI generators do not map directly to NI consumer costs, particularly under scenarios in which NI fails to meet renewable targets or conversely has surplus RES-E available to meet UK-wide targets
  - NI suppliers would in principle face buy-out penalties if RES-E targets were missed
  - ROCs are currently fungible between NI and GB, allowing for RES-E trading between UK regions
- NI consumer support costs for renewables would not necessarily be any lower in Scenario 1 than Scenarios 2 and 3 (and indeed may be higher depending on the penalty regime)
  - **Hence it is not valid to add the generator ROC payments above to net consumer cost impacts**

Conclusions

Scenario comparison in 2020

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- Estimated net consumer impacts are shown below:

Scenario	Curtailment option	Wind RES-E	Impact on wholesale prices of lower wind capacity (€M/yr)	Impact on wholesale prices of non-firm curtailment (€M/yr)	Wind replacement cost (€M/yr)	PSO wind REFIT cost (€M/yr)	Estimated net impact (€M/yr)	Estimated impact relative to Scenario 2 (€M/yr)
1	Grand-father	~26%	+68.7	+0.2	+4.5	+46.9	+120.3	**+42.0**
2	Pro-rata	~35%	-	+5.7	+27.6	+45.0	+78.3	**-**
3	Grand-father	~35%	-	+0.8	+42.3	+45.0	+88.1	**+9.8**

Market Schedule

Dispatch Balancing Costs

PSO

Conclusions

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- Grand-fathering (as per the SEM-12-028 consultation) could inhibit financing of non-firm generators subject to material levels of curtailment
  - This could compromise meeting 2020 RES-E target

- Our analysis indicates that the pro rata approach leads to lower consumer costs in 2020
  - If there was no investment in non-firm generation, net costs to consumers in 2020 are estimated at ~€42M/year (comparing Scenarios 1 and 2) as wholesale price increases are likely to outweigh savings from replacing curtailed wind
  - Sensitivity analysis implies that average SMP levels would need to fall by more €20/MWh and replacement costs rise by more than €10/MWh for additional PSO and curtailment costs under Scenario 2 to outweigh the potential wholesale price benefits of meeting the RES-E target
  - Further modelling could be conducted to quantify consumer impacts in more detail, but the analysis conducted in this study suggests that the direction of the effect is clear