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Options for allocating and realising distribution system capacity: Deciding between interruptible connections and firm DG connections

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Contents

1. Introduction

About the Flexible Plug and Play (FPP) Project

- The aim of the project is to trial innovative and cost-efficient technical and commercial solutions to integrate distributed generation to the electricity distribution network.
- Implemented by UK Power Networks under the Low Carbon Network Fund (LCNF) Scheme.
- EPRG is a key stakeholder.

About this Paper

- The purpose of this study is to *quantify the trade-off between selecting a distributed generation (DG) smarter connection with limited export capacity and a DG firm connection with full export capacity.*
- *A cost-benefit analysis of the different connection options for connecting DG customers in a specific constrained area in the UK (March Grid, operated by UK Power Networks) is performed for this purpose.*

2.Background – Curtailment

Definition of Curtailment: Any limitation that prevents the generator to export its maximum capacity to the distribution or transmission network.

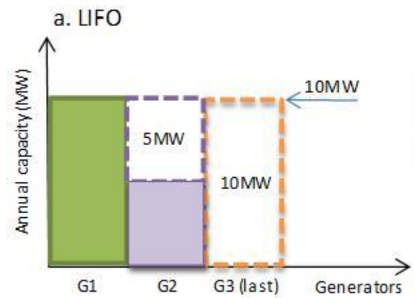
Rules for Allocation of Curtailment (knows as ‘Principles of Access’ or POA):

- **LIFO (last in first out):** Generators are given a specific order for being curtailed (based on a selected parameter such as the connection date).
- **Pro Rata:** Curtailment is equally allocated between all generators that contribute to the constraint.
- **Market-Based:** Generators curtailed by offering a market price at which they will accept curtailment.

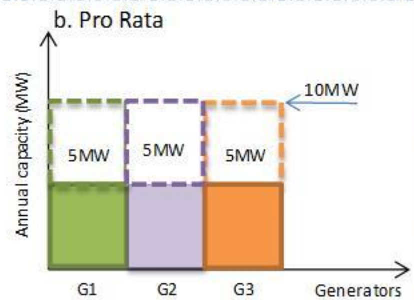
2.Background – Curtailment

Fig. 1: Principle of Access - Example

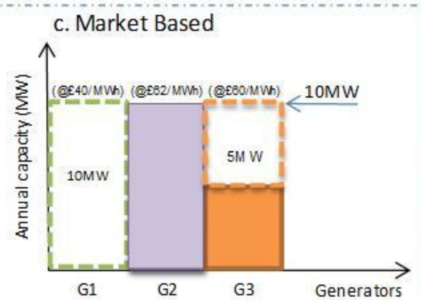
Allocation Rule | **Notes**



G3 is the first generator to be curtailed up to 10MW then G2 up to 5MW. Maximum level of curtailment is 10MW + 5MW = 15 MW. G1 is not affected.



G1, G2 and G3 are equally curtailed up to complete 15MW. Curtailed energy per generator is equal to: Maximum level of curtailment * Generator Capacity /(Total Capacity) = 15 * (10/30) = 5MW.



G1, G2 and G3 bid for being curtailed. The selection is made on cost order: G1 first @£40/MWh (10MW), G3 second @£60/MWh (5MW). G2 is not selected because the maximum level of curtailment has already been allocated (10MW+5MW=15MW).

Own elaboration.

2.Background – Curtailment

Risk Allocation Scenario in previous example:

- If there is a 10% probability of 15 MW curtailment and 90 % probability of no curtailment (in terms of installed capacity), the respective average and variances across POA would as follows:

Principle of Access	Nominal MW	Mean MW after Curtailment	Curtailment induced Variance
LIFO			
Third in Generator	10	9	1.25
Second in Generator	10	9.5	0.375
First in Generator	10	10	0
Pro Rata			
All Generators	10	9.5	0.375

- In case of market based three different scenarios could be observed:
  - Generator paid equal to the expected loss (to a maximum of 10% of output)
  - Generator paid more than the expected loss (to compensate for risk aversion)
  - Generator paid less than the expected loss (to reflect avoided internal costs)

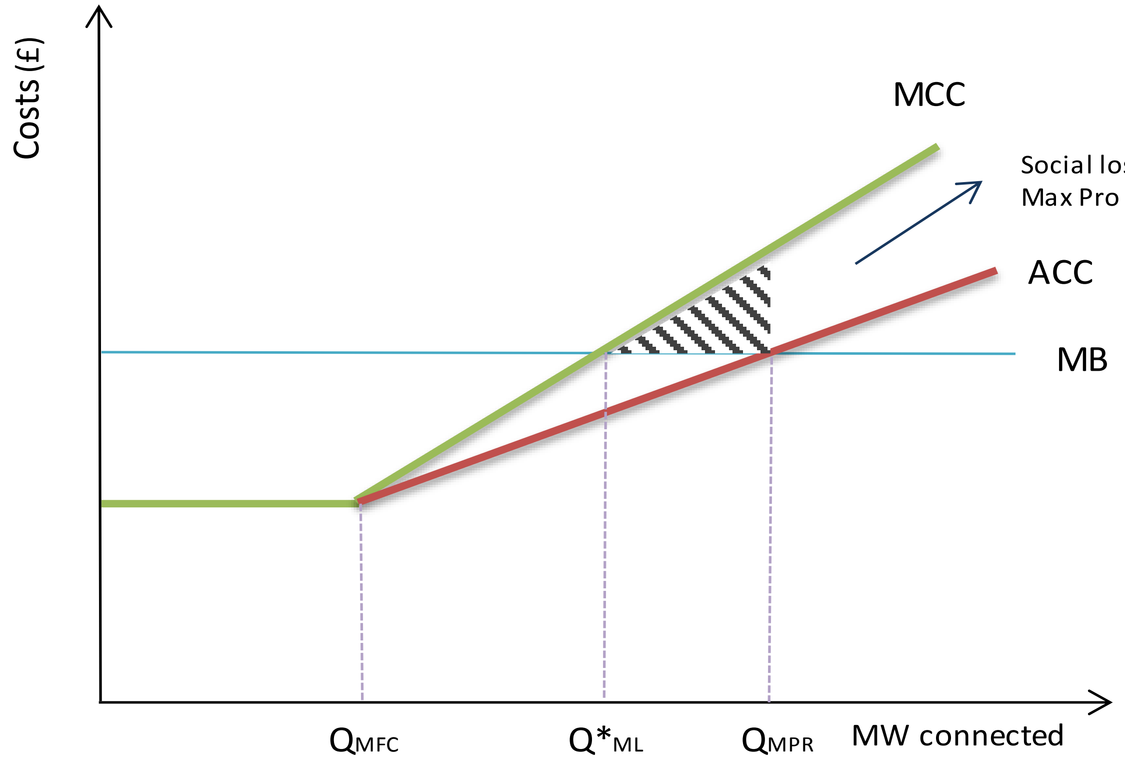
2.Background – Curtailment

What is best for society? (Social optimality):

- Assume that the MB to the system of each additional unit of DG capacity is constant (same subsidy and technology).
- **LIFO: reflects the social optimum** (each generator is exposed to their marginal connection/curtailment cost, MCC) to the system) . MCC should be = Marginal Benefit (MB).
- **Pro Rata: does not reflect the social optimum** (generator faces the average connection/curtailment costs, ACC). ACC=MB. Social loss = shaded area (Fig. 2).
- Shaded area: those incremental system costs above the system benefit (produced by each additional MW of wind generation beyond the point where MCC=MB).

2.Background – Curtailment

Fig. 2: Optimal connection (MW) with fixed constraint (ignoring risk)



Where **MCC** : Marginal connection cost, **ACC** : Average connectio cost, **MB** : Marginal benefits,

Q_{MFC} : Max firm connection, **Q^*_{ML}** : Max LIFO, **Q_{MPR}** : Max Pro Rata. Own elaboration.

2. Background – DG in the UK

a. Definition

- Generation units connected to the distribution grid (in the UK up to 132 kV)

b. Connection charges

- Shallowish connection (sole-use assets + % reinforcement costs)

c. Use of system charges

- On-going charges, introduced in 2005

d. **Incentives and Subsidies**

- Feed in Tariffs – FIT (up to 5 MW)
- Renewable Obligations – RO (over 5 MW)
- Contract for Difference (CfD) FIT: will replace RO in 2017
- LCNF (Low Carbon Network Fund): support to DNOs (up to £500m) for deployment of trials/new technologies/commercial initiatives
- IFI (Innovation Funding Incentives): encourage DNOs to promote research and development activities with a focus on technical development projects
- DG Incentives – recovery mechanism, reduces the risk to DNOs and customers of bad forecast of DG volumes and costs. To be removed next year. No longer required given the package of measures sets in RIIO-ED1

2. Background-Connections (non-firm, firm)

- **Non-firm or interruptible connection** allows a quicker and cheaper integration of DG by sacrificing the export of full generation capacity.
- **Firm connection**, the traditional connection, allows the export of full generation capacity, but at the same time it is also subject to higher connection costs (especially in case of reinforcement) in comparison with the non-firm connection option.
- The selection of either connection option will depend on the DG business model, and the market and regulatory context.

3. Cost Benefit Analysis Method

CBA: $\sum benefits - \sum costs$

$$\boldsymbol{Benefits = elect.\ revenues + incentives\ (FIT, RO, LEC) + embedded\ benefits + energy\ savings\ (only\ solar\ PV)}$$

$$\boldsymbol{Costs = generation\ costs\ (capex + opex) + FPPconnection\ costs + reinforcement\ costs}$$

Where:

All benefits and costs are discounted

Elect. Revenues: incomes from the sale of electricity in the wholesale market

Incentives: FIT: Feed-in-Tariff, RO: Renewable Obligation, LEC: Levy Exemption Certificate.

Energy savings: in the case of auto consumption (only for solar)

Generation costs: composed of capital and operational expenses

FPP Connection costs: related to those costs for interruptible connections, use of smart solutions

Reinforcement costs: those costs incurred by generators if a firm connection is required

Embedded benefits (EB): Those costs that generators may save when they are directly connected to the distribution network instead of the transmission network. Six types of embedded benefits.

3. Cost Benefit Analysis Method

Variables

1. Cost variables: CAPEX, OPEX, FPP connection costs, reinforcement costs, business as usual connection costs
2. Revenues: sale of electricity in the wholesale market, subsidies/incentives, energy savings (only for solar PV)
3. Embedded Benefits (EB): (1) generator avoidance balancing system charges, (2) generator transmission loss reduction, (3) distribution use of system charges, (4) supplier avoidance balancing system charges, (5) supplier avoidance balancing system charges, (6) distribution line loss
4. Technical variables: capacity factor (wind: 30%, solar PV: 9.7%, AD CHP: 84%), PV module degradation (0.55% pa), export rate (85%), losses (average transmission: 2%, ratio: 45% generator, 55% supplier.
5. Rent and tax: discount rate (10%), corporate tax (21%)
6. Power Purchase Agreement: set for sale of electricity and incentives/subsidies

4. Connection Scenarios

- Four scenarios are proposed:
  - Scenario 1: with partial interruptible connected capacity – 100% wind
  - Scenario 2: with full interruptible connected capacity –100% wind
  - Scenario 3: with full interruptible connected capacity- a mix of DG generation
  - Scenario 4: with full interruptible connected capacity and option of network reinforcement – 100% wind
- Diversity of scenarios:
  - illustrates and assesses different connection options in case of restricted capacity (constrained area)
  - provides insights about the possible solutions (deciding between smart interruptible connections or full connection subject to reinforcement) and the costs of selecting one or other (net present value of each solution)
  - contributes to a better explanation of the different connection situations that generators face in the real world

4. Connection Scenarios

- Assumptions:
  - All scenarios refer to a specific constrained area (March Grid) operated by UK Power Networks, the largest DNO in the UK (with 8.1m customers)
  - Total interruptible capacity quota: 33.5 MW (maximum interruptible capacity offered to generators under Pro Rata). After fulfilling this capacity a LIFO approach would be applicable
  - Fixed demand across the four scenarios
  - Only one level of curtailment across scenarios (maximum curtailment level that depends on technology). Different generators have different generation patterns
  - Curtailment level with full capacity quota: wind (5.33%), solar PV (2.57%), AD CHP (1.73%)
  - The number of generators and their capacity based on the list of generators provided by UK Power Networks
  - Export capacity (85%) only in case of solar PV

4. Connection Scenarios

Table 1: Summary of Scenarios

Scenarios	Non- firm capacity		Firm capacity [1/]		# Generators [2/]	Generation Mix			Curtailment
	full	partial	full	partial		wind	solar PV	AD CHP	level (%) [3/]
Scenario 1		18 MW		18 MW	5	100%			0.33
Scenario 2	33.5 MW			33.5 MW	7	100%			5.33
Scenario 3	33.5 MW			33.5 MW	11	82.84%	13.43%	3.73%	5.33
Scenario 4	33.5 MW		90 MW		7 (20)	100%			5.33

[1/] Due to the addition of 56.5 MW (33.5+56.5=90 MW) by 2019/2020. [2/] In Scenario 4 the number of generators is 20 after the period 2019/20

[3/] Only applicable to non-firm (smart) connections. In Scenario 3 curtailment level for solar PV and AD CHP are 2.57% and 1.73% respectively. In Scenario 4 this % is only valid up to the period 2019/20. After this, a firm connection if offered.

4. Connection Scenarios

Table 2: Generators' Figures (capacity, curtailment, costs)

Generators			Scenario 1	Scenario2	Scenario 3	Scenario 4		Costs (2012 prices)	
No	Type of generator	Capacity (MW)	Estimated curtailment - annual MWh	Estimated curtailment - annual MWh	Estimated curtailment - annual MWh	Estimated curtailment (2014-2019/20) - annual MWh	Estimated curtailment (2019/20 onwards) - annual MWh	Connection Costs (BAU offer) £	Connection Costs £
1	wind	0.5	4	70	70	70	0	1,900,000	234,779
2	wind	1	9	140	140	140	0	2,000,000	384,711
3	wind	1.5	13	210	210	210	0	1,900,000	157,137
4	wind	5	43	700	700	700	0	1,200,000	649,788
5	wind	10	86	1,400	1,400	1,400	0	4,800,000	590,817
6	wind	7.2		1,008	1,008	1,008	0	3,456,000	425,388
7	wind	8.3		1,162		1,162	0	3,984,000	490,378
8	wind	2.55			357			3,230,000	267,133
9	solar PV	4.5			113			1,080,000	233,916
10	ADCHP	0.5			64			1,900,000	350,000
11	ADCHP	0.5			64			2,500,000	100,000
12	ADCHP	0.25			32			2,205,750	117,450
13	wind	0.5					0	1,900,000	234,779
14	wind	1					0	2,000,000	384,711
15	wind	1.5					0	1,900,000	157,137
16	wind	5					0	1,200,000	649,788
17	wind	10					0	4,800,000	590,817
18	wind	7.2					0	3,456,000	425,388
19	wind	8.3					0	3,984,000	490,378
20	wind	0.5					0	1,900,000	234,779
21	wind	1					0	2,000,000	384,711
22	wind	1.5					0	1,900,000	157,137
23	wind	5					0	1,200,000	649,788
24	wind	10					0	4,800,000	590,817
25	wind	5					0	1,200,000	649,788

5. Results

- **Scenario 1: with partial interruptible connected capacity – 100% wind**
  - Illustrates the case where there is not enough demand to cover the full capacity available in a specific point of connection
  - Partial utilisation of total interruptible capacity quota (18 MW, 5 generators)
  - Low curtailment level: 0.33% (53% of total cap., partial use)

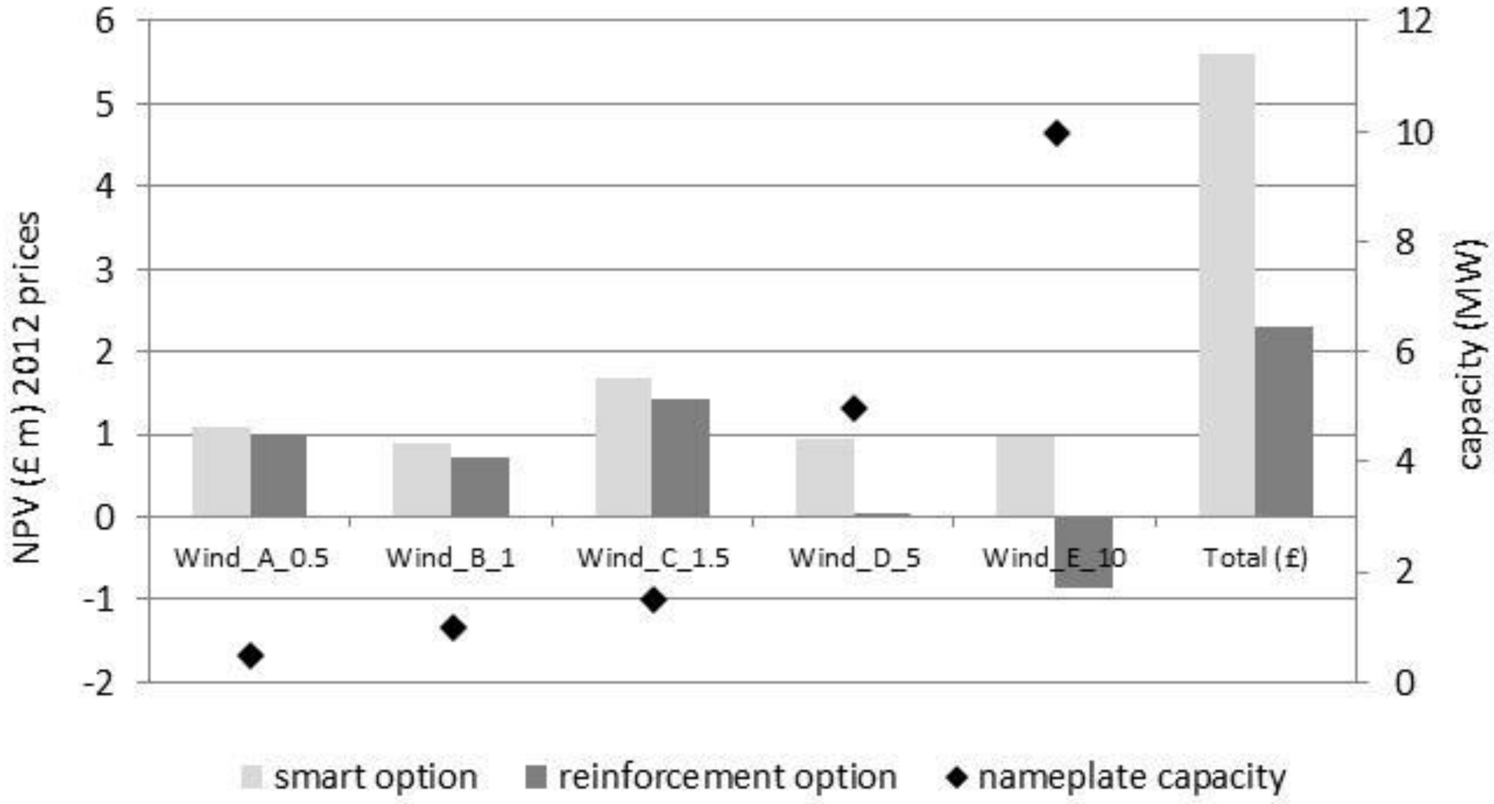
  Results:

  - Under the **smart connection** option all generators connect (with or without EB). Avoidance of reinforcement costs
  - Under the **reinforcement connection** option most of generators connect. Large generators are the most negatively affected due to the high share of reinforcement costs
  - Under **BAU connection** option, **no individual generator** (project) would connect.

5. Results

- **Scenario 1: with partial interruptible connected capacity – 100% wind**

Fig. 3: Scenario 1 - Results



5. Results

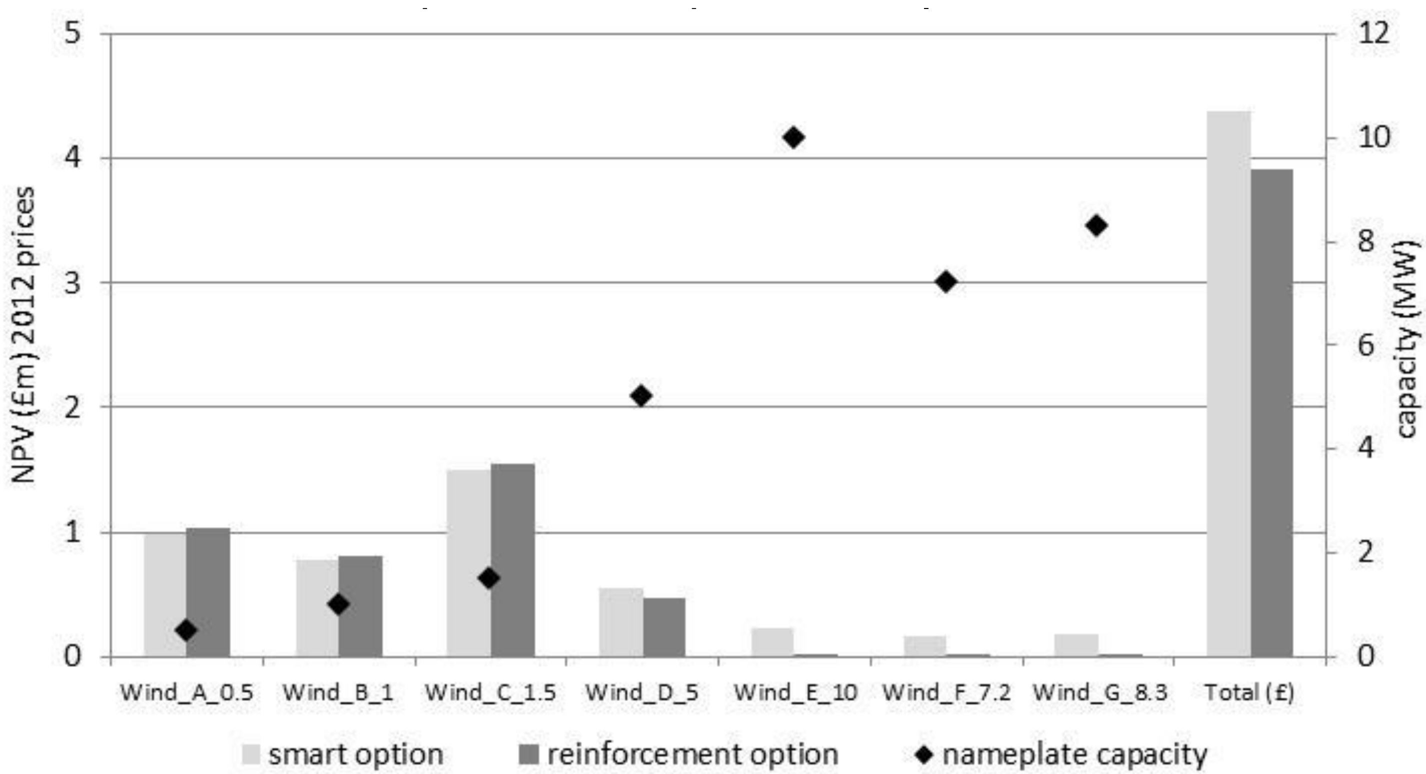
- **Scenario 2: with full interruptible connected capacity – 100% wind**
  - Illustrates the case where demand is enough to fulfil the available capacity at a specific point of connection
  - Full utilisation of total interruptible capacity quota (33.5 MW, 7 generators)
  - Maximum curtailment level: 5.33%

  Results:
  - Under the **smart connection** option all generators connect (with EB). Avoidance of reinforcement costs
  - Under the **reinforcement connection** option all generators connect (with EB). Large generators with lower share of reinforcement costs
  - Reinforcement connection option: best for small generators (<=1.5MW)
  - Smart connection option: best for large generators
  - Under BAU connection option, **no individual generator** (project) would connect.

5. Results

- **Scenario 2: with full interruptible connected capacity – 100% wind**

Fig. 4: Scenario 2 - Results



5. Results

- **Scenario 3: with full interruptible connected capacity – a mix of DG generation**
  - Enough demand to fulfil the available capacity
  - Full utilisation of total interruptible capacity quota (33.5 MW, 11 generators)
  - Maximum curtailment level:5.33% (wind), 2.57% (solar PV), 1.73% (AD CHP)

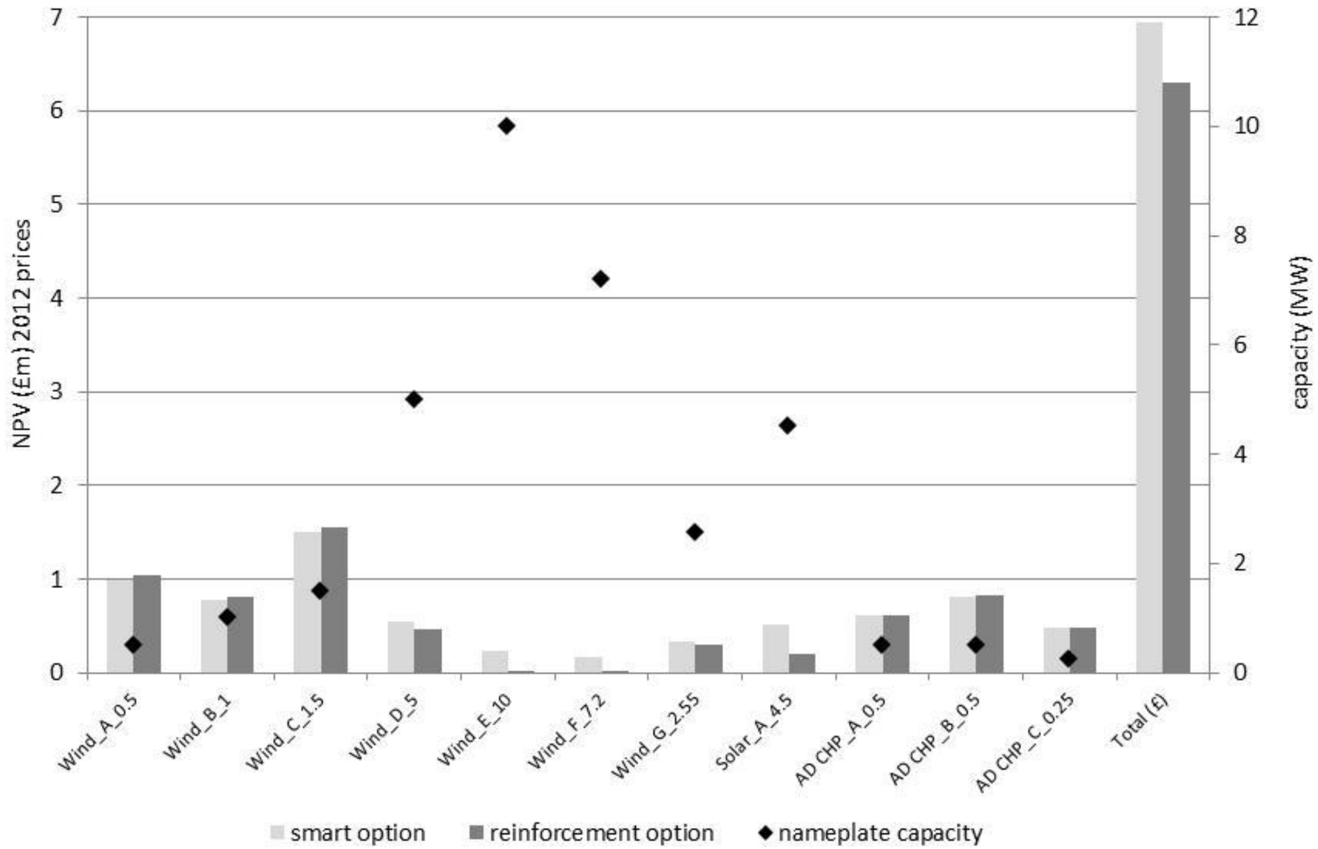
  Results:

  - Under the **smart connection** option all generators connect (with EB). Avoidance of reinforcement costs
  - Under the **reinforcement connection** option all generators connect (with EB). Large generators with lower share of reinforcement costs
  - Reinforcement connection option: best for small generators (<=1.5MW)
  - Smart connection option: best for large generators
  - Under BAU connection option, **none individual generator** (project) would connect.
  - Project NPV regarding solar PV influenced importantly by export energy rate (with 100%, project NPV decreases in 71%)

5. Results

- **Scenario 3: with full interruptible connected capacity – a mix of DG generation**

Fig. 5: Scenario 3 - Results



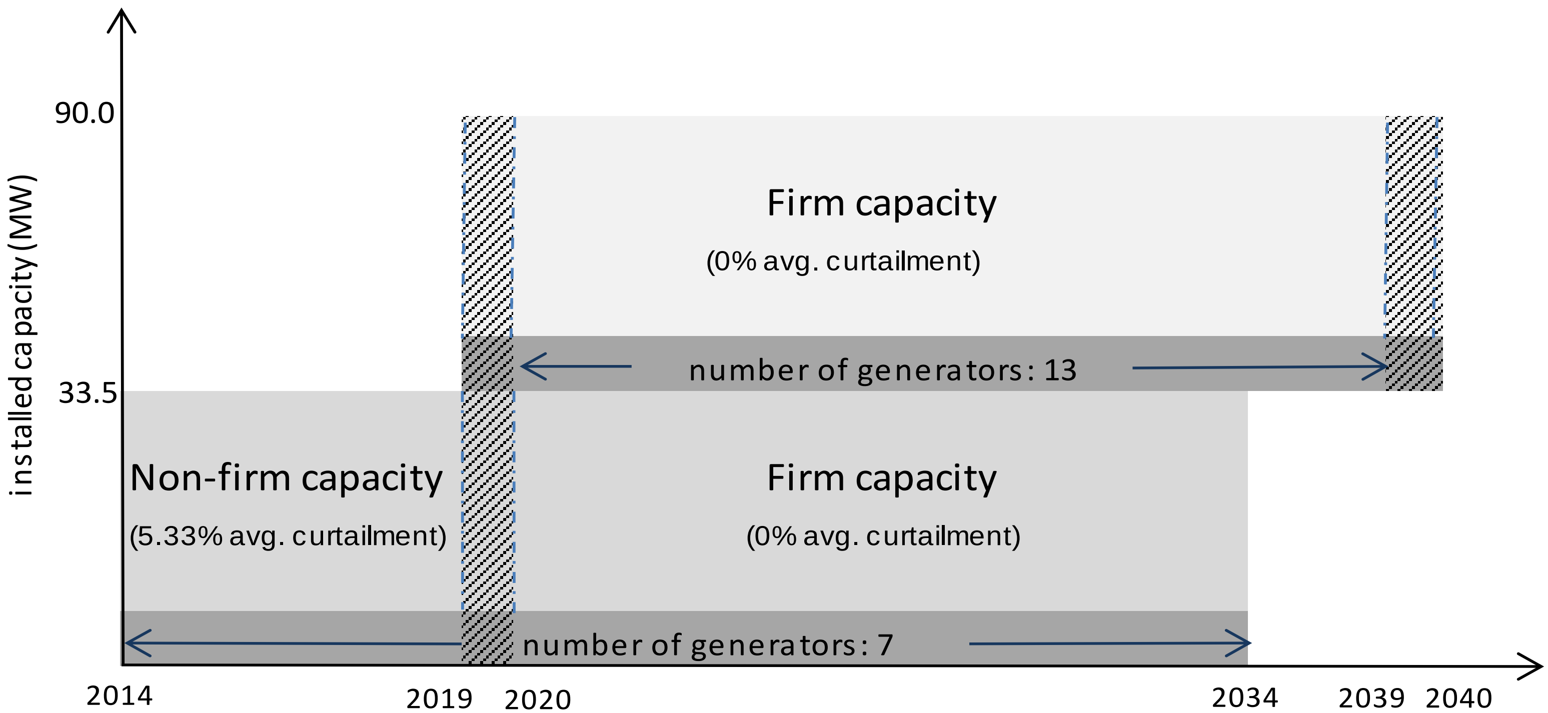
5. Results

- **Scenario 4: with full interruptible connected capacity and option of network reinforcement – 100% wind**
  - Enough demand to fulfil the available capacity (2014 and 2019/2020)
  - Option of full firm capacity (90 MW) in the medium term after reinforcement
  - Full utilisation of total interruptible capacity quota (33.5 MW, 7 generators) and full firm capacity (56.5 MW, 13 generators) in medium term
  - Maximum curtailment level:5.33% (before network reinforcement in 2019/2010), after this curtailment level: 0%
  - Measures the value of accelerating the connection of additional capacity by one year:
    - The project NPV is assessed in two consecutive years (2019/ 2020)
    - Evaluates the value of accelerating the connection of 56.5 MW by one year (and reach the maximum available firm capacity: 90 MW)
    - The difference of the project NPV under both years represents the value of accelerating these connections

5. Results

- **Scenario 4: with full interruptible connected capacity and option of network reinforcement – 100% wind**

Fig. 6: Scenario 4 – Installed capacity and curtailment level over time



5. Results

- **Scenario 4: with full interruptible connected capacity and option of network reinforcement - 100%wind**

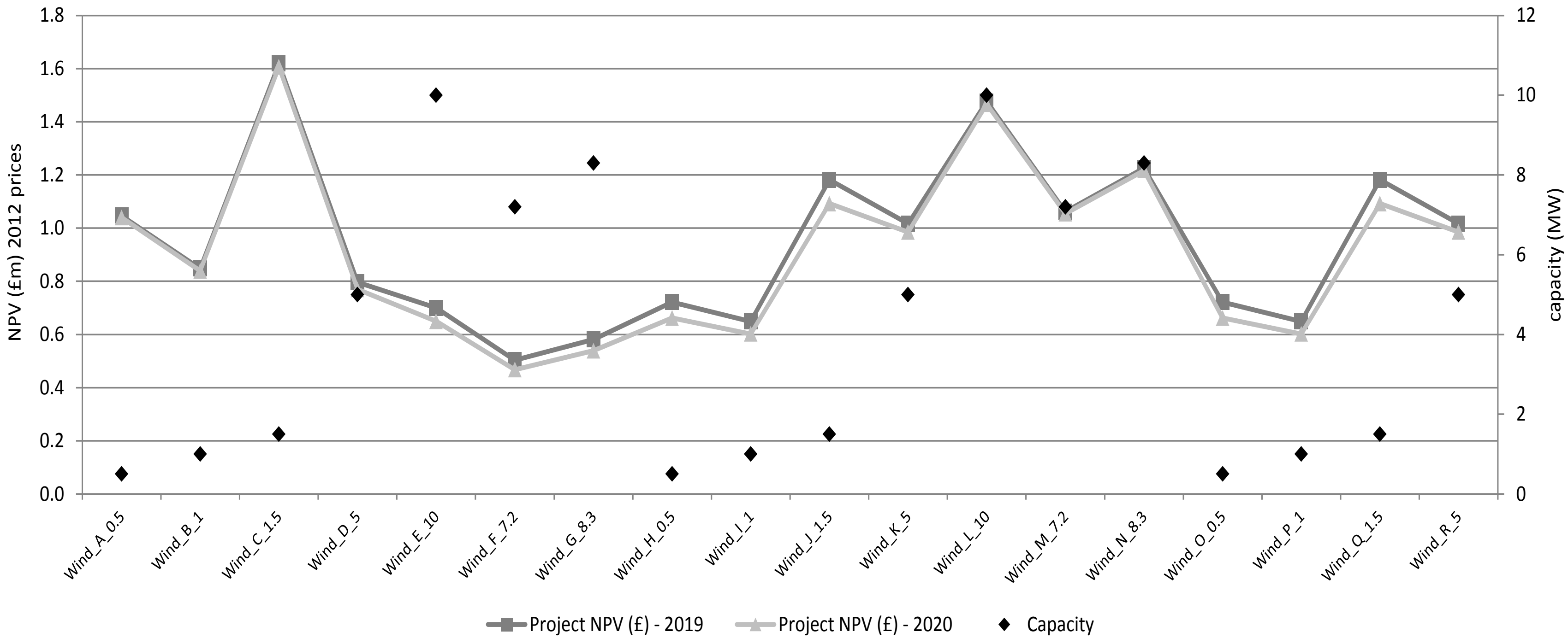
Results

- All generators connect by 2014 or 2019/2020
- Accelerating the connection of additional capacity by one year impacts the project NPV positively
- This means that taken into consideration all the benefits and costs associated with the connection of generators at specific connection point, advancing the connection of these set of generators has a positive impact on the whole project
- The NPV of accelerating network capacity by one year is £0.7m with embedded benefits or £0.5m without these benefits

5. Results

- **Scenario 4: with full interruptible connected capacity and option of network reinforcement – 100% wind**

Fig. 7: Scenario 4 – Results (with EB) Project NPV (2019/20)



5. Results

- **Summary of Results (Scenario 1, 2, 3 and 4) - NPV**

Table 3: Summary of Results

	With Embedded Benefits			Without Embedded Benefits		
Scenarios	**Smart connection option**	**Reinforcement connection option**	**Business as Usual**	**Smart connection option**	**Reinforcement connection option**	**Business as Usual**
Scenario 1						
NPV(£)	5.60	2.31 (4/5)	-2.39 (2/5)	4.48	1.19 (3/5)	-3.50 (2/5)
NPV(£/MW)	0.31	0.13	-0.13	0.25	0.07	-0.19
Scenario 2						
NPV(£)	4.38	3.91	-6.18 (2/7)	2.41 (4/7)	1.83 (4/7)	-8.26 (2/5)
NPV(£/MW)	0.13	0.12	-0.18	0.07	0.05	-0.25
Scenario 3						
NPV(£)	6.94	6.30	-9.04 (2/11)	5.00 (9/11)	4.27 (9/11)	-11.07 (2/11)
NPV(£/MW)	0.21	0.19	-0.27	0.15	0.13	-0.33
Scenario 4		In 2019			In 2020	
NPV(£)		19.49			18.78	
NPV(£/MW)		0.42			0.40	

Figures in parenthesis indicate the number of generators that will connect over the total. In the rest of cases all generators connect (positive NPV)

5. Results

Effect of demand growth on project NPV

- A sensitivity analysis considering different scenarios of demand growth that produces a reduction in the generation output is evaluated
- Three scenarios are proposed: a reduction of 25, 50 and 75% of the curtailed energy

Results:

- If demand grows up which produces a decrease in curtailed energy, project NPV increases importantly
- Lower curtailment levels reduce the value of firmness
- Project NPV will increase if the level of output decreases, thus there is a point in which the value of a non-firm connection (smart option) exceeds the value of a firm connection (reinforcement option).

5. Results

Effect of demand growth on project NPV – Scenario 2

- Upward trend in the number of generators that would prefer the smart connection option when curtailment level decreases
- With a curtailment level of 1.33% all generators would select the smart connection option.

Table 4: Effect of demand growth on project NPV across generators – Scenario 2

Generator	Capacity (MW)	Difference between firm and non-firm NPV			
		Base - 5.33%	4.00%	2.66%	1.33%
Wind_A_0.5	0.5	52,299	26,581	863	- 24,855
Wind_B_1	1	32,837	- 659	- 34,155	- 67,651
Wind_C_1.5	1.5	49,256	- 988	- 51,232	- 101,477
Wind_D_5	5	- 81,104	- 187,262	- 293,420	- 399,578
Wind_E_10	10	- 207,678	- 408,626	- 609,575	- 810,523
Wind_F_7.2	7.2	- 149,528	- 294,211	- 438,894	- 583,577
Wind_G_8.3	8.3	- 172,373	- 339,160	- 505,947	- 672,734

White values indicate that the firm connection option would be preferred and grey values indicate an opposite effect

5. Results

Effect of demand growth on project NPV – Scenario 3

- Similar trend than in Scenario 2
- With a curtailment level of 1.33% all generators would select the smart connection option (including solar PV and AD CHP)

Table 5: Effect of demand growth on project NPV across generators – Scenario 3

Generator	Capacity (MW)	Difference between firm and non-firm NPV			
		Base - 5.33%	4.00%	2.66%	1.33%
Wind_A_0.5	0.5	52,299	26,581	863	- 24,855
Wind_B_1	1	32,837	- 659	- 34,155	- 67,651
Wind_C_1.5	1.5	49,256	- 988	- 51,232	- 101,477
Wind_D_5	5	- 81,104	- 187,262	- 293,420	- 399,578
Wind_E_10	10	- 207,678	- 408,626	- 609,575	- 810,523
Wind_F_7.2	7.2	- 149,528	- 294,211	- 438,894	- 583,577
Wind_G_2.55	2.55	- 41,363	- 95,504	- 149,644	- 203,785
Solar_A_4.5	4.5	- 313,578	- 348,974	- 384,370	- 419,766
AD CHP_A_0.5	0.5	8,974	- 5,913	- 20,800	- 35,687
AD CHP_B_0.5	0.5	8,974	- 5,913	- 20,800	- 35,687
AD CHP_C_0.25	0.25	6,741	- 1,266	- 9,273	- 17,280

For solar PV Base= 2.57%, AD CHP=1.73%. Demand growth is applied over these percentages.

White values indicate that the firm connection option would be preferred and grey values indicate an opposite effect

6. Final Remarks

- This is not a full social cost benefit analysis. Social discount rates and full economic costs need to be used/included, as well as any missing central costs of smart infrastructure
- Results from the CBA are subject to uncertainty due to some static assumptions related to generation mix (and the associated curtailment levels), timescale of network upgrades and demand growth
- Results represent a conservative estimate of individual project value based on the simultaneous connection of all other projects
- Lower curtailment levels tend to reduce the value of firmness
- Small wind generators will always have advantage over the larger generators
- Solar PV generators *may* struggle to get a positive NPV over the project lifetime if a full export capacity is assumed

6. Final Remarks

- Substantial benefits from smart connection arrangements over conventional alternative for all generators below maximum available network capacity
- Pro-Rata curtailment may encourage too much connection behind a constraint boundary
- Towards maximum available network capacity, smaller generators might prefer to share reinforcement costs over smart connection
- There is substantial value from smarter connection if it accelerates connection and early reinforcement
- This implies Pro-Rata may be better than LIFO in medium run
- ***Smart commercial arrangements need further investigation, as the savings in costs and the benefit to DG acceleration appear to be substantial.***

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