Contents page for presentations by Workgroup members post the Workgroup Consultation Report

1. A working group, member presented to the group the results of load flow analysis that had been performed using the current transport and tariff model incorporating peak and year round load flows. The detailed diagrams and conclusions presented to the group to support working group discussion.

2. **DC Load flow analysis of effect on the transmission system of distribution connected generation at the same Grid Supply Point (GSP).**

   This demonstrated the e**ffect on flows on the transmission system of distribution connected generation or trasnmsion connected generation** when connected **via the same Grid Supply point**. It uses the current version of National Grid's transport model. This shows that identical flows result from connecting generation at either the transmission or the distribution level. The working group member postulated that this **demonstrates that Distribution and transmission connected generation** have the same **effect on transmission system flows** and hence the size of the transmission system when connected via the same GSP**.**

3. **Effect on the size (MWkm) of Transmission system of connecting generation (distribution or transmission) evenly or according to a locational signal**

   The second more involved analyst (many detailed load flows were set up and run) shows the effect on the size of the transmission system as a result of connecting generators at various locations on the trasnmsion system.

   The size of the trasnmsion system is output from the load flow as MWkm and represents the length of 400 kV transmission lines (cables and lower voltage lines are converted in to 400 kV equivalents) multiplied by the power flow. It does not include historic costs, the cost of non-locational items (substations transformers etc) or other RIIO costs eg. SO costs.

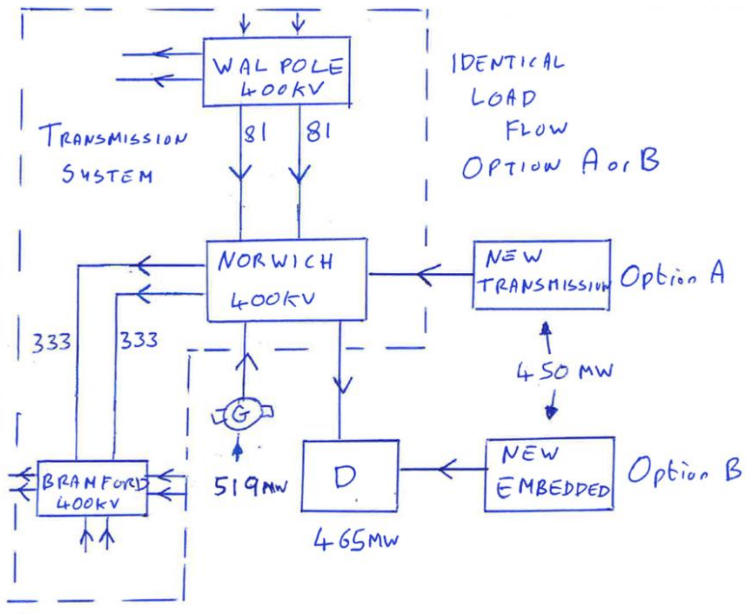
   The key scenario was connecting an **equal volume of MW in each generation zone** compared with **a MW connected pro rata to a locational signal.** The results show that if generation connected evenly over the system as opposed to pro-rata with a locational tariff the size of the transmission system (MWkm) is around 6% larger than it otherwise would be. The working group member postulated that this shows that the result of applying the current embedded benefit across all embedded generators with negligible locational signal is likely to result in a **larger, more costly transmission system** than would otherwise be the case.

Effect on the trasnmsion system of distributed generation.

DC Load flow analysis of effect on the transmission system of distribution connected generation

The 2016/17 National Grid Transport and Tariff Model was used to examine the difference in network flows and the size of the transmission system of connecting 450 MW of generation via demand (embedded) or transmission at Norwich 400KV substation (as shown in the diagram and table below). Norwich substation was chosen as it includes both demand and generation at the same Grid Supply Point.

Methodology - The 2016/17 Transport and Tariff Model was set up using tariff generation and demand data but forced to run an identical load flow by re-categorising all generation as CCGT (this allows all generation appeared in the Peak and Year round load flows), this simplified the analysis as only one generator scaling factor needed to be dealt with. Generation was scaled to meet demand as is required for a load flow model (~72% scaling factor) and the load flow run to determine the size (MWkm) of the network and the power flows on all transmission circuits (Base scenario). The MWkm represents the length of 400 kV transmission lines (cables and lower voltage lines are converted in to 400 kV equivalents) multiplied by the power flow. It does not include historic costs, the cost of non-locational items (substations transformers etc) or other RIIO costs eg. SO costs. Then 450 MW of transmission connected generation was added at one substation Norwich 400kV (NORM40) and the load flow was re-run (Option A). This was repeated by simulating the connection of 450 MW of embedded generating by reducing demand at the Norwich 400kV substation by 450 MW (Option B). As expected the power flows on all transmission system circuits produced identical results for Option A and B. These power flows are shown in the diagram below.



Overall the size of the transmission system (MWkm) reduced by 0.56% as a result of the connection of 450 MW of embedded/transmission generation as can be seen in the table below.

Scenario NG 16/17 tariff all plant type set to CCGT force one load flow (Year round)	Bus Name	Demand MW	Generation MW	Toatal load flow MWkm	% Network size change
Norwich 400 kV substation base load flow	NORM40	465	519	7,751,081	0.00%
Option A transmission + 450 MW generation	NORM40	465	969	7,707,548	-0.56%
Option B embeded generation - 450 MW demand lower	NORM40	15	519	7,707,549	-0.56%

Key Observations

1. The network flows on the transmission system as a result of connecting a similar volume of transmission generation or embedded generation at the same point **are identical**.
2. The change in the size of the transmission system as a result of connecting embedded or transmissions generation at the same Grid Supply point is identical. The increase or reduction in the size of the transmission system is only affected by the location of the GSP relative to other demand and generation connections and the network parameters.

Effect on the size (MWkm) of Transmission system of connecting generation (distribution or transmission) evenly or according to a locational signal.

Following on from the Appendix B analysis that looked at the effect of connecting embedded/transmission generation at the same Grid Supply Point further analysis was undertaken to establish the effect on the size of the network of connecting generation evenly across the network (i.e. no locational signal) or in proportion to a locational signal. As previously noted the MWkm represents the length of 400 kV transmission lines (cables and lower voltage lines are converted in to 400 kV equivalents) multiplied by the power flow. It does not include historic costs, the cost of non-locational items (substations transformers etc) or other RIIO costs e.g. SO costs.

Methodology - The 2016/17 Transport and Tariff Model was set up using tariff generation and demand data, the model was used without modification. The initial run established size of the network (Peak plus Year round MWkm) as used in the tariff calculation. Scenarios (1-6) were then performed to establish the effect on the size of the transmission system resulting from connecting 5000MW of conventional (CCGT type) generation in various generation tariff zones. Scenarios 7-9 were then performed that added different amounts of generation to each of the generation tariff zones based on even distribution (7), in proportion to the generation locational tariff (8) or the reverse generation locational tariff (9) the actual MW added to each zone are shown in the second table below.

Transport and tariff model 16/17 with additional MW showing change in size of			Peak MWkm	Year Round	Peak + Year Round	Annuitized cost **	% from base
Scenario	Zone	Change applied to zone	MWkm	MWkm	MWkm	£m	%
0	Base case tariff model		4,907,755	4,457,111	9,364,866	£224.87	0.00%
1	North Scotland (z1)	+5000 MW generation	7,677,102	5,453,463	13,130,565	£315.29	40.21%
2	Stirlingshire and Fife (z9)	+5000 MW generation	5,615,063	5,545,066	11,160,129	£267.98	19.17%
3	West Devon and Cornwall (Z27)	+5000 MW generation	5,042,423	5,131,648	10,174,071	£244.30	8.64%
4	West Midlands (z13-z18)	+5000 MW generation	4,857,261	4,751,375	9,608,636	£230.72	2.60%
5	Mid Wales and The Midlands (z18)	+5000 MW generation	4,705,604	4,567,725	9,273,329	£222.67	-0.98%
6	Central London (Z23)	+5000 MW generation	4,538,888	4,200,420	8,739,308	£209.85	-6.68%
7	All zones	185.1MW all zones *	4,702,668	5,601,791	10,304,459	£247.43	10.03%
8	All Zones	locational see table*	4,460,641	5,245,271	9,705,912	£233.06	3.64%
9	All Zones	Reverse locational*	5,179,169	5,943,590	11,122,759	£267.08	18.77%
	** Expansion constant £13.34/MWkm and Security Factor 1.8		* see table of MW per zone below				

Table of MW applied to each zone		Even all zones	Locational	Reverse locational
Name	Zone	MW	MW	MW
North Scotland	1	185.2	56.3	342.6
East Aberdeenshire	2	185.2	123.2	260.8
Western Highlands	3	185.2	88.6	303.2
Skye and Lochalsh	4	185.2	120.6	264.1
Eastern Grampian and Tayside	5	185.2	103.3	285.2
Central Grampian	6	185.2	63.6	333.7
Argyll	7	185.2	0.0	411.4
The Trossachs	8	185.2	119.2	265.8
Stirlingshire and Fife	9	185.2	189.4	180.1
South West Scotlands	10	185.2	144.0	235.5
Lothian and Borders	11	185.2	159.0	217.2
Solway and Cheviot	12	185.2	198.9	168.5
North East England	13	185.2	225.1	136.4
North Lancashire and The Lakes	14	185.2	197.9	169.6
South Lancashire, Yorkshire and Humb	15	185.2	191.7	177.2
North Midlands and North Wales	16	185.2	206.9	158.7
South Lincolnshire and North Norfolk	17	185.2	225.8	135.6
Mid Wales and The Midlands	18	185.2	237.1	121.7
Anglesey and Snowdon	19	185.2	186.1	184.1
Pembrokeshire	20	185.2	180.5	190.9
South Wales & Gloucester	21	185.2	216.2	147.2
Cotswold	22	185.2	254.5	100.5
Central London	23	185.2	336.8	0.0
Essex and Kent	24	185.2	266.4	86.0
Oxfordshire, Surrey and Sussex	25	185.2	293.1	53.3
Somerset and Wessex	26	185.2	307.7	35.6
West Devon and Cornwall	27	185.2	308.1	35.0
Total		5000.0	5000.0	5000.0

Key observations:-

1. As expected locating generation remote from demand centres (e.g. North Scotland) increases the size of the network whilst connecting generation close to demand centres (Central London) reduces the size of the network.
2. The increase in size of the network between generation located evenly over each tariff zone (scenario 7) as opposed to pro-rated to a locational signal (scenario 8) is around 6% larger.
3. The locational cost of the transmission network (MWkm multiplied by the expansion factor and the security factor) represents around 10% of the network cost with the remainder being made up of historic and non-locational items. The non-location related costs are included in the residual.
4. There is no difference between the size of the transmission system resulting from connection of distribution or transmission connected generation.

Cost-Benefit Analysis of Transitioning TNUoS (Triad) for CM 2014 & 2015 New-builds

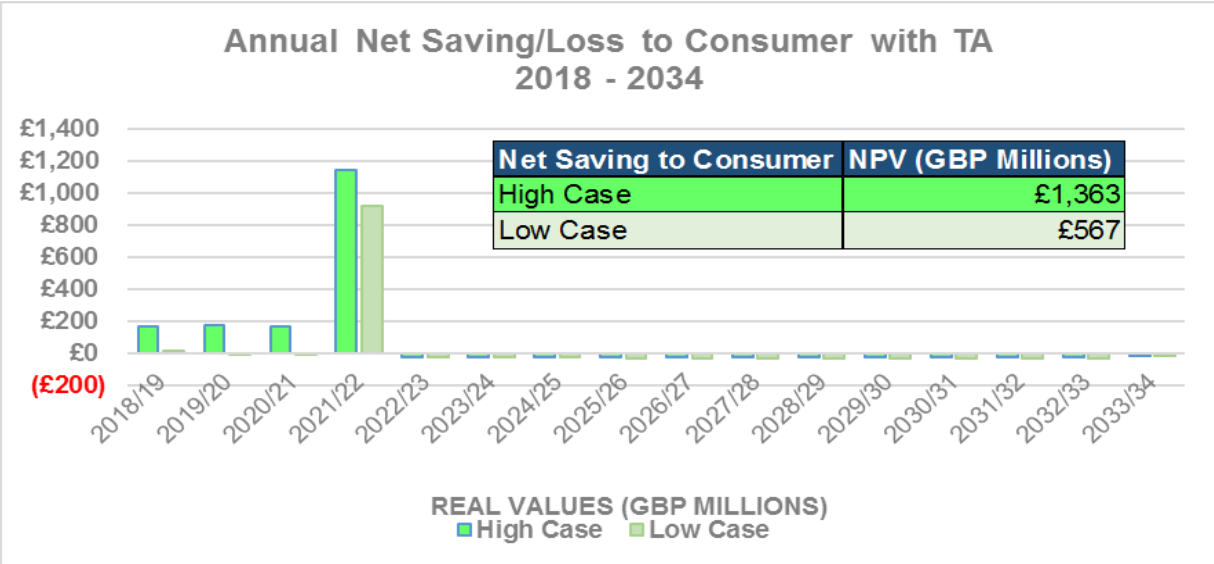
Summary

UK Power Reserve has conducted a cost-benefit analysis of introducing Transitional Arrangements for triad revenues for new-build distribution connected capacity procured under the T-4 2014 and 2015 capacity market auctions, versus the removal of embedded benefits.

Under the scenario of removing embedded benefits, it is predicted that new-build capacity procured in the T-4 2014 and 2015 capacity auctions will struggle to reach financial close, resulting in a shortfall of 1.7GW of capacity from 2018 onwards.

This analysis concludes that this capacity would need to be replaced with alternative transmission connected capacity in the subsequent T-1 and T-4 capacity auctions, at a higher cost to the end consumer, in order to maintain security of supply.

The analysis considers the transitioning of triad rates for committed new-build distribution connected capacity with less than 50MW of de-rated generation capacity holding 14 or 15 year capacity agreements, which forecasts a net saving to the end consumer ranging between **£1.4 billion - £0.6 billion**[1];



Removal of Embedded Benefits

In 2014 and 2015, the government procured in the region of 1.7GW of new-build capacity under the T-4 capacity market auctions, with obligations commencing in 2018 and 2019 respectively under long-term capacity agreements lasting up to 14 or 15 years. This sub-set of capacity connected to the distribution network were bid into the Capacity Market auction and to able to access triad revenues over the lifespan of their capacity agreements.

[1] Net Present Value based on 2.00% inflation between over the period 2018 – 2034.

Independent analysis from KPMG predicts that the complete removal of embedded benefits would result in this capacity defaulting on their capacity agreements, creating a shortfall of in security of supply from winter 2018/2019 onwards. This analysis considers the total cost of replacing this capacity with the next best cost-alternatives possible under following capacity auctions.

Effects on Future Capacity Auctions

This analysis forecasts that approximately 1.7GW of replacement capacity would need to be re-procured over the previously contracted period between 2018 – 2034 in future capacity auctions[2]. The analysis predicts that this new-build capacity would need to be replaced with existing capacity in the following three T-1 capacity auctions until 2021, which would then be replaced with new-build transmission connected capacity in the earliest possible T-4 auction from 2022 onwards.

In the following three T-1 auctions until 2021, it is assumed that the shortfall in capacity would need to be replaced with existing transmission-connected capacity (in lieu of any Contingency Balancing Reserve measures procured by National Grid, assessed as the better cost option[3]). It is estimated that a clearing price ranging between £39.97/kW[4] - £69.99/kW[5] would be achieved, based on previous costs of procuring existing thermal plant procured under the National Grid Supplementary Balancing Reserve ('SBR') scheme for winter 2016/17. Taking into account recent plant closures, capacity procured for those years and the additional shortfall in capacity, it is estimated that the target auction capacity would range between 2,477MW - 4,133MW for the next 2018/19 T-1 auction, and ranging between 3,450MW – 5,106MW for the following two T -1 auctions commencing in 2019/20 and 2020/21[6].

In the next T-4 auction for delivery in 2022, it is assumed that the shortfall in capacity would be replaced with new-build (OGCT or CCGT) transmission connected capacity, where there would be a sufficient lead-time for construction of four years. It is estimated that a clearing price ranging between £45/kW[7] - £49/kW[8] would be achieved. Taking into account recent plant closures, capacity procured for those years and the additional shortfall in capacity, it is estimated that the target auction capacity would range between 46,000MW - 48,000MW for the next T-4 auction.

The analysis concludes that the removal of embedded benefits would result in a net increase in capacity market payments over the lifespan of the contracted 1.7GW of distribution-connected capacity between the period 2018 – 2034. The marginal increase in capacity market payments

[2] Transitioned capacity defined as 1.73GW of capacity with capacity agreements in the 2014 & 2015 T-4 Capacity Market auctions with new-build contracts greater than 14 and 15 years, with less than 50MW of de-rated capacity per contract. Based on the National Grid Capacity Market register as of September 2016. Excludes terminated capacity agreements as of September 2016.
[3] 'Security of Supply and Capacity Market' (May 2016) Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf
[4] T-1 Capacity Market Clearing Price (Low Case), based on SBR procured unit cost for bid (SBR14) at £39.97/kW: National Grid, '*SBR Market Information Tender Results – Winter 2016/17*' (December 2015), Page 2, Available at: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=44323
[5] T-1 Capacity Market Clearing Price (High Case), based on SBR procured unit cost for bid (SBR15) at £69.99/kW: *Ibid*. Page 3.
[6] Target capacity based on: Shortfall in capacity from CM 2014 & 2015 capacity failing to reach financial close (767MW from 2018 & 983MW from 2019), plus original T-1 Target volume (2,500MW). Less TA Auction volumes (790MW). High case includes replacement capacity for new build CMU Trafford Power (1,656MW), low case assumes Trafford Power is commissioned by 2018.
[7] 'Net-CONE' DECC Estimate of new OGCT bid £45/kW: DECC, 'Electricity Market Reform: Capacity Market – Detailed Design Proposals' (June 2013), Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/209280/15398_TSO_Cm_8637_DECC_Electricity_Market_Reform_web_optimised.pdf
[8] DECC Estimate of new CCGT bid £49/kW – DECC, 'Background on setting Capacity Market parameters' Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/468203/Capacity_Market_-_parameters_0810.pdf

incurred from higher clearing prices than would have otherwise have been paid under new-build capacity agreements awarded in the T-4 2014 and 2015 contracts for 1,7GW[9], is calculated to be between **£1.4 billion - £2.3 billion**[10].

Cost of Transitional Arrangements of Triad Revenues

The total cost of transitional arrangements for 1.7GW of distributed connected capacity over the lifespan of their capacity agreements have been forecast under 2016/17 rates for their corresponding geographical locations[11]. This assumes 85% of 1.7GW of de-rated capacity generating during the three highest periods of peak transmission demand, at the average rate of National Grid's five year forecast of TNUoS rates in England and Wales[12], totalling **£0.96 billion**[13] over the period 2018 – 2034.

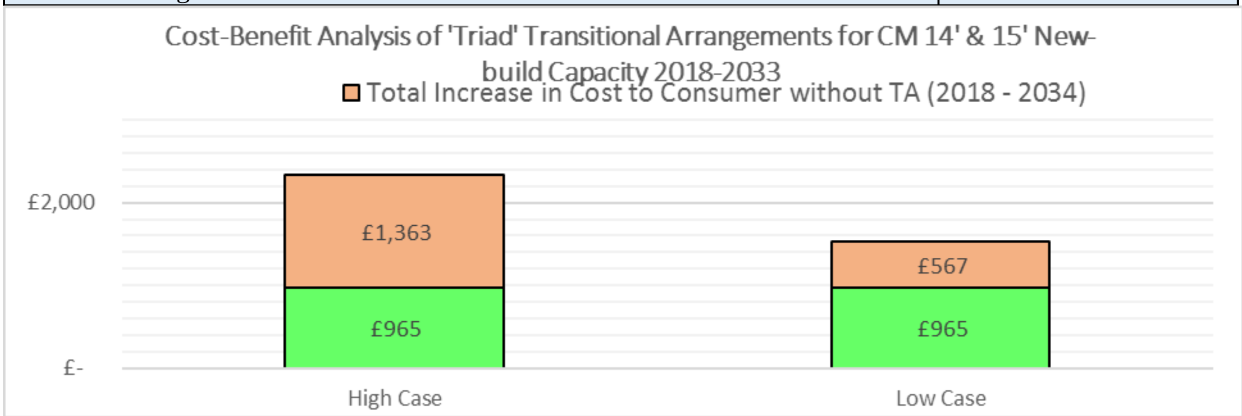
Conclusion

The analysis therefore concludes that the removal of embedded benefits would result in a net increase in capacity payments that exceed the cost of transitioning triad for this capacity, which represents a net saving to the consumer ranging between **£1.4 billion - £0.6 billion**[14] between the period 2018 – 2034.

Summary of Results:

Transitional Arranagments (High Case)	NPV (GBP Millions)	
Total Increase in Capacity Market Payments	£	2,328
Less Total Cost of Transitional Arrangements (16/17' Rates + RPI)	-£	965
Total Net Saving to Consumers	£	1,363

Transitional Arranagments (Low Case)	NPV (GBP Millions)	
Total Increase in Capacity Market Payments	£	1,532
Less Total Cost of Transitional Arrangements (16/17' Rates + RPI)	-£	965
Total Net Saving to Consumers	£	567



[9] Capacity payments calculated for T-4 2014 & T-4 2015 at clearing prices £19.40/kW and £18.00/kW for transitioned capacity, indexed with RPI (assumed 2%) as per the relevant Capacity Market Regulations and Auction Parameters.
[10] Net Present Value based on 2.00% inflation over the period 2018 – 2034.
[11] Triad revenues calculated based on geographical locations of capacity as recorded in the T-4 2014 & 2015 capacity market register as of September 2016. Where addresses not available, the mean average TNUoS Half Hour Demand Tariff in England & Wales has been used.
[12] National Grid 2016/2017 TNUoS Half Hour Demand Tariff TNUoS Forecast, p.13
file://ukprfs01/FolderRedirection/marlon.dey/Downloads/Forecast%20from%202016-17%20to%202019-20%20(2).pdf
[13] Net Present Value based on 2.00% inflation over the period 2018 – 2034.
[14] Cf.13.

Impact of Removal of Embedded Generator Triad Benefits on the GB Power System

Quantitative Analysis

18th July, 2016 – Version 2.0

Contents

1 Executive Summary

Winter 2015/16 saw levels of margin within the GB power market remain just above what was sufficient for secure operation. The difference between supply and demand fell below 2GW on two occasions across the winter.

The UK's embedded generation fleet's peak output was approximately 9GW in the winter of 2015-16. EnAppSys estimates are that there is approximately 2GW of baseload capacity, 4-5GW of solar generation from HH meters at the peak, 3-4GW of wind solar generation from HH meters at the peak and 1-2GW of peaking generation capacity[1]

Strong levels of renewable generation and low demand from consumers resulted in minimum daily thermal generation averaging 18.7GW, with a lower quartile of 15.9GW and an upper quartile of 21.7GW. Peak daily thermal generation reached 30.4GW on low-wind high-demand days.

Some large power stations had low utilization levels, which reduced their income and put pressure on their ability to cover fixed costs, resulting in mothballing and closures. Much of the UK's fleet doesn't have the flexibility and speed to fill in around renewable generation and to target peaks in demand.

As a result, there have been numerous closures since last winter, despite margins having been tight, as evidenced by National Grid's purchase of ~3.5GW of strategic reserve.

The large number of closures within the main market (particularly in 2016) have arisen as a result of power stations being reduced to insufficient running hours at insufficient prices, and therefore insufficient operating profits.

If new large power stations are to be built, then existing plants that sit on the margins of the market will see their running hours reduced and so will be in a similar situation to the plants that are already closing.

In order to avoid constructing new plants while inefficiently closing identical levels of existing capacity, power prices need to rise via a scarcity premium, or non-power market income must rise.

An extra source of non-power income could come from a higher Capacity Mechanism (CM) price. To have a significant impact upon the income levels of large power stations

[1] Source embedded generation analysis from SVAA P0276 data and http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=36393, 1GW estimate based on STOR flexible contract tendered volumes 15/16.

and to encourage the building of new CCGTs would probably require at least a £7/kW CM price increase up to at least £25/kW. Estimates of the trigger CM price vary; the price might need to rise to £45-50/kW, but we provide a conservative analysis in this report.

With 46.9GW of capacity targeted at £0/kW in the 2015 auction, the implied net cost to the system of a £25/kW CM price would be £328m. This is the same cost as constructing 4.7GW of new embedded generators earning triad income at £70/kW alongside current CM prices.

Without intervention and following recent closures, EnAppSys notes that the hours when the margin drops below 2GW are likely to increase from 2 hours in winter 2015/16 to an expected 49.5 hours in winter 2016/17.

A conservative approach has been taken with our modeling: we assume that 1.5GW of additional capacity will become available across winter 2016/17, provided by large thermal power stations. This is a rough estimate of the maximum extra capacity that was cut for cost-saving purposes but could be expected to become available in response to higher prices.

At the moment, there are no indications of plants increasing their TEC to benefit from tight margins for the winter of 2016/17. The increased availability at Keadby and Carrington is already included in the modelling ahead of this 1.5GW increase.

These tight margins and the slow response from large generators provide the backdrop for any changes to the embedded benefits regime.

Modelling carried out by EnAppSys and detailed in this report shows that in winter 2016/17 the system will see **an increase in costs of £507million-£764million due to the scarcity premium that will result from the increased periods with tight margins, if triads are removed.** This modelling involves the use of a scarcity price curve that is detailed further below.

In the Capacity Mechanism there are just under 2GW of embedded projects coming online that will in the future mean a cost of approximately £140m/annum at future higher TNUoS values. Overall these costs will be distributed via the common charging methodology but the rationale is that it is a neutral transaction as there would be lower requirement to build transmission infrastructure and the presence of embedded generation and its benefits result in lower transmission losses that would be passed to the consumer. Modelling of winter 2016/17 shows that the 2GW increase in margin offered by these plants could turn the modelled increase of £507m-£764m from increased market prices in a tight system into potential savings of £52m-£90m, by consistently boosting margins within the system and thereby reducing market prices.[2]

This places a net benefit to the system of £457m-£676m per annum as a result of the construction of the embedded plants with CM obligations. Their value to the system increases the sooner they come online. It is worth noting that transmitted generation would provide the same value to the system (all else held equal) were it able to show up to the market in time.

Should embedded benefits be removed from the system, EnAppSys forecast that

- 1GW of generation that operates via flexible STOR, and
- 1GW of generation that earns income from other ancillary services

might be insufficiently remunerated in the absence of triads to justify continued operations so could potentially exit the market.

If this exit were coupled with the cancelled construction of the 2GW of new embedded CM plants that are currently expected, modelling of winter 2016/17 shows a 2GW decrease in margin from that which existed in 2015/16, putting the system under serious stress.

Under such a scenario there would be an expectation that margins would drop below 2GW for 193 hours across the winter period and below zero for 49.5 hours. A drop below zero would not necessarily mean the lights going out, but would force the system to rely heavily on last-resort services such as Supplemental Balancing Reserve (SBR) and STOR (typically provided by embedded generators that are at least partially supported by triad income).

With the system under such stress, the scarcity of supply would have a considerable impact upon power prices: we estimate an increase in power costs of about £1.75bn – £3.33bn over the winter period. At the same time the system would need to source 4GW of capacity specifically to generate on peak days without impacting upon the viability of generators already in the market.

From a purely quantitative perspective there would appear to be a justification for the continuation of triads. Further, consumers put a value on security of supply – this soft benefit is not considered in this analysis. The focus of Triad generators on peak days ensures that embedded generators do not compete directly with existing plants, which

[2] With these plants normally supplementing triad income with operation in reserve markets such as STOR or FFR

sometimes have higher efficiencies and therefore lower energy costs, particularly over longer running periods.

This implies that in contrast to large new-build CCGTs, existing embedded plants don't need additional income to ensure that they are not forced out the market by new-build plant – there is a pressing need for new plant and old.

In this analysis we consider only the embedded generation that runs during evening peaks. We have not considered demand response nor embedded generation operating at baseload (waste-to-energy plants, anaerobic digesters etc) which might have triad income as a significant component of its revenue stream. For such plants Triad removal could put their viability at risk and therefore cause withdrawal from the market. Our exclusion of this scenario, which would serve to magnify the impact of the removal of triads, is in keeping with the conservative approach we have taken across this whole modelling exercise.

It is important to note that removing embedded generators' triad income will incentivise a shift towards behind-the-meter running. With higher power prices resulting from the removal of triads there will be a negative overall impact for consumers, including for those half-hour metered customers who are practicing triad avoidance. That might in the long run create more demand destruction or self-supply at a higher overall net cost to the system.

2 Background & Scope

2.1 Introduction

The transmission network is set up so that locally-connected distribution generators in England and Wales are treated as negative demand for the purposes of transmission charging.

By generating power during the three peak ‘triad’ periods each year, such ‘embedded’ generators reduce a retail power supplier’s peak use of the transmission system and therefore the associated charges. Suppliers compensate embedded generators for providing this service – compensation often referred to as “embedded benefits”. The triad periods are the three half hours of the year when the system is most likely to be under severe stress and are defined by National Grid as follows:

> *The Triads are the three half-hour settlement periods with highest system demand and are used by National Grid to determine charges for demand customers with half-hour metering and payments to licence exempt distributed generation. They can occur in any half-hour on any day between November to February inclusive but are separated from each other by at least ten full days.*

This means that embedded generators within the GB market can currently receive payments equivalent to the half-hourly demand TNUoS tariffs in a given charging year. TNUoS costs are paid for by suppliers and form part of their overall costs to supply. Overall the rationale is that it is a neutral transaction as the presence of embedded generation and its benefits result in lower transmission losses (that would be passed to the consumer) and low requirement to build transmission. Embedded generation has to pay in full its connection costs as opposed to centralised generation where the costs are spread across the market generators and consumers

These TNUoS charges vary from region to region, encouraging the construction of embedded generation and reduction of demand in regions where there is the greatest imbalance between supply and demand, and the greatest shortage of local power stations relative to local demand.

In April 2013 National Grid commenced a review that encompassed embedded benefits and TNUoS benefits. The review was concluded in 2014 and resulted in no changes to the system. The key reasons for not making changes were given as (1) greater transparency on embedded generation was in progress and it was felt prudent to wait for the results, (2) the volume of industry reform with the EMR coming in, (3) discriminatory treatment of generation over demand-side response if changes were implemented.

More recently Ofgem has raised a potential review of embedded benefits:

> *We are aware that small scale generators bring a range of benefits, including for security of supply, as they can help to meet peak demand by producing electricity when it is most needed. However, we are aware that small distribution connected generators receive an increasing level of benefits, which includes avoiding the generator transmission network charges and receiving payments from suppliers for helping them to avoid transmission charges for customers. We have previously expressed concerns that these arrangements are not fully cost reflective and continue to hold this view. Given the increasing scale of embedded generation and the increasing impact of distribution network flows on the transmission network, we are concerned that the lack of cost reflectivity of these arrangements could be having an increasing impact. However, we need to consider the wider implications for consumers of making any changes to these arrangements, taking account of wider benefits provided by embedded generators.*
>
> *We are currently considering the impact on consumers of changing the charging arrangements for distribution connected generators, whether there is a case for us to initiate any changes to the charging methodologies and how and when any such changes should occur. This includes whether any transitional arrangements are required. We have not yet reached a decision on this, but expect to set out a way forward on this matter in the summer.*
>
> *Ofgem Forward Work Program – March 2016*

This has come on a backdrop of TNUoS prices that have risen in England from £14-26/kW in 2010/11 to £33-46/kW in 2015/16. These values are currently forecasted to reach £61-80/kW in 2019/20.

This report looks into the landscape in which any potential changes might be made and goes on to consider what impact any changes to the embedded benefits regime might have, specifically relating to the implications upon security of supply - raised by Ofgem as a potential consequence of any changes.

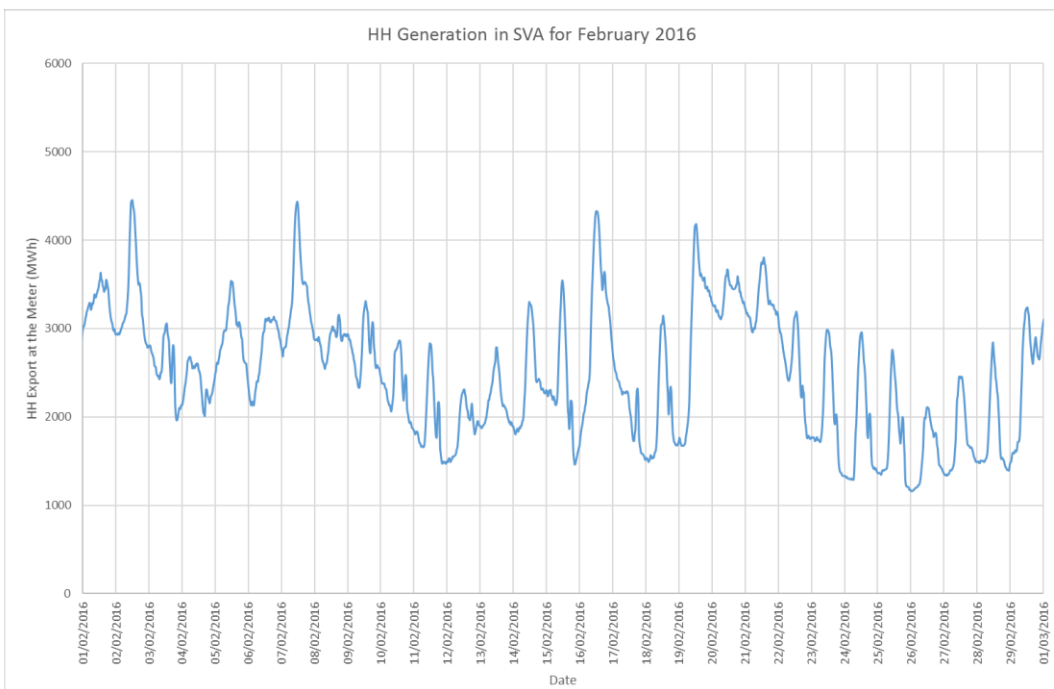
3 State of System in Winter 2015/16

The past decade has seen significant changes within the GB power market. In 2005 things were relatively stable, with 75% of power generation coming from coal- or gas-fired power stations that could be relied upon to deliver power across winter periods. A further 22% of power came from nuclear plant; only 6% of power generation come from interconnectors or renewable plants.

By 2015 the levels of generation from coal- or gas-fired plants had fallen to 51%, while recent closures at nuclear plants along with concerns over cracks found in graphite bricks at EDF’s plants resulted in a nuclear fleet providing a slightly reduced percentage of power generation. The remaining 29% of power was sourced from renewables (21% of total) and electricity imports (7% of total).

3.1 Embedded Generator Activity (Best View)

A typical embedded generation shape in the market is shown below. This chart uses P0276 data from Elexon and shows the sum of metered volume at a HH level for export meters in HH metering nationally for February 2016.



The chart shows that peak output was approximately 9GW (2 x HH metered volume) in February 2016. EnAppSys estimates are that there is approximately 2GW of baseload capacity, 4-5GW of solar generation from HH meters at the peak, 3-4GW of wind solar generation from HH meters at the peak and 1-2GW of peaking generation capacity. In terms of Capacity Mechanism new builds, the following table documents activity at all operators with successful new builds in the past two CM auctions.

Table 1

OPERATOR	FUTURE CAPACITY (MW)	EXITING (MW)	EXISTING (MW)	NEW BUILD With CM contract (MW)	Plants Without CM Contract (MW)
Carlton Power	1,656.2	0.0	0.0	1,656.2	569.6
ESB	809.9	362.2	0.0	809.9	0.0
UKPR	607.6	0.0	96.2	511.5	347.9
Green Frog Power	298.2	197.7	3.3	294.9	87.6
Peak Gen	244.7	0.0	0.0	244.7	207.1
Prime Energy	138.0	0.0	0.0	138.0	132.4
Eider	79.3	0.0	0.0	79.3	0.0
Noriker Power	75.6	0.0	0.0	75.6	18.9
Welsh Power	84.9	0.0	9.5	75.5	226.0
Alkane Energy	130.8	0.0	56.3	74.6	22.7
Sterling Power	70.0	0.0	0.0	70.0	40.0
Ferrybridge MFE	63.6	0.0	0.0	63.6	67.7
Plutus Energy	56.7	0.0	0.0	56.7	104.0
GDF Suez	3,089.1	1,521.5	3,042.6	46.5	0.0
FCC Environment	88.4	0.0	42.6	45.9	0.0
Power Balancing Services	45.2	0.0	0.0	45.2	0.0
First Renewable	35.9	0.0	0.0	35.9	47.3
Viridor Waste	22.8	0.0	0.0	22.8	30.7
TP Leaseco	19.8	0.0	0.0	19.8	0.0
Cadoxton Power	15.1	0.0	0.0	15.1	0.0

Of these operators, Carlton Power represent Trafford Power and ESB owns Carrington, but the remaining 1.92GW of de-rated capacity is all expected to come from small embedded generators.

These generators, designed to provide peak power on high-demand days, are a key source of new-build capacity within the GB power market.

3.2 State of Main Market

In general, the growth of wind capacity has meant that much of the winter period has seen ample levels of margin - strong wind output across winter months ensuring that there is a large excess of potential supply from thermal generators.

The challenge for the system is in dealing with high-demand days when levels of wind generation are low so capacity margins become very tight. Wind generation was fairly consistent last winter but dropped away on a small number of days. A low-wind high-demand day is the greatest challenge to the system in terms of ensuring security of supply. The danger is greatest when there is high atmospheric pressure over the UK – on cold still winter nights.

3.3 Closures/New-Builds Prior To Winter 2015/16

A number of power stations have closed in recent years:

- Barking (1.0GW; closed 2014),
- Cockenzie (1.2GW; closed 2013),
- Didcot A (2.0GW; closed 2013),
- Grain (1.3GW; closed 2012),
- King's Lynn (0.3GW; closed 2012),
- Kingsnorth (1.9GW; closed 2012),
- Littlebrook (1.1GW; 2015GW),
- Teesside (1.9GW; closed 2013)
- Tilbury B (0.8GW; closed 2013).

Much of this plant was due to close anyway before the end of 2015, having opted out of the Large Combustion Plant Directive, but their running for limited hours in the face of increasingly difficult economics has resulted in early closure. In many cases these plants have already been demolished.

Since 2010 a number of new power stations have been constructed including:

- Marchwood (0.8GW),
- Staythorpe (1.7GW),
- Langage (0.9GW),
- Grain CHP (1.3GW),
- Pembroke (2.0GW)
- West Burton B (1.3GW).

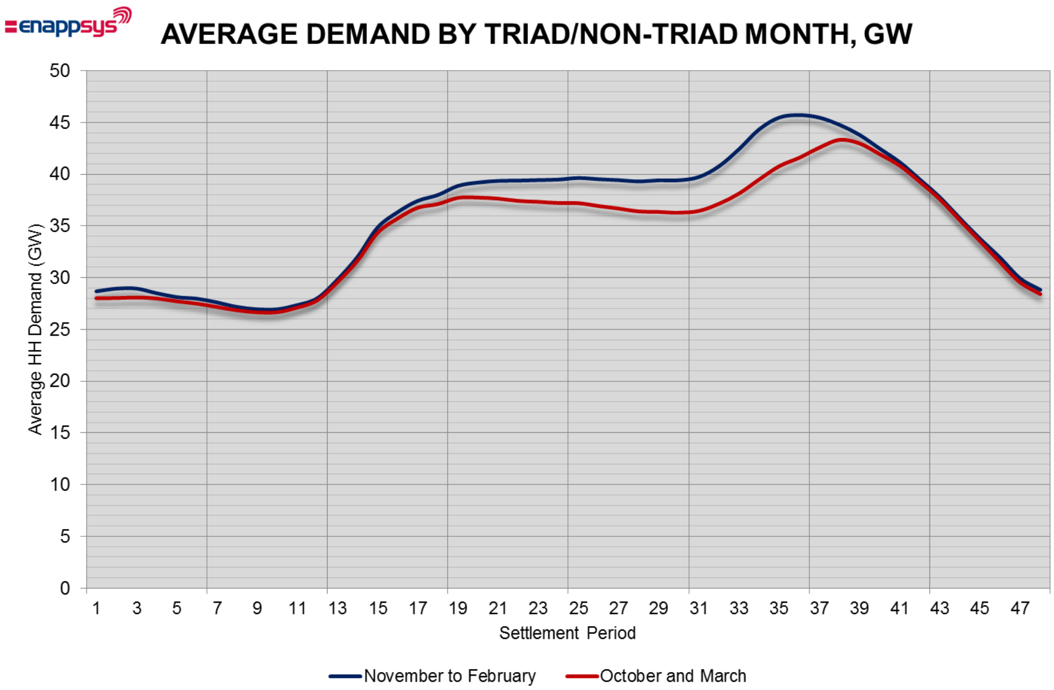
These new builds total 8.0GW, the last being commissioned in 2013.

3.4 November to February versus October and March

An interesting development in the past couple of years is that the shoulder periods are becoming tighter relative to the triad periods.

In winter 2015/16, the overall levels of margin within the system were generally lower outside of the triad months of November to February, which are usually considered to be the core winter months and are the only time during which triad periods apply.

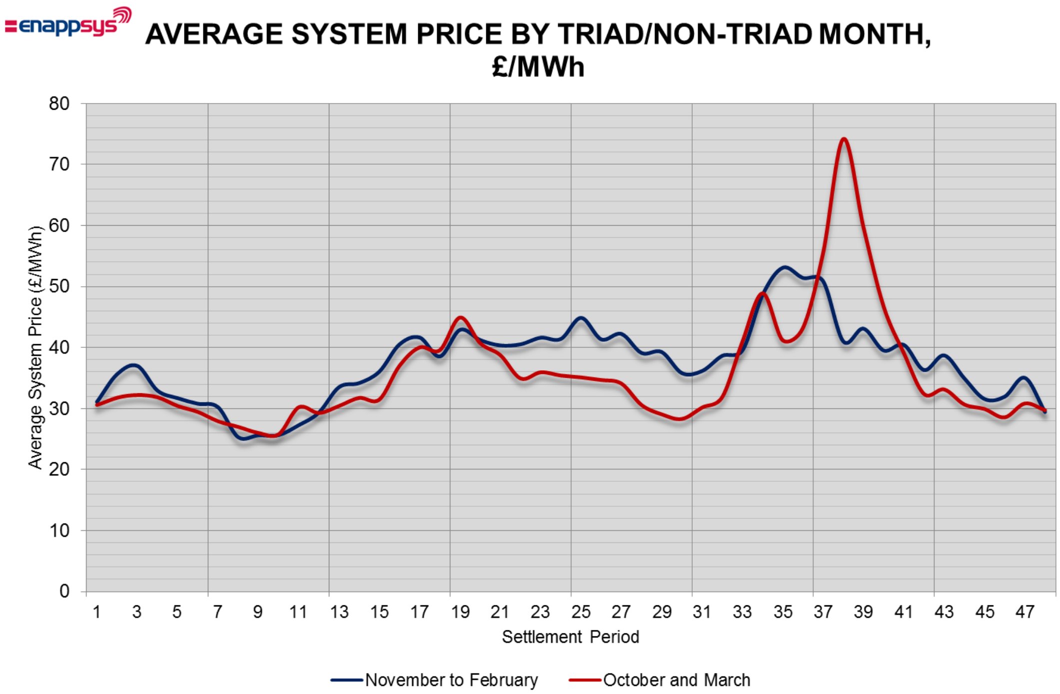
The following chart plots the average demand from November to February and during March and October:



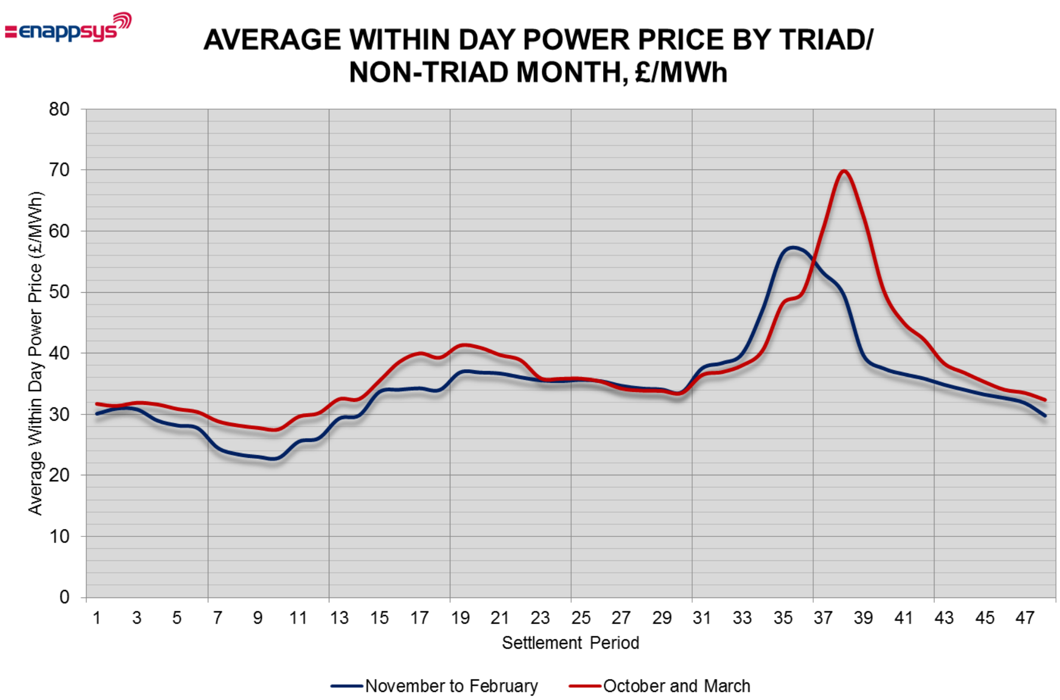
From November to February, embedded generators seek to increase their output and electricity consumers to decrease their requirement around peak periods.

The difference between margins during the two periods shown is unlikely to be solely down to the impact of TNUoS payments, but the reduction of peak demand in these months will contribute to the reduced demand for thermal generation and hence increased margins within the system.

These reduced margins impact system prices. The impact can be seen in the following chart:

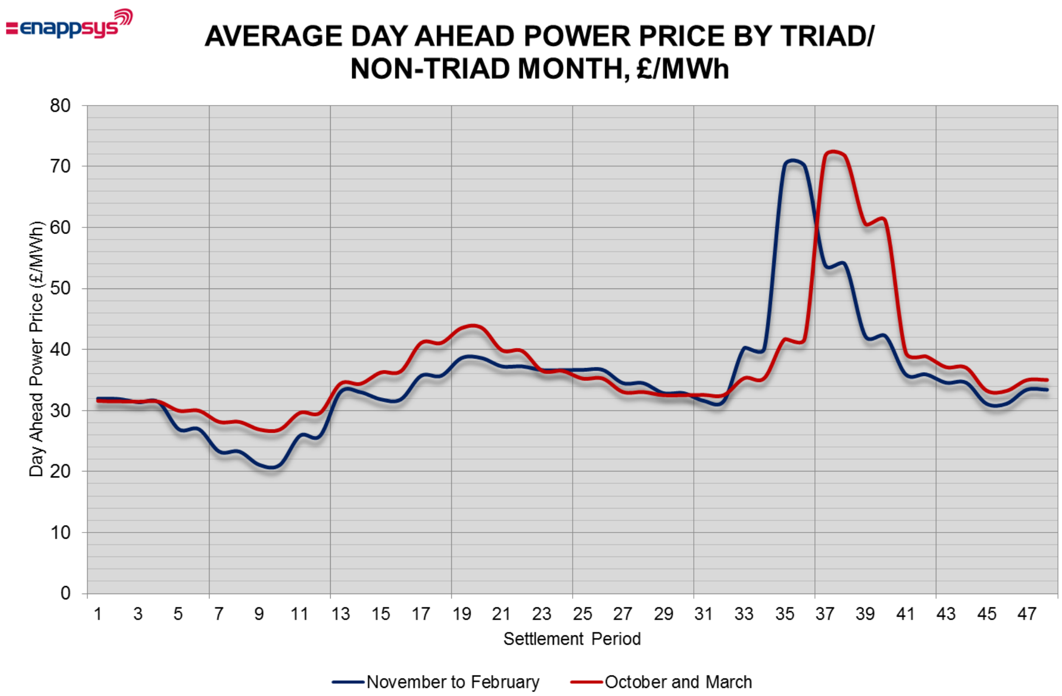


This in turn translates into higher within-day power prices in October and March:



The fact that November to February are triad months will not be the only driver of activity as wind generation is also higher then; but triad avoidance will be contributing towards the overall trend: there is a clear reduction in winter prices when embedded generation is chasing triads and benefitting from TNUoS, compared with the shoulder months where it is either in STOR or else responding only to strong price signals.

The same trend does not exist if one looks at day-ahead data, shown in the following chart:



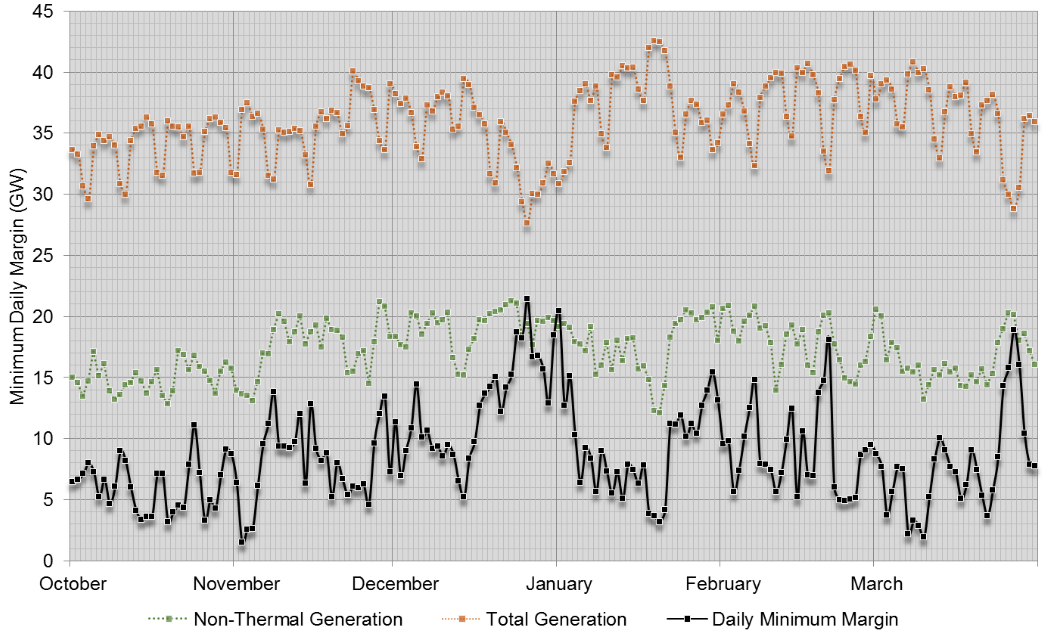
The day-ahead market price reflects the risk-weighted assumption that planned generation will operate to schedule and that demand will follow forecasts. The interaction of embedded generation in 'chasing Triads' is factored into the market: it is notable that when demand is at its highest in winter peaks, day-ahead prices do not show commensurate spikes, indicating that embedded generation is likely to be contributing to keeping winter day-ahead peak prices stable - the market assumes embedded generators will run during the peaks.

The movement in the demand peak is influenced by the change in sunset timing, as seen by the peak's shift between winter and the shoulder months.

3.5 Winter 2015/16 Margin Analysis

Across the full winter period of 2015/16 margins were 5GW or more on 85% of the days. Levels only dropped below 2GW on two days across the period (2nd November 2015 to 1.5GW and 10th March 2016 to just under 2.0GW).

A plot of the levels of minimum margins and average daily generation across the winter period can be seen in the following chart, alongside levels of non-thermal generation:



The periods of short margin generally occurred when levels of total generation were high and when levels of non-thermal generation were low. Across December and February, the system was particularly well supplied with wind power, which was a large contributor to healthy margins across much of the winter period.

These strong levels of renewable generation, coupled with high levels of nuclear generation meant that generation across the thermal fleet was relatively low.

Across winter 2015/16 levels of daily thermal generation averaged 18.7GW, upper and lower quartiles at 15.9GW and 21.7GW (a range of 5.7GW). Minimum and maximum levels of daily thermal generation were at much higher extremes, with a maximum daily generation at 30.4GW and minimum daily generation at 8.3GW (a range of 22.1GW).

This meant that whereas the requirements for peak thermal generation in winter 2015/16 were very high, the typical running hours for coal and gas plants were relatively low across the whole winter period.

These totals only account for large power stations. Embedded generators were reducing the amount of total generation required on the peak days. The loss of this embedded generation output from the system would increase the requirements for output from large coal and gas power stations on peak days.

Low thermal running hours were a key factor contributing to the high number of closures ahead of winter 2016/17. Since the winter of 2015/16 was mild, the requirements for 2016/17 could be much higher on peak days.

There are three key challenges posed in terms of ensuring security of supply within the GB power market:

1. Ensuring that levels of power supply are high enough to keep the lights on.
2. Ensuring that plants on the margins of the market are sufficiently rewarded to continue to participate in the market and continue to keep the lights on.
3. Ensuring that plants are available at the right time.

In the winter of 2015/16, levels of margin remained above what appear to be acceptable levels, despite the issue of two NISMs (Notice of Insufficient Margins). Recent closures will, however, place a larger stress upon the system in winter 2016/17 as large marginal plants were unable to ensure sufficient income to remain active in the market.

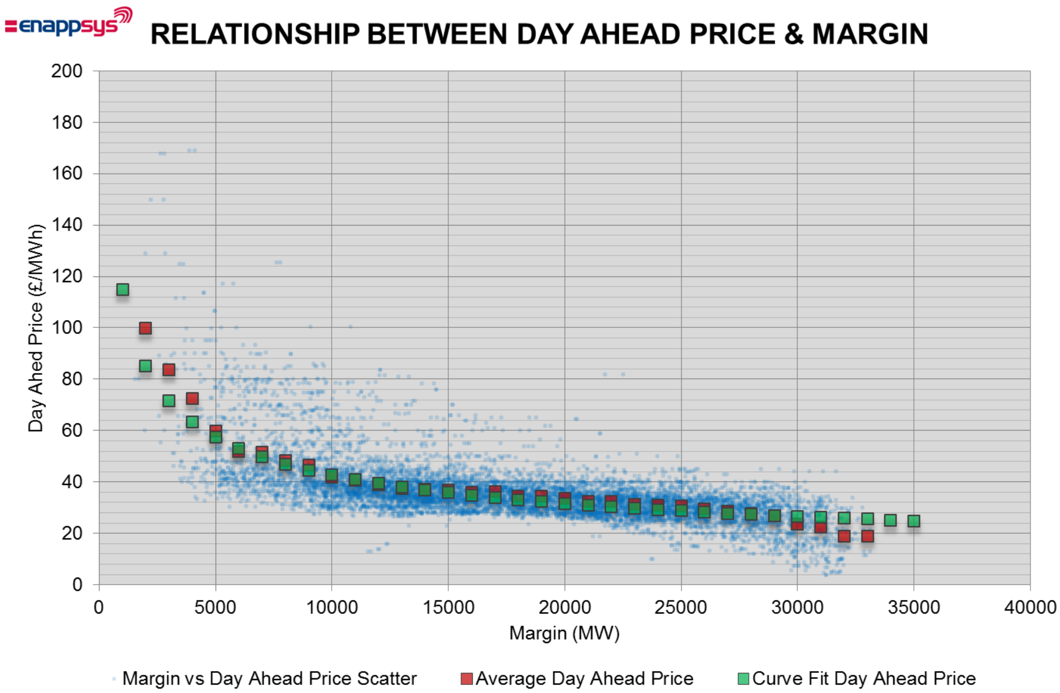
This second point is more challenging, since any new-build capacity will act to push existing plant down the merit order and further towards the margins of the market, reducing the operating hours of the more marginal plants. This in turn could put existing generators' futures in doubt, when they might have continued operations without the construction of the new plant. If the capacity of existing plant were sufficient to meet demand the newer more efficient plant would squeeze out the older plant.

The third point is key in maximising the value able to be derived from relatively low levels of overall market capacity available on peak days. The Capacity Mechanism has been designed around ensuring that generators maximise their ability to generate on days where there is a risk of forced lost load.

All this creates a requirement to build new plants at sufficient scale in a manner that does not reduce the operating income of existing marginal plants to a degree that they close down, and that these plants are available to the system when required.

3.6 Relationship Between Margin and Price

The relationship between the historic margin and day-ahead price can be seen in the following chart, along with a curve fit produced by EnAppSys:



The chart above represents a scarcity pricing function, which as demand exceeds supply and takes margins to zero, will tend towards infinity. However, the function can also be adjusted if a price cap is introduced by the government, deemed here to be either £300/MW/h or 1,000/MWh, based upon 10%-33% of the £3,000/MWh price that will result if SBR is utilised. In our modelling from this analysis these two price cap values have been used.

Since £3,000/MWh will be the cost that generators incur for any failed generation, prices should be pushed up towards that level.

4 State of Market Ahead of Winter 2016/17

Since the start of 2016, falling gas prices have meant that coal stations have been struggling to operate profitably. Furthermore, the government has been highlighting their intention to cease unabated coal-fired generation by 2025, in addition to the effect of Industrial Emissions Directive (IED). Many of these plants have therefore taken the decision to close.

4.1 Recent Closures/New-Builds

In 2016 final plant closures have occurred at:

- Eggborough (2.0GW; partial close 2016),
- Ferrybridge C (2.0GW; fully closed 2016),
- Ironbridge (1.0GW; fully closed 2016),
- Killingholme 1 (0.7GW; closed 2016),
- Killingholme 2 (0.9GW; closed 2016),
- Longannet (2.4GW; closed 2016),
- Rugeley B (1.0GW; closed 2016)

These power stations have now either closed down their last operating units or closed down all but a small share of their capacity, which will move into SBR (Supplemental Balancing Reserve – a service of last resort whereby generators are paid to remain out of the market but provide power when required to ensure that the lights remain on).

The total capacity of these stations amounts to 10GW, although some of this capacity was already lost to the system prior to last winter, as single units closed ahead of any full plant closures. The actual closures occurring during 2016 total around 5GW.

Drax's coal units and Fiddler's Ferry were also very close to closure before being awarded "black start" contracts from National Grid with a reported value of £113m over two years.

The total capacity that has closed since 2012 is 21.5GW.

A 0.9GW power station (Carrington) is currently into final commissioning. Trafford Power is the only large new-build power station to have won in the Capacity Mechanism, with a capacity of 1.9GW. Doubts about the owners' ability to finance their project have been worsening.

If Trafford Power fails then the largest new source of power procured via the Capacity Mechanism will have been obligated to small embedded stations, which amount to a total de-rated capacity of 1.9GW, due to be built by 18 separate developers.

4.2 Supplemental Balancing Reserve (SBR) Winter 2016/17

To offset the amount of capacity being lost ahead of expectations, National Grid brought in Supplemental Balancing Reserve (SBR), paying a fee to plant that was committed to shutting down for still providing power if needed as a last resort (ie as peaking plant).

Ahead of winter 2016/17 an increased amount of capacity has exited the markets and shifted into SBR:

	Unit	Owner	De-Rated Capability (MW)*
New Contracts	Eggborough Coal (775MW)	Eggborough	681
New Contracts	South Humber CCGT (750MW)	Centrica	654
New Contracts	Peterhead CCGT (additional 2 x 375MW)	SSE	646
New Contracts	Killingholme CCGT (600MW)	Uniper	523
New Contracts	Fiddlers Ferry Coal (480MW)	SSE	422
New Contracts	Deeside CCGT (additional 250MW)	Engie	218
15/16 Rollovers	Corby CCGT (353MW)	ESBi	308
15/16 Rollovers	Fiddlers Ferry GTs (2 x 17MW)	SSE	32
15/16 Rollovers	Keadby GT (23MW)	SSE	22
15/16 Rollovers	South Humber CCGT (20MW headroom)	Centrica	17
	MW Total		**3523**

The following generators have terminated their 2015/16 SBR contracts:

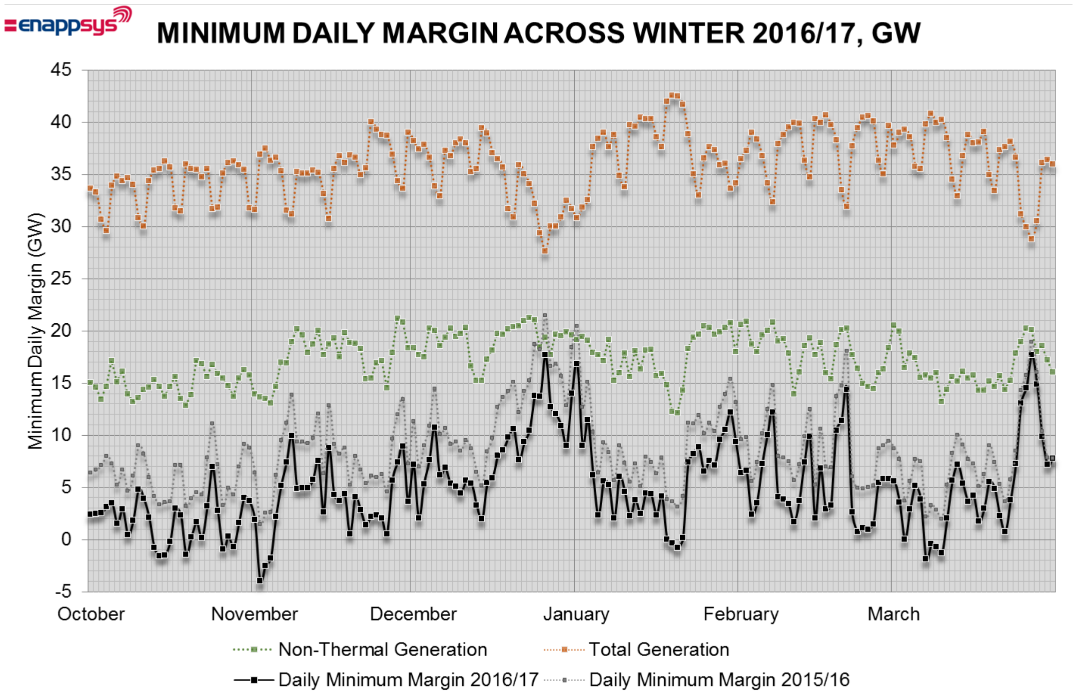
Unit	Owner	De-Rated Capability (MW)*
Ferrybridge GTs (2 x 16MW)	SSE	30
Barry CCGT (227MW)	Centrica	198
Killingholme CCGT (660MW)	Centrica	576
MW Total		**804**

The loss of capacity to this service of last resort comes following a winter in which margins were on occasions relatively tight, system prices rising as high as £518/MWh on 10th March 2016 and with two NISMs (Notices of Insufficient Margins) called.

4.3 Winter 2016/17 Margin Analysis

To assess the market next winter, EnAppSys has taken the levels of availability, generation and demand across winter 2015/16 and modelled what winter 2016/17 might look like based upon identical levels, but removing power stations that have closed or gone into SBR. The modelling also accounts for Keadby returning to full availability and Carrington becoming available at full capacity. Embedded generation is assumed to be undertaking its ‘normal’ triad avoidance.

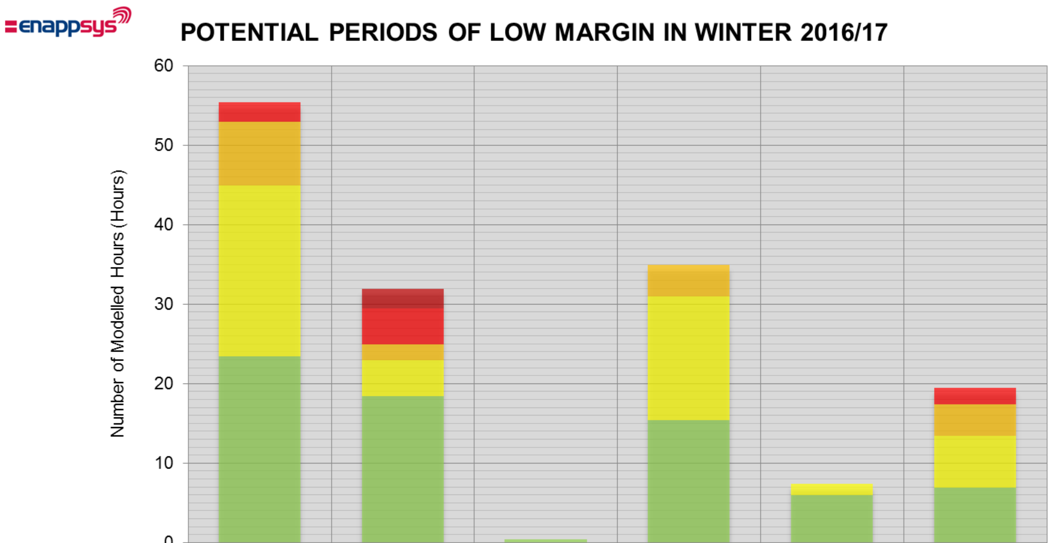
The impact of capacity closing or moving into SBR shows much tighter margins, with frequent periods where margins will drop below 0MW unless extra availability can be found:



The analysis excludes units that will be in SBR so does not imply that the lights will go out, but when SBR is used the system price will go up to £3,000/MWh, as it must only be used as a last resort and when there is an expectation of forced lost load unless it is activated.

This will potentially translate into power prices peaking as high as £3,000/MWh in winter 2016/17.

Without the use of SBR the following chart shows the number of periods where the margin is expected to drop below 2GW, unless generators that were unavailable in winter 2015/16 increase their levels of availability in the coming winter:



	October	November	December	January	February	March
Less Than -2 GW	0.0	2.5	0.0	0.0	0.0	0.0
-1 to -2 GW	2.5	4.5	0.0	0.0	0.0	2.0
-1 to 0 GW	8.0	2.0	0.0	4.0	0.0	4.0
0 to 1 GW	21.5	4.5	0.0	15.5	1.5	6.5
1 to 2 GW	23.5	18.5	0.5	15.5	6.0	7.0

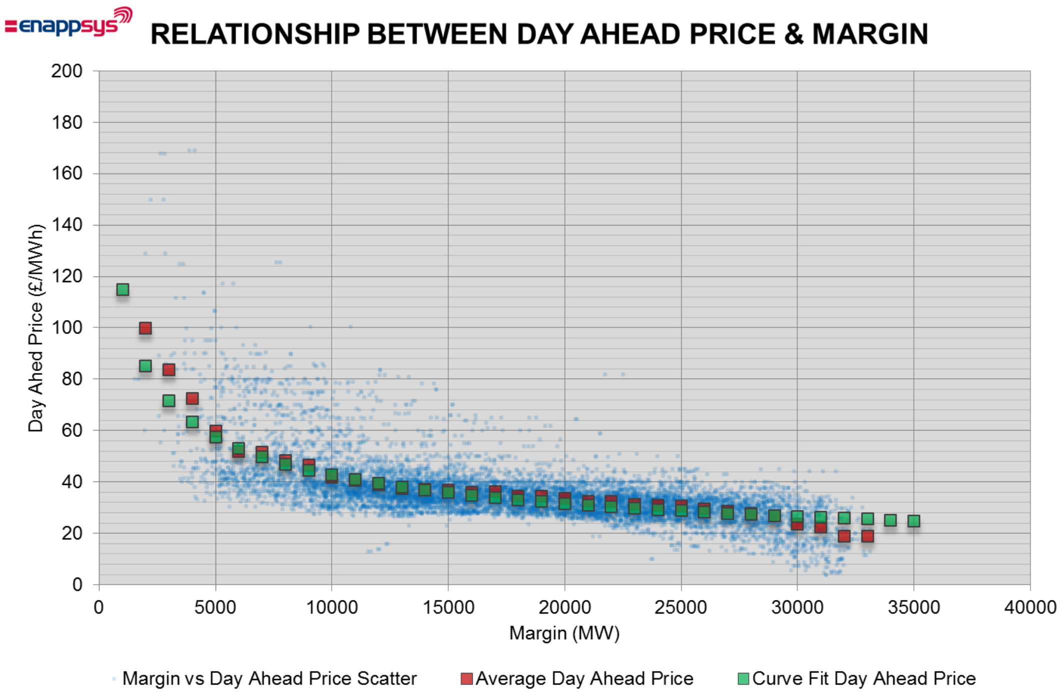
Such a frequency of low margins suggests a system on the very edge of having appropriate capacity and suggests that the system could see major price spikes through the winter as ‘scarcity pricing’ comes into play. Offsetting this will be any newly built embedded generators that have come online ahead of their 15-year Capacity Mechanism contracts.

Carrington has already been accounted for as an early new build, so the only other new builds available to improve the margin will be new embedded generators.

4.4 Modelling Potential Price Increases

The relationship between the historic margin and the day-ahead price can be used to estimate the expected overall cost to the system of the tighter margin in winter 2016/17 (as measured by the difference in expected power price multiplied by the total generation over the winter period).

This relationship has already been established in an earlier section of this report and is shown in the following chart:



This curve fit has been modified to apply a price cap of £300/MWh or 1,000/MWh which represents 10%-33% of the value of lost load (£3,000/MWh) and the expected system price if SBR is called. Since this value of lost load will be the price that generators will incur for any failed generation, prices should head towards £3,000/MWh.

This cap is arguably a very conservative assumption as a pure market would tend to deliver prices at or close to the next alternative action i.e. £3,000/MWh. In the GB market however, past history would suggest there would be intervention via legislative or regulatory change if prices consistently get to these levels. The industry has therefore been reluctant to drive prices to very high levels on a consistent basis. This could of course change in a very stressed market or with convincing signals from the government or regulator that price spikes are acceptable.

Ofgem's calculation of the value of lost load to consumers is in fact £17,000 per MWh; and current legislation proscribes a doubling of the £3,000 rate to £6,000 in October 2018.

Using the relationship between price and margin, the expected increase in price resulting from the changes in margin documented in the previous section can be calculated and used to identify the increased cost to the system resulting from scarcity of supply within the system.

Using the above approach, the cost of wholesale power is expected to increase by £1.33bn-£2.30bn, with mean prices increasing by £8.83-15.27/MWh, the two values based upon the price caps of £300/MWh and £1,000/MWh respectively. This growth is expected to be primarily be driven by very high prices around times of severe shortage. Median prices are expected to reach a more modest increment of £2.66/MWh in both cases.

This cost calculation is based upon multiplying the prices by demand over the winter period, with overall winter demand totaling 150.4TWh in all calculations.

In winter 2015/16 there were generators that had reduced levels of availability but which might be induced to increase their availability if market prices rise. It is possible that such an effect will occur next winter with tighter margins and higher prices.

The potential impact of this is limited by the fact that many such generators have moved into SBR, but EnAppSys estimate that there could still be up to a 1.5GW increase in availability across the winter period in response to stronger price signals.

Incorporating this into the analysis reduces the cost increase from the previous winter to an uplift of £0.51bn-£0.76bn, with mean prices increasing by £3.37-5.08/MWh. This 1.5GW increase is incorporated into all future and headline analyses within this report.

Based upon a simple trend fit combined with a simple cap, the figures do suggest that if the system margin does tighten, there could be considerable increases in the cost of supplying electricity due to shortages in the system.

5 Impact of Removal of Triad Income

If Triads are removed, there are a number of ways the market could be impacted. These include

(1) those assets that have been awarded 2018/2019 15-year Capacity Mechanism agreement or a CfD might not be built or might be delayed,

(2) existing embedded plant will be setting prices on the scarcity price model and hence will hold back generation (via mothballing) until a significant premium is available, or it might even exit the market entirely,

(3) Projects without a CM agreement or a CfD - new embedded projects, demand-side response (DSR) and renewables projects might not get developed, or are developed but with higher CM or CfD prices due to the impact of regulatory uncertainty on investor confidence

Conversely the continued growth in embedded generation which is not impacted by the removal of triads, which is typically renewable generation, should offset some of the costs arising from the impact of reduced margins as its capacity reduces the number of periods when margins are tight.

One of the key consequences of embedded benefits is that a large number of small, flexible and distributed generators (and demand-side units) provide a net demand reduction in peak periods without being centrally dispatched or dispatched by market price signals and in the remaining periods are available as reserve power, under contract to National Grid or to a supplier.

To model the consequence of the loss of embedded generation, EnAppSys has replicated the effect by increasing margins in line with the changing levels of embedded generation. This is consistent with the assumption that generators will target triads during evening peaks and then operate via STOR or main markets to boost overall margins during other hours.

5.1 Low Case

The low case follows the most conservative approach of a £300/MWh price cap and assumes that the system is still able to avoid a loss of load despite the loss of margin.

In this table the increases are compared with winter 2015/16 and the increase in power cost is the increase in price multiplied by demand for each half-hourly period. The reduction in power costs are then compared with the power cost if there is no change in embedded generation. The net benefit values account for an HH demand tariff at £70/kW and offsets this from any cost reductions.

Impact of Removal of Triad Income

The changes in net benefit to the system at different levels of embedded generation are as follows:

Increase In Embedded Generation (MW)	*Effect on Median Power Price (£/MWh) (+ve prices rise)*	*Effect on Mean Power Price (£/MWh) (+ve prices rise)*	*Effect on Overall Power Cost (£m p.a.)*	*Reduction in Power Cost from No Change (£m p.a.)*	*Net Embeded Generation Benefit (£m p.a.)*
5,000	-£2.86	-£4.11	-£617.8	£1,124.5	£774.5
4,800	-£2.73	-£3.92	-£589.5	£1,096.2	£760.2
4,600	-£2.60	-£3.73	-£560.4	£1,067.1	£745.1
4,400	-£2.46	-£3.53	-£530.7	£1,037.4	£729.4
4,200	-£2.33	-£3.33	-£500.2	£1,006.9	£712.9
4,000	-£2.19	-£3.12	-£468.9	£975.6	£695.6
3,800	-£2.05	-£2.90	-£436.8	£943.5	£677.5
3,600	-£1.90	-£2.68	-£403.7	£910.5	£658.5
3,400	-£1.76	-£2.46	-£369.7	£876.4	£638.4
3,200	-£1.61	-£2.22	-£334.6	£841.3	£617.3
3,000	-£1.46	-£1.98	-£298.2	£804.9	£594.9
2,800	-£1.31	-£1.73	-£260.2	£767.0	£571.0
2,600	-£1.15	-£1.46	-£220.0	£726.7	£544.7
2,400	-£1.00	-£1.18	-£177.5	£684.2	£516.2
2,200	-£0.84	-£0.89	-£134.0	£640.7	£486.7
2,000	-£0.68	-£0.60	-£90.0	£596.8	£456.8
1,800	-£0.51	-£0.31	-£46.1	£552.8	£426.8
1,600	-£0.35	-£0.00	-£0.1	£506.8	£394.8
1,400	-£0.18	£0.32	£48.7	£458.0	£360.0
1,200	£0.00	£0.68	£101.7	£405.0	£321.0
1,000	£0.17	£1.04	£156.6	£350.1	£280.1
800	£0.35	£1.42	£213.3	£293.4	£237.4
600	£0.53	£1.84	£276.4	£230.3	£188.3
400	£0.72	£2.32	£349.3	£157.5	£129.5
200	£0.91	£2.85	£429.2	£77.6	£63.6
0	£1.10	£3.37	£506.7	£0.0	£0.0
-200	£1.29	£3.90	£586.4	-£79.7	-£65.7
-400	£1.49	£4.46	£670.7	-£164.0	-£136.0
-600	£1.70	£5.11	£768.6	-£261.9	-£219.9
-800	£1.90	£5.83	£877.6	-£370.9	-£314.9
-1,000	£2.11	£6.62	£996.0	-£489.2	-£419.2
-1,200	£2.33	£7.43	£1,117.0	-£610.3	-£526.3
-1,400	£2.55	£8.32	£1,252.0	-£745.3	-£647.3
-1,600	£2.77	£9.36	£1,407.3	-£900.5	-£788.5
-1,800	£3.00	£10.41	£1,565.4	-£1,058.7	-£932.7
-2,000	£3.23	£11.61	£1,747.0	-£1,240.3	-£1,100.3
-2,200	£3.47	£12.84	£1,931.5	-£1,424.8	-£1,270.8
-2,400	£3.71	£14.10	£2,120.5	-£1,613.8	-£1,445.8
-2,600	£3.96	£15.49	£2,329.4	-£1,822.7	-£1,640.7
-2,800	£4.22	£16.82	£2,529.6	-£2,022.9	-£1,826.9
-3,000	£4.48	£18.20	£2,738.2	-£2,231.5	-£2,021.5
-3,200	£4.74	£19.62	£2,951.6	-£2,444.9	-£2,220.9
-3,400	£5.01	£21.02	£3,162.3	-£2,655.6	-£2,417.6
-3,600	£5.29	£22.60	£3,399.0	-£2,892.3	-£2,640.3
-3,800	£5.58	£24.27	£3,650.7	-£3,144.0	-£2,878.0
-4,000	£5.87	£25.89	£3,894.2	-£3,387.5	-£3,107.5
-4,200	£6.17	£27.55	£4,144.0	-£3,637.3	-£3,343.3

Increase In Embedded Generation (MW)	Effect on Median Power Price (£/MWh) (+ve prices rise)	Effect on Mean Power Price (£/MWh) (+ve prices rise)	Effect on Overall Power Cost (£m p.a.)	Reduction in Power Cost from No Change (£m p.a.)	Net Embeded Generation Benefit (£m p.a.)
-4,400	£6.48	£29.22	£4,395.3	-£3,888.5	-£3,580.5
-4,600	£6.79	£31.00	£4,662.2	-£4,155.5	-£3,833.5
-4,800	£7.11	£32.81	£4,935.3	-£4,428.5	-£4,092.5
-5,000	£7.45	£34.65	£5,211.1	-£4,704.4	-£4,354.4

5.2 High Case

The high case uses the less conservative £1,000/MWh price cap and assumes that the system is still able to avoid a loss of load, despite the loss of margin involved.

In this table the increases are compared with winter 2015/16 and the increase in power cost is the increase in price multiplied by demand during each half-hourly period. The reduction in power cost then compares to the cost if there is no change in embedded generation.

The net benefit values account for an HH demand tariff at £70/kW and offsets this from any cost reductions.

The changes in net benefit to the system at different levels of embedded generation are as follows:

Increase In Embedded Generation (MW)	Effect on Median Power Price (£/MWh) (+ve prices rise)	Effect on Mean Power Price (£/MWh) (+ve prices rise)	Effect on Overall Power Cost (£m p.a.)	Reduction in Power Cost from No Change (£m p.a.)	Net Embeded GenerationBenefit (£m p.a.)
5,000	-£2.86	-£4.11	-£617.8	£1,381.9	£1,031.9
4,800	-£2.73	-£3.92	-£589.4	£1,353.5	£1,017.5
4,600	-£2.60	-£3.73	-£560.4	£1,324.5	£1,002.5
4,400	-£2.46	-£3.53	-£530.7	£1,294.8	£986.8
4,200	-£2.33	-£3.33	-£500.2	£1,264.3	£970.3
4,000	-£2.19	-£3.12	-£468.9	£1,233.0	£953.0
3,800	-£2.05	-£2.90	-£436.8	£1,200.9	£934.9
3,600	-£1.90	-£2.68	-£403.7	£1,167.8	£915.8
3,400	-£1.76	-£2.46	-£369.7	£1,133.8	£895.8
3,200	-£1.61	-£2.22	-£334.6	£1,098.7	£874.7
3,000	-£1.46	-£1.98	-£298.2	£1,062.3	£852.3
2,800	-£1.31	-£1.73	-£260.2	£1,024.3	£828.3
2,600	-£1.15	-£1.46	-£220.0	£984.1	£802.1
2,400	-£1.00	-£1.07	-£161.4	£925.5	£757.5
2,200	-£0.84	-£0.70	-£105.9	£870.0	£716.0
2,000	-£0.68	-£0.34	-£51.8	£815.9	£675.9
1,800	-£0.51	£0.01	£2.1	£762.0	£636.0
1,600	-£0.35	£0.32	£48.1	£716.0	£604.0
1,400	-£0.18	£0.64	£96.9	£667.2	£569.2
1,200	-£0.00	£1.00	£151.1	£613.0	£529.0
1,000	£0.17	£1.48	£222.9	£541.2	£471.2
800	£0.35	£1.95	£293.2	£470.9	£414.9

Increase In Embedded Generation (MW)	Effect on Median Power Price (£/MWh) (+ve prices rise)	Effect on Mean Power Price (£/MWh) (+ve prices rise)	Effect on Overall Power Cost (£m p.a.)	Reduction in Power Cost from No Change (£m p.a.)	Net Embeded GenerationBenefit (£m p.a.)
600	£0.53	£2.37	£356.3	£407.8	£365.8
400	£0.72	£2.98	£448.1	£316.0	£288.0
200	£0.91	£3.84	£577.5	£186.6	£172.6
0	£1.10	£5.08	£764.1	£0.0	£0.0
-200	£1.29	£6.04	£908.9	-£144.8	-£130.8
-400	£1.49	£6.81	£1,024.0	-£259.9	-£231.9
-600	£1.70	£7.77	£1,168.4	-£404.3	-£362.3
-800	£1.90	£9.03	£1,358.4	-£594.3	-£538.3
-1,000	£2.11	£10.61	£1,595.3	-£831.2	-£761.2
-1,200	£2.33	£12.58	£1,892.2	-£1,128.1	-£1,044.1
-1,400	£2.55	£14.28	£2,147.2	-£1,383.1	-£1,285.1
-1,600	£2.77	£16.54	£2,487.5	-£1,723.4	-£1,611.4
-1,800	£3.00	£19.52	£2,935.3	-£2,171.2	-£2,045.2
-2,000	£3.23	£22.14	£3,330.8	-£2,566.7	-£2,426.7
-2,200	£3.47	£25.88	£3,892.8	-£3,128.7	-£2,974.7
-2,400	£3.71	£29.72	£4,470.2	-£3,706.1	-£3,538.1
-2,600	£3.96	£33.34	£5,014.0	-£4,249.9	-£4,067.9
-2,800	£4.22	£37.94	£5,706.6	-£4,942.5	-£4,746.5
-3,000	£4.48	£42.13	£6,337.5	-£5,573.4	-£5,363.4
-3,200	£4.74	£46.70	£7,024.3	-£6,260.2	-£6,036.2
-3,400	£5.01	£50.48	£7,592.9	-£6,828.8	-£6,590.8
-3,600	£5.29	£54.70	£8,226.9	-£7,462.8	-£7,210.8
-3,800	£5.58	£59.99	£9,022.5	-£8,258.4	-£7,992.4
-4,000	£5.87	£65.48	£9,849.7	-£9,085.6	-£8,805.6
-4,200	£6.17	£70.68	£10,630.7	-£9,866.6	-£9,572.6
-4,400	£6.48	£76.05	£11,438.7	-£10,674.6	-£10,366.6
-4,600	£6.79	£81.13	£12,202.8	-£11,438.7	-£11,116.7
-4,800	£7.11	£87.28	£13,128.2	-£12,364.1	-£12,028.1
-5,000	£7.45	£93.03	£13,993.2	-£13,229.1	-£12,879.1

5.3 Cost of TNUoS to the System

TNUoS costs are forecasted for most regions to rise to around £70/kW, with some regions seeing higher values and others seeing lower values.

This gives a rough cost to the system for embedded benefits for triads of £70m/GW, which can be used to identify a rough net cost to the system of any changes in levels of embedded generation.

From this it is possible to evaluate the impact on embedded generation resulting from legislative or regulatory change.

5.4 Summary of TNUoS Cost Impact

In the Capacity Mechanism there are just under 2GW of embedded projects coming online. Modelling of winter 2016/17 shows that the 2GW increase in margin offered by these plants could turn the modelled £507m-£764m cost increase into a potential £52m-£90m cost decrease by consistently boosting margins within the system.[3]

This places a net benefit to the system of £457m-£676m per annum as a result of the construction of these plants, the value to the system of these generators increasing the sooner they come online.

If embedded benefits were removed from the system, EnAppSys forecast that 1GW of generation that operates via flexible STOR, plus another 1GW of additional generation that earns income from other markets might be insufficiently remunerated to justify continued operation, in the absence of triads, and might potentially exit the market.

If this exit were coupled with the cancelled construction of the 2GW of new plants currently expected, modelling of winter 2016/17 shows that the net 2GW decrease in margin from the position in winter 2015/16 would put the system under serious stress.

Under such a scenario there is an expectation that margins would drop below 2GW for 193 hours across the winter period, while margins in the main market would drop below zero for 49.5 hours. This drop below zero would not necessarily mean the lights going out, but would force the system to rely heavily on last-resort services such as Supplemental Balancing Reserve (SBR) and STOR (typically provided by embedded generators that are at least partly supported by triad income).

With the system under such stress, the scarcity of supply would have a considerable impact upon power prices: an increase of £1.75bn-£3.33bn increase in prices. This would result in a £1.47bn-£3.05bn net cost increase. At the same time the system would need to source 4GW of capacity specifically to generate on peak days without impacting upon the viability of current generators, this additional transmission-connected capacity (likely to be CCGTs) would act to drive out lower-merit-order plant and would be compromised in the long run by increasing renewable generation penetration.

[3] With these plants normally supplementing triad income with operation in reserve markets such as STOR or FFR