CMP244: Extension of the TNUoS tariff notice period – National Grid actions

4th August 2015

nationalgrid

NG actions: contents

- Increase in under / over recovery associated with moving from 2 months notice to 15 months notice – including associated financing costs (action 26) and the impact this would have had on the G / D residuals
- Additional analysis raised by GG: Under / over recovery had we charged according to the tariffs from May 14 in July 15.
- Action 27: Diagram to illustrate current tariff setting process, plus what this would look like under 15 months notice.
- TO revenues
  - What error margin could there be in forecasting TO revenues *across* 2 price controls? (Action 19)
  - How do these change across the price control, and what is the error margin in forecasting these 15 months ahead? (actions 33 and 30)
- Generation and demand charging bases – what is the error margin forecasting these 15 months ahead in terms of revenue recovery? (action 30)
- Impact on cost reflectivity: Examples to consider; circuit changes, large infrastructure projects (Actions 12, 13, 14) *(analysis around change in generation to be shared on the day)*
- Impact of the €2.5 / MWh cap (actions 8 and 31)
- Action 28: How are the Transmission licence conditions around mid-year price changes backed off in the CUSC?
- Action 35: Week 24 data under a 15 month notice scenario
- Unanticipated events: NG role in the case of energy supply company administration
- Licence, code and other necessary changes logged to date (action 32)

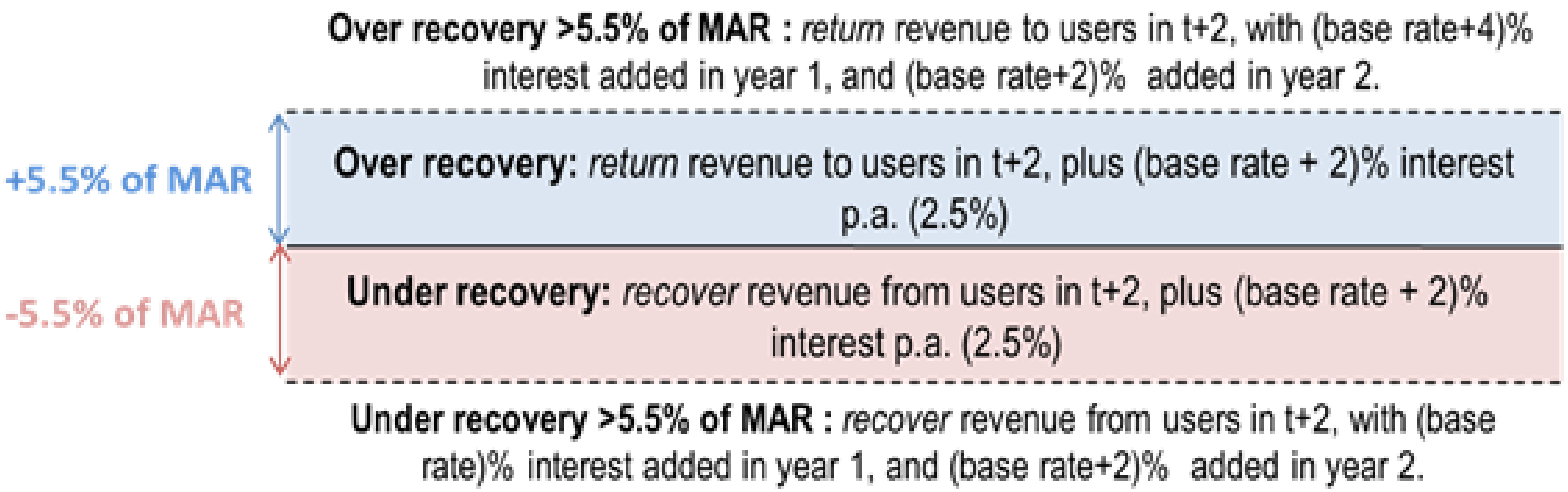
nationalgrid

Action 26 – potential change to under / over recovery due to moving to 15m notice from 2m (updated)

Year	Estimated under / over recovery 15m notice	As a proportion of TO revenue	Compared to current scenario (2 months notice)	As a proportion of TO revenue	**Delta (2m to 15m)**	**Drivers**
2014/15	-£186.3m	-7.6%	- £99m	-3.8%	**£87.3m**	Demand over forecast (Mild winter / embedded)
2013/14	*[Price control]*	*[Price control]*	- £54m	-2.5%		
2012/13	-£175.3m	-9.2%	£3m	0.1%	**£178.3m**	Rollover year
2011/12	-£89.2m	-5.4%	- £24m	-1.4%	**£65.2m**	
2010/11	-£40.7m	-2.6%	£12m	0.75%	**£52.7m**	Mid year price change

nationalgrid

Licence conditions: financing under / over recovery



As per National Grid's special licence condition 3A.14, the 'outside bandwidth' rates apply to the whole under or over recovery of revenue for the year t+1.

nationalgrid

Action 26 – Financing costs (updated)

Year	Estimated under / over recovery 15m ahead	**Cumulative financing costs added to TNUoS in t+2* (current licence cndtns)**	Financing costs for 15m if all at base rate +2%	Under / over recovery with 2m notice	**Financing costs added / *repaid to* TNUoS (all 5.1%)**
2014/15	-£186.3m	3% **£5.59m**	5.1% **£9.50m**	- £99m	**£5.05m**
2013/14	Price control	Price control		- £54m	**£2.75m**
2012/13	-£175.3m	3% **£5.25m**	5.1% **£8.94m**	£3m	***£0.15m***
2011/12	-£89.2m	5.1% **£4.55m**	Same	- £24m	**£1.22m**
2010/11	-£40.7m	5.1% **£2.08m**	Same	£12m	***£0.61m***

Red = 'Outside bandwidth' financing rate (under recovery greater than 5.5% of allowed revenue) Pink = close to hitting outside bandwidth financing rate.

nationalgrid

Impact of increased under / over recovery (plus financing costs) on the generation and demand residuals

Condition 5 report (January 2015):

*EU regulation limits the average annual use of system charges that generators pay to €2.5/MWh for the foreseeable future. With rising revenues this limit is reached in **2015/16** and consequently the revenue recovered from generation is capped and variations in allowed revenue are only reflected in demand tariffs.*

Worked example – **assuming G cap has been reached (impact on G residual is zero)** and

a) the 163m under recovery from 14/15 flows through into 16/17 tariffs (plus licence permitted financing costs) –(1st 2 columns) compared to;

b) 14/15 actual recovery plus financing costs flows through into 16/17 tariffs (2 RH columns)

Revenue (£m)	168.00	168.00	98.80	98.80	Average delta in tariffs
Demand Peak (GW)	52.00	49.00	52.00	49.00	
HH Tariff – delta (£/kW)	**3.23**	**3.43**	**1.90**	**2.02**	**1.37**
HH Charge Base (GW)	15.00	14.00	15.00	14.00	
HH Revenue recovered	48.46	48.00	28.50	28.23	
Therefore revenue remaining to be recovered from NHH (£m)	119.54	120.00	70.30	70.57	
NHH Demand (TWh)	27.00	27.00	27.00	27.00	
NHH Tariff average delta (p/kWh)	**0.44**	**0.44**	**0.26**	**0.26**	**0.18**

Under recovery financed at within bandwidth rates

Additional analysis – taking the example of the projected under recovery from 14/15 there would have been an under recovery of £186.3m added to tariffs in t+2, *plus* financing costs of £5.59m (assuming no change to licence conditions) – total £191.89m.

Again assuming the G cap had been reached (i.e. impact on G residual is zero) the impact on D tariffs would have been:

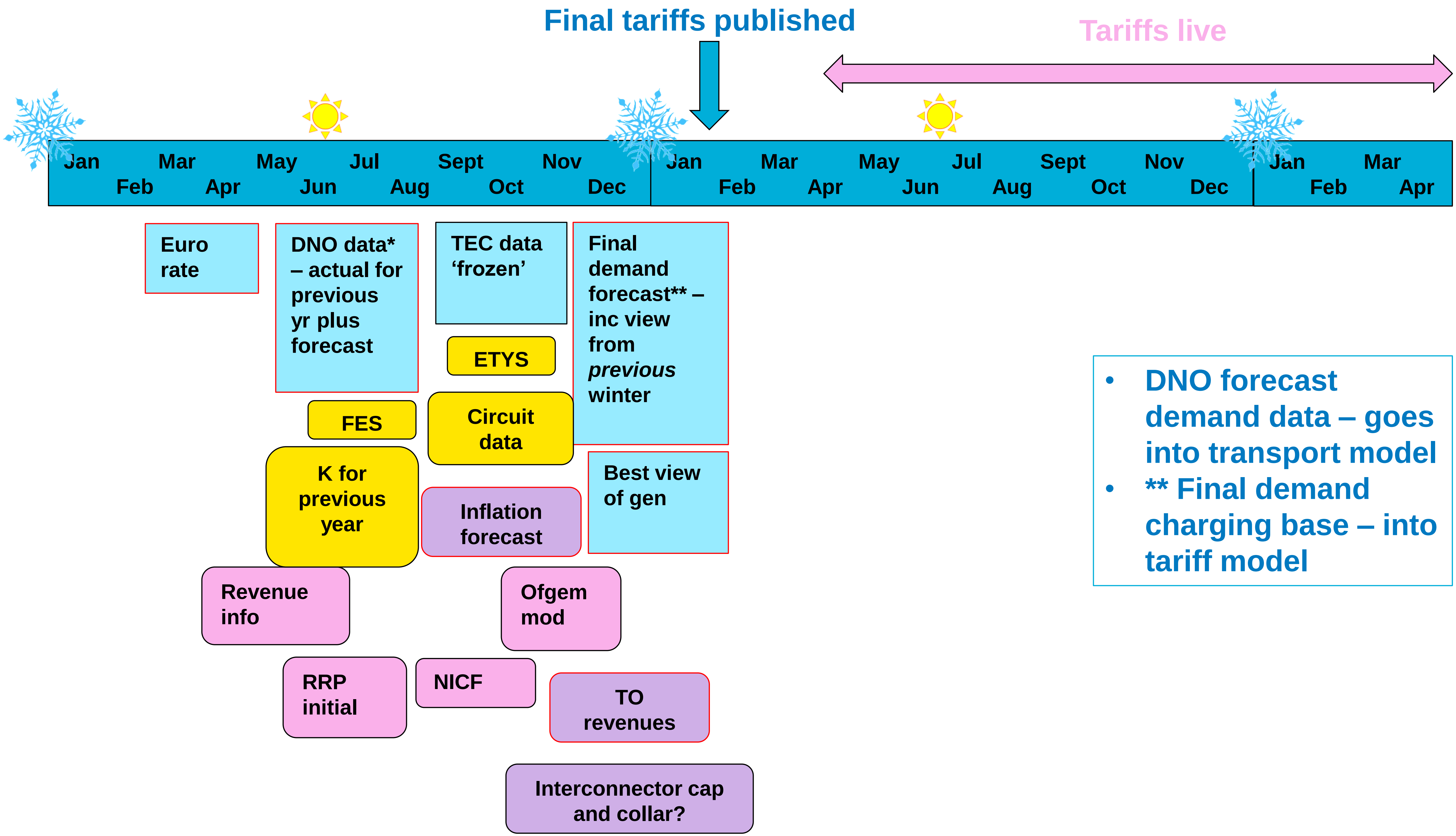
Revenue (£m)	**191.89**	
Demand Peak (GW)	49	
HH Tariff – delta (£/kW)	**3.92**	
HH Charge Base (GW)	14	
HH Revenue recovered	54.83	
Therefore revenue remaining to be recovered from NHH (£m)	137.06	
NHH Demand (TWh)	27.00	
NHH Tariff average delta (p/kWh)	**0.51**	

Additional analysis

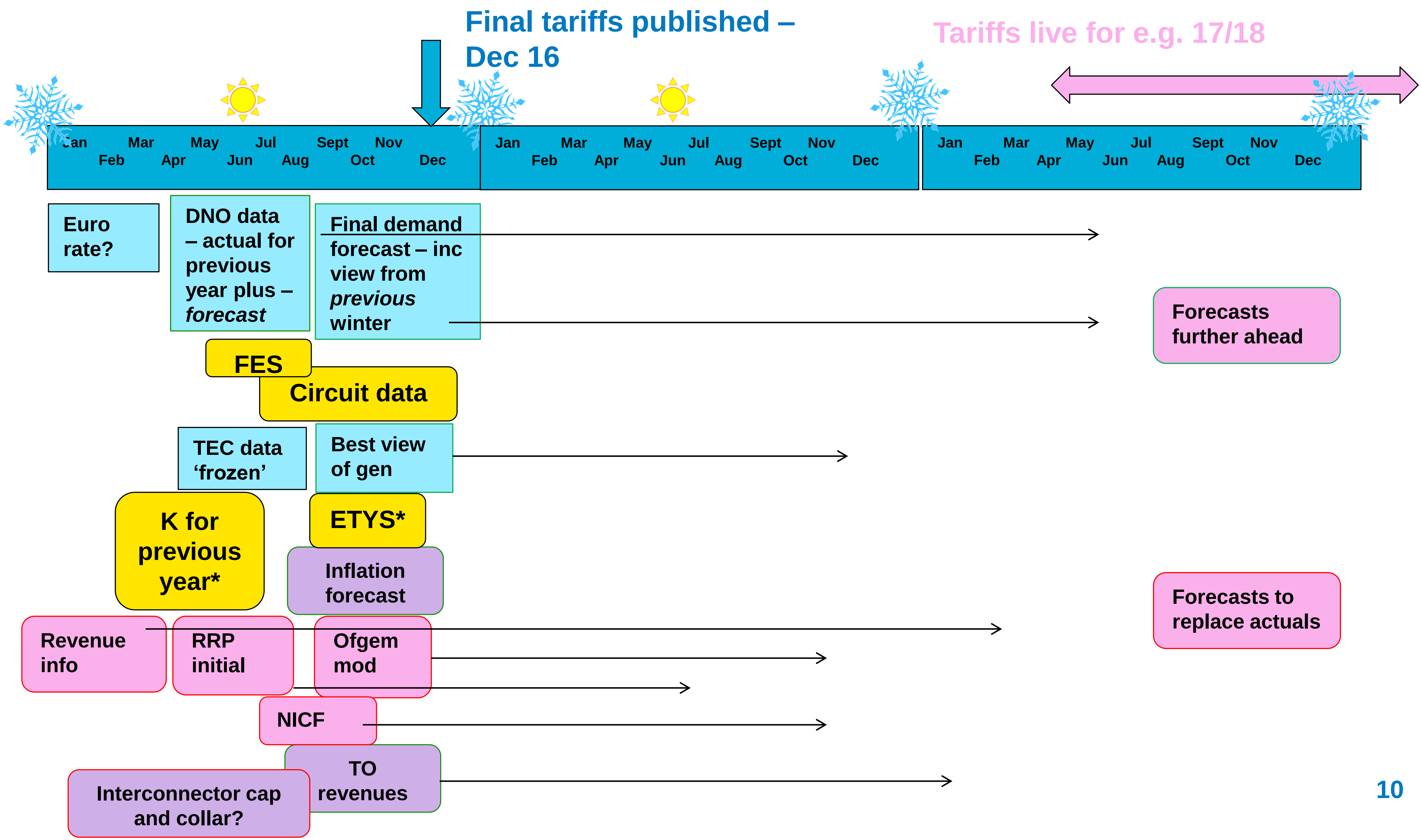
- What would under / over recovery of revenue have looked like if we had charged according to the forecast tariffs (published May 14) with the updated charging base as per the July 15 forecast?
  - Reduction in revenue from the wider element of generation tariffs by c**. £67m**
  - Reduction in revenue from demand of c. **£171m**

- Total under recovery **£238m** i.e. 9% of 15/16 revenue and into penal interest rates

Action 27: Diagram to illustrate current tariff setting process



Action 27: Diagram to illustrate 15m tariff setting process



Implications for k with 2 year lag:

2016/17	2017/18	2018/19	2019/20	2020/21
• Dec 16: **Tariffs set** for 2018/19. **Tariffs do not include K from 16/17 because not known at tariff setting.**	• Jul 17: Under/Over-recovery for 16/17 calculated.	• Final actual allowed **revenue includes K** due to 16/17 under/over recovery. • **Tariffs do not include K because not known at tariff setting.** • Dec 18: Tariffs set for 20/21 assuming K not collected/ refunded in 18/19.	• Jul 19: Under/over recovery for 18/19 calculated. (K not collected/ refunded.)	• Allowed revenue and tariffs include K due to 16/17 under/over recovery.

In this diagram debt / over recovery is held for 4 years (k 'paid off in t+4 i.e. 20/21 for 16/17). Other options:

- b) Change licence to collect in t+3
- c) Forecast k for collection in t+2 and adjust afterwards

For previous slide:

- Option a) full impact of under / over recovery collected via TNUoS tariffs in t+4
- Option b) full impact of under / over recovery collected via TNUoS tariffs in t+3
- Option c) **forecast** of under / over recovery impacts TNUoS tariffs in t+2. **Difference between actual and forecast** under / over recovery impacts TNUoS tariffs in t+3.
- Implication is that if there was an ‘opt out’ option on the table, parties would need to give at least 3 years notice, or 4 for option a.

Action 19: update: revenue forecasting across price controls

- Last Workgroup we noted that said that at the last price control, the forecast of revenue was out by c.16% 15 months ahead
- 16% of forecast 19/20 TNUoS revenue is £520m
- Further information from RIIO finance indicates that they estimate the forecast of *NG revenue alone* (not other onshore Tos or other elements of TNUoS revenue) could be out by +/- £400m. Therefore should increase this possible error margin.

nationalgrid

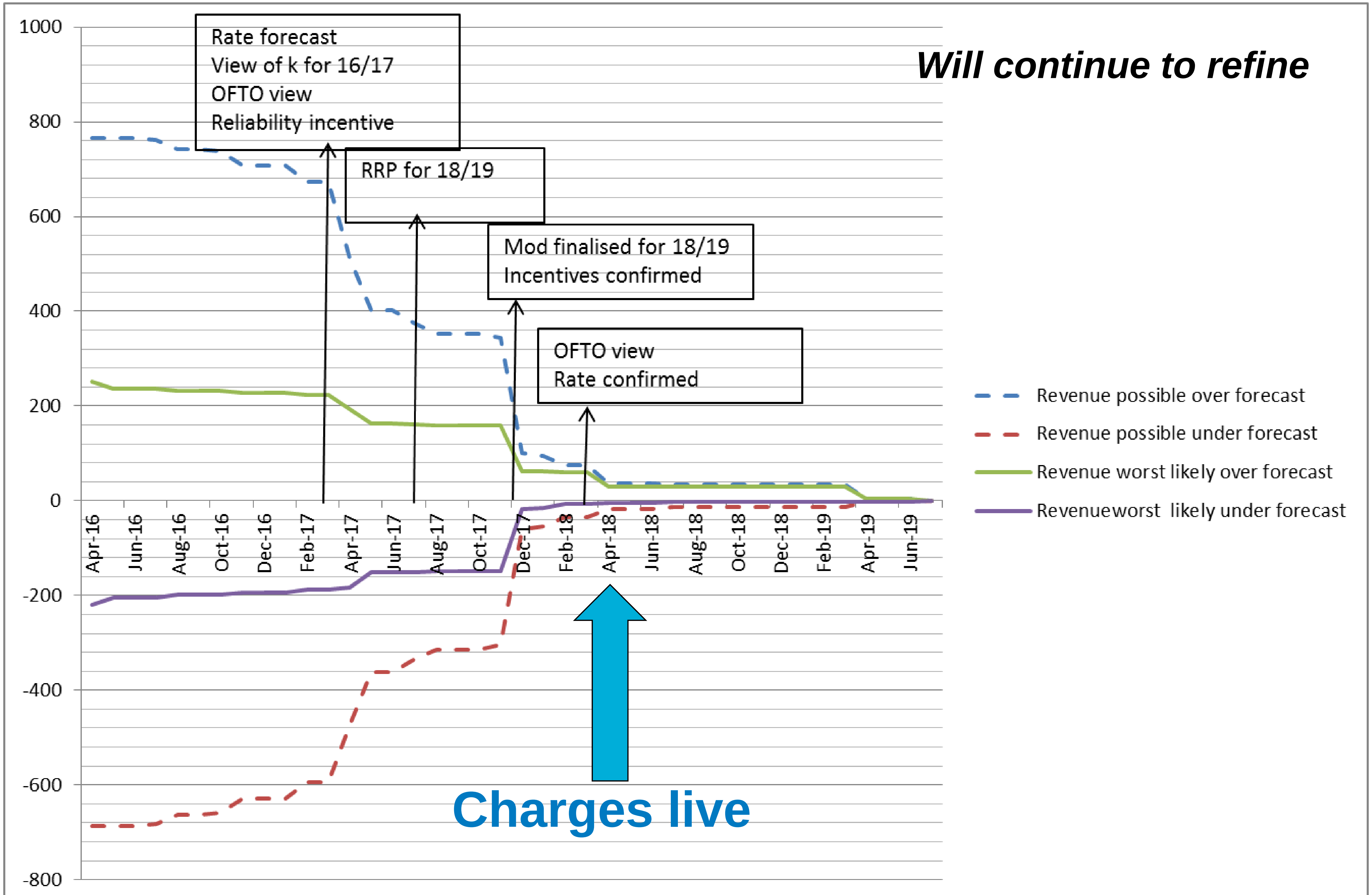
Action 33: How do TO revenues change during a price control?

- Baseline revenues for transmission owners are set at the start of each price control. In RIIO_T1 these were set according to expected performance against outputs, plus incentives for e.g. environmental, innovation and customer & stakeholder performance.
- These baseline revenues are subject to adjustment throughout the price control period.
- Each July Transmission Owners submit the *Regulatory Reporting Pack* (RRP) to Ofgem. This enables Ofgem to collect data from all licensees during the RIIO period to monitor their performance against the final price control proposals.
- Ofgem utilises the information in the RRP to set the ‘MOD’ mechanism in November for the following financial year. This is the mechanism by which many of the larger moving parts in RIIO flow through to allowed TO revenue, and includes significant items e.g. totex comparison to allowances, uncertainty mechanisms, changes to the cost of debt index etc.

Action 30. Potential error margins over time: revenue forecasting

- In addition to each onshore TO going through the mod process and changing their revenues as a result, there are a number of other components that impact the revenue that needs to be collected via TNUoS.
- Approx. **30** components of revenue forecast, including;
  - OFTO forecast (subject to value *and* timing errors)
  - Monies collected via TNUoS e.g. NICF (Network Innovation Competition Funding - need to forecast allocations)
  - Macro forecasts including RPI and average rate
  - ‘k’ (under / over recovery of revenue) from t-2
- What are the error margins on each of these components over time?

Action 30. Potential error margins over time: TNUoS revenue forecasting for the charging year 18/19 (begins April 2018)

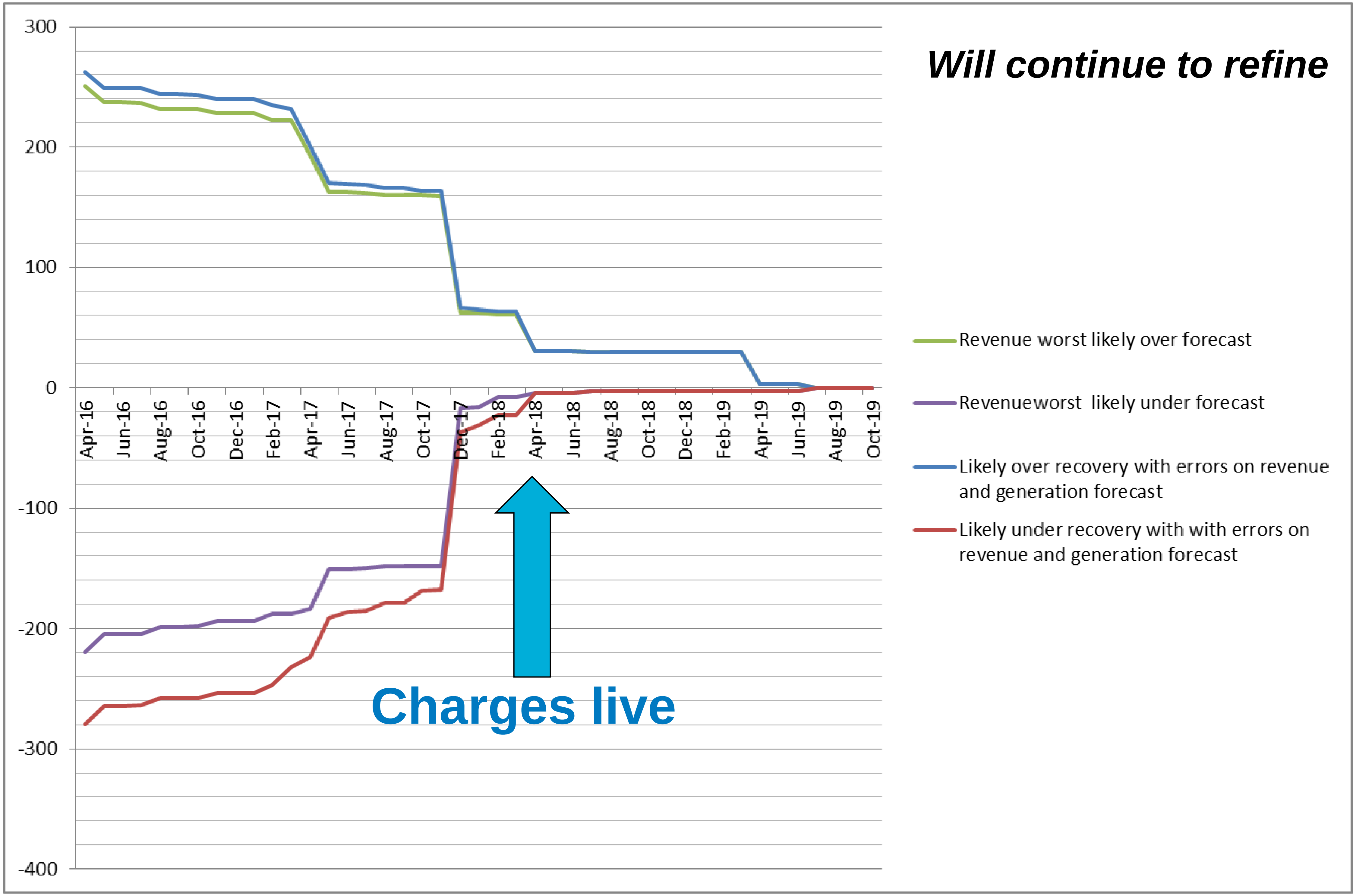


Action 30. Potential error margins over time: Forecasting generation

- Once revenue forecast, then need to look at the charging base from which it will be recovered: generation, HH demand, NHH demand.
- Generation forecasting subject to;
  - New generation project slippage (leads to over forecasting the generation base, and hence under recovering revenue).
  - Existing generator closure (if unanticipated leads to over forecasting the generation base and hence under recovering revenue) – *or* projects staying open longer than expected (opposite effect).
  - Therefore risk weighted towards over forecasting the gen base, and under recovering revenue.
  - Also need to forecast where the generation will be to get to a cost reflective signal.
- Other factors influence the accuracy apart from the timescale of forecast – e.g. user commitment policy, capacity market.

nationalgrid

Potential error margins over time: add in effect of generation forecasting for the charging year 18/19 (begins April 2018)

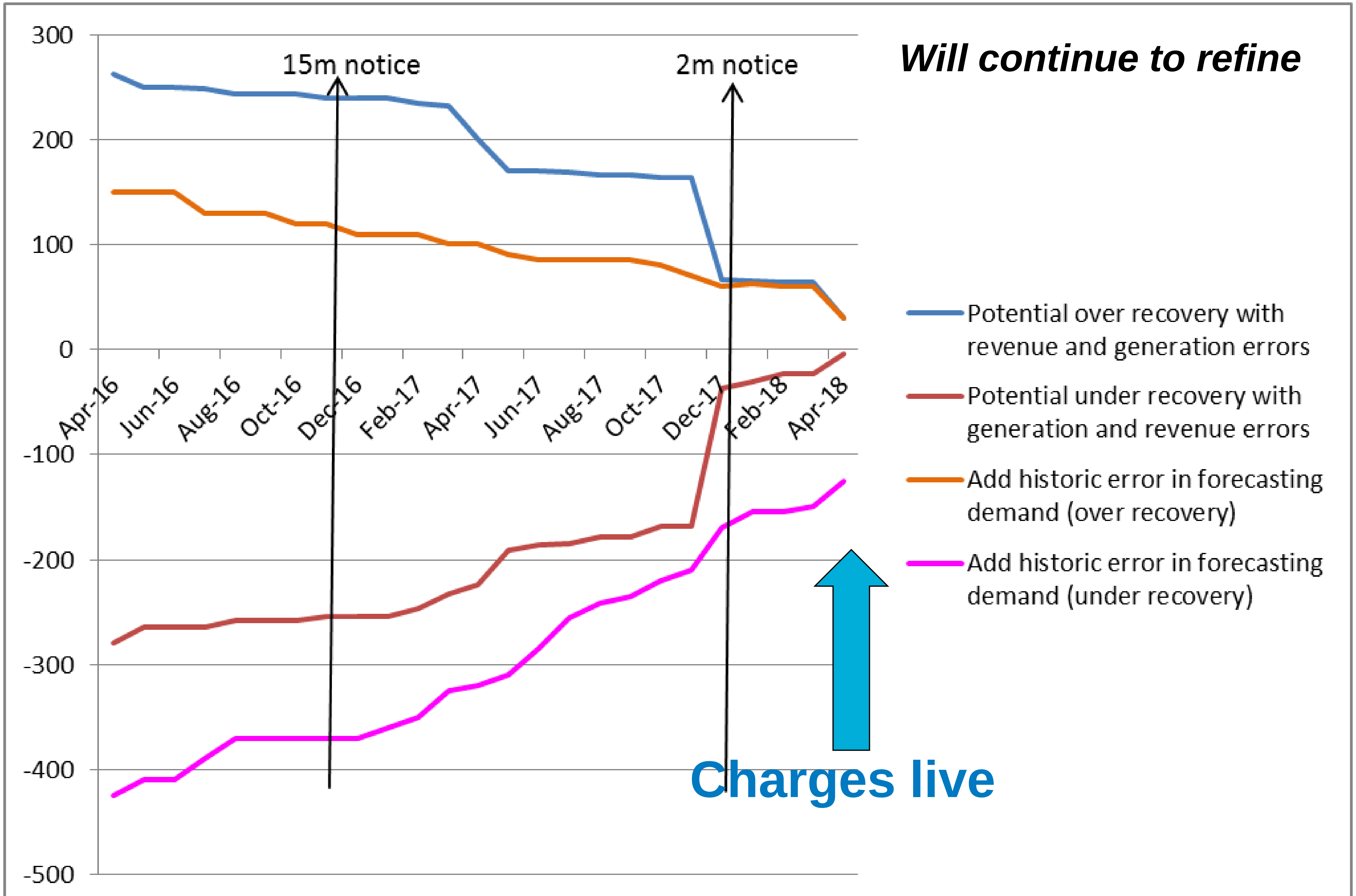


nationalgrid

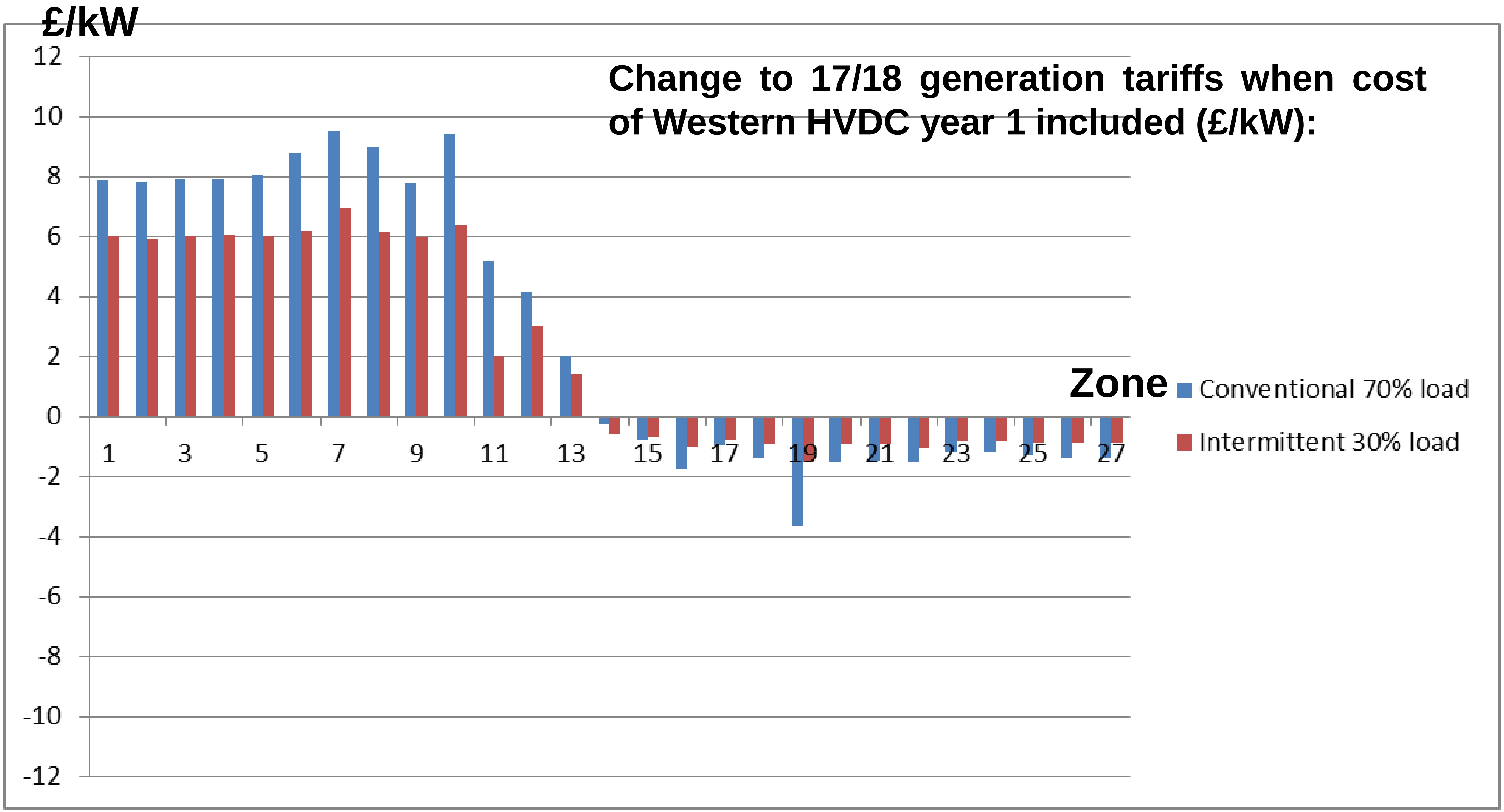
Potential error margins over time: add in effect of demand forecasting for the charging year 18/19 (begins April 2018)

- Like revenue, several components used to build up a picture of likely demand:
  - Economic data
  - Winter information
  - Weather and climate information
  - Customer behaviour – including technology developments
  - Future Energy Scenarios: qualitative information via customer and stakeholder engagement
- Much more difficult to quantify ‘possible’ margins on different components, plus internal work to improve forecasting will change processes.
- Best view of potential errors at the moment takes biggest historical errors in past 3 years. **As more customers move from NHH to HH charges, error margins could increase**.

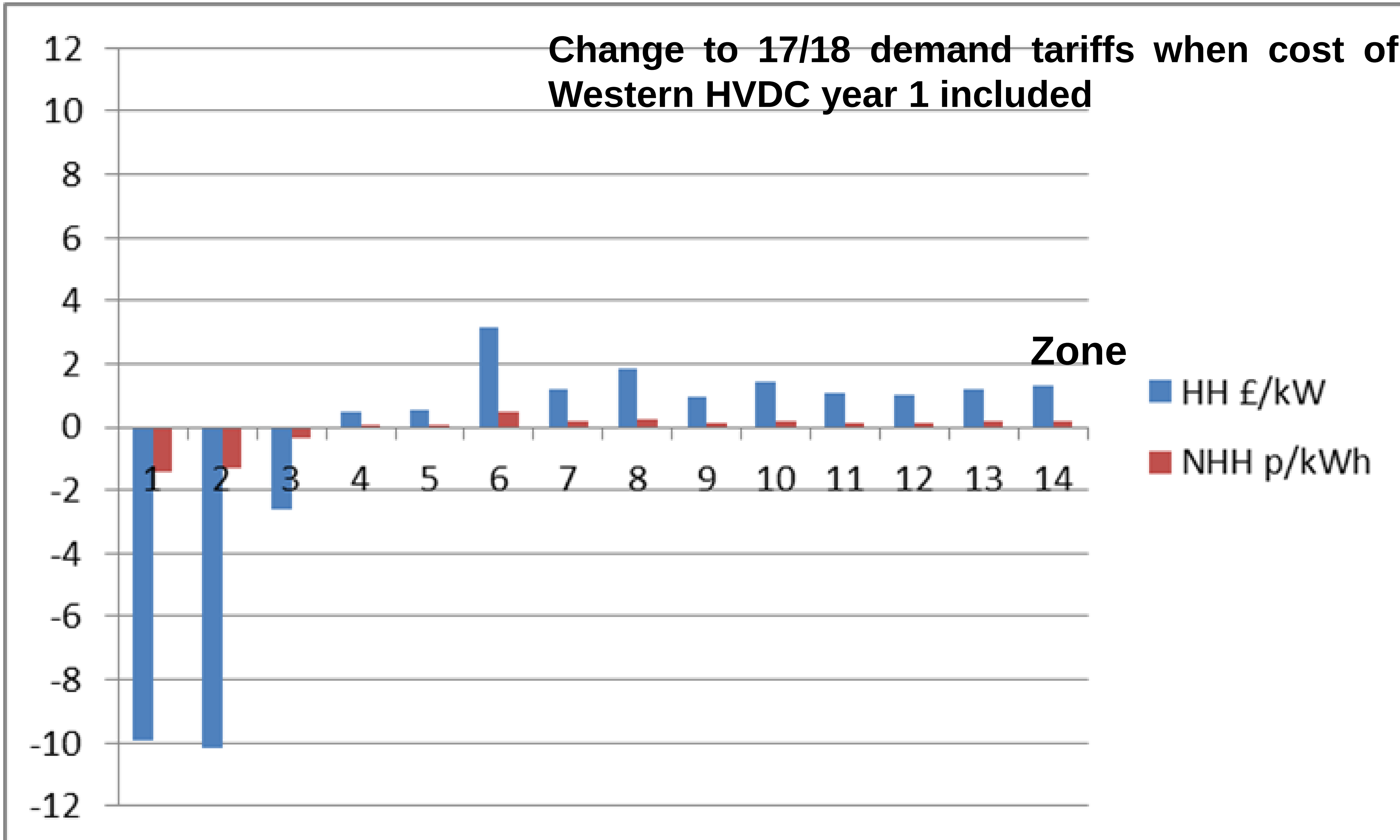
Potential error margins over time: add in effect of demand forecasting for the charging year 18/19 (begins April 2018)



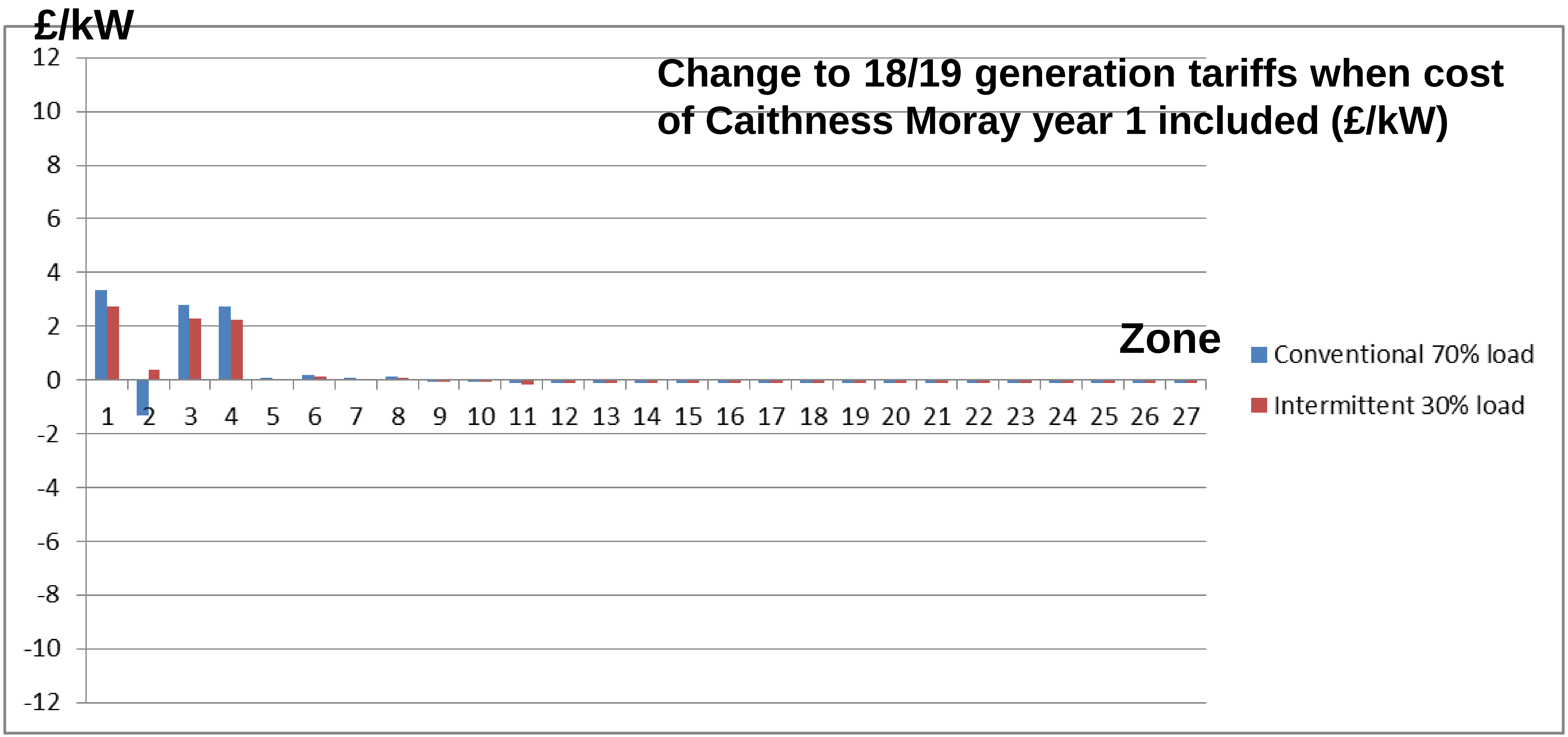
Cost reflectivity - Actions 13/14: impact of infrastructure delay on tariffs



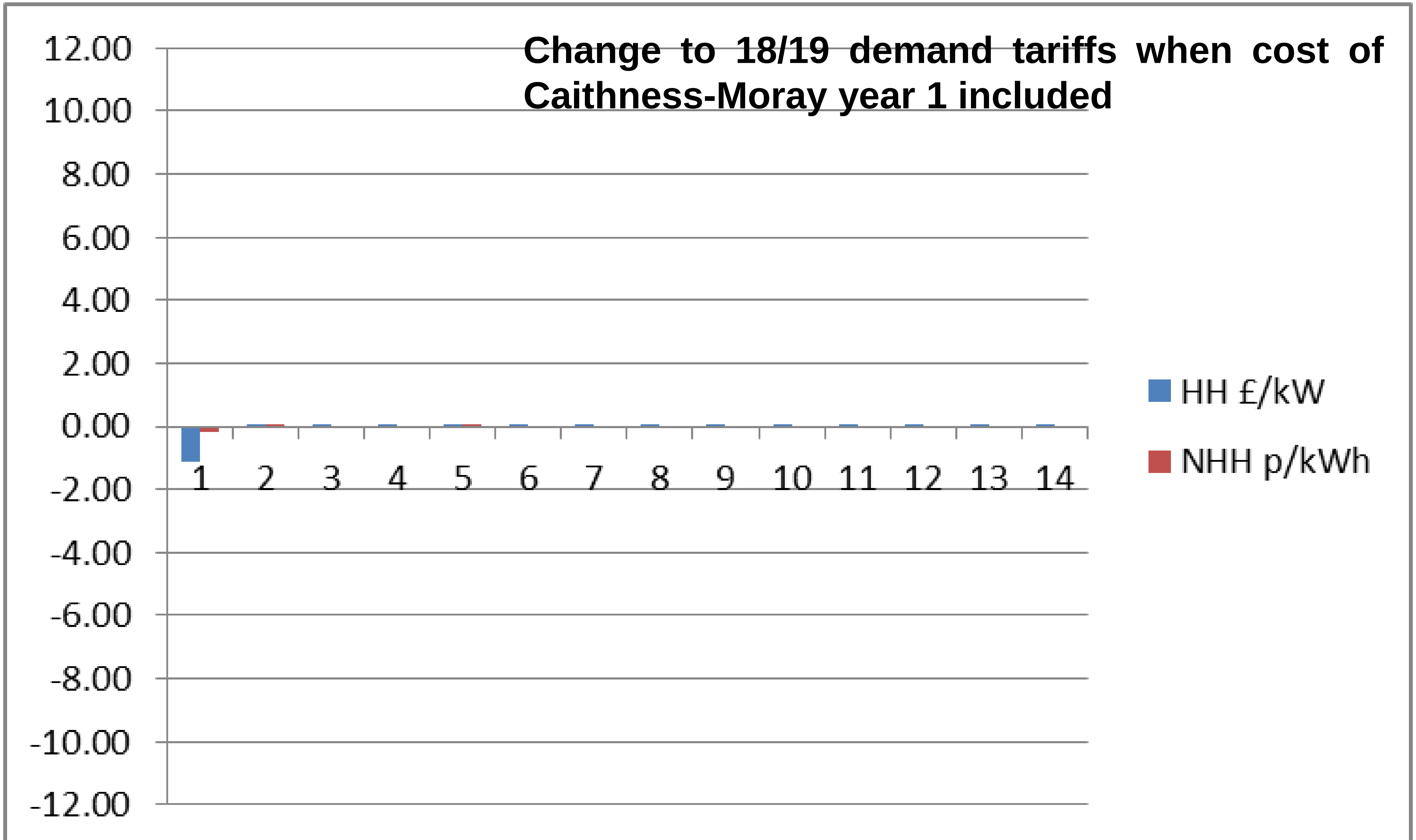
Cost reflectivity - Actions 13/14: impact of infrastructure delay on tariffs



Cost reflectivity - Actions 13/14: impact of infrastructure delay on tariffs

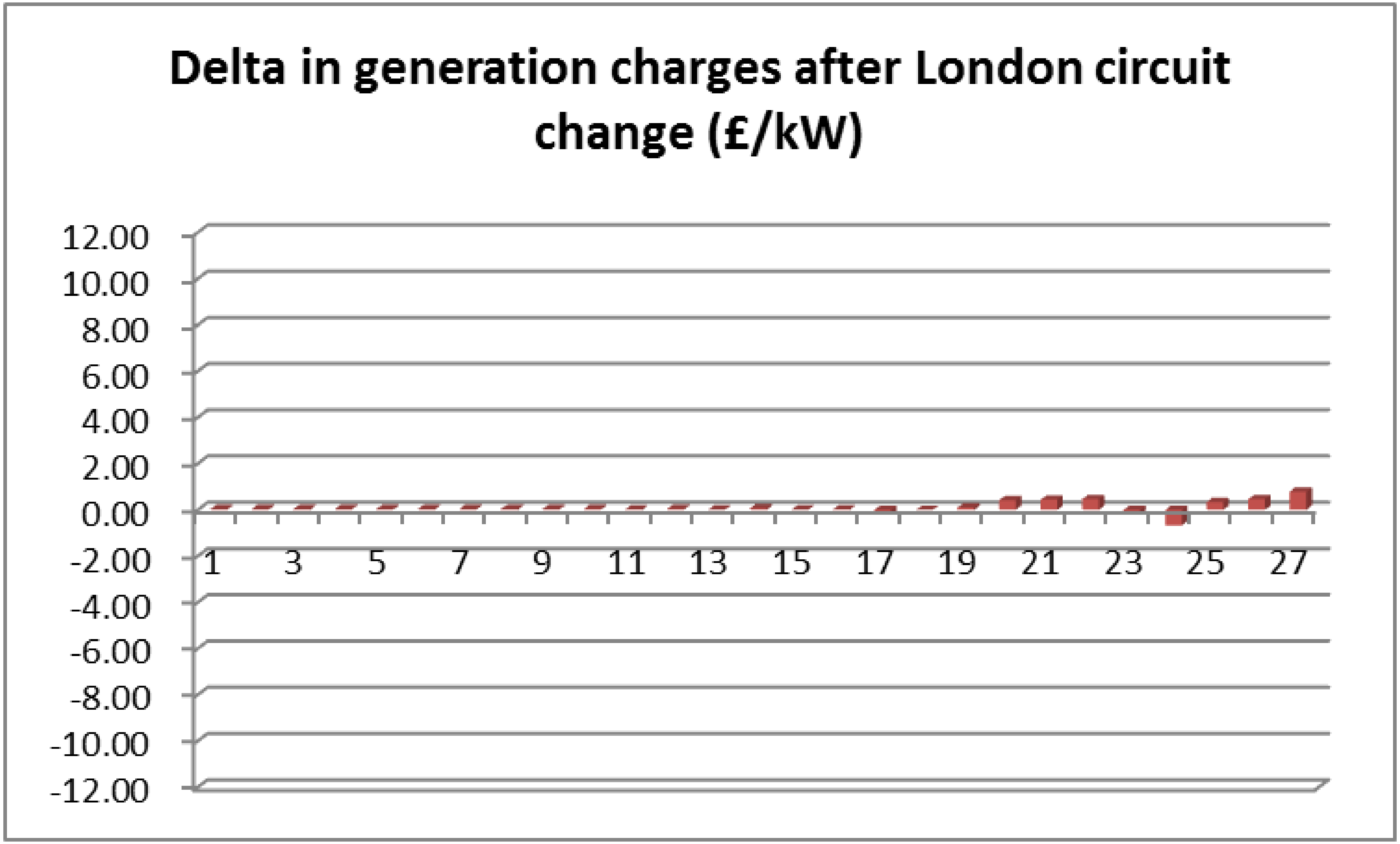


Cost reflectivity - Actions 13/14: impact of infrastructure delay on tariffs

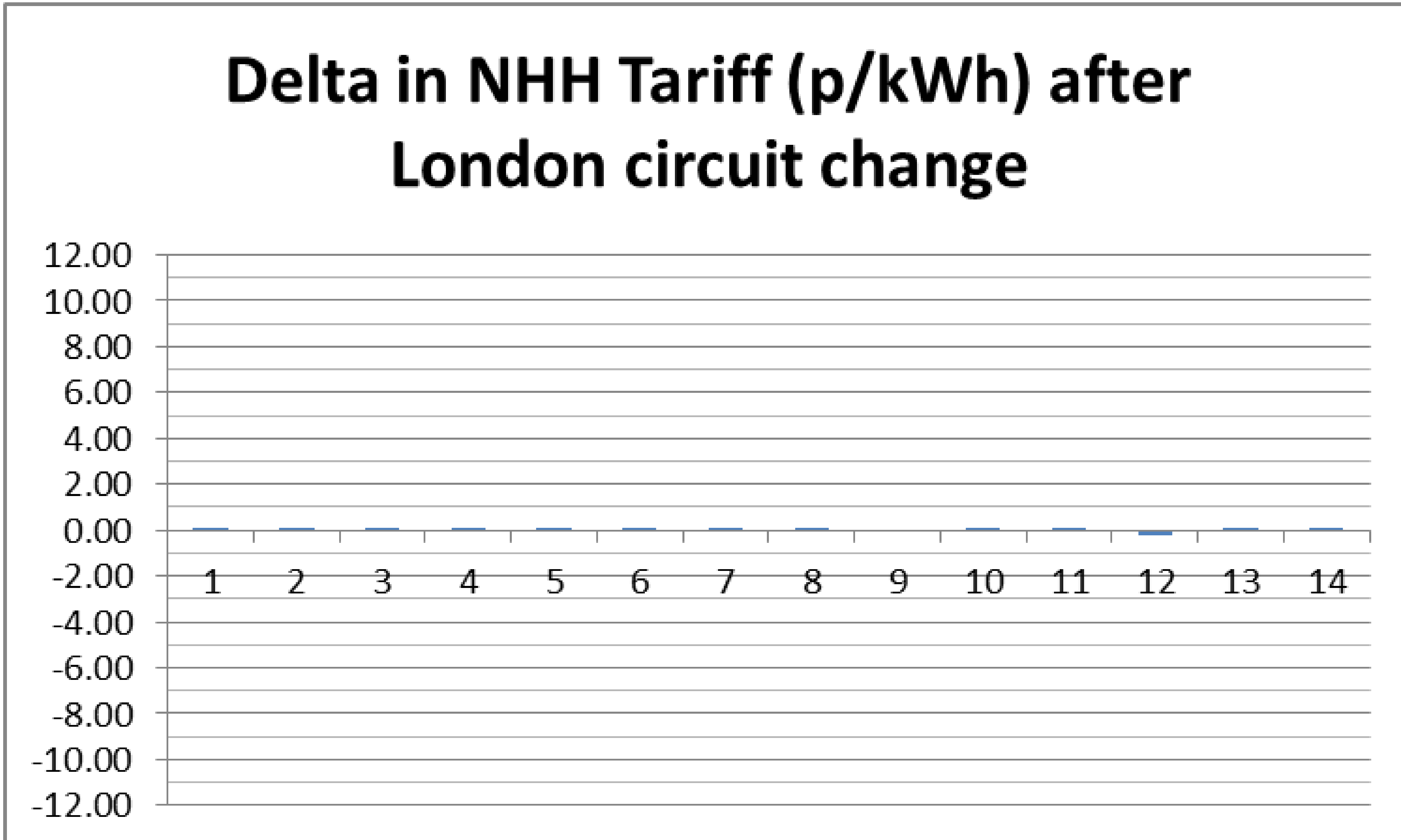


nationalgrid

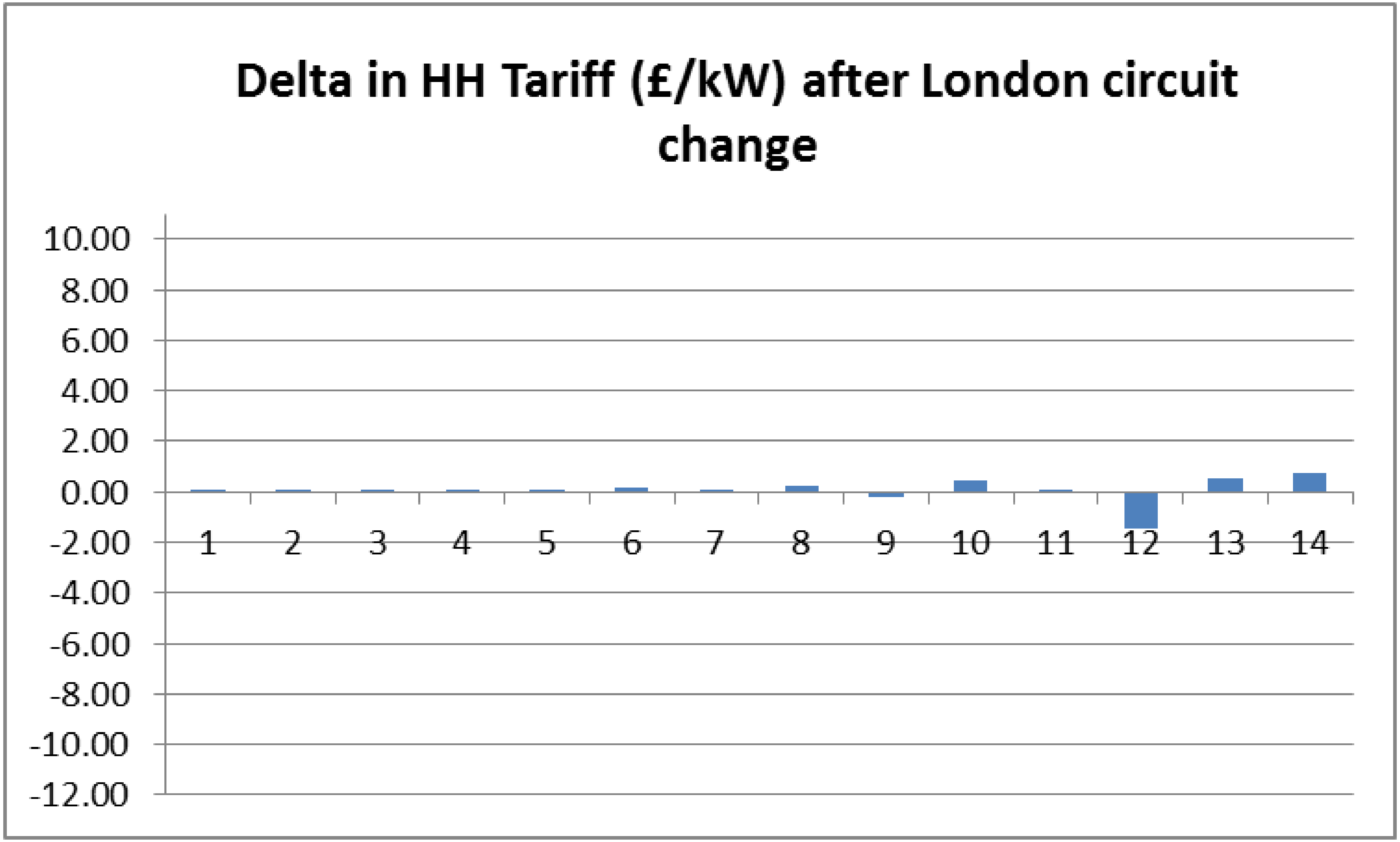
Cost reflectivity - Actions 13/14: circuit change example



Cost reflectivity - Actions 13/14: circuit change example



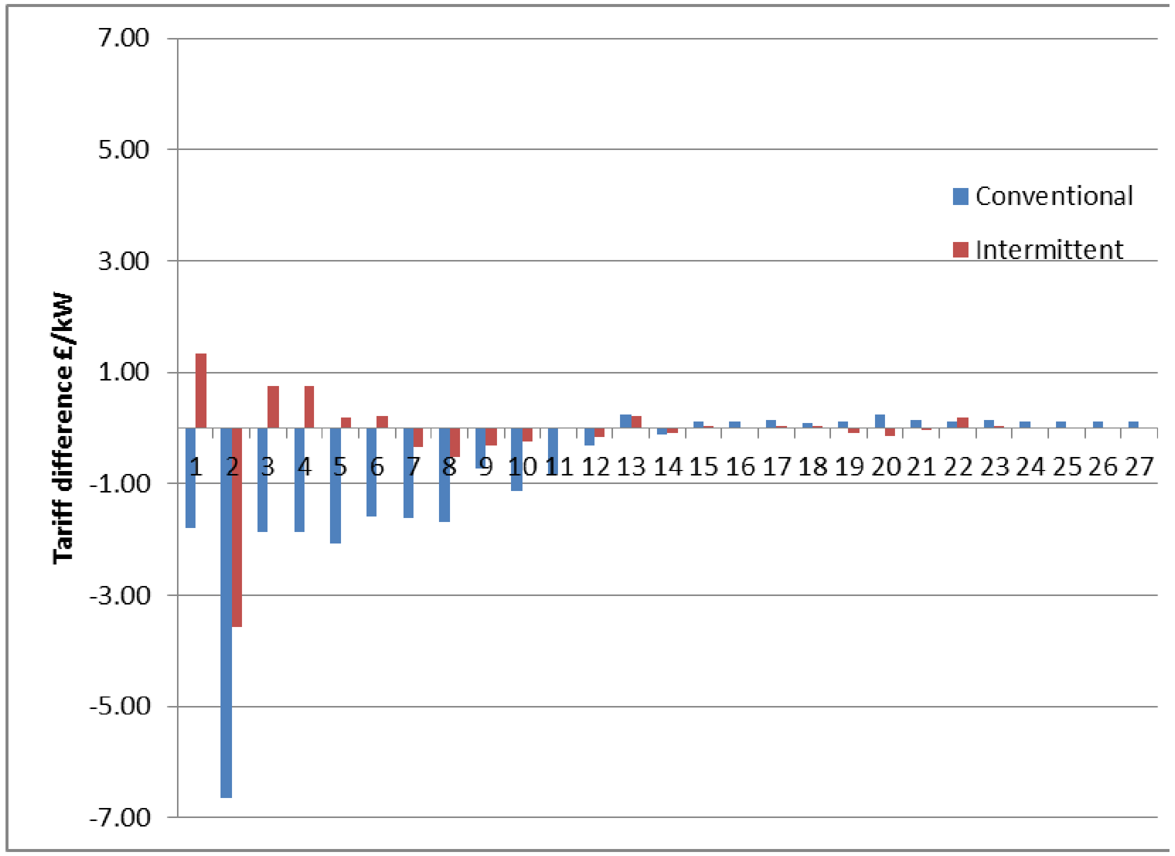
Cost reflectivity - Actions 13/14: circuit change example



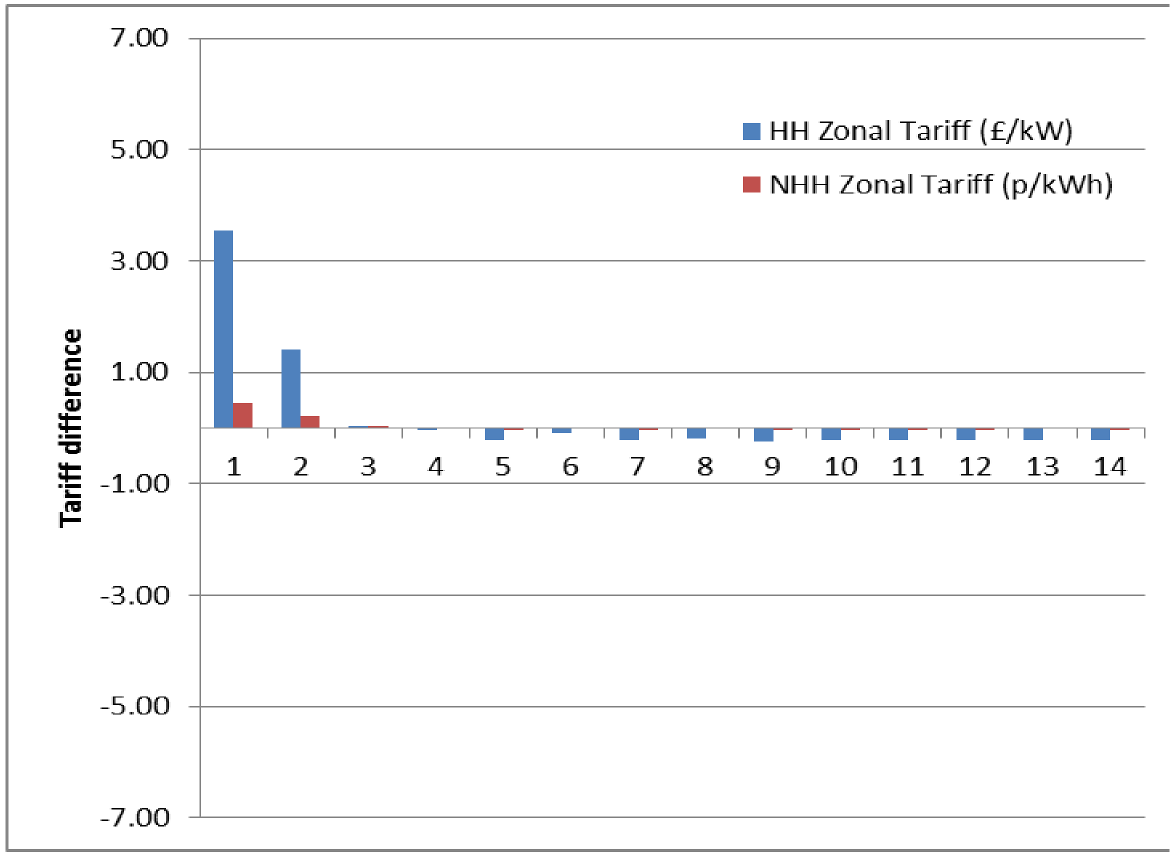
Cost reflectivity - Action 12: changes to generation

Reducing conventional generation in generation zone 2 by 400MW: Change in tariffs

Generation:



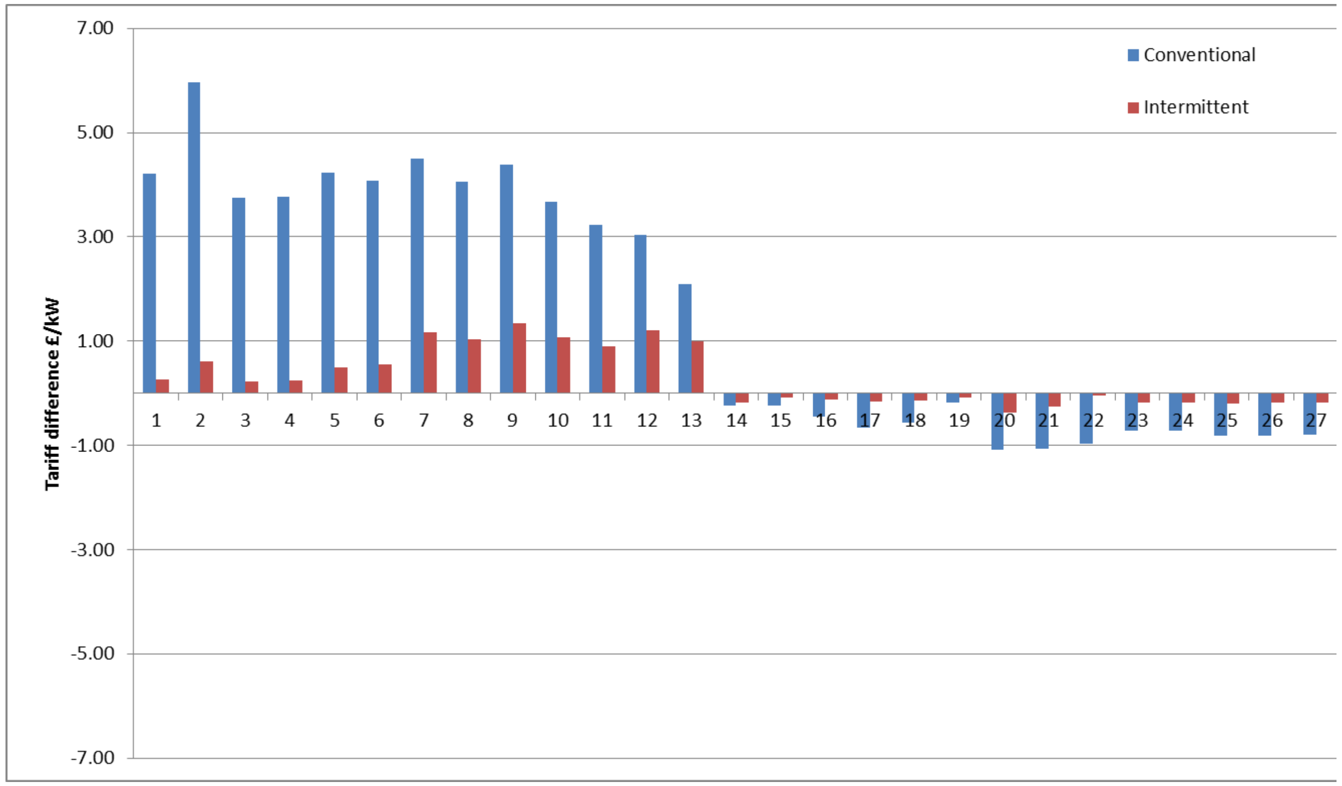
Demand:



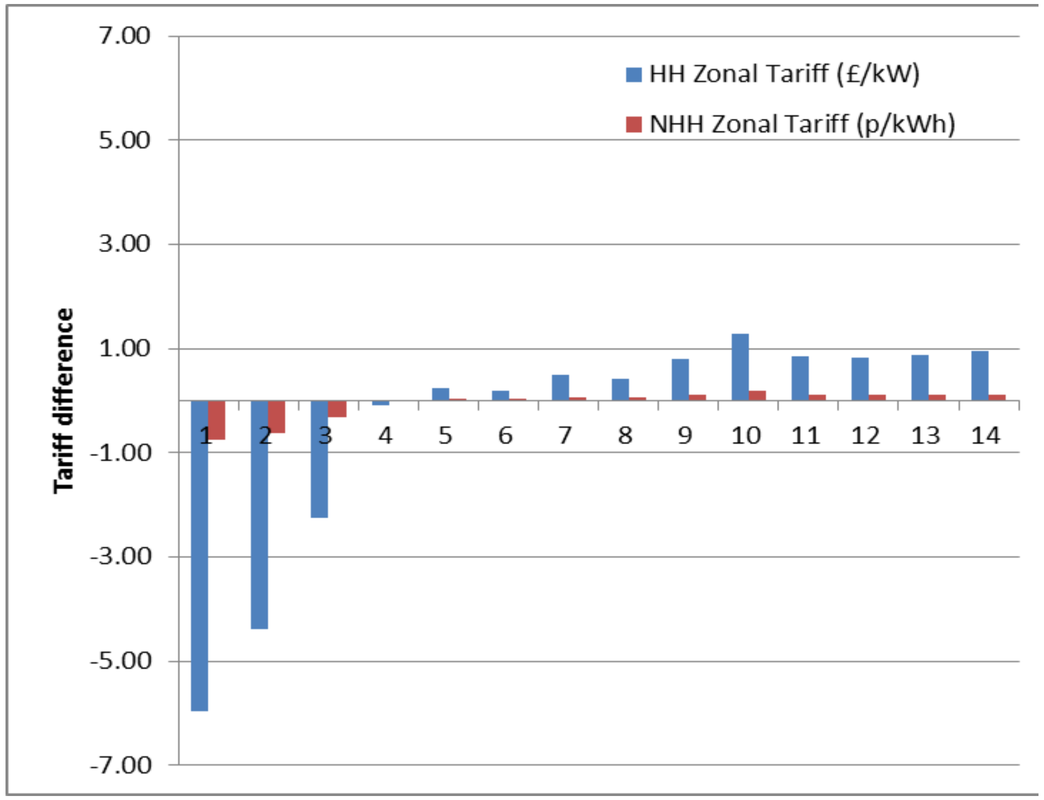
Cost reflectivity - Action 12: changes to generation

Increasing conventional generation in generation zone 2 by 400MW:
Change in tariffs

Generation:



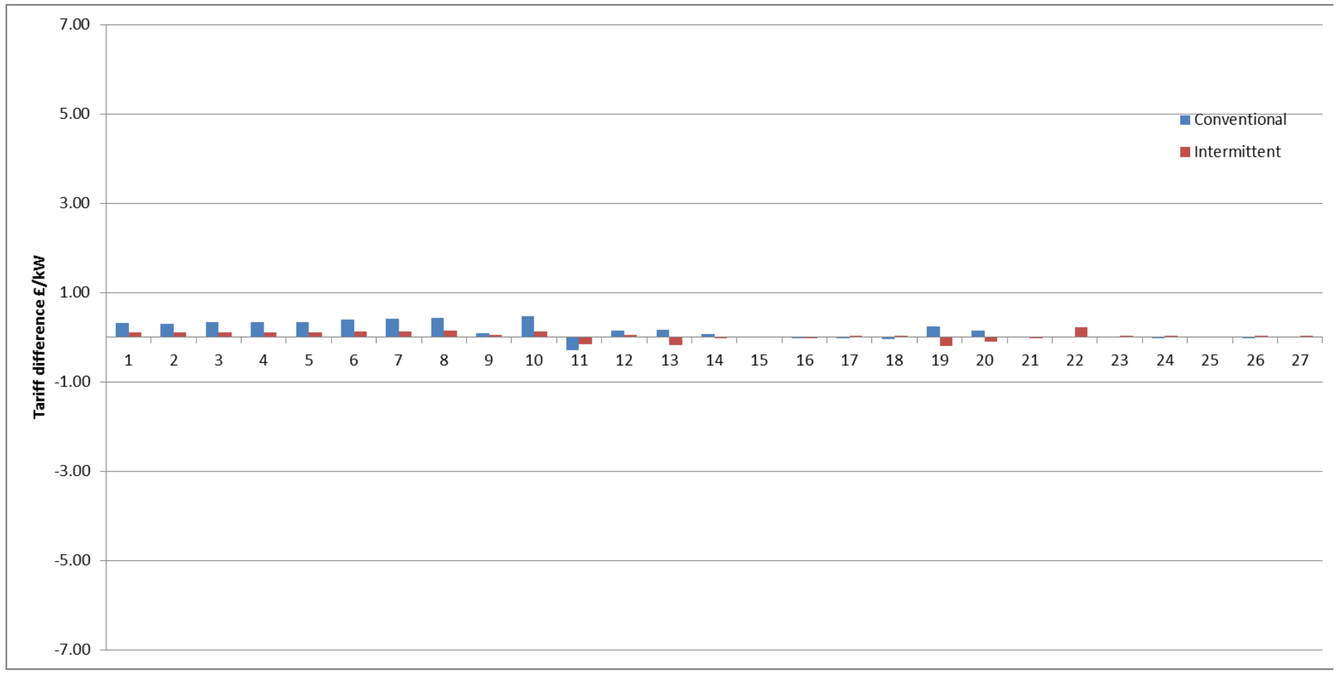
Demand:



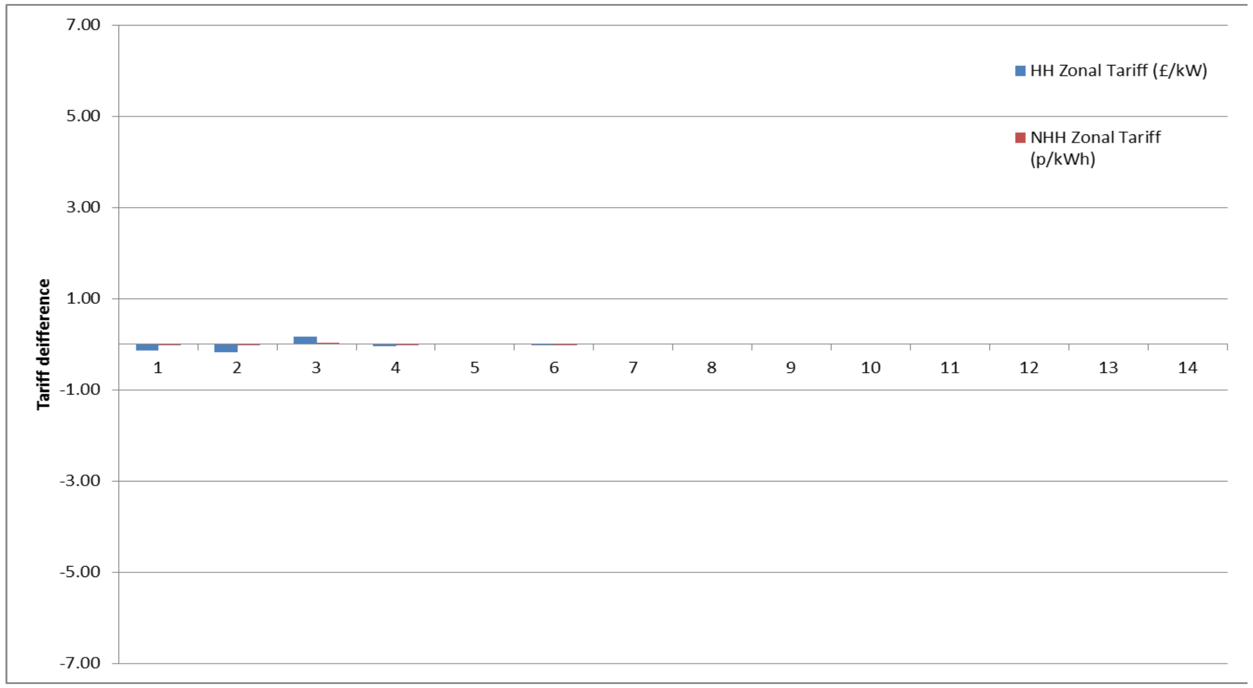
Cost reflectivity - Action 12: changes to generation

Reducing conventional generation in generation zone 13 by 1207MW: Change in tariffs

Generation:



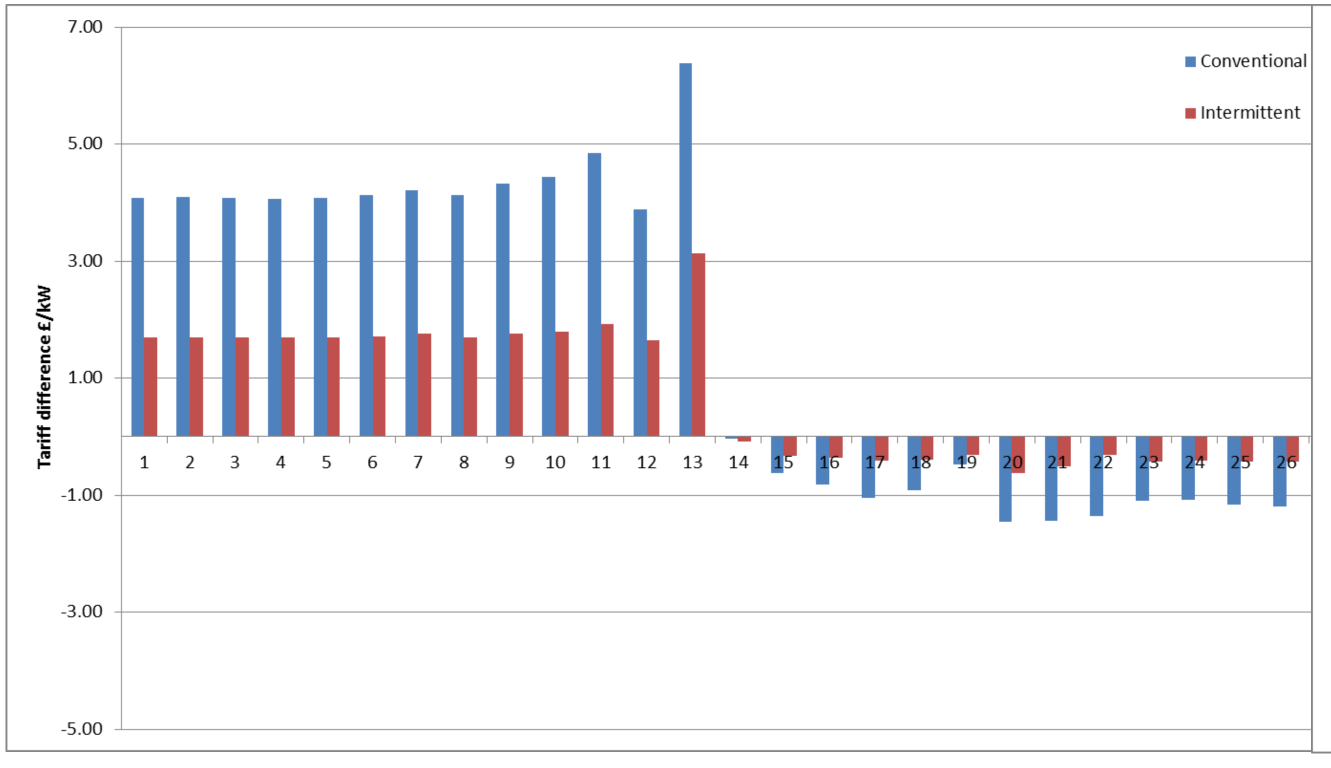
Demand:



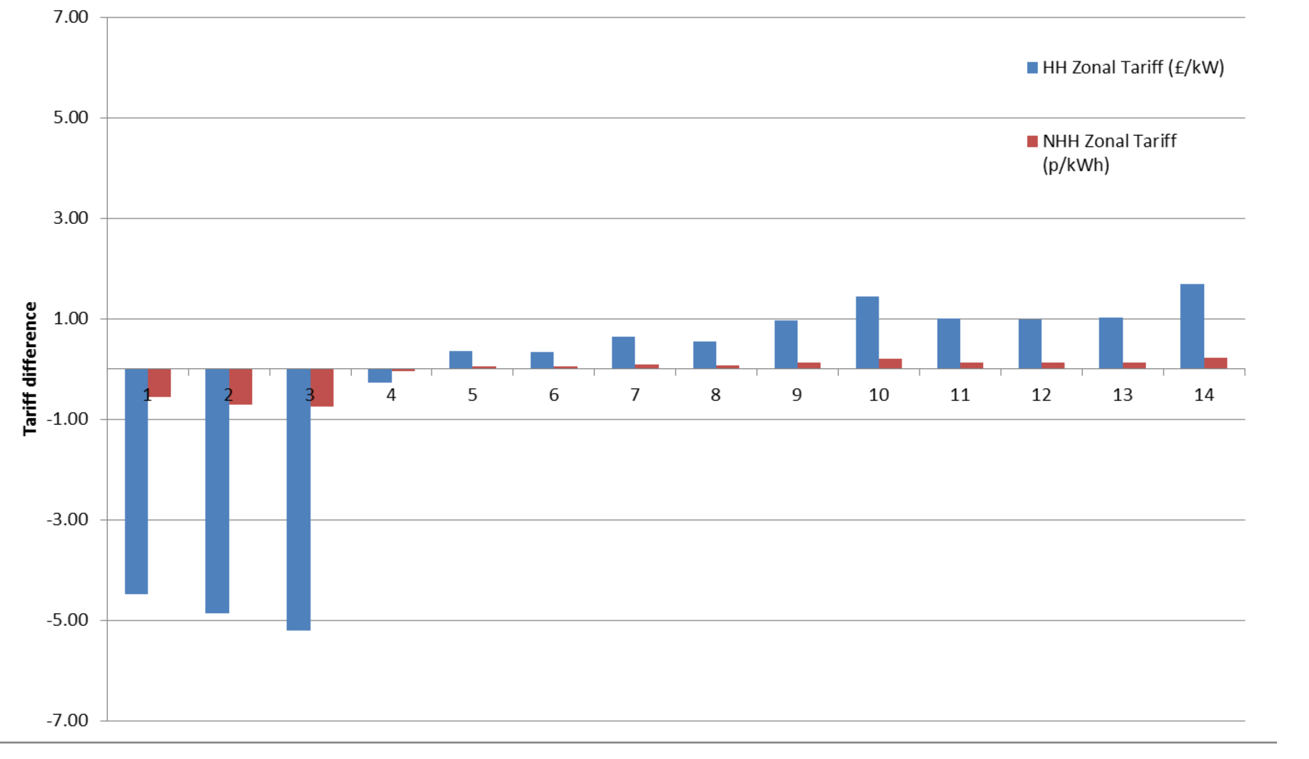
Cost reflectivity - Action 12: changes to generation

Increasing conventional generation in generation zone 13 by 1207MW: Change in tariffs

Generation:



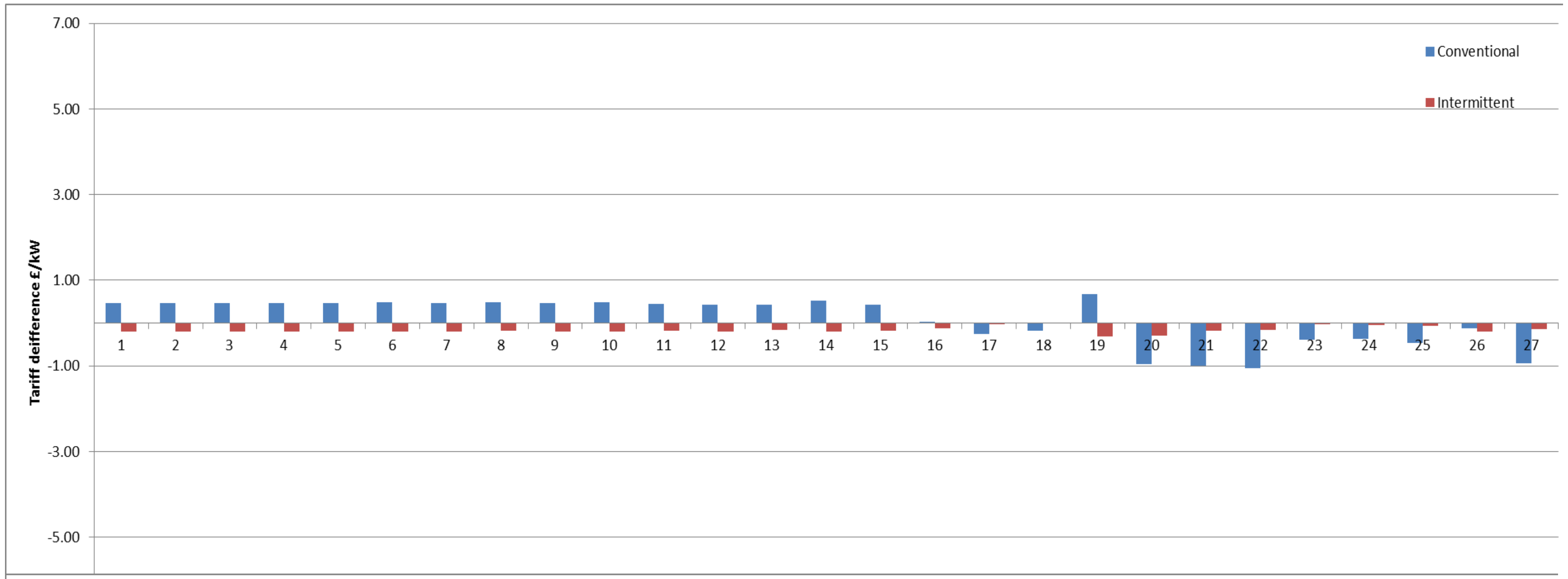
Demand:



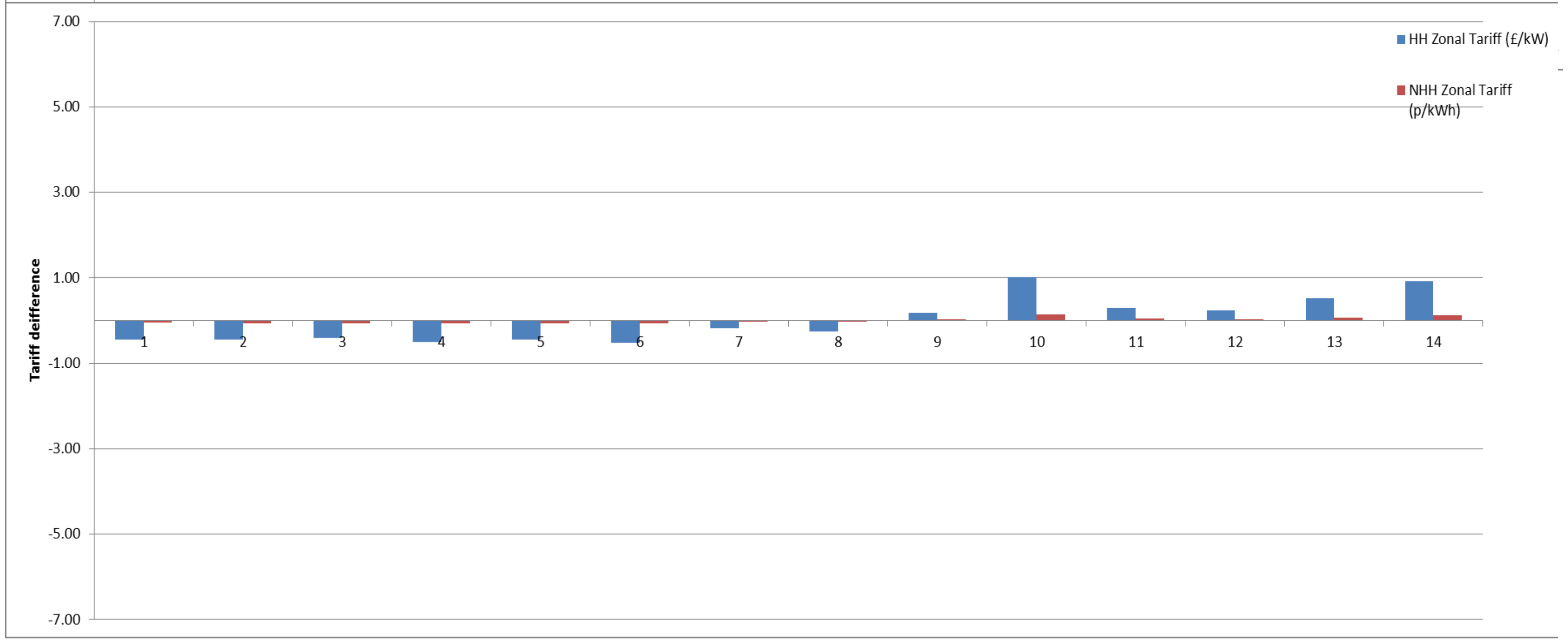
Cost reflectivity - Action 12: changes to generation

Reducing conventional generation in generation zone 26 by 920MW: Change in tariffs

Generation:



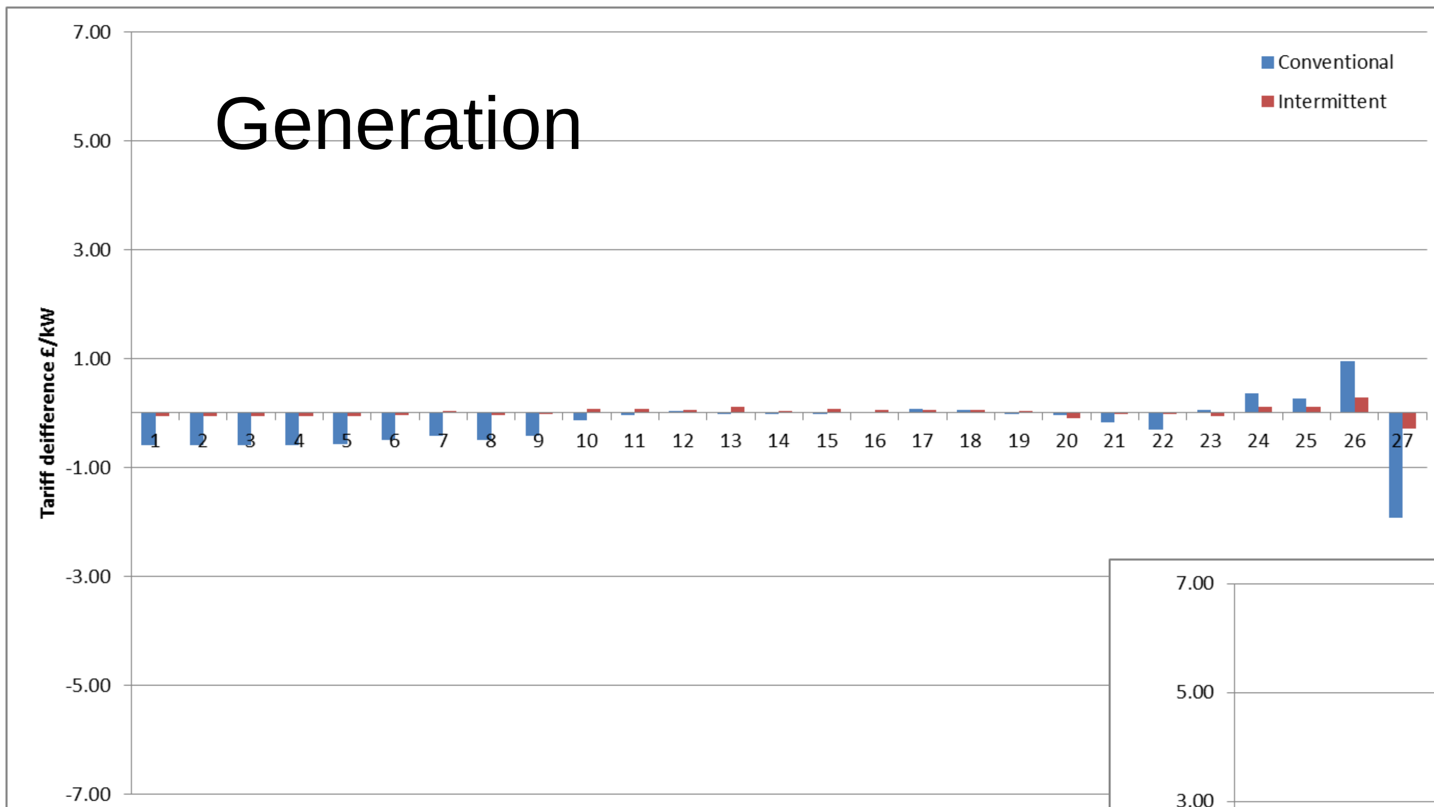
Demand:



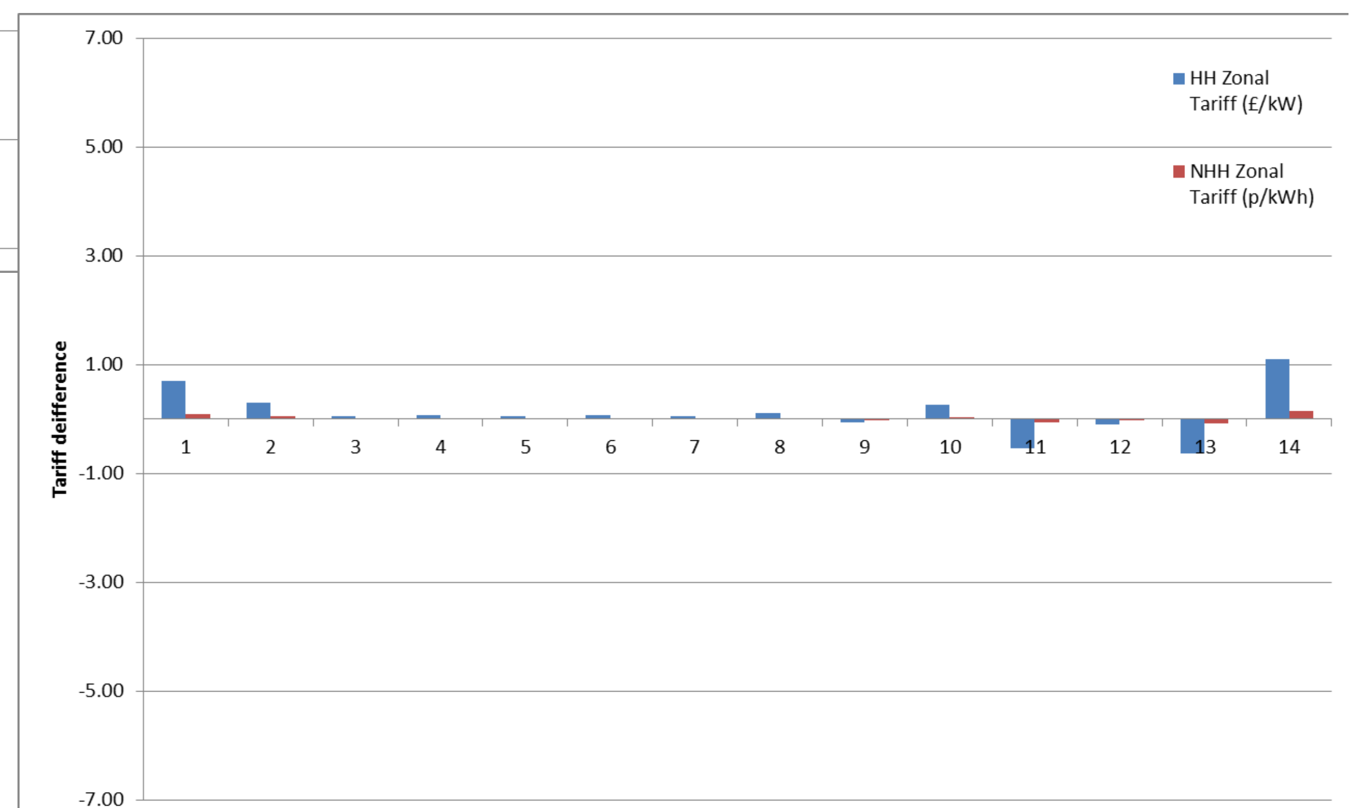
Cost reflectivity - Action 12: changes to generation

Increasing conventional generation in generation zone 26 by 920MW: Change in tariffs

Generation



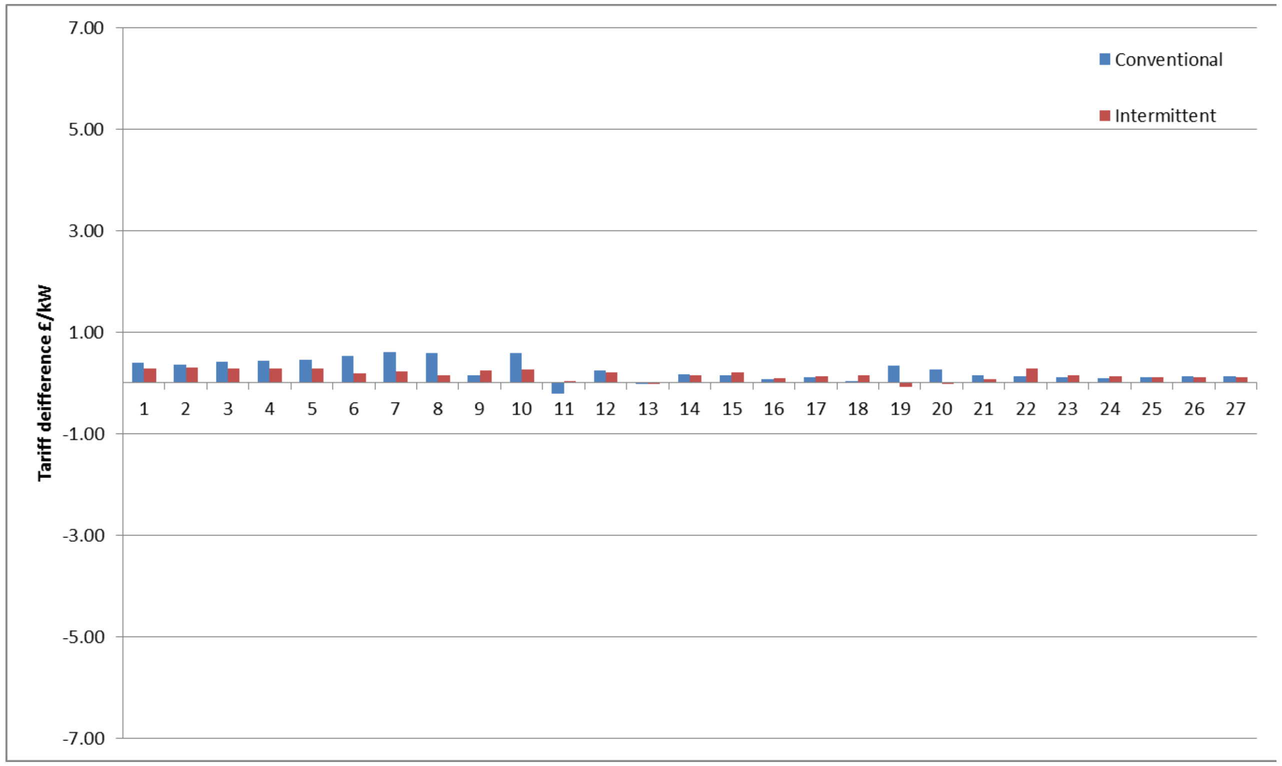
Demand:



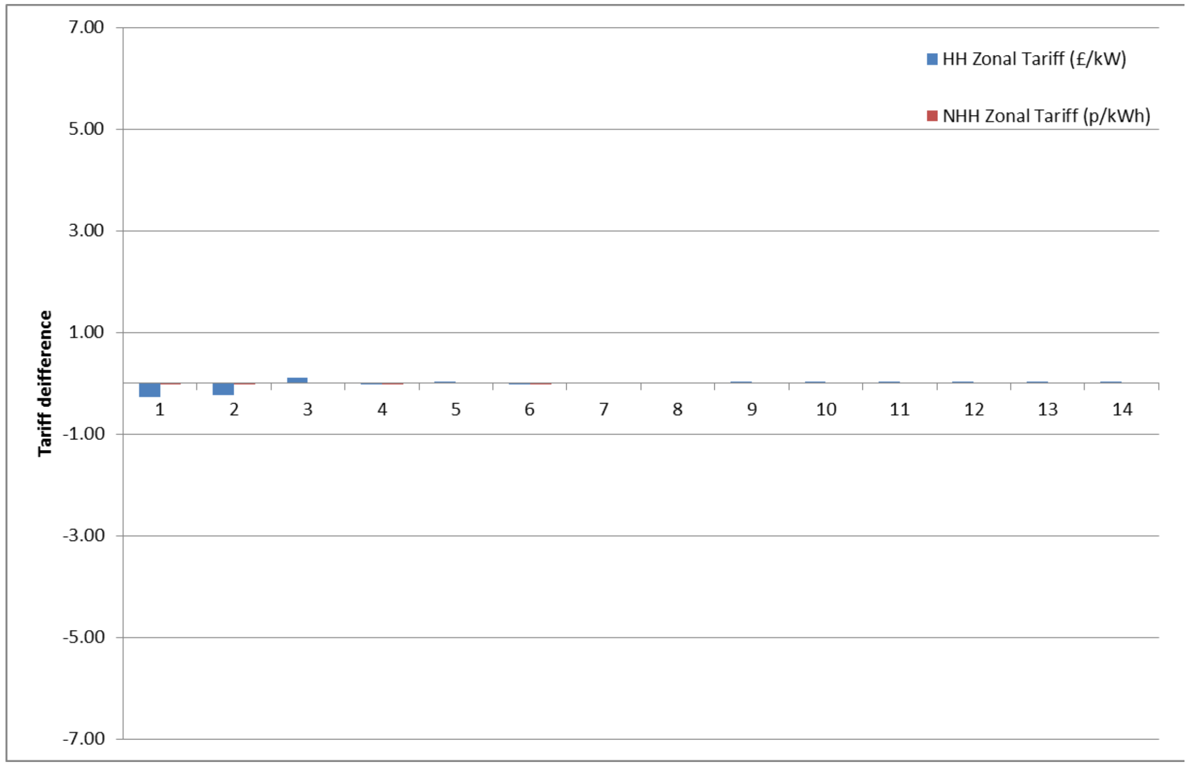
Cost reflectivity - Action 12: changes to generation

Reducing conventional generation in generation zone 15 by 1940MW: Change in tariffs

Generation:



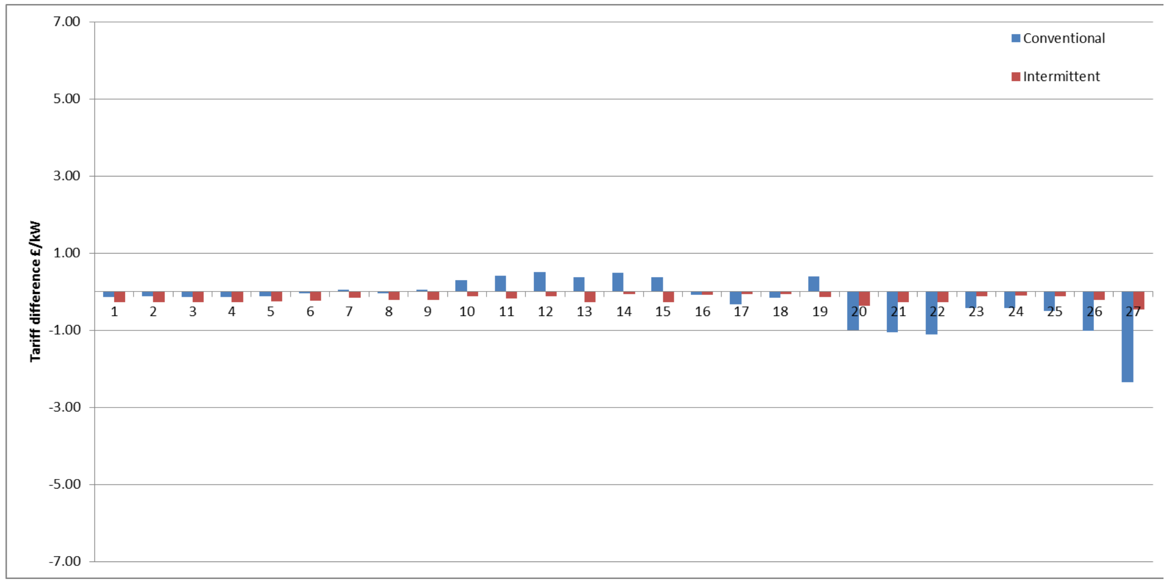
Demand:



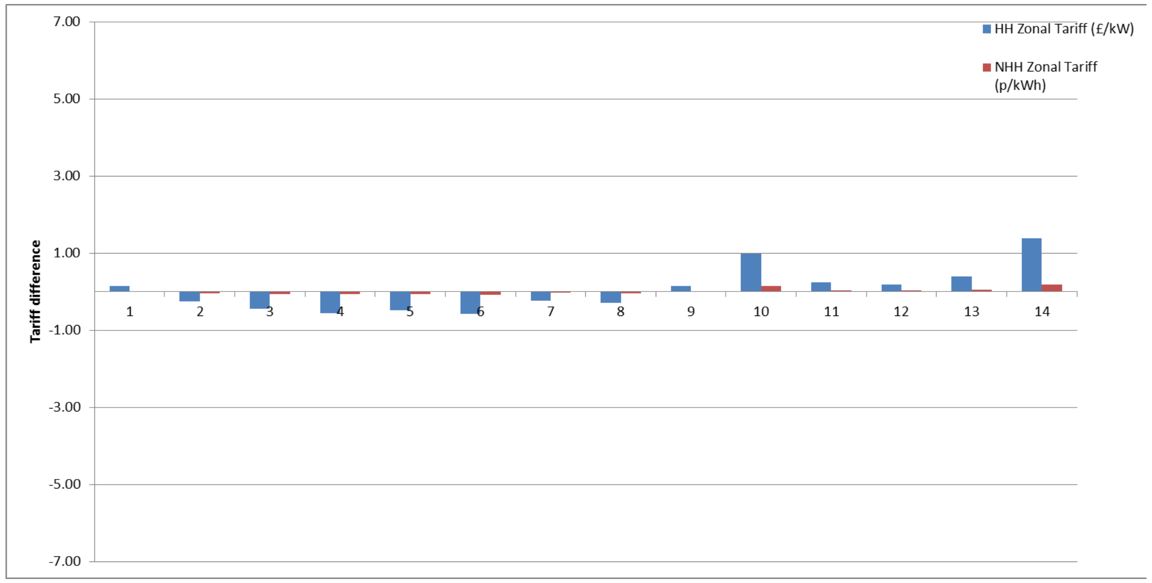
Cost reflectivity - Action 12: changes to generation

Increasing conventional generation in generation zone 15 by 1940MW: Change in tariffs

Generation:



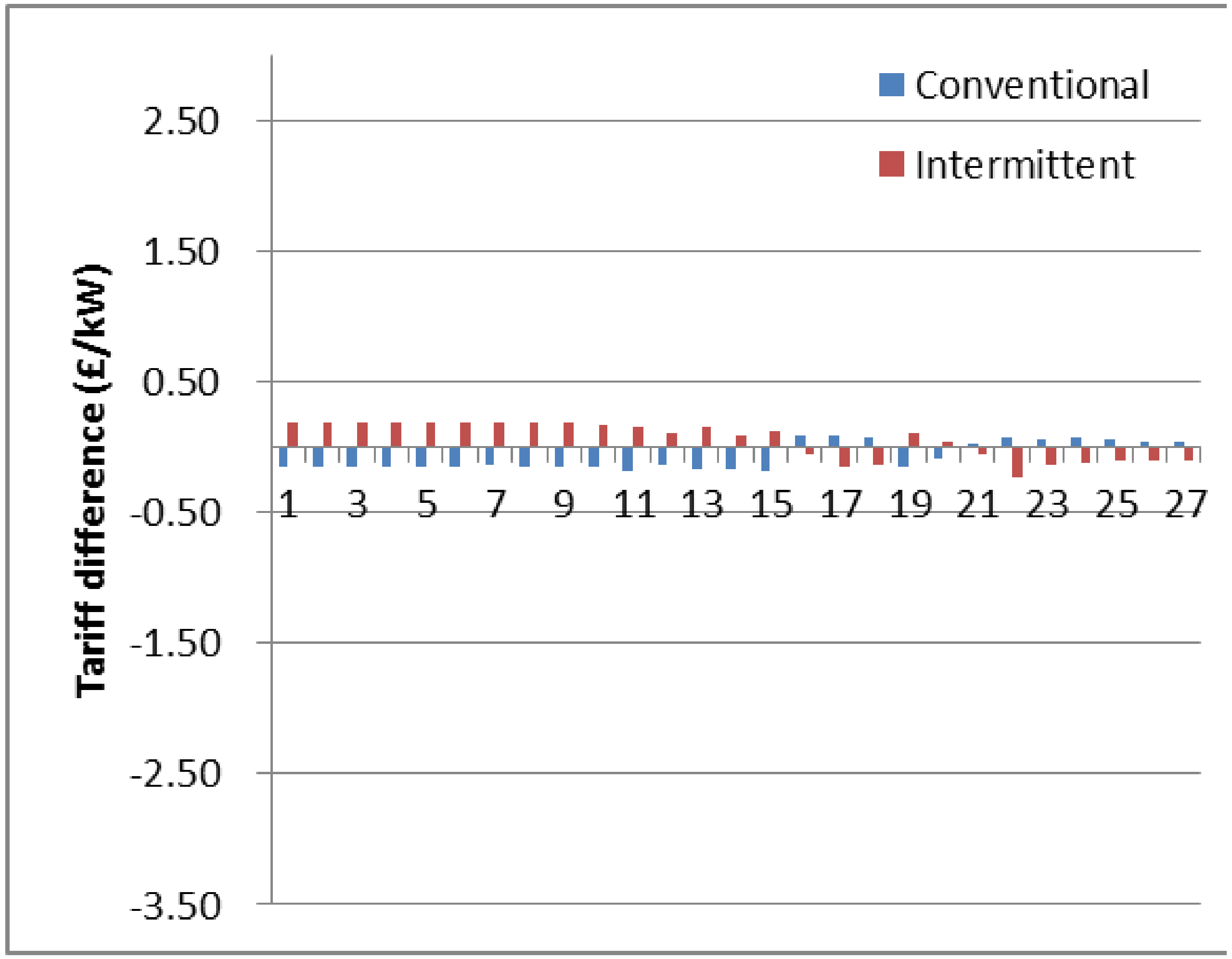
Demand:



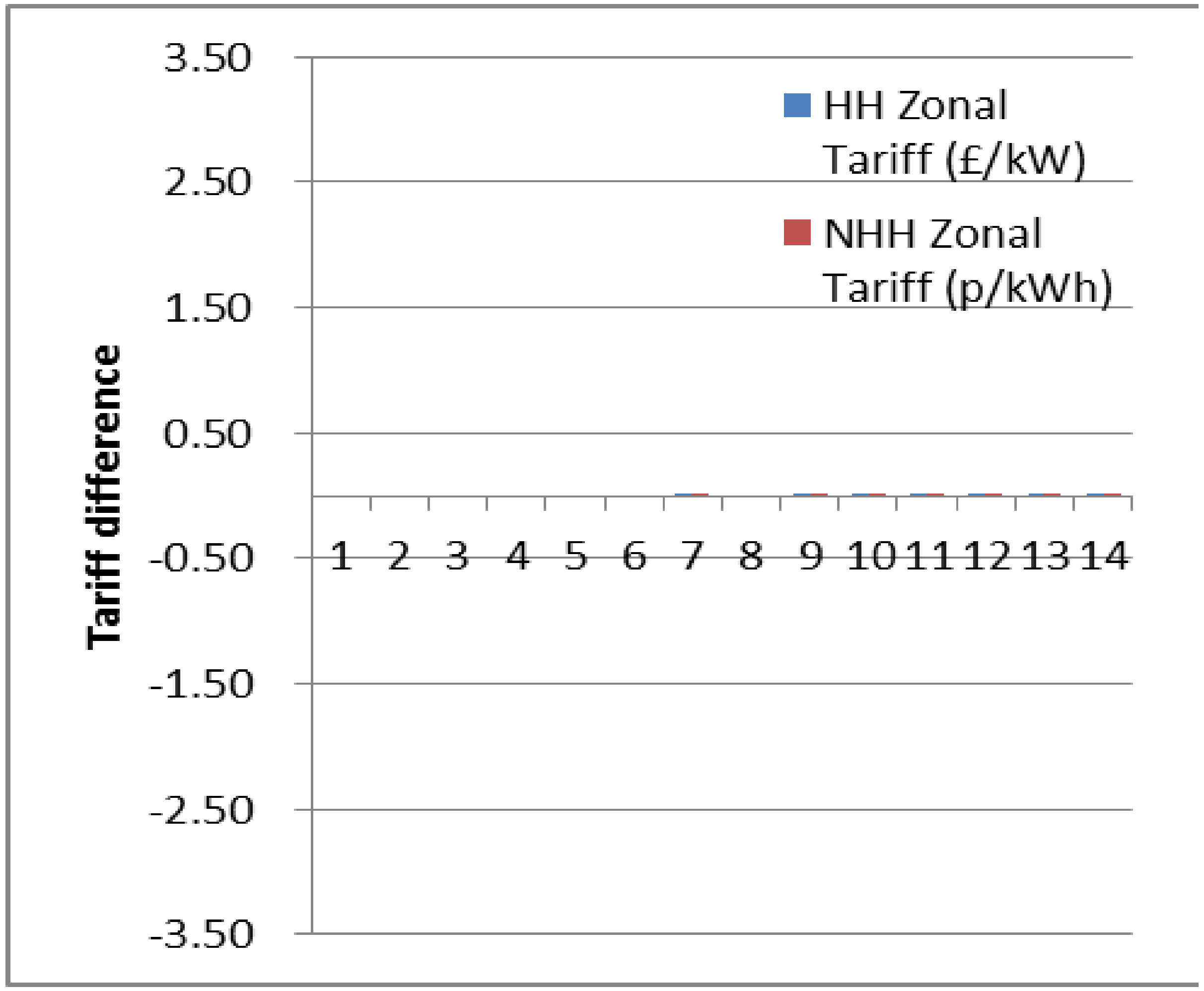
Cost reflectivity - Action 12: changes to generation

Reducing intermittent generation (onshore) in generation zone 11 by 374.5MW: Change in tariffs *(note change in y axis scale)*

Generation:



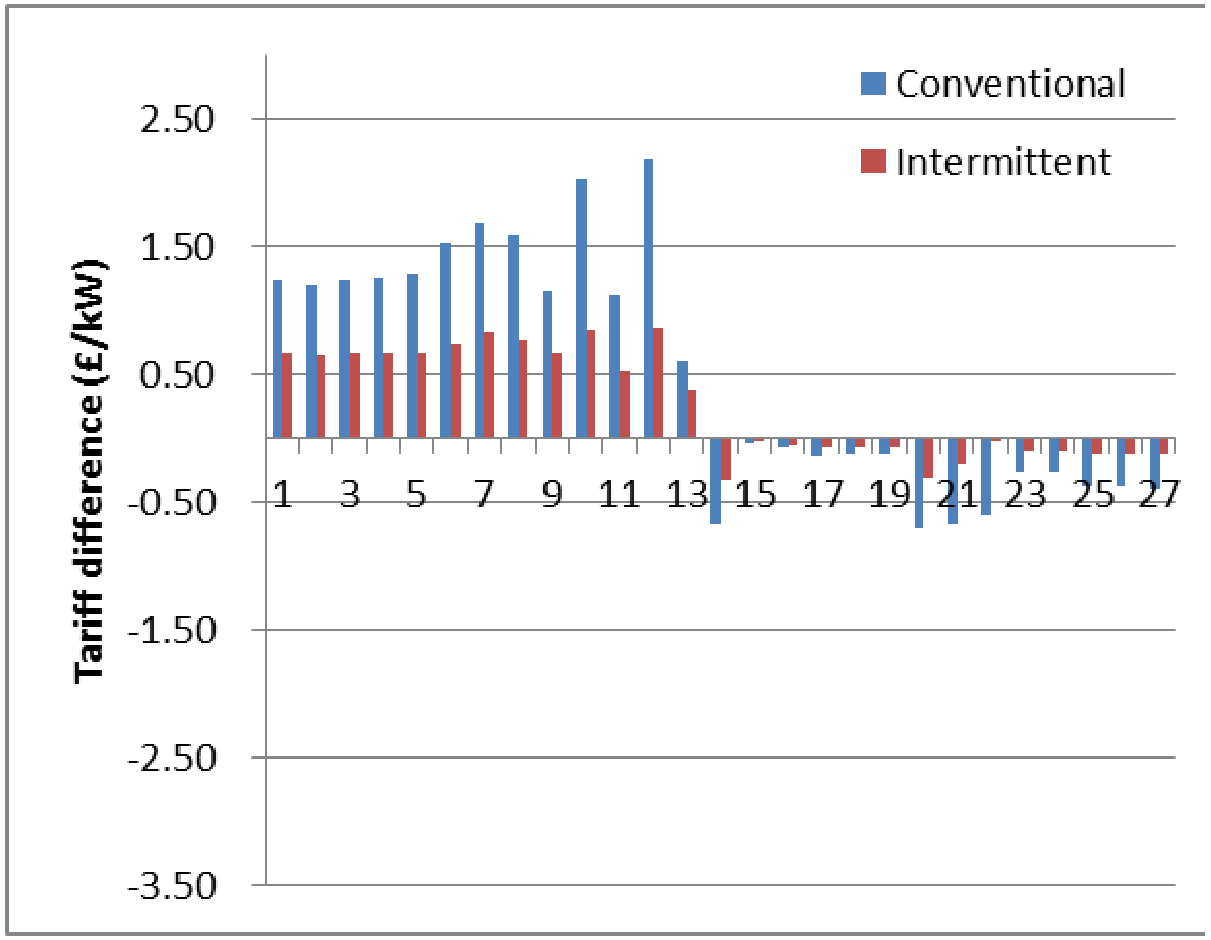
Demand:



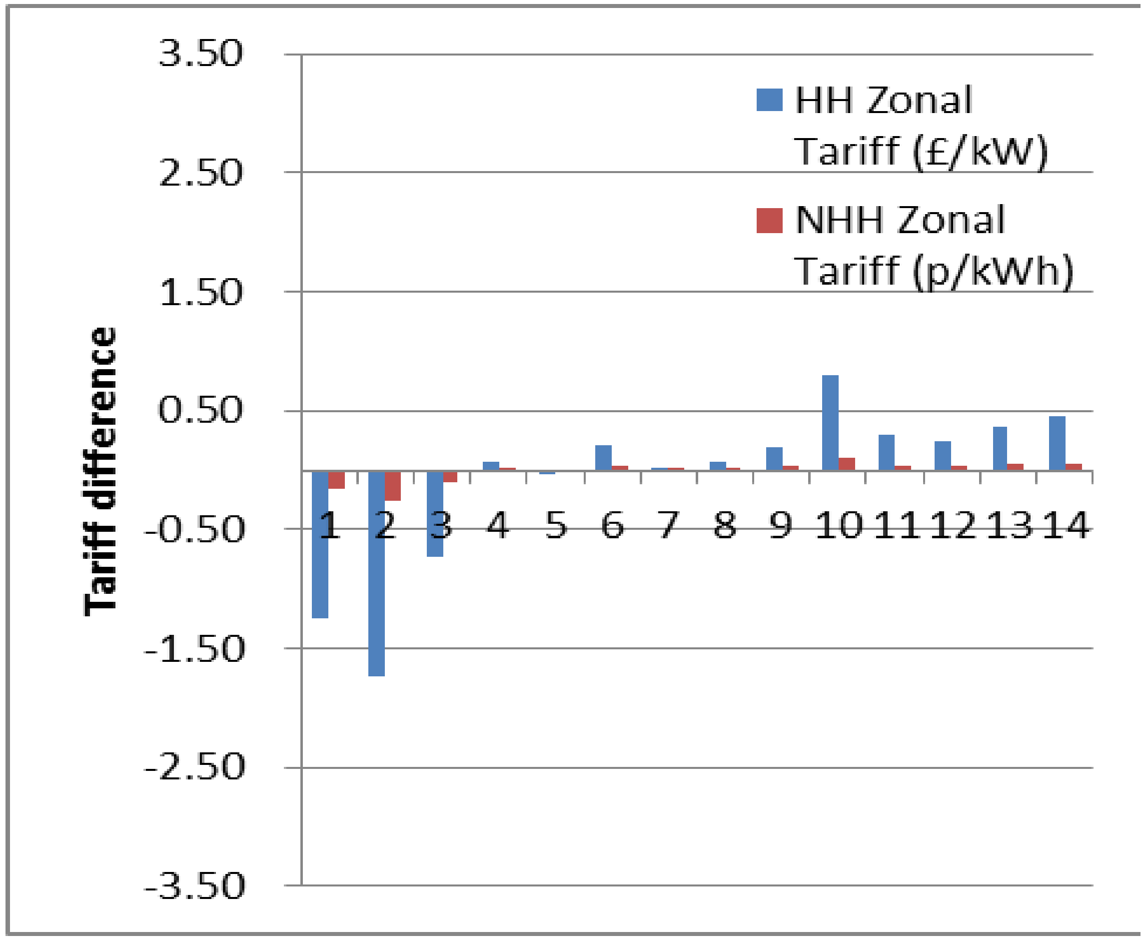
Cost reflectivity - Action 12: changes to generation

Increasing intermittent generation (onshore) in generation zone 11 by 374.5MW: Change in tariffs *(note change in y axis scale)*

Generation:



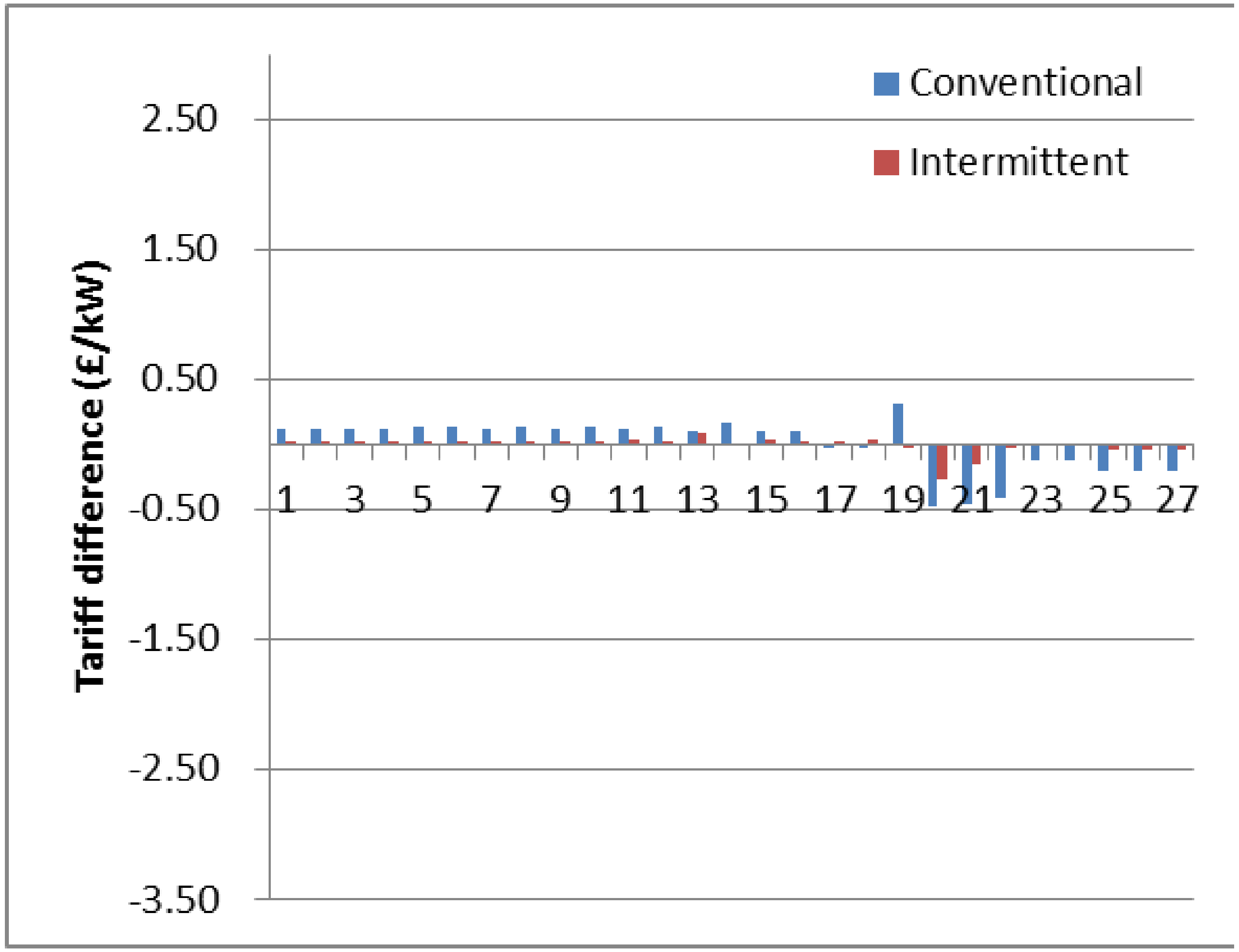
Demand:



Cost reflectivity - Action 12: changes to generation

Reducing intermittent generation (onshore) in generation zone 21 by 228MW: Change in tariffs *(note change in y axis scale)*

Generation :



Demand:

Change of less than 0.01p / kWh or £0.01/kW

Cost reflectivity - Action 12: changes to generation

Increasing intermittent generation (onshore) in generation zone 21 by 228MW: Change in tariffs *(note change in y axis scale)*

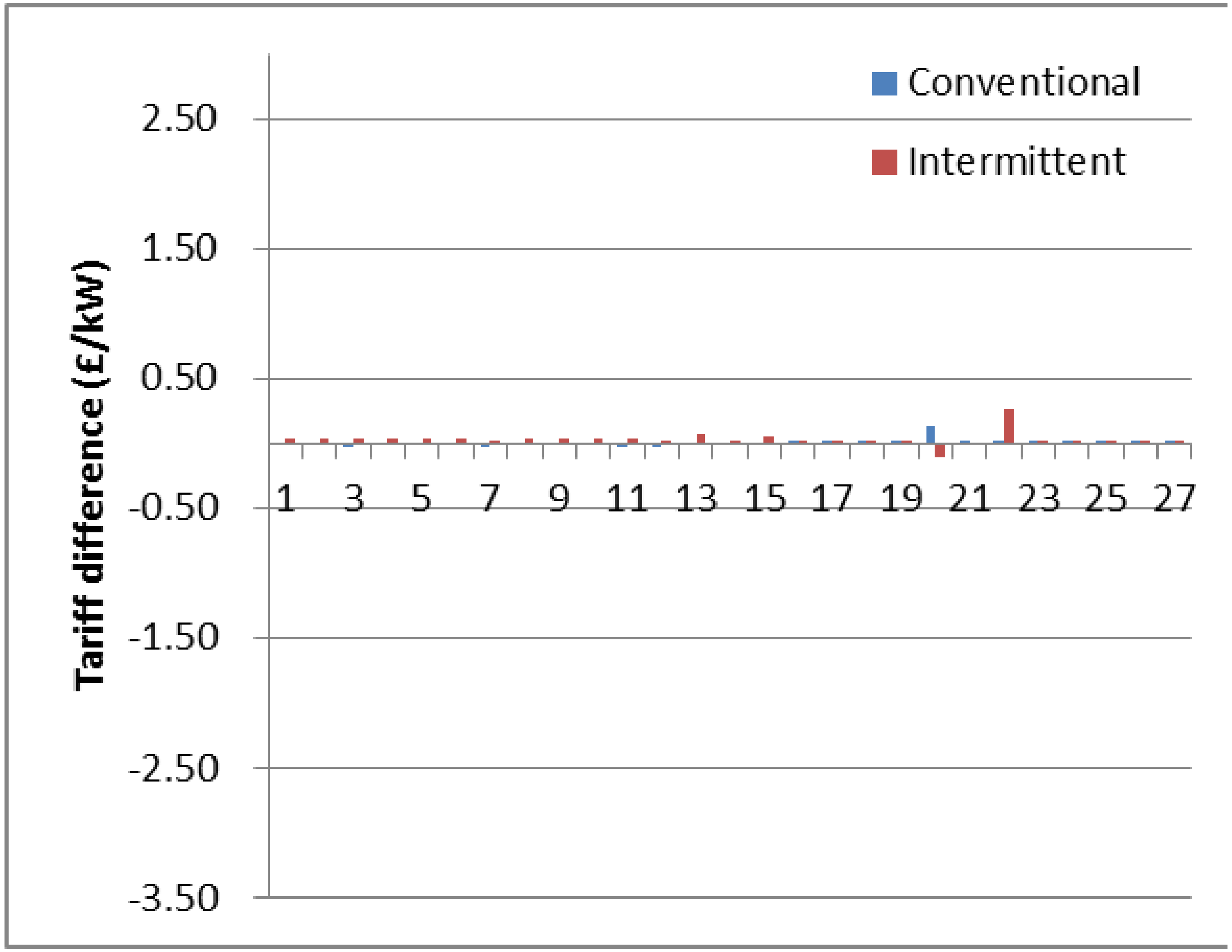
Generation: Demand:

No discernible change

Cost reflectivity - Action 12: changes to generation

Reducing intermittent generation (offshore) in generation zone 24 by 650MW: Change in tariffs *(note change in y axis scale)*

Generation :



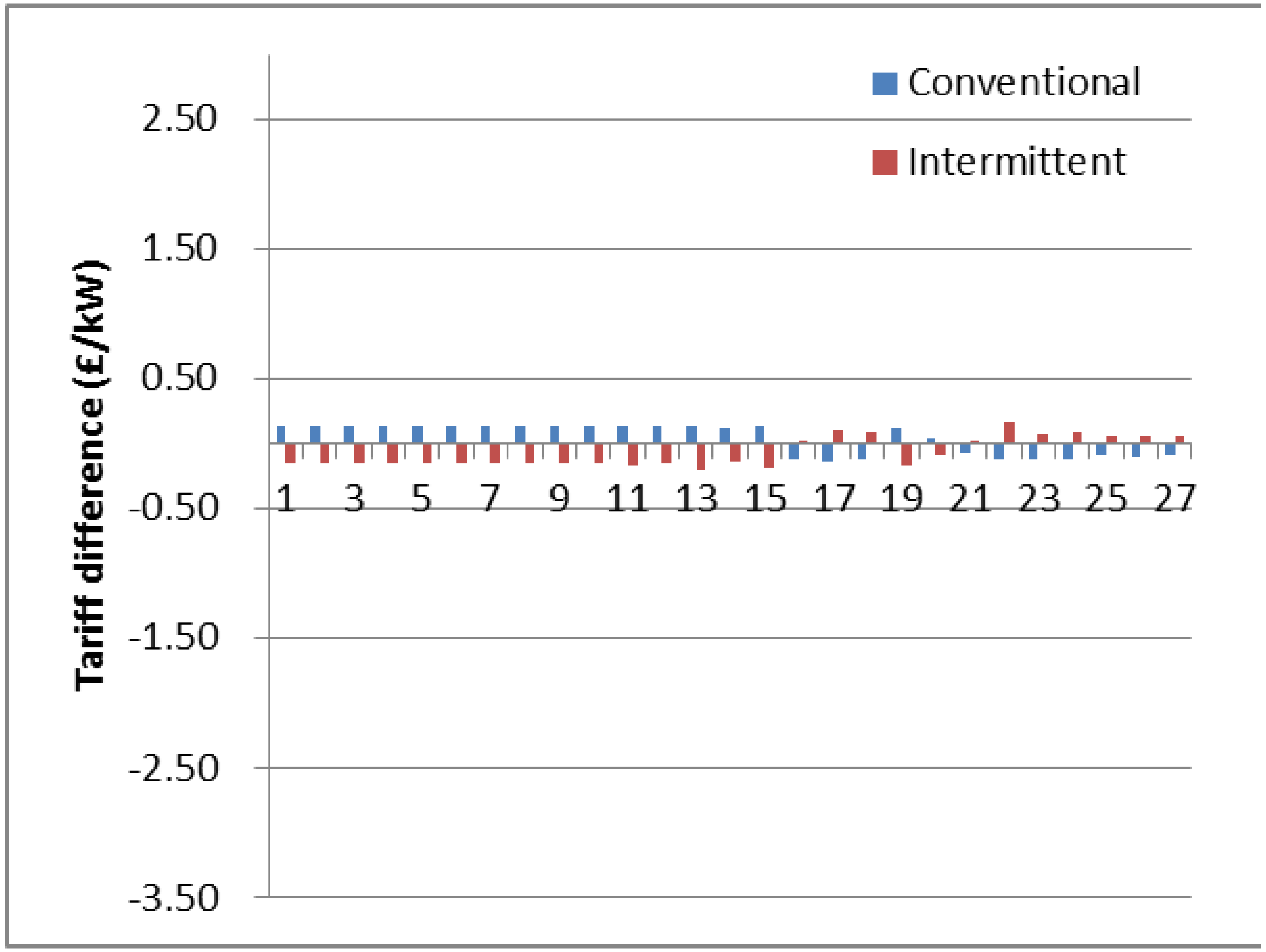
Demand:

Change of less than 0.01p / kWh or £0.01/kW

Cost reflectivity - Action 12: changes to generation

Increasing intermittent generation (offshore) in generation zone 24 by 650MW: Change in tariffs *(note change in y axis scale)*

Generation :



Demand:

Change of less than 0.01p / kWh or £0.01/kW

Cost reflectivity - Action 12: changes to generation

- Larger tariff changes when:
  - A circuit changes direction due to change in flows
  - Changes in circuits at the periphery of the transmission network
  - A change in flows causes a circuit to be re-classified from year round to peak or vice versa
  - A change in the ratio of intermittent: conventional generation in a zone. When intermittent generation exceeds conventional generation in a zone, all year round costs in that zone become non-shared. This would have the effect of increasing intermittent charges relative to conventional as shared costs are scaled by annual load factor, but non-shared are not.

nationalgrid

Action 31: re-calculation of necessary error margins (CMP224) under 15 months notice

- CMP224 sought to ensure that an appropriate error margin was included in the calculation of the G:D split to account for error in forecasting a) the revenue to be recovered from generation and b) total generation output 2 months ahead.
- CMP224 did *not* seek to calculate an error margin to cover the risk of exchange rate fluctuations.
- To calculate a 2 month error margin, the workgroup took the maximum observed forecasting error on both a and b 2 months ahead:
  - €2.5 = (Total revenue to be recovered from gen) x (exchange rate)

    Total annual system output - from chargeable gen
  - = (Max *over* forecasting error for gen revenue t-1 = 1.031) x (exchange rate = 1)

    Max *under* forecasting error for Total annual system output t-1 = 0.969
  - = 1.064 x forecast gen recovery x exchange rate

    forecast Total annual system output
  - **i.e. 7% error margin – 2 months ahead, set tariffs to recover average of €2.33**

nationalgrid

Action 31: re-calculation of necessary error margins (CMP224) under 15 months notice

- CMP224 workgroup said that given difficulties in getting hold of forecasting data for y +2, a **14% error margin** for forecasting with 12 months notice was calculated – i.e. a €2.15 cap.
- 16:17 Using an error margin of 7%, a €/£ exchange rate assumption of 1.36 and current system output assumptions would have given:
  - a generation revenue recovery of £458m,
  - a G:D split of 16.3 to 83.7 and
  - a generator residual of £0.21 / kW
- Keeping all assumptions the same, using a 14% error margin changes this to:
  - a generation revenue recovery of £430m (change of £28m)
  - a G:D split of 15.3 to 84.7,
  - a generator residual of -£0.20 / kW
  - And an increase in demand residuals (dependent on assumed charging bases):
    - Actual HH tariff delta: ~ £0.57 /kW
    - Average NHH tariff delta: ~0.07p /kWh

Action 31: re-calculation of necessary error margins (CMP224) under 15 months notice

- CUSC legal text (section 14.14.5) currently specifies that the OBR spring forecast of the £/€ exchange rate in the year ahead of charging should be used to set the G:D split (i.e. Mar 15 for 16/17 charging year)
- This would not be possible under a 15 month notice period, therefore legal text change required – could use ‘latest available’ or similar (exact publication timings of OBR forecasts have varied slightly year on year)

nationalgrid

Action 28: Licence and CUSC conditions – mid year changes

- NGET cannot change charges in year 'except in so far as the Authority otherwise directs or consents' (*Transmission Licence C4.5.b*) - how is this backed off in the CUSC?

- **3.14.1** Pursuant to the Transmission Licence and/or the CUSC and/or the Charging Statements and/or the Bilateral Agreements The Company may revise its Transmission Network Use of System Charges or the basis of their calculation. Where The Company proposes a change to the Transmission Network Use of System Charges then it shall notify the User as soon as practicable after the **proposal** is made to the Authority pursuant to the Transmission Licence. *[NB proposal to change tariffs requires 150 days notice to the Authority as per licence condition C4.5.a]*

- **3.14.3** Subject to paragraph 3.14.4 below, The Company shall give the User not less than two months prior written notice of any revised Transmission Network Use of System Charges, which notice shall specify the date upon which such revisions become effective (which may be at any time) and will make reference to the new tariffs set out in the relevant Charging Statements. The User shall pay any such revised charges from the effective date

- **3.14.4** Where in accordance with the Transmission Licence, the Authority determines a shorter period than 2 months for the implementation of revised charges, the notice period will be determined by the Authority. The notice will specify when the new charges are effective and the User shall pay any such revised charges from the effective date.

Action 35: Week 24 data under 15 months

- Week 24 data is used in the transport model (but not the tariffs model) to calculate the locational differential in TNUoS tariffs rather than the absolute size of tariffs. Effectively it is used to calculate ‘who’ pays / how charges are proportioned across users rather than ‘how much’ these charges are. overall
- Section 14.15.20 of the CUSC notes that *“The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update” (NB this is now the Electricity Ten Year Statement).*
- **Currently** week 24 data from e.g. 2015 is fed into the 2016 ETYS (published Oct), and then used to calculate charges for 17/18.
- Under a 15 month notice scenario, the 2016 ETYS (using 2015 data) would be used in Oct / Nov to set tariffs in Dec 2016 which would be live for 18/19 i.e. there would be another’s year lag in data (to t-3).
- Alternatively, there could be the opportunity to use 2016 data (if this had been received in time for analysis) for tariff setting in Dec 2016 *but* this would not be published publically until the next ETYS the following year. Would this follow the intention of 14.15.20?

nationalgrid

Unanticipated events: NG (as SO) role in the case of energy supply company administration

Context: (DECC):

- The purpose of energy supply company administration is to ensure that if a large gas or electricity supply company is in financial difficulty, arrangements are in place to allow the company to continue operating normally until it is either rescued, sold, or its customers transferred to other suppliers. This will reduce the risk of financial failure spreading across the energy market, maintain market stability and therefore protect consumers.
- **Transmission licence C24.1:** Where there is a shortfall during or at the completion of an energy administration or energy supply company administration, the Secretary of State, after consultation with the Authority and the licensee, may issue one or more shortfall directions to a licensee to 'modify the charges imposed by it in carrying on its licensed activities ("charges") to raise such amounts as are specified by the Secretary of State in a shortfall direction'.
- C24.6. For the purposes of sub-paragraph 3(a) and paragraph 5: (a) the licensee **may modify its charges notwithstanding that it has not given prior notice of such a variation required by any other condition of this licence and/or the CUSC** and any charges levied by the licensee after modification pursuant to sub-paragraph 3(a) or paragraph 5 of this condition shall be deemed to be compliant with the licensee's obligations under Condition C4 (Charges for use of system), Condition C5 (Use of system charging methodology) and Condition C13 (Adjustments to use of system charges (small generators)) as from time to time amended;
- (b) the **licensee shall not enter into any agreement with another party which does not permit it to vary its charges in pursuance of this condition** and shall take all steps within its power to amend, where necessary, any existing agreement to permit such variation

Potential changes logged to date (action 32)

CUSC	3.14.3	" The Company shall give the User not less than 2 months prior written notice of any revised Transmission Network Use of System charges"
	3.15.1	Definition of tariff forecast timetable
	14.14.10	“The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January”.
	14.28	Predictability of tariffs section “The Company is required …. to give Users 2 months written notice of any revised charges”.
	14.15.4, 14.15.6 to 14.15.18	Inputs to charging model (t-1), OBR spring forecast reference t-1
	14.19.1 and 14.19.2	TEC forecasts and generation forecasts
TO licence	Special conditions 3A: 14, 17, 20, 22	Conditions regarding over / under recovery
STC-P	14-1	Timing of revenue information