NORTHERN IRELAND RENEWABLE HEAT INCENTIVE

04 NOVEMBER 2016

INTERNAL NOTE

Cambridge Economic Policy Associates Ltd

Dear Andrew

NON –DOMESTIC RENEWABLE HEAT INCENTIVE

Please find responses to your letter of October 26th, 2016. In this I address your points to the best of my knowledge and from events which as you know, some of which took place close to six years ago. I can only report from the perspective of CEPA which was responsible for the economic appraisal. Should you wish to approach AEA Technology's successor firm for specific technology points, I can provide you with contact details. I have passed on your request to them, but at this point have not received a reply.

In addition to responding to your specific requests, as an annex I provide some additional observations. Whilst this is work in progress you may find it useful in putting the RHI into context, especially as regards comparisons with the GB scheme. I would also draw your attention to the two reports produced by DECC earlier on this year: "The Renewable Heat Incentive: a reformed and refocused scheme" and the accompanying Regulatory Impact Assessment, both of which can be easily downloaded from the BEIS website. I have drawn on these extensively in my own research – I believe they may provide useful context for you in terms of the challenges of operating even the much larger GB scheme.

Should it be of use to you I would be happy to make myself available for a call prior to November 9th.

General

Before responding to specific points it is probably worth drawing attention to something that thus far largely seems to have been forgotten, that being the context in which both the CEPA 2011 initial report and 2012 addendum were set:

- The RHI was *meant to be an incentive to produce renewable heat* – the key objective of the initial 2011 economic appraisal was to seek to determine tariff levels that would provide the right level of incentive for each type of renewable technology (given the counterfactual alternatives).
- Northern Ireland (NI) was expected to make its contribution to the UK total of 12%, this being the heat component of the UK's legally binding 15% total renewable energy target. At the time reaching a 10% target in NI was seen as a major challenge.
- Unlike Scotland and Wales, NI was not part of the GB scheme and therefore had the challenge, (risks) and costs[1] of implementing and running its own scheme, within the centrally provided allocation (our analysis being undertaken on the assumption of a hard budgetary constraint).

[1] The European Commission's European Regional Development Fund part-financed CEPA's 2011 report as well as other (but not the 2012 addendum).

- If the central budget was not used, it was lost to the NI economy (which we understand would have been unpopular).
- In terms of the level of acceptable subsidy cost, DECC set this at the level of subsidy per kWh for off-shore wind, which was 10p at the time (NI has never reached this level). All NI biomass subsidies were well below this figure.
- At the time of both reports, the GB scheme was also completely demand-led with no overall budgetary control; however, interim control measures were introduced in 2012 which allowed the scheme to be closed as short notice, followed by the introduction of degression in 2013 with proposals in 2016 for scheme caps. Individual installations in GB have **never** been capped.

The rationale and intention behind the initial CEPA recommendation, in the 2011 Report, that tiering was not needed.

During the production of the 2011 report CEPA was essentially working in parallel, but behind what DECC was doing. This often involved trying to predict what DECC's final proposals would be.

We were working under the assumption that NI would run its own scheme. At the this level, our assumption was that there would be a hard budget constraint – although it was not clear what the size of budget would ultimately be – with all of our modelling conducted under this assumption. We understood that DETI was having discussions with Ofgem as to how the scheme was to be administered. Our main task was to determine the level of incentive that was most likely to incentivize a switch from oil to different forms of renewable heat, given the potential that existed within NI and a largely oil counter-factual.

The main focus of work was a take-up model. The modelling approach was that used by DECC to generate its own initial tariff proposals (AEA Technology had provided engineering inputs to DECC's analysis too). Our internal notes suggest that this did not initially involve tiering.

To begin with we proposed a competitive form of subsidy allocation, rather than an administered one. This would have prevented overspend and minimised the risks of over and / or underspend. Although the report sets out some of the disadvantages of this approach, the main reason for changing was the desire of DETI to have something that was more in line with what DECC was doing.

The question of tiering occurred once we had produced initial proposals. At the time, what DECC was trying to achieve by the tiering was not completely clear. Our internal notes interpreted it as some form of "front-end loading", perhaps to encourage initial levels of production. It was not clear how the 15% threshold was arrived at. Although DECC has more recently definitely stressed the role of tiering being an *incentive mechanism* rather than a means of *budgetary control*,[2] DETI may have interpreted it as a form of control (given that degression was not introduced for another couple of years).

This understanding would certainly have been consistent with the comment in the report that as fuel costs were higher than the subsidy levels for all bands this therefore reduced the risk of heat generation solely for purposes of receiving the subsidy.[3]

At the time this would have been the clearest argument as to why there was little if any incentive to over-generate heat just to receive subsidies, especially for installations above 45kW, where the proposed subsidy was only 1.3p. At the higher proposed 4.5p tariff for installations <45kW, a further argument would have been the limited scale of reference boiler and associated low load factors would have reduced the potential to over-generate. This boiler was only 20kW, which would have been challenged to generate a 15% load factor.

Table 1.1: Recommended rates per band - biomass boilers

Technology	Group	Investor groups	Bands	Reference installation	Rate
Biomass boilers	Small	All domestics and small commercial/public sector	0 - Less than 45	20kW	4.5p
Biomass boilers	Medium	Large commercial/public sector (but not large enough for industrial)	45 - No upper limit[4]	200kW	1.3p

The appropriateness or not for a two-tier tariff was just one of many debates with the DETI team that occurred at the time. Indeed, it is important to recognise that DETI was an engaged and highly interested client, the team providing us with extensive and challenging comments.

A key issue was that the proposed subsidy levels were lower in NI than GB because of the oil counterfactual, heating oil being more expensive than gas, thus viewed by ourselves and others as requiring less of an incentive to switch (given the modelling methodology applied). As the subsidy rates were so much lower than those proposed for GB, many of the discussions were around whether or not the subsidy was sufficient and whether larger biomass should also have received a subsidy (which we did not believe was necessary given the oil counterfactual and the considerable economies of scale arising from the associated higher heat loads).

[2] See DECC RHI Impact Assessment 2016

[3] By the same logic, installations in GB would have had an incentive to produce up to the Tier 1 threshold.

[4] Based on our analysis, we recommend a zero rate for large industrial sites, and so recommend that they are excluded from this band.

However, the 2011 report did draw attention to the inevitably significant uncertainty at an early stage in the roll-out of renewable heat (as was also the case in GB); notably uncertainty on the relative prices of renewable fuels, operating costs and hassle costs[5]. The report also stated the obvious risk that the subsidy levels proposed for the RHI being either too high or too low and advised that the normal method of dealing with this risk is *"to have regular, planned, reviews of subsidy levels after a number of years of experience with the subsidy."* It also called for audit of systems in receipt of subsidy to ensure the scheme rules were being met.

CEPA's view on the implications for that recommendation arising from the subsequent recommendation by CEPA, following a consultation exercise, the tariffs (and in particular the small commercial biomass tariff) should increase.

From the outset it should be remembered that the 2012 addendum was a very limited exercise – **not** a review of the scheme - which considered a number of narrow issues, such as the appropriateness of the proposed banding and interaction between the RHI and the gas network, particularly as regards large industrial sites.[6] Specifically, there was a recalculation of the tariff levels – although not a review of the tariff structure - following consultation responses that had been provided to DETI. Some of the market feedback – most of which pushed for higher levels of subsidy – was rejected and some accepted. As regards *biomass* the main changes were:

- A re-banding that increased the smallest rate band to 20 <100kW (still half the level of the GB band) as a result of arguments made by consultation respondents that the previous banding was too general.
- An increase in the small scale tariff. The main drivers of the 2012 tariff change over 2011 were an increase in capex of 41% (the boiler being larger), changes in hassle costs (a 34% increase) and other changes, including inflation (a 25% increase). We were encouraged to incorporate such a level of hassle costs to bring the scheme into line with that in GB. Hassle costs were sourced from the DECC RHI 2009 Impact Report. Consultation respondents had argued that the tariff level was too low (many of whom wanted the higher GB tariffs) and which we remained convinced were not required.
- The medium / large band boundary was brought into line with GB, which operated a single tier tariff for the large band. No subsidy was proposed for NI.

[5] CEPA 2011, p.64

[6] Unlike the initial report, the addendum was funded presumably out of DETI's budget. Our understanding was that it was determined to minimise the costs of the exercise to in order to minimise the use of public money. In any event tariff levels would be reviewed regularly.

Increase in small commercial biomass tariff 2011-2012

Report	Technology	Group	Opex (£/kW/year)	Fuel cost (p/kWh)	Bands	Reference installation	Rate (p/kWh)
2011	Biomass boilers	Small	4.6	4.35	0 – 45	20kW	4.5
2012	Biomass boilers	Small	21.16[7]	4.39	20-100	50kW	5.9

In the modelling, the reference boiler was increased in scale to 50kW from 20kW which would have increased its potential load factor from what it was previously. This scale of boiler with an assumed 85% efficiency factor, would require still require a relatively high number of kWh heat production to hit even a 15% load factor (approximately eleven hours per day, 52 weeks per year, five days per week). As we now know, in the real world installations clustered just under the threshold 100kW, as set out above, the potential to undersize boilers being a stated risk in the 2012 report.

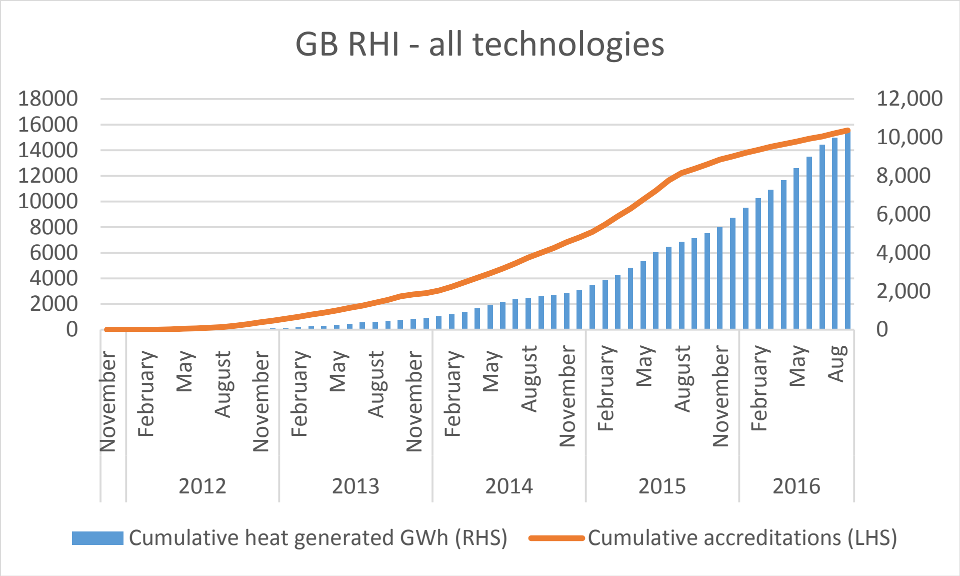
Again, the addendum stresses the need for regular reviews of tariffs which is also provided for in the business case (not to mention the legislation that introduced the scheme).

What have been the implications of the revised tariff?

It is a combination of the level of tariff and tiering that determine the value of tariff revenues and therefore the extent of the incentive. The power of the incentive in realising a switch to biomass will also be affected by a range of other cost and non-cost factors (such as the ease of switching, availability of installers etc). In turn, separate from the incentive or a desire to over-generate, the level of heat production will first and foremost be driven by the economic or social activity it is supporting.

As the data shows, despite the higher tariff there was very little uptake for several years. To a degree, uptake in GB was also initially slow and then increased (which may suggest the impact of other factors were more influential, for instance improvements in the supply of equipment or other enablers).

[7] This includes ongoing hassle costs.



As stated in the NAIO report, this new tariff was above the prevailing cost of pellets. Going on for five years after the event, we cannot find any evidence that this was explicitly discussed at the time between DETI and CEPA, at least in any correspondence. It is worth noting, however, that if a lower second tier tariff had been introduced, the Tier 1 tariff would have had to increase to compensate, if the same level of incentive was to be maintained. This could have increased the incentive to over produce to the Tier 1 /2 boundary (DECC found evidence of this – an average load factor of 15.22 in a recent evaluation of the GB RHI).

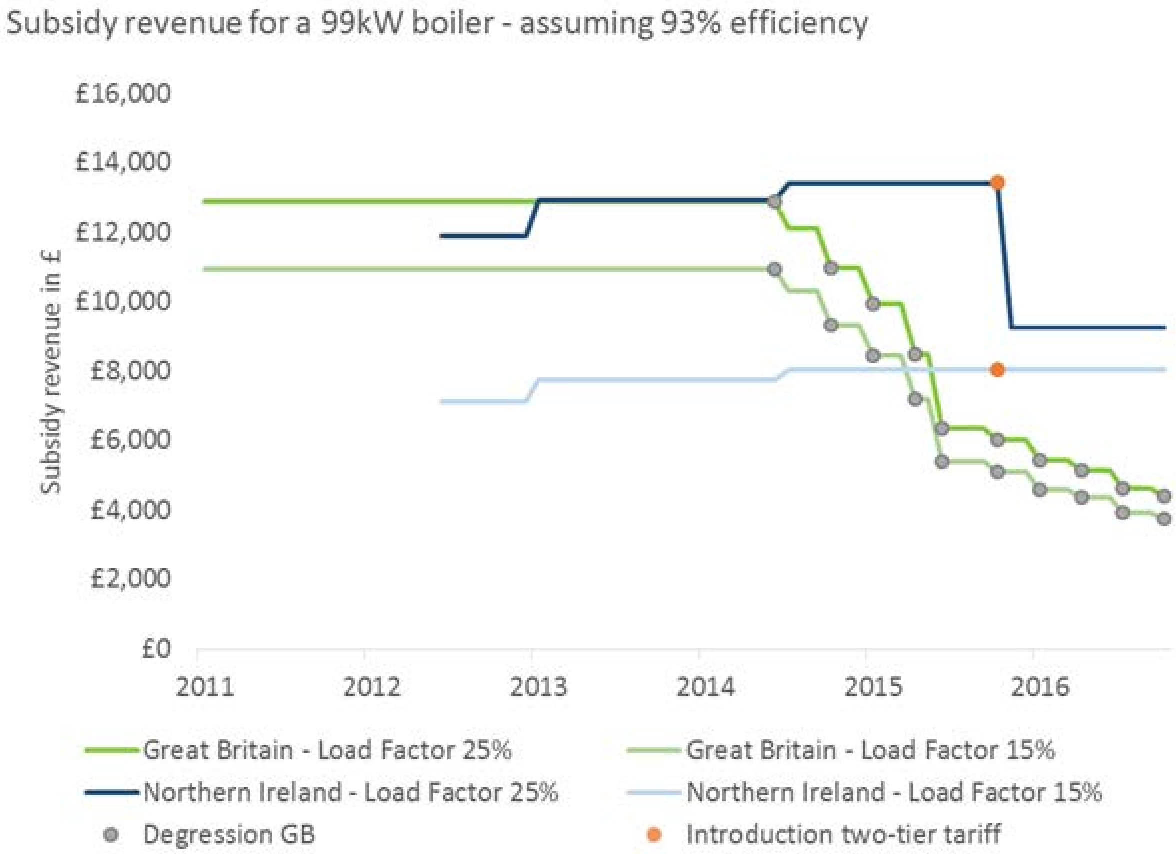
If the tariff level was excessively generous it might have been expected that it would have led to a greater uptake in applications sooner. Ironically, applications started to rise as the price of heating oil fell rapidly – more so, at least than the price of pellets.

Although the cost of pellets would have been lower, presumably any other potential variable costs, such as additional labour costs, associated with running the boiler would have varied with activity, which may or may not have provided a further deterrent to generating heat just for the sake of it (although this was not necessarily considered at the time). On the other hand, it may have turned out that for some installations, the cost of pellets was less relevant, if they had access to cheaper and / or local sources of biomass (eg furniture manufacture, forestry businesses etc).

However, it is important to note that it would be unlikely that everyone was out just to breach the schemes rules. For many installers, as set out in the Business Case, it would be the underlying activity supported by the heat that would have had a significant role in determining levels of heat production.

At this point in time (2012), however, if we are to compare the generosity of the NI scheme with that of GB, even using a 99kW boiler, given the GB tariff structure of Tier 1 8.94p and Tier 2 2.34p relative to NI's 5.9p, the breakeven load factor between the two would have been about 28% (c.224,300kWh per year)[8], well above the Tier 1 / 2 threshold of 15%. In other words, initially the GB scheme was much more generous – only at high load factors would the NI scheme be more attractive.

It is a combination of the different tariffs at different load factors that drive the revenues received. Whereas this increased in line with inflation in NI (even when the Tier 2 tariff was introduced), the degression mechanism in GB (introduced in 2013) led to ten reductions in tariff levels for small-scale biomass from May 2014. This brought down the revenues received rapidly (and has also choked off much demand for small biomass). The figure below shows the annual revenues for a 99kW installation joining both the NI and GB schemes at 15% and 25% load factors, since their respective introductions.



As can be seen, for all but the highest load factors the GB scheme was initially more generous than NI, but this then fell rapidly (from c£11,000 pa at 15% to c.£4,000 in roughly two years) as the degression mechanism kicked in (leading to slowing of accreditations, although not without similar, if less dramatic, spikes that occurred in NI). It might be expected that a similar reduction in tariffs might have achieved the same in NI, but the Tier 1 tariff was not adjusted down, although the introduction of the Tier 2 tariff would have reduced revenues at higher load factors.

[8] The Tier 2 tariff would apply above a load factor of 15%. This level is equivalent to over 9 hours of use per day, five days per week, 52 weeks per year.

As it is the overall revenue incentive that is important, it can be difficult to unpick impact of the tariff level from that of the tiering. However, two further analyses would be useful in exploring the role this further. The first would be to establish what loads each small scale biomass installation were generating in NI. Where did the modal group sit in terms realised load factors (eg 20%, 25% 30%+ etc) and was this changing over the years? What proportion were generating excessively high loads? Are there several outliers who were either legitimately or illegitimately generating high loads, such that excluding these reduces the average load for the rest? Or has everyone been generating at high loads?

Another analysis would be to compare the load factors of the average (or mode) pre-introduction of the two tariff regime with average / modal load factors of those post introduction of the two tiers. Have patterns of usage changed drastically? Excluding any outliers, if patterns are relatively the same, this would suggest that the industrial or commercial activity that heat production was supporting was the predominant driver of heat production for most users, rather than the tariff structure per se.

Our understanding is that the production of heat without an underlying commercial rationale is a breach of the scheme rules and therefore these heat generation figures should be excluded. As set out, we also note that those installations that have access to "free biomass" could generate heat profitably at whatever level of subsidy. We also note that close to 70% of generating capacity is owned by farming and associated businesses.

The way in which the CEPA recommendation on tiering was subsequently used within the internal DETI Business Case document of March 2012

The DETI reports claims that "Tiering is not included in the NI scheme because in each instance the subsidy rate is lower than the incremental fuel cost." This statement was accurate for the 2011 report. In the 2012 extension, the fuel cost for biomass and biogas were above the tariffs set.

Other than this this the business case was a relatively fair reflection of the 2011 and 2012 reports and importantly sets out the need for regular reviews (para 2.38).

Provide all assumptions and calculations underpinning each input into the tariff calculation for as highlighted in Annex B attached.

Input parameter	Unit	Biomass commercial pellets	Assumptions / calculations
Capex	£/kW (2010 prices)	608.40	AEA supplied
Fixed Opex	£/kW/year (2010 prices)	4.6	AEA supplied
Efficiency	percentage	85%	AEA supplied

Input parameter	Unit	Biomass commercial pellets	Assumptions / calculations
Load factor	percentage	17%	AEA supplied Load factor = Heat Demand per building / (Size * Annual usage) Heat Demand per Building (kWh/b/Yr) = 74,903 Size (kW) = 50 Annual usage (hours) = 8760
Size	kW	50	The reference installation is chosen as the installation requiring a subsidy that would incentivise half of the total potential output from the technology that could be taken up across the period 2011-20 if that rate was offered to that band in every year.
Lifetime	years	20	As per GB scheme
Fuel price	£ / kWh / year (2010 prices)	0.0439	AEA supplied, converted from £/GJ to £/kWh based on 2009 DUKES conversion factors
Upfront barrier costs	£ / installation (2010 prices)	5364.25	The final report shows 3,951, this was a typographic error (the higher number is what was used in the model). From DECC Impact Assessment
Ongoing barrier costs	£/ year	828	From DECC 2009 Impact Assessment
Fixed Opex including ongoing barrier cost	£/kW/year (2010 prices)	21.16	4.6 + ongoing barrier cost / size

Biomass (small commercial) – technology resource cost in £ per year

Variable	Calculations	Biomass (£)	Counterfactual (£)	Difference (£)
Annuitised Capital cost at 12%	PMT(discount rate, year, capex)	4,073	710	3,362
Annual operating costs	Fixed Opex * size	230	173	57
Annual fuel costs	Hours in year * load factor / efficiency * fuel price * size	3868	3902	-34
Annuitised Upfront barrier costs	PMT(discount rate, year, upfront barrier costs)	718		718
Ongoing barrier	See above	828		828

Variable	Calculations	Biomass (£)	Counterfactual (£)	Difference (£)
costs				
TOTAL				4,932

Provide all calculations inherent in arriving at the 5.9 proposed tariff subsidy

See attached spreadsheet.

Explain fully the rationale behind the assumption of a 17% load factor

Load factor = Heat Demand per building / (Size * Annual usage)

Heat Demand per Building (kWh/b/Yr) = 74,903[9]

Size (kW) = 50

Annual usage (hours) = 8760

Explain fully the rationale behind the assumption of using a 50kW boiler size for the 20kW to 100kW tariff band

To select the reference installation a fixed incentive rate is calculated for each band based on the £ / kWh subsidy required to make a reference installation viable. In line with DECC's methodology, the reference installation is chosen as the installation requiring a subsidy that would incentivise half of the total potential output from the technology that could be taken up across the period 2011-20 if that rate was offered to that band in every year. Total potential output is calculated as heat output that could be achieved if all technically viable segments within the band installed the technology.

In order to limit the impact of the policy on the gas network, if the reference installation delivering half of total potential output has a gas counterfactual, the incentive rate was revised down to the subsidy required by the next lowest group with an oil counterfactual.

[9] The heat demand value has been updated in 2012. It used to be 29,961 kWh/b/Yr

ANNEX

BUDGETARY CONTROL AND TIERING

- **In the view of DECC, tiering, along with tariff levels are first and foremost a means of incentivizing (or disincentivizing heat production) not a means of controlling it:**
  - Degression (introduced into GB in 2013) or an overall scheme cap (as GB is now introducing) are the principal means of budgetary control
    - Degressions reduce the tariff given once projected cost levels breach certain trigger points
    - Caps close the schemes to new applicant (first introduced as an interim control measure in GB in 2012, now a part of the UK government's approach)
    - Even now the GB scheme **does not cap the heat production of individual installations** as it is trying to incentivize heat production (for legitimate uses) to meet legally binding renewables and carbon targets, in which renewable heat has a significant role to play.

"budget management … is proposed through caps for spending and degression of tariffs for new entrants"

"tariff rates and structure: the tariff rates offered by the RHI establish the financial attractiveness of the RHI for potential participants."…. "through offering a rate of return on additional investment, as compared to the counterfactual"[10]

- **It is worth noting that in a demand-led scheme such as the RHI that was operating in both GB and NI, both of which experienced pronounced increases in uptake within short timescales, managing demand within a £25m annual budget compared to a £430m one[11], even if degression had been available, is a significantly more challenging task.**

SUBSIDY AS AN INCENTIVE

- **Subsidy revenue incentives are just one element (i) of the initial decision to install and (ii) in determining the level of heat production:**
  - Actual and greater than conventional upfront capital costs create a financing requirement for installers. Availability of own finance or external financing through, say, banks, will be likely important factors in the decision to install. (In order to improve affordability, in the case of the domestic scheme upfront barriers were addressed through provision of premium payments).
  - Once the decision to install renewable heat has been taken, in the absence of a breach of the scheme rules, the requirements of the underlying commercial or industrial activity

[10] DECC RHI Regulatory Impact Assessment 2016.
[11] DECC's 2015/16 budget

would be expected to be the main drivers of heat production. For instance, if heat is required for a viable industrial process it will continue to be generated irrespective of the level of subsidy.

- There can potentially be costs to over production of heat of in, say accommodation during the summer, could be unpleasant for guests or users of buildings.

- **Installers will look at the total subsidy revenues they will likely receive, the absolute costs involved in installation and the relative costs and benefits, including non-financial, of other heat options in deciding whether to choose renewable heat.**
  - It is the <u>overall level and profile of the anticipated subsidy revenue stream over time, relative to costs</u> that will be important – in the case of biomass this will need to contribute to any additional capital costs of biomass boilers versus conventional alternatives
  - Tier 1 revenues are not for capital costs and Tier 2 for operational costs, it is the level of overall revenue stream that is important and how long it will be provided for.
  - How different factors will be evaluated will likely differ between different potential installers (for instance, in terms of their relative ability to access finance).

- **All other things remaining equal, tiering provides a greater incentive to produce up to the Tier 1 / 2 threshold and a lower incentive to produce above it:**
  - Tiering relates to production within a given year
  - The extent of the relative incentives will depend on the differential between Tier 1 and Tier 2 levels
  - In a two tier system, with lower loads the level of the Tier 1 tariff will be the dominant driver of revenue, this influence will be steadily diluted the higher the level of load.
  - For a given load level, if the same amount of subsidy revenue was to be provided – and therefore the same degree of incentive – a reduction in a Tier 2 tariff would require an increase in the Tier 1 tariff. Thus, if NI had had a Tier 2 tariff, the Tier 1 tariff would have needed to be higher to create the same annual incentive.
  - In the GB scheme the initial tiers were set at 15% load factors for small < 200Kw and medium biomass, there was no tier for large > 200Kw (ie tiering was not a part of all schemes)
  - The 15% load factor was set at what was seen as being the likely output [check precise wording].
  - The larger the boiler the higher the potential load factors in terms of ability to generate heat. Assuming operations of five days per week, 52 weeks per year, a <u>15% load factor</u> would be equivalent to:
    - A 50kW boiler operating for [c.11] hours per day at an assumed 85% efficiency (the NI reference boiler in CEPA 2012)

    - A 99kw boiler operating for [c.5] hours per day at an assumed 93% efficiency (the NI boiler that turned out to be the most common NI installation)
    - A 199kw boiler for [c2.9] per day at an assumed 93% efficiency (the GB boiler that turned out to be the most common GB installation)

  - With the introduction of a **single[12] biomass size band in GB from 2016[13]**:

    - The load factor is being increased to 35% - **greater** than anticipated actual loads (ie for most installations GB is moving away from tiering, although it will still impact the very highest loads)
    - The new Tier 2 tariff will be **higher** than those prevailing for small and medium bands (which have previously being reduced by degression, which is now the key driver of tariff levels)

- **Banding, tariffs and tiering can singularly and collectively interact to create perverse incentives. In GB:**

  - There has been some evidence that banding, in some instances combined with the **15%** threshold, has potentially led to:

    - the installing of multiple small systems instead of a single larger system

    - the oversizing of installations to maximise Tier 1 payments (the majority of installations clustering around 199kW)

    - the over –production of heat (smaller biomass installations having an average load factor of 15.22%)

  - Creating a single tariff band, together with a higher **35%** Tier 1 threshold is now seen as reducing the opportunity for gaming the system.

- **If someone deliberately wants to breach the scheme rules by generating heat predominantly just to receive subsidy payments, the constraints they would face would be:**

  - The chances of being caught and any associated sanctions

  - The scale of boiler – less potential with smaller boilers

  - The extent of the benefits of doing so – the incremental subsidy receipts – being above the incremental costs of doing so and the extent of this to make it worthwhile:

    - The **incremental costs** of heat production include and volume driven costs such as fuel costs, any variable costs such as labour, increased maintenance, shortened equipment life plus any non-financial cost such as increased hassle factors.

[12] In GB the higher tariffs for small and medium biomass are seen as offering poorer value for money in subsidy terms compared to large biomass
[13] Note that the original CEPA 2011 proposal was for a single band above 45kW, given the limited number of <kW installations this effectively brings GB more into line with what was initially proposed for NI.

- Fuel costs may be specific to the installation; some activities will be able to access cheaper of free biomass (eg forestry and perhaps some construction and farming activities) – ie this is not always just the cost of wood pellets

- The greater the gap between revenues and costs the greater the benefit in cheating – this can alter over time depending on how tariff levels interact with costs.