Making a positive difference for energy consumers

Modification proposal:	**Connection and Use of System Code (CUSC): Allow suppliers submitted forecast demand to be export (CMP209 and CMP210)**		
Decision:	The Authority directs that CMP209 and CMP210 not be made[1]		
Target audience:	National Grid Electricity Transmission plc (NGET), all transmission system users, parties to the CUSC and all other interested parties		
Date of publication:	12 June 2013	Implementation Date:	N/A

Background to the modification proposals

Under the current Transmission Network Use of System (TNUoS) charging methodology ("the Methodology"), generation TNUoS charges are levied on:

- generators with a Bilateral Connection Agreement (BCA) with National Grid Electricity Transmission plc (NGET) in its role as System Operator (SO), and
- licensable[2] generators that have a Bilateral Embedded Generation Agreement (BEGA) with NGET[3].

All other generators are not liable for generation TNUoS charges.

The output of generators below a threshold of 100MW is treated as negative demand from a TNUoS charging perspective. This means that the output is liable for a credit equal to the demand TNUoS tariff[4]. Generators avoiding the generation TNUoS charge and receiving the demand TNUoS credit are known as receiving TNUoS "embedded benefits"[5].

Currently, demand TNUoS charges apply to electricity suppliers[6] based on their local demand liabilities measured at Triad[7]. Suppliers' demand TNUoS charges are based on demand forecasts they provide to NGET (as SO) in advance of Triad. The forecasts provided by each supplier are on a "net" basis, reflecting the ability of suppliers to act on behalf of embedded generators under 100MW. The output of such embedded generators is included in the supplier's forecast as negative demand thus reducing the level of demand TNUoS charges for which the supplier is liable. These charges are then adjusted to reflect actual net demand - this occurs after NGET has undertaken a reconciliation exercise using measurements of the metered volumes at each Balancing Mechanism Unit (BMU).

The CUSC currently prevents a supplier's forecast demand from being below zero for any BMU.

Under the current charging rules, where net demand is positive a supplier will receive the embedded benefit in the form of lower monthly TNUoS invoices from NGET. An embedded generator may receive a proportion of this TNUoS embedded benefit via a contractual arrangement with a supplier[8]. Where a supplier's net BMU demand is negative, it will not receive payment for the embedded benefits in the monthly TNUoS invoices from NGET (because

[1] This document is notice of the reasons for this decision pursuant to section 49A of the Electricity Act 1989.
[2] More information on exemptions from licences is available on the Department of Energy and Climate Change website: https://www.gov.uk/electricity-licence-exemptions
[3] This option of entering into a BEGA with NGET is also open to, but not mandatory for, licence-exempt embedded generators under 100MW in size.
[4] The historic charging assumption is that such generators will be embedded and any output will be used to meet local demand and offset the need for generation directly connected to the transmission system to transport power to meet this demand. Based on this assumption, the reduced power flow would lead to a reduced level of transmission investment which would otherwise be required for demand.
[5] The ability to secure these benefits depends on a combination of the CUSC arrangements and the trading options adopted by the embedded generator under the Balancing and Settlement Code.
[6] Demand TNUoS charges are levied on three categories of user: (i) the Lead Party of a Supplier Balancing Mechanism Unit; (ii) Power Stations with a BCA with NGET; (iii) Parties with a BEGA with NGET.
[7] The Triad describes the three settlement periods of highest system demand within a Financial Year. More detail on the structure of demand TNUoS charges is available in section 14.17 of the Methodology Statement.
[8] Depending on its meter registration, the output of an embedded generator would either contract with a supplier and have its output deducted from a supplier's demand requirements and reduce a supplier's TNUoS charge, or an embedded generator can contract directly with NGET to receive the demand TNUoS tariff credits.

it cannot submit monthly forecasts below zero). Instead such suppliers will receive payment at the annual reconciliation. This process takes place around June each year, approximately three months after the end of the charging year.

The increase in embedded generation over the last decade has increased the likelihood of some suppliers having more export than import at a BMU (ie net demand is negative) and the potential for suppliers to receive a TNUoS embedded benefit payment.

The modification proposal

Opus Energy (the proposer) raised CMP209 and CMP210 (jointly "CMP209/210") in April 2012, with the aim of improving competition in the supply of electricity and the cost reflectivity of charges. CMP209 proposes changes to the Methodology and is assessed against the relevant objectives. The changes proposed under CMP209 relate to suppliers' forecasts of net demand and allow supplier's net forecast to be below zero for any BMU at Triad (ie negative forecasts submitted to NGET). CMP210 proposes changes to the wider elements of the CUSC and is assessed against the applicable objectives. The changes proposed under CMP210 relate to the financial security that suppliers are required to provide to mitigate the risk of default.

Under the changes proposed by CMP209, suppliers would be allowed to submit a negative demand forecast for the charging year in respect of half hourly metered distribution connected customers[9]. This would allow suppliers with negative net demand (or in some cases embedded generators[10]) to receive payments on a monthly basis within that charging year under the TNUoS arrangements applied by NGET rather than wait to have the money credited back. Monthly payments would be made by NGET based on the forecast net demand provided by the supplier until actual net demand is confirmed at reconciliation.

The key features of the CMP209 original proposal are set out below.

- Existing and new suppliers would submit forecasts of half hourly demand based on gross information of demand and generation from which net demand would be calculated (currently, only net forecast demand information is submitted).
- Existing and new suppliers would submit their forecasts for half hourly demand as a split of demand due to conventional and intermittent generation.
- Existing and new suppliers would submit a breakdown of the capacity of generation embedded within a Supplier BMU for export half hourly demand due to conventional and intermittent generation.
- To assist NGET in validating the intermittent portion of a demand forecast (to derive a forecast to be used in determining whether a User's forecast is reasonable), the forecast would be subject to the application of an additional cap based on historical Triad transmission output information[11]. The conventional portion of a forecast would be validated through examination of historical gross metering data.

[9] The Workgroup decided not to progress similar changes in respect of Non Half Hourly metered customers as it considered that net negative forecasts were unlikely to occur for these customers.
[10] See footnote 5.
[11] This would introduce a cap based on a load factor applied to the submitted capacity. This load factor will be derived from an average load factor of onshore transmission connected windfarms for the previous three Triad periods. It was considered that transmission connected generation provides a suitable proxy in the absence of relevant information on embedded generation as it is often more likely to output during the winter peak period than embedded intermittent.

- Any interest on overpayment (ie where the net negative forecast submitted by a supplier is discovered to be too high at reconciliation) is paid by the supplier at the time of reconciliation.[12]

CMP210 seeks to mitigate the risk associated with paying suppliers in advance of the annual reconciliation, by extending the security arrangements which currently apply to suppliers with a positive net demand to cover suppliers with a negative net demand.

The CUSC Workgroup assessing CMP209/210 also developed an alternative solution (WACM1) under CMP209. Under WACM1, forecasts provided by each supplier would continue to be on a net basis (and not based on gross information of demand and generation from which net demand would be calculated). The changes in respect of security requirements under CMP210 are the same for the CMP209 original proposal and WACM1.

The proposed implementation date for CMP209/210 is 1 April 2014.

CUSC Panel recommendation

The Panel voted on CMP209/210 at its meeting on 30 November 2012. The majority of Panel members voted that the original proposal best meets the relevant objectives and the applicable objectives compared to WACM1 and the CUSC baseline, and so should be implemented. The Panel was equally split on whether WACM1 better meets the relevant objectives and the applicable objectives compared to the CUSC baseline. The full views of Panel members appear in the Final Modification Report ("the Report").

Further consultation

On 12 March 2013, we published a minded-to consultation[13] (our "March consultation") setting out our preliminary view, and seeking further information on the proposed changes. Our preliminary view, based on our initial assessment of the available evidence, was that neither the original proposal nor WACM1 better meet the relevant objectives or the applicable objectives as compared to the CUSC baseline.

Of the seven responses received, four were in favour of our preliminary position and three were against. A summary of the responses is set out in Appendix 1 and the responses are published in full on our website[14]. Our views in respect of the evidence and arguments raised by respondents are set out in the following sections and in Appendix 1.

The Authority's decision

We have considered the issues raised by CMP209 and CMP210 as set out in the Report. We have considered and taken into account the responses to the Code Administrator consultation, which are attached to the Report, and the responses to our March consultation. We have not changed our views as set out in our preliminary assessment. We have concluded that:

- on balance the original proposal and WACM1 under CMP209 would not better achieve the relevant objectives; and
- CMP210 would not better achieve the applicable objectives.

[12] This is consistent with the current arrangements for underpayment (ie where the net positive forecast submitted by a supplier is discovered to be too low at reconciliation).
[13] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=129&refer=Licensing/ElecCodes/CUSC/Ias
[14] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=129&refer=Licensing/ElecCodes/CUSC/Ias

The Authority has concluded that implementation of the modification proposal will not better facilitate the achievement of the applicable objectives of the CUSC[15]. We will not therefore direct this modification be made.

Reasons for our decision (CMP209)

In our March consultation, we published our preliminary view that the original proposal and WACM1 have the potential to better achieve relevant objectives (a) and (b) (ie improvements to competition and cost reflectivity respectively) but have a negative impact in respect of relevant objective (c) (which relates to taking account of developments in the transmission business). We noted that the benefits were not quantified but appeared to be quite small and, in the case of the original proposal, were not demonstrated to outweigh the risk of any changes being temporary and leading to wasted work and resource. In the case of WACM1, we considered that the benefits were outweighed by risk associated with the increased volatility of negative demand in a BMU (versus positive demand in a BMU) and the resulting reduction in forecasting accuracy. This view has not been changed by the responses to our consultation.

We set out below our assessment of CMP209 against each of the relevant objectives.

Objective (a) 'that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity'

Under the current TNUoS arrangements applied by NGET (in its role as SO), suppliers with positive net demand make monthly payments to NGET across the relevant charging year. These charges are then adjusted to reflect suppliers actual net demand position at Triad, ie suppliers receive an invoice after reconciliation in the following charging year for a demand TNUoS payment (where their net positive forecast was too low) or receive a demand TNUoS credit (where their net positive forecast was too high)[16]. Suppliers with an actual negative net demand position at Triad currently receive a payment from NGET after reconciliation in the following charging year. Our view is that this approach gives positive net demand suppliers a slight advantage over negative net suppliers in terms of the relative timing of payments from NGET to suppliers with negative net demand and from suppliers with positive net demand to NGET. This could have a negative impact on competition.

In our view, both the original proposal and WACM1 would provide a more equal environment by ensuring a supplier's net forecast (negative or positive) for any BMU at Triad will be subject to monthly charges and payments from NGET throughout the relevant charging year and then adjusted to reflect suppliers' actual net demand position at Triad (confirmed by NGET at reconciliation). We consider that this would be expected to marginally improve competition in the supply of electricity relative to the baseline.

Some respondents to our March consultation highlighted that cash flow is a significant issue for electricity suppliers, and consider that this is particularly so for smaller suppliers. Consequently, they considered that the impact of both proposals on competition in the supply of electricity will be greater than marginal. However, we do not consider that evidence has been provided to demonstrate this and therefore our view remains that the positive impact of the proposals on competition in supply is more marginal (taking into account the low prevalence of suppliers with negative net demand).

[15] As set out in Standard Condition C10(1) of NGET's Transmission Licence, see: http://epr.ofgem.gov.uk/document_fetch.php?documentid=5327

[16] Embedded generators that have chosen to contract directly with NGET to receive the demand TNUoS tariff credits will receive this benefit in the monthly TNUoS invoices they receive from NGET.

We note the opinion of NGET and some suppliers that if either the original proposal or WACM1 were implemented then embedded generation (not directly subject to the Methodology) would expect to receive payments in respect of their net demand in advance of Triad. They consider that this would expose all suppliers to the risk of inaccurate forecasts from generators, that smaller suppliers would find it more difficult to bear that risk and that this could have a negative impact on competition. In our view, the timing of payments from suppliers to embedded generation is a commercial matter for suppliers and generators to decide taking into the account the relevant costs and risks.

Some industry parties considered that both the original proposal and WACM1 would exacerbate a perceived advantage of embedded generation over transmission connected generation under the current TNUoS charging arrangements. They therefore considered the proposals would have a negative impact on competition in the generation of electricity. We understand that this perceived advantage is in respect of the value of TNUoS embedded benefit payments received from NGET under the transmission charging rules. In our view, this modification seeks to address the timing of TNUoS embedded benefit payments to electricity suppliers with negative net demand (or in some cases embedded generators[17]), and not the value of any payments. We also note that this issue was not fully investigated by the Workgroup, and that responses to our consultation provided no new arguments or evidence in this respect.

Overall, we consider that both the original proposal and WACM1 have the potential to better achieve this objective relative to the baseline but that the impacts do not appear to be significant (and robust evidence has not been provided to demonstrate that the impact is significant).

Objective (b) 'that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection)'

The original proposal and WACM1 will affect the timing of payments to suppliers with a negative net demand. This may have a small positive impact on the cost reflectivity of these payments relative to the baseline. This is because TNUoS charges (and credits) will match more closely the time at which the costs (or benefits) are incurred rather than being delayed until the following charging year. However, based on the analysis and information available in the Report, our view is that the improvement in cost reflectivity is unlikely to have a significant impact.

We therefore consider that both original proposal and WACM1 have the potential to only marginally better achieve this objective relative to the baseline.

Objective (c) 'that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses'

We note that the suppliers with negative net demand are a relatively new (and growing) feature of the GB electricity market, resulting from an increase in embedded generation over the last decade. We also understand that the rule prohibiting negative net forecasts was introduced at a time when suppliers with negative net demands were considered extremely rare.

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[17] See footnotes 5 and 10.

We see this as a development in the licensees' transmission businesses and consider that normally the original proposal and WACM1 could be seen to properly take account of this development. However, we are also aware that, following our decision to extend the expiry date of standard licence condition C13 ('Adjustment to use of system charges (small generators)')[18], NGET has committed to conduct a comprehensive review into the appropriate treatment of embedded generation from a transmission charging perspective during 2013[19]. To facilitate this review, NGET has recently established an informal working group to assist and provide expert advice[20].

The outcome of this review may result in the changes being required to NGET's systems and forecasting processes in order to implement a new potential set of arrangements. This could mean that any changes implemented following the implementation of the CMP209 original proposal or WACM1 could become obsolete within two years of implementation (ie if implemented in April 2014[21], the changes may be made obsolete in April 2016). As set out in our March consultation, our preliminary view was that this risk of wasted work to implement the original proposal resource outweighed the potential benefits discussed under objectives (a) and (b) above.

Responses to our consultation have confirmed that there would be significant costs triggered by implementing the original proposal. NGET estimates that its systems costs alone would be between £200,000 and £500,000 (subject to a full scoping exercise). There would also be systems costs for some suppliers and some costs associated with a consequential Balancing and Settlement Code (BSC) modification. Although some respondents query how great the risk of wasted work is, we consider that it is clear from the scope of the review there is a real risk that changes to implement the original proposal could become obsolete. Given the above, our view in respect of the original proposal remains that the potential benefits in terms of improved competition and cost reflectivity are outweighed by the risk and cost of wasted work.

As set out in our March consultation, our preliminary view was that forecasts of negative demand are considerably more volatile than those of positive demand, and therefore carry with them a greater risk of inaccuracy. This is particularly so for generation such as wind. The risk associated with inaccurate forecasting can be mitigated to some degree by requiring suppliers to submit detailed forecasts of gross demand and gross generation, as proposed under the original proposal. We consider that this risk would not be appropriately mitigated under WACM1 which only requires net forecast. Consequently, we do not consider that WACM1 properly takes account of developments in the Transmission Owners (TOs)' businesses discussed in this section. This view has not been changed by the responses to our consultation.

In our view, there is no strong case that real quantifiable benefits will arise from implementing the original or WACM1 solution and, therefore, the proposals do not better achieve this objective and do not improve on the baseline.

Reasons for our decision (CMP210)

As discussed above, CMP210 would extend security arrangements in place for suppliers with a positive net demand to cover suppliers with a negative net demand, under both the original proposal and WACM1. In our March consultation, our preliminary view was that, as we expected to reject both proposals under CMP209, CMP210 would have no impact and would be

[18] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=211&refer=Licensing/Work/Notices/ModNotice

[19] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/Charging/Documents1/NGET%20letter%20relating%20to%20the%20review%20of%20C13_5-3-12.PDF

[20] With the aim of seeking a decision from us on enduring charging arrangements in 2014 and implementing arrangements, if approved, from April 2016 at the latest. Information relating to this review is available on NGET's website: http://www.nationalgrid.com/uk/Electricity/Charges/Review-of-Embedded+Distributed-Generation-Benefit/

[21] NGET advised that changes to its IS systems would require in the region of 6-9 months minimum to capture changes required as a result of implementation of the original proposal.

neutral against all the applicable objectives. This view has not been changed by the responses to our consultation.

If CMP209 were to be rejected for the reasons discussed above, suppliers would not be able to submit negative demand forecasts. Consequently, CMP210 would have no effect and would be neutral in respect of all the applicable objectives.

Assessment against our principal objective and statutory duties

Our principal objective and statutory duties are to protect the interests of existing and future consumers. As discussed above, we consider that potential benefits in respect of cost reflectivity and competition in the supply of electricity are small under the original proposals for CMP209 and CMP210 and are outweighed by the probability that work to implement this modification would become obsolete after NGET's review of the treatment of embedded generation. We do not consider that resource implications of implementing the original proposal are commensurate with this risk. Ensuring that we and industry use our resources efficiently is an important element of protecting current and future customers. Therefore, we consider that rejecting the original proposals under CMP209 and CMP210 is consistent with our statutory duties.

Responses to our consultation also confirmed that changes to NGET's systems under WACM1 could be subsumed within ongoing changes. We also note that consultation responses from suppliers indicate that any costs to them would be small. This means that the implementation of WACM1 under CMP209 has the potential to marginally improve competition in the supply of electricity at a reasonable level of implementation cost. However, we note that WACM 1 (and the original proposal) would introduce a risk to NGET (and consumers) relative to the current baseline. The risk of facilitating the payment of suppliers with negative net demand in advance of Triad (ie in advance of them providing the benefit to the system) is that if such a supplier were to go out of business before they provide this benefit, or even before they are exposed to the actual demand after reconciliation, then NGET would have to recover the monies paid out from the remaining TNUoS parties.

Furthermore, we note that forecasts of negative demand are considerably more volatile than those of positive demand, carry with them a greater risk of inaccuracy and therefore require more credit to be provided by NGET relative to the current baseline. We consider that the ability of NGET to validate negative demand forecasts is not adequately addressed under the WACM1 arrangements, eg NGET has indicated that it has no ability to reject a forecast that they feel is unreasonable. We do not consider that evidence has been provided to demonstrate that the measures contained within the Methodology under WACM1 provide an appropriate means for mitigating the incentive created to over-forecast negative demand or the potential exposure of industry and consumers to this increased level of risk. We consider that the potential benefits in respect of cost reflectivity and competition in the supply of electricity are small under WACM1 and are outweighed by the additional risk of prejudice to industry and consumers of supplier default and inaccurate forecasting.

Therefore, we consider that rejecting WACM1 under CMP209 is consistent with our statutory duties.

Kersti Berge

Partner, Transmission
Signed on behalf of the Authority and authorised for that purpose

Appendix one – summary of responses

We received seven responses in total, including four from small suppliers. Four respondents agreed with our preliminary view that we should reject CMP209 and CMP210, and three disagreed. The small suppliers were split with two in favour of the proposals and two against. NGET is not in favour of the proposals.

This appendix gives a short summary of our understanding of the responses and our views where appropriate. The full responses are available on our website[22].

Cost of implementing the original proposal

Two respondents provided estimates of the costs to change their respective IT systems if the original proposal was implemented: NGET, £500,000; Good Energy £10,000 - £30,000 plus annual upkeep of £1,000 - £2,000. Green Energy does not consider there will be any additional IT systems costs for suppliers.

Three respondents provided estimates of the costs to them associated with a consequential BSC modification: NGET, £108,000 - £135,000; Good Energy £76,000, and Green Energy £11,200.

Scottish and Southern Energy plc (SSE) noted that a consequential BSC modification would require them to make changes to their system, but were unable to estimate the cost of the change. NGET also stated that the costs of implementing WACM1 could be subsumed within ongoing systems changes.

Our view: We consider that, overall, these responses demonstrate support the view that there would be a material cost to implementing the original proposal in respect of IT systems changes and a consequential BSC code modification. We note Green Energy's view that there will be no additional IT systems costs is contradicted by responses from other suppliers, and also that its estimate of the BSC costs does not include the estimated costs of implementing a modification.

Competition

Green Energy, Opus Energy and Cornwall Energy consider that the current arrangements provide a significant competitive advantage to suppliers with a positive net demand. In their view this particularly affects small suppliers who are more likely to have negative net demand, and is thus a barrier to new entrants to the market. Green Energy noted that its payments in respect of net demand totalled 1.5% of turnover. Opus Energy noted that the value of its embedded benefits portfolio is in the region of £1million.

SSE agreed with our provisional view that any competitive advantage for suppliers with a positive net demand would be slight.

Opus Energy and Cornwall Energy also disagreed with NGET's view that embedded generation do not receive payments until reconciliation. Opus Energy notes that it offers products under which the embedded generators receive monthly payments.

Smartest Energy, Good Energy, SSE and NGET consider that both proposals under CMP209/10 would have a negative impact on competition in the supply of electricity. They consider that implementing CMP209/10 would create an expectation that embedded generators would be paid on a monthly basis. They note that this would place risk of inaccurate forecasts of suppliers and that it would be harder for smaller suppliers to bear this risk.

[22] http://www.ofgem.gov.uk/Licensing/ElecCodes/CUSC/Ias/Documents1/CMP209-10%20consultation%20letter.pdf

NGET also considers that implementing CMP209/10 may exacerbate a perceived advantage that the current arrangements provide to embedded generation over transmission connected generation.

Our view: Our view remains that the impact on the competition in the supply of electricity will be small. However, we also acknowledge that there may be a 'knock on' effect in respect of competition in the generation of electricity, but we consider that this will also be slight.

As discussed above and in our preliminary assessment, we do not consider that the timing of payments between suppliers and generators is relevant to our assessment of the impact on competition in the supply or generation of electricity.

Potential for work to implement the original proposal to be wasted

SSE, NGET and Good Energy consider that there is a real risk of any changes to the BSC and related systems changes becoming obsolete. NGET highlights that the review may result in substantial changes to the regulatory treatment of embedded generation.

A number of respondents consider that the outcome of NGET's review of the arrangements is likely to be in place for 2016, and query the likelihood that work to implement the original proposal would be wasted.

Our view: Our view remains that there is a real risk that work to implement the original proposal would become obsolete. We agree with NGET that there could be changes to the treatment of embedded generation, and consider that there is a clear risk that associated changes to IT systems and the BSC may not be in line with the changes required to implement the original proposal.

Forecasting accuracy

Opus Energy disagree that NGET will be better able to assess the accuracy of gross positive and negative forecast than net forecasts. Cornwall Energy considers that NGET will need to further process gross forecasts in order to improve accuracy in comparison to net forecasts. Both Opus Energy and Cornwall Energy also note that volatility of negative demand impacts on net forecasts regardless of whether they are positive or negative.

Our view: Our view remains that NGET is better able to assess the accuracy of gross forecast as it will have more information to inform its assessment. However, we agree that the volatility of negative demand impacts on both positive and negative net demand.

NGET does not consider it would be feasible to make the system changes required for the original proposal in time for implementation on 1 April 2014. In its view, implementation would not be feasible until 1 April 2015.