SCOTTISHPOWER

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Director of Regulation

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Dear Jonathan,

BALANCING AND SETTLEMENT CODE MODIFICATION PROPOSAL – P272 – DRAFT IMPACT ASSESSMENT

Thank you for the opportunity to respond to the draft impact assessment on BSC Modification Proposal 272 (P272). Our answers to the consultation questions are provided in Annex 1 attached.

The BSC Panel's decision to reject the P272 proposal was based on a finely balanced cost-benefit assessment and Ofgem's revised impact assessment is no more conclusive. Ofgem's Monte-Carlo analysis gives a spread in possible NPV values from -£36m to +£47m, with an average NPV close to neutral (£0.42m). Ofgem invokes wider but unquantified benefits (such as greater efficiency across the market from stronger competition) to justify approving the proposal.

We agree that half hourly settlement is the way forward in the long term, and we support the principle behind P272. However we do not believe that it is in the interests of consumers to proceed with the modification on a timescale or manner that incurs inefficient costs, and have a number of concerns about the way in Ofgem has arrived at its current 'minded to' position:

a) We think the modelling assumptions over-estimate the benefits and under-estimate the costs, such that the average NPV is likely to be negative (see our responses to Questions 2, 4, 6, 8 and 11).

b) We do not think Ofgem has adequately taken into account the costs and timescales associated with other activities that would be necessitated by P272 (such as making necessary changes to the Change of Measurement Class (CoMC) process, DUoS validation, billing processes, collection, validation and aggregation of HH consumption data and annual HHDC site visits). IT timescales and costs are already under some pressure because of the existing backlog of initiatives.

c) As it is obliged to do under the code modification process, Ofgem has considered only the two start dates proposed to the BSC Panel, 1 April 2014 and 2015. This is a weakness as we think that alternative start dates such as 1 April 2016 (or even 1 April 2017) could significantly improve the cost benefit case and reduce the risks to the accuracy of the settlements process from adopting more aggressive timescales.

We are also strongly of the opinion that a thorough review of the Change of Measurement Class (CoMC) process will need to be carried out – and any necessary changes made – before P272 is implemented, so that the profile 5-8 customers can be efficiently migrated to half hourly settlement.

This work on CoMC will include, *inter alia*, implementing some or all of the recommendations arising from BSC Issue 46 (NHH Interoperability). Given the scale of change required for this process and the indicative timescales outlined at the last Issue 46 Group meeting, there is a risk that the required changes will not be in place for the proposed March 2015 implementation date. If P272 is implemented before these changes are in place and the PC 5-8 portfolio is moved to HH settlement via the current CoMC process, there will be a risk of a drop in settlement accuracy. We therefore think it would be unwise to attempt to implement P272 before 1 April 2015. Given the additional need to consider timescales for implementation of DCUSA-related change proposals, we think an implementation date of 1 April 2016 or later would be more prudent.

We therefore believe it would be more appropriate to remit the proposal back to the BSC Panel for a more comprehensive assessment of the implementation issues and associated costs, inviting it to consider alternative start dates as suggested above. We note that the BSC arrangements allow for the Authority to remit a 'Pending Modification Proposal' back to the BSC Panel to reconsider a proposed implementation date in the light of issues such as those we have highlighted[1], and it is our view that delaying implementation of P272 to 1 April 2016 or possibly later would better meet the Relevant BSC Objectives. At the same time, the BSC Panel should be invited to consider the various issues with the modelling approach raised in this response.

Should you wish to discuss any of the above points, please contact me via the details provided or contact Lorna Mallon (lorna.mallon@scottishpower.com).

Yours sincerely,

Rupert Steele

Rupert Steele
Director of Regulation

[1] BSC Section F - 2.7A Send Back Process: '2.7A.1 Where the Authority considers that it is unable to form an opinion in relation to a Modification Report submitted to it pursuant to paragraph 2.7.6 then it may issue a direction to the Panel: (a) specifying any additional steps that it requires in order to form such an opinion including drafting or amending the proposed text to modify the Code, revising the implementation timetable and/or proposed Implementation Date(s), revising or providing additional analysis and/or information; and (b) requiring such Modification Report to be revised and re-submitted to the Authority, and the Authority may include in such direction its reasons for why it has been unable to form an opinion (a "Send Back Direction")'

Annex 1

REVIEW OF OFGEM'S IMPACT ASSESSMENT GUIDANCE – SCOTTISH POWER RESPONSE

Q1. Do you agree with our approach to assessing the impacts of P272?

ScottishPower is concerned at the lack of quantitative data introduced to support the conclusions reached by the impact assessment. As a result, we must reiterate our response to P272, that the detailed analysis provided by the Mod Group yields such a wide variation of costs and benefits that we are unable properly to assess the merits or otherwise of the proposals.

Given the wide spread in NPV values generated by Ofgem's Monte-Carlo analysis (from -£36m to +£47m), the relatively small average NPV (£0.42m), and the reliance on load shifting to deliver around 44% of the estimated benefits, it might have been helpful to include some analysis to demonstrate how half-hourly (HH) customers respond to the mechanisms in place at present to encourage load shifting (ie via the Red/Amber/Green DUoS pricing signals).

In our view, this would provide a good indication of how likely PC 5-8 customers are to respond to tariffs designed to encourage demand side response (DSR). We also believe it would be beneficial if PC 5-8 consumers were to be asked directly for their opinions on P272, and on their willingness and capability to load shift, before any decisions are made regards implementation. Our own analysis of customer consumption patterns following introduction of DUoS price signals shows no evidence of load shifting behaviour in response (see our response to Question 4 below.)

Q2. Are there any additional, material impacts that we should consider?

There are a number of issues we believe must be resolved prior to implementing P272, but which do not appear to have been considered in the approach or the cost calculations within the consultation:

A thorough review and changes to the Change of Measurement Class (CoMC) process is essential prior to the implementation of P272. This includes:

- The mechanism for identifying sites which qualify for HH metering. This is currently set as a maximum demand threshold, whereby a simple check of the maximum demand register identifies whether a site belongs in the NHH or HH arrangements. However, once all PC 5-8 customers are settled HH, a new threshold for PC 3-4 (or 1-2?) will probably need to be established and this will also need to be simple and easy to understand;

- Supplier charges and the Performance Assurance and Monitoring System (PARMS) submissions in relation to CoMC;

- The potential creation of alternative Measurement Classes (as a result of the rejection of P280);

- Implementation of some or all of the recommendations arising from BSC Issue 46 (NHH Interoperability). Given the scale of change required for this process alone and the indicative timelines for change outlined at the last Issue 46 Group meeting (Nov 2014), there is an obvious risk that these required changes will not be in place for the 2015 implementation date.

Should P272 be implemented, the increase in HH metered sites may require a change to the governance and processes of the Technical Assurance (TA) of metering systems. This could result in an increased number of TA visits being required and an increase in associated costs to the entire HH market.

The Group Correction Factor (GCF) scaling weights will have to be reviewed and changes made in preparation for the increase in HH sites and the consequential decrease in NHH sites. If this is not addressed prior to the implementation of P272, the remaining NHH market could be adversely impacted by GCF adjustments as a result of inaccurate weightings being assigned to NHH profiling errors and HH metering errors. This will have a direct impact on consumers who remain in the NHH market.

In deciding whether to implement P272, consideration should be given to why so few PC 5-8 customers have so far elected to have HH metering. It would certainly seem, from a customer's perspective, that the current incentives to move to HH are insufficient. Whilst issues with DUoS charging have been recognised by Ofgem, it should be noted that customers may also face additional charges due to the differences been NHH and HH metering costs. For example, the costs to serve a traditional NHH customer for data retrieval (including MOP and MAP costs) are around 3 times less than for a HH customer (less than £20 per month for a NHH customer compared to around £60 per month for a HH customer). Further work needs to be done to understand how the impact on customers can be minimised if this Modification is to be implemented.

Another area to consider is how P272 fits in with the DCC and whether a better solution might be to look at the migration of all sites capable of being remotely read to the HH arrangements. There also needs to be some consideration of the impact on Group customers who have sites in both PC 5-8 and PC 3-4, as the proposed approach might impact on Group Billing arrangements and confuse customers with a mix of HH and NHH sites. Finally, given that smart meters have already been rolled out in many other countries (eg USA and Canada) we would have expected some evidence to be introduced here that might help to demonstrate real costs savings as a result of moving to HH settled.

Scottish Power welcomes Ofgem's comments on the introduction of a DCUSA Modification that would create new half-hourly tariffs for consumers in Profile Classes 5-8. This clearly needs to be progressed in a timely manner; however, we believe that Ofgem needs to gain assurances from DNOs that the actual level of charging will remain broadly the same.

We have included our response to the BSC consultation on P272 costs (July 2012) to highlight the financial impact on ScottishPower. We now believe these figures to be a conservative estimate and that the true impact will be higher.

Q3. **Do you agree that P272 would drive suppliers to encourage DSR among their customers?**

Exposing customers to price signals via ToU tariffs is likely to be the most effective way of encouraging DSR. We think it is likely that P272 would cause some suppliers to introduce time of use (ToU) tariffs for their PC 5-8 customers in order to minimise commercial risk if consumption patterns (and resulting wholesale costs) turned out to be different from those assumed in setting a non-ToU tariff.

However, suppliers face significant barriers to introducing ToU charges, not least customer preference for simpler tariffs (see our response to Q4) and the additional costs of developing and implementing ToU tariffs (eg new billing systems). We therefore think some suppliers will prefer to bear the commercial risk – or simply charge different customers different non-ToU tariffs which reflect the average cost of each customer's consumption profile.

If suppliers are charging ToU prices which are fully reflective of time varying costs, there is no particular economic incentive for them to encourage customers to shift their consumption pattern, unless as part of a strategy to improve customer loyalty and retention. It is possible that DSR may focus on specific niches, ie for types of business which have greater flexibility to load shift than others.

Q4. **Do you agree with our approach for quantifying the value of load shifting and load reduction, including the assumptions we made? Is there any evidence we have not identified that could inform our analysis?**

No, we do not believe that Ofgem provides sufficient justification for the assumptions it uses to quantify the value of load shifting and load reduction.

Load reduction

Ofgem assumes that around 0.4% of PC 5-8 consumption at system peak is reduced outright, equivalent to approximately 11GWh per annum. Assuming typical I&C energy costs (circa 7.7p/kWh in 2015), this gives an annual benefit of £0.85m, with an NPV of around £11m over the 20 year modelling period.[2]

We are concerned that this approach to estimating the benefits assumes that businesses that cut back their peak consumption do so costlessly. This would not be the case where, for example:

- A widget manufacturer cuts back on its production at times when the electricity price is at its peak because the marginal cost of making the widgets exceeds their value. In this case, the manufacturer's saving in energy costs is offset by the lost revenue from the widgets it does not produce using that energy.

- A business finds some way of substituting for the peak priced electricity such that it can deliver the same output for less consumption. Again, it is likely that the business would incur costs in doing so, which would offset the reduction in its energy bill.

It is difficult to think of any practical situations where a business would reduce peak consumption costlessly in response to time of use pricing. If the bill could be reduced costlessly under ToU pricing, it could equally well have been reduced without ToU pricing.

For these reasons, we believe that the £11m NPV contribution is no more than a theoretical maximum estimate of the benefit. The actual benefit is likely to be very much smaller.

Load shifting

Ofgem estimates that around 2.5% of peak demand would be shifted to off-peak periods as a result of exposing PC 5-8 customers to time of use pricing. This is based the assumption that around 22% of businesses shift their load in response to the price signal (ramping up over the first 5 years), around 25% of peak load is discretionary (ie capable of being shifted)

[2] Condoc para 4.35 and 'Build_UP' worksheet of Ofgem quantitative model.

and 40% of the discretionary load is actually shifted.[3] This load shifting results in an NPV contribution of £55m over the 20-year modelling period. We have a number of concerns with this estimate:

a) Ofgem appears to be assuming that businesses incur no cost in shifting their load. It is straightforward to think of examples where this would not be the case. For example, suppose a business operates its production line at full capacity throughout the day. With the introduction of ToU pricing it realises it can save money by increasing the capacity so that it can produce more when electricity is cheap and less when it is expensive. This will incur investment costs which must be set against the savings from reduced electricity bills. Of course there may be some instances where businesses are indifferent as to when consumption occurs, and can shift consumption costlessly, but this will not generally be the case. If our understanding of Ofgem's methodology is correct, the £55m is no more than an upper bound on the benefit.

b) Ofgem bases its assumption of 22% of businesses load shifting by 2020 on DECC's impact assessment on the roll-out of smart metering to smaller and medium non-domestic consumers (Profile Classes 3-4). Based on international evidence, DECC assumed a 20 per cent take up of static time-of-use tariffs, rising to 24 per cent by 2030. In using 22% (the midpoint of DECC's range), Ofgem implicitly assumes that no load shifting benefits would have arisen from the 3% of businesses who are assumed to have moved electively by 2019 (0.6% pa for 5 years) – whereas one might expect that these are the types of business who are most likely to load shift. If all the electives load-shifted, the incremental load shifting could be closer to 19% rather than 22%, reducing the NPV of the benefits by up to £8m.

c) Our own experience suggests that the response to ToU pricing may be less than assumed by DECC and Ofgem. Within our portfolio of half-hourly metered customers there is relatively little demand for time of use tariffs; if anything we are seeing an increasing preference for simple non-ToU tariffs. The main exception is pass through of DUoS ToU charges under the Common Distribution Charging Methodology (CDCM), where around half of our portfolio have taken this option. However analysis of consumption trends since April 2010 shows no material change in the proportion consumed in the peak 'Red' period (for which there is a circa 8p/kWh premium); if anything, the proportion consumed at peak has slightly increased. If, as we suggest, Ofgem remits this issue back to the BSC Panel, we would recommend that some additional econometric work is done to assess what can be inferred from existing HH metered business customers' response to DUoS charges.

d) The model does not appear to take account of the effect of increasing renewables penetration. As intermittent generation accounts for an increasing proportion of the GB electricity generation mix, prices in both peak and off-peak periods are likely to become increasingly volatile due to the dynamic impact of intermittent generation on within day prices. This will make the price differential between peak and off-peak periods less predictable and will shift the focus from static load shifting (between fixed peak/off-peak periods) to dynamic load shifting. An even smaller proportion of customers in the Profile Class 5-8 category are likely to be able to engage effectively in dynamic load shifting.

[3] See condoc Appendix 3, page 58. Strictly speaking, the 22%, 25% and 40% figures are the modes of assumed distributions. The average values are 22%, 30% and 38%, which multiply together to give 2.5%.

Conclusion

Taking the above factors together, we think the NPV of load reduction and load shifting benefits could be very much less than Ofgem estimates, possibly by a factor of two. This makes it doubly important this reform is introduced in a way that avoids unnecessary transitional costs.

Q5. **For those impacts stemming from suppliers reducing the costs of supplying energy (for example, by promoting DSR) that we did not quantify, do you have any suggestions on how we might do so?**

The financial impact on suppliers will be diverse and heavily dependent on each individual supplier's customer mix within the PC 5-8 customer category. It will also depend on each supplier's current and future ability to provide price signals and then to accurately forecast how their customers' demand will change as a result of those price signals. Any assessment of the financial impact / benefits would be need to be based on very high level, generic, assumptions that would be unlikely to reflect the true impact on any supplier. We therefore think Ofgem should continue to exclude such effects from its assessment.

Q6. **Do you agree with our approach to quantifying the value of improved forecasting, including the assumptions we made?**

No, we do not agree with Ofgem's approach to quantifying the value of improved forecasting. The 40% increase in demand forecasting accuracy assumed by the workgroup is not substantiated by supporting evidence and seems to us an implausibly high level of improvement.

It is not clear if any adjustment has been made to this assumption to account for the expected increase in the volatility of demand from those PC 5-8 customers who load shift in response to dynamic price signals. Such behaviour will lead to a decrease in the level of forecast accuracy, at least in the short to medium term, which will partially offset the improvement due to the availability of HH metered data.

Q7. **Could the costs of investing in forecasting capability for HH demand impact disproportionately on smaller suppliers or on new entrants?**

We leave it to smaller suppliers to answer this question.

Q8. **Do you agree that we have correctly identified the cost savings that suppliers could realise in managing the settlement process?**

Ofgem has assumed that the costs to suppliers, from appointing HH agents, will fall immediately as the agents begin to recover their own costs from a wider customer base. While we agree that some of the cost savings identified could be achieved, there is no guarantee that agents will reduce their costs immediately as a result of new-found economies of scale. While competition should drive costs down, market forces will take time to deliver the reduction, especially if customers choose to contract their own agents on the standard 3-5 year contracts. For this reason, we would suggest that the benefit associated with reduced agent costs is over-estimated. We think a more thorough analysis should be conducted of the impact of P272 on the NHH and HH Agent market and on whether the assumptions regarding competition are valid, including whether costs could be materially reduced by delaying the start date to take advantage of planned centralisation of data aggregation and data processing under the smart metering implementation programme.

Q9. **Do you agree with our assumption regarding the typical size of data quality teams employed by suppliers?**

No, we employ only a small fraction of that number of staff to look at data quality issues for PC 5-8 customers.

Q10. **Do you agree that meters of consumers in Profile Classes 5-8 are mostly read at the end of each month?**

We try to smooth out the profile of our reading activities throughout the month, to reduce operational spikes. While we endeavour to read such meters on a monthly basis, whether or not they are read at the end of each month depends on a number of factors, including the type of meter deployed. For example, AMRs tend to be read around the 20th of the month, or on the date requested by the customer if it is the customer who has the contract with the Data Retriever.

Q11. **Do you agree with our approach to quantifying the costs of P272 for suppliers and DNOs? If not, we encourage respondents to suggest alternative approaches.**

Supplier costs

We have two concerns about Ofgem's quantification of supplier costs, which we think is likely to understate the costs.

First, the input data for Ofgem's estimates of supplier upfront and ongoing costs was drawn from the P272 Mod Group's previous analysis, which had itself revealed widely divergent opinions of costs and benefits. Given the wide divergence between suppliers and the importance of these costs to the cost benefit case (total £117m NPV), we think more work could have been done to refine and validate this data. In ScottishPower's case, we have provided below a revised estimate of one-off costs, which is significantly higher than previously estimated to BSC. Our estimate of 'Other Costs' now includes provision for increased network data traffic and handling, communications, training and ancillary developments (demand forecasting, product/contracts, marketing and account management). This will use a mixture of internal and external resources.

Second, we think the costing analysis would benefit from greater understanding of how P272 will work in reality. In particular, how the P272 solution impacts on other industry activities such as:

- Upgrading the existing CoMC process to make it fit for purpose (as opposed to operating the CoMC process, which is included in the table above);
- DUoS validation;
- collection;
- validation and aggregation of HH consumption data; and
- annual HHDC site visits (a BSC requirement).

Until these impacts are understood, and more importantly costed, it will not be possible to properly quantify the costs of implementing P272.

DNO costs

From our perspective as a DNO, we would reiterate our concerns regarding the impact of P272 on the DUoS Billing Methodology and Systems. SP Energy Networks' HH portfolio currently consists of 12,000 MPANs, all billed monthly on a site-specific basis, albeit issued via electronic means. The portfolio of SPEN NHH Maximum Demand (MD) tariff customers is circa 16,000. The potential increase of 133% would impact on every area of the DUoS billing process (e.g. Registration, Data Flows, Processing, System Capacity and Performance, Calculation, Invoice Production, Debt Management, Credit Management, Invoice Clearance) as well as the validation routines within all supplier companies. Given that each HH MPAN requires a daily HH flow (D0275 or D0036) to be submitted and received via the existing DTN, utilising gateway interfaces from current applications, a major upgrade of these services is likely, and while application upgrade costs were estimated, there is a likely requirement for IT infrastructure review and development work.

The DUoS Billing process itself could prove to be longer by a factor of circa 2.5, which may impact on recent DCUSA changes whereby Billing Runs are restricted on a "best endeavours" basis (DCUSA Billing Sub-Group). Nonetheless, we believe that the changes could be incorporated within the proposed timeline of April 2015, but not earlier.

In light of the above, we would also refer here to P280 where the Industry Working Group approved a new methodology to allow NHH MD Records to be billed via the existing Supercustomer method (i.e. Aggregated Data but in the case of NHH MD portfolio this would become an aggregation of actual reads) which would have avoided a significant proportion of all the volumetric processing issues yet retained the majority of other benefits in which Ofgem are minded to support. We note that Ofgem overturned the recommendations of the original Mod Group and rejected P280.

Q12. **We welcome evidence from smaller suppliers of larger non-domestic consumers on the costs they could incur if P272 is implemented.**

We leave it to smaller suppliers to answer this question.

Q13. **We welcome information from suppliers on (1) how many consumers would need to move electively for them to incur upfront costs and (2) the costs that would be incurred, broken down by the cost categories listed in this chapter.**

We currently have over x,000 HH customers, but this figure is down from a peak of x,000 last year and we were able to service that volume of customers without stressing the relevant billing infrastructure.

On that basis we would expect to be able to accommodate at least x,000 customers moving electively from our PC 5-8 portfolio to HH settlement without incurring upfront costs (assuming all other factors remained static). This would be equivalent to around 15% of our PC 5-8 portfolio. Ofgem assumes in its modelling that only 0.6% of PC5-8 customers would move electively each year for the next five years. So even if Ofgem has underestimated the number of elective moves, we think it is most unlikely that we would incur upfront costs accommodating elective movers.

Q14. **Would consumers incur costs from termination of contracts with Supplier Agents? If so, we welcome information that could help us to assess these costs.**

There is a real possibility of this, although it depends almost entirely on individual commercial arrangements. Certainly, however, where the customer has a bundled contract with their own preferred agent, we would expect to find that termination clauses apply. Additionally, not all agents operate in the HH market so this may force the customer / supplier to change agent where, for example, the agent has failed to re-qualify in line with the relevant BSC Code Subsidiary Document, perhaps within a requisite timeframe.

Q15. **Do you have any comments on the results of our quantitative analysis?**

Our comments are within the responses above.

Q16. **If P272 is approved, would it be possible to implement the modification in less than fourteen month**

No, we do not believe it would be possible to implement this modification any sooner than April 2015. This is for a number of reasons.

A thorough review of the Change of Measurement Class (CoMC) process will need to be carried out - and any necessary changes made - before P272 is implemented. This will include, *inter alia*, implementing some or all of the recommendations arising from BSC Issue 46 (NHH Interoperability). Given the scale of change required for this process and the indicative timelines outlined at the last Issue 46 Group meeting, there is a risk that the required changes would not be in place for April 2015. If P272 were to be implemented before these changes are in place and the PC 5-8 portfolio is moved to HH settlement via the current CoMC process, there would be a risk of a drop in settlement accuracy. We therefore think it would be unwise to attempt to implement P272 before 1 April 2015.

From a DUoS tariff perspective there are several change proposals that are progressing through DCUSA in relation to 'Voltage Level' tariffs, including DCP 160, DCP 165 and DCP 179. These are being introduced to address identified anomalies within the existing tariff structure that make it beneficial for some customers to be settled either on a half hourly or non-half hourly basis. The new tariffs will be derived on a consistent basis to prevent customers being disadvantaged. There is also a requirement to develop a new tariff structure to reflect the introduction of half hourly metering to all customers through SMART and AMR metering. This new tariff structure will contain HH metered tariffs for all demand tariffs (except unmetered). If P272 were to be implemented before revised tariff structure is in place, currently targeted for 1 April 2015 (but dependant on the DCUSA change process), significant inconsistencies and inefficiencies could arise.

From the perspective of ScottishPower's supply business, we would find it challenging to implement this modification within 14 months, as it would clearly represent significant change to both our settlement and billing systems, at a time when we are completing migration of our processes to SAP. We would also need to change our DUoS validation – assuming the changes to DUoS, which we believe would be critical to the success of P272, are to be made.

Rather than bring forward the implementation date, we think that delaying the implementation date to April 2016 or April 2017 (to take advantage of synergies from smart meter programme) would be prudent in view of the risk of slippage to the programmes above. Furthermore, this could improve the cost-benefit case if the delay allows the issues with the CoMC process to be addressed or suppliers to exploit synergies with, for example, the wider Smart Meter Implementation Programme.

ScottishPower
December 2013