Making a positive difference
for energy consumers

Electricity System Operator incentives from April 2017

Consultation

Publication date:	4 August 2016
Response deadline:	15 September 2016

Contact: David Beaumont

Team: System Balancing

Tel: 020 7901 7000

Email: soincentive@ofgem.gov.uk

Overview:

Our current electricity System Operator (SO) incentives scheme ends on 31 March 2017.

We believe there is a need to conduct a fundamental review of SO incentives to ensure they reflect the changing nature of our electricity system and the SO's role within it. We expect to be in a position to implement the conclusions of this review in spring/summer 2018.

This document consults on our approach to SO incentives in the interim period, from 1 April 2017 until a new SO incentives framework is ready. There is a range of options for this period, including extending the current incentive scheme with limited changes; maintaining the same incentive framework but seeking improvements from the 2015-17 scheme; or not having any incentives at all. We are interested in stakeholder views on which option we should pursue.

Our current preferred option is to maintain the same incentive framework but to seek changes in a number of areas where there could be benefits to consumers. We welcome views on this position, and on the areas where we have identified potential changes, before we issue our initial proposals on our approach to SO incentives from 2017 later this year.

Associated documents

Electricity System Operator Incentives 2015-17: Final Proposals
https://www.ofgem.gov.uk/publications-and-updates/electricity-system-operator-incentives-2015-17-final-proposals

Electricity System Operator Incentives 2013-15: Final Proposals
https://www.ofgem.gov.uk/ofgem-publications/39898/electricity-system-operator-incentives-final-proposals-scheme-2013.pdf

National Grid's Electricity System Operator Incentives website:
http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/Incentives/

Contents

Executive Summary

The electricity System Operator (SO) plays a vital role in our electricity system. Its actions have a significant impact on the operation and evolution of our system and ultimately the costs passed through to consumers. An important part of the SO's role is taking balancing actions to keep the system safe and secure in real time. These actions cost approximately £850m a year and add around £9 to consumer bills.

We set financial incentives on the SO primarily to ensure the costs it incurs balancing the system are as efficient as possible. Our current SO incentives scheme ends on 31 March 2017. We therefore need to decide whether to set new incentives from April 2017, and if so, what form they should take.

The need for a fundamental review of SO incentives

Our energy system, and the SO's role within it, has undergone significant changes since the existing incentives approach was introduced. In particular, there has been a significant growth in intermittent and embedded generation; the government's Electricity Market Reform (EMR) has been implemented; our electricity system is more connected and integrated with neighbouring systems; and we have given the SO an increased role on system planning.

We believe now is the right time to fundamentally review SO incentives to ensure they reflect these changes and other future challenges in the electricity system. Especially now we have several years' experience with the existing incentives approach and evidence available in order to evaluate its effectiveness.

In addition, government has expressed its view that there is a case for greater independence of the SO, in order to remove conflicts of interest and enable it to promote more competition and flexibility in the electricity system. If there are any changes to the structure and role of the SO then it is likely our future incentives approach will need to adapt to reflect this. We are engaging with government on the future of the SO and expect there to be greater clarity on its thinking soon. We intend to issue a first consultation on longer term SO incentives once this is the case.

Recognising these wider developments, we expect to be in a position to implement the conclusions of our fundamental SO incentives review in spring/summer 2018. This document consults on our approach to SO incentives in the interim period; from 1 April 2017 until the new incentives framework is ready.

What to do in the interim period from April 2017

There is a range of options for our approach to incentives from 1 April 2017 until spring/summer 2018. These options include extending the current incentive scheme with limited change; maintaining the same incentive framework but seeking improvements from the 2015-17 scheme; or not having any incentives at all.

Our current preferred option is to maintain the existing SO incentives framework in broadly the same format, whilst making changes in a number of areas where we believe there would be benefits for consumers.

While we believe the current approach to setting a financial target for balancing costs may not be working as well as it could be, we consider there is evidence that this approach would still drive overall savings to consumers in the short term.

Scope of potential changes from the 2015-17 incentives scheme

In the event we decide to maintain the current SO incentives framework, we have identified a number of areas where we believe changes from the current scheme could be beneficial. These are outlined below.

Balancing Services Incentives Scheme (BSIS) adjustments

While we do not believe we should make any fundamental changes to the BSIS framework, we would consider beneficial adjustments. In particular, we would expect the SO to perform a full review of the methodologies and assumptions underpinning the BSIS models, to ensure BSIS targets are as accurate as possible. We are not proposing to change the BSIS cap and collar (£30m) or sharing factor (30%) at this time but welcome your views on how appropriate these values are.

Incentive on costs for Black Start services

We currently set an upfront financial target within BSIS for the cost of procuring Black Start services. This is based on the costs which we would expect the SO to incur over a two year scheme period. We welcome your views on whether or not this approach is the best way to set an incentive on the SO to incur efficient Black Start services costs from April 2017.

Incentives we do not propose to extend

We are not proposing to extend the Model Development Licence Condition, which sets a requirement on the SO to continue developing the BSIS target setting models so they are fit for purpose for future schemes. This is because we intend to review this target setting framework and the use of models as part of our fundamental incentives review. We are also not proposing to extend the SO Innovation Rollout Mechanism, which can grant the SO funds of up to £10m for innovative projects. This would make additional resource available for our fundamental review of incentives, where ensuring the SO faces pressure to innovate and drive longer term benefits for consumers will be a key consideration.

Potential new incentives

We have also identified three areas where new incentives could be beneficial in the short term. These are:

1. Short term demand forecasting – the rise in embedded generation has made demand forecasting more challenging. We are interested in stakeholder views on whether a new financial incentive on the SO's short term demand forecasts could be a beneficial introduction to ensure it takes steps to address these challenges.

2. Transparency and openness of balancing services procurement – we have heard views from stakeholders that the SO's suite of balancing services is hard to understand and access, and that it could use more market-based procurement approaches. We want to hear whether you believe any new requirements or incentives are needed to ensure the SO takes steps to address these concerns in the short term.

3. SO-TO funding mechanism – alongside potential new SO incentives from April 2017, we are considering introducing an additional tool for the SO to manage system operation costs effectively, by enabling it to fund

Transmission Operator (TO) works which can reduce overall system costs. We are consulting on the need for of this mechanism and its potential design, including whether there should be any associated changes to SO incentives.

Timings and next steps

We welcome your views on our approach to SO incentives from April 2017 to spring/summer 2018 by 15 September 2016. We then aim to issue initial proposals on our SO incentives approach from April 2017 later this year.

We are also beginning work on our fundamental review of the incentives that should apply from spring/summer 2018 onwards and intend to start engaging with stakeholders on this shortly.

1. Background and context

Chapter Summary

We believe there is a need to fundamentally review SO incentives to ensure they reflect changes and future challenges in the electricity system. We expect to be in a position to implement the conclusions of this review in spring/summer 2018. This consultation is on our proposed approach to SO incentives from 1 April 2017 (when our current SO incentives scheme ends) until the new framework is ready.

1.1. The electricity SO plays a vital role in our electricity system. An important part of its role is keeping the system safe and secure in real time. To do this it takes actions to keep the system frequency stable when there is an imbalance between demand and supply. It also takes balancing actions on different parts of the network to manage system issues and network constraints.

1.2. We set incentives on the SO to help ensure it takes actions which benefit consumers. These schemes, which have grown in sophistication over time, have primarily sought to ensure the SO has financial incentives to balance the system as efficiently as possible.

1.3. Our current incentives scheme expires on 31 March 2017. We therefore need to decide whether to implement a new incentive scheme from that date and if so, what form it should take and how long it should last.

The need for a fundamental review of SO incentives

1.4. The SO's actions have a significant impact on the operation and evolution of our electricity system, and ultimately the costs incurred by consumers. It is vital that the framework governing the SO's behaviour adapts and evolves to reflect wider developments.

1.5. Our energy system, and the SO's role within it, has undergone significant changes since the existing incentives approach was designed. In particular, there has been a significant growth in intermittent and embedded generation; the government's Electricity Market Reform (EMR) has been implemented; and our electricity system is more connected and integrated with neighbouring systems. We have also introduced a fundamentally different way of incentivising network operators (RIIO) and given the SO an increased role on system planning as a result of our Integrated Transmission Planning and Regulation project.

1.6. Growing levels of intermittent generation, embedded generation and interconnection have made balancing the system increasingly challenging. This has led to an increase in annual balancing costs (particularly constraints costs) over the last decade, and more volatility in the charges levied on market participants to recover these costs (see Chapter 2). It is important that the SO takes actions to mitigate the impact of these system trends, in order to ensure that the costs passed through to consumers by their suppliers are as efficient as possible.

1.7. We therefore believe there is a need for a fundamental review of SO incentives to ensure they are appropriate going forward. Especially now we have significant experience and evidence available in order to evaluate the effectiveness of the current approach. In particular, some of our key initial concerns with the current incentives framework are that:

- the existing scheme length (2 years) may be too short to encourage the SO to take a longer term view;
- gaps in the framework and inconsistencies with RIIO mean that trade-offs between network assets and operational costs may not be fully realised;
- the framework governing how a financial target for balancing costs is determined may not be working as well it could be, particularly due to a potential asymmetry of information between us and NGET when we validate the models that set this target;
- the current scheme may not be incentivising the SO to be sufficiently transparent about its actions and the procurement of its balancing services, which could impact on market efficiency;
- there may be scope for more external scrutiny of the SO's performance and increased reputational incentives; and
- potential changes to the future governance of the SO and its role in the electricity system, might mean we need to broaden and revaluate our approach to incentives (see below).

Potential wider developments with the SO

1.8. Government has recently expressed its view that there is a case for greater independence of the SO, in order to remove conflicts of interest and enable it to promote more competition and innovation in the electricity system.[1]

1.9. If there are any changes to the structure or role of the SO then our future incentives approach will need to adapt to reflect this. For example, there may be a need to widen the scope of our incentives framework and move away from an approach which has historically focussed on financial incentives on balancing costs.

[1] Please see the Secretary of State's reset speech (November 2015): https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy
And the National Infrastructure Commission's Smart Power report (March 2016): https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report

1.10. We are engaging with government on the future of the SO and expect there to be greater clarity on its thinking soon. We intend to issue a first consultation on longer term SO incentives once this is the case.

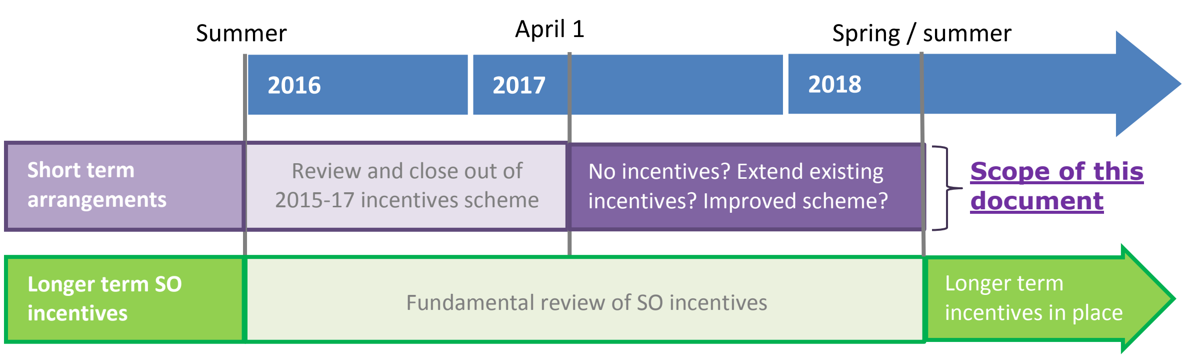
Short term incentives from April 2017

1.11. We believe we will be in a position to implement longer term incentives in spring/summer 2018. This will give us time to conduct a thorough review which takes account of any changes to the future role and structure of the SO.

1.12. **This document is about the arrangements that will apply in the interim period**; from when the current scheme ends in April 2017 until we are in a position to implement the conclusions of our fundamental review (see Figure 1). There is a range of options, including extending the current incentives scheme with limited or no changes; maintaining the same incentives framework but seeking improvements from the 2015-17 scheme; or not having any incentives at all.

1.13. Chapter 2 examines the pros and cons of continuing to place financial incentives on the SO using the existing framework versus not having incentives, whilst Chapter 3 looks at the potential scope of changes in the event we do decide to maintain the same framework.

Figure 1 – Proposed timings for future SO incentives



Timings and next steps

1.14. Following this consultation we intend to meet with stakeholders and further develop proposals for the arrangements from April 2017. We are aiming to issue initial and final proposals later this year.

1.15. We are also beginning our work on longer term SO incentives and intend engage with stakeholders shortly to help develop our thinking.

2. Whether to maintain the existing SO incentives framework

Chapter Summary

We set financial incentives on the SO to ensure the costs it incurs balancing the system are as efficient as possible. We welcome your views on whether we should continue to place financial incentives on the SO or not from April 2017 until we are in a position to implement the conclusions of our fundamental review of incentives. And if so, whether we should maintain the existing incentives framework and seek to make improvements to it.

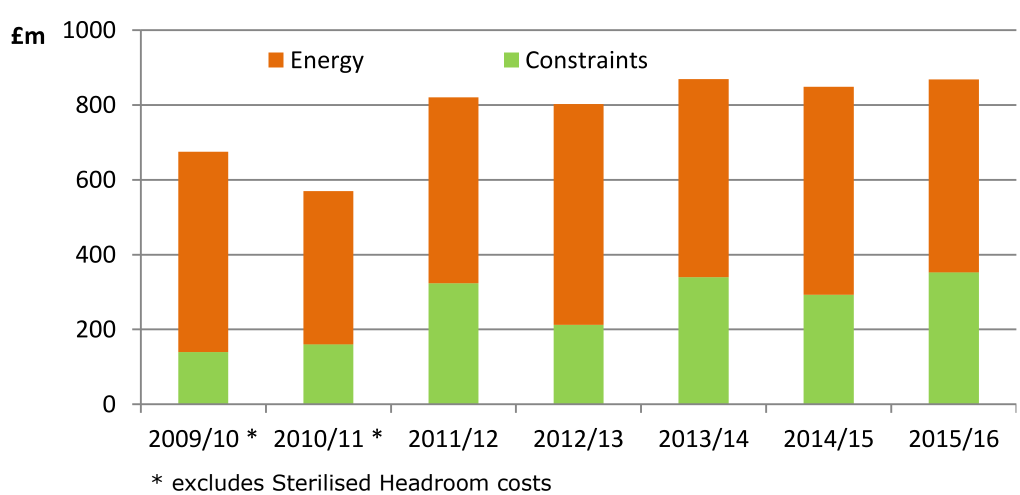
Question box

Question 1a: Should we place financial incentives on the SO in the period between 1 April 2017 and when we are in a position to implement longer term SO incentives?
Question 1b: If we maintain financial incentives from April 2017 to spring/summer 2018, should we use the existing BSIS framework?
Question 1c: Do you agree that if we maintain the existing incentives framework during this period, we should seek improvements from the 2015-17 scheme?
Please provide evidence to support your answers

The rationale for incentivising the SO

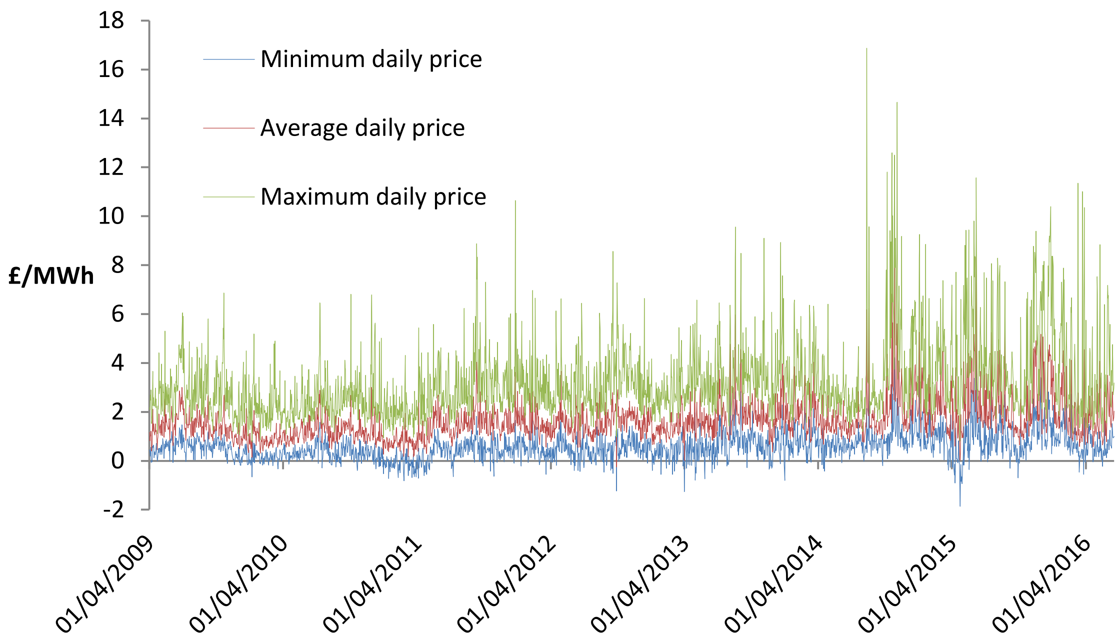
2.1. The electricity SO incurs approximately £850m per year in costs to balance the system and manage constraints on the network (see Figure 2). These costs are ultimately passed through to consumers through Balancing Services Use of System (BSUoS) charges and add around £9 to annual consumer bills.

Figure 2 – Energy balancing and constraints costs from 2009/10 to 2015/16



2.2. BSUoS charges are levied on suppliers and generators (and are therefore indirectly passed onto consumers). Parties' expectations about the size and volatility of these charges can have a big impact on trading and investment decisions. In particular, volatile and uncertain charges can create risk for generators, which can lead to inefficient premiums and dampened incentives to trade forward. As well as increasing in size, we have observed BSUoS charges becoming more volatile over the last seven years (see Figure 3).

Figure 3 – Daily BSUoS charges from 2009-16



2.3. As the SO is a monopoly business, it does not face pressure from competitors to innovate and take actions which drive down BSUoS charges and wider system costs. We therefore set incentives which aim to mimic these competitive pressures and drive efficient SO behaviour.

2.4. To do this we set a target cost for electricity SO balancing actions, based on the output of complex models, which forecast the efficient level of balancing costs given the specifics of the system. We also apply incentives on other behaviours which can help drive positive electricity system outcomes. An overview of our current incentives scheme can be found in Box 1.

2.5. Fundamentally, our incentives aim to recognise that short term financial rewards (or penalties) to the SO can lead to long term cost savings to consumers.

Box 1: Existing SO incentives framework

Balancing Services Incentive Scheme

The main incentive on the electricity SO is the Balancing Services Incentive Scheme (BSIS). We use two models to calculate a monthly target for balancing costs on a constrained network:

- The **energy model** is an econometric-based model that uses the historic relationship between the volume and cost of balancing the system to derive a target for the SO's energy balancing actions.

- The **constraints model** is a linear optimisation model that produces an optimal strategy for the SO to manage constraints in the balancing mechanism (BM), with a discount factor to take account of the availability of non-BM actions.

The combination of outputs from these models is combined an allowance for Black Start services to set a single BSIS financial target. If actual costs are below this target then the SO is permitted to receive an incentive payment, and if actual costs exceed the target then it faces an incentive penalty.

The size of this payment or penalty is determined by a sharing factor (which sets the percentage of over or underspend against the target that the SO will retain). The sharing factor, which is 30% under the exiting scheme, is in place to strike a balance between the risks and rewards faced by the SO and customers.

The maximum payment the SO can receive under the current incentive scheme framework is subject to an upper cap, and the maximum penalty it can be liable for is bounded by a lower collar. This is currently set at ±£30m in each year of scheme.

The current format of the BSIS scheme was introduced in 2011. Prior to 2011, the target was determined by a mixture of basic modelling, business plans and ex-post adjustments to account for variability. The 2011-2013 BSIS marked a step-change in our approach to setting BSIS targets because of the introduction of the energy and constraints models.

Both the constraints model and the energy model have increased in sophistication since 2011. For the 2015-17 scheme we also increased the sharing factor from 25% and the cap and floor from ±£25m. This was to sharpen the financial incentives on the SO to take account of the increasing challenge of system balancing.

The SO owns these models and is responsible for ensuring they set a robust and appropriate target. We validate the models and their methodologies at the start of the scheme and monitor the SO's use of them on an ongoing basis. Where we identify outputs which may not be reflective of the agreed methodologies we challenge the SO to justify these outputs and provide us with confidence that they are appropriate.

Additional Incentives

In addition to the BSIS target, the current framework contains a number of additional incentives. This includes a financial wind generation forecasting incentive; a fund for innovation; a requirement to report on transmission losses; and a requirement for the SO to develop the models which are used in BSIS. Please see Table 2 in Chapter 3 for a fuller overview of the specific aspects of the current scheme.

The case for and against maintaining financial incentives

Arguments against maintaining financial incentives

2.6. We are considering not putting in place any financial incentives from April 2017. This would allow us to fully focus on our fundamental review of incentives.

2.7. The value in having financial incentives on the SO in the short term (until we have more certainty about future SO governance, roles and longer term incentives) could arguably be less than for the previous two year schemes. This is because the SO would have less certainty about the parameters of any future SO incentives schemes and therefore whether it would be rewarded for actions which drive longer term benefits (i.e. after a potential interim scheme ends).

2.8. Not setting financial incentives would also remove the risk that we over reward the SO for behaviour that it might have displayed anyway (or penalise it unfairly). This is possible in the absence of a robust balancing costs target that accurately reflects 'business as usual' behaviour. Currently this target is identified by models owned by the SO. It is therefore dependent on the methodologies used to create these models and the assumptions that feed into them.

2.9. There is an inherent asymmetry of information between us and the SO when we validate the model methodologies and monitor the models' performance. We believe the existing target setting framework could be improved to make the SO more accountable for the accuracy of these targets. In particular, there may be scope for an improved, more formal governance framework for validating the models and solving issues. And there may also be a case for greater transparency and external scrutiny or audit of the models. We see fundamentally reviewing this framework as a priority for our work on longer term SO incentives.

2.10. Nevertheless, despite the potential need for improvements, we still believe there is evidence that the current target setting approach is incentivising the SO to take actions which drive overall savings for consumers (as outlined below).

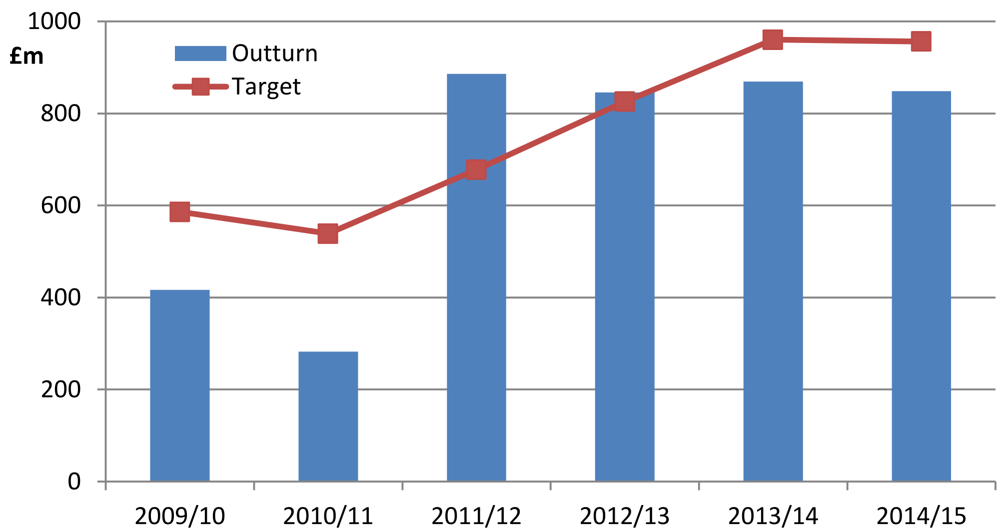
Reasons for maintaining financial incentives

2.11. Figure 4 shows the SO's performance against its BSIS target from 2009/10 to 2014/15. As outlined when we published our final proposals for the 2015-17 incentives scheme[2], we believe the rising trend in BSIS targets recognises that the SO's role is becoming increasingly complex as the system changes to accommodate more intermittent generation, the loss of inertia (making frequency control difficult), the closure of thermal plant (traditional providers of balancing services), increasing

[2] https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/electricity_so_incentives_-_final_proposals_2.pdf

interconnection, the growth in embedded generation and the connection of generation ahead of network reinforcements (as a result of Connect and Manage).

Figure 4 – BSIS performance 2009-2015



	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Outturn (£m)	417	282	886	846	869	849
Target (£m)	586	539	678	826	960	956
Payment to/From NGET(£m)	15.0	15.0	-48.7*		22.7	25.0
Cap/floor	Cap Hit	Cap Hit	In Range		In Range	Cap Hit

* From 2011-13, BSIS performance was measured as a two year scheme.

2.12. Despite the models forecasting an upward pressure on balancing costs we observe that the SO has kept balancing costs relatively stable in the last four years. Assuming that the BSIS target is a good reflection of the costs the SO would incur under business as usual, then incentives may have driven a reduction in balancing costs of around £200m from 2013-15, which translates to around £150m worth of benefits for consumers when accounting for payments to NGET.

2.13. Although there is some uncertainty with this figure (given the challenges of identifying counterfactual costs), we believe there is evidence of the SO changing its behaviour in response to financial incentives. Since the introduction of the current BSIS approach, through our monitoring work we have seen the SO take a number of different actions outside of the Balancing Mechanism (BM) in order to reduce balancing costs. This includes:

- **Contracts to minimise constraints costs** – given the increased challenge in managing constraints, the SO could incur losses against the incentive scheme target if it failed to look for cheaper ways of managing constraints. We have seen evidence of the SO reacting to this by establishing commercial contracts ahead of time. This includes contracts for intertrips (where specific generators are disconnected in the event of transmission faults) and location-specific voltage services. And in some cases we have seen the SO strike bundled contracts to secure better value for these services.

- **Trades with wind generators before Gate Closure** - we believe incentives have encouraged the SO to diversify its approach and respond to prices signals. We see further evidence of this in how it manages constraints on windfarms. In particular, the SO has alternated between taking actions in the BM and striking trades ahead of time, depending on the differential between the BM and traded prices.

- **Competition in the Short Term Operating Reserve (STOR) market** – the SO has aimed to increase competition in STOR tenders, including by attracting non-traditional providers (such as demand side providers). Increased liquidity in STOR provision has driven availability prices down from £45/MWh to around £4/MWh from 2011-14. This has seen the increased use of STOR instead of bids and offers in the BM. Our analysis suggests consumers could have saved around £16m as a result.

2.14. We believe the benefits of taking actions outside of the BM (such as the ones above) can be realised in relatively short timescales. In particular, the SO has the ability and experience quickly strike contracts with balancing providers. As such, it should still have an incentive to take measures to increase balancing efficiency under a shorter term incentives scheme.

Conclusion

2.15. Our current preference is to maintain financial incentives. We believe that strong financial incentives are an effective way to drive efficient SO behaviour. Removing financial pressure on the SO to take the most cost effective course of action from April 2017 could create significant risks for consumers, which we believe would outweigh the potential risk of over-rewarding the SO, particularly in the presence of a cap and collar on payments.

Question 1a: Should we place financial incentives on the SO or not in the period between 1 April 2017 and when we are in a position to implement longer term SO incentives? Please support your answer with evidence.

Incentives framework from April 2017

Overarching design

2.16. In the event that we decide to continue to place financial incentives on the SO from April 2017 until spring/summer 2018, we believe it would be beneficial to maintain the existing overarching SO incentives framework. In particular we would propose to retain the BSIS approach outlined in Box 1, where the SO's energy and constraints models are used to identify a financial target for balancing costs.

2.17. As the existing framework has been in place since 2011, NGET, industry and Ofgem have significant experience with this approach. Continuing with this framework, as opposed to making fundamental changes at this stage, should allow parties to focus resources on developing longer term incentives. In addition, we consider it inappropriate to make fundamental changes at this point until there is more clarity on the future governance of the SO.

2.18. As highlighted above, although we feel there is room for improvement in the current BSIS approach, we believe there is evidence that it would deliver overall benefits for consumers during a shorter term incentives scheme. At the same time we believe there are some areas of the existing framework where changes could be beneficial in the short term. These areas are outlined in the next chapter.

Question 1b: If we maintain financial incentives from April 2017 to spring/summer 2018, should we use the existing BSIS framework? Please support your answers with evidence.

Question 1c: Do you agree that if we maintain the existing incentives framework during this period, we should seek improvements from the 2015-17 scheme?

Scheme length

2.19. We consider the scheme should last from April 2017 until we are in a position to implement a new incentives framework, which we anticipate will be spring/summer 2018. Our preference would be to include licence provisions which allow flexibility with the end date of the scheme to ensure implementation can be adapted in response to any wider developments on the SO's future role or governance. To ensure this does not create too much uncertainty for industry we will update stakeholders regularly on the timescales of the review and our progress.

Within-scheme updates

2.20. The SO can make amendments to the BSIS models or inputs to the models at any point during the scheme where limitations are identified which prevent them from setting an appropriate target. The SO must submit a full explanation to the Authority which has the ability to reject the changes if they have not been fully justified. We propose to keep this mechanism if we maintain the BSIS framework, but to also consider whether any additional levers could be introduced to ensure the SO resolves model issues in a timely manner.

2.21. There are also licence provisions which allow the SO to make refinements to the BSIS target setting approach half way through the two year incentives scheme. In particular, it can update certain agreed model inputs (such as constraints model boundary limits to take account of the latest year-ahead transmission outage plans). And it can also propose changes to the model methodologies (for example, where it believes that changes are needed to reflect differences in the SO's system balancing approach). We will consider further whether there is a need to retain theses mid-scheme update mechanisms if we decide to introduce a shorter length scheme.

3. Scope of potential changes from the 2015-17 scheme

Chapter Summary

In the event we decide to maintain the existing SO incentives framework from April 2017 until spring/summer 2018, we feel there are a number of beneficial changes that can be made from the 2015-17 scheme. We welcome stakeholder views on these areas before we issue initial proposals on our approach to SO incentives from 2017 later this year.

Question box

Question 3a: How could the BSIS target setting approach and modelling methodologies be improved in the short term?
Question 3b: Do you believe the existing BSIS sharing factor and cap and floor remain appropriate?
Question 4: What is the best way to set an incentive on the SO to incur efficient costs when procuring Black Start from April 2017?
Question 5a: Do you agree that we shouldn't maintain the MDLC?
Question 5b: Do you agree that we shouldn't maintain the SO IRM? Are there any alternative ways to encourage innovative behaviour from the SO in the short term?
Question 6a: Do you believe there is a need for a new incentive on short term demand forecasts from April 2017? How could this be designed? What timescales should it be based on: week ahead, day-ahead, hour-ahead, other?
Question 6b: Do you think there needs to be any changes to the wind generation forecasting incentive or new incentives on any other system forecasts?
Question 7: Do you think the SO's procurement of balancing services needs to be more transparent and open? If so, what steps should be taken? Should the SO pursue more market-based approaches? Should we introduce any incentives or requirements on the SO in this area from April 2017?
Question 8: Do you agree with our proposed scope of changes? Is there anything else you believe should be changed, added or removed from the existing scheme?

3.1. In the event that we maintain the current SO incentives framework we consider that there are good arguments for seeking to introduce improvements to the scheme which expires in March 2017. In particular we are minded to:

- Consider proposals for simple, beneficial changes to BSIS parameters and the target setting approach;
- Review the incentive on costs for Black Start services;
- Remove incentives which are unlikely to be beneficial under a shorter term scheme;
- Add new incentives which could be easy to implement and have clear benefits to consumers.

3.2. Our current thinking on changes is outlined below and summarised in Table 2.

BSIS changes

3.3. As outlined in Chapter 2, our current preference is not to make fundamental changes to the BSIS framework and target setting approach if we maintain financial incentives. However, as with the move from the 2013-15 to the 2015-17 BSIS scheme, we would expect the SO to conduct a thorough review of the methodologies underpinning the constraints and energy models[3], and a full refresh of the coefficients and assumptions that feed into them, before we make a decision on whether to approve them.

3.4. We would also want the SO to consider whether there are any additional adjustments to the BSIS model methodologies which could help ensure that the targets are as accurate as possible. This could include, for example, evaluating whether any of the current ex-ante inputs should become ex-post inputs, and whether the constraints model needs to be adapted to account for actions outside the BM which could be classed as 'business as usual' actions.

3.5. One of the model inputs which may require evaluation is demand, and whether or not using ex-post rather than ex-ante demand would be more suitable. This is because differences between demand forecasts and outturn demand can have a significant impact on performance against the BSIS target. Separately, we are also considering the case for a new incentive to ensure the SO takes measures to improve its short term demand forecasts (see below).

3.6. As highlighted in Chapter 2, our preference would be to retain the licence provisions which allow the SO to propose amendments to the models or models inputs where limitations or errors are identified which prevent them from setting an appropriate target. However, we also want to consider further whether any additional levers should be introduced so we have more ability to ensure the SO solves modelling issues in a timely manner.

3.7. We are not proposing to change the cap and collar or sharing factor at this time. However we want to consider further whether £30m and 30% would remain appropriate and we welcome stakeholder views on this.

Question 3a: How could the BSIS target setting approach and modelling methodologies be improved in the short term?

Question 3b: Do you believe the existing BSIS sharing factor and cap and floor remain appropriate?

---

[3] The BSIS model methodologies can be found here: http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/bsis/

Incentive on costs for Black Start services

3.8. We currently set a target up front for the costs of procuring Black Start[4] services, based on the costs which we would expect the SO to incur over a two year scheme period. This is included in the overall BSIS target. The SO also has the ability to apply for changes in this Black Start target after one year. This can be done through a Mid Scheme Review, or potentially through the 'Income Adjusting Event' element of the licence condition.

3.9. Over the past two years NGET has applied for updates to the incentive scheme targets. In the 2014 mid-scheme update the target was increased from £21.45m to a conditional maximum of £36.35m. This year Ofgem agreed to increase NGET's 2016-17 target to a maximum of £34.74 million from £22.35m. In addition to this, there is currently an Income Adjusting Event notice from NGET which, if successful, would imply an increase in the target to just under £150m.

3.10. In light of these changes, we are interested in your views on whether setting an upfront financial target for Black Start costs within BSIS from April 2017 would be the best approach or not. And if not, whether any alternative approaches (such as an ex-post assessment of whether costs are efficient) could be more suitable in future.

Question 4: What is the best way to set an incentive on the SO to incur efficient costs when procuring Black Start from April 2017?

Incentives we do not propose to maintain

Model Development Licence Condition

3.11. The Model Development Licence Condition (MDLC) sets a requirement on the SO to continue developing the BSIS target setting models so they are fit for purpose for future SO incentives schemes. We intend to fundamentally review our approach to financial incentives and the use of these models as part of our work on longer term SO incentives. We therefore do not think it is sensible to have a requirement on the SO to develop the existing BSIS target setting models while this review is ongoing.

Question 5a: Do you agree that we shouldn't maintain the MDLC?

---

[4] Black Start is the procedure to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. For more information please see: http://www2.nationalgrid.com/uk/services/balancing-services/system-security/black-start/

SO Innovation Rollout Mechanism

3.12. Under the SO Innovation Rollout Mechanism (IRM), the SO can apply for up to £10m to fund innovative projects during the first year of the incentives scheme. We review any applications and make a decision on whether to grant the funds. If successful, these funds become available in the second year of the scheme.

3.13. We are not proposing to maintain the SO IRM because we do not believe that it would be successful under a shorter term scheme. In particular, there would be limited time for the SO to develop proposals, and for us to review them and make a decision on funding before the introduction of a longer term scheme. Removing this incentive would also make more resource available for our fundamental review of SO incentives. Ensuring the SO faces pressure to innovate and develop solutions which drive longer term benefits for consumers will be an important consideration for this work.

Question 5b: Do you agree that we shouldn't maintain the SO IRM? Are there any alternative ways to encourage innovative behaviour from the SO in the short term?

Potential new incentives

Short term demand forecasting

3.14. Accurate short term[5] demand, wind generation and margin forecasts by the SO are vital for balancing efficiency. Accurate forecasts increase certainty for the SO and help ensure it takes appropriate balancing actions at the appropriate time. In addition, accurate published forecasts can help market participants self-balance and respond effectively to price signals, which can further increase balancing efficiency. Equally, inaccurate forecasts can send misleading signals to the market which can lead to inefficient trading and dispatch, creating unnecessary costs to parties and ultimately consumers.

3.15. System forecasting is becoming increasingly difficult given the rise in intermittent generation (which is less predictable because it is dependent on weather) and interconnectors (which are also dependent on system conditions in neighbouring countries). The increase in generation connected directly to the distribution system is also making transmission level demand harder to predict. It is vital that the SO reacts to these challenges and takes steps to ensure its forecasting is accurate going forward. This includes maintaining robust IT systems and processes, dedicating resource towards understanding system trends, and investing to seek continuous improvements.

[5] Forecasts less than one year-ahead; including season-ahead, week-ahead, day-ahead, hour-ahead etc.

3.16. Table 1 provides an overview the different short term forecasts published by the SO.

Table 1 – short term forecasts published by the SO

Area	Details	Published
Demand[6]	Day / Day Ahead Forecast demand in every settlement period during the current day and the following day.	Typically updated 4 times a day; by 04:00, 10:00, 16:30 and 22:00.
	2 – 14 days ahead Forecast demand in the predicted peak period in each day from 2 days ahead to 14 days ahead.	Every business day
	2 – 52 weeks ahead Forecast demand in the predicted peak period in each week from 2 weeks ahead to 52 weeks ahead.	Each Thursday
Wind generation	Wind generation forecasts for each settlement period from 9pm on the current day (D) until 9pm on D+2.	04:30, 10:30, 16:30, 22:30 each day.
Margins	Indicative margins Forecast indicative margin in every period during the current day and the following day. Difference between the sum of the Maximum Export Limits submitted for that period and forecast demand.	Every half hour (uses Day/Day Ahead demand forecasts)
	Indicative imbalances Forecast indicative system imbalance in every period during the current day and the following day. Difference between the sum of the Physical Notifications submitted by generators and forecast demand.	Every half hour (uses Day/Day Ahead demand forecasts)
	De-rated margin (DRM) and Loss of Load Probability (LoLP) Forecast DRM and LoLP values for today, tomorrow and day after. These are calculated in accordance with the LoLP Calculation Statement[7].	Every half hour

3.17. There is currently a financial incentive on the SO to produce accurate day-ahead wind generation forecasts. Under this incentive, the SO receives a reward or penalty depending on how its average forecasting error each month compares to an agreed target. However, there is not currently an incentive on short term demand forecasts[8].

3.18. Figure 5 shows that there has been a slight upward trend in the SO's 2-day ahead (2DA) and 7-day ahead (7DA) absolute demand forecast errors, whilst Figure 6 shows that there has been an increasing tendency for the SO to overestimate

[6] The SO produces different types of demand forecast – please see BM reports for more detail: http://www.bmreports.com/bwx_help.htm
[7] Please see: https://www.elexon.co.uk/wp-content/uploads/2015/10/Loss_of_Load_Probability_Calculation_Statement_v1.0.pdf
[8] We note that NGET already has an incentive to produce accurate longer term (year ahead and four year ahead) demand forecasts under its EMR incentives.

demand, particularly during winter[9]. This could reflect the increased challenge of forecasting presented by the rise in embedded generation and triad avoidance, which may be dampening transmission demand compared to historical estimates.

Figure 5 – 2DA and 7DA mean absolute demand forecast error (monthly)

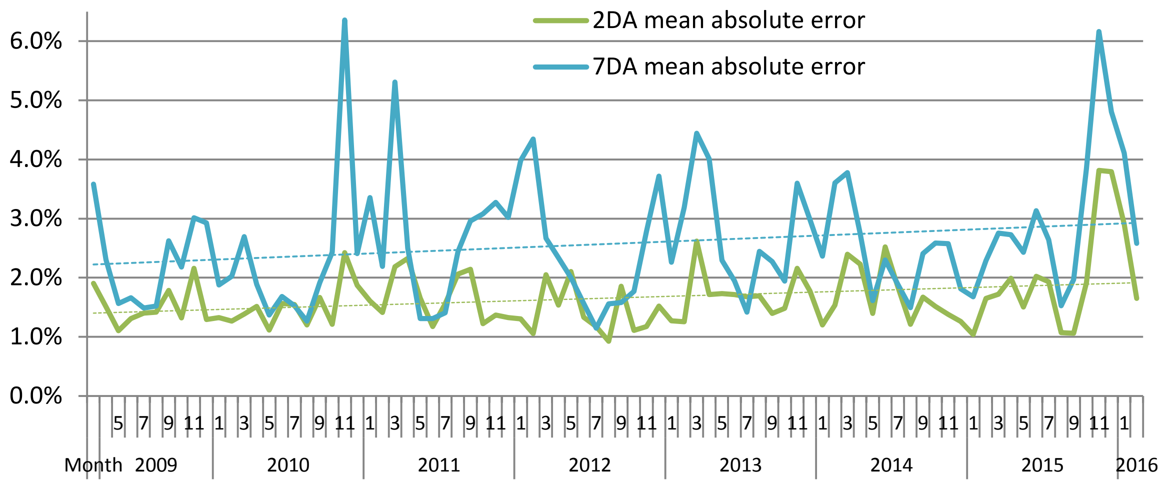
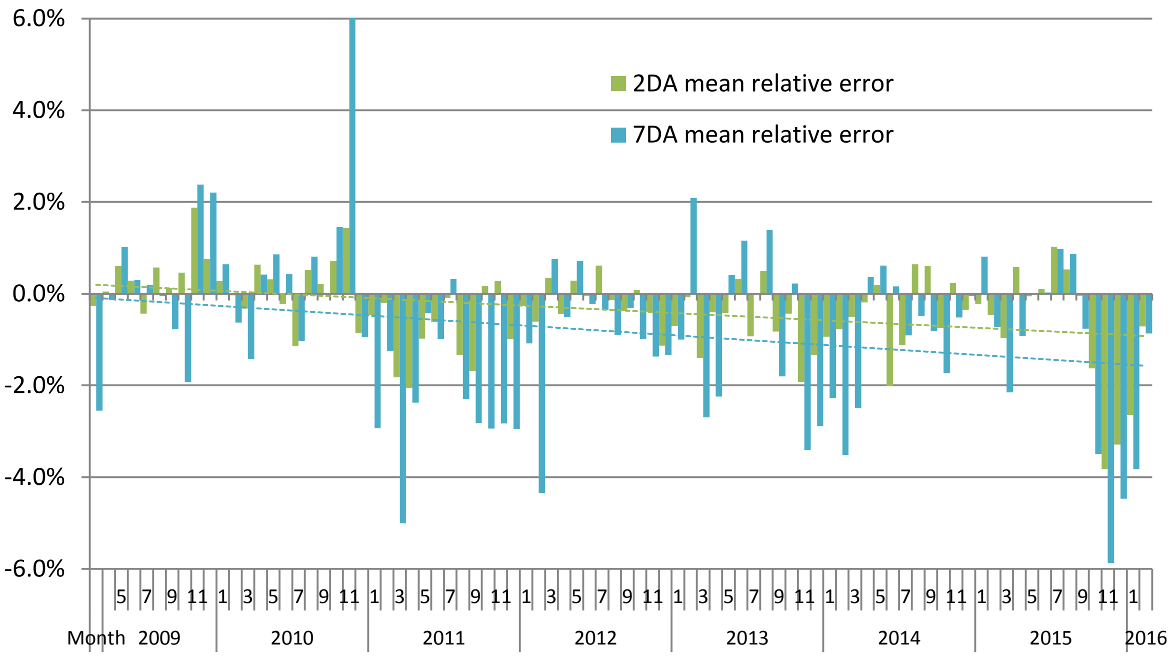


Figure 6 – 2DA and 7DA mean relative demand forecast error (monthly)



[9] This analysis compares the SO's 2-14 day-ahead peak demand forecast with peak daily Initial National Outturn Demand, using data from NETA reports.

3.19. Given the increasing challenges in this area, we are interested in stakeholder views on whether a new financial incentive on short term demand forecasts would be a beneficial introduction from April 2017.

3.20. A new incentive on demand forecasts could be designed in a similar way to the current wind generation forecasting incentive. However, for both demand and wind, we believe it could also potentially be beneficial to review the case for measuring performance at more granular time intervals. For example, the SO could face financial penalties for exceeding certain maximum error bounds in any week, day or period. This would mean that the SO could be penalised for very inaccurate short term forecasts, irrespective of its average monthly performance. We believe this would sharpen the incentive on the SO to ensure its short term forecasts always meet a certain level of accuracy.

3.21. We recognise that under a shorter scheme there may be less incentive on the SO to take actions which drive forecasting improvements over longer time horizons. However, we believe this is an important area going forward, and consider that there are steps the SO could take to seek improvements before spring/summer 2018.

3.22. We are not considering an explicit financial incentive on margin forecasts. This is because demand and wind expectations are direct inputs to margins, so any improvements in this area should feed through to more accurate margin forecasts.

Question 6a: Do you believe there is a need for a new incentive on short term demand forecasts from April 2017? How could this be designed? What timescales should it be based on: week ahead, day-ahead, hour-ahead, other?

Question 6b: Do you think there needs to be any changes to the wind generation forecasting incentive or new incentives on any other system forecasts?

Transparency of balancing services and openness of procurement

3.23. We have heard views from stakeholders that the SO's balancing services can be hard to understand and access, and that its procurement approach could be more transparent and open.

3.24. The SO procures a large number of different ancillary services[10]. Some of these services also contain multiple sub categories and bespoke schemes to help facilitate participation[11]. We are concerned that having too many different services may cause confusion and that some of these services may overlap. We therefore

[10] Please see NGET's Procurement Guidelines for an overview of the balancing services the SO purchases and the mechanisms typically used to purchase them: http://www2.nationalgrid.com/uk/industry-information/electricity-codes/balancing-framework/transmission-license-c16-statements/

[11] For example, Short Term Operating Reserve (STOR) includes BM STOR, non-BM STOR, 'Enhanced Optional STOR' and 'STOR Runway'.

believe the SO needs to consider whether there should be more bundling of services in order to increase transparency and minimise distortions.

3.25. We would also like the SO to consider other ways it can make its suite of balancing services more transparent and accessible. It is important that a broad range of providers are able to compete for balancing services and that product requirements do not inefficiently restrict providers from competing for other revenue streams. This may mean the SO needs to engage more with a wider range of stakeholders (such as Distribution Network Operators) in order to optimise the design and timing of its procurement.

3.26. We also note that the SO uses a variety of procurement techniques for its balancing services. This includes the use of market mechanisms, normally through a tender-based selection process, and often the use of bilateral contracts. We want the SO to consider whether there should be more widespread use of auctions or tenders on its products to ensure open and fair competition. And where markets for a required service don't exist, how these markets could be developed going forward.

3.27. We believe this should be key area of focus for the SO over the next two years and beyond. We therefore intend to consider whether any new incentives or requirements are needed to ensure the SO takes actions in the short term to increase the transparency of its balancing services and procurement activity. We would welcome further stakeholder views on what changes might be needed in this area and whether we should introduce any additional requirements from April 2017.

Question 7: Do you think the SO's procurement of balancing services needs to be more transparent and open? If so, what steps should be taken? Should the SO pursue more market-based approaches? Should we introduce any incentives or requirements on the SO in this area from April 2017?

Incentive on SO-TO funding

3.28. There are potential efficiencies to be gained from greater coordination and collaboration between the SO and the Scottish Transmission Operators (TOs). There may be occasions where if the TO increases its expenditure (eg, by compressing an outage) it can reduce system balancing costs, leading to overall system cost savings.

3.29. In coordination with the SO and Scottish TOs, we have been considering the case for a SO-TO funding mechanism. This could build on an existing process which allows the SO to request TOs to move outages for security reasons and compensate them for their costs. Subject to the outcomes of this consultation, we believe it could be beneficial to introduce this mechanism in April 2017. We are considering whether there should be any associated changes to incentives alongside the mechanism (eg, whether the cost of these actions should be included in the overarching financial incentives framework or incentivised under a separate financial incentive).

3.30. Please see Appendix 1 for our consultation this mechanism, including questions on the potential associated changes to incentives.

Table 2 – Overview of existing SO incentives and potential changes

What	Description	2015-2017	Potential changes from April 2017
BSIS parameters			
Scheme length	Amount of time that the scheme is in place.	Two year scheme with potential one year update of target, cap and floor and some inputs.	From April 2017 until we implement longer term incentives (12-16 months).
Target setting approach	Methodology used to define the target against which the SO's costs are compared.	Use of models to identify a target for energy balancing and system balancing costs.	Same approach using energy and constraints models. Consider simple, beneficial changes to model methodologies and governance.
Cap and floor	Maximum return/loss that the SO can make from the scheme.	±£30m in each year of scheme.	No proposed change.
Sharing factor	Percentage of under/overspend that the SO retains.	30%	No proposed change.
Income adjusting events	Provisions to apply for changes to the target in light of unforeseen events.	Materiality threshold for opening an application to £10m. Tight definition to provide greater certainty.	No proposed change.
Black start	How the cost incurred by the SO in order to procure sufficient black start capability is treated.	Target set up front built up from the different costs which we would expect the SO to incur over the scheme period. SO has ability to apply for changes to the target for the second year of the scheme.	Review up-front target setting approach.
Additional existing incentives			
System Operation-Innovation Roll-out Mechanism	Funding for the roll-out of innovation.	SO can apply for up to £10m which becomes available in the second year of scheme. We make a decision on funding based on certain criteria.	Do not maintain.

What	Description	2015-2017	Potential changes from April 2017
Wind generation forecasting incentive	Incentive to produce accurate day-ahead wind generation forecasts.	A maximum of ±£200k each summer month and ±£300k each winter month based on the SO's day-ahead forecast accuracy measured against a defined target. With a cap at 0% error and a collar at 2 times the target.	Review incentive and potentially align with a new short term demand forecasting incentive (see below).
Transmission losses incentive	Incentive for the SO to reduce transmission losses.	Requirement to report on the actions it takes which contribute to transmission losses.	No proposed change.
Model development licence condition	Requirement for the SO to develop the models which are used to set a BSIS target.	Requirement to continue developing the target setting models so they are appropriate for future schemes.	Do not maintain.
Potential new incentives from April 2017			
Demand forecasting incentive	Potential financial incentive on the SO to improve the accuracy of its short term demand forecasts. Could be designed similarly to the current wind forecasting generation incentive.		
Transparency of balancing services procurement	Potential new requirement on the SO to encourage it to take steps to make its balancing services more transparent and accessible, and to use more market-based approaches to procurement.		
Incentive on SO-TO funding	Evaluate whether any changes are needed to incentives alongside the potential introduction of a new SO-TO funding mechanism (designed to give the SO an additional tool to manage system costs by funding TO works).		

Question 8: Do you agree with our proposed scope of changes? Is there anything else you believe should be changed, added or removed from the existing scheme?

Appendix 1 – Consultation on SO-TO mechanism

Summary

In recent years, closer cooperation between the SO and Transmission Operators (TOs) has presented opportunities to increase efficiencies on the electricity system. There has been an improvement in the level of coordination between the SO and the TOs that has helped lower total system costs, partly resulting from the introduction of the Network Access Policy (NAP). However, there is still a gap in the current arrangements where the TO could incur increased expenditure to realise system cost savings which are currently being missed. At present, there is no mechanism through which the SO can fund the TO for carrying out works which lead to total system cost savings.

Given the potential for greater efficiencies, we have been working to design a mechanism that would allow the SO to exchange funds with the TO for works which reduce total system costs. Subject to the outcome of our consultation on the SO arrangements that should apply when the current incentive scheme ends, we believe it would be beneficial to introduce this mechanism in April 2017 alongside a potential new incentive scheme.

Background

1. The decisions that TOs make, and the actions that they carry out, have a fundamental impact on the SO’s costs. However, the SO and TOs are incentivised under two distinct schemes, and due to the differing nature of their operation, are incentivised to deliver different outcomes.

2. The SO’s principal function is to operate the national electricity system, ensuring that supply meets demand on a second by second basis, whilst managing constraints on the network. This function is currently carried out by National Grid Electricity Transmission (NGET). The SO is incentivised to minimise the cost of balancing the electricity system through the BSIS model, by comparing outturn costs incurred against a target cost.

3. The TO’s role is to build, own, and maintain the physical assets that make up the electricity system. In Scotland this function is carried out by Scottish Power Transmission Ltd (SPT) and Scottish Hydro Electricity Transmission Ltd (SHETL). Under the RIIO model, the TO is incentivised for building, owning and maintaining the electricity network, as well as delivering a suite of outputs, at the lowest cost. Any underspend that either the TO or SO makes against its respective incentive target, is shared with consumers via sharing factors.

4. The SO-TO code (STC) sets out the relationship between the SO and the TOs. Specifically, it outlines the processes that both the SO and TOs are required to follow in order to coordinate outages on the GB transmission system. As part of the STC, the TOs, in close coordination with the SO, are required to put together a number of outage plans. One of these is the year-ahead outage plan which is approved by the SO and which sets out the outages that the TO will undertake within the coming year.

5. The SO can reject an outage proposed under the year-ahead outage plan submitted by the TOs, however this is an inflexible tool. The SO cannot make suggestions to alter the proposed outages, but can only approve or reject outages in the plan. Once agreed, the year-ahead outage plan can only be amended under specific circumstances.

6. Within the STC, there is a procedure (STCP 11-3) that is available to the SO to compensate the TOs for moving outages within-year. Licence condition 4C in NGET's special licence conditions allows NGET to recover funds through BSIS for payments related to STCP 11-3. We do not approve these projects on a case-by-case basis, but rather the costs are assessed on a compounded, annual basis.

7. Further to the STC, the TOs were required to develop a Network Access Policy (NAP) as part of the RIIO-T1 price control. The NAP is designed to facilitate efficient performance and effective liaison between the System Operator (SO) and Transmission Owner (TO) in relation to the planning, management and operation of the electricity system. The NAP considers actions that the SO can take to coordinate with the TOs to manage the network in the most efficient manner, for example, managing planned and unplanned outage arrangements in ways that minimise their contribution to system constraints.

8. We recognise that there have been significant improvements in the way in which the SO-TO relationship is managed, and consider that benefits have stemmed from closer coordination and cooperation. We also recognise that there is the potential for further improvements and efficiencies to be realised. The SO has a number of tools at its disposal through which it can manage the system. A SO-TO funding mechanism would give the SO another tool to manage the system more efficiently.

9. In our 2015-2017 SO Incentives Final Proposals[12] we recognised that there might be a future need for an SO-TO funding mechanism but that the benefits at the time weren't clear. We agreed that we would continue to engage with the SO and TO, and through the NAP meetings to consider the need to introduce it. After renewed discussions with the SO and TOs we believe that this is the right time to develop a mechanism to ensure that potential savings aren't lost. Aligned with the end of the current SO incentives scheme, April 2017 presents a good opportunity to

[12] https://www.ofgem.gov.uk/publications-and-updates/electricity-system-operator-incentives-2015-17-final-proposals

introduce the mechanism alongside the next potential SO incentives arrangements consulted on in this document.

Need for the introduction of a mechanism

10. The relationship between the SO and the TOs is becoming increasingly important with strong interdependencies between the two. It is only possible to enable total system cost savings when doing so does not require significant costs being incurred by either party. There is no way for the SO and the TOs to exchange funds to optimise total system costs when doing so for economic reasons. In some situations, the TO could incur greater costs, than those allowed under RIIO, and help to minimise total system costs. However the TO, under the current regulatory framework, would be financially disadvantaged doing so. This means that savings are being missed.

11. The SO and the TOs are subject to incentives relevant to their specific functions, the SO on operating the system, and the TOs on building and maintaining the system. Despite the STC and NAP focusing more on the whole system perspective, currently no party is financially incentivised to consider the impact actions have on total system costs.

12. We consider that it is in consumer's interest to establish a framework that enables more efficient total system costs. For the SO to be able to enable total system cost savings, it needs to have a mechanism or tool through which it can elicit certain behaviours. Introducing a mechanism that allows the SO to transfer funds to the TO and reduce system costs for purely economic reasons would help fill this gap.

Benefits

13. We consider there are potentially significant benefits that would be brought about from the introduction of a SO-TO mechanism. There is the potential for a more efficient trade off of costs between the SO and TOs which could be passed on to consumers. We have seen a number of examples from the TOs and SO where future actions could lead to estimated system cost savings of many times more than the cost of the TO taking those actions (for example, an expenditure of around £50k leading to estimated savings of £950k).

14. As the electricity system develops, and its challenges evolve, we anticipate greater dependency between the actions of those parties building and maintaining the system, and those operating it. There are currently a number of schemes and initiatives with a focus on increasing coordination between the SO and TOs. An SO-TO funding mechanism would help contribute to that aim of increased coordinated working, and consequently in achieving more efficient outcomes for consumers.

15. Introducing the mechanism from April 2017 may also allow some learnings from experience with the mechanism to be factored into our fundamental review of the SO incentives arrangements from spring/summer 2018.

Drawbacks

16. There are also a number of potential risks in delivering a funding mechanism. For example, there is a risk that it could encourage less cooperation between the SO and TOs when developing their outage plans, which could result in efficiencies being lost in the planning stage. However, we would still expect close cooperation between the parties in the development of outage plans under the NAP, and would ensure that our approval process challenged any inefficient planning and ensured value for money.

17. In order to quantify the savings that additional TO actions have, outturn costs need to be compared with the costs that would have been spent had the TO not incurred additional costs from taking additional actions. There is a difficulty in calculating the counterfactual savings resulting from additional TO actions, meaning that – depending on the design on the mechanism and the SO incentive arrangements that apply – there a risk of actions being funded which do not increase overall system efficiency or result in the SO being unfairly rewarded or penalised.

18. It is relatively simple to calculate the overall GB outturn constraint costs that the SO has incurred in balancing the system within a certain period. It is more challenging assessing what the counterfactual constraint costs would have been had the TO not have taken any additional actions. This has been our experience in relation to BSIS, where it is harder to quantify an individual action.

Question 9: Do you agree that there is a need for a mechanism that allows the SO to exchange funds with the TOs? Are there any additional pros and cons that we should consider in our analysis? Do you agree it should be introduced from April 2017?

Types of mechanism

19. Before discussing the specifics of the mechanism it is important to set out our preferred approach. We consider that the SO is the party best placed to identify and determine potential total system cost savings. The SO currently uses a number of tools and mechanisms to manage the system, for example signing long term contracts with generators. We envisage that this funding mechanism will provide an additional tool that the SO can use to operate the system efficiently and economically.

20. Our preferred option is to allow the SO to access a pot of money, equivalent to the ~£1.4m currently available under the licence and STCP 11-3. This money would be available to the SO to fund TO works where there is an economic rationale for doing so, and would consider projects further out than the near term (within-year). Ofgem would have oversight of projects that exceeded a predetermined level of costs.

21. We anticipate that the process could be similar to that under the current STCP 11-3, where Ofgem wouldn't need to sign-off of every individual project, considering

the projects costs were below a threshold. Appropriate incentives would need to be placed on the SO through the licence to induce behaviours that lead to total system cost savings and efficient outcome for consumers.

22. Over the course of 2016, we have discussed the need for a mechanism with the SO and the TOs. As part of these discussions, two options have been proposed and developed that we would like stakeholder's views on: a codified, and a contractual approach. Our preferred approach is the codified approach, but welcome views on both approaches developed to date. The following section will provide a high-level overview of the two frameworks, and provide an assessment of the respective frameworks pros and cons.

Codified approach

23. In coordination with the TOs, we have developed a codified proposal broadly in line within the existing regulatory framework. The SO and TOs currently coordinate actions via both the STC and the NAP, and this proposal builds on those. Under this proposal the SO and TOs would look to introduce a new STC procedure (likely STCP 11-4), which would allow the SO to transfer funds to the TOs for works carried out from the within-year stage until 2021, for economic reasons.

24. Under the procedure, either the SO or the TOs, would identify actions that the TO could take that results in system savings. The SO would undertake further analysis to determine the level of potential savings and would decide whether to fund the TO for carrying out that action. If instructed, the TO would then carry out the work and the SO would transfer funds to the TO on completion of the works.

25. The codified approach builds on the existing regulatory framework. It would be relatively simple to incorporate these changes into the existing structure and would cause little disruption with existing processes. The codified approach would be flexible enough to accommodate a range of TO actions.

26. However, the codified approach is more prescriptive and potentially lacks the flexibility associated with the contracting approach, as the STC has more legal processes involved with it. When National Grid procures balancing services, this is done on a more flexible contractual basis. Choosing to develop a codified approach for this mechanism carries the risk of representing a departure from the contractual arrangements used under balancing services.

Contractual approach

27. We have also explored the potential of using a contractual approach that would sit outside of the current regulatory framework. The emphasis of this approach would be for Ofgem to establish a broad framework that the mechanism would sit within, and for the SO and the TOs to come to an agreement on the specificities through contractual negotiation. Determining which parties bear what level of risk, potential risk premiums, provisions for non-delivery, and general arrangements would all be agreed and set out through a contract between the SO and the relevant

TO in a bespoke (and potentially on a case-by-case) basis. This approach would not be subject to the same regulatory approval by Ofgem.

28. A contractual approach would provide the SO and the TOs the flexibility to negotiate innovative agreements, and would be able to accommodate a range of TO actions. Ofgem would be able to take a more hands-off approach, getting involved only in capital intensive works where the level of costs exceeded a certain level.

29. However, the contracting approach raises questions around the appropriate allocation of risk. It would be crucial that the SO and the TOs were able to agree which parties bear what level of risk. It might be difficult for the SO and TOs to agree on an allocation of risk in delivering the project that both parties approve.

30. During the development of these two options, the Scottish TOs have expressed a preference for the codified approach. They considered that the codified approach was the most appropriate framework for implementing the mechanism as it provides most certainty with respect to the process. Sitting in the existing framework, the codified approach would set out the explicit obligations on each of the parties and details of the mechanism, rather than leaving them to negotiation and uncertainty each time the mechanism were triggered.

31. At this stage, we have a preference for the codified approach. We consider that the codified approach would provide sufficient flexibility to accommodate a range of outages and projects, while providing more certainty around the process. We also consider that the codified approach would be beneficial to consumers as long as there are appropriate incentives on the SO to only take efficient actions. However, we welcome stakeholder views on this preference.

Question 10: Do you agree with the codified-approach?

Mechanism Features

32. In this appendix we have outlined the potential need for a SO-TO mechanism and have explained what the mechanism could look like at a high level. There are a number of important considerations that would have to be taken into account when developing the more detailed features of the mechanism and these are set out below.

Engineering

33. There are a number of actions that the TO can take that have an impact on the SOs system costs. If the SO were able to influence these actions, they would be able to influence the level of system costs that are then passed on to consumers. We have identified three broad classes of actions that could fall under the remit of this mechanism.

34. **Moving and compression of outages** – Outages can have a significant impact on constraint and curtailment costs, especially during periods of high wind generation. If the SO was able to instruct and fund the TO to move an outage, the SO could save significant amounts of money in constraint cost savings. Similarly, compressing the hours of an outage could also result in constraint cost savings. For example, shortening an outage from five 8 hour days, to four 10 hour days.

35. **By-passes and other temporary solutions** – Temporary solutions like by-passes are another action that the TO can take to reduce constraint costs. By installing temporary by-pass circuits, the SO can avoid significant periods of time where sections of the network would have to be out of action, increasing the constraint costs.

36. **Introduction of new assets in the system** – The TOs can also invest in new capital assets, like substations, transformers, voltage compensation equipment and overhead line reinforcements. Improving the resilience of the network can reduce the SOs constraint costs considerably and could also be considered in the actions included in the mechanism.

Financial

37. In designing the mechanism, there are a number of financial considerations that need to be taken into account. This section will explore these in more detail.

38. Our current preferred approach is that the TO would agree a cost estimate of the works with the SO. Upon completion, the SO would pay the TO for the works considering that the works are delivered as agreed. The monies paid to the TO would be for the additional work, and any savings (positive or negative) would not impact the money that is paid to the TO.[13] In other words, the TO would be paid regardless of whether the SO achieves constraint cost savings or not. We consider this important as the TO has no influence over those savings so should not be exposed to either up upside or downside risk.

39. **How is that accounted for under RIIO?** Once the TO has delivered the works as agreed, the SO would transfer the funds to the relevant TO. We envisage that the SO would transfer funds to the TO via the excluded services mechanism as set out in special condition 8B of NGETs transmission licence. The excluded services mechanism is currently used for STCP 11-3 which allows SO to transfer funds to the TOs for moving outages. For consistency, we consider it appropriate to use the same mechanism.

[13] Under STCP 11-3, the TO is still payed even if it delivers the project late, i.e. there is no incentive for timely project delivery. There is the risk that this can result in constraint cost savings not being maximised.

40. **How does the SO get paid?** In order for the SO to fund TO actions, we consider that there will be two mechanisms at the SOs disposal. Under the current STCP 11-3, there is a 'pot' of circa £1.4 million that the SO can use for compensating the TO for within-year outage changes. We consider that there would be an equivalent pot available to the SO under the SO-TO funding mechanism that could be accessed for lower cost investments.

41. Initial analysis suggests that typical project costs falling within the scope of this mechanism would cost between £10,000 and £100,000. In addition, for larger investments that exceed the self-governance pot, Ofgem would need to assess and approve these costs on a case by case basis. If this mechanism is introduced, we propose to review the size of the funding pot once we have an idea of the number of projects coming forward.

42. **Impact on BSUoS?** We anticipate that the SO would receive a positive or negative incentive income similar to the current Balancing Services Incentive Scheme (BSIS) to fund the additional TO works. Current BSIS income is funded by BSUoS payments, and we consider that this is probably the appropriate means for funding this mechanism. It may be that TNUoS payments are however more appropriate for funding works under this mechanism. We welcome stakeholders' views on the most appropriate charging mechanism to fund additional TO works recognising industry's expertise in this area.

43. **Cost recovery -** There are several approaches that the SO could take to recover the cost of the TO funding through BSUoS. The levy could be spread at a flat rate across all settlement periods in the year. Under this method, the additional investment for the TO action would be spread equally across all settlement periods, regardless of which settlement periods the system cost savings are realised. This would allow for a simple methodology for apportioning the charge and the levy and would operate in a similar way to current STCP 11-3 outage change costs. However, spreading the levy across all settlement periods means all payers are charged for something that may not directly benefit them.

44. A second method, when referring to outages, would be to levy the charge across the period in which the outage was scheduled in the original plan. For example, if you were to reduce a three week outage to two weeks, then levy the charge across the initial three weeks. Again, this methodology is relatively easy to understand and calculate. However, there are difficulties in accurately assigning levy charges to the settlement periods in which the constraint payment savings are realised.

45. On the other hand, it may be more appropriate to levy the charge over the period in which the constraint payment savings are realised. On the face of it, this would be the fairest method for apportioning costs, as those parties that benefit from constraint cost savings should pay for the investment that enabled those savings to being realised. However, it can be difficult to come to an agreement on exactly when the period of benefit is, making it difficult to levy the charges over the correct settlement periods.

Question 11: What do you consider to be the most appropriate cost recovery levy methodology?
Question 12: Do you agree with the proposed approach with regard to the financial aspects of the mechanism outlined above?

Regulatory oversight and incentives

46. It is crucial that we ensure the appropriate level regulatory oversight for the funding mechanism. We consider that for small investments self-governance arrangements, like those under STCP 11-3, should be adequate in the presence of appropriate SO incentives. For investments exceeding a certain level however, we believe we should be involved in assessing and approving those costs to ensure there is scrutiny of significant costs. We would need to determine a threshold at which additional investments come to us for approval.

47. It would be important to have a threshold that is appropriate for the level of investment and risk in question. After consideration of the typical cost of works that we expect to fall under this mechanism, we believe a threshold of £1.4m in line with the current arrangements under STCP 11-3 could be appropriate.

Question 13: Do you agree with our proposed investment threshold for Ofgem approval?

48. **Incentives on the SO -** The SO is currently incentivised to incur efficient system balancing costs through BSIS. In order to ensure the SO has a financial incentive to only fund TO works which lead to overall system cost savings, the cost of these actions could also be included in the SO's financial incentive on balancing costs (assuming we continue to place financial incentives on the SO from April 2017). This would, in effect, provide the SO with another 'tool' for efficiently managing the system and to reduce costs against the modelled forecast of total BSUoS costs. If BSIS is retained in its current form from April 2017, it would be relatively easy to include this mechanism within this framework. The benefit of this approach, compared to creating a separate financial incentive, is that it would reduce the risk of the SO being rewarded twice for the same action.

49. However, if the costs for funding the SO-TO mechanism were to be included as part of the overarching financial incentive on balancing costs, there could be less transparency over the individual effectiveness of the mechanism as compared with the other tools at the SOs disposal. BSIS performance is currently assessed holistically with all measures taken contributing to the overall performance. This may detract attention from the individual performance of the mechanism.

50. On the other hand, placing a separate financial incentive on the costs involved with the SO-TO funding mechanism might encourage the SO to focus attention on working more closely with the TOs. It could be more transparent and would allow for the clear reporting of each additional action to be made. However, appropriate measures would need to be taken to ensure the SO was not rewarded twice for the same action.

Question 14: Do you think the costs incurred through a mechanism should be incentivised as part of an overarching financial target on balancing costs, or as part of a separate financial incentive?

51. We are proposing to limit the mechanism to the end of the RIIO-T1 period. We expect the SO and the TOs to work together so that the most efficient, whole system solution is reflected in the business plans for the next price control period starting in 2021. However, we will consider extending the scheme into RIIO-T2 if there is a strong case for doing so. For example, there may be projects that span both RIIO-T1 and RIIO-T2 which might be less efficient if these are treated differently under the two price control periods.

Question 15: What, if any, impact will limiting the mechanism to the end of RIIO-T1 period have on the efficiency of potential projects that cover both RIIO-T1 and RIIO-T2 periods?
Question 16: Are there any other criteria we should consider for such projects?

52. It is crucial that we ensure transparency with the proposed mechanism so that stakeholders and industry would be able to scrutinise our decisions, and those taken by the SO and TOs. We consider that for each investment or action taken by the TO there would be a robust and detailed reporting procedure that would set out the investment, forecast savings, and post-event analysis of the actual savings. For larger investments, we would expect a much more detailed and robust analysis completed by both Ofgem and the relevant stakeholders.

Question 17: What level of transparency would you want regarding this mechanism?

Changes required to existing framework

53. In order to implement the mechanism in April 2017, there would be a number of changes required to the existing codes and licences. We explore these further below.

STC – A new procedure (STCP 11-4) would need to be created to describe the mechanisms process. The STC would also need to be updated to reflect the new procedure

National Grid Special Licence Condition 4C – The new mechanism would require additional terms to reflect the new funding 'pot', the new schemes incentive revenue, and a new special condition to describe the mechanism.

Statement of use of system charges – These would need to be updated to include a definition for the new mechanism.

Excluded services – It may be necessary to introduce a new excluded service in the TOs licence to enable the SO to fund them for additional works.

Question 18: Do you consider that we have identified the changes required correctly? Are there any other changes required to the existing framework in order to implement the mechanism?

Question 19: Are there any other factors that you think we need to consider in the design of the mechanism?

Next steps

54. Subject to the conclusion of our overarching consultation on SO incentives, in order to implement the mechanism in April 2017, there are a number of steps we would need to take. In the first instance we would closely consider responses to this consultation and build on industry feedback received. Taking into account responses we aim to develop initial proposals for the SO-TO funding mechanism and plan to consult on these later in the year. After consulting on our initial proposals we would then consider the relevant licence changes and modifications to industry codes that are required.

55. We also consider that there is potential scope to work with the DNOs to establish if an equivalent mechanism could bring benefits to SO – DNO relationship. As the SO and DNOs operations increasingly overlap, and they increase the level of coordination, we need to consider if there are trade-offs to be made in this respect too. We are keen to explore the options in this area and implications for SO incentives as part of our fundamental review of the incentive arrangements from spring/summer 2018 onwards.

Appendix 2 - Consultation Response and Questions

Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

Responses should be received by 15 September 2016 and should be sent to:

- David Beaumont
- System Balancing
- 9 Millbank
  London
  SW1P 3GE
- 0207 901 7000
- SOincentive@ofgem.gov.uk

Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

CHAPTER 2: Whether to maintain the existing incentives framework

Question 1a: Should we place financial incentives on the SO in the period between 1 April 2017 and when we are in a position to implement longer term SO incentives?
Question 1b: If we maintain financial incentives from April 2017 to spring/summer 2018, should we use the existing BSIS framework?
Question 1c: Do you agree that if we maintain the existing incentives framework during this period, we should seek improvements from the 2015-17 scheme?
Please provide evidence to support your answers

CHAPTER 3: Scope of potential changes from the 2015-17 scheme

Question 3a: How could the BSIS target setting approach and modelling methodologies be improved in the short term?
Question 3b: Do you believe the existing BSIS sharing factor and cap and floor remain appropriate?

Question 4: What is the best way to set an incentive on the SO to incur efficient costs when procuring Black Start from April 2017?
Question 5a: Do you agree that we shouldn't maintain the MDLC?
Question 5b: Do you agree that we shouldn't maintain the SO IRM? Are there any alternative ways to encourage innovative behaviour from the SO in the short term?
Question 6a: Do you believe there is a need for a new incentive on short term demand forecasts from April 2017? How could this be designed? What timescales should it be based on: week ahead, day-ahead, hour-ahead, other?
Question 6b: Do you think there needs to be any changes to the wind generation forecasting incentive or new incentives on any other system forecasts?
Question 7: Do you think the SO's procurement of balancing services needs to be more transparent and open? If so, what steps should be taken? Should the SO pursue more market-based approaches? Should we introduce any incentives or requirements on the SO in this area from April 2017?
Question 8: Do you agree with our proposed scope of changes? Is there anything else you believe should be changed, added or removed from the existing scheme?

APPENDIX 1 – Consultation on SO-TO mechanism

Question 9: Do you agree that there is a need for a mechanism that allows the SO to exchange funds with the TOs? Are there any additional pros and cons that we should consider in our analysis? Do you agree it should be introduced from April 2017?
Question 10: Do you agree with the codified-approach?
Question 11: What do you consider to be the most appropriate cost recovery levy methodology?
Question 12: Do you agree with the proposed approach with regard to the financial aspects of the mechanism outlined above?
Question 13: Do you agree with our proposed investment threshold for Ofgem approval?
Question 14: Do you think the costs incurred through a mechanism should be incentivised as part of an overarching financial target on balancing costs, or as part of a separate financial incentive?
Question 15: What, if any, impact will limiting the mechanism to the end of RIIO-T1 period have on the efficiency of potential projects that cover both RIIO-T1 and RIIO-T2 periods?
Question 16: Are there any other criteria we should consider for such projects?
Question 17: What level of transparency would you want regarding this mechanism?
Question 18: Do you consider that we have identified the changes required correctly? Are there any other changes required to the existing framework in order to implement the mechanism?
Question 19: Are there any other factors that you think we need to consider in the design of the mechanism?

Appendix 3 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk